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

2026-09-21

Newfoundland and Labrador Hydro
Shirley Walsh
Email: shirleywalsh@nlh.nl.ca

Dear Ms. Walsh:

Re: Newfoundland and Labrador Hydro - 2026 General Rate Application - To NLH - Requests for Information - 2nd Round

Enclosed are Requests for Information PUB-NLH-126 to PUB-NLH-188 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
Mike McNiven
Board Secretary

MM/cj

ecc **Newfoundland and Labrador Hydro**
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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-NLH-126 to PUB-NLH-188

Issued: September 21, 2026

<u>Test Year Revenue Requirement</u>

PUB-NLH-126 Response to PUB-NLH-008, Table 1

Hydro states that its next rate setting year will be 2031. Explain how approval of the proposed rates would be in compliance with the legislative requirement that approved rates "should provide sufficient revenue to the producer or retailer of the power to enable it to earn a just and reasonable return as construed under the *Public Utilities Act* so that it is able to achieve and maintain a sound credit rating in the financial markets of the world".

<u>Test Year Supply and Supply Cost Forecast</u>

PUB-NLH-127 Response to PUB-NLH-039

Provide Hydro's forecast labour and resource plan for the period 2026-2030, including:

a) A list of all major capital projects planned, underway, or expected to be completed during the period, including the anticipated start and completion dates for each project.
b) For each project, the forecast capital expenditure and identification of whether the project is regulated or non-regulated.
c) For each project, the forecast staffing requirements, including a breakdown of: internal Hydro resources; external contractors and consultants; and specialized third-party resources.
d) A description of how Hydro prioritizes and allocates labour and other resources among competing regulated and non-regulated capital projects.
e) Identification of any forecast resource constraints, labour shortages, or competing project demands that could impact the timing, cost, or execution of regulated capital projects over the 2026-2030 period.

<u>Industrial Customer Rate Change and Rate Structure</u>

PUB-NLH-128 Volume I, Section 6.7; Exhibit 17

a) Identify the rate-design principles used to evaluate the proposal and describe how the principles were balanced and evaluated (i.e. economic efficiency, cost causation, revenue adequacy, bill stability, fairness, and simplicity).
b) Identify any resources used by Hydro or CA Energy in concluding that an hours-of-use rate design is appropriate for the Island Industrial class (i.e. economic literature, regulatory precedents, or other authorities).
c) Explain why an hours-of-use design provides a superior price signal for this customer class relative to a conventional demand-and-energy rate.

d) Explain why Hydro did not consider a demand charge based on coincident peak to account for the importance of timing of peak demand in driving system demand costs.

e) Explain why Hydro did not introduce time-varying elements to this rate design to improve the efficiency of price signals given the importance of grid utilization timing in achieving net benefits.

PUB-NLH-129 **Volume I, Section 6.7.1**

The 2027 Test Year average embedded demand cost for Island Industrial customers is $17.54/kW per month. Hydro proposes a demand charge of $5.50/kW-month which will recover approximately 31 percent of embedded demand costs, with the remainder through the first-block energy charge.

a) Explain why the proposed approach is more efficient than a cost reflective rate with a demand charge of $17.54/kW-month.

b) What type of customer behavior impacts can be produced or expected by not reflecting the full demand-related cost in the demand charge?

PUB-NLH-130 **Volume I, Sections 6.7.1 and 6.7.2**

Hydro proposes a first-block rate of 6.694¢/kWh after selecting the $5.50/kW-month demand charge and the 300-hour block boundary. The Application states that the first-block price is intended to recover the remaining revenue requirement after the demand charge and second-block rates have been determined.

a) Identify the amount of generation demand, transmission demand, energy-related fixed costs, and any other costs recovered through the first-block rate.

b) Quantify any marginal energy costs recovered in the first-block rate.

c) Explain the economic basis for recovering demand-related costs through a volumetric kWh charge whose revenues vary with energy consumption.

d) Quantify the change in Hydro's recovery of demand-related costs if Island Industrial energy consumption differs from forecast by plus and minus 5 percent while customer peak demands remain unchanged.

e) Explain how any resulting over- or under-recovery would be treated.

PUB-NLH-131 **Volume I, Section 6.7.3; Table 6-7; Exhibit 17**

Hydro states that the second-block energy price is based on forecast export prices and reflects the opportunity cost of the market value of exports. The proposed rates are 8.889¢/kWh for December through March and 3.285¢/kWh for April through November.

a) Provide the complete derivation of each seasonal second-block price including the hourly market price data, customer load profiles, loss factors, exchange rates, and any other adjustments used.

b) Identify the market hub or pricing point represented by the export-price forecast and the source and vintage of the forecast.

