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February 21, 2019

The Board of Commissioners of Public Utilities
Ms. G. Cheryl Blundon, Board Secretary
Prince Charles Building
210 - 120 Torbay Road,
St. John's, NL, A1A 2G8

Dear Ms Blundon:

Re: NLH Proposal for Network Addition Policy and Transmission Expansion Plan – Labrador Interconnected Group RFIs LAB-NLH-073 to LAB-NLH-109

We are writing in respect of the above-noted application. The Labrador Interconnected Group wishes to pose Requests for Information, numbered LAB-NLH-073 to LAB-NLH-109.

Should you have any questions, please be sure to contact me.

Respectfully,
Olthuis, Kleer, Townshend LLP
PER:

SENWUNG LUK
PARTNER

SL/tw

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

IN THE MATTER OF the proposed Network Addition Policy and Labrador Transmission Expansion Plan

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Requests for Information

by the Labrador Interconnected Group

LAB-NLH-73 to LAB-NLH-109

February 21, 2019

Requests for Information Regarding

LAB-NLH-73. Re: Labrador Expansion Study, pp. 9-10 (pp. 17-18 pdf); Appendix C, page 4 (p. 162 pdf)

Preamble:

> Section 2.3 describes the exceptions to the application of the Transmission Planning Criteria in Labrador.

Citation:

> It is noted that in 2017, equipment operating at 46 kV became the responsibility of the Newfoundland and Labrador System Operator ("NLSO") and was therefore reclassified from distribution to transmission. The Wabush Substation 46 kV transformer power ratings have subsequently been recalculated as per Section 6.1 of *NLSO Standard – Transmission Facilities Rating Guide TP-S-001*.

a) Please confirm or correct the following statements:

   i) The Labrador East and West systems are not considered part of the Primary Transmission System (PTS), and so the n-1 criterion is not necessarily applied across the board there;

   ii) The Labrador West Local Network (46 kV) is now part of the NLSO's Transmission System, and a such is subject to different planning criteria than is applied to distribution networks;

   iii) The change from distribution to transmission planning criteria has resulted in a derating of 5 MVA at the Wabush Substation;

b) Please describe all other changes in transformer ratings or other criteria that affect system planning in the Labrador West region that are related to the shift to NLSO control and/or the change to transmission planning criteria;

c) Please indicate whether any similar changes have occurred with respect to the Labrador East region and, if so, provide details.

LAB-NLH-74. Re: Labrador Expansion Study, p. 11 (p. 19 pdf), Table 3

a) Please confirm that the July 2018 P90 forecast presented here has not been previously filed with the Board;

b) Is any supporting documentation available with respect to this forecast? If so, please provide it;

c) Please confirm that, until now, Hydro has generally presented P50 forecasts, and describe the quantitative relationship between a P50 forecast and a P90 forecast;

d) Please provide a breakdown each of these forecasts (Labrador East and Labrador West) into:

   i. The baseline P50 forecast, excluding all data centre loads (existing and future) as well as all industrial loads,

   ii. Forecast loads, under the P50 baseline forecast, for all existing data centres,

   iii. Forecast loads, under the P50 baseline forecast, for all existing industrial loads,

   iv. Forecast future (additional) data centre loads included in the baseline P50 forecast,

   v. Forecast future (additional) industrial loads in the baseline P50 forecast, and

   vi. Additional load added to convert the baseline P50 forecast to a P90 forecast;

e) For existing data centre customers in Labrador East and in Labrador West, please indicate i) their actual 2018 coincident peak demand and ii) their actual 2018 total energy consumption;

f) Are there any existing or forecast data centre customers in Labrador that are served without directly from the Churchill Falls Generating Station, without relying on either the Labrador East or Labrador West transmission systems? If so, please identify their capacities, distinguishing between existing and forecast loads.

LAB-NLH-75. Re: Transmission Expansion Policy, Table 3, p. 11 (p. 19 pdf)

Preamble:

> The load forecast is provided through 2043.

What effect, if any, might the expiration of the Hydro-Québec Power Contract in 2041 have on the transmission requirements described in the Transmission Expansion Study? Has Hydro undertaken any work with respect to how the availability of Upper Churchill Generation capacity might affect transmission planning in Labrador? Please explain your answer.

LAB-NLH-76. Re: Labrador Expansion Study, p. 14 (p. 22 pdf); p. 15-16 (p. 23-24 pdf)

Citation 1 (page 14):

> Note 16: As noted in Section 2.2 the baseline forecast for western Labrador does not include new major customer interconnections and can be supplied by the existing transmission system. There are, therefore, no deficiencies for this baseline scenario. Expansion requirements associated with incremental loads are presented in Section 7. (underlining added)

Citation 2 (pages 15-16):

> The transfer capability of the existing Labrador West Transmission System is 350 MW under normal operating conditions with all equipment in service. This is due to voltage limitations at the WTS. As outlined in Section 3, the P90 baseline load forecast will exceed 350 MW in 2019 and will reach 383 MW by the year 2043.[17]
>
> > Note 17: As discussed in Section 3.1.2, the baseline load forecast includes load increases associated with Tacora operations at the Wabush Mines site. In the event this does not materialize, the load forecast will not exceed 350 MW and additions to increase system capacity will therefore not be required.

a) Please identify the precise passage in Section 2.2 referred to in note 16;

b) Please explain the coherence between Citation 1 and Citation 2.

LAB-NLH-77. Re: Labrador Expansion Study, p. 8 (p. 16 pdf), Table 2

Preamble:

Table 2 provides the power ratings of the Wabush Substation transformers under the transmission planning criteria.

a) Please provide the equivalent table based on the distribution classification previously applied to the Wabush Substation.

b) Please indicate the effect of the derating of the Wabush Substation due to the application of transmission planning criteria on the need for the proposed Wabush Substation upgrades, indicating which of the proposed modifications would not be required or would not be required until a later date if the distribution-based ratings had been maintained;

c) If certain upgrades are required under the new ratings but would not be required under the old ratings, please explain in detail for each one why the investment is justified from the customers' perspective.

