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Newfoundland and Labrador Hydro's Proposed Network Addition Policy and Transmission Expansion Study

submitted to the
NL Public Utilities Board

on behalf of

the Labrador Interconnected Group

by

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1. INTRODUCTION

1.1. Mandate

I have been asked by the Labrador Interconnected Group to review both the Labrador Transmission Expansion Study (TES) and the proposed Network Addition Policy (NAP), and to make comments and recommendations thereon.

I hereby acknowledge that I have a duty to the Public Utilities Board to give evidence that is fair, objective and non-partisan, and that is related only to matters within my expertise. I further acknowledge that my duty to assist the PUB overrides any duties to the Labrador Interconnected communities.

1.2. Overview

In this proceeding, Newfoundland and Labrador Hydro ("NLH" or "Hydro") seeks approval of its proposed Network Addition Policy (NAP) for the Labrador Interconnected System. In support of the NAP, it has also filed a Transmission Expansion Study (TES) but, as I understand it, it has not formally sought Board approval for that document.

The proposed NAP and the accompanying TES were prepared in response to the challenges posed by the arrival in Labrador of a new industry — cryptocurrency mining, generally referred to by Hydro as "data centres".[1] These "data centres" are very different from other types of firms

[1] Although Hydro uses usually the term "data centre" to refer to cryptocurrency mining activities, it would be more appropriate to refer to them as "calculation centres". (Hydro does occasionally also refer to them as cryptocurrency customers, as in NP-NLH-033, page 1.) Most such "data centres" are devoted to mining bitcoin, which is by far the most widely used cryptocurrency.

The term "data centre" is more appropriately applied to installations that store and distribute data but these installations require robust internet connections that are not presently available in Labrador.

In order to avoid confusion, I will follow Hydro's practice and refer to cryptocurrency mining operations as "data centres" (with quotation marks).

in that a) they are part of a large, mobile worldwide industry that seeks out jurisdictions with the lowest cost electricity, b) they consume great quantities of power, with load factors approaching 100%, c) they require little capital investment other than computers that can easily be moved, allowing them to arrive (or depart) on short notice, and d) their profitability is highly dependent on the worldwide price of the underlying cryptocurrency (usually bitcoin), which is highly volatile.

Because of its very low electricity prices, Labrador is a particularly attractive location for these "data centres". However, because its transmission systems (both East and West) are highly constrained, even small new "data centre" loads can make necessary transmission upgrades of a much greater scale. In this sense, Labrador is very different from the other low-cost North American regions where cryptocurrency mining has taken hold. As a result of these unique challenges, Labrador requires unique solutions.

Electricity costs represent a large proportion of the variable costs associated with cryptocurrency mining, and so, for each bitcoin price, there is a threshold electricity cost below which mining activities become unprofitable, resulting in cessation of operations. On the other hand, if bitcoin prices rise, worldwide cryptocurrency mining loads will likely continue to expand.

This filing was called for by the Board in P.U. 9(2018), in the context of the debates over the approval of the Muskrat Falls Happy Valley Interconnection (MFHVI) Project in the 2018 Capital Budget Application. In that proceeding, the Labrador Interconnected Group (LIG) had pointed out that the likelihood of exceeding the 77-MW transfer capacity to Labrador East — an essential element in the project's justification — was largely due to the addition of new "data centre" loads, and it called for Hydro to implement a network addition policy which would ensure that "new businesses should pay their fair share of the infrastructure costs that must be incurred to serve them".[2]

In its order, the Board accepted the submissions of LIG and the Iron Ore Company of Canada (IOC) and called upon Hydro to produce a Network Addition Policy and a Transmission Expansion Study for Labrador.[3]

The record of the 2018 CBA shows that, due to several general service contracts previously signed by Hydro with "data centre" customers in Labrador East, it became necessary to make certain costly investments in its transmission system; however, there was no mechanism in place to require those customers to directly contribute in whole or in part to the costs that they caused. The primary goal of the NAP is to establish such a mechanism.

In light of the foregoing, it is important to evaluate the NAP in terms of whether or not it provides an adequate mechanism to ensure that new customers — and in particular new "data centre" customers — are required to contribute to the costs of new transmission infrastructure that they make necessary.

The present report is organized as follows. First, it will review in more detail the procedural history leading up to the present review. Section 2 will address the NAP itself, and its underlying logic. Since, as we shall see, the NAP incorporates many elements directly from the TES, that document will be examined in Section 3. Section 4 will discuss certain issues raised in the preceding sections, and Section 5 will summarize the report's findings and present recommendations to the Board that flow from them.

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[2] LIG Submissions with respect to 2018 Capital Budget Application (revised March 15, 2018), page 14, para. 52.

[3] The link between the NAP and new "data centre" loads is also made explicit in a document recently produced by the Newfoundland and Labrador Government entitled *Protecting You from the Cost Impacts of Muskrat Falls,* which states (at page 12):

> A key prospect is the data centre sector that has been growing significantly in Labrador and has been the subject of Newfoundland and Labrador Hydro regulatory filings with the PUB such as the Network Additions Policy posted at www.pub.nf.ca/index_reports.htm.

1.3. Procedural history

Before reviewing the details of the NAP, it is important to place it in context. The need for a network addition policy was first identified in my expert report for the 2013 Amended GRA of NLH, presented on behalf of the Innu Nation, where I raised the issue of the allocation of costs resulting from transmission system expansion, in the Labrador Industrial Transmission Rate (LITR). I demonstrated that, should the then-proposed Labrador West Transmission Project (LWTP) go ahead, it would result in drastic rate impacts for existing users. In particular, IOC would have ended up paying 53% of the annual cost of the LWTP, compared to just 16% for Alderon, the additional load that would have created the need for the LWTP project.[4]

In section 4.2.2.4 of that report, I pointed out that the Federal Energy Regulatory Commission (FERC) had developed policies designed to avoid results like these, where native load rates increase dramatically as a result of a utility providing transmission service to a third party. I recommended that the Board clarify how it would allocate the costs of a transmission project like the LWTP, and drew its attention to FERC's network upgrade policy.[5]

In its 2018 Capital Budget Application, Hydro proposed the Muskrat Falls Happy Valley Interconnection. The Board summarized the project's *raison d'être* as follows:

> Hydro stated that the project is necessary to reliably support load levels beyond 77 MW in the Upper Lake Melville area. Hydro explained that the load for the area is forecast to grow from 79.9 MW in 2017 to 104.0 MW in 2042 and the capacity of the transmission system must be increased to support loading levels beyond its current 77 MW limit.[6]

[4] Raphals evidence, 2013 Amended GRA, page 49, Table 17.

[5] Ibid., page 72.

[6] P.U. 43(2017), page 11 (p. 14 pdf).

The Board found that « the evidence does not demonstrate that the proposed approach is necessary and consistent with the least-cost provision of service »[7], and deferred consideration until a later date.

In P.U. 9(2018), the Board quoted submissions of the Labrador Interconnected Group (LIG) to the effect that:

> Hydro had not met the onus set out in Order No. P.U. 43(2017) and that, in particular, Hydro had not provided sufficient information in relation to the longer term needs of the Labrador Interconnected system and the role of the proposed interconnection project in meeting those needs.[8]

It further quoted the LIG submissions detailing the importance of new "data centre" loads in the justification for the the project:

> In relation to load growth <u>the Labrador Interconnected Group submitted that the potential to exceed the 77 MW load limit is attributable directly to the new data center loads</u>. The group noted that <u>the actual duration of peak events is very brief and suggested that transient peaks could easily be reduced through judicious load management</u>. The group stated:
>
> > In our view, failure to take load durations into account in the planning process will inevitably lead to overbuilding the system, with important cost consequences that would be borne by our citizens.
>
> The Labrador Interconnected Group submitted that demand management programs may resolve the capacity constraint and suggested either voluntary load constraints or mandatory curtailment provisions in new service agreements. In the view of the Labrador Interconnected Group the Board has the authority to order Hydro to pursue curtailment policies to protect the adequacy of supply and to promote the stated power policy of the Province. The group pointed out that on average between 2013 and 2017 a customer in Happy Valley-Goose Bay experienced about 8.4 interruptions of service each year, with a total duration of 20.66 hours, and suggested that the length of the curtailment associated with new service agreements would likely be less. The Labrador Interconnected Group noted that Hydro has not approached the data center customers to determine whether they would be amendable to such curtailment.[9] (notes omitted; emphasis added)

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[7] Ibid., page 12 (pdf 15).

[8] P.U. 9(2018), page 3.

[9] Ibid., page 5.

As noted in the decision, the LIG asked the Board to:

> 1. Defer approval of the project until Hydro's next capital budget application.
>
> 2. Order Hydro to pursue necessary demand-side measures for all data center customers exceeding 0.5 MW capacity.
>
> 3. Order Hydro to refrain from entering any power contracts for which it does not have sufficient transmission capacity.
>
> 4. Order Hydro to file its Labrador transmission planning study as soon as practicable, earlier than fall 2018.
>
> 5. Require that Hydro submit a network addition policy for the Board's approval prior to its next capital budget application.[10]

In its submissions, LIG had further stated:

> By deferring approval of the Project until after the establishment of a network addition policy or a policy dealing with data centres, the Board will be able to attribute an appropriate portion of the costs of the new infrastructure to the new customers who are actually necessitating the new construction.[11]

The Board's findings included the following:

> Based on the record it appears that, despite the size of the forecast load increase relative to the existing loads on the system and the costs associated with addressing this increase, Hydro has not completed a comprehensive plan to address load growth and reliability on the Labrador Interconnected system. In particular Hydro did not demonstrate that it has explored options to manage load in the context of additional demand. Hydro admitted that it did not discuss load curtailment with existing and prospective customers, despite the potential benefits in relation to transient or short duration peaks. Further <u>Hydro does not appear to have considered alternatives to protect existing customers from the risks of significant stranded costs given the relative size and nature of the new customers</u>, especially in light of the concerns in relation to the impact of price elasticity.[12]

The Board further noted :

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10 Ibid.

11 LIG Submissions with respect to 2018 Capital Budget Application (revised March 15, 2018), page 16, para. 58.

12 Ibid., page 8.

> As a part of the application for approval of such a significant project Hydro is required to demonstrate that it conducted appropriate planning for the system in a comprehensive manner which would include development of reasonable planning criteria, identification of needs on the system and assessment of reasonable alternatives. This planning must address both Labrador East and Labrador West as they are both part of the Labrador Interconnected system. In addition, Hydro would be expected to address its obligation to provide least cost reliable service, considering the impact on existing customers of meeting new loads which may affect adequacy or reliability on the system. Hydro acknowledged that it could apply to the Board to be relieved of its obligation to serve but argued that, while this issue is important, it should not impact the approval of the proposed project. The Board does not accept this position and believes that Hydro should address this issue before this project is approved.[13]

The Board came to the following conclusion :

> The Board is persuaded by the arguments of the Labrador Interconnected Group, representing the majority of the communities in Labrador East, and IOC that this project should be deferred until further information is provided by Hydro. This information should include:
>
> 1. An expansion study for the Labrador Interconnected system (both Labrador East and Labrador West) for a reasonable planning horizon, which addresses: i) planning criteria, including a discussion of the current reliability concerns and future reliability criteria; ii) base load forecasts and sensitivities; iii) expansion plans to meet the various load forecast scenarios; iv) the condition of existing assets and an estimate of remaining life; v) cost benefit analysis of the alternatives; and vi) estimated projected rate impacts associated with the proposed expansion scenarios.
>
> 2. A network addition policy setting out how new customers will be treated in regards to their impact on the system and how costs will be allocated among customers for reliability, economic, transmission, and load upgrades, either in the cost of service or through contributions in aid of construction.[14]

On October 31, 2018, Hydro filed a Labrador Transmission Expansion Study (TES, amended on Nov. 5, 2018), and on December 14, 2018 it filed a proposed LIS Network Additions Policy (NAP).

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[13] Ibid., pages 8-9.

[14] Ibid., page 9.

On March 5, 2019, the Board issued P.U. 9(2019) which approved the MFHVI transmission project, explaining that the filed documents provided sufficient information to proceed without awaiting approval of the TES and the NAP. [15]

The full costs of the MFHVI will be borne by ratepayers, with no capital contributions from the "data centre" customers that, to a large extent, made it necessary. This would not have been the case had the proposed NAP been in force at the time, and similar situations are unlikely to occur in the future if the proposed NAP (or a variant thereof) is approved by the Board.

2. NETWORK ADDITION POLICY

2.1. Overview

Hydro proposes to apply an Upstream Capacity Charge (UCC) to reduce impacts on other customers, after exempting the cost of the first 200 kW for any new customer (the "Basic Capacity Investment Credit" or BCIC).[16]

For projects less than 1500 kW (and also for larger projects which do not result in advancing the Transmission Expansion Plan), the Upstream Capacity Charge (UCC) is based on an Expansion Cost per kW multiplied by the project capacity, minus the BCIC.

For projects of 1500 kW or more, a preliminary assessment is carried out to determine if the project would result in accelerating the Transmission Expansion Plan. If not, UCC is determined as for small projects, described above. If the project is found to cause acceleration of the Transmission Expansion Plan, UCC is based on the Expansion Advancement Cost, explained in section 2.5, below.

[15] Ibid., pages 6 and 8.

[16] LIS NAP Summary Report, page 4-5.

2.2. Applicability

The proposed NAP applies to any person who applies for Service (the "Applicant"). The Demand Revenue Credit applies to industrial customers only, but the other provisions apply to all applicants.

In its incremental load forecasts, Hydro distinguishes between "rural loads", "industrial loads" and "data centre loads". This reflects that fact, discussed earlier, that "data centre" loads differ in many fundamental ways from other types of loads. Indeed, it is because of them that the Board ordered Hydro to develop a Network Addition Policy in the first place.

It is recommended that the NAP apply to industrial and "data centre" loads, but not to other rural loads.

