IN THE MATTER OF the *Electric 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.

CONSUMER ADVOCATE
AMENDED REQUESTS FOR INFORMATION
CA-NLH-001 to CA-NLH-224

Issued: August 6, 2026

A. Proposed Rate Adjustments

CA-NLH-001 (Reference: Chapter 1, pages 1.17, 1.21, 6.33; Chapter 6, Section 6.8.3, page 3)

The Application states that *"Government has directed Hydro to structure future rate applications such that retail electricity rate increases attributable to Hydro's costs are targeted at 2.25% annually for Domestic customers on the Island Interconnected System through 2030, with rates structured for other customers on the Island Interconnected System [Footnote 17 – Such as Island Industrial Customers] in a manner that is compatible with this target rate increase."* It is also stated that *"Hydro is proposing a decrease in rates as of July 1, 2027 in comparison to July 1, 2026 rates for Island Industrial customers of 14.3%. The rate decrease reflects the 2027 Cost of Service Study revenue requirement of $42.8 million and utilization of the Project Cost Recovery Rider on July 1, 2027 to target the annual rate increase."*

(a) Explain whether Hydro considered the public policy implications of proposing material rate decreases for certain customer classes in light of: Government direction to limit rate increases for customers on the IIS including Island Industrial Customers to 2.25%; Hydro's proposed 2.25% rate increase for Newfoundland Power Domestic customers and Rural Labrador Interconnected customers; Hydro's proposal to take a loss of $502 million for rate mitigation purposes in the 2027 Test Year; and Hydro's proposal to transfer the Island Industrial Customer revenue deficiency of $2.7 million to the Supply Cost Variance Deferral Account.
(b) Identify any alternative cost allocation or rate design approaches considered by Hydro that would have moderated the proposed decreases to some classes during a period in which Government rate mitigation is being relied upon to limit overall rate increases to other classes to ease the cost-of-living pressures for customers. If not, explain why.
(c) What would the rate mitigation amount be if Island Industrial Customers received a rate increase similar to Newfoundland Power?
(d) What would the rate mitigation amount be if the rate increase for Newfoundland Power Domestic customers and Rural Labrador Interconnected customers were 0%?
(e) Were any intervenors consulted on the proposed rate increases/decreases proposed in this Application prior to filing? If so, provide details on the nature of those discussions.

CA-NLH-002 (Reference: Application)

All-in electricity rates:

(a) Provide a table comparing the average all-in electricity rates for each of Hydro's customer classes and the Domestic customer class served by Newfoundland Power on July 1 of each year since 2018 through to the rates proposed for 2027 in the 2026 GRA. In addition, show the year-over-year percentage rate increase and the cumulative rate increase for each class since July 1, 2018. Further, include a column in the table showing what rates would be for each of these customer classes on July 1, 2027 based on the 2027 Test Year without rate mitigation.
(b) Confirm that the initial rate change implemented under the government's rate mitigation plan occurred July 1, 2024 and identify the rate classes that were impacted by this rate change.

CA-NLH-003 (Reference: Application, Chapter 1 – Overview, page 1.20)

Hydro states *"The calculation of the cost of service for Labrador Interconnected System Domestic and General Service customers indicated an estimated rate increase of approximately 8.5%. To mitigate the impact on customers, with support from Government, Hydro is proposing to smooth the required rate increase over a four-year period, beginning with a 2.25% annual rate increase proposed to take effect on July 1, 2027. This increase is consistent with Domestic and General Service Island Interconnected System rates effective July 1, 2027."*

(a) Are these customers served from Hydro's distribution system or its transmission system?
(b) Are these customers required to pay for Muskrat Falls?
(c) Is any portion of rate mitigation allocated to these customers?
(d) What is the revenue deficit that results from limiting the rate increase for these customers to 2.25% and how will it be recovered?

CA-NLH-004 (Reference: Application)

(a) Did Hydro discuss the rate increases/decreases proposed in the 2026 GRA discussed with Newfoundland Power and the Island Industrial Customers prior to filing?
(b) Were the rate increases/decreases proposed in the 2026 GRA discussed with government prior to filing, particularly the optics of imposing a 2.25% rate increase on Newfoundland Power Domestic customers, some of whom are on fixed incomes, when granting a 14.3% rate decrease for Island Industrial Customers?

B. Load Forecast

CA-NLH-005 (Reference: Application, Chapter 2, Exhibit 4)

Hydro states that the proposed 2027 Test Year load forecast is based on the Reference Case load forecast, adjusted to reflect updated Industrial customer demand. Provide:

(a) the aggregate annual Industrial customer energy requirements (GWh) and winter peak demand (MW) reflected in the original Reference Case load forecast and the proposed 2027 Test Year forecast;
(b) the aggregate adjustment made by Hydro to Industrial customer energy requirements and winter peak demand;
(c) a description of the reason(s) for each material adjustment;
(d) whether the adjustments were based on updated customer information, Hydro judgment, revised economic assumptions, or other factors; and
(e) the total number of Industrial customers for which Hydro adjusted the Reference Case forecast.

CA-NLH-006 (Reference: Application)

Provide a table that consolidates for industrial customers in total separately for Island and Labrador, for each year 2019 through 2025:

(a) total number of industrial customers;

(b) total forecast energy (GWh);
(c) total actual energy (GWh);
(d) total forecast winter peak demand (MW);
(e) total actual winter peak demand (MW);
(f) the annual variance (GWh, MW and %) and
(g) a brief explanation of material variances including whether such variances are driven by customer operational decisions, economic conditions, customer provided forecast inaccuracies and/or Hydro forecasting assumptions.

CA-NLH-007 (Reference: Application)

Provide, for each year beginning with the approved 2017 GRA, the forecast annual system peak demand and the corresponding actual annual system peak demand, together with the forecast error expressed in MW and as a percentage.

CA-NLH-008 (Reference: Application)

Provide, for each year beginning with the approved 2017 GRA, the forecast and actual coincident peak demand (CP) responsibility by customer class. If actual CP responsibility is not available, explain how Hydro assesses the accuracy of the class CP forecasts used in the Cost-of-Service study.

CA-NLH-009 (Reference: Application: Table 2-1 and Schedules A-I through A-III)

Provide a table that includes for each year from 2017 through 2025 broken down by each major customer class and each electric system: (i) forecast energy requirements; (ii) actual energy requirements; (iii) forecast peak demand; (iv) actual peak demand; and (v) the variance (GWh & MW and %).

As part of the response, include a column that identifies the drivers of the material variances and separately identifying the effect (GWh and MW) due to: customer growth; population changes; industrial customer changes; electrification initiatives; electric heating; electric vehicles; electricity price impacts; conservation and demand management; and other material forecast adjustments.

CA-NLH-010 (Reference: Application)

Hydro identifies numerous drivers affecting the Island forecast, including, for example, population growth, customer growth, industrial demand, electric vehicles, and electricity price. For each year 2025 through 2027, quantify the incremental effect of each driver on: (i) annual energy (GWh); and (ii) peak demand (MW).

CA-NLH-011 (Reference: Application)

Hydro states that the GRA forecast is intended for rate setting and differs from forecasts used in other proceedings. Provide:

(a) each load forecast currently used, to the extent that the forecasts differ, for rate setting; resource planning; reliability planning; and capital planning/projects;
(b) a comparison of annual energy and demand assumptions for each common year; and
(c) the rationale for material differences.

CA-NLH-012 (Reference: Volume 1, Schedule A-1)

Provide annual forecast and actual energy sales by customer class for each year beginning with the approved 2017 GRA to the proposed 2027 Test Year.

CA-NLH-013 (Reference: Application, Volume 1, page 2.13, footnote 22)

Hydro states that the Reference Case reflects current and committed government decarbonization policies and programs. Identify each policy, program or initiative assumed in the preparation of the 2027 Test Year load forecast along with:

(a) the expected implementation date;
(b) the assumed customer participation;
(c) the incremental annual energy impact (GWh);
(d) the incremental winter peak impact (MW); and
(e) whether the policy is legislated, funded, approved or otherwise committed.

CA-NLH-014 (Reference: Application)

Provide a table identifying the following for the Island Industrial Customer class: number of customers, peak demand and annual energy consumption for each of the past 5 years.

C. Operations, Reliability, and Customer Service

CA-NLH-015 (Reference: Chapter 1, page 1.1)

The Application states *"The Muskrat Falls Hydroelectric Generating Facility, the Labrador Transmission Assets and the Labrador-Island Link (collectively known as the "Muskrat Falls Assets") provide customer benefits by improving system reliability and export/import capability, enabling significant reductions in Holyrood TGS generation and fuel usage, as included in the 2027 Test Year.*"

(a) Is the effective load meeting capability of the Muskrat Falls assets during a LIL shortfall event 0 MW for six weeks in the winter period?
(b) Quantify the benefits that the Muskrat Falls assets have on the reliability of the IIS from a capacity and energy planning perspective. Specifically, provide a comparison of the reliability of the IIS both with and without the Muskrat Falls assets under the LOLH criterion and alternatively, the LIL shortfall event criterion.
(c) How does the equivalent forced outage rate assumed for the LIL compare to HVDC transmission elsewhere?

CA-NLH-016 (Reference: Chapter 2, Table 2-1)

Hydro indicates that overall energy requirements have increased by 0.5% (or 53 GWh) in the eight-year period between the 2019 Test Year and the proposed 2027 Test Year. Identify and quantify the principal drivers of forecast load growth (both energy and demand) over the Test Years. As part of the response, provide:

(a) a table similar to Table 2-1 that includes the energy and demand forecast as part of the 2019 Test Year between the three systems and in total;

(b) the energy and demand forecast between the three systems as reflected in the 2027 Test Year; and
(c) a description of the material drivers of the change and expressed in GWh or MW.

CA-NLH-017 (Reference: Volume 1, pages 2.1 to 2.4).

Hydro states (page 2.2, lines 4 to 7) *"…Hydro regularly gathers customer feedback on reliability, outages, billing and customer support. This input informs service improvements, asset management, and long-term capital planning."* Hydro states (page 2.2, lines 14 to 15) *"Hydro measures customer service performance through a combination of transactional and relationship-based surveys, as well as spot engagement surveys."* Hydro states (page 2.3, lines 1 to 2) *"Hydro also conducts biennial Residential and General Service customer satisfaction surveys."*

(a) Please provide the details of the transactional customer survey results from 2019 through to 2025.
(b) Please provide the details of the 2024 residential biennial customer satisfaction survey.
(c) Please provide the details of the 2024 digital engagement process.
(d) Please summarize the feedback received from residential customers from 2019 to 2025 as part of the various surveys and describe actions taken by Hydro based on residential customer survey feedback.

CA-NLH-018 (Reference: Volume 1, page 2.3)

Hydro states (lines 7 to 12) *"…customer feedback indicates that reliability is important to customers, but that affordability remains a higher priority…Hydro remains mindful of this perspective as it manages its infrastructure and applies asset management practices to support prudent investment while maintaining reliability"*.

(a) Provide a summary of Hydro's strategic asset management plan.
(b) Provide a summary of any assessment by external consultants as to Hydro's level of maturity with respect to asset management practices.

CA-NLH-019 (Reference: Volume 1, pages 1.14 to 1.17)

Hydro outlines the high-level results of a digital public engagement survey of all electricity customers in the province that was carried out in January of 2024. Provide a copy of the January 2024 digital public engagement survey, including the questions used for the survey and reports that were provided to Hydro management that detail the results of the survey.

CA-NLH-020 (Reference: Volume 1, page 2.10)

Hydro states (lines 4 to 5) *"Since commissioning, the Muskrat Falls Hydroelectric Generating Facility has been outperforming the Electricity Canada five-year average of 6.03% for similar units across Canada. The four generating units achieved a weighted DAFOR of 1.35% in 2025…"* Describe the similar units that Hydro is using as comparable to Muskrat Falls and how the age of these similar units has been taken into consideration by Hydro in terms of benchmarking performance.

CA-NLH-021 (Reference: Volume 1, page 2.35).

Hydro states (lines 7 to 8) *"A new joint potential study completed with Newfoundland Power, which will inform the next five years of CDM programming on the Island Interconnected System."* Provide the new joint potential CDM study completed with Newfoundland Power.

CA-NLH-022 (Reference: Application, Chapter 2, pages 2.9 to 2.11)

Hydro references the reliability performance of the Muskrat Falls assets and the apparent general improvement in reliability of both Muskrat Falls generation and the LIL.

(a) Does Hydro consider the new assets to be now passed the initial breaking-in period?
(b) How is the reliability performance improvement being reflected in Hydro's planning process?

CA-NLH-023 (Reference: Application, Chapter 2, page 2.16)

Hydro states *"At the commencement of the spring period in 2026, Hydro was able to reduce reliance on Holyrood TGS by reducing operations down to one unit, as planned."* Is this consistent with the information provided in the April 2026 Monthly Energy Supply Report for the IIS indicating that Holyrood TGS Unit 1 was in operation for the entire month of April, and Holyrood TGS Unit 2 was in operation for the first 9 days of the month?

CA-NLH-024 (Reference: Application, Chapter 2, page 2.25)

Hydro states *"Since 2019, Hydro has incurred $9.1 million in costs to deliver CDM initiatives to achieve its 16,067 MWh in cumulative energy savings."*

(a) What is the total *"behind-the-meter"* contribution to the IIS by 2035 assumed in Hydro's planning forecast?
(b) By comparison, Manitoba Hydro identifies *"customer-side solutions totalling 860 MW"* over the next 10 years (see Manitoba Hydro's 2025 Integrated Resource Plan published January 2026, page 14). Explain why Manitoba's customer-side solutions appear to be much more successful than NL's customer-side solutions, including a comparison of *"customer-side solution"* amounts to peak demand in each province by the year 2035.

CA-NLH-025 (Reference: Exhibit 16, page 8)

Hydro states that *"By the year 2032, the most loss-of-load risk occurs during the winter period, coinciding with LIL outages."*

(a) What is the risk of loss-of-load in 2029 during the winter and non-winter months, and how much of this is attributable to i) LIL outages, and ii) Holyrood outages?
(b) What is the risk of loss-of-load in 2029 during a LIL Shortfall Event?
(c) Given that most loss-of-load risk coincides with LIL outages, why is it necessary to have a LIL shortfall event criterion in addition to the LOLH criterion?

CA-NLH-026 (Reference: Exhibit 16, page 8)

Hydro states *"The first large capacity resource option (Bay d'Espoir Unit 8) is required* *in 2031 to meet the planning reserve margin requirements, and the second large capacity resource option (Avalon CT) is advanced to 2031 to mitigate the loss of load associated with a potential LIL shortfall event."* Is the first large capacity resource required in 2031 to mitigate the loss of load associated with a potential LIL shortfall event or to meet Hydro's LOLH criterion, or both? Provide supporting documentation.

CA-NLH-027 (Reference: Volume 1, figure 1-3, page 1.12)

Hydro provides (figure 1-3) a diagram of its corporate structure post-amalgamation and indicates that it filed a Report on Amalgamation Activities with the Board in April of 2025.

(a) Provide a description of the purposes and activities of each of the subsidiaries that are listed on figure 1-3.
(b) Provide a copy of the April 2025 Report on Amalgamation Activities for the record of this proceeding.

CA-NLH-028 (Reference: Volume 1, pages 1.13 and 1.14)

Hydro outlines (pages 1.13 and 1.14) a number of the transformative changes that are expected as part of the transition of the Electricity Industry.

(a) Provide a Hydro's most recent corporate strategy or corporate strategic plan.
(b) Provide Hydro's most recent corporate risk management report.
(c) Provide a detailed description of the strategies that Hydro is executing to manage the transformative changes that are expected in the energy sector.

CA-NLH-029 (Reference: Volume 1, page 2.45)

Hydro states (lines 14 to 15) *"Leveraging the use of technology within the organization supports all aspects of Hydro's business, mitigates operational risk, and enables the productivity of Hydro's workforce..."* Provide Hydro's artificial intelligence strategy or describe Hydro's progress towards such a strategy, and how this strategy is designed to improve customer service and enable the productivity of Hydro's employees.

CA-NLH-030 (Reference: CBC Article posted July 23, 2026 (https://www.cbc.ca/news/canada/nova-scotia/maritime-provinces-energy-mou-regional-electricity-operator-9.7280914))

New Brunswick, Nova Scotia and Prince Edward Island have signed an MOU which includes development of a *"regional road map for electricity transmission by next spring and will consider creating an independent electricity system operator to manage power delivery in the Maritimes."* Was the government of NL asked to participate, and if not, does it intend to approach the other 3 provinces about participating in this element of the MOU?

D. Muskrat Falls Supply Costs and Recovery Mechanics

CA-NLH-031 (Reference: Volume 1, page 128; Schedules C-I, C-III, C-IV, C-V, Volume 1, pages 223-227).

Reconcile the 2027 Test Year Muskrat Falls supply cost total of $780.4 million to all supporting schedules and workpapers, including the Muskrat Falls PPA, Labrador Transmission Assets payments, Transmission Funding Agreement, and Muskrat Falls PPA Sustaining Capital Deferral credit. Provide an Excel workbook with formula links from the total to each supporting line item in Schedules C-I, C-III, C-IV, and C-V, including source contract/workpaper references for each line item, and identify whether each line is actual, forecast, contract formula, escalation factor, true-up, or management forecast.

CA-NLH-032 (Reference: Volume 1, table 4-3, page 4.6 and page 4.7)

Hydro provides (table 4-3) a table which summarizes the sub-components of the Muskrat Falls Supply Costs from 2024 Actual to the 2027 Test Year - with the Base Block Capital Costs Recovery representing approximately 69% ($216.1 M/$315.3 M) of the total Muskrat Falls PPA supply costs for the 2027 Test Year. Hydro states (lines 2 to 4 of page 4.7) *"The Base Block Capital Costs Recovery is based on the volume of energy delivered and ensures all costs related to the development of Muskrat Falls Hydroelectric Generating facility are recovered over the term of the Muskrat Falls PPA."*

(a) Provide the calculations of the Base Block Capital Costs Recovery that were used to derive the amounts for 2024 Actual to the 2027 Test Year in table 4-3.
(b) Extend table 4-3 to include 2028 Forecast to 2030 Forecast and provide the calculations of the Base Block Capital Cost Recovery to derive the forecast amounts.

CA-NLH-033 (Reference: Application, Chapter 4, Table 4-1, page 4.2)

Hydro indicates that Muskrat Falls costs included in the 2027 Test Year are $780.4 million. Rate mitigation in the 2027 Test Year is $502 million. In Hydro's opinion:

(a) Does the $780.4 million cost of the Muskrat Falls assets less the rate mitigation value of $502 million reflect the value of the Muskrat Falls assets in 2027?
(b) What is the value of the Muskrat Falls assets to the IIS? For example, is its value equivalent to the capacity and energy produced by the Muskrat Falls assets and delivered to the IIS multiplied by the marginal cost of capacity and energy on the IIS?
(c) What is the market value of the Muskrat Falls assets?
(d) Is the cost of the Muskrat Falls assets competitive with the cost of the Reference Expansion Plan?