LAB-NLH-78. Re: Labrador Expansion Study, pp. 17-18 (pp. 25-26 pdf)

Preamble:

Table 6 shows the capacity deficit for the Wabush Substation growing from 3.1 MWA in 2018 to 5.3 MVA in 2043.

a) Taking into account the response to LAB-NLH-76, please indicate the capacity deficits for the years 2018-2043 if the power ratings were calculated based on the distribution system classification used previously.

LAB-NLH-79. Re: Labrador Expansion Study, pp. 18-19 (pp. 26-27 pdf)

Citation:

A load flow analysis was performed to assess the network of 46 kV transmission lines that supply Hydro Rural customers in Labrador City and Wabush. …

The results of the analysis indicate that <u>transmission lines overloads exist in peak load conditions</u>. To prevent the thermal overloading in the baseline forecast condition, the reconductoring of 46 kV transmission lines L32, L33, and L40 is required. The capital cost associated with this work is estimated to be approximately $1.4 million. This work will ensure sufficient capacity to meet peak load conditions for the 25-year study period.

To prevent overload conditions in the sensitivity forecast condition, the reconductoring noted above, as well as that of L36, is required. The capital cost associated with this work is estimated to be approximately $1.8 million. This work will ensure sufficient capacity to meet peak load conditions for the 25- year study period. (underlining added)

a) Please indicate for how many hours per year these overload conditions are experienced, in both the base and sensitivity cases.

b) Please indicate for how many hours per year these overload conditions would be experienced, in both the base and sensitivity cases, if all existing and future data centre loads were curtailed during the peak 300 hours.

LAB-NLH-80. Re: Labrador Expansion Study, pp. 20-21 (pp. 28-29 pdf)

Citation 1:

The proposed plan for Alternative 1 is to offload L1301/L1302 under peak conditions through the interruption of customer load and the operation of back-up generation on the Happy Valley–Goose Bay system.

Citation 2:

> The capital budget estimate for this project is approximately $8.2 million. The majority of the lifecycle costs associated with this alternative are operational costs for fuel and controlled customer interruption.

Preamble:

> According to Table 7 on page 27, the CPV of this alternative is $52.4 million.

a) Referring to the Labrador East baseline P50 forecast provided in response to LAB-NLH-74, excluding all data centre loads (including existing loads), please indicate how many times per year the forecast loads would exceed 77 MW, and for how many total hours per year;

b) Referring again to the Labrador East baseline P50 forecast provided in response to LAB-NLH-74, excluding all data centre loads (including existing loads), please indicate how many hours of operation of the HVYGT would be required each year, assuming the operating regime described in this section;

c) Please provide detailed assumptions and calculations in Excel format (including formulas), demonstrating a CPV of $52.4 million for Alternative 1.

LAB-NLH-81. Re: Labrador East Reliability Plan, Monthly Status Report, December 17, 2018, page 2

Citation:

> **2.3 Inspections of L1301/L1302**
>
> Status: Ongoing
>
> Progress to Date: Ongoing
>
> Hydro has carried out infrared inspection of all line splices on L1301/L1302, with no defective splices discovered. Hydro has carried out several aerial patrols, most recently on November 5, 2018. No additional deficiencies were identified from the last aerial patrol. Patrols will continue at six-week intervals throughout the 2018-2019 winter season, with the next patrol scheduled for December 19, 2018.

a) Have any deficiencies been identified in L1301/L1302 since these regular inspections began? If so, please provide a list of all such deficiencies identified and the corrective measures that were taken.

b) Given these findings and the ongoing inspection protocol, please provide Hydro’s best estimate of the probability of a major outage of the L1301/L1302 during winter 2018/19 and 2019/20.

c) Does Hydro own and operate any other radial transmission lines constructed in the 1970s or earlier? If so, please identify each one, and the refurbishments currently planned (if any), including estimated commissioning date and capital cost.

LAB-NLH-82. Re: Labrador Expansion Study, p. 20 (p. 28 pdf)

Citation :

> For this alternative and as long as the power is delivered over L1301/L1302, the HVYGT must be capable of reliably switching from synchronous condenser mode to generation mode whenever the Labrador East load is expected to exceed 82.5 MW.[21] Although additional capacity is not required until the load reaches 82.5 MW, the switch to generation mode must occur before the load in Labrador East reaches 65 MW. If the HVYGT were to trip during the mode conversion process at a load greater than 65 MW, there is a significant risk of system voltage collapse. Consequently, Hydro would be forced to extend the operation of the HVYGT during peak conditions (i.e., above 65 MW) to ensure system reliability, which translates into an increased amount of additional fuel being consumed by the HVYGT.

a) With regard to the risk described in the Citation of a trip during conversion of the HVYGT from condenser to generator mode, has Hydro encountered such problems in the past with respect to this generator? If so, please indicate a) how many times such as conversion has been effectuated in the last twenty (20) years, and the number of times a trip has occurred;

b) In addition to its own experience described above, is Hydro's concern based :

   i. on risks identified in the literature? If so, please provide references;

   ii. on standard utility practice? Please provide references regarding best practices for switching between condensor and generator mode for a gas turbine.

c) Has Hydro ever switched the HVYGT from condensor to generator load at a load level of more than 65 MW? If so, please indicate how many times this has occurred in the last ten years, and explain the circumstances;

d) If load for a winter peak had been forecast at 81 MW but, due to a change in the weather forecast that occurred when load was already at 75 MW, that peak was now expected to rise to 84 MW, would Hydro switch the HVYGT to generator mode despite this risk, or would it instead engage in customer curtailment?

LAB-NLH-83. Re: Labrador Expansion Study, p. 34 (p. 42 pdf)

Citation:

9 Customer Rate Impacts

There is significant uncertainty with respect to specific customer rate impacts associated with the expansion of the transmission system in Labrador. As presented in Section 7, the size and timing of customer requests will have a significant impact on expansion requirements. Further, the application of the Network Addition Policy has the potential to impact cost allocations to ensure fairness. It is only by performing a detailed system impact study in response to a specific customer request that such rate calculations can be performed.

For the purposes of this Expansion Study, Figure 6 has been provided as a basis for the generic calculation of forecast rate impacts for rural and industrial customers in Labrador as a function of the capital costs of a transmission system expansion.