2.3. The "beneficiary pays" approach

In its Network Additions Policy Review (Oct. 1) and in its proposed Network Additions Policy (December 14), Hydro states that it has adopted the "beneficiary pays" approach to guide the development of its new policy. While this approach is not precisely defined, Hydro states:

> This approach associates increased cost responsibility with benefits resulting from a transmission investment rather than with shares of peak demand. The beneficiary pays approach thus underpins the assignment of otherwise common costs to those who benefit substantially from those costs.[17]

In contrasting this approach to one based on shares of peak demand, Hydro appears to take the view that, for example, when the addition of a relatively small new load makes a capital investment necessary, the costs of that investment should be borne primarily by the new load rather than by the larger incumbent loads.

[17] Network Additions Policy Review, page 6.

Hydro's review is supported by a discussion paper by Christensen Associates that presents an overview of approaches to transmission cost allocations in different North American jurisdictions.[18] The Christensen paper makes clear that "beneficiary pays" is a complex concept, the application of which raises many difficult questions:

> Operationally, the *beneficiary pays* approach is challenging in terms of benefit definition, participant definition, and benefit measurement. Obtaining agreement among participants regarding cost allocation methodology is a necessary precursor to transmission project initiation. [note omitted] If Hydro follows the broadly defined steps of U.S. transmission entities, *beneficiary pays* would appear to entail a process that roughly adheres to the following steps:
>
> • Take account of the types of benefits considered elsewhere in North American, and determine what might be included in benefits criteria, for categorization of transmission facilities;
>
> • Explore the analytical methods and models used to estimate the various types of benefits, including the distribution of benefits.
>
> • Define cost allocation rules for Hydro's defined categories of facilities, where cost allocation methods broadly adhere to *beneficiary pays* principles;
>
> • Categorize transmission facilities in Hydro's transmission plans in terms of net benefits;
>
> • Determine Hydro's transmission plans, and categorize specific facilities of the plan according to predefined criteria; and,
>
> • Assign costs to participating parties—i.e., transmission customers—according to the predefined cost allocation rules.[19]

While it is appropriate to state that Hydro's proposal is influenced by the "beneficiary pays" approach, it should not be seen as a full implementation thereof, nor should one conclude that the details are made necessary by it.

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[18] Transmission Cost Allocation Methods to Account For Network Additions, Christensen Associates Energy Consulting, LLC, July 18, 2018. Appendix A to Hydro's Network Additions Policy Review dated October 1, 2018.

[19] Ibid., pages 23-24 (pages 41-42 pdf).

2.4. UCC for customer requests of less than 1500 kW

2.4.1. Proposed calculation of Expansion Costs per kW

For customer requests of less than 1500 kW, the Upstream Capacity Charge is based on the Expansion Cost per kW, fixed in Appendix A as $465/kW. The derivation of this figure is found in the Network Additions Policy Summary, reproduced below.[20]

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**

Comparing this table with information found in the TES (reproduced in Table 4 on page 33 of this report), we see that the projects identified there as Phases 2, 3 and 4 for Labrador East are included in the Derivation of Expansion Costs per kW, but that the Phase 1 project (the Muskrat Falls Happy Valley Interconnection) is not. Hydro explained this exclusion as follows:

> The derivation of expansion cost in the "Network Addition Policy" involves the cost of transmission system expansion to meet incremental load beyond the baseline load forecast. … Transmission system projects that are required to meet the baseline load forecast are not a component of this calculation.
>
> <u>The Muskrat Falls to Happy Valley Interconnection is the least-cost transmission system solution to meet the baseline forecast in eastern Labrador</u>. As such, this interconnection is part of the baseline expansion plan, as defined in the "Labrador Interconnection System Transmission Expansion Study." This project is therefore excluded from the derivation of expansion cost.[21]

[20] Table 1, page 5.

[21] LAB-NLH-059b. Unless otherwise noted, all emphasis in quotations is added.

The exclusion of the MFHVI project demonstrates the extent to which Hydro's proposed methodology for setting customer contributions for network additions depends on the precise definition chosen of the "baseline forecast". In the TES, the baseline forecast is defined as a P90 forecast, including "data centre" customers with existing service contracts, through 2043. This forecast, illustrated in Figure 2 on page 30 of this report, shows Labrador East loads growing to 94.8 MW in 2043. Thus, network additions to provide service up to this level are considered to be part of the baseline forecast, and so not "additional" — despite the fact that historic peak loads in Labrador East have never exceeded 71.1 MW.[22] The relationship between the Muskrat Falls Happy Valley Interconnection (MFHVI) project and the baseline forecast in eastern Labrador is more complex than this citation suggests. The issue will be addressed in section 4, below.

For Labrador West, the derivation includes only Wabush Terminal Station upgrades and 230 kV uprating. No mention is made of the many other projects analyzed to meet incremental load in Labrador West, nor is there any provision for increasing the Labrador West capacity by more than 33 MW. Notably, the calculation excludes Alternative 17, which is identified as a preferred alternative in the TES should additional capacity be required.

Hydro explains this exclusion on the basis that this project would only be required in the event of a large new load.[23] Arguably, however, the phase 4 project in Labrador East (construction of a second line from Muskrat Falls to Happy Valley) could be similarly characterized.

2.4.2. Alternate approaches to calculation of Expansion Costs per kW

These observations raise the question: Is it appropriate to exclude from the Expansion Costs the cost of network additions that would be needed under the "baseline" forecast, but which would not be needed until much later? In other words, insofar as a new customer makes necessary in

22 IOC-NLH-026.
23 LAB-NLH-090a, page 2 of 2.

the very short term a transmission upgrade that would otherwise not have been required until the mid-2030s, should not the customer be held responsible for the costs of accelerating that upgrade, even though the upgrade is found in the "baseline" forecast?

As we shall see in the next section, Hydro proposes to resolve this problem for larger projects by calculating the advancement (or acceleration) cost, rather than the direct cost of these projects. For smaller projects, however, it is important to include all relevant projects in the derivation of the Expansion Cost per kW.

In response to an RFI, Hydro recalculated the Expansion Costs per kW based on different combinations of inclusions and exclusions. These are summarized as follows:

Table 2. Alternate scenarios for computing Expansion Cost per kW

Description	**$/kW**	**source**
a) Include the MFHVI Project	$500	LAB-NLH-100, Table 1
b) Add Alternative 17 and include full cost of Wabush TS Upgrades, rather than incremental cost	$796	LAB-NLH-100, Table 2
Combine a) and b)	$793	LAB-NLH-100, Table 3

Arguably, Hydro is correct to exclude the MFHVI Project and to include only the incremental cost of Alternative 5, based on its baseline forecasts. However, it is clearly appropriate to include Alternative 17, because it is the recommended option for loads above 434 MW in Labrador West.

Based on the information provided in LAB-NLH-100, we can modify Table 1 by adding Alternative 17, as follows:

Table 3. Derivation of Expansion Costs per kW (with Alternative 17)

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
	100,000	Alternative 17	153,150	1,532
Sub-Total	**291,000**		**239,650**	**824**
O&M				**12**
Total				**836**

In the examples reviewed later, customer contributions will be evaluated both using the proposed value of $465 and the value derived here ($836/kW).

2.4.3. Effects of implementing proposed UCC for customer requests of less than 1500 kW

As described in the previous section, the methodology proposed by Hydro for determining UCC for projects of less than 1500 kW would result in charges ranging from $465/kW, according to Hydro, or $836/kW, if Alternative 17 is included. Since the UCC excludes the cost of the first 200 kW (Basic Capacity Investment Credit), that means that, for a 1 MW project, the required advance payment would be either (1000 * 465) – (200 * 465) = $372,000 or (1000 * 836) – (200 * 836) = $668,800, depending on the Expansion Cost used.

The NAP does not set out details as to how these charges would be assessed, but presumably they would have to be paid before service could be initiated.

It is recommended that the NAP require that the Customer Contribution be paid in full before any transmission upgrade works are initiated, and that no commitments on Hydro's part be binding until that time.

Under s. 8 of the NAP, Board approval is required for any UCC calculated as greater than $200,000. Using the $465/kW value proposed by Hydro, this means that Board approval would be required for any project of 630 kW or more. Using the higher value of $836/kWh, this threshold would fall to 439 kW.

In its responses, Hydro acknowledged that the addition of small or mid-sized customers could result in the need for significant capital upgrades, which might "vastly exceed" the additional transmission capacity required by those customers:

> It is confirmed that the need for significant capital upgrades on the Labrador Interconnected System can be triggered by the connection of one or more small or mid-sized customers.
>
> It is confirmed that it is possible a capital upgrade on the Labrador Interconnected System which would be triggered by the connection of one or more small or mid-sized customers might <u>vastly exceed</u> the additional transmission capacity required by those customers.[25]

This indeed was the case for the "data centre" customers in Labrador East awarded general service contracts by Hydro in recent years. While their total required capacity was just 6.2 MW, they triggered the need for the $20.0 million MFHVI project, which added 27 MW to system capacity.

Let us assume, for the sake of argument, that these 6.2 MW of "data centre" customers consisted of five projects of 1240 kW. How would the proposed policy have played out for each of them, under those circumstances?

Taking into account the 200 kW Basic Capacity Investment Credit for each of these projects, the UCC for each one would be (1240 – 200) * $465 = $483,600 or (1240 – 200) * $836 = $869,440. The combined contributions of the five customers would therefore amount to either $2.4 million or $4.3 million, depending on the Expansion Cost applied.

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[25] LAB-NLH-085a and b, p. 1 of 2.

Hydro has expressed the opinion that charges of this scale would be "unlikely to prevent potential customers from taking service".[26]

In my testimony in another proceeding before the Board, I referred to testimony in a Quebec hearing from the North American director of a large Japanese firm involved in cryptocurrency mining.[27] According to his testimony, bitcoin mining produces revenues of about 14¢ per kWh consumed.[28] If that value is correct, a 1240 kW bitcoin mining operation would generate revenues of about $1.4 million per year. The infrastructure contributions described above would therefore represent either 33% (at $465/kW) or 60% (at $836/kW) of the customer's first-year revenues. Assuming a 10-year lifetime, it would represent between 3.3% and 6.0% of the project's total revenues.

The relatively modest scale of these figures tends to support Hydro's opinion that these charges would be unlikely to prevent potential customers from taking service. This is also not Hydro's stated purpose in implementing the proposed policy. Rather, it is Hydro's view that:

> … the proposed contribution approach provides a reasonable balance in the sharing of the cost responsibility between the customers requesting service and the existing customers (i.e., through the provision of rate stability).[29]

How does this look from the perspective of other ratepayers? Under this hypothetical example, the new customers' contributions would represent 12% to 22% of the investment cost of the MFHVI project ($20.0 million), leaving the remainder (78% to 88%) to be recovered in rates. On the other side of the ledger, ratepayers do obtain a substantial reliability benefit from the new

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[26] LAB-NLH-085c, p. 2 of 2.

[27] Raphals, P., Moratoria Applied to Cryptocurrency Loads in Low-Cost Jurisdictions (July 22, 2018), page 20.

[28] This figure will of course vary with the market value of bitcoin. At the time when that comment was made, bitcoin prices were around $8,000, only slightly higher than their current level.

[29] LAB-NLH-085c, p. 2 of 2.

interconnection, and the new customers will also, through their electricity rates, contribute to defraying the annual costs of the new infrastructure.

These relatively modest contributions to infrastructure costs contrast greatly with the approach taken in other jurisdictions, where the party causing the need for new investment is responsible for most or all of its cost. It also contrasts with the outcome from applying the same NAP to other specific cases, as described in the next section. This issue will be explored further in section 4.

2.5. UCC for customer requests of 1500 kW or more

2.5.1. Upstream Capacity Cost

As noted above, for projects of 1500 kW or more, a preliminary assessment is first carried out to determine if the project would result in accelerating the Transmission Expansion Plan. If not, UCC is determined as for small projects, described above. If the project is found to cause acceleration of the Transmission Expansion Plan, UCC is based on the Expansion Advancement Cost, which represents:

- the Cumulative Present Value of the cost of acceleration of the Transmission Expansion Plan, including:
    - the Capital Costs of the required transmission upgrades and their O&M costs,
    - net of their reliability benefits, based on the change in Expected Unserved Energy multiplied by the cost of backup energy (limited to a maximum of 50% of the cost of acceleration);
- minus the Basic Capacity Investment Credit (200 kW multiplied by the Expansion Cost per kW),
- minus (for Industrial Customers only) the Demand Revenue Credit (DRC), based on the present value of the forecast revenue from transmission demand charges over a 25-year period.

The methodology for determining the Expansion Advancement Cost is set out in section 2 of Appendix B to the NAP:

UCC = Expansion Advancement Cost – Basic Capacity Investment Credit – Demand Revenue Credit, where

Expansion Advancement Cost = Acceleration Cost – Reliability Benefits, where:

Acceleration Cost = CPV of Capital cost + CPV of O&M costs, and

Reliability Benefits = CPV of (Change in Expected Unserved Energy * Cost of Backup Energy), and

Reliability Benefits are limited to 50% of Acceleration Cost.

In order to better understand this methodology, an RFI was submitted to Hydro requesting numerical examples of a) a 10 MW data centre load in Labrador East, b) a 30 MW data centre load in Labrador West, and c) the addition of the two data centre customers that have since been granted service contracts in Labrador East, assuming that the NAP had been effect at the time.

In response, Hydro presented responses, supported by spreadsheets, to the first two requests.[30] However, it said it was unable to respond to the last request, as it had no baseline expansion plan for the relevant period.

2.5.2. Determination of Expansion Advancement Cost — examples

The two numerical presented by Hydro are presented in the following sections. A third example is also presented, based on the addition of a large mining load in Labrador West.

2.5.2.1. Advancement Cost for a new Labrador East "data centre" load

In the first example, Hydro looked at a 10 MW "data centre" load in Labrador East, starting in 2021. As the analysis ignores all upgrades required to meet the Baseline Forecast (including MFHVI), the only upgrades required to serve the new load are the Phase 2 Transformer Upgrades (the first line in Table 1, above), at a cost of $5,000,000 (in 2019 dollars), which would need to be in service in 2042.

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30 LAB-NLH-101. The examples discussed above in section 2.4.3 correspond to this request.