CA-NLH-034 (Reference: Volume 1, pages 145, 153; Schedule F (page 248); Volume 2, pages 76, 79)

Reconcile all 2027 Test Year rate mitigation amounts referenced in Chapter 5, Schedule F, Schedule G, Exhibit 3, and related workpapers. Provide a table identifying each mitigation amount, its source document/page/workpaper, the vintage/date of forecast, whether it is rounded, whether it applies to revenue requirement, cost of service, customer bills, or deferral-account treatment, and the reason for any difference between amounts.

CA-NLH-035 (Reference: Application, Chapter 1, Chart 1-4, pages 1.19 to 1.20)

Hydro provides a chart that outlines the increases and decreases in revenue requirements between the 2019 Test Year and the 2027 Test Year by revenue requirement component, including the Muskrat Falls Supply Costs and Rate Mitigation as discrete component categories.

(a) Provide an analysis of the net 2027 Test Year revenue requirement impact associated with the Muskrat Falls Project including (i) Muskrat Falls Supply Costs (ii) Rate Mitigation and (iii) any other revenue requirement increases or decreases that are included in other revenue requirement components in Chart 1-4 (fuel, power purchases, other adjustments/net export revenues etc.) that result from the Muskrat Falls Project.
(b) Provide the overall rate increase and Residential rate increase that would be required for the 2027 Test Year in absence of the rate mitigation.

CA-NLH-036 (Reference: Application, Chapter 1, Chart 1-4, page 1.20)

It is understood from Chart 1-4 that the 2019 Test Year revenue requirement was $643 million, Muskrat Falls supply costs are $780 million, rate mitigation is $502 million, and the revenue requirement is $1,300 million before the rate mitigation adjustment which brings the 2027 revenue requirement down to $798 million.

(a) How much of Hydro's proposed revenue requirement would have to be denied by the Board before Hydro would change its proposed rate increase for IIS customers?
(b) Are the Muskrat Falls supply costs 121% of the 2019 Test Year revenue requirement?

CA-NLH-037 (Reference: Volume 1, pages. 127, 151; OC2013-343; NLR 120/13)

Provide a crosswalk identifying each statutory provision, Order in Council, exemption order, contract, Board order, or other legal instrument relied on by Hydro to support its position that Muskrat Falls Project costs are recoverable from Island Interconnected System customers without Board disallowance, reduction, or prudence adjustment. Provide the crosswalk in table form, with columns for instrument, section/order reference, cost category, Hydro's interpretation of Board authority, recovery mechanism, and whether Hydro considers allocation, rate design, deferral treatment, carrying charges, reporting, or audit conditions to remain within the Board's authority. Specifically:

(a) map each dollar of the $780.4 million 2027 Test Year Muskrat Falls supply cost to one of the three enumerated payment categories in OC2013-343 clause 1(a)-(c), and identify any residual amount outside all three;
(b) confirm whether Hydro agrees that NLR 120/13 s. 2(2)(a) limits the exemption to the *Public Utilities Act* and *EPCA* Part II only, leaving *EPCA* Part I (ss. 3-4) in full force;
(c) confirm the date on which the OC2013-343 clause 3(b) commissioning condition was satisfied.

CA-NLH-038 (Reference: Application, Volume 1, page 4.1)

Hydro states (lines 8 to 11) *"Government's rate mitigation plan effectively mitigates approximately 39% of Hydro's overall costs…This provides rate predictability up to 2030…these costs are outside of the Board's jurisdiction for review or prudence assessment…Hydro is providing this information in the interest of transparency and accountability, to ensure stakeholders and customers have the opportunity to consider all material costs reflected in Hydro's cost of providing service."*

(a) Confirm (or otherwise explain) that approximately 60% of Hydro's 2027 Test Year regulated revenue requirement ($780 million of Muskrat Falls Supply

Costs/unmitigated revenue requirement of $1.3 billion) is under the control of Hydro's Board of Directors and not subject to the Board's disallowance, reduction or regulatory adjustment.

(b) Explain what Hydro means by stating that stakeholders and customers will have the opportunity to *"consider"* the Muskrat Falls supply costs in this proceeding.

CA-NLH-039

(Reference: Application, Chapter 1, page 1.9)

Hydro states *"The Muskrat Falls Assets are a significant component of the province's generation portfolio and, while managed by Hydro, are exempt from the Act, regulation and oversight by the Board."* Footnote 16 states *"OC2013-343 and the Muskrat Falls Project Exemption Order expressly provide that all associated costs are fully recoverable through Island Interconnected System customer rates and are not subject to disallowance, reduction, or regulatory adjustment."*

(a) Do the IIS customer rates proposed in the 2026 GRA fully recover the cost of the Muskrat Falls assets without *"disallowance, reduction, or regulatory adjustment"*?
(b) From an accounting perspective, how does Hydro categorize the rate mitigation cost of $502 million; i.e., a regulatory adjustment?
(c) While the Board does not have oversight of the Muskrat Falls assets, does it have oversight of rate mitigation amounts?

CA-NLH-040

(Reference: Volume 1, Chart 4-1 and page 4.15, including footnote 59; Tables 4-3, 4-4 and 4-5)

(a) Hydro states (lines 10 to 12) *"…approximately 90% of Hydro's costs under the Muskrat Falls PPA and Transmission Funding Agreement are commercially fixed and are unable to be changed or influenced by Hydro."* Explain why costs under the Muskrat Falls PPA and Transmission Funding Agreement are unable to be changed or influenced by Hydro, when the subsidiaries that have negotiated this PPA and agreement are controlled by the same Board of Directors that control Hydro.
(b) Provide the calculation supporting this split, in Excel, identifying each cost line included in each category and whether the split is calculated before or after the Muskrat Falls PPA Sustaining Capital Deferral credit.
(c) For each operationally managed line, provide budget-to-actual results for 2021-2025, forecast values for 2026-2027, variance explanations, procurement controls, and any performance benchmarks.

CA-NLH-041

(Reference: Volume 1, pages 150-151; Schedule C-II, page 224; Schedule D-I, page 229)

Reconcile the monetized NLH Deferred Energy, net export revenue credit, transmission tariff revenue credit, and any related SCVDA or Long-Term SCVDA treatment included in the 2027 Test Year. Provide workpapers showing export energy volumes, prices, losses, transmission tariff revenues, cost offsets, rate mitigation interactions, and deferral-account treatment, identifying which credits reduce revenue requirement directly and which flow through variance accounts.

CA-NLH-042

(Reference: Volume 1, page 4.4)

Hydro states (lines 4 to 7) *"At the end of each year, Hydro may either defer the resulting NLH Deferred Energy for future use or monetize all or a portion of it at the Annual Average Sales Price. The Annual Average Sales Price reflects the net proceeds from*

Muskrat Falls energy and capacity sales to external markets during the year.” Summarize the calculations of monetized energy and Annual Average Sales Price from the Muskrat Falls PPA.

CA-NLH-043 Reference: Volume 1, table 4-2, page 4.5)

Hydro provides (table 4-2) a table which summarizes the total monetized deferred energy ($ million) for 2024 Actual ($73.8 million) to the 2027 Test Year ($38.1 million).

(a) Provide the calculations of the monetized energy and Annual Average Sales Price that were used to derive the monetized deferred energy for 2024 actual to the 2027 Test Year in table 4-2.
(b) Extend table 4-2 to include 2028 Forecast to 2030 Forecast and provide the calculations of the monetized energy and Annual Average Sales Price used to derive the forecast amounts.

CA-NLH-044 Reference: Volume 1, table 4-4, page 4.10)

Hydro provides (table 4-4) a table which summarizes the sub-components of the Labrador Transmission Assets Payments from 2024 Actual to the 2027 Test Year - with the LTA Capital Costs Recovery representing approximately 80% ($39.7 M/$49.4 M) of the total costs for the 2027 Test Year. Hydro states (lines 3 to 4 of page 4.10) *“The Labrador Transmission Assets Payments ensure the full recovery of the Labrador Transmission Assets from Muskrat Falls Corporation under the Generator Interconnection Agreement…”*
(a) Provide the calculations of the LTA Capital Costs Recovery that were used to derive the amounts for 2024 Actual to the 2027 Test Year in table 4-4.
(b) Extend table 4-4 to include 2028 Forecast to 2030 Forecast and provide the calculations of the LTA Capital Costs Recovery to derive the forecast amounts.

CA-NLH-045 (Reference: Volume 1, table 4-5, page 4.12)

Hydro provides (table 4-5) a table which summarizes the sub-components of the Transmission Funding Agreement Supply Costs from 2024 actual to the 2027 Test Year - with the Rent components of return on equity, interest and depreciation representing approximately 92% ($426.3/$465.1) of the total costs for the 2027 Test Year. Hydro states (lines 5 to 6) *“Unlike the Muskrat Falls PPA, the Transmission Funding Agreement payments are not dependent on the volume of energy; rather they are based on a return on rate base approach.”*

(a) Provide the calculations of the return on equity, interest and depreciation that were used to derive the amounts for 2024 actual to the 2027 Test Year in table 4-5
(b) Extend table 4-5 to include 2028 Forecast to 2030 Forecast and provide the forecast calculations of return on equity, interest and depreciation to derive the forecast amounts.

CA-NLH-046 (Reference: Volume 1, page 4.13, footnote 53)

Hydro states (footnote 53) *“The service life of the LIL is determined by commercial contracts, is linked to cost recovery and not necessarily equal to the actual estimated useful life of the asset.”*

(a) Explain in detail how the service life of the LIL has been determined by commercial contracts.
(b) Provide the estimated useful life of the LIL and compare to the service life that has been determined by commercial contract.

CA-NLH-047 (Reference: Volume 1, page 4.14)

Hydro states (lines 3 to 5) *"...Rent increased by $10.5 million from the 2024 to the 2027 Test Year. This increase is primarily related to higher bank interest earned in 2024, which is net against the financing costs charged to Hydro."*

(a) Explain how higher interest earned which is presumably a reduction to financing costs and Rent charged to Hydro - results in an increase in Rent or an increase in costs charged to Hydro.
(b) If the above quoted variance explanation is not accurate, provide a revised variance explanation for the increase in Rent between 2024 Actual and the 2027 Test Year.

CA-NLH-048 (Reference: Volume 1, page 4.16). Hydro states (lines 13 to 15)

Hydro states that *"Hydro manages all areas of its operations, both regulated and non-regulated, to the same standard, applying an operational philosophy of Good Utility Practice and in line with its mandate to provide least-cost, reliable service in an environmentally responsible manner."*
(a) Provide Hydro's vision statement and explain how Hydro sees its business model changing in an era of an energy transition.
(b) Provide Hydro's perspectives on the role of strategy and emerging utility practices in working toward its vision in an era of the energy transition and associated transformative change.

CA-NLH-049 (Reference: Volume 1, page 127; Schedules C-III and C-V (Volume 1, pages 225, 227)).

Describe Hydro's processes for verifying Muskrat Falls PPA, LTA, and TFA invoices and charges before including them in revenue requirement, deferral accounts, or rate mitigation calculations. Provide audit-right provisions, internal control descriptions, invoice review procedures, exception reports, dispute history, external audit or independent review summaries, and any unresolved billing or interpretation issues from 2021-2027.

CA-NLH-050 (Reference: Volume 1, pages 145, 153; Schedule F, page 248; Schedule G, page 357).

Provide the annual and monthly customer bill impact of each major Muskrat Falls cost component before and after rate mitigation, by customer class and representative usage level, for Domestic, General Service, Newfoundland Power, Island Industrial, Rural Interconnected, Labrador Interconnected, Labrador Industrial, and isolated-system classes where applicable. Show impacts by PPA, TFA, sustaining capital deferral, export credits, rate mitigation, SCVDA/Long-Term SCVDA, and working capital effects.

E. Rate Mitigation, Affordability, Net Export Revenue & the Post-2030 Rate Path

CA-NLH-051 (Reference: Application)

Provide illustrative calculations showing the impact of actual Net Export Revenue differing from the 2027 Test Year forecast by: i) +/- 10%; ii) +/- 25%; and iii) +/- 50%. As part of the response, provide a table that compares the forecasted amount Long-Term Supply Cost Variance Deferral Account as proposed to each scenario.

CA-NLH-052 (Reference: Application)

Provide, for each year from 2019 through 2025:

i. forecast Net Export Revenue;
ii. actual Net Export Revenue;
iii. the dollar and percentage variance between forecast and actual; and
iv. brief explanation of material variances.

CA-NLH-053 (Reference: Application)

Provide the range of 2027 Net Export Revenue that Hydro considers reasonably possible.

CA-NLH-054 (Reference: Application, Chapter 1, page 1.10)

Hydro states *"The profits of these exports benefit customers by mitigating costs associated with the Muskrat Falls Assets."* Provide a table showing the cost of the Muskrat Falls assets compared to the profits from exports associated with the Muskrat Falls assets, the fuel savings at Holyrood and any other savings derived from the Muskrat Falls assets. Base costs and savings on the 2027 Test Year revenue requirement assigned to IIS customers.

CA-NLH-055 (Reference: Application, Chapter 2, page 2.19)

Hydro states *"Export profits generated by Hydro are used to benefit customers either directly by offsetting Hydro's supply costs or through the funding of rate mitigation."* Identify export profits and the amounts allocated to each customer class in the 2027 Test Year.

CA-NLH-056 (Reference: Volume 1, pages 153, 171; Schedule D-V, page 239; Schedule F, page 248; Schedule G, page 357; Volume 3, page 697)

Provide an annual rate-path exhibit for 2027 through 2035, in Excel, under at least the following scenarios:

(a) the current rate mitigation plan continues at its current design and funding level past 2030;
(b) mitigation declines after 2030;
(c) mitigation ends after 2030 with no successor mechanism;
(d) deferral account balances outstanding at 2030 (including but not limited to the Power Purchase Expense Recognition balance, the Muskrat Falls PPA Sustaining Capital Deferral Account, the AFUDC Deferral Account, the Holyrood TGS Accelerated Depreciation Deferral Account, and the Long-Term SCVDA) are disposed of on the amortization schedules and carrying rates as currently filed; and
(e) the same deferral balances are disposed of on an accelerated basis (e.g., half the current amortization period). For each scenario and year, show class-level annual revenue requirement, mitigation amount, customer revenue, rate increase,

representative Domestic and General Service monthly bill impacts, and the outstanding balance of each named deferral account. State the key assumptions (load, hydrology, export prices, fuel costs, Muskrat Falls supply costs, Holyrood retirement timing, WACC) explicitly and hold them constant across scenarios so the comparison isolates the mitigation and disposition choices being tested.

CA-NLH-057 (Reference: Volume 2, Exhibit 3, Implementation of Rate Mitigation Plan Report, October 2024, pages 5 and 6).

Hydro states (lines 9 to 11 on page 5 and lines 1 to 2 on page 6) *"…Government's current rate mitigation plan matures in 2030…Government has committed publicly to rate mitigation post-2030…Hydro will work with the Government in advance of 2030 on future rate mitigation requirements."*

(a) Provide a status update on the development of a rate mitigation plan for the post-2030 period.
(b) Provide Hydro's current projections of the amount of rate mitigation funding that would be required in the post-2030 period (2031 Forecast to 2035 Forecast).

CA-NLH-058 (Reference: Application, Chapter 1, page 1.18)

Hydro states *"Government's rate mitigation plan has been incorporated into Hydro's 2027 Test Year and reflects the funding required to offset the portion of Hydro's costs that are not expected to be recovered through customer rates."*

(a) What has driven the increase in rate mitigation funding from an average of $350 million per year (pages 1.17 and 1.18) to over $500 million per year?
(b) Does the proposed rate mitigation amount of $502 million impact customers other than those on the IIS?
(c) Explain how Hydro satisfies itself that funding upwards of $350 million per year of rate mitigation from internal sources is financially sustainable through 2030.

CA-NLH-059 (Reference: Volume 2, Exhibit 3, Implementation of Rate Mitigation Plan Report, October 2024, table 2, page 5).

Hydro provides (table 2) a table which summarizes projected rate mitigation required and rate mitigation funding sources and timing from 2024 to 2030. The projected rate mitigation funding includes LCP Dividends and Hydro internally generated funding. LPC Dividends includes any excess cash generated from operations associated with the Lower Churchill entities which is forecast to be provided to the parent company through a common dividend. Hydro states (lines 3 to 5 on page 5) *"Orders in Council…directed the retirement of the 2023 SCVDA balance of $271.3 million over the 2024-2026 period. This timing is reflected accordingly in Table 2, spread evenly over the three years."*

(a) Explain whether the required rate mitigation is a back-calculation of the amount of funding required to achieve 2.25% rate increases to 2030 or a forward-looking forecast of amounts available to mitigate rate increases.
(b) Provide a detailed explanation of how Table 2 on page 5 of Exhibit 3 results in the retirement of the $271.3 million balance of the 2023 SCVDA balance over the 2024 to 2026 period.
(c) Elaborate on which of the Hydro subsidiaries the LCP dividends are expected to be provided from and how the projections to 2030 have been calculated.

(d) Provide a description and breakdown of the projection of Hydro's various internally generated funding sources for rate mitigation in Table 2 from 2024 to 2030.

CA-NLH-060 (Reference: Volume 1, table 5-6, page 5.10)

Hydro provides (table 5-6) a table which summarizes Rate Mitigation Funding by source (hydro's internal sources, Government of Canada Convertible Debenture and Government Grant) from 2023 Actual to the 2027 Test Year.

(a) Provide a breakdown of Hydro's internal sources of rate mitigation funding between LCP Dividends and internally generated rate mitigation funding from 2023 Actual to the 2027 Test Year.
(b) Provide a breakdown and description of the sources of Hydro's own internal generated rate mitigation funding from 2023 Actual to the 2027 Test Year.
(c) Provide a summary of the repayment terms and conversion terms of the Government of Canada Convertible Debenture.
(d) Extend table 5-6 to include the most current 2028 Forecast to 2030 Forecast of rate mitigation funding and comment on the reasons for the changes in the projections of this funding and expected sources of Hydro's own internal rate mitigation funding in this timeframe.

CA-NLH-061 (Reference: Volume 1, pages 184, 187-188, 199, 201; Schedule F, page 248; Schedule G, page 357)

Provide bill-impact and affordability analysis by customer class, usage band, geography, heating type, and rural/isolated status, under mitigated, unmitigated, and post-2030 scenarios, identifying any affordability metrics Hydro tracks beyond average bill increases. In addition, provide the following data, by customer class and sub-class where available, for the most recent five years for which data exists:

(a) an arrears aging schedule (30/60/90/120+ days past due), with year-over-year trend;
(b) disconnection and reconnection counts by month, broken out by season and, to the extent recorded, by heating type;
(c) enrollment, utilization, average plan size, and default/re-arrears rate for any existing payment-plan or equalized/levelized-billing program;
(d) electric-heat penetration by customer class or geographic/distribution zone, to the extent recorded;
(e) a bill-impact distribution by consumption decile for the proposed 2027 rate changes within the Domestic class;
(f) residential bad-debt write-off counts and dollar values, trended as far back as reasonably available. Note any category Hydro does not currently collect, and state whether Hydro considers it feasible to begin tracking it prospectively.

CA-NLH-062 (Reference: Exhibit 12, page 14)

Hydro states *"Note that the Utility bill increase probably meets the constraints on domestic customers, since the excess over the 2.25% limit might plausibly be applied to business customers of the utility."* Is Hydro proposing this in the 2026 GRA and is it consistent with the rate mitigation directives?