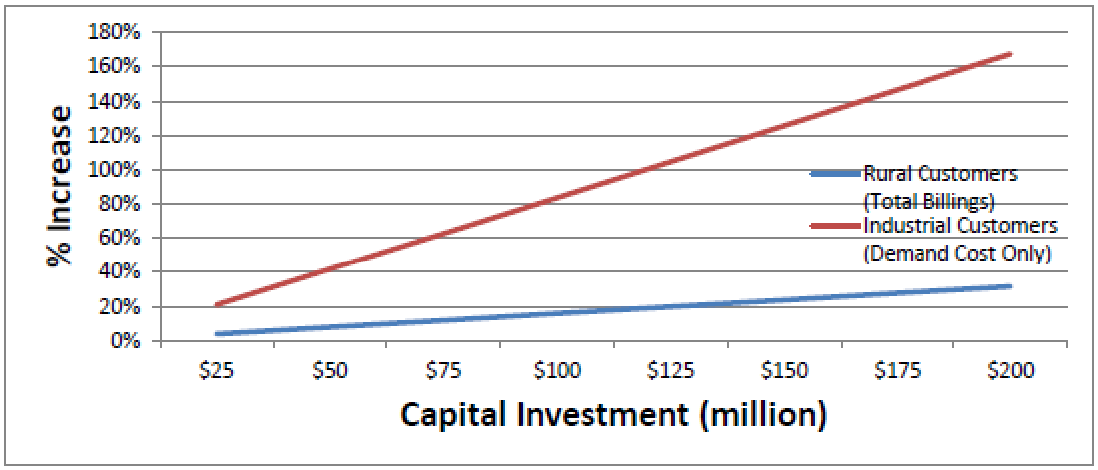

Figure 6: Projected Rate Increase vs. Capital Investment

Preamble:

Figure 6 suggests a linear relationship between capital investment and rate increases. However, given that the transmission expansion projects selected in the study are large and “lumpy”, the relationship between load increases and rate impacts does not follow a straight line.

Please present block graphs, separately for Labrador East and Labrador West, that indicate:

a) On the x-axis, peak load,

b) On the left y-axis, capital expenditures for transmission infrastructure required to meet the peak load on the x-axis, and

c) On the right y-axis, the % rate increase for rural customers resulting from those investments.

LAB-NLH-84. Re: Labrador Expansion Study, p. 32 (p. 40 pdf)

Citation :

> 7.2.1 Considerations for an Interconnection to Hydro-Québec
>
> As per Table 11, if incremental loads are such that forecasted loads in Labrador West exceed 434 MW, the least-cost alternative will involve an interconnection with Hydro-Québec at its Bloom Lake ("BLK") Station.
>
> Hydro has been in consultation with Hydro-Québec TransÉnergie ("HQT") with respect to interprovincial interconnection alternatives. These discussions have included cooperative transmission planning activities and have allowed for a shared understanding of commercial processes if such an interconnection were to be pursued.
>
> From a transmission planning perspective, a preliminary load flow study has been performed cooperatively by personnel from both utilities. The outcome of this analysis is that HQT has validated Hydro's load flow models and analysis and has provided preliminary confirmation of the technical viability of the interconnection.
>
> From a commercial standpoint, personnel from HQT have informed Hydro that if the interconnection is to be pursued, a Transmission Service Request will need to be submitted.[34] This request will be for a point-to-point service to a new delivery point to be established at the border in western Labrador. This request will trigger the system impact study process.

a) Please:

   i. confirm that neither the Bloom Lake nor the Flora Lake substations currently exist; and

   ii. provide a map showing the locations of these two proposed substations and the new lines required to interconnect them to both the HQ and NLH transmission systems.

b) Please explain Hydro's power supply assumptions with respect to the Hydro-Québec interconnection scenario. Would Hydro purchase electricity from Hydro-Québec, or would it wheel its own power over the HQ transmission system? If neither option has been excluded, please describe the advantages and disadvantages, both economic and otherwise, of each.

LAB-NLH-85. Re: Labrador Expansion Study, p. 33 (p. 41 pdf)

Citation:

> As evident from Section 7, the connection of a large customer can trigger the need for significant capital upgrades on the LIS. Consequently, there must be a

mechanism in place to allocate any costs or benefits to the customer(s) advancing the need of a major capacity upgrade.

a) Please confirm that the need for significant capital upgrades on the LIS can also be triggered by the connection of one or more small or mid-sized customers;

b) Please confirm that, given the lumpiness of the transmission system, it is possible that the capital upgrades on the LIS that would be triggered by the connection of one or more small or mid-sized customers might vastly exceed the additional transmission capacity required by those customers;

c) Is it Hydro's view that if, in such a situation, the prohibitive nature of the capital upgrade cost flowing from the « beneficiary pays » approach prevents the potential customer(s) from taking service, that would be a sign that the system is working properly? If not, what is the desired outcome in such a situation?

LAB-NLH-86. Re: Labrador Expansion Study, pages 11 (pdf 19) and Appendix B, page 9 (p. 73 pdf)

Preamble:

> Table 3 (page 11) provides a Baseline Coincident Peak forecast for Labrador West growing from 342.4 MW in 2018 to 382.9 MW in 2043.
>
> Table 2 of Appendix B (page 73 pdf) shows these same values in the column identified as "baseline peak", and adds separate columns for "Data Centre", rising from 27.1 MW in 2020 to 51.5 MW in 2022 and remaining at that level through 2043, and a final column "Coincident Peak with Alderon", which appears to add 65 MW to the "Coincident Peak with Data Centres" column, from 2022 through 2043.
>
> Note 9 to Table 2 specifies that the baseline peak load forecast includes Hydro Rural, IOC and Tacora.

a) Please break down the Baseline Peak column into:

   i. Regular loads excluding and data centre and industrial loads;

   ii. Data centre loads; and

   iii. Industrial loads.

b) Please explain the source and justification for the forecast of data centre loads found in Table 2 of Appendix B, which grow from 0 in 2019 to 27.1 MW in 2020 to 51.5 MW in 2022, and remain at that level through 2043.

c) Please describe and quantify Hydro's perception of the uncertainty of these forecast data centre loads, compared to the other future loads in the forecast. Insofar as Hydro considers the forecast data centre loads to be more uncertain, please explain how it has integrated that uncertainty into its planning process;

d) Please provide an update on the Alderon project, including Hydro's estimate of the likelihood that it will represent a 65 MW load starting in 2022;

e) Please provide an update regarding any other potential mining projects in Labrador of which Hydro is aware, indicating for each one:

   i. The amount of power (MW) that would eventually be required;

   ii. The earliest date at which that power could be required; and

   iii. Hydro's estimation as to the likelihood that this power will be need at this date.

f) Please discuss what criteria Hydro used to determine which potential loads to include in the Baseline Load Forecast.

g) Please provide a forecast for Labrador East similar to one shown in Table 2 of Appendix B, showing potential future load additions for data centre and other uses.