PUB-NLH-132 **Volume I, Section 6.7.3; Table 6-7; Exhibit 17**

Hydro proposes two seasonal second-block prices, one for December through March and another for April through November, notwithstanding that the underlying marginal energy values vary by hour and by month.

a) Explain the economic rationale for averaging hourly or monthly marginal energy costs into two seasonal prices.

b) Provide the load-weighted marginal cost for each month of the Test Year for the Island Industrial class.

c) Provide the annual quantity of second-block consumption occurring in each month and the weighting methodology used to derive the seasonal rates.

d) Quantify the difference between revenues and customer bills under the proposed two-season design and under monthly marginal-cost-based second-block prices.

e) Explain if Hydro considered time-of-use or other temporal differentiation within the winter and non-winter seasons and provide any analysis performed.

f) Explain the criterion Hydro used to determine that the efficiency gain from additional temporal differentiation did not justify the associated complexity.

PUB-NLH-133 **Volume I, Section 6.7; Exhibit 17**

a) Did Hydro or CA Energy model any customer demand response to the proposed rate design? If yes, provide the price elasticity, load-shifting, peak-demand response, production response, or other behavioral assumptions used and identify the supporting source for each.

b) Provide Hydro's estimate of the change in peak demand and annual energy consumption expected as a result of the proposed rate design and explain how such changes have been reflected in Hydro's load forecast, revenue forecast, or resource planning.

PUB-NLH-134 **Volume I, Section 6.7; Exhibit 17; 2019 Wholesale and Island Industrial Rate Design Review Update Report**

a) Describe and compare all materially different rate designs considered by Hydro or CA Energy in developing the proposal including:

(i) proposed rate parameters, class revenue recovery, customer-specific annual bill impacts, and percentage of consumption exposed to marginal-cost pricing;
(ii) criteria and weights used to compare the alternatives; and
(iii) explanation why the proposed design was preferred to each alternative.

b) Which features of the proposed rate does Hydro consider essential to achieving efficient pricing and which are primarily intended to address revenue recovery, bill impacts, or administrative considerations.

c) Provide any quantitative scorecard, decision matrix, memorandum, presentation, or other analysis used by Hydro or CA Energy to select the proposed design.

PUB-NLH-135 **Response to PUB-NLH-047**

a) Provide the data for each of the past 10 years identifying how often Corner Brook Pulp and Paper has utilized Generation Outage Power.

b) Please describe the compensation provided to Hydro for the provision of Generation Outage Power and provide illustrative calculations.

PUB-NLH-136 **Responses to PUB-NLH-050 and PUB-NLH-051**

a) Given the availability of Generation Outage Power to Corner Brook Pulp and Paper and the frequency in which its demand requirements exceed its Power on Order, would it be reasonable for Corner Brook Pulp and Paper to pay stand-by charges? Explain.

b) Explain the methodology typically used to derive stand-by charges.

PUB-NLH-137 **Response to PUB-NLH-060**

Provide the non-firm volumes and revenues for 2025 and 2026 separately for the Labrador Non-firm customers and the Island Industrial customers. For the Island Industrial Customers, separate the data for non-firm sales reflecting supply using hydraulic production versus supply using thermal production.

PUB-NLH-138 **Response to PUB-NLH-061**

Would Hydro consider it reasonable to modify the liquidated damages provision in the service agreements and use a demand charge more reflective of the embedded demand cost from the 2027 Test Year Cost of Service Study (net of mitigation) to reduce the risk of demand revenue loss from the departure of an Island Industrial Customer? Explain.

<u>Rural Deficit</u>

PUB-NLH-139 **Response to PUB-NLH-063**

Has Hydro explored if Federal Government funding would be available to support infrastructure projects that could have a material load impact on an isolated system in indigenous communities? Does this type of program exist in in other Canadian provinces? Explain.

PUB-NLH-140 **Response to PUB-NLH-064**

Provide the basis for the projected purchase price for Hydro's energy purchases from the Nain Wind Micro-grid project.

<u>Export Forecast, Export Revenue and Opportunity Cost</u>

PUB-NLH-141 **Response to PUB-NLH-070**

When does Hydro plan to file its long-term ponding agreement with the Board?

<u>Long Term Supply Cost Variance Deferral Account</u>

PUB-NLH-142 **Response to NP-NLH-110**

NP-NLH-110 provides the existing Supply Cost Variance Deferral Account and the Long-Term Supply Cost Variance Deferral Account by component and by month for 2027, and the existing account at December 31, 2026.

a) Provide the forecast Long-Term Supply Cost Variance Deferral Account balances by component and by month for 2028 through 2030.

b) Restate NP-NLH-110, Attachments 1 and 4 to reflect the transfer of approximately $45 million of the Rural Rate Alteration balance to Newfoundland Power Inc. approved in Order No. P.U. 15(2026). Provide the additional rate mitigation required and the effect on the balance transferred to the Long-Term Supply Cost Variance Deferral Account.