In addition, Hydro considers it necessary to add 10 MW of temporary generation to supplement the HVY Gas Turbine during the ~3 days per year of line maintenance, adding $250,000 of annual equipment rental costs, plus annual fuel costs growing from $7,500 in 2021 to $88,000 in 2044.[31]

Based on a 6.5% discount rate, these costs result in a CPW of $4.4 million. It should be noted that 94% of these costs result from the backup generation, as the transmission upgrade only occurs during the last three years of the analysis period and accounts for just 6% of the total cost.

This Acceleration Cost of $4.4 million, minus the $93,000 BCIC, results in a total UCC (before Reliability Benefits[32]) for the customer of $4,325,162, or $432/kW — a cost slightly lower than the Expansion Cost of $465/kW used for projects under 1500 kW and those that do not cause acceleration, as described above.

The result would be very different, however, if the 6.2 MW of "data centres" that currently have service contracts in Labrador East did not exist.[33] In that case, the cost of advancing the MFHVI project would also enter into the calculation.

In order to evaluate the <u>advancement</u> cost of building MFHVI in 2021, we would need to know when it would be required without the proposed load. Putting aside — again, for illustrative purposes — the reliability arguments in support of the MFHVI and looking at it only as a transmission capacity expansion project, the question becomes: in the absence of new "data centre" loads, when would MFHVI have been required to meet the Labrador East load forecast?

In fact, the scenario described here is similar to the one described in LAB-NLH-080, where Hydro was asked to detail the number of hours per year in which Labrador East loads would

[31] The fuel consumption suggests average use of under 1 MW for the first decade and 2 MW for the second, it is not clear why Hydro sees the need to rent 10 MW of temporary generation starting in year 1.

[32] Reliability Benefits will be addressed below in section 2.5.3.

[33] This example can be seen as a companion to the one presented above in section 2.4.3, which evaluated the customer contribution for five 1.2 kW "data centre" loads.

exceed the existing transfer limit of 77 MW, in the absence of any "data centre" loads. The response, displayed graphically in Figure 1, below, demonstrates that, even in 2043, the current transfer capacity would only have been exceeded in 83 hours during the years. It seems reasonable to suppose that, with 10-20 years advance notice, Hydro would likely be able to institute CDM or load management programs sufficient to meet loads during these 83 hours. Thus, for these illustrative purposes, we can assume that, without "data centre" loads, MFHVI would not have been required within the 20-year planning period.

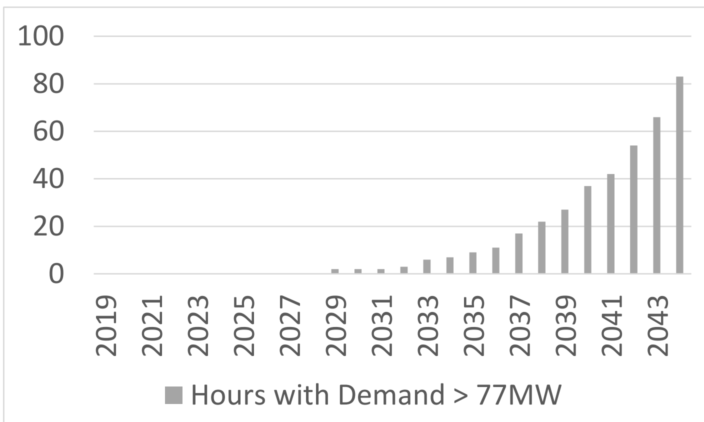

Figure 1. Labrador East – Hours per year with Demand above 77 MW in the absence of all "data centre loads.

Under these assumptions, the UCC for a 10 MW "data centre" load would be very much greater than the $4.4 million identified in Hydro's analysis. The $20.0 million MFHVI project would be added in 2021 ($21 million after escalation), and its remaining book value of $11.3 million would be subtracted in 2044. The backup generation costs would remain. The result is an Acceleration Cost of $19,382,780, almost 4 ½ times greater than the Acceleration Cost based on Hydro's assumptions.

If, on the other hand, we were to assume that the MFHVI would otherwise be needed in 2035, the UCC (before reliability benefits) would fall by half to $9.7 million.

These results suggest that, had the NAP been in force when the service requests of Hydro's existing "data centre" clients in Labrador East were received, those customers would have been obliged to cover 50% to 100% of the capital costs of the MFHVI project in order to obtain service.

These examples also demonstrate how sensitive the UCC is to the hypotheses regarding the baseline forecast and the expansion plan required to serve it.

2.5.2.2. Advancement Cost for a new Labrador West "data centre" load

In the event of a 30 MW "data centre" load in Labrador West starting in 2021, Hydro considers it necessary to add Alternative 5. However, it deducts from this cost that of Alternative 4, consisting of certain elements of Alternative 5, which it considers to be required for the Baseline Forecast. The incremental capital cost of $16.7 million becomes, with escalation, $17.3 million.

No other additional costs are involved, except the withdrawal of the book value of these assets ($9.4 million) in 2043. After discounting, the Acceleration Cost is $12,529,036. After subtracting the BCIC of $93,000, this results in a UCC of $12,436,036, for an average expansion cost of $414.53/kW.

If, on the other hand, the total cost of Alternative 5 were to be used, rather than the incremental cost in relation to Alternative 4, the UCC would almost double to $23,716,680, for an average expansion cost of $790.56/kW.

This example demonstrates once again how sensitive the results are to the precise definition of the Baseline Forecast and the corresponding Transmission Expansion Plan.

2.5.2.3. Advancement Cost for a large mining project in Labrador West

As noted above in section 1.3, my expert report for the 2013 Amended GRA demonstrated that, under the Labrador Industrial Transmission Rate that is now in force, in the event that the Labrador West Transmission Project (LWTP) were to go ahead to serve Alderon's Kami mine project, Alderon would pay just 16% of the project's annual cost.

In response to an RFI, Hydro pointed out that, in the LWTP Exemption Order, the LWTP was defined as "the new 230 kV transmission system between Churchill Falls and Labrador West", corresponding to Alternative 7 under the TES. In order to better understand the implications of the NAP, it is worthwhile to inquire into how the costs of Alternative 7 would be shared under the it.

The capital cost of Alternative 7 is identified as $272.82 million. Adding this cost in 2022, and removing the remaining book value in 2043, results in an Acceleration Cost of $205.1 million. Assuming that building Alternative 7 would likely substantially reduce expected unserved energy, one might expect this amount to be reduced by a substantial proportion of the $5.1 million cost attributed to EUE under the *status quo.* Subtracting this amount leaves a UCC of some $200 million, which represents about 73% of the capital cost of the project.

Alternatively, if it were the lower cost Alternative 17 that were developed instead of Alternative 7, the UCC would be on the order of $110 million, out of a capital cost of $153.15 million — again representing some 72%.

This is clearly a much greater contribution than the 16% of annual costs attributable to Alderon under the existing LITR. **This example demonstrates that the proposed NAP would in fact greatly increase the extent to which the beneficiaries of transmission expansion projects would be required to contribute to project costs, and demonstrates why — even if it is imperfect — it is important that it come into force promptly.**

2.5.3. Determining the value of Reliability Benefits using Expected Unserved Energy

To determine the final UCC, Hydro's proposal deducts from these advancement costs an estimate of the customer benefits resulting from improved reliability as a result of the transmission upgrade. While it is appropriate to take reliability benefits into account, the proposed approach is problematic. It reduces the Acceleration Cost by a dollar-for-dollar credit — up to a maximum of 50% of these acceleration costs — for any reduction in Expected Unserved Energy (EUE) across the entire system.

In effect, Hydro proposes to credit the new consumer for any reduction in the cost of expected unserved energy that would result from the transmission advancements required to serve the new load (up to the 50% maximum). However, while the inconvenience of unserved energy is indeed borne by incumbent ratepayers, the costs attributed thereto are not actually incurred by them.

The method for calculating the Expected Unserved Energy is illustrated in Appendix A to Appendix E to the TES. It involves multiplying the unavailability rate of each option by the total forecast energy consumption for the year.

The difference between the two values represents the reduction in expected unserved energy. To value it, Hydro uses an estimate of the average realized price for exports.[34] While this is indeed the price signal seen by Hydro (since unused recall power is exported at this price[35]), it is not seen by regulated consumers in Labrador.

Since unserved energy in fact increases the pool of unused recall power available for export, one could argue that, in reducing expected unserved energy, the transmission expansion creates an additional cost for Hydro, rather than a benefit.

If the energy that is unserved due to transmission outages were in fact replaced by backup energy purchased in external markets, Hydro's proposal would be an appropriate methodology for estimating its cost. In fact, however, that energy is not provided at all. In crediting the new customer for the full value of the EUE (up to a limit of 50% of the advancement costs), it is as if other consumers were reimbursing the new customer for saving them costs that they do not in fact incur.

[34] IOC-NLH-037.

[35] Until such time as the LIL is in service. Thereafter, it is expected that most unused recall power will instead be used to displace generation at Holyrood, which has a much higher value.

There is of course a value to improved reliability. There is however no reason to believe that this methodology captures it appropriately.

Viewed another way, the proposal regards the status quo — the annual expected unserved energy in Labrador East and Labrador West — as a pool of potential revenues to offset the costs of transmission expansion. These two pools have precise values: $571,500 in Labrador East, and $5,028,000 in Labrador West.[36] However, they are not based on costs actually incurred.

It is important to note that every new customer that does not require a transmission upgrade has the effect of degrading reliability and so <u>increasing</u> EUE for all consumers. These amounts too can be quantified. Hydro has estimated that, in Labrador East, the 6.2 MW of "data centre" customers added in recent years resulted in an increase in EUE of $113,060, whereas those in Labrador West resulted in an increase in EUE of $1,047,600.[37] No compensation was provided to existing customers for the loss of reliability that serving these new customers entailed.[38]

In support of its approach, Hydro references a NAERC study of "Probabilistic Adequacy and Measures", which states:

> EUE along with the value of loss load (VOLL) can be used to monetize the cost of loss of load <u>to justify, prioritize or rank transmission or other capital projects</u>.[39]

However, there is a great difference between using VOLL (or EUE) as a measure to "justify, prioritize or rank" projects, and actually using it to calculate the required payments — the equivalent of reimbursing the customer for the reduction in EUE.

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[36] LAB-NLH-102g, page 4 of 6.

[37] LAB-NLH-103b and c.

[38] LAB-NLH-103d.

[39] PUB-NLH-059.

Furthermore, the proposed mechanism potentially rewards the new customer for upgrading a portion of Hydro's electrical system to a reliability standard exceeding Hydro's overall system reliability standards.[40]

For all these reasons, it is recommended that the Board not adopt Hydro's proposal regarding Reliability Benefits.

2.6. Demand Revenue Credit

In Section 5.3 of the NAP, Hydro proposes a Demand Revenue Credit (DRC), available to industrial customers only, that reduces the required customer contribution based on the assumption of a service life of 25 years. This provision reflects the fact that, during these 25 years, the customer's rates will also contribute to the capital cost of the transmission upgrade it caused. In the event that service life is estimated to be lower than 25 years, the DRC is reduced by 3% per year.

The New York State Public Service Commission (NYSPSC) has taken a different approach in the rate rider established for high load density customers (primarily cryptocurrency miners). First, as a customer contribution, the new customer is required to pay:

> 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.[41]

Thus, in place of the complex mechanism proposed by Hydro, the customer is required to pay the upfront capital costs for all new facilities required in order to supply the requested service. This difference will be addressed below in section 4.

[40] PUB-NLH-061.

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

However, as long as the new customer continues to take service, his rates will in effect include payments toward these same facilities. In order to avoid double-charging the customer, the portion of its rates that cover fixed assets and operating costs ("non-supply related revenues") are refunded for the first ten year's under which that the customer continues to take service:

> 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.

The approach embodied in the NYSPSC Rider A is perhaps more elegant, but Hydro's proposed DRC would have substantially the same effect.

It is recommended that the provisions of the proposed NAP concerning the Demand Revenue Credit be approved.

3. LABRADOR TRANSMISSION EXPANSION STUDY

As noted above, Hydro is apparently seeking the Board's approval for the proposed NAP, but not for the TES. However, the NAP relies directly on information in the TES. For this reason, approval of the TES, or at least of certain key elements of it, is necessary.

3.1. Load forecasts

The TES relies on a July 2018 P90 demand forecasts for Labrador East and Labrador West which had never before been presented to the Board.[42] Until now, Hydro has generally presented P50 forecasts "for the Labrador Interconnected system<u>s</u>" (*sic*).[43] Hydro's peak demand forecasts are derived from forecast energy requirements combined with a historical load factor. The P50 forecast is based on the historical average load factor, and the P90 forecast adds a fixed scalar, based on the 90th percentile historical load factor. These scalars are estimated at 3 MW for

[42] LAB-NLH-074a.

[43] LAB-NLH-074c.

Labrador East and at 4.5 MW for Labrador West.[44]

Hydro considers this variability to be due entirely to weather conditions, reflecting "more severe wind and/or cold temperatures". It therefore appears that the peak load forecast is based entirely on the medium forecast of energy requirements, not taking into account any other uncertainty in relation to that forecast.

The only mention of a high or low load growth scenario that I have identified in Hydro's evidence is in a response to an RFI from IOC, where it mentions that: " Low load growth scenarios would have a forecast peak in excess of 104 MW, but less than 125 MW." However, these "low load growth scenarios" clearly do not refer to the baseline forecast, as the first sentence of the same response states that: "The baseline load forecast [for Labrador East] is expected to reach 94.8 MW by the year 2043." The response goes on to refer to "intermediate load growth scenarios" with a forecast peak in excess of 125 MW, high load growth scenarios with a forecast peak in excess of 162 MW.

These "scenarios" rather apparently represent the "load triggers" for incremental additions to Labrador East transmission capacity — not actual load growth scenarios, which remain very much lower. **It is recommended that Hydro's load forecasts take the uncertainty of the underlying forecast of energy requirements into account, by using low, medium and high forecasts.**

In addition to the baseline peak load forecast for each region, sensitivity forecasts are described. The baseline peak forecast includes forecast rural loads as well as expected loads for all "data centres" which had service contracts at the time of the forecast.[45] These loads are 7.2 MW in

[44] IOC-NLH-014.

[45] LAB-NLH-074d.