LAB-NLH-87. Re: Labrador Expansion Study, pages 22 (pdf 30)

Citation:

> Since the power delivered to the Labrador East System will flow through the two, 315 kV lines under this scenario …

Please explain how the costs to the Labrador Integrated System of using these 315 kV lines would normally be calculated, if such charges were allowed under provincial laws and regulations. Please quantify your response.

LAB-NLH-88. Network Addition Policy, page 8 (pdf), Re: Labrador Expansion Study, p. 38 (pdf)

Citation 1 (Network Addition Policy)

Table 1
Derivation of Expansion Costs per kW

Region	Capacity kW	Description	2019 Capital Investment ($000)	Direct Investment $ per kW
Labrador East	21,000	Transformer Upgrades at HV-GB	5,000	238
	37,000	Transformer Upgrades at HV-GB and MF Terminal Station	15,000	405
	100,000	Construct second line from MF to HV-GB	50,000	500
Labrador West	33,000	Wabush TS Upgrades and 230 kV uprating	16,500	500
Sub-Total	**191,000**		**86,500**	**453**
O&M[9]				12
Total				**465**

Citation 2 (Expansion Study):

Table 10: Labrador East – Proposed Future Phases

Phase	Load Trigger (MW)[30]	Project Description	Cost Estimate ($ million)[31]
1	>77	MF to HVY Interconnection	20
2	>104	Transformation Upgrade at HVYTS[32]	5
3	>125	Transformation Upgrade at HVYTS and MFATS2[33]	15
4	>162	Construction of Second Line from MF to HVY	50

a) Please confirm that the three expansion projects identified for Labrador East in the Network Addition Policy are identical to the projects identified as Phase 2, 3 and 4 in the table from the Transmission Expansion Study;

b) Please explain why the Phase 1 project from the Transmission Expansion Study (the MF to HVY Interconnection) was not included in the derivation of expansion costs in the Network Addition Policy, even though it is identified as a future project in the Transmission Expansion Study (sections 5.1.2, 6.1.1 and 7.1) and has not to date been approved by the PUB.

LAB-NLH-89. Re: Labrador Expansion Study, Appendix B, page 15 (p. 79 pdf); Network Addition Policy, page 8 (pdf),

Citation 1:

Table 5: Overview of CPW of Preferred Alternatives and Transfer Capacity

Alt	Description	Forecast (MW)	Winter Firm Capacity (MW)	Non-Firm Capacity (MW)	Estimated Cost ($ million)	CPW ($ million)
4	WTS Upgrades (Baseline)	383	252	387	15.1	13.2
5	WTS Upgrades (Low Incremental)	434	252	454	31.7	27.6
17	315 kV Transmission Line from BLK to FLK with 46 kV connection from FLK	499	499	600	153.2	148.1

Citation 2:

Table 1
Derivation of Expansion Costs per kW

Region	Capacity kW	Description	2019 Capital Investment ($000)	Direct Investment $ per kW
Labrador East	21,000	Transformer Upgrades at HV-GB	5,000	238
	37,000	Transformer Upgrades at HV-GB and MF Terminal Station	15,000	405
	100,000	Construct second line from MF to HV-GB	50,000	500
Labrador West	33,000	Wabush TS Upgrades and 230 kV uprating	16,500	500
Sub-Total	**191,000**		**86,500**	**453**
O&M[9]				12
Total				**465**

Please explain the relationship between the three Labrador West projects listed in Table 5 of Appendix B of the Transmission Expansion Study and the one Labrador West project found in Table 1 (Expansion Cost Derivation) of the Network Addition Policy.

LAB-NLH-90. Re: Network Addition Policy, page 8 (pdf)

Citation 1:

Table 1
Derivation of Expansion Costs per kW

Region	Capacity kW	Description	2019 Capital Investment ($000)	Direct Investment $ per kW
Labrador East	21,000	Transformer Upgrades at HV-GB	5,000	238
	37,000	Transformer Upgrades at HV-GB and MF Terminal Station	15,000	405
	100,000	Construct second line from MF to HV-GB	50,000	500
Labrador West	33,000	Wabush TS Upgrades and 230 kV uprating	16,500	500
Sub-Total	**191,000**		**86,500**	**453**
O&M[9]				12
Total				**465**

a) Please explain by what process Hydro decided which projects to include in the derivation of expansion costs.

b) Please explain why the MFHVI project is not included in the derivation of expansion costs.

c) Please explain why the additional expansion projects planned for Labrador West are not included in the derivation of expansion costs.

LAB-NLH-91. Re: Network Addition Policy, page 19 (pdf)

Citation:

> **Transmission Expansion Plan** refers to the most recent transmission system expansion plan for the Labrador Interconnected System filed with the Board. The Transmission Expansion Plan identifies Transmission Upgrades required to serve various load growth scenarios and the estimated costs to implement each upgrade.
>
> **Expansion Advancement Cost** means the difference between the cost of acceleration of the Transmission Expansion Plan and the value to existing Customers from acceleration of the Transmission Expansion Plan.

a) Please identify which specific elements of the Labrador Transmission Expansion Study filed with the Board on October 31, 2018 and revised on November 5, 2018 constitute the "Transmission Expansion Plan" for purposes of the Network Addition Policy.

b) Please indicate precisely which of the load forecasts found in the Transmission Expansion Study are used to determine the Transmission Expansion Plan for the purposes of the Network Addition Policy.

c) Please indicate whether or not, and if so to what extent, the load forecasts used to determine the Transmission Expansion Plan for the purposes of the Network Addition Policy include future data centre and industrial loads.

d) Are the Alderon and data centre loads indicated in Table 2 of Appendix B included in the Baseline Load Forecast?

e) Please indicate at what frequency the Transmission Expansion Plan and the Network Addition Policy will be updated. Will each update be subject to Board approval? Please explain the approval process that is foreseen.

f) Please identify which specific elements in the the Labrador Transmission Expansion Plan are used to determine whether or not acceleration of the Transmission Expansion Plan is required, and its cost.

g) Please explain, with numerical examples in Excel format with all formulas intact, how the cost of acceleration of the Transmission Expansion Plan is calculated.