CA-NLH-063 (Reference: Volume 1, page 153; Volume 2, pages 76, 80)

Identify all sources of 2027 rate mitigation funding, including Hydro internal sources and Government of Canada Convertible Debenture funding, and explain the risks associated with each source. Provide source-by-source funding amounts, legal/contractual basis, timing, conditions, forecast uncertainty, accounting treatment, cash-flow timing, and the consequences if funding is delayed or lower than forecast.

CA-NLH-064 (Reference: Volume 1, page 184; Schedule F (page 248); Schedule G (page 357); Volume 2, page 79)

Explain whether and how rate mitigation affects customer price signals, including conservation, peak demand, high-usage customers, marginal-cost pricing, and demand response opportunities. Provide any analysis Hydro performed on whether mitigation changes consumption, peak demand, class cost responsibility, or customer incentives; if no analysis was performed, explain why.

F. Operating Costs and Productivity

CA-NLH-065 (Reference: Volume 1, page 2.29)

Hydro states (lines 3 to 4 and footnote 61) *"Inflation since the 2019 Test Year has been substantial, with costs escalating by approximately 28% when compounded year over year...Weighted inflation rate compounded year over year from 2019 Test Year using GDP deflator (32%) and labour inflation (25%)."*

(a) Provide the data by year from the 2019 Test Year to 2027 Test Year to support the compound GDP deflator of 32% and compound labour inflation of 25%.
(b) Explain the differences between a GDP deflator and consumer price index (CPI) and which inflation metric Hydro believes is the most appropriate to assess performance with respect to non-labour related costs.
(c) Provide the Newfoundland and Labrador CPI by year including the 2019 actual to the 2025 actual and 2026 to 2027 forecast CPI (if available).
(d) Provide the increase in Newfoundland & Labrador average weekly earnings by year including the 2019 actual to the 2025 actual and 2026 to 2027 forecasts (if available).

CA-NLH-066 (Reference: Volume 1, page 3.2)

Hydro states (lines 10 to 11) *"From 2024 to 2027, inflation is expected to result in an increase of more than 10%..."* Provide the index and data for 2024 to 2027 that Hydro is relying on to assert inflation over the 2024 to 2027 period of more than 10%.

CA-NLH-067 (Reference: Volume 1, page 3.4)

Hydro states (lines 11 to 12) *"Labour costs in the 2027 Test Year of $96.4 million are approximately 9% lower than the 2019 Test Year in real dollars."*

(a) Provide the index and data that Hydro is relying on by year to assert that labour costs over the 2019 to 2027 period are 9% lower than the 2019 Test Year in real dollars.
(b) Provide a calculation of the cumulative nominal increase in labour costs over the period from the 2019 Test Year to the 2027 Test Year.

(c) Provide a calculation of the cumulative nominal increase in labour costs over the period from the 2019 Test Year to the 2027 Test Year, adding back salaries deferred into the General Expenses Capitalized Deferral Account.

CA-NLH-068 (Reference: Volume 1, pages 117 and 148; Schedule D-V, page 239; Order No. P.U. 32(2025))

Recompute Hydro's claimed $8.0 million non-labour and $9.0 million labour real-dollar savings (2019 Test Year to 2027 Test Year) under a constant capitalization policy - holding Hydro's overhead capitalization rate at its 2019 level rather than the increased rate approved in Order No. P.U. 32(2025) - and state what portion of the claimed savings is attributable to genuine cost reduction versus the reclassification of costs from operating expense to the capitalized/deferred track. Provide the recomputed 2027 Test Year operating costs and savings figures under the 2019 capitalization policy alongside the as-filed figures, with a line-by-line bridge identifying the capitalization-policy-driven portion of the difference.

CA-NLH-069 (Reference: Schedule B-II, Volume 1, page 220; Volume 1, page 121 (footnote 33); Schedule B-III)

(a) Provide the complete derivation of the 2027 Test Year's $4.0 million productivity allowance, including whether it originates from a Board order (as the 2019 figure did, per Order No. P.U. 16(2019)), a Hydro self-imposed target, or another source; identify the baseline against which the allowance is measured as incremental savings; and provide a workpaper showing how $4.0 million was calculated, identifying whether the figure was independently re-derived for the 2027 Test Year or carried forward from 2019.
(b) Explain why the 2027 Test Year allowance is allocated by function and department while the 2019 Test Year allowance of the identical dollar amount was not, and confirm whether this allocation-method change affects the allowance's magnitude, its verifiability, or only its presentation; provide the function-by-department allocation table for the 2027 allowance and confirm whether an equivalent retrospective allocation of the 2019 allowance is available.

CA-NLH-070 (Reference: Schedule B-II (Volume 1, page 220); 2017 GRA Volume 1 (Revision 5, July 4, 2018), Schedule 3-X (pages 165, 167)).

Provide a single reconciled table showing Hydro's actual operating costs by functional area for each year 2018 through 2026 (actuals where available, forecast for years not yet complete), cross-walked to both:

(a) the 2017 GRA's approved 2018 and 2019 Test Year figures by the functional taxonomy used at that time (Schedule 3-X), and
(b) the current functional taxonomy used in this GRA's Schedule B-II, noting explicitly where departmental groupings were changed, combined, or renamed between the two filings. Provide the crosswalk in Excel with a mapping key showing which current functional line corresponds to which former functional line, flag any function where actual costs have grown faster than the 2017 GRA's approved forecast contemplated, and provide Hydro's explanation for each such function.

CA-NLH-071 (Reference: Volume 1, table 3-2, page 3.5)

Hydro provides (table 3-2) total salaries for the 2019 Test Year and from 2024 actual to the 2027 Test Year. Provide a breakdown of the salaries by business unit and division by year for the 2019 Test Year to the 2027 Test Year and a variance analysis for material increases and decreases in the salaries by business unit and division over that timeframe.

CA-NLH-072 (Reference: Volume 1, page 2.39)

Hydro states (lines 9 to 10) *"Operational efficiencies may serve to offset upward cost pressures rather than generate standalone savings."* Elaborate on what Hydro is intending to communicate to the Board and intervenors through the above quoted passage from the GRA filing.

CA-NLH-073 (Reference: Volume 1, page 2.51)

Hydro states (lines 11 to 17) *"Applied from an enterprise-wide perspective, the productivity allowance has been allocated across departments as a percentage of total budgeted dollars...these efficiencies are embedded in the forecast as avoidable expenditures rather than discrete line-item reductions."*

(a) Clarify if Hydro's 2027 Test Year $4.0 million productivity allowance has been allocated to all departments on an across-the-board basis or has been targeted toward specific departments or cost elements.
(b) Explain the difference in Hydro's view between avoidable expenditures as compared to discrete line-item reductions.

CA-NLH-074 (Reference: Volume 1, page 121 (footnote 33); Volume 1, page 117 (Table 3-2))

(a) Provide Hydro's actual year-end FTE complement, budgeted FTE complement, and vacancy count/rate, by functional area, for each year 2019 through 2026, and the budgeted/forecast FTE complement for the 2027 Test Year, in Excel.
(b) Explain the methodology for setting the 2027 Test Year's 55-FTE vacancy allowance - more than triple the 15-FTE allowance set in Order No. P.U. 16(2019) - and provide its dollar value, consistent with how the 15-FTE/$1.3 million 2019 figure was quantified.
(c) Confirm what portion of the FTE growth reflected in the 2027 Test Year's labour costs is offset by capitalization to the General Expenses Capitalized Deferral Account, and provide the FTE count associated with that capitalized portion, with a reconciliation showing capitalized-versus-expensed FTE growth for 2024 through the 2027 Test Year.

CA-NLH-075 (Reference: Volume 1, chart 2-11, pages 2.25 and 2.26)

Hydro states (lines 17 to 18 on page 2.25) *"To support work required now and into the future, Hydro's FTE compliment is increasing by approximately 5.6% over the eight-year period between test years."* Hydro provides a bar chart (chart 2-11, page 2.26) of regulated FTEs from the 2019 Test Year to the 2027 Test Year.

(a) Explain if chart 2-11 is based on gross FTEs or is net of FTEs where the associated salary costs have been deferred into the General Expenses Capitalized Deferral Account.

(b) Provide a breakdown of gross regulated FTEs from the 2019 Test Year to the 2027 Test Year by business unit and division and a variance analysis of the changes in FTEs by business unit and division over that timeframe.
(c) Provide a breakdown of projected gross regulated FTEs from 2028 Forecast to 2030 Forecast by business unit and division and an associated variance analysis of the projected changes over that timeframe.

CA-NLH-076 (Reference: Volume 2 (Exhibit 6), pages 256-258; Volume 1, page 117 (footnote 19); Order No. P.U. 3(2025), page 26)

(a) Provide the full list of utilities in Southlea's recommended comparator group, identifying which are government-owned and which are investor-owned, and the specific quantitative adjustment applied for the *"Atlantic compensation market differential."*
(b) Provide Hydro's current total compensation positioning (percentile) relative to the comparator group, by employee category (union, management, executive), both before and after the salary adjustments proposed in this GRA.
(c) Confirm whether short-term or long-term incentive pay for any employee category is included in the 2027 Test Year revenue requirement, and if so, provide the methodology and dollar amount, having regard to the Board's treatment of short-term incentive pay in Order No. P.U. 3(2025). Provide supporting workpapers for each of (a) through (c).

CA-NLH-077 (Reference: Volume 1, page 2.23 and 2.24 and Volume 2, Exhibit 6)

Hydro states (lines 17 to 18 and 22 to 24 of page 2.23) *"Hydro targets 50th percentile as the competitive position within its comparator market…Southea found that the appropriate comparator group for Hydro is other Canadian utilities, including government-owned and investor-owned utilities…"* Hydro states (lines 13 to 21 pf page 2.24) *"To address survey outcomes and start to realign its position with its comparator market, Hydro increased its compensation levels, administering economic increases of 4% in 2024 and 4% in 2025…Hydro continued to be approximately 11% below the 50th percentile target at the end of 2025…Hydro has forecast modest salary adjustments though its 2027 Test Year that are required to close the gap with Atlantic Canadian utility comparators…"*

(a) Clarify if the prior comparator group that Hydro has used for its compensation policy is Atlantic Canadian utilities.
(b) Explain if Hydro has adopted the Southea recommendation to change the comparator group to other Canadian utilities or not.
(c) Provide the timeframe over which Hydro plans to target a 50% percentile of either the prior/current comparator group or the new comparator group.
(d) Provide a quantification of the overall cost of the 4% economic increases in 2024 and 2025.
(e) Provide the economic increases forecast by Hydro for 2026 and 2027 and quantify the overall cost impacts of these increases. (e) Describe and quantify the cost implications of full implementation of the Southea recommendation for the 2027 Test Year and for the years 2028 to 2030.
(f) Explain if and how Hydro has factored the projected revenue requirement and rate increase impacts of the Muskrat Falls Project into its compensation approach for the 2024 to 2030 timeframe.

CA-NLH-078 (Reference: Volume 1, page 2.28)

Hydro states (footnote 60) *"...Hydro's operating costs in 2025F, 2026F and 2027TY are shown net of deferred salaries to the General Expenses Capitalized Deferral Account as approved in Board Order No. P.U. 32 (2025)."*

(a) Provide the $ of salaries by business unit and division and in total that have been or are forecast to be deferred into the General Expenses Capitalized Deferral Account for each of 2025 Actual, 2026 Forecast and the 2027 Test Year.
(b) Explain the nature of salaries that have been or are forecast to be deferred into the General Expenses Capitalized Deferral Account.

CA-NLH-079 (Reference: Volume 1, page 1.11)

Hydro states (lines 6 to 7) *"A significant reorganization of the executive structure occurred in November 2021, with a sizable reduction in the executive team from 18 positions down to 11…"* Provide an estimate of the savings (net of allocations amongst affiliates) to Hydro regulated operations in the 2027 Test Year related to the reduction of the executive team.

CA-NLH-080 (Reference: Volume 1, page 3.1)

Hydro states (lines 15 to 18) *"Hydro has compiled its forecast for the 2027 Test Year using a combination of zero-based budgeting and historical average approach. The major cost components…were derived using zero-based budgeting, including, but not limited to, employee salaries and benefits, professional services and SEM costs."* Provide a list and quantification of the related $ associated with those historic FTEs and costs items from 2026 (or prior years) that were not justified to continue for the 2027 Test Year and directly result from Hydro's zero-based budgeting approach.

G. Revenue Requirements

CA-NLH-081 (Reference: Volume 1, chart 2-8, page 2.11 to 2.12)

Hydro states (lines 11 to 12 on page 2.11 and lines 4 to 6 on page 2.12) *"Since 2019, Hydro's total annual capital expenditures have averaged approximately $140 million, including Major Projects…an upward trend in spending over the 2024 to 2027 period…with forecasted spending of $284 million in 2026 and $532 million in 2027."*

(a) Provide a breakdown of capital spending from 2019 actual to the 2025 actual by investment category (major projects, sustainment, capacity and growth and operational support etc.) and by investment sub-category (sub-categories under each main investment category).
(b) Provide a breakdown of capital spending from 2026 Forecast to the 2030 Forecast by investment category and investment sub-category.

CA-NLH-082 (Reference: Volume 1, table 5-5, page 5.7)

Hydro provides (table 5-5) a table which compares components of other revenue requirement adjustments for the 2019 Test Year and 2027 Test Year. Hydro states (lines

3 to 10) *"…other adjustments… increased by approximately $57.7 million in comparison to the 2019 Test Year...the primary driver of the increase is net export revenue of $40.2 million…also contributing to the variance is an increase in transmission tariff revenue of $18.3 million…involves payment of a "point-to-point"* transmission tariff by the transmission customer."

(a) Explain who the transmission customer is that pays transmission tariff revenues to Hydro.
(b) Extend table 5-5 to include 2028 Forecast to 2030 Forecast of other adjustments and comment on the reasons for changes in projected other adjustments.

CA-NLH-083 (Reference: Volume 1, table 5-7, page 5.11 and table 5-8, page 5.12)

Hydro provides (table 5-7) a table which compares components of total rate base for the 2019 Test Year and 2027 Test Year, which indicates that total average capital assets in rate based increased $335.2 million and that the Muskrat Falls related working capital allowance is $115.1 million for the 2027 Test Year. Hydro provides (table 5-8) a table which indicates that the Muskrat Falls related working capital has been calculated assuming revenue lag days of 44.5, expense lead days of 7.8 and cash operating expenses of $806.0 million.

(a) Provide a schedule of capital project additions to rate base from the 2019 Test Year to the 2027 Test Year.
(b) Provide the calculations to derive the Muskrat Falls revenue lag of 44.5 days and expense lead of 7.8 days.
(c) Reconcile the $806.0 million of Muskrat Falls cash operating expenses in the working capital calculation to the $780.0 million of Muskrat Fall Supply Costs included in revenue requirement for the 2027 Test Year.
(d) Extend table 5-7 to include 2028 Forecast to 2030 Forecast of average rate base and comment on the reasons for changes in projected components of average rate base.

CA-NLH-084 (Reference: Volume 1, Schedule D-I and Schedule D-II)

Hydro provides (Schedule D-I and D-II, pages 1 to 7) details of revenue requirements, financial results and forecasts from the 2019 Test Year to the 2027 Test Year.

(a) Provide Hydro's Annual Report for the year ended December 31, 2025 on the record of this proceeding.
(b) Provide Schedules D-I and Schedule D-II (pages 1 to 7) that include 2028 Forecast to 2030 Forecast amounts.

CA-NLH-085 (Reference: Volume 1, page 2.18)

Hydro states (lines 1 to 3) *"Imports, when available, can occur through a combination of day-ahead commitments and real-time transactions; however, they are not forecast to occur during the 2027 Test Year, as the deliveries are considered non-firm."* Describe and quantify the cost implications for the 2027 Test Year of assuming no imports (firm or non-firm) over the Maritime Link.

CA-NLH-086 (Reference: Volume 1, page 2.43)

Hydro states (lines 20 to 21) *"From 2019 through 2024, Hydro's regulated business* *segment has maintained capital investment levels below its ten-year historical average."* Provide the analysis to support Hydro's assertion that capital investments in the last six-years are below its ten-year historical average.

CA-NLH-087 (Reference: Volume 1, table 5-2, page 5.3 and schedule D-I)

Hydro provides (table 5-2) a table which compares two components of Fuel costs for the 2019 Test Year and 2027 Test Year, No. 6 and other fuels and Diesel and CT fuels. Hydro states (lines 6 to 8 of page 5.3) *"No. 6 fuel costs decreased by $129.7 million primarily as a result of the commissioning of the Muskrat Falls Assets, allowing for materially lower thermal generation at Holyrood TGS to be replaced by clean hydro generation from Muskrat Falls."* Schedule D-I indicates that Fuel costs for 2022 Actual to 2026 Forecast were significantly higher than 2021 Actual and the Forecast for the 2027 Test Year.

(a) Explain why Fuel costs significantly increased between 2022 Actual and 2026 Forecast.
(b) Extend table 5-2 to include 2028 Forecast to 2030 Forecast of fuel costs and comment on the reasons for changes in projected fuel costs.

CA-NLH-088 (Reference: Volume 1, table 5-3, page 5.4 and page 5.5)

Hydro provides (table 5-3) a table which compares components of power purchases for the 2019 Test Year and 2027 Test Year. Hydro states (lines 1 to 3 of page 5.5) *"The primary driver of the $14.8 million decrease in the 2027 Test Year power purchases…is lower off island power purchases…due to imports over the Maritime Link, which were forecast in the 2019 Test Year but are not forecast for 2027."*

(a) Provide a table of Off-Island power purchases for the 2019 Test Year to 2025 Actual and the 2026 Forecast.
(b) Extend table 5-3 to include 2028 Forecast to 2030 Forecast of fuel costs and comment on the reasons for changes in projected power purchased costs.

H. Depreciation and Asset Service Lives

CA-NLH-089 (Reference: Order No. P.U. 1(2024), page 2; Volume 3, pages 695-697)

Given that the $2.5 million deadband on the Holyrood TGS Accelerated Depreciation Deferral Account was established, per the Board's own characterization, on the basis that it represented the average depreciation expense variance at the time, and Hydro's current filing forecasts a 2028-2030 swing averaging approximately $50 million per year — roughly 16 to 20 times the deadband threshold — explain why the existing fixed $2.5 million deadband remains an appropriate materiality filter for the account going forward. Provide:

(a) Hydro's position on whether the current deadband remains fit for purpose given the disclosed 2028-2030 forecast;
(b) if Hydro proposes to retain the $2.5 million figure, the specific justification for doing so notwithstanding the disclosed magnitude mismatch; and

(c) if Hydro is open to re-calibration, at least one alternative deadband design (e.g., a percentage of forecast accelerated depreciation rather than a fixed dollar figure), with its resulting dollar threshold for each of 2028, 2029, and 2030.