c) Explain why each supply cost variance component of the Long-Term Supply Cost Variance Deferral Account is forecast at zero throughout the Test Year at NP-NLH-110, Attachment 2, while NP-NLH-110, Attachment 3 forecasts material variances in the same components, including a Holyrood Thermal Generating Station fuel cost variance of $129,709,981 and a net revenue from exports variance of $40,178,592 for the year. Provide the Long-Term Supply Cost Variance Deferral Account computed on the variance assumptions used in Attachment 3.

d) Reconcile the transfers out of the existing Supply Cost Variance Deferral Account in March 2027 ($63,974,591 for utility customers and $12,062 for industrial customers at NP-NLH-110, Attachment 1) with the transfers into the Long-Term Supply Cost Variance Deferral Account (NP-NLH-110, Attachment 2, $59,091,893 and $2,605,778) identifying every difference in amount and in timing.

e) Provide Hydro's current and forecast short-term borrowing rate for 2027 through 2030, and the annual revenue requirement difference per $100 million of balance between financing at that rate and at the approved weighted average cost of capital of 4.88 percent.

<u>Deferral Accounts Excluding Long-Term Supply Cost Variance Deferral Account</u>

PUB-NLH-143 **Responses to PUB-NLH-097, PUB-NLH-099 and PUB-NLH-100**

a) Confirm that capital additions relating to the Holyrood Thermal Generating assets that are subject to the accelerated depreciation are included in rate base when the capital addition is placed in service and that rate base is reduced by the accumulated depreciation relating to these assets.

b) Assuming that the balance in the deferral account is forecast to be owing from customers, does this mean that Hydro is earning on these assets again?

c) Explain why Hydro is requesting to include this deferral account in rate base.

d) Has Hydro considered whether a carrying charge/credit would be appropriate for this deferral account instead of including it in rate base? Explain why or why not.

e) If there is a future extension to end of steam generation past March 31, 2030, will there be a true-up/adjustment of depreciation for the assets that have been subject to accelerated deprecation based on March 31, 2030? Explain the process Hydro will use if a future extension were to occur and how would it impact the deferral account.

PUB-NLH-144 **Responses to CA-NLH-099 and PUB-NLH-095**

a) In response to CA-NLH-099, Hydro stated that it earns a return on the Muskrat Falls and Labrador Transmission Assets sustaining capital costs that have been included in rate base pursuant to Board Order No. P.U. 33(2021). Confirm that the Board did not approve inclusion of deferral account in rate base and clarify whether or not Hydro has earned a return on rate base since this account was approved in Order No. P.U. 33(2021).

b) Both the Board and the Consumer Advocate requested confirmation on whether Hydro will be earning a return on the Muskrat Falls Sustaining Capital Deferral Account, which represents capital work on assets that are not under the Board's jurisdiction. Explain Hydro's rationale for deciding that it is appropriate for Hydro to be earning a return on these assets when Hydro Regulated has limited control over the approval of the sustaining capital relating to Muskrat Falls and the Labrador Transmission assets.

c) Has Hydro considered whether a carrying charge would be appropriate for this deferral account instead of including it in rate base? Explain why or why not.

Power Service Arrangements with Corner Brook Pulp and Paper Limited

PUB-NLH-145 **Response to PUB-NLH-110, Attachment 2**

The winter price for the cogeneration purchases from Corner Brook Pulp and Paper is 14 cents per kWh which reflects an energy and capacity payment. Explain the basis for the capacity payment for co-generation purchases given Hydro already has a capacity assistance agreement with Corner Brook Pulp and Paper.

PUB-NLH-146 **Response to PUB-NLH-114**

a) Given that "Hydro's current energy purchase agreement with Corner Brook Pulp and Paper does not provide Hydro with a contractual right to capacity", explain why Corner Brook Pulp and Paper was not requested to provide capacity assistance in January 2026 when the Bay d'Espoir generating station capability was severely limited due to frazzle ice conditions.

b) Confirm that during this period Hydro continued to make energy purchases under the Corner Brook Pulp and Paper energy purchase agreement.

c) Explain how the January 2026 capacity shortage incident demonstrates that capacity assistance agreements receive priority over energy purchase arrangements with Corner Brook Pulp and Paper.

Rural Reliability

PUB-NLH-147 **Response to PUB-NLH-117**

a) How many of Hydro's distribution feeders are equipped with reclosers that are remotely monitored through its SCADA system? In the response provide the actual number in service at the end of 2025, the number planned for completion in the approved 2026 Capital Budget Application and the number planned for completion in the 2027 Capital Budget Application. Also, include the total number of distribution feeders in Hydro's various distribution systems.

b) How many of Hydro's reclosers that are remotely monitored through its SCADA system are located downstream from Hydro's substations allowing for the sectionalizing of feeders remotely to reduce the number of customers impacted by equipment failure?

PUB-NLH-148 **Response to PUB-NLH-117**

With respect to Secure Remote Access, provide examples where Hydro is currently implementing solutions that have resulted in improved service restoration.