LAB-NLH-92. Re: Network Addition Policy, page 16 (pdf)

Citation:

> **Expansion Cost per kW** means an estimate of the cost of potential transmission upgrades, as provided in the Transmission Expansion Plan, divided by the additional capacity provided by those transmission upgrades. Hydro will update the Expansion Cost per kW within three months of filing a new Transmission Expansion Plan with the Board.

Given the substantial differences in expansion options for Labrador East and for Labrador West, both in terms of costs and of thresholds, please explain Hydro's reasoning in fixing a single Expansion Cost per kW that combines expansion projects from both.

LAB-NLH-93. Re: Labrador Expansion Study, pp. (23-24 and 31 (pp. 31-32 and p. 39 pdf); Network Addition Policy, page 8 (pdf)

Citation 1 (pp. 23-24, Expansion Study):

> 5.2 Long-Term Supply to Labrador West
>
> 5.2.1 Transmission System Capacity Upgrades
>
> The analysis provided in Appendix B includes a description of the system additions that would be required to increase transmission system capacity in western Labrador to meet the peak baseline forecast of 383 MW.

The upgrades include the commissioning of the third synchronous condenser at Wabush Terminal Station,[23] the installation of an additional 23 MVAR of shunt compensation, and replacement of transformers T4 and T5 with 125 MVA units. These upgrade will increase system capacity to meet the baseline peak load forecast of 383 MW.

The estimated capital cost of this project is approximated 1 to be $15.0 million.[24]

Citation 2 (Transmission Expansion Study, page 31)

7.2 Labrador West

The existing 230 kV transmission system has a non-firm winter capacity of 350 MW and is adequate only if supply to industrial customers is restricted. System additions that would be required to meet the unrestricted baseline load forecast of 383 MW are described in 5.2.1. Hydro has conducted further analysis to determine the least-cost options incremental loading scenarios given a significant potential for incremental load in Labrador West. This comprehensive analysis is provided in Appendix B. Table 11provides a summary of the preferred alternatives.

Table 11: Preferred Alternative for Incremental Lab West Load Levels

Lab West Load (MW)	Least-Cost Option	Description of Alternative	Capital Cost ($ million)
> 383	Alternative 5	• Commissioning of SC3 • Replacement of T4, T5, and T6 with 125 MVA units for loss of largest transformer • Replacement of four, 46 kV circuit breakers due to exceeding fault level • Installation of 72 MVARs of reactive compensation (needed for loss of SC#3) • Thermal Upgrade of L23/L24 to 75°C conductor temperature	31.66
> 434	Alternative 17	• Construction of 50 km of 315 kV transmission line from Bloom Lake, ("BLK") to Flora Lake ("FLK") and 5 km of 230 kV from FLK to WAB. • BLK 315 kV and WAB 230 kV Line Terminations • Construction of new 315/230/46 kV terminal station at FLK • Installation of four 40.2 MVAR capacitor banks on FLK 230 kV Bus • Commission synchronous condenser SC3 • Upgrade of 14, 46 kV breakers with 2000 A, 31.5 kA breakers • 25 km of new 46 kV distribution lines plus upgrades to existing distribution lines	153.15

Citation 3 (Network Addition Policy)

Table 1
Derivation of Expansion Costs per kW

Region	Capacity kW	Description	2019 Capital Investment ($000)	Direct Investment $ per kW
Labrador East	21,000	Transformer Upgrades at HV-GB	5,000	238
	37,000	Transformer Upgrades at HV-GB and MF Terminal Station	15,000	405
	100,000	Construct second line from MF to HV-GB	50,000	500
Labrador West	33,000	Wabush TS Upgrades and 230 kV uprating	16,500	500
Sub-Total	**191,000**		**86,500**	**453**
O&M[9]				12
Total				**465**

a) Please confirm that the single expansion project identified for Labrador West in the Network Addition Policy (Citation 3) is identical to the one identified in the citation from the Transmission Expansion Study (Citation 1).

b) Please explain why the two projects identified in Table 11 of the Transmission Expansion Study, required if Lab West loads increase beyond 383 MW, were not included in the derivation of expansion costs in the Network Addition Policy (Citation 3).

LAB-NLH-94. Re: Transmission Expansion Study, Appendix B, Appendix A (“Labrador West Future Transmission Supply Alternatives”)

Preamble:

Appendix A to Appendix B presents 17 “alternatives” for the Labrador West Transmission system.

a) Please provide a table summarizing the key data regarding these 17 alternatives. The following format is suggested, with alternatives sorted based on firm capacity provided:

Alternative #	Alternative name	Applicable Load Forecast	Principal elements	Resulting system capacity (MW)		Capital Cost
				Firm (n-1)	Total (all equipment in service)	

b) Please indicate which of the options studied in Appendix B is the Labrador West Transmission Project (LWTP), as described in the Labrador West Transmission Project Exemption Order NLR 11/14.

   i. According to NLR 11/14, "Newfoundland and Labrador Hydro is exempt from the *Electrical Power Control Act, 1994* and the *Public Utilities Act* for all planning, design, construction and contribution activities pertaining to the Labrador West Transmission Project. » Please explain how the consequences of this exemption with respect to the Transmission Expansion Plan, the Network Addition Policy, and the various actions that the Board will take in relation to these two documents.

   ii. Insofar as other options described in the Transmission Expansion Plan include some of the elements described in section 2 of NLR 11/14, please explain Hydro's understanding of the implications of the Exemption Order with respect to these other options.

   iii. Please indicate the amount that has been expended by Hydro to date with respect to the Labrador West Transmission Project (LWTP).

   iv. Please indicate whether Hydro is considering writing off the past expenditures on the LWTP and, if so, when such an action could be taken.