Labrador East (as of 2019) and 6.7 MW in Labrador West (as of 2020).[46] The baseline peak load forecast also includes industrial loads for IOC and Tacora Resources.

Hydro's sensitivity forecasts include additional forecast "data centre" and industrial loads and, for Labrador East, the possible DND boiler conversion.[47] An additional 65 MW for Alderon starting in 2022 is apparently also considered in the Labrador West sensitivity forecast.[48] It appears that no other uncertainties are included.

There is no clear presentation of the sensitivity forecasts in the TES itself, though indications are found in the appendices and in responses to RFIs. Table 2 on page 73 pdf appears to represent the sensitivity forecast for Labrador West, though it is not identified as such. Table 2 on page 54 pdf presents the "sensitivity incremental forecast" for Labrador East, but only the incremental amounts, not the forecast including these incremental amounts.

Furthermore, there is substantial unexplained variation from one forecast to another. For example, the 2018 Operating Load Forecast for Hydro Rural Systems dated "Spring 2018" shows forecast loads for Labrador West in 2023 of 84.1 MW,[49] while the response cited previously shows P50 forecast 2023 loads for Labrador West of 71.3 + 6.7 = 78.0 MW. The discrepancy between these two forecasts, dated just six months apart, is neither noted nor explained.

More generally, the lack of a clear and consistent format for presenting baseline and sensitivity load forecasts makes analysis laborious. **It is recommended that, in the future, Hydro present both P50 and P90 baseline load forecasts for both Labrador East and Labrador West**

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46 Ibid., Tables 1 and 2. There are no existing data centre customers in Labrador that are being served from Churchill Falls town site (e.g., directly from Churchill Falls Generating Station) and no data centre customer loads currently forecast to be served at this location (LAB-NLH-074f.).

47 TES, Table 2, page 54 pdf for Labrador East.

48 TES, Table 2, page 73 pdf.

49 LAN-NLH-074, Attachment 1, page 28 of 35 (p. 34 pdf). This is presumably a P50 forecast.

regularly and in a consistent format, setting out the date of the forecast and highlighting and explaining all significant changes from the previous forecast.

It is also recommended that, in the future, sensitivity forecasts for each region be clearly identified and broken down by type of incremental load.

3.1.1. Labrador East

Hydro's December 2018 Operating Load Forecast for Rural Hydro Systems makes clear that, aside from the possible conversion to electric boilers by DND, it is "data centre" loads that are driving the load forecast in Labrador East:

> This system serves the communities of Happy Valley, Northwest River, Sheshatshui and Mud Lake. The load growth experience of the past decade has included a period of robust growth preceding and following the sanction of the Muskrat Falls project followed by the more recent period of modest load growth. The Department of National Defence's (DND) general service account is the largest customer and accounts for approximately 15 percent of total system sales. Happy Valley- Goose Bay has recently been a location of interest for data center developers that are seeking low cost power provision.
>
> <u>Looking forward, the near term load growth on the system is driven by general service sales growth associated with data center developments that have been approved for service</u>. Residential customer growth is expected to return to average historical levels within the medium term outlook. <u>There are potential loads associated with further data center developments</u> and a by DND who have expressed a desire to replace their oil-fired central heating plant boilers to electric boilers. [51]

In response to an information request, Hydro separated out the data centre loads from other loads in its Labrador East forecast.[52] The following graph summarizes the data provided.

[51] LAB-NLH-074, Att. 1, page 17 of 35 (p. 23 of pdf).

[52] LAB-NLH-074, Table 1.

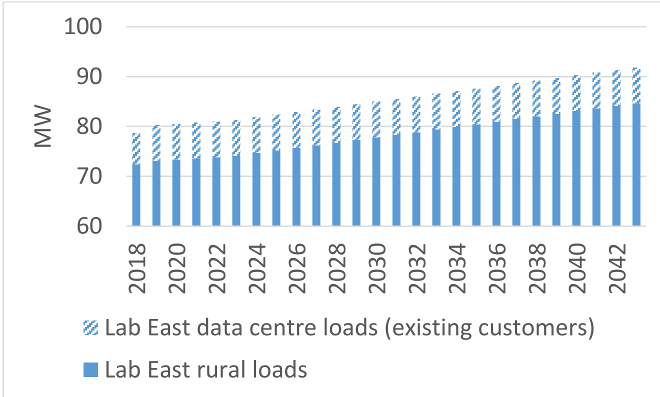

Figure 2. Labrador East P50 rural load forecast and "data centre" loads from existing customers

It should be noted that forecast load growth for non-"data centre" rural customers is only about 0.5 MW/year. Indeed, without the "data centre" loads, peak loads were not expected to exceed the 77-MW capacity of the existing transmission system until 2029 (according to the P50 forecast) or 2023 (according to the P90 forecast).

As noted above, Hydro proposes a sensitivity scenario in which "data centre" loads increase by 15 MW in 2020 and by 30 MW as of 2022, and in which DND load also increases by 12 MW in 2022. Hydro explains that its sensitivity forecast of "data centre" loads is based on the loads provided by customers on their applications for electrical service.[53] Hydro further notes that it "does not have data or information available that can be relied upon to quantify the uncertainty of data centre loads reflected in the load forecasts."[54] It would thus appear that Hydro's sensitivity forecast of data centre loads simply represents the additional loads for which service requests have been filed but not approved, and thus fails to recognized that there is a real possibility that Hydro will see additional "data centre" applications in the future.

In PUB-NLH-065, Hydro indicates that its actual peak demand in 2018 was more than 12 MW lower than its P90 forecast for that year — a forecast issued just six months earlier. In addition

53 LAB-NLH-086b.

54 LAB-NLH-086c.

to the weather factors, it indicates that "forecast new data centre customer load" was "5 to 6 MW lower than had been forecast". It must be noted that the forecast "data centre" load for 2018 was just 6.3 MW.[55] Thus, it appears that very little of the forecast load for "data centres" with signed service contracts actually materialized in 2018.

(In light of this information, it is difficult to make sense of the reported data centre consumption of 14.6 GWh in Labrador East in 2018.[56] Hydro was unable to provide the 2018 coincident peak demand of these customers, but, at 100% load factor, it would take just 1.67 MW to generate this level of consumption. That would be just 4.6 MW less than the 6.3 MW found in the forecast.)

Given that such loads represent a very substantial portion of the load forecast for future years, and that the justification for the transmission additions recently approved (MFHVI) is indeed related to cryptocurrency mining loads, it is surprising that Hydro has not seen fit to report in detail to the Board on these issues.

It is recommended that Hydro report to the Board on a quarterly basis:

1. **The number of cryptocurrency contracts signed, and their combined load;**
2. **The maximum non-coincident peak load drawn by each of these customers in the last quarter;**
3. **The total energy consumed by these customers in the last quarter;**
4. **The total number of pending cryptocurrency applications, and their combined loads.**

3.1.2. Labrador West

[55] LAB-NLH-074, Table 1, page 3 of 5.

[56] Ibid., page 5 of 5.

Hydro's December 2018 Operating Load Forecast confirms that, as in Labrador East, it is data centre loads that are driving the load forecast in Labrador West. Load growth for non-data centre rural customers is only about 0.2 MW/year.[58]

There is however 33.6 MW of industrial growth forecast from existing customers, from 2018 through 2021.[59]

> Historically the retail load growth experience in Labrador west generally correlated with the strength or weakness in the global iron ore industry, however with the expansive growth in demand for global data processing requirements largely associated with data mining, Labrador west has become a location of interest for data center developers seeking low cost power provision. The two largest customers located on the Labrador City distribution system are data center developments with existing power requirements exceeding 7.5 MVA.
>
> The forecast for near term load growth within the region is largely associated with increased energy sales to existing and new data center developments. Residential customer growth and associated electricity
>
> sales are expected to remain dependent on re-establishment of mining operations at Wabush or new mining developments. Through the medium term, forecasted load growth reflects modest residential customer growth and energy sales compared to the longer term historical levels experienced on these two systems. There are potential loads associated with further data center developments for both the Labrador City and Wabush systems.

The sensitivity forecast also includes 65 MW of industrial load from Alderon, starting in 2022.[60]

3.2. Alternatives

[58] LAB-NLH-074, Att. 1, pages 17-18 of 35 (pp. 23-24 of pdf).

[59] Ibid.

[60] TES, page 73 pdf.

3.2.1. Labrador East

Sections 5.1, 6.1.1 and 7.1 of the TES present the alternatives analyzed for Labrador East. However, the proposed future evolution of the Labrador East transmission system is most clearly presented in Table 3 of Appendix A to the TES, reproduced here:

Table 4. Labrador East – Proposed Future Phases

Phase	HVY Load that would Initiate Project (MW)[6]	Project Description	Cost Estimate[7] ($ million)
1	>77	**Muskrat Falls to Happy Valley Interconnection**	20.0
2	>104	**Transformation Upgrade at HVYTS** (Replace T2 or T4 with a 83 MVA unit)	5.0
3	> 125	**Transformation Upgrade at HVYTS and MFATS2** (HVYTS: Replace T2 or T4 with a 83 MVA unit) (MFA TS2: Replace both T1 and T2 with two 250 MVA units)	15.0
4	>162	**Construction of Second Line from Muskrat Falls to Happy Valley**	50.0

The table identifies four distinct phases for expanding the transmission capacity over and above the status quo with its limit of 77 MW, which are sequential and cumulative. Increasing capacity above 77 MW would require an investment of $20.0 million (MFHVI); increasing it above 104 MW would require an investment of $25 million ($20.0 + $5.0 million); increasing it above 125 MW would require an investment of $40 million ($20.0 + $5.0 + $15.0 million); and increasing it above 162 MW would require an investment of $90 million ($20.0 + $5.0 + $15.0 + $50.0 million).

However, as noted above in section 2.4.2, Hydro considers phase 1 (the MFHVI project) to be required to meet its baseline forecast, and so does not include it in the derivation of the Unit Expansion Cost.

3.2.2. Labrador West

Sections 5.2, 6.1.2 and 7.2 of the TES present the alternatives analyzed for Labrador West. Unfortunately, even reading these sections together with Appendix B to the TES (pages 63 through 116 of the pdf), it is difficult to follow how these various alternatives and scenarios fit together.

In response to an RFI[61], Hydro presented a summary of these alternatives in tabular form, which are reproduced in a more compact format below.

Alternative 1 is the status quo. Alternatives 2 and 3 are essentially identical, and represent upgrades that can serve up to 350 MW, but only 252 MW firm, at a cost of $1.82 million.

Table 5. Labrador West – Alternatives 1 through 3

Alt. #	Alternative Name	Load Forecast (MW)	Principal Elements	Resulting System Capacity (MW) Firm (n-1)	Total (all equipment in service)	Capital Cost ($ million)
1	Status Quo	335	Upgrade of distribution lines L32, L33, and L40	252	350	1.43
2	Status Quo – Tacora Load (Interruptibles)	383	Curtailment in excess if 350 MW at $10/kW/month;	252	350	1.82
			Upgrade of distribution lines L32, L33, L36 and L40			
3	Status Quo – Tacora + Data Centres (Interruptibles)	434	Curtailment in excess if 350 MW at $10/kW/month;	252	350	1.82
			Upgrade of distribution lines L32, L33, L36 and L40			

Alternatives 4 and 5 increase the non-firm capacity to over 400 MW, without increasing the firm capacity. Hydro explains that Alternative 4 is required to meet the baseline load forecast, whereas Alternative 5 is not. Hydro considers Alternative 5 to be the recommended option for meeting loads greater than 383 MW.[62] (Only the incremental cost ($16.5 million) and capacity (33 MW) of Alternative 5 are included in calculating the Expansion Cost per kW[63], which is discussed below.) Thus, the recommended alternative for loads between 383 and 434 MW can meet these loads only with all equipment in service, and not in the event that the largest equipment is out of service (n-1).

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61 LAB-NLH-094, pages 2 through 8 of 10.

62 TES, page 31, Table 11.

63 LAB-NLH-093, page 3 of 4.

Table 6. Labrador West – Alternatives 4 and 5

Alt. #	Alternative Name	Load Forecast (MW)	Principal Elements	Resulting System Capacity (MW) Firm (n-1)	Total (all equipment in service)	Capital Cost ($ million)
4	Tacora Upgrade	383	Commissioning of SC3	252	421	15.12
			Replace T4 and T5			
			New 23 MVA cap bank			
			Replace 4, 46 kV breakers			
			Upgrade of distribution lines L32, L33, L36 and L40 breakers			
5	Tacora and Data Centers Upgrade	434	Commissioning of SC3	252	454	31.66
			Replace T4, T5 and TG6			
			New 72 MVAR cap bank			
			Replace 4, 46 kV breakers			
			Thermal upgrade of L23/L24			
			Upgrade of distribution lines L32, L33, L36 and L40 breakers			

Alternatives 6 through 14 all increase firm capacity to 434 MW and Alternative 15 increases it to 482 MW, as shown in Table 7. None of these alternatives is included by Hydro in its Preferred Alternatives,[64] and so none of them are included in the Expansion Cost per kW calculation.