PUB-NLH-149 **Response to PUB-NLH-117**

With respect to SCADA Network Upgrades, provide examples where Hydro is currently implementing solutions that involve remote operation of downstream devices that have resulted in improved service restoration.

PUB-NLH-150 **Response to PUB-NLH-117**

How many customers are served by the remotely monitored and controlled reclosers at Upper Salmon Generation Station, Hampden Terminal Station and Jackson's Arm Terminal Station?

PUB-NLH-151 **Response to PUB-NLH-117**

What is Hydro's plan to deploy the new genset dispatch technology in its remaining diesel communities?

PUB-NLH-152 **Response to PUB-NLH-117**

Explain how the Thunderstorm Management Cloud Service is deployed throughout Hydro and which employees have access to the technology?

PUB-NLH-153 **Response to PUB-NLH-117**

Has Hydro considered the impact of the volume of information increases on the Energy Control Centre operators and what measures are being put into place to prioritize the more granular information available to ensure key system events are not missed? In the response, address alarm fatigue and the additional distribution information now being presented to the operators.

PUB-NLH-154 **Response to PUB-NLH-117**

a) Provide a complete list of all transmission lines and power transformers that have been upgraded with modern digital multifunction relays.

b) In addition to transmission lines and power transformers, have similar modern digital multifunction relays been deployed by Hydro on distribution feeders and rural systems? If yes, provide a list of all distribution systems that have been upgraded with modern digital multifunction relays.

PUB-NLH-155 **Response to PUB-NLH-117**

a) Does Hydro currently have, or plan to implement, an outage management system to work with the nine technology solutions identified to further enhance customer outage response?

b) What is Hydro's plan for distribution automation beyond the reclosers located in substations? In the response, discuss any reports or studies undertaken by or for Hydro to explore the potential benefits for distribution automation in Hydro's rural distribution systems.

PUB-NLH-156 **Response to PUB-NLH-118**

a) Provide additional SAIDI and SAIFI charts for each of the requested geographic location that include the (i) the specific location data, (ii) Hydro's system comparator, (iii) the CEA comparator and (iv) Newfoundland Power's comparator.

b) For each geographic location discuss Hydro's performance compared with each of the other three comparators and how the nine technology solutions identified in the response to PUB-NLH-117 (a) are being used to improve customer outage response.

PUB-NLH-157 **Response to PUB-NLH-120, Attachment 1**

Does Hydro assess high risk assets for routine maintenance opportunities or inclusion in in-service failures program that may be able to be performed more quickly?

PUB-NLH-158 **Response to PUB-NLH-121**

Table 1 identifies multiple locations where Protection Relay Replacement will be completed. Will these replacements involve new modern digital multifunction relays with communications capability? If yes, describe any enhancement in the data being provided by these replacement relays and any impact this might have on customer outage response.

PUB-NLH-159 **Response to PUB-NLH-122**

a) Hydro states that new reclosers, gang switches and sectionalizers were recently installed in L'Anse-au-Loup, Farewell Head, Bottom Waters and two new reclosers are planned for English Harbour West. Are any of these devices equipped with communications capability and are they currently connected to Hydro's SCADA system?

b) What is Hydro's approach, including timelines, to placing purchased equipment with communications capability into service?

c) Does Hydro have access to Newfoundland Power's mobile substations and mobile generators when necessary? If yes, explain the equipment sharing arrangements currently in place between Hydro and Newfoundland Power that makes mobile substations and mobile generators available to Hydro when necessary.

PUB-NLH-160 **Response to PUB-NLH-123**

a) For each of the Assets identified in Table 1, provide the list of actual transmission, distribution, substation and terminal station equipment (i.e. breakers, reclosers, voltage regulators, tap changers, disconnect switches, etc.) that are currently able to be remotely monitored and controlled from the Energy Control Centre.

b) For the period from 2021 to 2025, provide a table identifying each time that the diesel generator backup units at St. Anthony Diesel Plant and

Hawke's Bay Diesel Plant were remotely started and stopped, the reason for the remote operation and the duration for each event.

c) Does Hydro have other diesel generator backup units other than St. Anthony Diesel Plant and Hawke's Bay Diesel Plant? If yes, provide a list of these other diesel generator backup units including what if any equipment is remotely monitored and controlled from the Energy Control Centre. If not, what are Hydro's plan to extend remote monitoring and control to these diesel generator backup units?

d) Hydro states that the ability to remotely control distribution equipment will improve outage response times. Provide Hydro's estimate for the potential improvement for each of the reliability indices provided in Charts 1 and 2 in the response to PUB-NLH-118 when a broad deployment of remotely control distribution equipment has been completed.

PUB-NLH-161 **Response to PUB-NLH-124**

How does Hydro ensure that indices used to prioritize feeder projects do not negatively impact smaller rural feeders with poor reliability performance from being included in the annual Upgrade Worst-performing Distribution Feeders?