LAB-NLH-95. Re: Transmission Expansion Study, Appendix B, Appendix A ("Labrador West Future Transmission Supply Alternatives"); Labrador Expansion Study, p. 32 (p. 40 pdf)

a) Please indicate which of the alternatives presented in response to the previous question involve a new interconnection with Hydro-Québec;

b) Please provide and explain Hydro's estimates of the costs involved in this approach, broken down into:

   i. Hydro's own capital investments;

   ii. Hydro-Québec's direct investments in construction a required post and lines;

   iii. Hydro-Québec's upstream transmission upgrades required to provide the required service; and

   iv. The ongoing transmission tariff expenses flowing from using point-to-point service for either export or wheel-through service under Hydro-Québec's open access transmission tariff.

LAB-NLH-96. Re: Transmission Expansion Study, Appendix B, Appendix A, Alternative 1 (page A2, p. 82 pdf)

Citation:

> This scenario represents the lightest forecasted load condition where Tacora operations at the Wabush Mines do not materialize as per the baseline forecast and loads do not exceed 350 MW. In this case no transmission system additions are required other than 46 kV line upgrades for the reliable supply to Hydro Rural load.

a) Please provide an analysis of the likely evolution of Tacora demand, including best- and worst-case scenarios, and Hydro's current best estimate of the most likely one.

b) Please explain the basis on which the existing transmission capacity is apportioned between Tacora, IOC, data centres and other customers, during times when it is exceeded by demand.

LAB-NLH-97. Re: Transmission Expansion Study, Appendix B, Appendix A, Alternative 3 (page A4, p. 84 pdf)

a) Please confirm that:

i. Alternative 2 is based on the "Baseline Peak" of the Western Labrador forecast found in Table 2 (page 9) of Appendix B, and excludes future data centre loads;

ii. Alternative 3 is not in fact an alternative, but simply states that the remaining alternatives will also take into account the forecast data centre loads set out in the third column of the Western Labrador forecast found in Table 2 (page 9) of Appendix B;

iii. Loads of greater than 434.5 MW are not foreseen in Labrador West until after 2043, unless the Alderon project (Kami Mine) comes into operation, in which case loads greater than 434.5 MW would be experienced as early as 2022.

b) Please provide an analysis of the likelihood that the Kami Mine project will go ahead, and of the possible timing.

LAB-NLH-98. Transmission Expansion Study, Appendix C, page 7 (pdf 165)

Citation:

> Analysis has been completed on the 46 kV network based on the following load forecast sensitivities:
>
> 1) Base case forecast excluding data centers:
>
> a. Wabush Substation 2043 - 2044 Peak Coincident 1 Load = 25.4 MW

2) Base case forecast including data centers

a. Wabush Substation 2043 - 2044 Peak Coincident Load = 25.9 MW

a) Please confirm that the additional data center load for the Wabush substation is forecast to be 0.5 MW.

b) Please explaining how this load forecast was arrived at.

LAB-NLH-99. Re: Network Addition Policy Summary Report, page 3

Citation:

> The LIS Transmission Expansion Plan filed with the Board on October 31, 2018 identifies future transmission upgrades to the LIS reflecting Hydro's demand forecast. The LIS Transmission Expansion Plan also provides the capital projects that are available to serve peak demand increases that are in excess of Hydro's forecast.

a) Please confirm that the « LIS Transmission Expansion Plan filed with the Board on October 31, 2018 » refers to the « Labrador Interconnected System Transmission Expansion Study » filed with the Board on October 31, 2018, and revised on November 5, 2018.

LAB-NLH-100. Re: Network Addition Policy Summary Report, section 2.3.2, page 5 (p. 8 pdf)

Citation:

> The Expansion Cost per kW is an estimate of the cost of potential transmission upgrades on the LIS (not reflected in the Transmission Expansion Plan) divided by the additional capacity provided by those transmission upgrades.

a) Please confirm that Table 1 (Derivation of Expansion Costs per kW) describes the derivation of the Expansion Cost of $465/kW set out in Appendix A to the Policy.

b) Please explain what is meant by the parenthetical expression "not reflected in the Transmission Expansion Plan ». Are not the projects described in Table 1 found in the Labrador Interconnected System Transmission Expansion Study?

c) Please explain the basis upon which Hydro decided which projects from the Labrador Interconnected System Transmission Expansion Study to include in Table 1.

d) With respect to Labrador East, please explain why the MFHVI project, described at Alternative 2 in section 5.1.1 and recommended in section 11.2 of the Transmission Expansion Study, was not included in Table 1.

e) With respect to Labrador West, please explain why the Alternatives 5 and 17, selected as the preferred alternatives in Table 11 on page 31 of the Transmission Expansion Study and included as recommendations in section 11.2, were not included in Table 1.

f) Please recompute the Expansion Cost per kW under the following hypotheses:

    i. Inclusion of the MFHVI project;

    ii. Inclusion of Alternatives 5 and 17 for Labrador West; and

    iii. Inclusion of the MFHVI project and Alternatives 5 and 17.

g) Please explain why Hydro chose to develop a single Expansion Cost per kW, rather than distinct Expansion Costs for Labrador East and Labrador West.