CA-NLH-090 (Reference: Volume 1, table 5-4, page 5.5 and page 5.6, Volume 2, Exhibit 7 and Volume 3, Exhibit 8)

Hydro provides (table 5-4) a table which compares depreciation and accretion for the 2019 Test Year and 2027 Test Year. Hydro states (lines 14 to 16 of page 5.5 and lines 1 to 9 of page 5.6) *"In the 2027 Test Year, depreciation and accretion is $31.9 million higher than in the 2019 Test Year….as a result of Hydro's capital program, including projects related to Holyrood TGS, which are depreciated at an accelerated rate given its planned retirement…partially offset by reduced depreciation rates proposed in the depreciation study…The depreciation study recommends the use of updated estimates of the service life of assets. The combined impact of these changes on Hydro's revenue requirements for the 2027 Test Year is a decrease of $7.3 million from the 2019 Test Year."*

(a) Provide a breakdown of the net $31.9 million increase in depreciation from the 2019 Test Year to the 2027 Test Year between plant additions, plant retirements, Holyrood TGS accelerated depreciation and the impacts of the depreciation study.
(b) Provide an analysis that supports the $7.3 million decrease in depreciation expense between the 2019 Test Year and 2027 Test Year as a result of changes proposed in the depreciation study by plant category.
(c) Identify the most material increases and decreases in depreciation expense that result from the depreciation study and provide summary explanations of the reasons for the proposed useful life changes related to these material increases and decreases.
(d) Extend table 5-4 to include 2028 Forecast to 2030 Forecast of depreciation and accretion and comment on the reasons for changes in these projected costs.

CA-NLH-091 (Reference: AFUDC Deferral Account Application (April 14, 2026), page 14; Volume 1, page 160 (footnote 76); Volume 3 (Exhibit 8), page 73 (Table 1); Volume 1, page 149)

Reconcile the following four composite depreciation rate figures appearing in the record: (i) 2.28%, cited as the currently Board-approved rate from the 2016 Depreciation Study per Order No. P.U. 16(2019); (ii) 2.34%, cited at Volume 1 page 160 footnote 76 as the composite rate in the latest Depreciation Methodology Study, attributed to a weighted average of composite rates in Exhibit 8; (iii) 2.27%, the *"Total Plant In Service"* calculated annual accrual rate in Exhibit 8's own Table 1; and (iv) 2.10%, the *"Total Plant"* rate (including the H02 Holyrood accelerated asset) on the same table. Confirm whether 2.34% reflects a different aggregation basis, a different vintage (the 2023 study versus the 2024 update), or a transcription or rounding artifact; provide the specific page, table, and formula from which the 2.34% figure is derived, showing its calculation in full. State which rate Hydro is actually proposing to apply to the AFUDC Deferral Account's amortization going forward, and confirm whether the AFUDC Application's Table 2 arithmetic is affected by any pending change from 2.28% to a different approved composite rate arising from this GRA's approval of the 2023 Depreciation Study and 2024 Technical Update.

CA-NLH-092 (Reference: Volume 3, page 696 (footnotes 5-6))

Produce the full Life Extension Condition Assessment studies performed by Hatch Ltd.

for the Holyrood Thermal Generating Station — both the original study performed in 2021 (attached to Hydro's March 31, 2022 filing as Attachment 2) and the 2024 refresh (attached to Hydro's March 7, 2025 filing as Attachment 1) — including the engineering basis for the specific timing and dollar magnitude of the capital projects driving the $43.5 million (2028), $55.2 million (2029), and $13.8 million (Q1 2030) accelerated-depreciation forecast. If Hydro's position is that production is unnecessary because the studies were filed in the referenced proceedings, provide the specific filing/docket reference and page numbers, together with any summary or extract already prepared for regulatory purposes that ties specific Hatch-identified capital projects to specific in-service years within the 2028-2030 window.

CA-NLH-093 (Reference: Volume 2, page 321; Volume 3 (Exhibit 8), page 73)

(a) Confirm whether the exclusion of the H02 Holyrood accelerated-depreciation asset from ordinary survivor-curve treatment (Survivor Curve *"N/A,"* net salvage 0%, calculated annual accrual rate 0.00% in both the 2023 Depreciation Study and the 2024 Technical Update) is a recommendation made by Concentric Advisors, an instruction given by Hydro to Concentric, or a convention inherited from the 2016 Depreciation Study; identify whether any alternative treatment (e.g., a shortened but still survivor-curve-based approach) was considered and rejected, and if so, why; and provide the documentation of that decision, including any memoranda, correspondence, or study-scoping documents.
(b) Explain the basis for the growth in the H02 asset's original cost from approximately $210.3 million in the 2023 Depreciation Study to $271.6 million in the 2024 Technical Update, providing a schedule of the capital additions to the H02 asset class between the two studies' cut-off dates, with dollar amounts and in-service dates for each material addition.

I. Finance and Cost of Capital

CA-NLH-094 (Reference: Volume 1, page 127; OC2013-343)

Confirm whether the exemption of Muskrat Falls Project costs from Board disallowance or reduction under OC2013-343 and related instruments reduces Hydro's cost-recovery risk, for the exempted cost categories, relative to costs that remain subject to ordinary prudence review. Provide a direct confirmation or denial; if Hydro disputes that the exemption reduces cost-recovery risk for the exempted categories, explain the basis for that position.

CA-NLH-095 (Reference: Volume 1, page 144; OC2009-063)

Provide any risk assessment, cost-of-capital analysis, or similar internal or consultant-prepared study conducted by or for Hydro that addresses the business or financial risk profile underlying the 4.05% embedded cost of debt or the 8.60% return on equity used in this GRA. Provide the document(s) in full, or confirm that no such Hydro-specific risk assessment exists. If none exists, confirm that Hydro's cost of capital is derived entirely from Newfoundland Power's separate rate-setting process under OC2009-063 without any independent Hydro-specific risk analysis.

CA-NLH-096 (Reference: Volume 1, table 5-10 and table 5-11, page 5.15, schedule D-IV and schedule

D-II, page 4 of 7)

Hydro provides (table 5-10) a table with a comparison of the average debt and finance charges and (table 5-11) a table which calculates the return on rate base and rate of return on rate base with a comparison between the 2019 Test Year and the 2027 Test Year. Schedule D-IV provides a summary of the composition of Hydro's total debt from the 2019 Test Year to the 2027 Test Year. Schedule D-II, page 4 of 7 provides the calculation of return on rate base.

(a) Provide an explanation of the source and calculation of the total forecast interest rate for debt Series 4A of 4.68% in 2026 and debt Series 5A of 4.73% in 2027 with a breakdown between the forecast benchmark interest rate and forecast provincial spread and confirm that the quoted interest rates do not include the debt guarantee fee.
(b) Provide the projected % rate of the debt guarantee fee for 2026 Forecast and 2027 Test Year.
(c) Explain why Interest Cost of Service Exclusions ($8.792 million) that related to the disallowed portion of the debt guarantee fees are included in the Net Interest component ($81.3 million) of Return on Rate Base (Schedule D-II, page 4 of 7) and ultimately in total revenue requirements for the 2027 Test Year.

CA-NLH-097 (Reference: Volume 1, page 5.1)

Hydro states (lines 3 to 5) *"...rates charged by Hydro should provide it with an opportunity to earn a fair, just, and reasonable rate of return to achieve and maintain a sound credit rating in the financial markets…"* Explain if Newfoundland & Labrador Hydro or Hydro regulated operations have their own standalone credit rating.

CA-NLH-098 (Reference: Volume 1, pages 1.2 and 1.17)

Hydro states (lines 21 to 23 of page 1.2) *"The purpose of this application is to update the rates to be charged by Hydro for the supply of electricity, enable the review of costs and how they are allocated amongst classes and allow for an opportunity for Hydro to earn a just and reasonable return"*. Hydro states (lines 11 to 16 of page 1.17) *"Government has directed Hydro…these directions effectively cap the recovery of Hydro's costs through customer rates and shift a portion of costs away from ratepayers."* Explain if the direction from Government in the Rate Mitigation Plan is to effectively cap Hydro's return on equity and shift a portion of these costs away from ratepayers.

CA-NLH-099 (Reference: Application, Chapter 5, page 5.1)

Hydro states *"Hydro's revenue requirement is generally comprised of the return on rate base and other reasonable costs, including operating costs, fuels, power purchases, other supply costs and depreciation; however, for the 2027 Test Year, the revenue requirement includes Muskrat Falls supply costs and is calculated net of rate mitigation funding that offsets a portion of Hydro's costs that would otherwise be recovered through customer rates."* Is Hydro allowed a return on assets that are not under Board jurisdiction? Is Hydro proposing to earn a return on the costs of the Muskrat Falls assets, or on the costs of the Muskrat Falls assets less the cost of rate mitigation?

CA-NLH-100 (Reference: Volume 1, Schedule D-IV)

Hydro provides (Schedule D-IV)) a summary of the composition of Hydro's total debt from the 2019 Test Year to the 2027 Test Year.

(a) Summarize the terms (interest rate and repayment) of the promissory notes included in Schedule D-IV and indicate if the related interest rate is a variable rate or fixed rate.
(b) Identify any of the debt series provided in Schedule D-IV that are long-term variable rate debt.
(c) Provide a schedule from the 2019 Test Year to the 2027 Test Year that calculates the % of Hydro's total debt portfolio that is comprised of short-term variable rate debt and long-term variable rate debt.
(d) Provide Hydro's policy and financial guidelines with respect to limits on the use of variable rate debt in its debt portfolio.

CA-NLH-101 (Reference: Schedule D-IV (Volume 1, page 238); Volume 1, page 151 (footnote 40))

Confirm the scope of the provincial guarantee of Hydro's debt: which categories of Hydro debt (debentures, promissory notes, or other instruments per Schedule D-IV) are covered by a Government of Newfoundland and Labrador guarantee, and confirm whether Newfoundland Power's debt carries an equivalent provincial guarantee on the same or a different basis. Provide a direct confirmation or denial for each debt category.

CA-NLH-102 (Reference: Order No. P.U. 33(2021), page 8)

Provide Hydro's short-term borrowing rate (commercial paper, operating line, or equivalent) for each year from 2019 through the most recent available date, as an annual (or, if available, monthly) series, identifying any changes in the facility or instrument used over that period.

J. Debt Guarantee Fee

CA-NLH-103 (Reference: Schedule D-IV (Volume 1, page 238, note 2); Schedule D-III (page 237, note 3); Schedule D-II (pages 233, 235); Order No. P.U. 16(2019), page 69 (item 7(c)))

Confirm whether the disallowed portion of the Debt Guarantee Fee reflected in the current filing's *"Interest Cost of Service Exclusions"* line traces directly to the disallowance ordered in Order No. P.U. 16(2019) item 7(c), and if so, describe the methodology used to calculate the disallowed amount in each year since 2019. Provide a narrative and, if available, a calculation showing the continuity (or lack of continuity) between the P.U. 16(2019) disallowance and the disallowed amounts embedded in the current filing for each Test Year and actual year from 2019 to 2027. If the current disallowance methodology differs from what P.U. 16(2019) ordered, explain the difference and its basis.

CA-NLH-104 (Reference: Schedule D-IV (Volume 1, page 238); Schedule D-II (pages 233, 235); Schedule D-III (page 237))

State the basis-point rate (or other rate basis) at which the Debt Guarantee Fee is calculated, and identify the specific legal instrument (statute, Order in Council, guarantee agreement, or other instrument) under which the Government of Newfoundland and

Labrador guarantees Hydro's debt and charges this fee. Provide the fee's calculation basis, the governing instrument in full or by citation, and confirm whether the rate has changed at any point in the 2019-2027 period shown in Schedule D-IV.

CA-NLH-105 (Reference: Schedule D-IV (Volume 1, page 238))

Explain the composition of the Debt Guarantee Fee and the drivers of its growth from $8,513,000 (2019 Test Year) to $10,571,000 (2027 Test Year), including the approximately $1.3 million increase between the 2025 forecast ($9,008,000) and the 2026 forecast ($10,327,000). Provide a year-by-year reconciliation showing the effect of

(a) growth in guaranteed debt principal outstanding,
(b) any change in the fee rate itself, and
(c) any other driver, on the total fee for each year 2019-2027.

CA-NLH-106 (Reference: Schedule D-IV (Volume 1, page 238))

Provide a table showing, for each year 2019 through 2027 (Test Years and actuals as available), the total Debt Guarantee Fee, the portion disallowed from cost of service, the portion recovered from customers, and the recovered amount as a percentage of the total fee. Reconcile the disallowed amount to the *"Interest Cost of Service Exclusions"* line in Schedule D-IV, and - noting that the exclusion line is not guarantee-fee-specific - identify what portion of Interest Cost of Service Exclusions in each year is guarantee-fee-related versus other excluded interest items.

K. Cost of Service

CA-NLH-107 (Reference: Application)

Effect of Approved COS Methodology Changes. Provide a table that identifies each Cost-of-Service methodology change approved since the 2017 GRA. As part of the response, provide a table that quantifies the cumulative shift in allocated revenue requirement cost responsibility of each customer class resulting from all methodological changes.

CA-NLH-108 (Reference: Application)

In order to understand the changes in allocated revenue requirement by class that flow from Cost-of-Service methodology changes separately from system/cost changes since the 2017 approved GRA, provide a table of the allocated revenue requirement by customer class flowing from the approved 2017 GRA and the proposed 2027 Test Year separately identifying the impact due to: i) changes in system configuration (for example Muskrat Falls, Labrador-Island Link etc.); ii) changes arising from Cost-of-Service methodologies; and iii) changes in forecast loads, coincident peaks and customer numbers.

CA-NLH-109 (Reference: Application)

Explain how Hydro determined that each methodology change since the approved 2017 GRA improves the overall allocation of costs within the integrated provincial electricity system, rather than improving the allocation of an individual cost component in isolation.

As part of the response, explain how Hydro assessed the cumulative impact of the proposed methodology changes on overall class revenue responsibility. If not, explain why not.

CA-NLH-110 (Reference: Application)

Provide a consolidated table that compares of all material demand and energy allocators reflected in the approved 2017 GRA and proposed 2027 Test Year Cost of Service Studies, including for each allocator: i) the allocator value or customer-class percentage in each Test Year; ii) the underlying billing demand, coincident peak, and energy used to derive the allocator; and iii) an explanation of each material change. As part of the response, quantify the effect of changes in the allocator values, separate from changes in classification methodology and changes in total revenue requirement, on the allocated revenue requirement of each customer class.

CA-NLH-111 (Reference: Application, Chapter 6, page 6.2)

Hydro states *"The functionalization of Hydro's existing generation and transmission assets have remained the same."* How has Hydro functionalized and classified existing generation and transmission assets in the cost of service study?

CA-NLH-112 (Reference: Application)

Provide a table that compares the 2027 Rural Deficit allocated to each customer class to the 2027 Rural Deficit allocation by customer class assuming that industrial customers were not excluded from contributing toward the Rural Deficit and identify any material assumptions and/or caveats.

CA-NLH-113 (Reference: Application)

Provide a table that compares the Rural Deficit allocated (in both $ and %) to each customer class flowing from the 2017 approved GRA and the proposed 2027 Test Year. As part of the response, also include a column that provides a brief description of the drivers of material variances.

CA-NLH-114 (Reference: Application)

Provide a table that compares the amount of the proposed 2027 Rural Deficit recovered from each customer class through proposed rates to the Rural Deficit allocated in the Cost-of-Service Study. As part of the response, include a column with a brief description of the drivers of material differences.

CA-NLH-115 (Reference: Application, Chapter 2, page 2.36)

Hydro states *"The Rural Deficit is approximately 8% of Hydro's overall revenue requirement."* It is understood that the revenue shortfall in the 2027 Test Year is 39% ($502 million / $1300 million).

(a) What are each of these deficits when translated into cents/kWh?
(b) Identify the amount of the 2027 Rural Deficit allocated to Newfoundland Power customers and explain how Hydro reconciles that allocation with the fact that, owing

to rate mitigation, Newfoundland Power customers' rates recover less than the cost of supply. Provide any analysis Hydro has undertaken on this point.

CA-NLH-116 (Reference: Schedule F (Volume 1, pages 248, 250); Schedule G (Volume 1, pages 357, 359))

Provide a customer-class comparison of Schedule F and Schedule G showing mitigated and unmitigated allocated costs, forecast revenues, revenue-to-cost ratios, revenue deficiencies/sufficiencies, and bill impacts, in Excel, by system, function, class, and rate class. Include explanatory notes for each material difference and identify how rate mitigation is allocated in the cost-of-service study.

CA-NLH-117 (Reference: Schedules F.1.2 – G.1.2, Class Revenue-to-Cost Ratios)

(a) Explain whether Hydro targets unity or a revenue-to-cost ratio bandwidth (say of 95% - 105% or 90% - 110%) in the translation of class allocated cost to rate design. As part of the response, discuss the rationale for the tolerance band.
(b) Explain how long Hydro's revenue-to-cost ratio bandwidth has been in effect, including when it last undertook a review as part of a public proceeding. As part of the response, provide Hydro's evidence (including evidence of any external consultant prepared on behalf of Hydro, the PUB or other intervenor).
(c) Provide a consolidated table that compares the revenue-to-cost ratios by class including and prior to rate mitigation flowing from the current 2027 Test Year. As part of the response, explain the drivers of any variance in revenue-to-cost ratios between the two scenarios.
(d) Provide a consolidated table that compares the revenue-to-cost ratios by class: i) flowing from the 2017 approved GRA; ii) the current 2026 proposed GRA prior to rate mitigation; and iii) the current 2026 proposed GRA including rate mitigation. As part of the response, explain the drivers of the variance between the 2017 approved GRA and the proposed 2026 GRA.

CA-NLH-118 (Reference: Application)

Provide a reconciliation between the allocated revenue requirement by customer class reflected in the proposed Cost of Service Study and the revenue recovered from each customer class through the proposed rates after application of rate mitigation, identifying each adjustment made between the Cost-of-Service Study and the proposed revenue recovery.

CA-NLH-119 (Reference: Application)

Provide a table comparing the revenue to cost ratios for each of Hydro's customer classes for the 2027 Test Year both with and without rate mitigation.

CA-NLH-120 (Reference: Schedules beginning with F.2.3E)

Provide a table that consolidates all specifically assigned assets included in the proposed Cost of Service Study together with the annual Direct O&M Charge and Indirect O&M Charge assigned to each asset

CA-NLH-121 (Reference: Application, Chapter 6, page 6.22)

Hydro states *"Specifically assigned charges recover costs incurred for assets that are in service solely for each Island Industrial Customer."* Does Hydro follow a similar approach for Newfoundland Powers connection assets?

CA-NLH-122 (Reference: Application, Chapter 2, page 2.12)

Hydro states *"Recognizing the scale of planned capital investment and broader cost-of-living pressures faced by customers, Hydro reduces or defers capital investment, where appropriate."*

(a) Maintaining Holyrood TGS and the Hardwoods and Stephenville gas turbines in service until 2030 indicates that Hydro believes that the benefits during this period exceed the high costs, poor reliability performance and detrimental environmental and safety impacts of these facilities. Quantify the benefits versus costs and risks for the period up to 2030.
(b) Retiring Holyrood TGS and the Hardwoods and Stephenville gas turbines in 2030 indicates that Hydro believes that the benefits in the period beyond 2030 no longer exceed the high costs, poor reliability performance and detrimental environmental and safety impacts of these facilities. Quantify the benefits versus costs and risks for the period 2030 to 2035.

CA-NLH-123 (Reference: Application)

Provide a table with the allocated rate base and revenue requirement by customer class separately for each of the following; i) Muskrat Falls; ii) Labrador-Island Link; and iii) the Maritime Link.