<u>Cost of Service Methodology – Classification of Wind</u>

PUB-NLH-162 **PUB-NLH-103(a) and (b); CA-NLH-146 and Attachments 1 and 2; Exhibit 16; Volume I, Section 6.3.1**

a) Provide the average Effective Load Carrying Capability calculation of the existing 54 MW of wind capacity, expressed as a percentage.

b) If Hydro maintains that the average does not differ significantly from the marginal value at 50 MW, reconcile that position with the declining marginal Effective Load Carrying Capability curve in Exhibit 16, which falls from 43 percent at 50 MW to 38 percent at 100 MW.

c) Provide an Effective Load Carrying Capability for the existing 54 MW computed against the 2027 Test Year system with Holyrood TGS in service.

PUB-NLH-163 **Response to PUB-NLH-103(b)**

a) Explain why a marginal capacity value computed for planning purposes on a 2032 system is an appropriate classifier for an embedded cost incurred on the 2027 system.

b) Identify any other resource in the Cost of Service study whose classification is set by a capacity value study.

PUB-NLH-164 **Response to PUB-NLH-108(b)**

Reconcile Hydro's use of an Effective Load Carrying Capability measure to classify wind with its position at PUB-NLH-108(b) that an Effective Load

Carrying Capability based measure is outside the scope of a capacity credit calculation for Newfoundland Power hydraulic generation.

PUB-NLH-165 **Responses to CA-NLH-146 and PUB-NLH-005, Table 3**

Restate both attachments in CA-NLH-146 with rate mitigation recalculated in the three-line format used at PUB-NLH-005, Table 3.

PUB-NLH-166 **Volume I, Section 6.3.1; Responses to PUB-NLH-084, Attachment 1; PUB-NLH-088(d); and CA-NLH-146**

In relation to the St. Lawrence and Fermeuse wind purchase agreements:

a) Confirm or correct the following
   (i) payment to the Seller is a function solely of the Energy purchased in the month;
   (ii) neither agreement provides for a capacity charge, an availability payment, or a fixed annual payment; and
   (iii) Hydro incurs no payment obligation under either agreement in a month in which no Energy is delivered. If not confirmed, identify the provision that addresses payment and state the amount that would be payable in a month of no delivery.

b) Provide Appendices A, B, C and E, to each of the St. Lawrence and Fermeuse agreements.

c) Provide the Commercial In-Service Date of each facility and the resulting expiry date of the twenty-year Term defined at Article 1.01.

d) Advise of any amendments or assignments of each agreement.

e) State whether Hydro has exercised, or intends to exercise, the option at Article 9.01 of either agreement to acquire the facility. If it has not, state the reason.

f) Reconcile Article 2.01, which obliges Hydro to pay for Energy made available or capable of being made available, with Article 2.02, which computes the monthly payment on the Energy purchased in the month, and with Article 6.12, which permits either party to interrupt the supply or receipt of Power and Energy without penalty or liability for damages.

g) Advise whether Hydro has at any time paid for curtailed energy under either agreement; and provide the curtailment history of each facility by year and by cause, distinguishing curtailment taken under Articles 6.07 and 6.12 from curtailment taken for any other reason.

h) Explain how a payment obligation that varies solely with delivered energy supports classification of any portion of either purchase as demand-related.

i) Identify the demand-related cost that the 22 percent demand classification (CA-NLH-146) is intended to capture and state whether Hydro's position is that an effective load carrying capability measure describes the causation of cost rather than the contribution of the resource to reliability. Confirm if this rationale also applies to the treatment of purchases in the Long-Term Supply Cost Variance Deferral Account under PUB-NLH-088(d).

Cost of Service Methodology – Rate Mitigation

PUB-NLH-167 Response to PUB-NLH-005

a) Describe the mechanism by which Newfoundland Power's Test Year rate change is held constant as cost of service allocations change and identify the instrument that fixes the rate change, including Order in Council OC2024-062 if applicable, and the provision that authorizes the offsetting adjustment to the project cost recovery rider.

b) State whether Newfoundland Power's net revenue requirement is itself fixed for the Test Year, confirming or correcting the description of the third line of PUB-NLH-005, Table 3 as returning Newfoundland Power to a capped revenue requirement of $636,815,801.

c) From CA-NLH-146, the rate mitigation amounts for Newfoundland Power, Island Industrial, and Rural Island Interconnected customers sum to $501,963,983. State whether the $501,963,983 is an input to the calculation or a residual produced by it. Identify which quantity is held constant when allocations change (i.e. rate change, project cost recovery rider rate, or the rate mitigation draw). Provide the basis by which a reduction in the mitigation applied to one class is reflected in the others. Reconcile why the total mitigation fell by approximately $8.9 million in the sensitivity at PUB-NLH-005, Table 3 while it is identical in both runs at CA-NLH-146.

d) State the share of any change in allocated cost that reaches the rates of each class after the mitigation adjustment, and provide the calculation.

e) When the project cost recovery rider is adjusted to hold a class's rate change constant following a change in its allocated cost, identify what absorbs the difference (i.e the rate mitigation draw, Hydro, or another class). Provide the calculation for an assumed increase and decrease of $1 million in Newfoundland Power's allocated cost.