LAB-NLH-101. Re: Network Addition Policy Summary Report, section 2.3.3, page 6 (p. 9 pdf)

Citation:

> Hydro proposes a more detailed system impact review process to deal with customer requests of 1500 kW or larger. These requests will trigger a preliminary assessment to determine if compliance with the request will require an acceleration of the Transmission Expansion Plan.
>
> …
>
> If acceleration of the Transmission Expansion Plan is necessary, Hydro will determine the Expansion Advancement Cost. This amount will reflect the difference between the cost of acceleration of the Transmission Expansion Plan and the value of the acceleration of the Transmission Expansion Plan to existing customers.

a) Please explain how Hydro will determine whether or not acceleration of the Transmission Expansion Plan would be required, given that said Plan does not contain any timetables or other indication of when certain investments would be required.

b) Please indicate in detail how the cost of acceleration of the Transmission Expansion Plan will be determined.

c) Please provide numerical examples, with detailed calculations presented in Excel format with formulas intact, to demonstrate how the cost of acceleration of the Transmission Expansion Plan will be determined, including :

i. The addition of a 10 MW data centre load in Labrador East, starting in 2021;

ii. The addition of a 30 MW data centre load in Labrador West, starting in 2021.

d) Please provide an additional detailed numerical example in Excel format for the following hypothetical example : in 2016, for the addition of the two data centres that now have service contracts in Labrador East, assuming that the proposed Network Addition Policy had been in effect.

LAB-NLH-102. Re: Network Addition Policy Summary Report, section 2.3.3, page 6 (p. 9 pdf)

Citation 1:

> If acceleration of the Transmission Expansion Plan is necessary, Hydro will determine the Expansion Advancement Cost. This amount will reflect the difference between the cost of acceleration of the Transmission Expansion Plan and the value of the acceleration of the Transmission Expansion Plan to existing customers. The value to existing customers will be determined based upon the forecast reduction in Expected Unserved Energy (“EUE”) resulting from the capital advancement.
>
> EUE is a measure of the amount of customer demand not served due to capacity shortfalls. For the purposes of Network Additions Policy analysis, EUE is valued using the approximate cost of backup generation based on the projected costs of gas turbine fuel. Such approach serves as a proxy for reliability to customers.

Citation 2 :

> The following procedure is used to determine the EUE for the study period.
>
> 1. Prepare a set of cases to reflect a range of loading conditions for the Transmission Expansion Plan and the accelerated plan scenarios.
>
> 2. Assess system capacity in consideration of applicable Transmission Planning Criteria[8]. Assessments will include a review of equipment ratings, voltages, and the transient stability metrics for the Labrador Integrated Transmission System, as applicable. Identify transfer limits for each case for all contingency conditions.
>
> 3. Prepare profiles of peak loads for the study period, based on historical load data, as well as peak load and energy forecasts.

4. Determine the capacity shortfall for the various peak load profiles, measured as the difference between transmission transfer capability and expected loads.

5. Calculate EUE based on the probability associated with the set of possible peak load levels and capacity shortfall multiplied by the expected unavailability of each system element. The assumed unavailability of each element is based on CEA reliability data.

6. Multiply the EUE by the cost of backup energy to determine the proxy value power outage costs of EUE.

7. Calculate the CPV of the EUE cost for the Transmission Expansion Plan and the accelerated plan using appropriate discount rates.

a) Please confirm or correct the following statement : In the process described in points 5 and 6 of Citation 2, the EUE for the Transmission Expansion Plan is based on the Baseline Load Forecast and on the physical characteristics of the system as it exists today and following planned improvements, and is measured in MWh or in GWh.

b) Please confirm that EUE is calculated separately for Labrador East and for Labrador West or, in the alternative, explain why that is not the case.

c) Please confirm or correct the following statement : The « forecast reduction in Expected Unserved Energy ("EUE") resulting from the capital advancement » is calculated by comparing the value described above in question (a) with that resulting from a scenario in which the prospective load has been added and the required advancement of the Transmission Expansion Plan has taken place.

d) Please calculate the EUE for the Transmission Expansion Plan as described in question (a) above -- that is, the status quo EUE against which the EUE resulting from the capital advancement will be compared – for both Labrador East and Labrador West.

e) Please confirm or correct the following statement : The « cost of backup energy » used in step 6 is based on a forecast fuel price for each year of the planning period.

f) Please provide the forecast fuel prices used for the calculations required in step 6.

g) For the status quo (the scenario against which accelerated plan scenarios will be measured), please provide in Excel format with all formulas intact :

i) the EUE for each year of the study period (step 5),

ii) the unit cost of backup energy for each year of the study period (step 6),

iii) the proxy value power outage costs of EUE (step 6), and

iv) the CPV of the EUE cost for the Transmission Expansion Plan (step 7).

h) Please confirm or correct the following statement. The EUE cost identified in step 7 is not actually incurred by LIS customers. It is an estimate of the potential cost of providing unserved energy rather than an estimate of the cost to customers of outages.

i) Please confirm or correct the following statement : The reliability benefits associated with a new load will equal the CPV of the EUE cost for the accelerated plan minus the value provided in response to question (g) (iv), as long as they do not exceed 50% of the cost impacts resulting from the acceleration of the Transmission Expansion Plan.

LAB-NLH-103. Re: Network Addition Policy Summary Report, section 2.3.3, page 6 (p. 9 pdf)

a) Please confirm or correct the following statement : The addition of a new load which does not require acceleration of the Transmission Expansion Plan will normally tend to increase the EUE.

b) Please estimate the increase in the EUE for Labrador East that resulted from the addition of data centre loads in recent years, and provide the detailed calculations used in preparing that estimate (in Excel format with all formulas intact).

c) Please estimate the increase in the EUE for Labrador West that resulted from the addition of data centre loads in recent years, and provide the detailed calculations used in preparing that estimate (in Excel format with all formulas intact).

d) Please confirm or correct the following statement : Existing users are in no way compensated for the increase in EUE cost that results from the addition of new users to the Labrador Interconnected System.

e) Please explain why it is appropriate for existing users to compensate new users for any reduction in EUE cost that flows from acceleration of the transmission expansion plan at their expense, but not to be compensated by new users for any increase in EUE cost that they cause.

LAB-NLH-104. Re: Network Addition Policy Summary Report, section 2.3.4, page 8 (p. 11 pdf)

Citation 1:

> Given the level of uncertainty associated with duration of service for customers who do not meet the definition of Industrial Customers in the proposed Network Additions Policy, Hydro is proposing non-industrial customers not receive a Demand Revenue Credit.