64 TES, page 31, Table 11.

Table 7. Labrador West – Alternatives 6 through 15

Alt. #	Alternative Name	Load Forecast	Principal Elements	Resulting System Capacity (MW)		Capital Cost
		(MW)		Firm (n-1)	Total (all equipment in service)	($ million)
6	Third 230 kV Line from CF to Wabush	434	New 215 km of 230 kV line from CF to WSTS and terminations			
			Commissioning of SC3	434	527	251.24
			Replace T4, T5 and TG6			
			New 19 MVAR cap bank			
			Replace 15, 46 kV breakers			
			Upgrade of distribution lines L32, L33, L36 and L40			
7	Third 230 kV line from CF to FLK (230/46kV)	434	News 215 km of 230 kV line from CF to FLK to WSTS and terminations	434	528	272.82
			Commissioning of SC3			
			New 230/46 kV TS at FLK including new 29 MVAR cap bank			
			Replace 10, 46 kV breakers			
			25 km of new 46 kV distribution lines			
			New 50 km of 315 kV line from BLK to FLK and terminations			
8	315 kV Line from	434	New 315/230 kV TS at FLK including 73 MVAR cap bank	434	514	141.4
	BLK (HQ) to FLK		New 50 km of 315 kV line from BLK to FLK and terminations*			
	(315/230 kV)		Commissioning of SC3			
			Replace T4, T5 and TG6			
			Upgrade of distribution lines L32, L33, L36 and L40 breakers			
9	315 kV Line from	434	New 50 km of 315 kV line from BLK to FLK and terminations*	434	502	146.99
	BLK (HQ) to FLK		New 315/230/46 kV TS at FLK including 73 MVAR cap bank			
	(315/230/46 kV)		New 5 km of 230 kV line from FLK to WTS and terminations			
			Commissioning of SC3			
			Replace 14, 46Kv breakers			
			25 km of new 46 kV distribution lines			
10	315 kV Line from CF to FLK (315/230/46 kV)	434	New 210 km of 315 kV line from CF to FLK and terminations	434	574	335.86
			New 315/230/46 kV TS at FLK including 29 MVAR cap bank			
			New 5 km of 230 kV line from FLK to WTS and terminations			
			Commissioning of SC3			
			Replace 13, 46Kv breakers			
			25 km of new 46 kV distribution lines			
11	315 kV Line from	434	New 210 km of 315 kV line from CF to FLK and terminations	473	563	397.97
	CF and BLK to		New 50 km of 315 kV line from BLK to FLK and terminations*			
	FLK (315/230/46 kV)		New 315/230/46 kV TS at FLK			
			Commissioning of SC3			
			Replace 10, 46Kv breakers			
			25 km of new 46 kV distribution lines			
12	250 MW Monopole from BLK to FLK	434	New 50 km of 200 kV HVdc line from BLK to FLK and terminations*	453	585	347.9
			Construction of FLK and BLK Converter Bldg. and Filter Banks*			
			New 230/46 kV TS at FLK including new 29 MVAR cap bank			
			New 5 km of 230 kV line from FLK to WTS and terminations			
			Commissioning of SC3			
			Replace 4, 46Kv breakers			
			25 km of new 46 kV distribution lines			
13	250 MW BtB	434	New 50 km of 230 kV line from BLK to FLK and terminations*	434	612	233.16
	Converter at BLK		Construction at BLK of VSC BtB Conv erter*			
	– 230 kV Line from BLK to FLK		New 230/46 kV TS at FLK including new 29 MVAR cap bank			
			New 5 km of 230 kV line from FLK to WTS and terminations			
			Commissioning of SC3			
			Replace 10, 46Kv breakers			
			25 km of new 46 kV distribution lines			
14	250 MW BtB Converter at BLK	434	New 55 km of 230 kV line from BLK to WTS and terminations*	434	603	216.7
	– 230 kV Line		Construction at BLK of VSC BtB Converter*			
	from BLK to		Commissioning of SC3			
	Wabush		Replace T4, T5, and T6			
			New 10 MVAR cap bank			
			Replace 10, 46Kv breakers			
			Upgrade of distribution lines L32, L33, L36 and L40			
15	200 MW Gas	434	Installation of 4, 50 MW gas turbines and fuel storage	482	573	589.2
	Turbine		Replace T4, T5, and T6			
			Replace 15, 46Kv breakers			
			Upgrade of distribution lines L32, L33, L36 and L40			

Finally, Alternatives 16 through 17 increase firm capacity to 499 MW. Hydro includes Alternative 17 as part of its Preferred Alternative, but does not include it in calculating the Expansion Cost per kW.

Table 8. Labrador West – Alternatives 16 and 17

Alt. #	Alternative Name	Load Forecast (MW)	Principal Elements	Resulting System Capacity (MW)		Capital Cost
				Firm (n-1)	Total (all equipment in service)	($ million)
16	3rd 230 kV Line to FLK (230/46 kV)	499	New 210 km of 230 kV line from CF to FLK and terminations	499	636	279.72
			New 315/230/46 kV TS at FLK including 29 MVAR cap bank			
			New 230/46 TS at FLK including 126 MVAR cap bank			
			New 5 km of 230 kV line from FLK to WTS and terminations			
			Commissioning of SC3			
			Replace 10, 46Kv breakers			
			25 km of new 46 kV distribution lines			
17	315kV Line from	499	New 50 km of 315 kV line from BLK to FLK and terminations*	499	600	153.15
	BLK (HQ) to FLK		New 315/230/46 kV TS at FLK including 161 MVAR cap bank			
			New 5 km of 230 kV line from FLK to WTS and terminations			
			Commissioning of SC3			
			Replace 14, 46Kv breakers			
			25 km of new 46 kV distribution lines			

As mentioned in section 2.4.1, Hydro explains this exclusion as follows[65]:

> Hydro excluded the approximately $150 million capital project providing an interconnection between Labrador West and Québec (Alternative 17) as its expected that this project would only be required if a large load addition was requested requiring the acceleration of this project. In this circumstance, the proposed "Network Additions Policy - Labrador Interconnected System" would calculate the contribution requirement on the difference between the cost of the acceleration of this project and the value of the benefits to existing customers as a result of accelerating this project.

In other words, Alternative 17 is excluded from the Expansion Cost per kW calculation because this value is used only for calculating the contribution requirement for small projects; Alternative

65 LAB-NLH-090a, page 2 of 2.

17 would only be required in the event of a large load addition, such as the Alderon project mentioned in the sensitivity forecast.

The preferred alternatives for Labrador West identified in the TES are shown in the following table:[66]

Table 9. Preferred Alternatives for Incremental Lab West Load Levels

Lab West Load (MW)	Least-Cost Option	Capital Cost ($ million)
> 383	Alternative 5	31.66
> 434	Alternative 17	153.15

However, it is precisely because the addition of small loads tends to accelerate the need for large future projects that the Expansion Cost per kW is derived from the costs of projects such as phases 2-4 for Labrador East. Given this logic, Alternative 17 should be included therein as well.

3.2.2.1. HQ alternatives

Alternatives 8, 9, 11 through 14 and 17 all involve new interconnections with Hydro-Québec, through the existing Bloom Lake (BLK) station.[67] The elements of the various alternatives that would have to be carried out by Hydro-Québec are marked with an asterisk in Table 7 and Table 8.

It appears from Hydro's responses that it developed these cost estimates on its own, as its contacts with Hydro-Québec regarding these alternatives remained at an extremely preliminary stage.[68]

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[66] From TES, Table 11, Page 31.

[67] LAB-NLH-084 and IOC-NLH-047. BLK is owned by Quebec Iron Ore company. In the event that this company does not agree to make its installation available, Hydro suggests than an alternative may be to use the existing Normand Terminal Station owned by Hydro-Québec.

[68] LAB-NLH-095b, page 1 of 5.

The procedures required for obtaining point-to-point service from Hydro-Québec TransÉnergie (the company's functionally separate transmission division) are carefully laid out in its Open Access Transmission Tariff.[69] They can be summarized as follows[70]:

- A written application must be provided (s. 17.1), setting out the information described in s. 17.2, which must include the locations of the Point of Delivery and the Point of Receipt, the identities of the Delivering and Receiving Parties, the location of the generating facility providing the capacity and energy to be transmitted,[71] and other details; and
- A deposit of one month's charge for the reserved capacity must also be provided (s. 17.3).
- Within one month, HQT must advise whether or not a System Impact Study will be required under s. 19.1 (s. 17.5). If a System Impact Study is required, it will be carried out by the methodology set out in Appendix D.
- Within one month, Hydro must submit the technical data required to conduct the study, and agree to paying its costs (s. 19.1).
- TransÉnergie will use due diligence to complete the System Impact Study within 120 days (s. 19.3).
- Within 15 days of receipt of the System Impact Study, Hydro would have to either execute a service agreement or confirm its intent to execute a Facilities Study Agreement and, where appropriate, a Connection Agreement (s. 19.3), which would include an estimate of the contribution required under the Network Upgrade policy set out in Attachment J.

The TES indicates that a preliminary load flow study has been performed cooperatively by personnel from both utilities, which apparently has provided "preliminary confirmation of the technical viability of the interconnection."[72] However, Hydro indicates that no study report was

[69] TransÉnergie's OATT is available at http://www.oasis.oati.com/hqt/index.html.

[70] This brief overview omits many important details set out in the OATT.

[71] Hydro has not determined if it would purchase the required power and energy from outside the province, or wheel its own power through Quebec. LAB-NLH-084b, page 2 of 5.

[72] TES, page 32.

generated as part of this exercise, but rather that its results were discussed in a conference call in October 2018.[73]

As noted earlier, the investment estimates for works by Hydro-Québec included in Table 7 and Table 8 were developed by Hydro, presumably based on its estimate of what it would expect to pay to develop such facilities within the province. However, Hydro further notes that Hydro-Québec's required upstream transmission upgrades and transmission tariffs have not been determined for each of these alternatives,[74] whether Hydro wheels its own power through Quebec or purchases power and energy from Hydro-Québec or from a third party.

TransÉnergie's own transmission tariffs are set annually by the Régie de l'énergie du Québec. The current tariff, on an hourly non-firm basis is $9.14/MWh. However, one must assume that Hydro will require firm service, likely at the capacity of the interconnection. At $80.06/kW-yr, a 300 MW firm reservation would require an annual payment of some $24 million.[75] The present value of such payments over 20 years (at a 6% discount rate) amounts to over $275 million.

I conclude from this brief analysis that the cost estimates for alternatives that include a new interconnection with Hydro-Québec are extremely uncertain, and are likely substantially understated.

3.2.2.2. Implications of changes in planning criteria

The creation of the NLSO and the accompanying changes in management structures has led to important changes in the standards applied to different parts of the Labrador transmission system.

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[73] IOC-NLH-046. It should be noted that the TES is dated October 31, 2018 (revised on November 5). Given the reported timing of the conference call, it is likely that much of the analysis presented in the TES was carried out prior to obtaining these results.

[74] LAB-NLH-095, page 1 of 5.

[75] TransÉnergie's tariffs are also available at http://www.oasis.oati.com/hqt/index.html.

The Labrador East and West systems are not considered part of the Primary Transmission System, and as a result, the n-1 criterion is not necessarily applied across the board in these areas.[76]

The Labrador West network is classified as a "local network", and so is not subject to strict application of Transmission Planning Criteria as defined in "NLSO Standard Transmission Planning Criteria Doc # TP-S-007.[77] The Labrador East network is considered a "radial network".

Hydro furthermore indicates that the Labrador West Local Network (46 kV) is now classified as part the Newfoundland and Labrador Interconnected System. Ratings for equipment within this jurisdiction are now calculated on the basis of "NLSO Standard – Transmission Facilities Rating Guide, TP-S-001," as opposed to methodologies defined in distribution planning standards. This change in methodology has resulted in a 4.9 MVA reduction in firm transformer capacity at the Wabush Substation.[78]

In addition to the changes in the ratings of the 46 kV power transformers, ratings of the 46 kV transmission lines were also revisited and calculated in accordance with "NLSO Standard – Transmission Facilities Rating Guide, TP-S-001" using an assumed 50°C operating temperature. This resulted in a substantial reduction in the conductor ratings, as shown in the following table:

Table 1: Comparison of Transmission and Distribution Calculated Conductor Ratings

46 kV Transmission Line	Transmission Planning Winter Rating (MVA)	Distribution Planning Winter Rating (MVA)
L32 Sections 1 and 2	59.4	72.0
L40 Section 1	42.6	51.5
L33 and L40 Section 2	60.2	72.9
L36	36.7	44.4

[76] LAB-NLH-073 a) i), page 2 of 3.

[77] NP-NLH-020.

[78] LAB-NLH-073 a) ii) and iii), page 2 of 3.

Taken together, these changes result in a substantial downgrading of the capacity of the Wabush Transmission Station and the 46 kV lines connected to it. As such, **it would appear that the need for at least some of the equipment called for to meet the baseline forecast in Labrador West (Alternative 4) is made necessary simply by changes to the ratings of the existing equipment.**

It is recommended that, before any transmission upgrades are approved by the Board for Labrador West, the justification for these changes of ratings be carefully examined in the Capital Budget Application process.

4. DISCUSSION

4.1. Capital investments and rate increases

In the TES, Hydro provides a graph showing a linear relationship between capital investment and rate increases, both for LIS rural and industrial customers.[79]

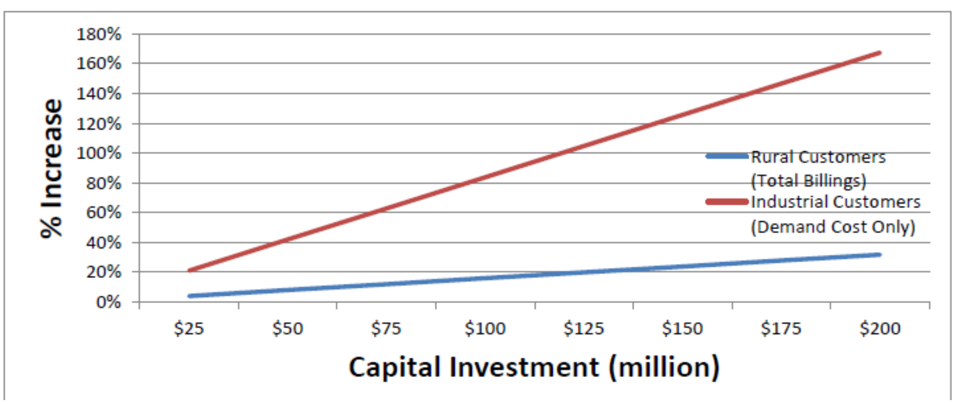

Figure 3. Project Rate Increase vs. Capital Investment

In response to an RFI, Hydro provided a similar graph showing the relationship between capital investment and the industrial demand charge, reproduced below: [80]

[79] TES, Figure 6, page 34.

[80] IOC-NLH-048.