Cost of Service Methodology – Holyrood Thermal Generating Station

PUB-NLH-168 Responses to PUB-NLH-102(c), (d), and (e); IIC-NLH-022(b) and (c) and Attachment 1; CA-NLH-154; CA-NLH-159(a) and (c); PUB-NLH-084, Attachment 1; PUB-NLH-005, Table 3

IIC-NLH-022(b) states that approximately 455 GWh of Holyrood TGS production is forecast in the 2027 Test Year. The minimum generation commitment is 424 GWh annually and 31 GWh can be dispatched above that commitment to meet peaking demand. PUB-NLH-102(c) states that the Holyrood TGS forecast production in the 2027 Test Year is directly attributable to operating the units at minimum stable output for reliability purposes only.

a) Reconcile the two statements and explain if 100 percent of Test Year Holyrood TGS fuel consumption is caused by the requirement to keep units available for reliability.
b) Provide the barrels of No. 6 fuel and the fuel cost corresponding to the 424 GWh and to the 31 GWh separately, by month, and state the heat rate assumed for each.
c) Provide a detailed breakdown of the minimum generation commitment schedule in CA-NLH-159(a) showing the derivation of the 424 GW and confirming that the residual 31.6 GWh is dispatch above minimum stable output.
d) Provide a revised Schedule F classifying the fuel associated with the minimum generation commitment as demand-related and the balance as energy-related, with the resulting class cost of service and class revenue requirement, and with rate mitigation recalculated.

PUB-NLH-169 **Responses to PUB-NLH-102 and IIC-NLH-002**

a) Reconcile the statement "the likely small share of fuel costs, which limits the cost allocation impacts of moving to demand-related allocation" with the $65.0 million of Test Year No. 6 fuel cost and with IIC-NLH-022(c), which reports that classifying that fuel on the capacity factor reduces Island Industrial cost responsibility by approximately $2.4 million, or 5.5 percent of that class's cost of service.
b) At what impact would Hydro consider the classification as material?
c) Explain if it is Hydro's position that consideration of past practice and materiality displace cost causation where the two point in different directions.
d) Provide the class effect of classifying as demand-related the $2.23 million fuel cost increment identified at PUB-NLH-102(e) as arising from the 563-kWh-per-barrel conversion factor relative to the 2019 Test Year value of 583 kWh per barrel, and confirm that Hydro attributes that increment to running units at minimum output for reliability purposes.

PUB-NLH-170 **Response to PUB-NLH-084**

Explain why combustion turbine fuel and diesel fuel are classified as demand-related at PUB-NLH-084, Attachment 1, while Holyrood No. 6 fuel is classified as 100 percent energy-related.

PUB-NLH-171 **Volume I, Section 6.2.2; Schedule F 4.3; Exhibit 4; Exhibit 14, note 2; Responses to PUB-NLH-101; PUB-NLH-102(a) and (b); PUB-NLH-037(b); CA-NLH-159(a) and (f); IIC-NLH-022(a); IIC-NLH-016**

The method for determining capacity factor appears to be inconsistent on the record:

- PUB-NLH-102(a) states the capacity factor formula as forecast net production divided by the product of net capacity and hours in a year and computes 455,225,658 kWh divided by the product of 466,000 kW and 8,760 hours, or 11.16 percent.

- Exhibit 14, footnote 2 describes the method as dividing net production by the product of capacity and hours in service. The unit commitment schedule at PUB-NLH-037(b), commits Holyrood TGS units on 167 days of the Test Year which, computed on hours in service, results in a capacity factor of approximately 24.4 percent on a plant basis and approximately 47.5 to 49.7 percent on a committed unit-capacity basis.

a) Confirm or correct each of the two computations described above, showing the arithmetic.

b) Explain what "hours in service" means for this purpose.

c) Confirm that minimum stable output is 70 MW per unit and 50 MW per unit from March 15, as implied in the 817.2 GWh figure at CA-NLH-159(c).

d) Provide the Test Year forecast of hours committed, hours synchronized, and hours at or above minimum stable output, by unit.

e) Reconcile the description of the method at Exhibit 14, footnote 2 with the calculation performed at Schedule F 4.3 and stated at PUB-NLH-102(a), and state which of the two Hydro regards as the method in use.

f) Confirm that the 2019 Test Year capacity factor of 15.74 percent reported at PUB-NLH-102(a), Table 1 was computed on an 8,760-hour denominator and provide the 2019 Test Year net production and net capacity.

g) Reconcile the net capacity of 466 MW used in the capacity factor calculation with the firm capacity of 490 MW in three units reported at Exhibit 4.