Citation 2 (from New York State Public Service Commission, Rider A to New York Municipal Power Agency tariff[1]):

C. CUSTOMER COST CONTRIBUTION

A Customer requesting service under this Rider will be responsible for:

a. reasonable costs of conducting the feasibility study; and

b. the entire cost of any new facilities necessary to supply the requested service. The payment of these costs will be required, in cash, before new facilities will be constructed. At the end of each full year of service, for the first ten years, the customer will receive a refund equal to the lesser of the annual non-supply related revenues from the customer, or one-tenth of the cost contribution paid by the customer under this paragraph.

a) Please confirm that, in referring to customers with a « level of uncertainty associated with duration of service of Industrial Customers », Hydro is referring primarily to customers working in the field of cryptocurrency.

b) Should other non-industrial customers present themselves that do not present a high level of uncertainty with respect to duration of service, please explain why they should not also benefit from a Demand Revenue Credit.

c) Is the Demand Revenue Credit conceptually similar to the annual refund provided for in the NYMPA Rider A, approved by the New York State Public Service Commission, "in accordance with the 'traditional' method of 'subtracting incremental net revenues over an appropriate time period from the project cost' [2]"? Please explain the similarities and differences.

LAB-NLH-105. Re: Network Addition Policy Summary Report, page 3 (p. 6 pdf)

Citation 1:

For customer requests that require the acceleration of the LIS Transmission Expansion Plan, Hydro will base its contribution requirement on the difference between the cost of the acceleration of the LIS Transmission Expansion Plan and the value of the benefits to existing customers as a result of accelerating the Transmission Expansion Plan.

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[1] NYSPSC, Case 18-E-0126, Order Approving Tariff Amendments with Modifications (March 19, 2018), page 7.

[2] Raphals, P., Moratoria Applied to Cryptocurrency Loads in Low-Cost Jurisdictions (July 22, 2018), page 11.

Citation 2 (from New York State Public Service Commission, Rider A to New York Municipal Power Agency tariff[3]):

C. CUSTOMER COST CONTRIBUTION

A Customer requesting service under this Rider will be responsible for:

a. reasonable costs of conducting the feasibility study; and

b. the entire cost of any new facilities necessary to supply the requested service. The payment of these costs will be required, in cash, before new facilities will be constructed. At the end of each full year of service, for the first ten years, the customer will receive a refund equal to the lesser of the annual non-supply related revenues from the customer, or one-tenth of the cost contribution paid by the customer under this paragraph.

a) Please confirm or correct the following statement : The proposed Network Addition Policy differs from the policy adopted by the New York State Public Service Commission for the New York Municipal Power Agency in that, under the Network Addition Policy, a new customer is responsible only for the cost of advancing transmission investments from the date when they would otherwise be required (minus the value of reliability benefits to existing consumers), whereas the NYSPSC policy requires the new customer to pay <u>the entire cost</u> of any new facilities necessary to supply the requested service.

b) Please explain the significance of the difference between the Network Addition Policy and the policy adopted by the New York State Public Service Commission in Rider A for the New York Municipal Power Agency tariff.

c) To illustrate this difference, please compare the customer contributions that would be required under the Network Addition Policy for the examples mentioned in LAB-NLH-100 c) and d), with the amounts that would be required under the NYSPSC policy.

d) Please explain why Hydro has chosen to adopt the approach found in the Network Addition Policy, as opposed to the one adopted by the NYSPSC in Rider A to its NYMPA tariff.

LAB-NLH-106. Re: Network Addition Policy, page 7 of 23 (page 20 pdf)

Citation:

This section will apply to determine the required Upstream Capacity Charge to supply demand requests of greater than 200 kW from an Applicant.

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[3] NYSPSC, Case 18-E-0126, Order Approving Tariff Amendments with Modifications (March 19, 2018), page 7.

a) Please confirm that, for demand requests of up to 200 kW from an Applicant, there is no Upstream Capacity Charge.

b) Please explain what tools, if any, are available to Hydro if it suspects that two or more demand requests of under 200 kW are from related companies.

LAB-NLH-107. Re: Network Addition Policy, pages 21-22 (pdf)

Citation:

> Upon receipt of an Applicant's Demand request of 1500 kW or greater, Hydro will conduct a preliminary assessment to determine if compliance with the request would require acceleration of the Transmission Expansion Plan.
>
> If acceleration of the Transmission Expansion Plan is required, Hydro will determine the Expansion Advancement Cost. This cost reflects the difference between the cost of acceleration of the Transmission Expansion Plan and the value to existing Customers from plan acceleration. The value to existing Customers will be determined based the forecast reduction in Expected Unserved Energy resulting from the capital advancement. However, the credit provided based on the Expected Unserved Energy value to Customers will not exceed 50% of the cost of acceleration of the Transmission Expansion Plan. The procedures used to determine the Expansion Advancement Cost are provided in Appendix B to this Policy.
>
> The Upstream Capacity Charge will then be computed as the Expansion Advancement Cost less the Basic Capacity Investment Credit and, when applicable, less the Demand Revenue Credit.

a) Please explain what baseline will be used for the timing of the Transmission Expansion Plan, in order to determine whether or not a project results in its acceleration.

b) Please provide a numerical example of the computation of the Upstream Capacity Charge for a project of more than 1500 kW which results in acceleration of the Transmission Expansion Plan.

LAB-NLH-108. Re: Network Addition Policy Summary Report, section 2.3.4, page 8 (p. 11 pdf)

Citation :

> The Demand Revenue Credit is determined by applying the Demand Revenue Credit per kW of $250 (reflecting the present value of the forecast demand revenues to be paid by Labrador Industrial Customers) by the increased demand requirement of the Industrial Customer.

Please provide detailed calculations in Excel format with all formulas intact demonstrated the derivation of the value of $250/kW found in the Citation.

LAB-NLH-109. Re: Network Addition Policy

Preamble:

> Because the increments of transmission expansion projects are “lumpy”, it is possible that a relatively small demand request may result in the need to proceed with a relatively large expansion project.

For a hypothetical situation where a 5 MW demand request results in a $20 M expansion project, please estimate:

a) the Upstream Capacity Charge that would be required of the customer,

b) the resulting annual revenue requirement increase,

c) the annual revenue requirement increase that would be borne by existing customers, and

d) the resulting average rate increase, once the capital cost is fully included in rate base.