

1 Q. **Reference: Reference Schedule 1, page 14**

2 It is stated

3 The costs associated with a failure during peak winter demand would also be
4 significantly higher than those during the summer months. Hydro estimates that
5 the cost to replace 153 MW with generation from the Holyrood Thermal
6 Generating Station (TGS would be approximately \$120/MWh.” Footnote 34
7 states “Analysis based on Bay d’Espoir Units 1 and 2 production data from the
8 previous five years, January to March. Economic offsets via the Maritime Link
9 and Labrador-Island Link were not considered. Assumed a Holyrood TGS
10 Derated Adjusted Forced Outage Rate of 15%. Assumed Holyrood TGS full
11 production during these months. Cost of Bunker C is based on the June 2022
12 rate (\$147/bbl.)”

13 a) Why were imports (or curtailed exports) over the LIL and Maritime Link not considered for
14 replacement capacity and energy?

15 b) Does this suggest that Holyrood TGS costs for both capacity and energy in the winter
16 months during this time frame should be the basis for marginal costs on the IIS rather than
17 the opportunity cost of exports?

18 c) A cost of \$120/MWh for production from Holyrood TGS appears low. Please provide the
19 calculation including all assumptions.

20 d) Is the October 2023 Marginal Cost Update the most recent version of Hydro’s marginal
21 costs? If not, please provide the latest version.

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24 A. a) Imports over the Labrador-Island Link (“LIL”) and Maritime Link (“ML”) were not considered
25 for replacement capacity and energy, as, historically, Newfoundland and Labrador Hydro
26 (“Hydro”) has not been able to secure firm import arrangements over the ML. Although
27 Hydro engages with market participants on an annual basis to assess the potential
28 availability of firm capacity for planning purposes, such capacity is generally unavailable or

1 cannot be reliably secured. Consequently, firm imports cannot be considered a dependable
2 resource for operational reliability.¹

3 Hydro relies on the full transfer capability of the LIL to meet domestic system requirements.
4 As such, Hydro does not have discretionary incremental transfer capability available for
5 curtailment.

6 For this analysis, Hydro assumed that limited curtailment of energy exports could be
7 undertaken to partially serve Island demand due to firm contractual export commitments;
8 regardless, forecasted energy exports during peak demand periods are insufficient to fully
9 offset the loss of 153 MW of capacity and associated energy. Accordingly, while the
10 potential to curtail exports and deliver incremental energy over the LIL was recognized,
11 thereby reducing reliance on Holyrood generation, this capability was appropriately
12 excluded in the analysis using a replacement energy cost assumption of \$120/MWh.²

13 Imports were excluded from the analysis, as Hydro's assumption and experience have been
14 that imports during peak winter periods would be non-firm in nature and therefore not
15 reliably available for capacity adequacy purposes. In addition, forecasted import energy
16 prices were expected to be high, as the winter peak period occurs in the highest forecasted
17 price months. Hydro's forecasted marginal energy prices reflect the costs of transmission
18 and losses associated with exporting energy from the Island Interconnected System. To
19 accurately reflect the cost of imports, export-related transmission and loss components
20 would need to be removed and replaced with the applicable market export fees,
21 transmission costs, and losses associated with importing energy. A review of the
22 August 2025 marginal cost forecast indicates that average marginal energy prices for the
23 months of January and February exceeded \$200/MWh. Given the expected cost, non-firm
24 availability, and limited magnitude of potential imports during the peak winter period,
25 Hydro excluded imports in this analysis.

¹ Further details can be found in "Reliability and Resource Adequacy Study Review – 2025 Near-Term Reliability Report," Newfoundland and Labrador Hydro, November 20, 2025, s. 3.5.

² Please refer to part c) of this response for additional information on that calculation.

1 **b)** No. This analysis does not suggest that the costs associated with the Holyrood Thermal
2 Generating Station (“Holyrood TGS”) should be treated as Hydro’s marginal costs.

3 Hydro’s marginal capacity costs represent the forward-looking costs associated with
4 meeting incremental demand, including capacity expansion, capital investment, and ongoing
5 operations required over time. These costs do not include existing assets that are already
6 required to meet forecasted system peak demand and reliability requirements.

7 Marginal energy cost represents the cost of producing one additional unit (MWh) of
8 electricity to serve load or avoided cost for a reduction in load. The Holyrood TGS is forecast
9 to be operated primarily to meet system reliability and capacity requirements rather than to
10 provide incremental energy. Given that the Holyrood TGS is required for capacity purposes
11 and, when committed, is forecast to operate at minimum stable output in the near term,
12 Holyrood TGS energy costs are excluded from Hydro’s marginal energy cost determination.