PUB-NLH-172 **Volume I, Section 6.2.2; Exhibit 14; Responses to PUB-NLH-082; PUB-NLH-102(c); and CA-NLH-159(a), (b), (d), and (e)**

Exhibit 14 recommends that the third Holyrood TGS unit be classified separately from Units 1 and 2, and premises its endorsement of the existing method on Units 1 and 2 operating at higher capacity factors than in recent years.

a) Reconcile the Exhibit 14 premise with the 2027 Test Year forecast capacity factor of 11.16 percent, which is the lowest in the record and below the 15.74 percent of the 2019 Test Year.

b) Did Hydro adopt the recommendation to classify the third unit separately? If no, explain why not in light of the statement that the third unit is offline but available throughout the Test Year.

c) Provide the class revenue requirement effect of classifying the third unit as 100 percent demand-related and the remaining two units on their own capacity factors, with rate mitigation recalculated.

d) Identify any classification methods Hydro considered for Holyrood TGS production plant other than the capacity factor method and explain why it was not adopted (i.e. peak credit, equivalent peaker method, separate treatment of standby capacity).

e) Has CA Energy reviewed the 2027 Test Year forecast since the July 30, 2025 memorandum? If yes, provide the results of that review.

PUB-NLH-173 **Response to CA-NLH-159 (d) and (e)**

In CA-NLH-159(d) and (e) Hydro states that it is "committed to investing necessary capital expenditures to ensure the availability of all three units at Holyrood to support system reliability."

The basis on which capital is committed to preserve availability bears directly on the classification of Holyrood TGS non-fuel costs and on the Holyrood TGS Accelerated Depreciation Deferral Account. Please confirm if Hydro maintains that the requested information in CA-NLH-159(d) and (e) is not necessary for a satisfactory understanding of the matters to be considered in the Application, and if so, identify the reasons.

__**Cost of Service – Newfoundland Power Generation Credit**__

PUB-NLH-174 **Response to PUB-NLH-108**

Hydro identifies four reasons for requesting that Newfoundland Power maximize hydraulic generation: economic dispatch before increasing loading on Holyrood units, support for system reserves, facilitating equipment outages, and offsetting transmission corridor limits.

a) For each dated observation in PUB-NLH-108, Attachment 1, identify which of the four reasons prompted the request.

b) Provide a re-derived hydraulic credit using only those observations in which a request to maximize all hydraulic generation was issued in support of system reserves, and provide the mean, median, and tenth-percentile (P90) value of that restricted sample.

PUB-NLH-175 **Response to CA-NLH-135, Tables 1 and 2**

a) Explain why the recent 2020-2024 window should be preferred given that it is the least stable of those examined.

b) Explain if the dispersion within the selected window has any bearing on the reliability of the resulting credit.

PUB-NLH-176 **Responses to NP-NLH-104 and NP-NLH-108**

Should a performance-based analysis of the thermal credit be conducted given the thermal generation requests reported in NP-NLH-104 and the operation of the Greenhill and Wesleyville gas turbines reported in NP-NLH-108? If no, state what additional data would be required and when Hydro expects to have it.

PUB-NLH-177 **Response to NP-NLH-099**

Hydro states that its operational practice is generally to request that Newfoundland Power maximize available hydraulic generation before committing higher cost standby generation resources.

a) Provide the most recent copy of Hydro's operational practice for dispatching generation resources showing the order of priority for each resource.

b) When establishing the position on the dispatch order for Newfoundland Power's run of the river hydro plants, what if any consideration was given to the limited amount of storage available throughout the winter season?

c) Explain what is meant by the phrase *maximize available hydraulic generation*. In the response, discuss the expectation for generators that were on before the request and for generators that were offline before the request and the impact, if any, on the efficient operation of Newfoundland Power's generation.

d) What is Hydro's understanding of the impact the number of requests by Hydro each year to maximize available hydraulic generation on Newfoundland Power's annual energy production? In the response, comment on whether the Generation Credit and Newfoundland Power's requirement to meet Normal Production annually work together or does one negatively impact the other?

e) Considering the current operation of the Island Interconnected System with the Labrador Island Link in service, where does Hydro see the greatest value with Newfoundland Power's hydraulic generation, either in providing low-cost energy to the system or in supporting capacity requirements during system peak days?

PUB-NLH-178 **Response to NP-NLH-101**

The second test is based on the total generation level sustained regardless of the relative contribution from hydraulic and thermal generation. Explain Hydro's rationale for using two different processes for the first and second test.

PUB-NLH-179 **Response to NP-NLH-103**

a) For the December through March winter periods for the period from 2020 to 2025, Table 1 identifies an average of 39 requests were made by Hydro over a 121-day winter period. As Newfoundland Power's hydraulic generating plants are essentially small run of the river plants, does Hydro consider the number of requests excessive?

b) What impact does the number of requests per winter season have on Newfoundland Power's ability to support the actual peak day when it occurs?

c) In Hydro's view, what prevents Newfoundland Power from providing maximum hydraulic production at levels closer to the rated capacity of its generators when called upon to do so by Hydro? In the response address if low reservoir levels is the reason, or equipment being out of service, or some other reason exists that prevents higher generation levels.