CA-NLH-124 (Reference: Application)

Provide a consolidated schedule identifying, for each material generation asset, power purchase and generation-related credit or revenue included in the proposed 2027 Cost of Service Study:

(a) The 2027 Test Year cost/revenue amount;
(b) The demand/energy classification percentages; and
(c) The resulting allocation by customer class. For example, include: i) Muskrat Falls PPA costs; ii) Transmission Funding Agreement costs; iii) Net Export revenues; iv) Wind Purchase costs; v) Holyrood non-fuel costs; vi) Holyrood fuel costs; vii) Other Power Purchases; viii) Rate Mitigation Funding; ix) Transmission Tariff revenue; and x) Greenhouse Gas Credit revenue.

CA-NLH-125 (Reference: Order 37(2019), Chapter 6, page 6.3)

As part of the Settlement Agreement in 2019 parties agreed that the single coincident peak approach shall continue to be used in the cost allocation of production/generation demand costs and transmission among customer classes. Hydro agreed to further review the contribution of different customer classes to the uncertainty parameters in its planning studies (e.g. P50 vs P90) and file a report with its next General Rate Application.

(a) Confirm whether the report contemplated by the Settlement Agreement has been filed as part of this proceeding.
(b) If yes, identify the document, exhibit or schedule in which the report is contained.

(c) If no, explain why the report has not been filed and indicate when Hydro intends to complete and file the review.

CA-NLH-126 (Reference: Application)

Provide a table that compares the approved 2017 GRA forecast coincident peak responsibility, energy, and customer numbers by customer class underpinning the approved 2017 Cost of Service Study to the proposed 2027 Test year. As part of the response, include a column that identifies the material drivers of change.

CA-NLH-127 (Reference: Application)

Provide the 2017 Cost of Service Study as approved.

CA-NLH-128 (Reference: Application)

To understand how costs have migrated by class, provide a table that compares allocated revenue requirement by class (% and $) from the 2017 approved GRA and the 2027 proposed GRA showing for each: i) generation; ii) transmission; iii) distribution; iv) Rural Deficit; v) Customer costs; vi) Total allocated revenue requirement; and vii) percentage of total revenue requirement.

CA-NLH-129 (Reference: Schedule F (Volume 1, page 251); Schedule G (Volume 1, page 360))

Provide Newfoundland Power's internal allocation of the Island Interconnected rate mitigation credit across its own retail rate classes (Domestic, Domestic All Electric, General Service tiers, Special, and Street and Area Lighting): the sub-class-level cost-of-service study or allocation schedule NP uses to distribute the mitigation credit it receives from Hydro, showing the dollar amount and resulting revenue-to-cost coverage-ratio effect for each sub-class, mitigated and unmitigated. If this data properly belongs to Newfoundland Power rather than Hydro, identify which party should respond and on what basis.

CA-NLH-130 (Reference: Schedule F, Volume 1, page 248; Schedule G, page 357; Volume 2, Exhibit 4)

(a) For each year from 2010 to 2027F, provide a table showing the total number of NP customers by customer class, with Domestic customers decomposed by regular and all-electric.
(b) For the same years, provide annual total sales in MWh to each group of customers in (a).
(c) For the same years, provide annual total sales in MWh per customer for each group.
(d) For January 2023 to June 2026, provide monthly electricity sales (kWh) per customer for Domestic regular, Domestic all-electric, each class of General Service, and street-lighting customers. Provide the four tables in Excel or equivalent tabular format, with a customer-class taxonomy matching the classes used in Schedules F and G. If this data properly belongs to Newfoundland Power rather than Hydro, identify which party should respond and on what basis.

CA-NLH-131 (Reference: Chapters 5 and 6; Exhibits 14 to 17)

Hydro's Application proposes a number of changes to cost allocation methodologies and rate design. These proposals rely upon a variety of principles, including embedded cost causation, demand and energy cost classification, marginal-cost pricing, opportunity-cost pricing, and customer price signals. Explain how Hydro has ensured that these proposals operate together as a cohesive framework for establishing rates. In particular:

(a) Describe the overarching principles Hydro applied in developing the proposed cost allocation methodologies and rate design.
(b) Explain how the proposed cost allocation methodologies and rate design collectively achieve the objectives of fairness, cost causation, economic efficiency, and equitable cost recovery.
(c) Explain how Hydro reconciles the use of embedded-cost principles for cost allocation with the use of marginal-cost and opportunity-cost principles in rate design.
(d) Explain how Hydro determined which system costs are appropriately reflected through: i) demand-related cost allocation; ii) energy-related cost allocation; iii) demand charges; iv) First and Second Block Energy rates; and v) other rate components.
(e) Explain how Hydro ensured that demand-related system costs reflected in marginal or opportunity-cost pricing signals have been appropriately distinguished from those recovered through embedded cost allocation methodologies.
(f) Explain how Hydro assessed whether the proposed cost allocation methodologies and rate design, when considered collectively rather than individually, produce an equitable allocation of costs among customer classes. If not, explain why.
(g) Confirm whether Hydro performed an overall assessment of the cumulative interaction of the proposed cost allocation methodologies and rate design. If so, provide that assessment. If not, explain why not.
(h) Explain whether Hydro considered alternative integrated approaches that would have resulted in a different overall balance between demand-based recovery, energy-based recovery and marginal-cost pricing.

CA-NLH-132 (Reference: Chapter 6, Sections 6.2, 6.3, 6.6 and 6.7; Exhibits 14 to 17)

Hydro proposes cost-of-service methodologies that affect the demand and energy classification of supply costs. Hydro also proposes an Island Industrial rate design that reduces the demand charge and introduces marginal-cost-based Second Block Energy rates.

(a) Explain whether Hydro evaluated the combined effect of: i) all proposed changes to the demand and energy classification of system costs; ii) the relative demand and energy allocation factors of Newfoundland Power and Island Industrial customers; iii) the reduction in the Island Industrial demand charge; iv) the recovery of demand-related costs through the Island Industrial First Block Energy rate; and v) the pricing of Island Industrial Second Block Energy at forecast marginal export value. If not, explain why.
(b) Quantify the change in the 2027 Test Year revenue requirement allocated to Newfoundland Power and Island Industrial customers resulting from each proposed change to the demand or energy classification of costs, compared with the previously approved methodology.
(c) Provide the applicable demand and energy allocation percentages for Newfoundland Power and Island Industrial customers and explain how each proposed classification change affects the relative allocation of costs between the two customer classes.
(d) Provide the cumulative change in the revenue requirement allocated to Newfoundland Power and Island Industrial customers resulting from all proposed classification changes.

(e) Explain why greater emphasis on demand-related classification for cost-allocation purposes is appropriate at the same time Hydro proposes: i) reducing the Island Industrial demand charge from $10.73 to $5.50 per kW per month; and ii) recovering most Island Industrial demand-related costs through the First Block Energy rate.

(f) Explain whether the combined cost-allocation and rate-design proposals are expected to increase, decrease or have no effect on the contribution made by Island Industrial customers toward recovery of Hydro's embedded fixed system costs, relative to the previously approved methodologies and rate structure.

(g) Quantify the change in the amount of embedded fixed system costs recovered from: i) Newfoundland Power; and ii) Island Industrial customers, under the proposed cost-allocation methodologies and rate designs, compared with the previously approved methodologies and rate structures.

(h) Explain whether Hydro assessed the combined effect of the proposals on rates ultimately paid by Newfoundland Power's residential customers and provide the results of any such assessment. If not, explain why.

CA-NLH-133 (Reference: Chapter 6, Sections 6.4 and 6.7; Exhibit 17)

(a) Explain Hydro's view as to whether rates that reflect allocated cost responsibility are not necessarily, by that fact alone, fair and equitable rates.

(b) Explain Hydro's view of fairness and equity in the context of rate design, including whether fairness and equity require consideration of factors beyond cost causation and revenue-to-cost alignment.

(c) Identify and explain how considerations of fairness and equity beyond cost causation are reflected in Hydro's proposed rates for Newfoundland Power and Island Industrial customers.

CA-NLH-134 (Reference: Exhibit 12, page 12 and 14)

Hydro states *"If the demand-and-energy approach represents a better estimate of the cost responsibility of each class than does the energy-only allocation, then a move to the demand-and-energy approach results in an appropriate small cost shift toward the Utility customer and away from the Island Industrial customers."* Hydro also states *"Hydro could elect to recover/reimburse costs/credits based solely on energy consumption. This is a simple and well-founded practice in rider pricing bearing on generation-related costs, based on the jurisdictional review."* Given this, and the fact that under Hydro's planning criteria the Muskrat Falls assets provide 0 MW during a LIL shortfall event, why is Hydro not recommending recovery and reimbursement of costs/credits based solely on energy?

L. Newfoundland Power Generation Credit

CA-NLH-135 (Reference: Cost of Service Methodology Application (August 22, 2025), page 97; Technical Conference Presentation (October 14, 2025), page 44)

Recalculate the proposed NP hydraulic generation credit using

(a) a 10-year historical window (2015-2024) and

(b) a rolling 5-year window for each start year from 2015 through 2020, in each case using the same *"maximize event"* measurement basis as the filed 64,000 kW proposal, and report the resulting kW figure for each window together with the standard deviation of the annual observations within each window. Also explain the basis for selecting the specific 2020-2024 window used in the filed proposal, including whether any earlier years were examined and excluded and, if so, on what criteria, given Hydro's statement at the technical conference that it *"did not find a reason to exclude any years."*

CA-NLH-136 (Reference: Volume 1, page 181; Technical Conference Presentation (October 14, 2025), page 53; 2017 GRA Settlement Agreement (April 11, 2018), page 5 (item 25); Order No. P.U. 37(2019), pages 9-10; 2017 GRA Volume 1 (Revision 5, July 4, 2018), page 185)

Identify the specific exhibit, workpaper, application, or Board order in which the existing 83,486 kW NP hydraulic generation credit was first calculated, approved, or adopted as the figure Hydro now proposes to reduce, and provide that document or an excerpt sufficient to show its derivation. Provide:

(a) the originating exhibit, order, or workpaper containing the figure's derivation methodology (window, metric, data source, and calculation), with page or paragraph citation;
(b) a reconciliation between 83,486 kW and the 2017 GRA record's reported hydraulic (~94,191 kW) and combined (~118,077-118,054 kW) generation-credit figures for the 2018/2019 Test Years, explaining whether 83,486 kW reflects a subsequent annual update, a different accounting convention, or a different underlying dataset, and identifying the specific document or proceeding in which any such update occurred; and
(c) confirmation of whether 83,486 kW has been reviewed or re-derived at any point between the 2019 Test Year and this GRA, and if so, in what filing.

CA-NLH-137 (Reference: Schedule G (Volume 1, page 376); Volume 1, page 183 (Table 6-2))

Provide the hydraulic generation credit's dollar-valuation table, in the same format as Schedule G 1.5's thermal generation credit valuation, showing the generation demand rate, gross credit value, NP's cost-share percentage and amount, and net value of credit to NP, for each of 83,486 kW, 74,000 kW, and 64,000 kW. If any input (generation demand rate, coincident peak, or NP's cost-share percentage) differs between the thermal and hydraulic credit calculations, identify the difference and its basis.

CA-NLH-138 (Reference: Tables 6-1 & 6-2, pages 6.8 – 6.9)

In order to understand the isolated impact to each customer class associated with the change in the Newfoundland Power generation credit only, provide a table that compares the cost allocation impact by customer class between the approved 2017 GRA and the proposed 2027 Test Year. As part of the response, include: i) total revenue requirement by class assuming the approved 2017 GRA generation credit of 118.1 MW; ii) the total revenue requirement by class as proposed in the current 2026 GRA; iii) the variance ($ and %) by customer class; and iv) a brief discussion of the driver (s) of the change in allocated cost by customer class.

CA-NLH-139 (Reference: Application)

Explain which generation costs are avoided by Newfoundland Power's generation and whether the credit reflects the demand-related value, energy-related value, or both.

CA-NLH-140 (Reference: Technical Conference Presentation (October 14, 2025), page 44)

Provide the complete dataset underlying the reserve-versus-actual generation comparison presented at page 44 of the October 14, 2025 technical conference presentation — covering all events from 2015 forward (consistent with the window requested in CA-NLH-014), rather than the excerpt presented — showing for each Hydro-requested *"maximize"* event during system peak: the date, NP's available hydraulic capacity, NP's actual delivered hydraulic output, and the shortfall or surplus. Also provide Hydro's explanation of why the pattern of shortfalls in this dataset is, or is not, material to the reliability of the hydraulic generation credit as a planning input.

CA-NLH-141 (Reference: Schedule G (Volume 1, page 463); Cost of Service Methodology Application (August 22, 2025), page 97; Technical Conference Presentation (October 14, 2025), page 44)

State, as a general matter, what principle governs Hydro's choice between a multi-year historical average and a single current/test-year figure when calculating a classification or credit input for cost-of-service purposes, and explain why that principle produces a 5-year average for the NP hydraulic generation credit but a single test-year figure (11.16%, rather than Hydro's own calculated 5-year average of 18.43%) for Holyrood TGS capacity-factor classification. Provide a narrative statement of the governing principle, if one exists as a matter of Hydro policy or practice, and confirm whether the same principle was applied, considered, or rejected for each of the two items deferred to this GRA by Order No. P.U. 14(2026). If no single governing principle exists, confirm that the choice was made independently for each item and identify the item-specific rationale in each case.

CA-NLH-142 (Reference: Cost of Service Methodology Application (August 22, 2025), page 97; Technical Conference Presentation (October 14, 2025), page 86)

Regarding Newfoundland Power's hydraulic generating plants that underlie the NP hydraulic generation credit:

(a) what is the value of those plants based on the cost of purchases from Hydro and the NP hydro generation credit included in Hydro's cost of service study;
(b) provide a table listing all such plants, their capacities, and each plant's monthly generation for January 2025 through June 2026; and
(c) do any of NP's hydraulic plants have significant reservoirs, or are they all run-of-the-river, and if any have significant reservoirs, provide quantitative reservoir information. If this data properly belongs to Newfoundland Power rather than Hydro, identify which party should respond and on what basis.

CA-NLH-143 (Reference: Application, Chapter 6 – Rates and Regulations)

Pages 6.7 through 6.9 explain the Newfoundland Power generation credit.

(a) When, and for what reasons, does Hydro call upon Newfoundland Power i) curtailable load, ii) thermal generation, and iii) hydro generation?
(b) What increase in generation does Newfoundland Power typically provide when Hydro calls upon it to increase hydro generation?

(c) In the past 4 years, how many times, and for what reasons, has Hydro called upon Newfoundland Power i) curtailable load, ii) thermal generation, and iii) hydro generation?

(d) In the past 4 years, how many times, and for what reasons, has Hydro called upon Island Industrial Customers for capacity assistance?

(e) Given that the Utility Wholesale Rate now reflects marginal energy costs, why does Hydro still call upon Newfoundland Power to increase its hydro production for energy savings? Are these energy savings over and above that reflected in the Wholesale Rate, and if so, are these savings conveyed to Newfoundland Power customers whose rates recover the costs of Newfoundland Power's hydro facilities?

(f) Does Hydro call upon Island Industrial Customers to curtail load when it can produce energy savings?

(g) Provide the step-by-step process followed by Hydro in the cost of service study to convey the capacity credits to Newfoundland Power for curtailable load, thermal generation and hydro generation.

(h) Quantify the dollar savings amounts conveyed to Newfoundland Power in the cost of service study for: i) curtailable load, ii) thermal generation, and iii) hydro generation. i) Provide the calculation and assumptions used in the calculation of the capacity assistance credit given Island Industrial Customers.

M. Wind Purchase Classification

CA-NLH-144 (Reference: Volume 1, pages 183-184 (including footnote 11))

Provide the complete fall-2025 Effective Load Carrying Capability (ELCC) study underlying the proposed 43% demand / 57% energy wind-purchase classification, including the study's author, methodology, input data, and the full calculation producing the 43%/57% split. Provide the study report in full (or the relevant excerpt if part of a larger report), the underlying wind-generation and load data used, and a comparison table showing how the 2018 study's 22%/78% split and the 2025 study's 43%/57% split were each calculated, so that the methodology change — not just the numerical result — can be assessed.

CA-NLH-145 (Reference: Volume 1, page 184 (footnote 11); Order No. P.U. 14(2026), page 3; Cost of Service Methodology Settlement Agreement (May 15, 2026), page 2)

Confirm whether Hydro considers the wind generation classification change (22%/78% to 43%/57%) to be properly before the Board in this General Rate Application, and if so, identify the procedural basis, given that it was neither a settled item under the 2026 Cost of Service Methodology Settlement Agreement nor one of the two items expressly deferred to this GRA by Order No. P.U. 14(2026). Provide a direct yes/no confirmation and, if yes, cite the specific provision, order, or filing practice Hydro relies on to treat a classification change introduced after the Settlement Agreement's execution as properly before the Board in this proceeding without a separate methodology application or deferral designation.

CA-NLH-146 (Reference: Volume 1, pages 183-184; Schedule F (page 250); Schedule G (page 359))

Restate the 2027 Test Year Schedule F and Schedule G class-level revenue-to-cost coverage tables using the prior 22% demand / 78% energy wind-purchase classification in place of the proposed 43%/57% split, holding all other inputs unchanged. Provide the restated tables in the same format as filed, by customer class and NP sub-class, with a table showing the dollar and coverage-ratio delta between the 22%/78% and 43%/57% classifications for each class.

CA-NLH-147 (Reference: Application)

Provide a table with the following: i) the total annual wind purchase costs included in the 2027 Test Year Cost-of-Service-Study; ii) the amount allocated to each customer class under the proposed 43% demand/57% energy classification; iii) the amount that would be allocated to each customer class using a 22% demand/78% energy classification; iv) the amount allocated to each class assuming a 100% energy classification; and v) any other classification considered by Hydro. As part of the response, provide the resulting change in allocated revenue requirement by class relative to Hydro's proposal.

CA-NLH-148 (Reference: Application)

Explain why Hydro considers the marginal Effective Load Carrying Capability of wind to be an appropriate basis for classifying the purchase costs of wind facilities. As part of the response: i) explain how Hydro purchases wind power pursuant to its PPA (for example does Hydro pay for power purchases based on energy only or some combination of energy and demand); ii) provide the ELCC, accredited capacity or equivalent capacity contribution attributed specifically to the existing wind facilities in Hydro's 2027 resource adequacy analysis; iii) identify the dependable capacity, if any, assigned to those facilities for operating reserve, planning reserve and contingency purposes; and iv) explain why the percentage capacity contribution should be applied directly to the full contractual purchase cost as the demand-related classification percentage.

CA-NLH-149 (Reference: Application)

Explain why the proposed purchased wind classification represents a more appropriate allocation of integrated system costs than the previously approved methodology. As part of the response, discuss how the proposed methodology considers the multiple functions and characteristics of purchased wind resources within the integrated provincial electricity system, rather than solely their marginal capacity contribution.