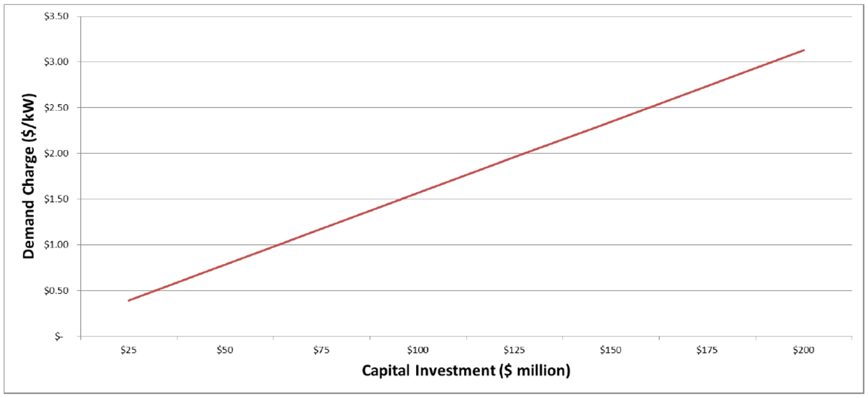

Figure 4. Labrador Industrial Customer Incremental Demand Charge

However, Hydro indicated that it is unable to graph required transmission investments and consequent rate increases against load growth, as the information would vary depending on which TES alternative was retained.[81]

In Table 11 of the TES (page 31), and again in section 11.2, Hydro recommends implementing the following upgrades in Labrador West:

- To meet the baseline forecast: Alternative 4 ($15.1 million);
- To serve loads of 383 MW or more: Alternative 5 (an additional $16.5 million); and
- To serve loads of 434 MW or more: Alternative 17 (an additional $153.2 million).

Thus, to meet loads of 434 MW or more, investments of some $184.8 million would be required. Based on the two figures reproduced above, this would result in increasing the demand charge for Labrador industrial rates by approximately $3.00/kW (an increase of 160%), and increasing rural Labrador rates by approximately 30%.

Similarly, in Table 10 of the TES (page 30), Hydro recommends implementing the following upgrades in Labrador East:

- To meet loads of 77 MW or more: Phase 1 ($20.0 million);
- To serve loads of 104 MW or more: Phase 2 (an additional $5.0 million);

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[81] LAB-NLH-083.

- To serve loads of 125 MW or more: Phase 3 (an additional $15.0 million); and
- To serve loads of 162 MW or more: Phase 4 (an additional $50.0 million).

Thus, to meet loads of 162 MW or more, investments of some $90 million would be required. Based on Figure 3, above, this would result in increasing the demand charge for Labrador industrial rates by an additional approximately $1.50/kW, and increasing rural Labrador rates by some 15%.

If all these new loads appeared in both Labrador East and Labrador West, the combined additional transmission investment required would be some $274.8 million, which would apparently result in increasing the demand charge for Labrador industrial rates by approximately $4.50/kW, and increasing rural Labrador rates by some 45% (not shown in above graphs).

It goes without saying that any contributions to these transmission investments required under the Network Additions Policy would reduce these net investments and the accompanying rate increases.

4.2. Relationship between MFHVI project and the Labrador East baseline forecast

As indicated in the citation on page 11, Hydro considers the MFHVI project to be an element of the least-cost transmission system solution to meet the baseline forecast in eastern Labrador. Normally, however, upgrades required to meet the baseline forecast are required to meet <u>future</u> loads included in that forecast, rather than existing ones.

We have also see in section 3.1.1 that the Labrador East baseline forecast included 7.2 MW of "data centre" loads as of 2019 from existing customers, and that forecast new "data centre" customer load in 2018 was "5 to 6 MW lower than had been forecast".

In fact, at the time that these "existing data centre loads" were granted service contracts, the Labrador East transmission system did not have sufficient capacity to reliably serve them. That is why the Phase 1 upgrade identified in Table 1 (the MFHVI project) was required in order to reliably serve them.

To the best of my knowledge, Hydro has never provided a clear explanation as to why these loads were added at a time when the infrastructure required to serve them reliably on an ongoing basis was not available and had not even been approved by the Board.

Going forward, **it is recommended that new loads only be added when the infrastructure required to serve them reliably on an ongoing basis is already in place.**

4.3. Cryptocurrency issues

There can be no doubt that new cryptocurrency mining loads ("data centres") play a very significant role in creating pressure to expand the LIS transmission system. This role was highlighted in Hydro's Network Additions Policy Review, which begins as follows:

> <u>Introduction</u>
>
> This report outlines Hydro's current practices with respect to cost responsibility for network additions and identifies revisions that are necessary to determine the changes required to ensure the goal of maintaining just and reasonable rates is achieved in dealing with new transmission additions.
>
> <u>There is currently an issue on the Labrador Interconnected System</u> ("LIS") with respect to the potential impact of network additions on customer rates. <u>Hydro has experienced recent load growth in Labrador primarily due to the arrival of data centres/cryptocurrency mining sites to the region. While these technology-based customers may not necessarily request to be served at a transmission voltage, their arrival can require the addition of upstream network facilities. Under the current network additions approach, the costs resulting from such network additions are treated as common for recovery from all ratepayers on the Labrador Interconnected System.</u>
>
> This report provides an option for consideration in light of the customer load requests in Labrador. Subsequent to the completion of Hydro's LIS expansion study, specific recommendations will be made to deal with new service requests.[82]

Information presented in the present proceeding makes it possible to describe the scope of these impacts:

- In Labrador East:

[82] Hydro, Network Additions Policy Review (October 1, 2018), page 1.

  - annual growth for rural customers (excluding "data centres") averages just 0.5 MW/year; **total growth excluding "data centres" is forecast to be just 12.2 MW from 2018 through 2043;**
  - "data centres" that now have service contracts are expected to use 7.2 MW starting in 2019; **additional "data centre" growth is forecast at 30 MW** starting in 2022 — **more than four times the forecast rural load growth.**
- In Labrador West:
  - annual growth for rural customers (excluding data centres) averages just 0.2 MW/year; **total rural load growth excluding data centres is forecast to be just 6.1 MW from 2018 through 2043**;
  - "data centres" that now have service contracts are expected to use 6.7 MW starting in 2020; **additional data centre growth is forecast at 51.5 MW** starting in 2022 — **almost 8 ½ times the forecast rural load growth.**

Thus, the combined forecast data centre loads as of 2022 (including those currently holding service contracts) is 37.2 MW in Labrador East and 58.2 MW in Labrador West, for a total of 95.4 MW. This represents almost 40% of rural peak loads in Labrador, and 17.8% of total peak loads (including industrial).

These figures are apparently based on the applications or inquiries that have already been received. However, if provincial political and regulatory policies are set in a way that transparently paves the way for additional data centre loads — including through a Network Addition Policy that imposes only modest incremental costs on them —applications for much greater quantities of power will likely materialize as well.

Hydro describes its understanding of the uncertainty surrounding these forecasts as follows :

> Hydro has observed via various media reports that <u>the data centre loads forecast for the Labrador Interconnected System represent only a portion of a much larger global demand for the data centre industry</u>. Hydro believes the uncertainty with local data centre load is likely to be associated with the ability of the local industry to remain competitive compared with other jurisdictions. The approach used by Hydro in this instance to integrate load uncertainty into its planning process has been to develop both baseline and sensitivity load forecast cases from which alternate system expansion plans have been developed.

Hydro is certainly correct that the service applications it has received represent only a small portion of a much larger global demand for the data centre (cryptocurrency mining) industry.

This global demand is itself affected by very great uncertainty, largely related to the price of bitcoin (which represents the vast majority of these cryptocurrency mining activities). In the last two years, bitcoin prices have ranged from CA$1,500 to CA$25,000. Since last December, they have hovered around CA$5,000, as seen in the following graph.[83]

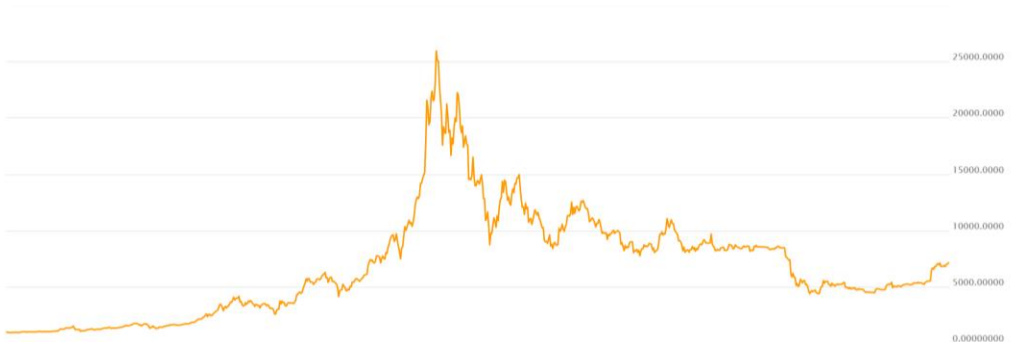

Figure 5. Bitcoin prices, 2017 - 2019

Electricity costs represent the vast majority of the variable costs associated with cryptocurrency mining, and so, for each bitcoin price, there is a threshold electricity cost below which mining activities become unprofitable and so will cease.

This means that, if bitcoin prices fall to very low levels for an extended period of time, the worldwide cryptocurrency mining loads will likely fall dramatically or even disappear. On the other hand, if bitcoin prices rise to high levels for an extended period of time, the worldwide cryptocurrency mining loads will likely continue to expand. Given its very low electricity rates, bitcoin mining will remain profitable in Labrador even at prices well below their current level.

As Hydro is no longer signing service contracts for loads in excess of the transfer capacity of the Labrador transmission system, it is not surprising that the pace of new cryptocurrency service requests may have fallen. However, there is no reason to believe that more service applications will not be filed in the future, especially if the Board establishes a process whereby transmission upgrades would be undertaken to meet new cryptocurrency mining loads, and the upfront costs

[83] https://coinsquare.com/markets/bitcoin

to new users is not prohibitively high. Under such circumstances, Hydro would likely find itself the recipient of new service requests for very large amounts of electricity — far more than the remaining recall power. At that point, unless the Board establishes a system whereby new cryptocurrency miners pay the marginal cost of new generation built to serve them, expensive new generation will gradually drive up the cost of electricity in Labrador until it is no longer cost competitive with other low-cost jurisdictions.

On April 15, 2019, the Government of NL announced a new policy to protect residents from the rate impacts of Muskrat Falls.[84] The document seems to suggest that revenues from cryptocurrency mining could somehow mitigate these rate impacts. The relevant section reads:

> **8 - Add value to energy surplus**
>
> Government will work with Newfoundland and Labrador Hydro and Nalcor to <u>seek expressions of interest to auction a quantity of surplus energy and capacity to a new domestic customer from 2021 to 2026</u>. Offering an amount of minimum capacity ("firm") provides greater certainty for new customers than offering non-firm energy and no capacity ("non-firm") into export markets, thus achieving greater value for the province. Nalcor's 2018 realized export price (after deducting costs including transmission fees and operating costs) was 3.8 cents/ kWh for non-firm energy sales.
>
> <u>A key prospect is the data centre sector</u> that has been growing significantly in Labrador and <u>has been the subject of Newfoundland and Labrador Hydro regulatory filings with the PUB such as the Network Additions Policy</u> posted at www.pub.nf.ca/index_reports.htm. "Data Centre" typically refers to an energy intensive customer with computer servers or other computer equipment to store or process computer data such as Google, Apple, and Amazon, and "blockchain" data processing associated with cryptocurrencies such as Bitcoin.
>
> There is currently 12 megawatts of data centre demand from data centres in Labrador that consumed 73.9 gigawatt hours of energy in 2018.[85] <u>There are presently 320 megawatts of new outstanding service requests from data centres in Labrador</u>. North American electricity

[84] GNL News Release, "Premier Ball Releases Plan to Protect Residents from the Cost Impacts of Muskrat Falls" and "Protecting You From the Cost Impacts of Muskrat Falls", April 2019, http://www.gov.nl.ca/muskratfallsframework.

[85] In LAB-NLH-074, Hydro indicated total data centre consumption in 2018 as 14.6 GWh for Lab East and 54.5 GWh for Lab West, for a total of 69.1 GWh.

> rate comparisons demonstrate higher value can be achieved from this sector in Labrador while remaining competitive.
>
> Given the significant recent Labrador load growth from these customers and outstanding requests for service, and the data centre moratorium in place in other jurisdictions, there is evidence Newfoundland and Labrador can achieve greater revenue growth.[86]

Unfortunately, in announcing its interest in achieving revenue growth from "data centres", government appears to neglect the fact that:

a) "data centres" have expressed interest in power in Labrador because of its very low cost, and will undoubtedly show no interest whatsoever in purchasing power at even heavily discounted Island rates;

b) by inviting "data centres" to consume more and more recall power, it will reduce if not entirely eliminate the amount of available recall power that can be brought onto the Island to reduce generation from Holyrood, and will also foreclose the possibility of new industrial loads in Labrador, which would create vastly more employment that do "data centres"; and

c) increasing loads in Labrador will make inevitable the very costly transmission upgrades described in the TES, the costs of which, according to the proposed Network Addition Policy, the new "data centre" customers would pay only a small share.

It is important to recognize that most of the pressure for transmission upgrades in Labrador — both those that are currently underway (the $20 million Muskrat Falls Happy Valley Interconnection) and those that are envisaged in the TES — are, to a large extent, caused by existing and future "data centre" (cryptocurrency mining) customers.

In the fall of 2018, a lengthy hearing was held before the Régie de l'énergie concerning a proposal by Hydro-Québec Distribution (HQD) to create a block of energy to be reserved for cryptocurrency use and to auctioned off to the highest bidders. Under HQD's proposal, all cryptocurrency clients would be obliged to curtail their operations, at the utility's request, during the 300 hours of peak demand.

86 Ibid., pages 12-13.

While the Régie has not yet issued its decision in this matter, information presented during the hearing sheds considerable light on this new industry and its unique characteristics.

Because these customers normally operate at full capacity their loads are normally fully present at regional and system peak.[87] However, because their business model is based on continuously performing complex calculations, their revenues are produced continuously throughout the year. Thus, interruption does result in reduced revenues, but only in proportion to the duration of the interruption. It was confirmed by several industry participants in the hearing that curtailment for 300 hours per year during peak periods (3.4% of the year) would not constitute a serious impediment for them.