PUB-NLH-180 **Response to NP-NLH-103**

As multiple requests can be made by Hydro for Newfoundland Power to maximize available hydraulic generation on the same day to deal with morning and evening peaks, add a column to Table 1 identifying the number of days during each period where requests were made by Hydro.

PUB-NLH-181 **Response to NP-NLH-103**

In a table provide the dates for every generation test completed by Newfoundland Power, whether the test was completed successfully, what levels of hydraulic and thermal production were achieved, and Newfoundland Power's actual production at the time of peak for that winter season.

PUB-NLH-182 **Response to NP-NLH-103**

In a table provide the number of times each year Hydro requested Newfoundland Power to maximize available hydraulic generation going back to the introduction of the Generation Credit and the annual generation test. In the response, address any variance in the number of requests year over year explaining what may have changed with the operation of the power system.

PUB-NLH-183 **Response to NP-NLH-104**

Revise Table 1 to show Avalon Hydro Generation and All Hydro Generation separately.

PUB-NLH-184 **Response to NP-NLH-105**

Hydro identifies four reasons for requesting Newfoundland Power to maximize available hydraulic generation, (i) economic dispatch (i.e., before increasing loading on Holyrood units), (ii) to support system reserves. (iii) facilitating equipment outages and (iv) offsetting transmission line corridor limits.

a) When did Hydro begin using these four reasons to formally request Newfoundland Power to maximize its hydraulic generation?
b) Explain how each of these four reasons relate to the requirement for Newfoundland Powers hydraulic generators to support peak day capacity needs.
c) Rank the four reasons in order of priority from highest to lowest with the highest priority having the greatest impact on the operation of the Island Interconnected System.

PUB-NLH-185 With respect to Thermal Generation Requests, which of Hydro's transmission line corridors would require Newfoundland Power's thermal generation in Greenhill, Wesleyville and Port aux Basques to be placed online?

PUB-NLH-186 **Response to PUB-NLH-108, Cost of Service Methodology Technical Conference presentation, Slides 39-46**

When considering Newfoundland Power's hydro generation contribution during peak, Hydro assessed all formal requests to maximize both Island and Avalon hydro generation two weeks leading up to the system peak.

a) Describe what Hydro considered in the assessment.

b) How did Hydro determine that Newfoundland Power's run of the river plants would recover from requests to maximize hydro generation over a two-week period during the winter season?

c) Slides 42 through 44 identify 24 instances over the period 2017 through 2024 where Hydro requested Newfoundland Power to maximize hydro generation during the winter months. However, Slide 45 identifies 304 instances in the winter months where Hydro formally requested Newfoundland Power to maximize hydro generation. Explain the differences in the number of instances and the impact of the difference on Newfoundland Power's ability to maximize hydro generation on the days surrounding peak day?

d) On Slide 46 Hydro states it did not find any reason to excludes any years from the 5-year average Generation Credit at peak. Yet, the data for February 20, 2020 and February 11, 2021 indicate that Hydro made requests to maximize Newfoundland Power's hydro generation on 7 and 9 days respectfully in the prior 14-day period. What is the basis of Hydro's determination that this number of requests would not have depleted Newfoundland Power's reservoirs to the point where those dates would be excluded from the 5-year average?

PUB-NLH-187 **Response to PUB-NLH-108**

Did Hydro receive an explanation from Newfoundland Power on the reasons for the recurring pattern of shortfalls between reported available hydraulic capacity and actual generation when requested by Hydro to maximize?

PUB-NLH-188 **Volume II, Exhibit 4**

Exhibit 4 indicates one of the key drivers of the 2027 Test Year load increase for Newfoundland Power is the installation of electric boilers at Memorial University of Newfoundland ("MUN"). Response to IIC-NLH-010 indicates that a capacity assistance credit is not reflected in the 2027 Cost of Service Study because the boilers at MUN have not yet been commissioned and terms of the capacity assistance agreement have not been finalized.

a) Reconcile why it is appropriate to include the capacity requirements of the new MUN boilers in the 2027 Test Year peak load forecast and not reflect MUN's ability to curtail the electric boilers in the 2027 Cost of Service Study.

b) Provide any written correspondence from Newfoundland Power to Hydro with respect to the expected impacts of the MUN boilers on its energy and peak demand requirements.

c) Provide a comparison of the 2027 revenue requirements and the projected rate increases for Newfoundland Power and the Island Industrial Customers (net of rate mitigation) if the curtailable credit for Newfoundland Power was increased by the capacity requirement of the MUN electric boilers.

DATED at St. John's, Newfoundland and Labrador, this 21st day of September, 2026.

BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

Per

Mike McNiven
Board Secretary