CA-NLH-150 (Reference: Application)

Provide a table that consolidates for each of the St. Lawrence and Fermeuse wind facilities for each year from the 2017 approved GRA through 2025: i) installed capacity; ii) the annual capacity factor; iii) the output at the annual Island Interconnected System peak; iv) the output during each of the ten highest Island Interconnected System load hours; v) the average output during those ten hours; and vi) the frequency with which output during those hours was below 10%, 20%, 30% and 43% of installed capacity. As part of the response, explain how the historical results support the proposed 43% demand classification.

CA-NLH-151 (Reference: Application, Chapter 6, page 6.9)

Hydro states *"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."*

(a) Identify the wind generators on the IIS including location, number of wind turbines, capacity and annual energy production.
(b) Identify the amount of capacity assumed to be provided by wind generators on the IIS in Hydro's planning studies.
(c) Did the referenced study assume that the 50 MW of wind generation was spread across the IIS, or located in only one or two areas of the Island? Specifically, how was geographic diversity taken into consideration in the referenced study?
(d) How are the costs of existing wind generation treated in the 2027 Test Year cost of service study?

CA-NLH-152 (Reference: Schedule G (Volume 1, pages 460, 463); Schedule F (page 250); Schedule G (page 359))

Restate the 2027 Test Year Schedule F and Schedule G class-level revenue-to-cost coverage tables using a Holyrood non-fuel capacity factor of 18.43% (the 5-year average, 2020-2024, reported in Schedule G 4.3) in place of the proposed 11.16% current/test-year figure, holding all other inputs unchanged. Provide the restated Schedule F 1.2 and Schedule G 1.2 tables in the same format as filed, by customer class and sub-class (including the Domestic and Domestic All Electric sub-classes within Newfoundland Power's book), together with a table showing the dollar and coverage-ratio delta between the filed (11.16%) and alternative (18.43%) classification for each class.

N. Holyrood TGS Classification

CA-NLH-153 (Reference: Schedule G, Volume 1, pages 460, 463; Schedule F, page 250; Schedule G, page 359)

Restate the classification of Holyrood TGS non-fuel costs under each of the following two alternatives, holding all other inputs unchanged:

(a) an operating-factor method; and
(b) an explicit reliability/standby subfunctionalization in which the portion of Holyrood's costs attributable to its reliability/backup role is separately functionalized and classified. For each alternative, provide the restated Schedule F and Schedule G class-level revenue-to-cost coverage tables in the same format as filed, side-by-side with the status quo capacity-factor method, with dollar and coverage-ratio deltas by class.

CA-NLH-154 (Reference: Technical Conference Presentation (October 14, 2025); Schedule F (page 250); Schedule G (page 359))

At the October 14, 2025 technical conference in the Cost of Service Methodology proceeding, a three-scenario comparison of Holyrood TGS cost-allocation approaches was discussed. Provide that three-scenario comparison for the 2027 Test Year, cross-walked to class-level revenue-to-cost coverage in the Schedule F and Schedule G formats, identifying for each scenario the classification method applied, the resulting allocation of Holyrood non-fuel costs by class, and the coverage-ratio effect by class relative to the filed treatment.

CA-NLH-155 (Reference: Application)

Provide a table that compares the total allocated rate base and revenue requirement by customer class associated with the Holyrood Thermal Generating Station as approved flowing from the 2017 GRA to the proposed 2027 Test Year. As part of the response, add a column that briefly identifies the drivers for any material variances.

CA-NLH-156 (Reference: Application, Chapter 6, page 6.6)

Hydro states *“The classification of the Holyrood TGS generation costs, excluding fuel, be based on a test year forecast capacity factor.”* On the same page Hydro states *“The Holyrood TGS continues to be operated primarily as a base load plant, as it was at the time of the previous settlement and Board Order regarding this issue.”*

(a) How are Holyrood TGS costs, excluding fuel, being treated in the cost of service study?
(b) How are other base load plants being treated in the cost of service study?
(c) If the base load Holyrood plant is being treated differently than other base load plants, explain why.
(d) What is the firm energy requirement on the IIS in 2027? How much of this will be met with production from Holyrood TGS? Could the firm energy requirement be met if Holyrood were not online?

CA-NLH-157 (Reference: Application, Chapter 6, page 6.24)

Hydro states “Thermal sources *can still be the marginal supply for non-firm energy, such as when the Holyrood TGS is being operated to provide energy to the Island Interconnected System.”*

(a) How much energy is Holyrood expected to produce for system supply purposes in the 2027 Test Year?
(b) Is thermal energy production reflected in Hydro’s marginal costs and the proposed rates for Newfoundland Power and the Island Industrial Customers?

CA-NLH-158 (Reference: Hydro’s 2027 CBA, Schedule 3, page 3))

Hydro states *“In 2025, Holyrood TGS was responsible for approximately 11% of the Island’s energy needs.”* Clarify. Was Holyrood *“needed”* to provide 11% of the Island’s energy needs or could this energy have been provided from other sources if Holyrood had not been online and required to meet minimum loading requirements?

CA-NLH-159 (Reference: Hydro’s 2027 CBA, Schedule 3, page 14)

Hydro states *“It is assumed that units will be mostly online during the winter Operating Months, and as such, there will not be a requirement to exercise idle units by starting them and running them up to full load regularly.” Further, “Holyrood TGS units will typically be online and staged to meet load requirements, as needed, from mid-October through the March timeframe.”*

(a) Will Holyrood TGS units be online during non-winter months?

(b) It is understood from CA-NLH-009, Attachment 1 from Hydro's 2025 Build Application that capacity reserve margins in 2027 and 2028 are about 45%. Why is it necessary to keep all three Holyrood TGS units online in the winter months?
(c) Would the cost of fuel for bringing 3 Holyrood units online during a winter period be about $144 million ($0.21/kWh * 136 days * 24 hours/day * 70,000 kW * 3 units)?[1] Correct this calculation as necessary.
(d) Is Hydro committing capital on Holyrood TGS consistent with maintaining current reliability levels equating to a DAUFOP of about 20%?
(e) If Holyrood were to remain in service beyond 2030, would Hydro commit capital consistent with maintaining current reliability levels equating to a DAUFOP of about 20%?
(f) Will planned outages for work at Bay d'Espoir extend into the winter months?

CA-NLH-160 (Reference: Application, Chapter 6, page 6.6)

Regarding Hydro's utilization of the Holyrood TGS during the winter months:

(a) When a third unit is brought on in anticipation of higher demand, are the other two units held at the same output level, leaving the third unit alone to increase the output of the TGS?
(b) Why is the third unit brought on rather than increasing output of the two operating units?
(c) When the output of the TGS is increased to meet anticipated increases in IIS demand, what other Hydro generation assets are combined with the TGS response to meet the anticipated demand and in what sequence?
(d) If in February 2026 daily IIS peaks and consumption had been uniformly 5% higher than actually experienced then describe Hydro's likely utilization of the Holyrood TGS, Muskrat Falls/LIL and other generation assets as well as curtailment exports to address that situation.

CA-NLH-161 (Reference: Application, Chapter 6)

Provide the following information related to the Holyrood TGS winter operations:

(a) A table showing generation (MW) by hour for each of the three units from December 1, 2025 to March 31, 2026.
(b) A table showing monthly values of Holyrood TGS energy generation (MWh), Holyrood TGS fuel consumption, Holyrood TGS fuel cost, and IIS electricity consumption (MWh) for December 2024 to March 2025 and December 2025 to March 31, 2026.

O. Rate Design – Newfoundland Power

CA-NLH-162 (Reference: Application, Chapter 6, pages 6.14 to 6.15)

Regarding Hydro's demand charge applicable to Newfoundland Power:

(a) It is indicated (page 6.14) that the current demand charge of $5 per KW per month, was approved in the 2017 GRA due to consideration of *"marginal capacity cost and the increase in embedded demand costs."* (i) Why is marginal capacity cost a relevant consideration in setting a demand charge and is it more or less important for 2027 than 2017? (ii) Why is embedded demand cost a relevant consideration in setting a demand charge and is it more or less relevant for 2027 than 2017?

(b) Hydro (page 6.15) proposes to increase the demand charge for Newfoundland Power from $5.00 per KW per month, which was set in 2017, to $5.50 but indicated that the average embedded demand cost has increased from $12.21 per KW in the 2019 Test Year Cost of Service Study to $20.40 per KW. Why is the increase in the demand charge not commensurate with the increase in the average embedded demand cost?

(c) What was the marginal cost of capacity in 2017 and what is its forecast value for 2027?

(d) It is stated (page 6.15) in regard to the 50 cent per KW increase in the demand charge that *"Hydro believes that such an increase will continue to provide the appropriate demand management signal to Newfoundland Power?"* Explain what is meant by *"appropriate demand management signal to Newfoundland Power"* and how a new charge that is much less in inflation-adjusted terms than its 2017 value is an appropriate signal.

CA-NLH-163 (Reference: Chapter 6, Section 6.6.2)

Hydro states that the proposed demand charge of $5.50 per kW per month will continue to provide an appropriate demand-management signal to Newfoundland Power.

(a) Explain how Hydro determined that $5.50 per kW per month constitutes an appropriate demand-management signal.

(b) Provide the marginal capacity cost, or other capacity-related cost information, considered in establishing the proposed demand charge.

(c) Explain why Hydro selected a 10% increase rather than maintaining the existing charge or moving the charge closer to the 2027 Test Year embedded demand cost of $20.40 per kW per month.

(d) Quantify the portion of Newfoundland Power's allocated demand-related costs recovered through the proposed demand charge and the portion recovered through the First Block Energy rate.

CA-NLH-164 (Reference: Chapter 6, Section 6.6.3 and Table 6-4)

(a) Provide the calculation supporting each proposed quarterly First Block quantity, including the forecast Newfoundland Power energy purchases, demand revenues, First Block revenues, Second Block revenues and total revenues by month and quarter.

(b) Show the proportion of Newfoundland Power's annual power-purchase expense and Hydro's annual revenue from Newfoundland Power forecast to be recognized in each quarter under: i) the existing block quantities; and ii) the proposed block quantities.

(c) Explain the principal factors resulting in the proposed reduction in the monthly First Block quantity for January through March from 590 GWh to 340 GWh.

(d) Provide the forecast quantity and percentage of Newfoundland Power's monthly purchases billed in the First and Second Blocks for each month of the 2027 Test Year.

CA-NLH-165 (Reference: Chapter 6, Section 6.6.4 and Table 6-6)

(a) Provide the complete calculation of the proposed First Block Energy rate of 11.815 cents per kWh.

(b) Identify the amount of Newfoundland Power's 2027 Test Year revenue requirement recovered through: i) the demand charge; ii) the First Block Energy charge; iii) the winter Second Block Energy charge; and iv) the non-winter Second Block Energy charge.
(c) For the revenue recovered through the First Block Energy charge, identify the amounts associated with demand-related costs, energy-related costs, the Rural Deficit and any other material cost categories.
(d) Explain the principal drivers of the increase in the First Block Energy rate from 8.515 cents per kWh to 11.815 cents per kWh.

CA-NLH-166 (Reference: Application, Chapter 6 – Rates and Regulations)

Regarding the proposed reduction in the Second Block Energy Rate for Newfoundland Power by 7.6%, from 9.698 cents to 8.958 cents per KW/month:

(a) In light of Hydro's continued reliance on Holyrood TGS to meet high demand during the winter months, should not the second block energy rate also include consideration of marginal capacity cost?
(b) Would a higher winter block rate provide a stronger incentive for Newfoundland Power to maximize its use of its hydro plants during the winter months?
(c) In a report for Hydro, Christensen Associates Energy Consultants presented estimates of Hydro's monthly all-in marginal cost, i.e., marginal cost of energy plus operating reserves and capacity cost associated with generation and transmission services (see Hydro's September 16, 2024 Application for Adjustment to Wholesale Utility Rate, Schedule 1, Attachment 1, Table 6). Provide the 2027 forecast for these all-in-marginal costs.

CA-NLH-167 (Reference: Application, Chapter 6, page 6.15)

Hydro states *"Hydro implemented a quarterly blocking structure in the wholesale rate charged to Newfoundland Power effective January 1, 2025. Hydro is proposing to revise the existing block structure so that approximately the same proportion of revenue for Hydro (power purchase costs for Newfoundland Power) is reflected in each quarter, based on the 2027 Test Year costs."*

(a) Has Hydro given consideration to any other rate designs for Newfoundland Power? Provide a summary of the rate designs considered and the analysis that led to Hydro's proposed rate design.
(b) Did Hydro consider implementing a real-time pricing rate with the potential to change rates hourly for Newfoundland Power and the Island Industrial customers? Would this potentially help Hydro manage periods of high cost and/or high risk to reliability based on financial incentives rather than the current command and control method, and be similar to how competitive electricity markets work?
(c) Did Hydro consider the real-time pricing rate offerings in other provinces for large industrial customers? For example, Ontario had a real-time pricing rate offering for its large industrial customers more than 30 years ago before implementing its competitive electricity market.

CA-NLH-168 (Reference: Application, Chapter 6, page 6.14)

Hydro states that, effective January 1, 2025, in the update to the wholesale rate structure charged to Newfoundland Power, Hydro's marginal cost of energy was changed to the opportunity cost of the market value of exports.

(a) During the winter months (December 2025 to March 2026), other than for established contractual obligations, how much energy and capacity was exported by Hydro that could have been otherwise available to the IIS if needed?
(b) When Hydro anticipates an increase in demand, why does it not reduce exports to meet the increased demand rather than use unit 3 at Holyrood?
(c) Is the IIS system sufficiently integrated and connected to North American markets such that Hydro can address fluctuations in IIS energy consumption during winter months entirely by offsetting changes in the amount of exports?
(d) Is Hydro's marginal cost of energy more accurately determined as weighted average of marginal costs of the sources used to obtain extra energy for the IIS?

CA-NLH-169 (Reference: Application, Chapter 6, page 6.17)

Hydro states that *"Following the approval of a revised Power Service Agreement in 2021, which eliminated prior generation credit and secondary operating arrangements, and the subsequent approval of stand-alone capacity assistance and CoGen agreements, Hydro no longer relies on secondary power service arrangements associated with CBPP."* Provide a copy of this Power Service Agreement with CBPP for the record.

P. Rate Design – Island Industrial

CA-NLH-170 (Reference: Chapter 6, Sections 6.7.1 to 6.7.3; Exhibit 17)

Hydro proposes to reduce the Island Industrial demand charge from $10.73/kW per month to $5.50/kW per month while increasing recovery of embedded demand costs through the First Block Energy rate.

(a) Explain why Hydro considers maintaining a demand charge equal to that proposed for Newfoundland Power to be an appropriate rate design objective for the Island Industrial class.
(b) Explain why Hydro proposes to reduce the Island Industrial demand charge from $10.73/kW per month to $5.50/kW per month when the embedded average demand cost for the class is $17.54/kW per month.
(c) Identify and explain the marginal capacity cost, avoided capacity cost, or other capacity-related information considered in establishing the proposed demand charge.
(d) For each alternative demand charge level evaluated, provide: i) the associated First Block Energy rate; ii) the amount and percentage of embedded demand costs recovered through the demand charge; iii) the amount and percentage of embedded demand costs recovered through the First Block Energy rate; iv) annual class revenue by rate component; and v) the resulting overall class bill impact.
(e) Explain how the proposed reduction in the demand charge is expected to affect Island Industrial customers' incentives to reduce or manage: i) monthly billing demand; ii) system coincident peak demand; and iii) demand during periods of limited system capacity.

CA-NLH-171 (Reference: Application, Chapter 6, page 6.20)

Hydro states "Hydro is proposing to maintain *a demand charge of $5.50 per kW per* *month, equivalent to that proposed for Newfoundland Power. The proposed demand rate will recover approximately 31% of the embedded demand costs from Island Industrial customers and 27% from Newfoundland Power, with the remainder recovered in the first block rates."*

(a) Why is Hydro recommending demand charges that recover less than 32% of embedded demand costs when there is a capacity shortfall forecast on the IIS?
(b) Provide a comparison of the proposed demand charges to the marginal cost of capacity.
(c) Are the proposed rates for Island Industrial Customers revenue neutral from an individual customer perspective or a class perspective?
(d) Provide a proof that the proposed Island Industrial Customer rates are revenue neutral.

CA-NLH-172 (Reference: Exhibit 1, page 4)

Hydro states *"The choice of demand price does alter somewhat the signal to the customer to control peak demand."* Would the efficiency of the price signal be improved if the demand charge varied by season to reflect marginal capacity costs? For example, might an industrial customer be encouraged to take a production shutdown in summer rather than winter if the winter demand rate were double the summer demand rate?

CA-NLH-173 (Reference: Chapter 6, Sections 6.6 and 6.7; Exhibit 17)

Hydro proposes material changes to the Island Industrial rate design intended to provide customers with marginal-cost price signals and opportunities to modify their demand, energy consumption and load factor. Hydro proposes more limited changes to the Newfoundland Power wholesale rate design.

(a) Explain whether Hydro assessed the relative ability of Island Industrial customers and Newfoundland Power's residential customers to respond to the respective proposed rate structures and avoid or reduce billed costs. If not, explain why.
(b) Provide a table that identifies the rate-design options available to Island Industrial customers to reduce their bills under the proposed rate and explain whether each option is expected to produce a corresponding reduction in Hydro's system costs or foregone revenues.
(c) For each identified rate-response opportunity, quantify: i) the forecast reduction in total industrial customer bills; ii) the corresponding reduction in Hydro's costs or increase in net system revenues; and iii) any residual revenue requirement that remains to be recovered from customers.
(d) Explain how Hydro ensures that reductions in Island Industrial bills resulting from changes in billing demand, load factor, timing of consumption or movement between rate blocks do not shift recovery of fixed or embedded system costs to Newfoundland Power.
(e) Explain whether Hydro considered rate-design changes for Newfoundland Power or residential customers that would provide comparable opportunities to reduce bills through economically beneficial changes in demand or consumption. If not, explain why.
(f) Explain how Hydro determined that the proposed rate structures result in an equitable sharing of fixed and embedded system costs between customers with substantial ability to alter their billing determinants and residential customers with more limited ability to do so.

CA-NLH-174 (Reference: Exhibit 17 page 21)

Hydro states *“Based on the foregoing analysis, Hydro may prefer a design with a $5.50 per kW demand price and a 300 HOU block boundary (currently 54% of class load factor). This results in modest bill impacts relative to the current design. Other choices can readily be made, though, if alternative bill impacts recommend themselves.”* Does Christensen believe that when compared to the current rate design, the proposed rate design is superior with respect to 1) revenue recovery, 2) fairness, and 3) efficiency? How important are rate impacts?

CA-NLH-175 (Reference: Exhibit 17, page 3)

Hydro states *“The utility benefits from the design as well, since variations in bills due to variations in consumption by customers more closely match variations in cost to serve.”* Why is this beneficial? Should this be an objective of any rate design?

CA-NLH-176 (Reference: Exhibit 17, page 14)

Hydro states *“Table 4 presents similar results for an intermediate level of demand price, set at $5.50 per kW. (This level is chosen to approximate the expected demand price level of the Utility rate. Thus, this scenario is one in which prices and the rate structure are designed to parallel those of the Utility rate: a block design with seasonal marginal cost-based tail block pricing and a similar demand price.)”* Is this important given that Newfoundland Power demand reflects the demand of its retail customers over which Newfoundland Power has limited control, while industrial customers have control over the demands they place on the power system?