The same hearing also heard testimony from the provincial association of municipal distributors (*l'Association de redistributeurs d'électricité du Québec*, or AREQ), who already have a substantial number of cryptocurrency clients in operation. AREQ explained that its members systematically required all cryptocurrency clients to contractually commit to curtail their consumption for up to 400 hours per year, under direct control of the municipal utility. An excerpt of the relevant sections of one of these contracts was produced in evidence, and is translated in Appendix A.

As noted earlier, in response to an RFI, Hydro presented the number of hours in which Labrador East rural loads (excluding "data centre" loads) are forecast to exceed 77 MW (the maximum that can be served by the existing system, prior to the commissioning of the MFHVI). Its response, summarized in Figure 1, on page 20, shows that this load would not be exceeded during more than 10 hours per year until 2036, and even in 2043 would only be exceed during 83 hours.[88]

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[87] Hydro assumes a load factor of 95% for its "data centre" customers, and hence assumes that 95% percent of their installed capacity will be present at peak, as seen in Table 2 of Appendix A to the TES (page 54 pdf).

[88] Plotted from data in LAB-NLH-080, Table 1, page 2.

Hydro accompanies these data with the following proviso:

> Table 1 summarizes the number of times per year and the total estimated hours per year the Happy Valley-Goose Bay demand would exceed 77 MW, <u>assuming no data centres are in service</u>. However, Newfoundland and Labrador Hydro ("Hydro") notes <u>that there are existing data centres</u> which contribute to the total load. <u>Hydro has no reason to believe the data centre load will not be part of the future total load. The numbers below provide no useful basis for future planning.</u> (emphasis added)

However, the load profile described in this response does not presume that "no data centres are in service", but only that their loads are not present during system peak. In other words, **the pressure on the Labrador transmission system created by the increase in peak demand due to forecast "data centre" activity could be largely or completely eliminated by an obligation — whether contractual or regulatory in nature — on the part of these customers to curtail their consumption during peak periods.** As was amply demonstrated in testimony by leading cryptocurrency companies in the Quebec hearing, **such a constraint would constitute at most a minor irritant to these customers.**

In order for the Board to impose such an obligation on cryptocurrency customers, it would likely have to first establish a **distinct rate class for cryptocurrency customers**, as has already been done by several regulators, notably in New York State and in Washington State.[89] (The forthcoming decision from the *Régie de l'énergie du Québec* is likely to also create a cryptocurrency rate class.)

Such a proceeding would of course be distinct from the present proceeding concerning the Network Addition Policy, and also from future Capital Budget Applications in which the various upgrades discussed in the TES would be analyzed. It is important, however, to keep in mind the interrelationships between different proceedings. **There is a pressing public interest in ensuring that regulatory silos do not prevent measures which, while creating at most a**

[89] See my expert report filed in the proceeding regarding an application for a load restriction in Labrador East. The precise definition of the new rate class varies from one jurisdiction to another.

minor inconvenience for existing and future data centre customers, could contribute to avoiding transmission investments of tens of millions of dollars, or more.

In some cases, the capital contribution required under the NAP for a "data centre" project to go ahead would be so great as to make the project uneconomic. Insofar as, without the NAP, such a project would have required substantial additions to the Labrador transmission system that would have imposed large annual costs on existing customers for many years to come, the cancellation of such a project is likely to be in the public interest.

In other cases, a "data centre" project may require substantial additions to the Labrador transmission system but, under the terms of the proposed NAP, the capital contribution required of the proponent would be modest. In these cases, the additions required to the Labrador transmission system may nevertheless impose large annual costs on existing customers for many years to come. Under such circumstances, it is far from certain that the proposed project would be in the public interest.

In this way, "data centre" loads are very different from other rural loads, which contribute in one way or another to building the communities in which they are situated. The two projects exempted by the Board in recent months from the application of Regulation 17 — a daycare centre and a government office building — provide good examples of why the NAP should **not** apply to regular rural loads. As noted earlier, the Board required Hydro to file an NAP precisely in order to respond to the challenge of "data centres". Applying it across the board to all new loads would not be appropriate.

4.4. Adequacy of the proposed approach based on advancement costs

FERC's network upgrade policy, described in my report concerning Hydro's 2013 Amended GRA, is meant to ensure that existing customers are not adversely affected by transmission upgrades undertaken in order to provide service to new users. Hydro's proposed Network Addition Policy, however, is not sufficient to meet this goal. This is true both in the case of new industrial users (which are unregulated, under the current legislative and regulatory regime) and of new "data centre" users, which are regulated customers.

As recognized by Hydro, under this regime it would still be entirely possible, indeed likely, for a small new load to trigger construction of transmission assets far out of proportion to that load, the costs of which would be borne primarily by existing consumers. Unlike the FERC policy, whereby uneconomic projects would not go forward because the party causing the addition would bear the full weight of its costs, the proposed policy makes it likely that uneconomic projects would indeed go forward.

The advancement approach is problematic, notably because, as demonstrated above, it is extremely sensitive to assumptions. A methodology in which a customer's capital cost contribution may vary by hundreds of percent depending on initial assumptions is not robust.

That said, it must be acknowledged that the proposed policy is an improvement over the *status quo,* where the costs of any network upgrade that is not exclusively used by a single customer are automatically shared across the entire customer base without any capital contribution from the new load(s) that caused the upgrade. This in particular was true for the MFHVI project and the data centre loads that made it necessary.

For this reason, it is recommended that the Board provisionally adopt the proposed NAP, while requiring an ongoing process to amend it and improve upon it.

Hydro defends its proposed policy as being consistent with the beneficiary pays approach.

> Hydro's policy gives consideration to the beneficiary pays approach. Hydro believes the use of the Expansion Advancement Cost, which considers both the cost of acceleration of the Labrador Transmission Expansion Plan and the benefits to existing customers of the acceleration of the plan, is consistent with the beneficiary pays approach. Hydro's position that the beneficiary pays approach is the appropriate concept to follow is further explored in Hydro's "Network Additions Policy Review," filed with the Board on October 1, 2018.[90]

[90] LAB-NLH-105d.

However, as noted earlier, the Christensen Associates Discussion Paper included in the Network Additions Policy Review makes clear that "beneficiary pays" is a very broad concept which can be applied in many different ways. Indeed, the NYSPSC requirement that the customer advance the full cost of all facilities necessary to supply energy is arguably more consistent with the "beneficiary pays" approach than is Hydro's proposal based on advancement costs only.

Hydro has not explicitly set out its reasons for choosing the advancement cost approach over the approach based on the full cost of all facilities necessary to provide the required service, which underlies FERC's Network Upgrade Policy as well as NYSPSC's Rider A.

It is recommended that Hydro continue to explore the approach underlying the FERC network upgrade policy whereby a new customer covered by the policy must take full cost responsibility for the network additions required to provide service.

4.5. Relationship between NAP and TES

The proposed NAP relies in several ways upon information provided (or that should be provided) in the TES. For this reason, it is important that the TES also be reviewed and approved by the Board.

More specifically, the NAP relies on the TES for the following information, which is essential to its operation:

1) The Expansion Cost per kW, fixed in Appendix A, is derived on the basis of information presented in the TES; and
2) The Transmission Expansion Plan, relied upon in s. 5.2 of the NAP, is derived from information presented in the TES.[91]

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91 The Transmission Expansion Plan is defined in the NAP as follows:

> **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.

Section 1.1 of Appendix B to the NAP states:

> Hydro performs an annual assessment of the previous Transmission Expansion Plan for the LIS based on its current demand forecast. This assessment allows for the determination of the timing of transmission system additions and modifications necessary to ensure safe, reliable, and economical long-term operation. On this basis, a new Transmission Expansion Plan is developed.
>
> Hydro filed its Transmission Expansion Plan for the LIS on October 31, 2018.[92]

Hydro thus apparently considers the TES to constitute the Transmission Expansion Plan, and further states that it will be updated annually. However, the TES as filed is inadequate to support the NAP because:

1) While the Baseline Coincident Peak forecast is clearly set out (in Table 3 on page 11 of the TES), the "various load growth scenarios" called for in the definition of the Transmission Expansion Plan are not clearly set out;
2) The Transmission Upgrades required to serve various load growth scenarios are not clearly set out in the TES, nor are their costs.

Under the proposed NAP, for new loads larger than 1500 kW, the contribution they would be required to make in support of required transmission additions would depend on the acceleration they would cause to the baseline Transmission Expansion Plan. The failure of the TES to clearly set out the Transmission Expansion Plan means that the methodology described in Appendix B to the NAP cannot be applied. The inputs required for the acceleration analysis include, among other things, "Hydro's Transmission Expansion Plan, including capital costs, asset replacement schedules and operating costs", which are not clearly set out in the TES.

Appendix B to the NAP indicates that the Transmission Expansion Plan is to be updated annually:

> **1.1 Transmission Plan Development**
>
> Hydro performs an annual assessment of the previous Transmission Expansion Plan for the LIS based on its current demand forecast. This assessment allows for the determination of

92 NAP, Appendix B, page 18 of 23.

> the timing of transmission system additions and modifications necessary to ensure safe, reliable, and economical long-term operation. On this basis, a new Transmission Expansion Plan is developed.
>
> Hydro filed its Transmission Expansion Plan for the LIS on October 31, 2018.

The last sentence suggests that Hydro considers the TES to in fact constitute the Transmission Expansion Plan. The first paragraph indicates that it expects it to be updated annually.

Given the great extent to which load forecasts can vary from year to year, as well as the changes that can occur in transmission planning, it is indeed appropriate that the Transmission Expansion Plan, and hence the TES, be updated annually. Given the importance of the information contained therein, it is also important that it receive Board approval.

It is recommended that the TES be amended in accordance with the recommendations herein, that it be updated annually and that it require approval by the Board.

5. FINDINGS AND RECOMMENDATIONS

5.1. Network Addition Policy

Findings:

1. Under the proposed Network Addition Policy, new customers for which service cannot be provided without substantial additions to the Labrador transmission system would be required to contribute to the capital cost of those additions.
2. This report has identified several ways in which the proposed NAP could be improved. However, even without the suggested modifications, it represents a significant improvement over the existing approach.

It is recommended that the proposed Network Addition Policy be adopted provisionally. It is further recommended that the Board order Hydro to continue work, in collaboration with stakeholders, in order to explore the various modifications suggested herein.

5.1.1. Applicability

Findings:

3. The proposed NAP applies to any person who applies for Service (the "Applicant"). The Demand Revenue Credit applies to industrial customers only, but the other provisions apply to all applicants.

It is recommended that the NAP apply to "data centre" and industrial loads, but not to other rural loads.

Finding:

4. The NAP does not set out details as to how these charges would be assessed, but presumably they would have to be paid before service could be initiated.

It is recommended that the NAP require that the Customer Contribution be paid in full before any transmission upgrade works are initiated, and that no commitments on Hydro's part be binding until that time.

5.1.2. Expansion costs per kW

Findings:

5. For customer requests of less than 1500 kW, and for larger customer requests which do not result in acceleration of the Transmission Expansion Plan, the Upstream Capacity Charge is based on the Expansion Cost per kW, fixed in Appendix A as $465/kW.
6. The derivation of this value is described in the NAP Summary Report, making reference to the TES. It is meant to reflect the cost of transmission system expansion required to meet incremental load beyond the baseline load forecast, but the Transmission Expansion Study fails to clearly set out:
    a. the baseline load forecast,
    b. the Transmission Expansion Plan it would require (required projects and dates when they would be needed),
    c. the incremental forecasts, nor
    d. the transmission upgrades that would be required to meet the incremental forecasts.
7. Furthermore, the choice of which expansion projects to include in deriving the Expansion Cost per kW appears to be somewhat arbitrary.

For purposes of calculating the Expansion Cost per kW, it is recommended that Alternative 17 be included, resulting in a value of $836/kW.

Findings:

8. Using this approach, the UCC for a 1-MW customer request would be either $372,000 (at $465/kW) or $668,800 (at $836/kW).
9. Using this approach, Board approval would be required for any project of at least 630 kW (at $465/kW) or 439 kW (at $836/kW).
10. A hypothetical example demonstrates that, if this policy had been in place before the first cryptocurrency customers were connected in Labrador East, a 1240 kW customer request would have had to make a contribution of $483,600 (under the $465/kW rate) or $869,440 (under the $836/kW rate).
11. The combined contributions of five 1200-kW customers (equivalent to the 6.1 MW "data centre" load) would therefore amount to either $2.4 million or $4.3 million, depending on the rate applied, representing either 12% or 22% of the capital costs of the MFHVI project, leaving the remainder (78% to 88%) to be recovered in rates.

12. Based on reasonable assumptions, these amounts would reflect either 3.3% (at $465/kW) or 6.0% (at $836/kW) of these customers' revenues over 10 years, confirming Hydro's estimation that these charges would be unlikely to prevent potential customers from taking service.

5.1.3. Customer requests greater than 1500 kW requiring acceleration of Transmission Expansion Plan

5.1.3.1. Results

Findings:

13. Using Hydro's spreadsheet model for calculating advancement costs, several specific cases were analyzed. Addition of a 10 MW "data centre" in Labrador East, starting in 2021, would require a customer contribution of $4,325,162, or $432/kW.
14. This cost is made up mostly of temporary generation costs for the annual 3-day maintenance period of the Happy Valley Gas Turbine, made necessary by the increased load.
15. Hydro's calculations appear to include more temporary generation than would actually be required. As the fuel consumption suggests average use of under 1 MW for the first decade and 2 MW for the second, it is not clear why Hydro sees the need to rent 10 MW of temporary generation starting in year 1.
16. Under slightly different circumstances, the required contribution would have very different:
    a. If the service contracts for 6.2 MW "of data centre" loads in Happy Valley were not in place, these loads would not form part of the baseline load forecast.
    b. As a result, the MFHVI project would not to be considered as part of the transmission system expansion required to meet that baseline load forecast.
    c. As a result, the MFHVI project would be included in the transmission system expansion required to meet the incremental load under study.
    d. Under these circumstances, the Acceleration Cost would have been $19.4 million, almost 4 ½ times greater than the Acceleration Cost described above.
17. A similar analysis of a 30-MW "data centre" project in Labrador West resulted in a UCC of $12.5 million, for an average expansion cost of $414.53/kW.
18. If, however, the total cost of the Alternative 5 expansion were to be used rather than the incremental cost in relation to Alternative 4, the UCC would almost double to $23,716,680, for an average expansion cost of $790.56/kW.