13 Under normal operating conditions, if Hydro requires an additional increment of energy, the
14 forecast response is to reduce exports. Accordingly, the foregone opportunity to export
15 energy represents Hydro’s marginal energy cost. If, however, operational conditions arise
16 where hydroelectric generation or transmission assets are unavailable, and Hydro must rely
17 on incremental thermal generation to meet load, the cost of thermal energy would then
18 represent the marginal energy cost for that period.

19 **c)** The following assumptions were included in Hydro’s calculation of production from the
20 Holyrood TGS:

- 21 ● Holyrood TGS DAFOR³ of 15%;
- 22 ● Assumed full Holyrood production during these months;
- 23 ● Economic offsets via the ML and LIL were not considered; and
- 24 ● The cost of Bunker C was based on a June 2022 rate of \$147/bbl.

³ Derated Adjusted Forced Outage Rate (“DAFOR”).

1 This calculation included production data for Units 1 and 2 at the Bay d’Espoir Hydroelectric
2 Generating Facility (“Bay d’Espoir”) for January through March during the 2018–2022 period
3 to determine the average production that could be replaced by the Holyrood TGS. The
4 calculation also included the associated fuel cost, which is subject to variation. The cost of
5 replacement energy was determined to be \$239/MWh.

6 During the loss of Bay d’Espoir Units 1 and 2, it is possible that other hydro units could be in
7 a position to generate more; increased deliveries over the LIL could be possible as well,
8 based on system conditions.⁴ Either could offset some of the difference in lost production
9 before requiring increased Holyrood TGS generation. Therefore, the value that was reported
10 in the application was 50% of the original value calculated, resulting in a cost of replacement
11 energy of \$120/MWh.

12 **d)** The latest Marginal Cost Projection for 2026–2045 is provided as CA-NLH-004,
13 Attachment 1.

⁴ The additional cost of taking more energy over the LIL was not considered as part of this analysis.

2025 Marginal Cost Projection for 2026-2045 Island Interconnected System

Energy Supply Costs					
	Winter		Summer	Winter	Annual
Year	On-Peak \$/MWh	Off-Peak \$/MWh	All-Hours \$/MWh	All-Hours \$/MWh	All-Hours \$/MWh
2026	106.62	90.01	39.19	97.39	58.49
2027	100.83	84.05	35.80	91.51	54.27
2028	85.88	69.58	28.17	76.82	44.29
2029	65.26	55.99	25.68	60.11	37.09
2030	63.93	55.58	25.34	59.29	36.60
2031	67.76	56.83	27.76	61.69	39.01
2032	71.74	59.62	28.94	65.00	40.90
2033	71.58	59.73	29.89	64.99	41.53
2034	71.94	62.43	29.20	66.65	41.61
2035	72.63	65.76	29.74	68.81	42.69
2036	70.37	62.99	30.67	66.27	42.47
2037	72.77	62.95	30.23	67.31	42.53
2038	77.31	67.08	30.89	71.62	44.39
2039	76.92	67.40	30.82	71.63	44.35
2040	79.83	74.17	33.85	76.68	48.05
2041	82.08	78.47	35.85	80.07	50.51
2042	84.20	77.00	37.69	80.20	51.78
2043	87.24	77.68	36.47	81.93	51.54
2044	94.60	84.63	36.63	89.06	54.01
2045	98.76	90.09	39.75	93.94	57.71

Capacity Costs			
	Generation	Transmission	G&T
Year	\$/kW	\$/kW	\$/kW
2026	318.92	23.45	342.37
2027	233.96	24.06	258.02
2028	214.60	24.69	239.29
2029	274.16	25.33	299.49
2030	452.33	25.99	478.32
2031	860.39	26.67	887.06
2032	617.24	27.37	644.61
2033	680.45	28.08	708.53
2034	508.49	28.82	537.31
2035	356.96	29.57	386.53
2036	536.48	30.34	566.82
2037	552.43	31.14	583.57
2038	568.87	31.95	600.82
2039	585.80	32.79	618.59
2040	603.25	33.64	636.89
2041	621.22	34.52	655.74
2042	639.73	35.43	675.16
2043	658.80	36.35	695.15
2044	678.44	37.30	715.74
2045	698.68	38.28	736.96

Notes:

Base of Energy, Generation and Transmission Capacity is NL Hydro's Marginal Cost (December 2025)

Winter Season defined as December through March.

On Peak Hours Winter 7:00 a.m. to 10:00 p.m., Monday through Friday

On Peak Hours Summer 8:00 a.m. to 10:00 p.m., Monday through Friday