CA-NLH-177 (Reference: Application)

Discuss any other hours-of-use block boundaries and demand-charge levels evaluated by Hydro and CA Energy. As part of the response, discuss why these alternatives were rejected.

CA-NLH-178 (Reference: Exhibit 17, page 1)

Hydro states *“Hydro is proposing to replace this structure with an “hours of use”* (HOU) rate design whose purpose is to reflect the changing costs to Hydro of providing generation and transmission services. In the utility’s view, an HOU design is an appropriate way both to recover required revenues and to inform customers about the marginal cost to serve new load (which is also the marginal savings from reducing it).” It goes on to say (page 1) *“Hydro asked Christensen Associates Energy Consulting to investigate aspects of the new design in order to facilitate decision making regarding a final rate structure for external review, and to develop initial prices based on forecasted revenue requirements and marginal costs.”*

(a) Did Hydro and the Island Industrial Customers agree to an hours of use rate design prior to the submission of the 2026 GRA?
(b) Had Hydro committed to an hours of use rate design prior to retaining Christensen to undertake this study? Was Christensen asked to review the merits of an hours of use rate design versus other potential rate designs?
(c) The report states *“if this design gains approval”*. Specifically, whose approval?

(d) Does Christensen believe that this rate design best meets the objectives of 1) recovery of the revenue requirement, 2) fairness, and 3) efficiency?

CA-NLH-179 (Reference: Chapter 6, Sections 6.7 to 6.7.3; Exhibit 17)

Hydro states that the proposed Second Block Energy rates are intended to expose incremental industrial energy consumption to marginal-cost pricing.

(a) Define the term *"incremental consumption"* as used in developing the proposed Island Industrial rate design.
(b) Explain whether the 300-hour boundary was developed to distinguish between existing industrial consumption and consumption expected to occur in response to the proposed Second Block pricing.
(c) Explain whether existing or forecast base industrial consumption will be priced at the proposed marginal-cost-based Second Block Energy rates.
(d) Explain how Hydro determined that First Block revenues together with demand-charge revenues will recover the Island Industrial class's embedded costs after accounting for existing consumption billed at Second Block rates.

CA-NLH-180 (Reference: Chapter 6, Sections 6.7.2 and 6.7.3; Exhibit 17)

Hydro proposes to price Island Industrial Second Block Energy using forecast seasonal export prices.

(a) Describe the calculation of the proposed winter and non-winter Second Block Energy rates. As part of the response, identify all adjustments made to the forecast export prices and provide the rationale for such adjustments.
(b) Explain whether the proposed Second Block rates reflect the value of preserving energy for sale or use during higher-priced periods. If not, explain why.
(c) Explain how Hydro determined that it will be economically indifferent between supplying Second Block energy to Island Industrial customers and exporting that energy.
(d) Quantify the forecast annual contribution of Second Block industrial sales toward recovery of Hydro's fixed and embedded system costs.
(e) Quantify the forecast change in export volumes and export revenues resulting from the proposed Island Industrial rate design.

CA-NLH-181 (Reference: Exhibit 17, page 3)

Hydro states *"Further improvement in price efficiency requires movement to time-varying pricing."* Has Hydro considered moving to time-varying pricing now given that it improves price efficiency and that industrial customers often have energy managers with the sophistication and motive (to reduce production costs), enabling appropriate responses to time-varying rates? Why or why not?

CA-NLH-182 (Reference: Exhibit 17, page 4)

Hydro states *"The algebra is complicated by the fact that increasing peak demand usually has multi-month implications under Hydro's current definition of billed demand."* Should Hydro's current definition of billed demand be changed to improve the efficiency of the price signal?

CA-NLH-183 (Reference: Exhibit 17, page 7)

Hydro states *"Christensen Associates Energy Consulting developed a model that calculates Island Industrial customer bills, first under the current rate design at current prices, then using updated prices required to recover the utility's target forecasted revenues. (Both calculations use forecasted customer usage and demand levels for calendar 2027.) Finally, the model uses the new HOU rate design at price levels sufficient to recover the same class forecasted revenue requirement for 2027."* In Christensen's opinion, should the proposed rates be established to collect the same class revenue requirement, or the same individual customer revenue requirement? More specifically, should rates be revenue neutral on an individual customer basis or a customer class basis?

CA-NLH-184 (Reference: Exhibit 17, page 14)

Hydro states *"The lowest load factor customer fails to reach Block 2 when the HOU block boundary is set at 400 but reaches Block 2 in seven months when the block boundary is 200 HOU. This customer's load factor is somewhat seasonal. When the block boundary is 200 HOU, they reach Block 2 in all winter months but not in several nonwinter months."*

(a) Is a seasonal load factor a good reason for having rates that vary seasonally and reflect marginal costs?
(b) What are the repercussions of a customer not reaching Block 2 in a non-winter month?

CA-NLH-185 (Reference: Chapter 6, Section 6.7.5)

Hydro presents Island Industrial bill impacts reflecting changes in base rates, rate design, specifically assigned charges, the Project Cost Recovery Rider and other adjustments.

(a) Provide the aggregate forecast 2027 annual revenues collected from the Island Industrial class under: i) the existing base rates and existing rate design, using 2027 Test Year billing determinants; ii) rates designed to recover the 2027 Test Year revenue requirement while retaining the existing demand-and-energy rate structure; iii) Hydro's proposed hours-of-use base-rate design; and iv) Hydro's proposed hours-of-use rate design including the forecast Project Cost Recovery Rider, CDM Recovery Adjustment and all other applicable riders and charges.
(b) For each scenario requested in part a above, separately identify: i) the demand-charge revenue; ii) the First Block Energy revenue; iii) the Winter Second Block Energy revenue; iv) the Non-Winter Second Block Energy revenue; v) the specifically assigned charges; vi) the Project Cost Recovery Rider revenue; and vii) total class revenue.
(c) Quantify, on an aggregate class basis, the dollar and percentage bill impact attributable to: i) changes in the Island Industrial revenue requirement; ii) changes in base-rate design; iii) the reduction in the demand charge; iv) the introduction of the First Block and seasonal Second Block Energy rates; v) changes in specifically assigned charges; and vi) changes in riders and adjustments.
(d) Provide a summary of forecast customer bill impacts for the Island Industrial class showing: i) the minimum; ii) the maximum; iii) the average; iv) the median; and v) the number of customers experiencing bill decreases or increases of greater than a 10% decrease or greater than a 10% increase.

CA-NLH-186 (Reference: Chapter 5, Section 5.7; Chapter 6, Sections 6.7 and 6.10.2)

(a) Identify the principal billing determinants and assumptions that create revenue risk under the proposed Island Industrial rate design.
(b) Provide sensitivity analyses showing the effect on Island Industrial class revenues of: i) a 5% and 10% reduction in annual energy consumption; ii) a 5% and 10% reduction in billing demand; iii) a 5% and 10% reduction in load factor; iv) a shift of consumption between winter and non-winter months; and v) a lower-than-forecast Second Block consumption.
(c) Explain how any deficiency or surplus arising from actual Island Industrial billing determinants that differ from forecast will be recorded and ultimately assigned.
(d) Confirm whether any portion of an Island Industrial revenue deficiency could be recovered from Newfoundland Power or its customers. If so, explain the circumstances and provide the applicable allocation and recovery methodology.
(e) Confirm whether all Island Industrial amounts recorded in the Supply Cost Variance Deferral Account or any other variance account will remain assigned to the Island Industrial customer class. If not, explain how the amounts will be allocated among customer classes.

CA-NLH-187 (Reference: Exhibit 17, page 1)

Hydro states *"Marginal costs have fallen to reflect the availability on the Island of incremental energy and capacity from the North American mainland instead of from the island's own peaking generation."* How much capacity and energy from the North American mainland, excluding Muskrat Falls/LIL, is incorporated in Hydro's 2027 Test Year?

Q. Deferral Accounts, Carrying Charges, and Risk Transfer

CA-NLH-188 (Reference: Order No. P.U. 33(2021), pages 8, 11; Volume 1, pages 170-171; Volume 3 (Exhibit 10), page 690)

Explain why Hydro proposes WACC-based financing charges for the Long-Term Supply Cost Variance Deferral Account rather than short-term borrowing cost, embedded debt cost, risk-free rate, no carrying charge, or another rate — and specifically why the reasoning the Board applied in Order No. P.U. 33(2021), requiring short-term borrowing costs for the existing SCVDA, does not apply here. Provide Hydro's policy rationale, precedent analysis, risk analysis, expected account balance profile, expected recovery timing, and customer impact under alternative carrying-charge rates, and identify the specific utility risk for which WACC compensates Hydro.

CA-NLH-189 (Reference: Volume 1, page 171; Volume 3, page 714)

Provide Hydro's projected Long-Term Supply Cost Variance Deferral Account balance for each year from 2027 through 2035, under scenarios approximating the 10th percentile (low), 50th percentile (expected/median), and 90th percentile (high) supply-cost outcomes, together with the key assumptions (hydrology, export prices, load, fuel prices) driving each scenario. If Hydro does not currently produce a probabilistic supply-cost projection, provide whatever scenario or sensitivity analysis it does use to plan for LT-SCVDA balance variability, and confirm that no probabilistic projection exists if that is the case.

CA-NLH-190 (Reference: Volume 3, pages 685-690)

Confirm whether the Long-Term Supply Cost Variance Deferral Account's ten variance streams, taken together, are intended to substantially insulate Hydro's earned return from forecast error (load, hydrology, export price, fuel, and mitigation-funding variance) within a test year. Provide a direct confirmation or denial, and identify any category of forecast risk relevant to Hydro's cost of service that is not captured by the Long-Term SCVDA or another deferral or variance mechanism disclosed in this GRA.

CA-NLH-191 (Reference: Volume 1, pages 5.27 and 5.28)

Hydro states (pages 5.27, lines 10 to 27 and 5.28, lines 1 to 12) *"…the Board ordered that the calculation of financing charges on the existing Supply Cost Variance Deferral Account be calculated based on Hydro's short-term borrowing costs…Hydro's proposal is for the Long-Term Supply Cost Variance Deferral Account to come into effect on January 1, 2027. This account will continue to capture variances between Hydro's incurred supply costs and those included in Hydro's most recently approved test year; however, these variances and the resulting balance in this account are expected to be much lower in comparison to the existing Supply Cost Variance Deferral Account as project costs and rate mitigation funding will be included in Hydro's cost of service and test year revenues, prior to this account becoming effective…balances are not expected to be material and fast-growing…For these reasons, this long-term approach…differs from the existing…Hydro is proposing…using the weighted average cost of capital as approved in Hydro's test year."*

(a) Provided a detailed explanation of why Hydro expects that the balances in the Long-Term SCVDA will be much lower and not as fast as growing when compared to the existing SCVDA, considering that the forecast unrecovered balance at December 31, 2027 appears to be in excess of $1.75 billion (Schedule D-V) and the annual difference between Muskrat Falls costs (in the order of $780 million) and rate mitigation (in the order of $500 million) are in the order of $280 million per year.
(b) Confirm (or explain otherwise) that charging financing costs at the proposed weighted average cost of capital instead of at the approved short-term borrowing rate will increase the balance outstanding in the Long-Term SCVDA.
(c) Provide a calculation of the forecast carrying costs for the Long-Term SCVDA by year from the 2027 Test Year to the 2030 Forecast for (i) the weighted average cost of capital, (ii) the short-term borrowing rate and (iii) cumulative difference between (i) and (ii) from the 2027 Test Year to the 2030 Forecast. Exhibit 2 – Review of

CA-NLH-192 (Reference: Volume 1, page 159; Schedule D-V, page 239)

Provide a master continuity schedule for all existing and proposed deferral, variance, and regulatory asset/liability accounts reflected in the 2026 GRA, showing for each account from 2024 through 2030: opening balance, additions, transfers, dispositions, amortization, carrying charges, closing balance, rate-base treatment, financing rate, customer-class allocation, proposed recovery period, account definition source, and approval status.

CA-NLH-193 (Reference: Volume 1, Schedule D-V)

Hydro provides (Schedule D-V) a summary continuity schedule (opening balance on January 1, 2027, additions, dispositions and amortizations and ending balance on

December 31, 2027) for deferred charges for the 2027 Test Year only.

(a) Provide a Schedule D-V summary of deferred charges for each year of the eight-year period from 2019 Actual to 2026 Forecast.
(b) Provide a Schedule D-V summary of deferred charges for each year of the three-year period from 2028 Forecast to 2030 Forecast.
(c) Explain the implications of the recent release (May 27, 2026) of a permanent standard for regulatory accounting (IFRS 20 – Regulatory Assets and Regulatory Liabilities) by the IASB.

CA-NLH-194 (Reference: Volume 1, pages 5.16 to 5.21 and Schedule D-V)

Hydro provides (pages 5.16 to 5.21) a description of its proposals with respect to ten regulatory deferral accounts. Hydro provides (Schedule D-V) a summary continuity schedule for deferred charges for the 2027 Test Year.

(a) Provide a summary table of the Board Order and Board approved amortization period for those regulatory deferral accounts that are listed on Schedule D-V and for which there is no commentary provided in Chapter 5 (pages 5.16 to 5.21) of the GRA filing.
(b) Provide a schedule that summarizes which of the deferral accounts on Schedule D-V are collected through revenue requirements and which are collected through rate riders.
(c) Explain why there are no Regulatory Adjustments related to regulatory deferral accounts in Hydro's Revenue Requirement Analysis (Schedule D-I).
(d) Provide a schedule that summaries where the proposed amortization can be found in Hydro's Revenue Requirement Analysis (Schedule D-I) for those deferral accounts that are approved to be collected/refunded or proposed to be collected/refunded through revenues requirement in the 2027 Test Year.

CA-NLH-195 (Reference: Application)

Provide a consolidated schedule for each regulatory deferral account for which an amortization, disposition or recovery amount is included in or proposed for the 2027 Test Year, showing: i) the 2027 amount; ii) whether recovery is through base rates, a rate rider, the Supply Cost Variance Deferral Account or another mechanism; iii) the COS methodology; iv) the resulting amount allocated to each customer class; and v) whether the proposed allocation follows the COS methodology of the underlying cost that gave rise to the deferral and if not, explain why.

CA-NLH-196 (Reference: Volume 1, pages 165-166, 171)

Hydro states that remaining balances in the existing SCVDA will be addressed in a future application after the GRA. Provide 2024-2030 continuity schedules for the existing SCVDA, including project cost recovery, rate mitigation funding, fuel, load, export revenue, and other variance components, together with the forecast balance, drivers, expected filing date, proposed disposition methodology and review process, and customer impact of that future application.

CA-NLH-197 (Reference: Volume 1, pages 5.22 and 5.23 and Schedule D-V. Exhibit 10, Section A)

Hydro states (page 5.22 lines 15 to 18 and page 5.23, lines 1 to 2) *"The existing Supply Cost Variance Deferral Account accumulates costs, revenues and variances from the*

2019 Test Year until the conclusion of Hydro's 2026 GRA; after that time, once a new test year is approved, Hydro proposes transitioning to the Long-Term Supply Cost Variance Deferral Account, effective January 1, 2027. Hydro will propose the disposition of any balances remaining in the existing Supply Cost Deferral Account after the transitioning to the Long-Term Supply Cost Variance Deferral Account in an application following the GRA." Hydro provides (Schedule D-V) a summary continuity schedule (opening balance on January 1, 2027, additions, dispositions and amortizations and ending balance on December 31, 2027) for the *"Power Purchase Expense Recognition"* and *"Muskrat Falls Export Revenue Recognition"* deferred charges for the 2027 Test Year only. Forecast balances in these deferred charges as at December 31, 2027 are $1.713 billion and $40.960 million, respectively, with a total of $1.754 billion. Hydro provides (Section A of Exhibit 10) the Long-Term Supply Cost Variance Deferral Account Definition which specifies nine underlying variances that together make up this regulatory deferral account.

(a) Confirm (or explain otherwise) that the *"Power Purchase Expense Recognition"* and *"Muskrat Falls Export Revenue Recognition"* deferred charges in Schedule D-V are the forecasts of the ending balances in the existing Supply Cost Variance Deferral Account (SCVDA) at December 31, 2026 and the forecast additions to the Long-Term SCVDA during the 2027 Test Year.
(b) Provide a detailed continuity schedule of the existing SCVDA for each year up to and including the 2027 Test Year that is broken down between the nine underlying variances in Exhibit 10 and breaks out carrying costs as a separate item.
(c) Provide a detailed continuity schedule of the Long-Term SCVDA for each year of the three-year period from 2028 Forecast to 2030 Forecast that is broken down between the nine underlying variances in Exhibit 10 and breaks out carrying costs as a separate item.
(d) Explain why it is in the public interest that discussions related to the disposition of the $1.754 billion and growing Long-Term SCVDA be deferred to a future application following the current GRA proceeding, as opposed to occurring at the current GRA proceeding.

CA-NLH-198 (Reference: Application, Chapter 1, page 1.18)

Hydro states *"Variances from the test year forecast will continue to be deferred as part of Hydro's Supply Cost Variance Deferral Account framework."*

(a) What is the purpose of this deferral account and what will be done with the proceeds once rate mitigation ends?
(b) How will actual rate mitigation dollar amounts be determined beyond 2027?
(c) Given that IIS rates are fixed at an equivalent 2.25% annual rate increase for Newfoundland Power's Domestic customer class through 2030, why is it important to track costs in this deferral account rather than undertake a cost of service study when rate mitigation ends?

CA-NLH-199 (Reference: Volume 1, pages 135-136; Volume 3, pages 676, 680)

Explain and quantify the proposed Muskrat Falls PPA Sustaining Capital Deferral Account treatment, including how current sustaining capital payments are removed from immediate supply-cost recovery and replaced with amortization based on composite depreciation rates. Provide continuity schedules for 2024-2035 showing additions, AFUDC, amortization, carrying charges, ending balances, revenue requirement impact, and class allocation, together with the derivation of the 1.42% and 1.71% composite depreciation rates and any sensitivity to alternative amortization periods.

CA-NLH-200 (Reference: Volume 1, pages 5.19 to 5.20)

Hydro provides (pages 5.19 to 5.20) a description of its proposals with respect to the Muskrat Falls PPA Sustaining Capital Deferral Account, with a balance of $43.6 million on January 1, 2027, a proposed amortization period based on the composite depreciation rate (Muskrat Falls Generating Facility of 1.42% and Labrador Transmission Assets of 1.71%, respectively) with $0.7 million of amortization proposed for the 2027 Test Year.

(a) Provide a breakdown of the January 1, 2027 balance of $43.6 million in the Muskrat Falls PPA Sustaining Capital Deferral Account by year and type of sustaining capital expenditure.
(b) Provide a breakdown of the $9.030 million of proposed additions to the Muskrat Falls PPA Sustaining Capital Deferral Account for the 2027 Test Year.
(c) Provide a calculation of the weighted average composite depreciation rate for the Muskrat Falls Sustaining Capital Deferral Account that Hydro is proposing for the 2027 Test Year.

CA-NLH-201 (Reference: Order No. P.U. 33(2021), pages 8, 11; Volume 1, pages 170-171; Schedule D-V (page 239))

Provide carrying-charge sensitivity analysis for all material deferral and variance accounts using WACC, embedded debt cost, short-term borrowing cost, risk-free rate, and zero carrying charge, showing annual 2027-2035 revenue requirement impacts, total customer cost, class impacts, and ending balances under each assumption.

CA-NLH-202 (Reference: Exhibit 10 – Deferral Account Definitions)

Would it be more transparent and efficient if Hydro were to combine a number of these deferral accounts relating to the IIS into a single supply cost deferral account reflecting the difference between the actual cost of supply and the cost of supply included in the 2027 Test Year?

CA-NLH-203 (Reference: Volume 1, page 5.16)

Hydro provides (page 5.16) a description of its proposals with respect to the Business Systems Transformation Program Deferral Account, including an additional $7.8 million of forecast deferred costs to December 31, 2026 and a proposed amortization period of eight years spanning two regulatory review cycles, with $1.8 million of amortization proposed for the 2027 Test Year.

(a) Provide a breakdown of the additional $7.8 million of forecast costs to be deferred to December 31, 2026 and a summary of the business case associated with each component of this additional proposed deferred amount.
(b) Provide the average expected useful life of the Business Systems Transformation Program expenditures.
(c) Explain why the proposed amortization period is based on the timeframe of two regulatory review cycles (eight years) and not the underlying useful live of the associated intangible assets.

CA-NLH-204 (Reference: Volume 1, pages 5.18 to 5.19)

Hydro provides (pages 5.18 to 5.19) a description of its proposals with respect to the Phase Two Hearing Costs Deferral Account and Reliability and Resource Adequacy Study Review Deferral Account, with proposed amortization periods of eight years spanning two regulatory review cycles for both regulatory deferral accounts with $0.8 million of combined amortization proposed for the 2027 Test Year. While understanding Hydro's approach to the eight-year amortization period for these two regulatory deferral accounts being focused on moderating near-term rate impacts to customers - explain if Hydro considered a shorter amortization period of four years (one regulatory review cycle) in recognition of the significant build up in other regulatory deferral accounts such as the Long Term Supply Cost Variance Deferral Account.

CA-NLH-205 (Reference: Volume 1, page 5.21)

Hydro provides (page 5.21) a description of its proposals with respect to the GRA Hearing Cost Deferral Account, with a cost estimate of $1.5 million in external regulatory costs, a proposed amortization period of four years spanning one regulatory review cycle, with $0.4 million of amortization proposed for the 2027 Test Year. Provide a breakdown of the $1.5 million of forecast external regulatory costs related to the 2027 Test Year regulatory process.

CA-NLH-206 (Reference: Volume 1, page 5.21 and Exhibit 11, pages 2 and 3)

Hydro provides (page 5.21) a description of its proposals with respect to the Holyrood TGS Accelerated Depreciation Deferral Account, with a balance owing to customers of $11.443 million as at January 1, 2027. Hydro is not proposing the disposition of this balance in the current GRA proceeding. Hydro indicates (Exhibit 11, pages 2 and 3) that assuming an end-of-steam generation date of March 31, 2030 and considering recent capital projects to be placed in service at the end of 2027 and only depreciated for approximately two years - the balance in this deferral account would be projected to shift to a balance of $27.9 million owing from customers at March 31, 2030. Further, Hydro outlines the uncertainty related to the actual retirement date and submits that it would be premature to advance a recovery proposal in the current GRA and as such will address the disposition in a future GRA filing. Provide an update on the amount and timing of any forecast capital additions related to the Holyrood TGS and expected retirement date since the filing of the 2026 GRA.

CA-NLH-207 (Reference: Exhibit 10 – Deferral Account Definitions)

Explain the rationale for the proposed Electrification Cost Deferral Account, including why existing regulatory mechanisms are insufficient. Please also describe the status of Hydro's electrification programs in light of the current generation shortfall on the Island Interconnected System.

CA-NLH-208 (Reference: Volume 1, pages 165, 167; Volume 3 (Exhibit 12), page 714)

For each proposed deferral or variance account, identify whether Hydro proposes any materiality threshold, deadband, cap, sharing mechanism, prudence review, or annual review before recovery from customers. If Hydro proposes no such feature for an account, explain why full pass-through is appropriate for that account.

CA-NLH-209 (Reference: Schedule D-II (Volume 1, page 233); Schedule D-V (page 239))

Identify all deferral and regulatory asset balances included in rate base and all balances excluded from rate base but receiving separate interest, finance charges, or carrying charges. Provide a table showing each balance, rate-base inclusion status, return or financing rate, revenue requirement impact, accounting rationale, and Board precedent, and confirm that no balance receives both rate-base return and separate financing charges unless explicitly approved.

CA-NLH-210 (Reference: Volume 1, page 167; Volume 3 (Exhibit 12), pages 701, 714; (Exhibit 13), page 716)

Explain and support Hydro's proposed allocation design for Long-Term SCVDA components, including demand/energy splits, cost-of-service allocator choices, rural rate alteration, export revenue, greenhouse gas credits, load variation, and rate mitigation components. Provide a component-by-component allocation table, compare Hydro's proposal to energy-only recovery, demand-and-energy allocation, and other feasible alternatives, and provide customer-class impacts under each approach.

CA-NLH-211 (Reference: Volume 3, page 690 (Section B, Item 2.0); Volume 1, page 171; Order No. P.U. 33(2021), page 8)

(a) Confirm what specific disposition protocol - trigger, timing, and approval process - governs when accumulated Long-Term SCVDA balances will actually be returned to or recovered from customers, given that the account definition itself does not state a disposition schedule and Hydro's narrative treats disposition as a matter for *"a future application."* State the specific conditions (e.g., balance threshold, elapsed time, or calendar trigger) that would cause Hydro to file a disposition application, and confirm whether the Board or intervenors have any mechanism to compel disposition if Hydro does not do so voluntarily.

(b) Explain why the LT-SCVDA should be financed at Hydro's full WACC - a rate that includes an equity return compensating for risk of non-recovery - rather than a short-term or debt-like rate, having regard to the Board's holding in Order No. P.U. 33(2021), which applied short-term borrowing costs to the economically similar predecessor SCVDA. Provide Hydro's position on whether recovery of LT-SCVDA balances is subject to any prudence, forecast, or non-recovery risk comparable to the risk WACC is meant to compensate for capital investment, and if Hydro contends such risk exists, identify and quantify it.

R. Intercompany Transactions and Shared Services Costing

CA-NLH-212 (Reference: Volume 2, Exhibit 2, Attachment 1, pages 2, page 7 and page 11)

Hydro provides (lines 10 to 14 of page 2) a summary of its costing framework which includes three primary means of charging costs among the lines of business (1) Type 1- Administration Fee costs (2) Type 2 – Costs related to the provision of Corporate Services and (3) Type 3 – Cost recovery business units. Hydro states (lines 19 to 21 of page 7) *"Where an employee is expected to provide equal service to the regulated and non-regulated business, the default is a non-regulated business unit."* Hydro states (lines 8 to 9 of page 11) *"Certain functions incur costs on a cost recovery basis. In these cases, all* *costs with the activity are charged in accordance with the applicable cost recovery arrangements."*

(a) Confirm (or otherwise explain) that the primary difference between Type 1 and Type 2 is that Type 1 costs are allocated by cost drivers and Type 2 costs are allocated based on timesheets.
(b) Explain why the default for assignment of an employee to a home business unit is to a non-regulated business unit as opposed to a regulated business unit.
(c) Elaborate on the differences in Hydro's costing framework between cost recovery business units (Type 3) and Type 1 and Type 2 business units.

CA-NLH-213 (Reference: Volume 2, Exhibit 2, Attachment 2 (KPMG Report), page 13)

KPMG states *"KPMG's review is limited to the assessment of Hydro's cost allocation methodologies. KPMG was not engaged to assess the reasonableness of the shared/common services costs being allocated. Therefore, the principle of 'prudency' has not been considered in our evaluation."*

(a) Identify the last GRA in which Hydro's shared/common services costs were reviewed by the Board for the prudency of the underlying costs.
(b) Explain how Hydro expects the Board to reach a conclusion on the prudency of the underlying shared/common services costs being allocated in this proceeding, without a prudency review of the underlying shared/common service costs.

CA-NLH-214 (Reference: Volume 2, Exhibit 2, Attachment 2 (KPMG Report), pages 16 and 22)

KPMG provides (page 16) a high level summary of Manitoba Hydro's integrated cost allocation methodology (ICAM). KPMG outlines (page 22) that Hydro considered the use of a Massachusetts Formula (three-factor allocator), which is generally calculated using a combination of a revenue metric, a PPE/capital assets metric and a labour metric. KPMG further outlines that Hydro identified some concerns with a revenue component of a three-factor allocator. KPMG also indicated that Hydro's proposed hybrid allocator (50% weight to gross PPE and 50% weight to total O&M cost) is similar to that of comparator utilities BC Hydro, Manitoba Hydro and OPG. In Order 120/25 (directive 8, page 193), dated September 16, 2025, the Manitoba Public Utilities Board directed that for rate-setting purposes the Manitoba hydro ICAM be revised such that the %activity charges and %hybrid allocators be replaced by a three-factor allocator that equally weights (1/3 to each factor) activity charges, assets and revenues.

(a) Explain if KPMG considers the Massachusetts Formula (multi-factor allocator) to be a North American regulated utility industry standard for the allocation of shared/common service costs, with the multi-factors generally being revenues, assets and labour.
(b) Elaborate on the concerns that Hydro has with respect to including a revenue component in its proposed hybrid allocator.
(c) Provide the calculations of the hybrid cost allocator including the forecast gross PPE and total O&M and weighting for Hydro regulated and non-regulated operations and the proposed weighted hybrid allocator for the 2027 Test Year.
(d) Provide an estimate and the associated calculations of the impact to the shared service cost allocations to Hydro's regulated operations for the 2027 Test Year, if a revenue factor was added to its proposed hybrid allocator, with 1/3 weight to revenues, 1/3 weight to gross PPE and 1/3 weight to O&M costs.

CA-NLH-215	(Reference: Volume 2, Exhibit 2, Attachment 2 (KPMG Report), pages 18 and 19)

KPMG provides (pages 18 and 19) a summary of how labour costs are calculated which are comprised of three components (1) hourly base rate (2) bill rate markup calculated as 68% for the 2026 forecast and (3) a fixed overhead charge of $12.00 for the 2026 Forecast. Confirm (or explain otherwise) that if an hourly base rate for a position is $50.00/hour – that the labour cost for that position in the Hydro allocation framework would be ($50.00 *1.68) = $84.00 +$12.00 = $96.00/hour.

CA-NLH-216	(Reference: Volume 2, Exhibit 2, Attachment 2 (KPMG Report), pages 20 and 21)

KPMG indicates (pages 20 and 21) that the proposed change to exclude Admin BU components in the Hydro updated cost allocation framework results in a $0.6 million higher cost allocation to Hydro's regulated operations as compared to the prior inclusion of such costs. KPMG states (page 21) *"The shift in allocations can generally be explained by the fact that more of the Admin Fee BUs 'Home" assignments are on the non-regulated side of the business."* Explain if KPMG's view is that the shift of an additional $0.6 million of shared/common cost allocations to Hydro's regulated operations as a result of a proposed change to exclude Admin BUs components is justified based on the principle of cost-causation or if this shift is simply a result of a simplification in the proposed Hydro intercompany cost allocation framework.

CA-NLH-217	(Reference: Volume 2, Exhibit 2, Attachment 2 (KPMG Report), pages 25, 31 and 37)

KPMG indicates (pages 25, 31 and 37) that the allocation of (1) Information Systems, (2) Network Services, and (3) Business System Transformation - is allocated based on various forms of average users and results in approximately 57% to 58% of these shared costs being allocated to Hydro's regulated operations and 42% to 43% being allocated to non-regulated operations for the 2026 Forecast. The KPMG descriptions of these three cost pools indicate a diverse mix of costs that relate to information systems for individual IT users and overall enterprise systems/application development.

(a) Explain if Hydro considered the use of a hybrid allocator to allocate the three information technology shared costs pools, considering that cost causation related to enterprise systems and application development should appropriately reflect the size, scope, scale and complexity of affiliate operations.
(b) Explain if the use a hybrid allocator for these three information technology shared costs pools would simplify the Hydro intercompany cost allocation framework by eliminating the need for calculation of a number of metrics related to average users.
(c) Provide an estimate of the impact to Hydro's regulated operations net shared cost allocation of allocating the three information technology shared costs pools for the 2027 Test Year using the proposed hybrid allocator (and not the proposed average user allocators).

CA-NLH-218	(Reference: Volume 2, Exhibit 2, Attachment 2 (KPMG Report), pages 29, 30, 32 and 33)

KPMG indicates (pages 29, 30, 32 and 33) that based on the review of intercompany cost allocation practices of a Canadian utility comparator group – several of Hydro's proposed cost allocators are not common or not consistent for a number of the shared /common service cost pools (Hydro Place office space and related costs, procurement, accounts payable and general ledger). Explain if Hydro is concerned that a number of its proposed intercompany cost allocators are either not common or not consistent with the cost allocation practices of a Canadian utility comparator group based on the research conducted by KPMG.

CA-NLH-219 (Reference: Volume 1, table 3-3, page 3.7)

Hydro provides (table 3-3) net administration fees for the 2019 Test Year and from 2024 actual to the 2027 Test Year which Hydro indicates represents non-regulated administration fees net of Hydro's regulated administration fee recovery.

(a) Provide a breakdown of non-regulated administration fees charged to Hydro and Hydro's regulated administration fee recoveries charged to non-regulated operations.
(b) Explain why the Net Administration Fees charged to hydro have increased by $1.9 million from the 2019 Test Year to the 2027 Test Year.

S. Emerging Loads, Churchill Falls 2041, Carbon Compliance, and GRA Process

CA-NLH-220 (Reference: Volume 2 (Exhibit 4), pages 105, 109; OC2022-266)

(a) Confirm whether the 2027 Test Year load forecast (or any sensitivity or scenario analysis prepared but not filed) embeds any assumption, explicit or implicit, about a new wind-hydrogen, ammonia, data-centre, or other large industrial load materializing on the Island Interconnected or Labrador Interconnected System within the 2027-2035 period.
(b) Identify any interconnection inquiry, capacity request, or preliminary discussion Hydro has received from a wind-hydrogen or data-centre proponent as of the date of this filing or the date of response, providing a table of inquiries received in the past three years with proponent name (to the extent not confidential), requested capacity, requested in-service date, and current status (active, withdrawn, lapsed, or other).
(c) Given that OC2022-266 establishes a Government direction that Hydro is not obligated to supply firm power to cryptocurrency-mining customers, confirm whether any comparable direction, policy, or Hydro-initiated position exists or is contemplated for wind-hydrogen or data-centre loads generally.

CA-NLH-221 (Reference: Volume 2 (Exhibit 4), page 105)

(a) Describe any minimum-take, take-or-pay, contract-term, exit-fee, or collateral/creditworthiness provision that currently applies, or would apply, to a new Island Industrial or Labrador Industrial customer requesting a large (e.g., greater than 25 MW) new firm-power interconnection, providing Hydro's current industrial tariff terms relevant to this question.
(b) If no such provisions currently exist, identify any provision, mechanism, or policy that would protect existing ratepayers from bearing stranded generation, transmission, or interconnection costs if such a large new load is added to the system and subsequently reduces its offtake, delays its in-service date, or exits entirely (as occurred with the cryptocurrency-mining load embedded in the 2019 Test Year forecast), or confirm that none exists.
(c) State whether Hydro has considered, or would consider, a separate rate class or schedule for large new industrial loads incorporating cost-causation-based charges

for upstream generation and transmission infrastructure attributable to that load, rather than average-cost industrial rates, and whether Board approval of such tariff terms would require a separate application or could be addressed in this GRA.

CA-NLH-222 (Reference: Volume 1, generally; Volume 2 (Exhibit 4); Volume 3, generally)

Confirm whether any revenue, cost-saving, or supply assumption relating to the Churchill Falls Power Contract's 2041 expiry, any successor or replacement agreement, or any Memorandum of Understanding or similar instrument with Hydro-Quebec regarding post-2041 Churchill Falls power is embedded, directly or indirectly, in

(a) the 2027 Test Year revenue requirement,
(b) the rate mitigation plan's sufficiency analysis through 2030, or
(c) any post-2030 rate-path modeling Hydro has performed, whether or not filed in this GRA. Provide a direct confirmation or denial for each of (a), (b), and (c). If any such assumption exists, describe it and its magnitude; if internal analysis exists but is not filed, identify it by name and date and state whether Hydro will produce it. If no such assumption is embedded, confirm that affirmatively and state whether Hydro has performed any internal analysis of the Churchill Falls 2041 expiry's effect on Island Interconnected System costs or rates that is not reflected in this filing.

CA-NLH-223 (Reference: Schedule A-V (Volume 2); Volume 3, page 690 (Section A, Item 10.0))

(a) Confirm whether the 2027 Test Year fuel cost forecast includes any allowance for federal carbon-pricing costs (whether under the federal fuel charge, an output-based pricing system, or the federal Clean Electricity Regulations' compliance costs, if and as applicable to Holyrood TGS or any other Hydro-operated fossil-fuel generation) for the Island Interconnected, Labrador Interconnected, or isolated systems.
(b) If such costs are included, state the dollar amount embedded in the 2027 Test Year and the forecast methodology and assumptions.
(c) Confirm whether any variance between forecast and actual carbon-pricing or Clean Electricity Regulations compliance costs would flow through the existing SCVDA, the proposed LT-SCVDA (and if so, under which of the ten named variance streams), a separate mechanism, or would instead be borne by Hydro without deferral-account protection. If carbon-pricing costs are not currently embedded in the test year, confirm whether Hydro anticipates seeking a new deferral account or rate rider for such costs in a future filing, and on what timeline.

CA-NLH-224 (Reference: Volume 1, pages 1.17 to 1.18 and 5.16; Schedule E-I; Volume 2, Exhibit 3)

(a) Describe the mechanism by which Hydro's rates effective July 1, 2028, July 1, 2029 and July 1, 2030 will be established, including whether each annual rate change will be implemented through a general rate application, a rate adjustment application, escalation of 2027 Test Year rates, or another process, and identify the statutory or regulatory authority for changing rates in each of those years in the absence of a new test year.
(b) Confirm whether Hydro's revenue requirements for 2028, 2029 and 2030 will be subject to Board review and approval before rates for those years take effect. If not, explain how differences between Hydro's actual costs in those years and the 2027 Test Year forecast will be identified, reviewed and ultimately recovered from or returned to customers, including the role of the proposed Long-Term Supply Cost Variance Deferral Account.

(c) Confirm whether Hydro anticipates that the 2027 Test Year will be the only Board-reviewed test year in effect during the remaining term of the Government's rate mitigation plan through 2030. If so, explain why this is consistent with the Board's supervisory role and with Hydro's own characterization of a typical three-to-five-year general rate application cadence.

(d) Identify the annual reporting Hydro proposes to provide to the Board and intervenors between the conclusion of this proceeding and its next general rate application with respect to: (i) actual versus 2027 Test Year revenue requirements; (ii) the balances and activity in each deferral and variance account; and (iii) the status of rate mitigation funding.

DATED at St. John's, Newfoundland and Labrador, this 6th day of August, 2026.

Per: ______________________________

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