19. These examples demonstrate how sensitive the UCC is to the hypotheses regarding the baseline forecast and the expansion plan required to serve it.
20. A similar analysis was undertaken with respect to a large incremental mining load in Labrador West, such as Alderon's Kami Mine. It was found that, if Alternative 7 (the Labrador West Transmission Project) were to be developed at a capital cost of $272.82 million, the UCC would be on the order of $200 million, representing 73% of that capital cost.
21. If, on the other hand, Alternative 17 were developed instead of Alternate 7 (as recommended in the TES), the UCC would be on the order of $110 million, out of a capital cost of $153.15 million — again representing some 72%.
22. These examples demonstrate that the proposed NAP would in fact greatly increase the extent to which the beneficiaries of transmission expansion projects would be required to contribute to project costs, and demonstrates why — even though it is far from perfect — it is important that it come into force promptly.

5.1.3.2. The "advancement" approach

Findings:

23. FERC's network upgrade policy is meant to ensure that existing customers are not adversely affected by transmission upgrades undertaken in order to provide service to new users. Hydro's proposed Network Addition Policy is not sufficient to meet this goal.
24. Under this regime it would still be entirely possible, indeed likely, for a small new load to trigger construction of transmission assets far out of proportion to that load, the costs of which would be borne primarily by existing consumers. Unlike the FERC policy, whereby uneconomic projects would not go forward because the party causing the addition would bear the full weight of its costs, the proposed policy makes it likely that uneconomic projects would indeed go forward.
25. The advancement approach is problematic, notably because it is extremely sensitive to assumptions. A methodology in which a customer's capital cost contribution may vary by hundreds of percent depending on initial assumptions is not robust.
26. The proposed policy is nevertheless an improvement over the *status quo*, where the costs of any network upgrade that is not exclusively used by a single customer are automatically shared across the entire customer base without any capital contribution from the new load(s) that caused the upgrade. This in particular was true for the MFHVI project and the data centre loads that made it necessary.

It is recommended that the provisions of the NAP regarding expansion cost and acceleration cost be adopted provisionally.

It is further recommended that the Board order Hydro to continue work, in collaboration with stakeholders, in order to explore possible modification to the "advancement" approach retained by Hydro, or the possible application of the approach underlying the FERC network upgrade policy whereby a new customer covered by the policy must take full cost responsibility for the network additions required to provide service.

5.1.4. Determining the value of Reliability Benefits using Expected Unserved Energy

Findings:

27. Hydro proposes to credit the new consumer for any reduction in the cost of expected unserved energy (EUE) that would result from the transmission advancements required to serve the new load (up to the 50% maximum). EUE is calculated based on expected unavailability rate, and it is valued based on the average realized price for exports.
28. While this price signal is seen by Hydro, it is not seen by regulated consumers in Labrador.
29. While the inconvenience of unserved energy is indeed borne by incumbent ratepayers, the costs attributed thereto (estimated by Hydro as $571,500 for Labrador East and $5,028,000 for Labrador West) are not actually incurred by them.
30. Under the proposal, new customers would be credited for the reliability improvements resulting from the transmission upgrades that they cause, which result in decreasing EUE for all customers. However, new customers that do not require transmission upgrades are not penalized for degrading reliability and so increasing EUE for all consumers.
31. Hydro has estimated that, in Labrador East, the 6.2 MW of "data centre" customers added in recent years resulted in an increase in EUE of $113,060, whereas those in Labrador West resulted in an increase in EUE of $1,047,600.
32. It is common to use EUE to "justify, prioritize or rank transmission or other capital projects".[93] However, it is not common practice to include these amounts directly in rates.

It is recommended that Hydro's proposed method for integrating Reliability Benefits in the Upstream Capacity Charge not be retained. It is further recommended that the Board

[93] PUB-NLH-059.

order Hydro to continue work, in collaboration with stakeholders, in order to identify a better way to take Reliability Benefits into account.

5.1.5. Demand Revenue Credit

Findings:

33. Hydro's proposed Demand Revenue Credit (DRC), available to industrial customers only, reduces the required customer contribution based on the assumption of a service life of 25 years. In the event that service life is estimated to be lower than 25 years, the DRC is reduced by 3% per year.
34. Under the approach used by the New York State Public Service Commission (NYSPSC) in Rider A of the NYMPA tariff, the portion of the customer's rates that cover fixed assets and operating costs ("non-supply related revenues") are refunded for the first ten year's under which that the customer continues to take service.
35. The approach embodied in the NYSPSC Rider A is perhaps more elegant, but Hydro's proposed DRC would have substantially the same effect.

It is recommended that the provisions of the proposed NAP concerning the Demand Revenue Credit be approved.

5.2. Labrador Transmission Expansion Study

Findings:

36. The proposed NAP relies in several ways upon information provided (or that should be provided) in the TES, including:
    a. The Expansion Cost per kW, fixed in Appendix A, is derived on the basis of information presented in the TES; and
    b. The Transmission Expansion Plan, relied upon in s. 5.2 of the NAP, is derived from information presented in the TES.
37. The failure of the TES to clearly set out the Transmission Expansion Plan means that the methodology described in Appendix B to the NAP cannot be applied. The TES as filed is inadequate to support the NAP because:
    a. While the Baseline Coincident Peak forecast is clearly set out, the "various load growth scenarios" called for in the definition of the Transmission Expansion Plan are not clearly set out;

b. The Transmission Upgrades required to serve various load growth scenarios are not clearly set out in the TES, nor are their costs.

It is recommended that the TES be amended in accordance with the recommendations herein, that it be updated annually, and that it require approval by the Board.

5.2.1. Load forecasts

Findings:

38. There is no clear presentation of the baseline forecasts for Labrador East and West.
39. The baseline forecasts are based on the medium forecast of energy requirements, not taking into account any other uncertainty in relation to that forecast.
40. There is no clear presentation of the sensitivity forecasts in the TES itself, though some indications are found in the appendices.
41. There is substantial unexplained variation from one forecast to another.

It is recommended that Hydro's load forecasts take the uncertainty of the underlying forecast of energy requirements into account, by using low, medium and high forecasts.

It is recommended that, in the future, Hydro present both P50 and P90 baseline load forecasts for Labrador East and Labrador West regularly and in a consistent format, setting out the date of the forecast and highlighting and explaining all significant changes from the previous forecast.

It is also recommended that, in the future, sensitivity forecasts for each region be clearly identified and broken down by type of incremental load.

It is recommended that Hydro report to the Board on a quarterly basis:

1. **The number of cryptocurrency contracts signed, and their combined load;**
2. **The maximum non-coincident peak load drawn by each of these customers in the last quarter;**
3. **The total energy consumed by these customers in the last quarter;**
4. **The total number of pending cryptocurrency applications, and their combined loads.**

5.2.2. Alternatives

Findings:

42. Four distinct phases are identified for expanding the transmission capacity in Labrador East over and above the current limit of 77 MW, which are sequential and cumulative. Increasing the capacity above 77 MW would require an investment of $20.0 million (MFHVI); increasing it above 104 MW would require an investment of $25 million ($20.0 + $5.0 million); increasing it above 125 MW would require an investment of $40 million ($20.0 + $5.0 + $15.0 million); and increasing it above 162 MW would require an investment of $90 million ($20.0 + $5.0 + $15.0 + $50.0 million).
43. The alternatives for Labrador West are not clearly presented in the TES. Based on RFI responses, a concise summary is presented.
44. The preferred alternatives identified in the TES for Labrador West are Alternative 5 for loads above 383 MW ($31.66 million), and Alternative 17 for loads above 434 MW ($153.15 million).

Findings:

45. Hydro considers the MFHVI project to be an element of the least-cost transmission system solution to meet the baseline forecast in eastern Labrador. Normally, however, upgrades required to meet the baseline forecast are required to meet future loads included in that forecast, rather than existing ones.
46. At the time that these "existing data centre loads" were granted service contracts, the Labrador East transmission system did not have sufficient capacity to reliably serve them. That is why the Phase 1 upgrade (the MFHVI project) was required in order to reliably serve them.

It is recommended that new loads only be added when the infrastructure required to serve them reliably on an ongoing basis is already in place.

47. Several of the alternatives for loads over 434 MW involve a new interconnection with Hydro-Québec, through the existing Bloom Lake (BLK) station. These include the lower cost alternatives.
48. These cost estimates were developed with minimal input from Hydro-Québec, and fail to take into account either the upstream transmission upgrades that may be required or the transmission tariffs that would inevitably have to be paid. It is estimated that, for a 300 MW interconnection, annual tariffs are likely to cost some $24 million, for a present value over 20 years of some $275 million.
49. **The cost estimates for alternatives that include a new interconnection with Hydro-Québec are extremely uncertain, and are likely substantially understated.**

5.2.3. Implications of changes in planning criteria

Findings:

50. The creation of the NLSO and the accompanying changes in management structures has led to important changes in the standards applied to different parts of the Labrador transmission system.
51. These changes have resulted in a substantial downgrading of the capacity of the Wabush Transmission Station and the 46 kV lines connected to it. As such, it would appear that the need for at least some of the equipment called for to meet the baseline forecast in Labrador West (Alternative 4) is made necessary simply by changes to the ratings of the existing equipment.

It is recommended that, before any transmission upgrades are approved by the Board for Labrador West, the justification for these changes of ratings be carefully examined in the Capital Budget Application process.

5.3. Other issues

5.3.1. Capital investments and rate increases

Findings:

52. In the TES, Hydro provides a graph showing a linear relationship between capital investment and rate increases, both for LIS rural and industrial customers. In response to an RFI, Hydro provided a similar graph showing the relationship between capital investment and the industrial demand charge.
53. To meet loads of 434 MW or more in Labrador West, investments of some $184.8 million would be required, which would result in increasing the demand charge for Labrador industrial rates by an additional approximately $3/kW, and increasing rural Labrador rates by some 30%.
54. To meet loads of 162 MW or more in Labrador East, investments of some $90 million would be required, which would result in increasing the demand charge for Labrador industrial rates by an additional $1.50/kW, and increasing rural Labrador rates by some 15%.
55. Any contributions to these transmission investments required under the Network Additions Policy would reduce these net investments and the accompanying rate increases.

5.3.2. Cryptocurrency loads

Findings:

56. While its application is not limited thereto, the driving force behind the development of the proposed NAP has been the arrival of cryptocurrency mining activities (referred to by Hydro as "data centres") in Labrador.
57. In Labrador East, annual growth for rural customers (excluding "data centres") averages just 0.5 MW/year; total growth excluding "data centres" is forecast to be just 12.2 MW from 2018 through 2043. "Data centres" that now have service contracts are expected to use 7.2 MW starting in 2019; **additional "data centre" growth is forecast at 30 MW starting in 2022 — more than four times the forecast rural load growth.**
58. In Labrador West, annual growth for rural customers (excluding data centres) averages just 0.2 MW/year; total rural load growth excluding data centres is forecast to be just 6.1 MW from 2018 through 2043. "Data centres" that now have service contracts are expected to use 6.7 MW starting in 2020; **additional data centre growth is forecast at 51.5 MW starting in 2022 — almost 8 ½ times the forecast rural load growth.**
59. Thus, the combined forecast data centre loads as of 2022 (including those currently holding service contracts) is 37.2 MW in Labrador East and 58.2 MW in Labrador West, for a total of 95.4 MW. This represents almost 40% of rural peak loads in Labrador, and 17.8% of total peak loads (including industrial).
60. As Hydro is no longer signing service contracts for loads in excess of the transfer capacity of the Labrador transmission system, it is not surprising that the pace of new cryptocurrency service requests may have fallen. However, there is no reason to believe that more service applications will not be filed in the future, especially if the Board establishes a process whereby transmission upgrades would be undertaken to meet new cryptocurrency mining loads, and the upfront costs to new users is not prohibitively high. Under such circumstances, Hydro would likely find itself the recipient of new service requests for very large amounts of electricity — far more than the remaining recall power. At that point, unless the Board establishes a system whereby new cryptocurrency miners pay the marginal cost of new generation built to serve them, expensive new generation will gradually drive up the cost of electricity in Labrador until it is no longer cost competitive with other low-cost jurisdictions.
61. Most of the pressure for transmission upgrades in Labrador — both those that are currently underway (the $20 million Muskrat Falls Happy Valley Interconnection) and those that are envisaged in the TES — are, to a large extent, caused by existing and future cryptocurrency customers.
62. Because these customers normally operate at full capacity their loads are normally fully present at regional and system peak. However, because their business model is based on continuously performing complex calculations, their revenues are produced continuously throughout the year. Thus, interruption does result in reduced revenues, but strictly in

proportion to the duration of the interruption. It was confirmed by several industry participants in a recent Quebec hearing that curtailment for 300 hours per year during peak periods (3.4% of the year) would not constitute a serious impediment for them.

63. The same hearing also heard testimony from the provincial association of municipal distributors, who already have a substantial number of cryptocurrency clients in operation. Its members systematically require all cryptocurrency clients to contractually commit to curtail their consumption for up to 400 hours per year, under direct control of the municipal utility. An excerpt of the relevant sections of one of these contracts is translated in Appendix A.

64. The pressure on the Labrador transmission system created by the increase in peak demand due to forecast "data centre" activity could be largely or completely eliminated by an obligation — whether contractual or regulatory in nature — on the part of these customers to curtail their consumption during peak periods. Such a constraint would constitute at most a minor irritant to these customers.

65. In order for the Board to impose such an obligation on cryptocurrency customers, it would likely have to first establish a distinct rate class for cryptocurrency customers, as has already been done by several regulators, notably in New York State and in Washington State. (The forthcoming decision from the Régie de l'énergie du Québec is likely to also create a cryptocurrency rate class.)

66. There is a pressing public interest in ensuring that regulatory silos do not prevent measures which, while creating at most a minor inconvenience for existing and future data centre customers, could contribute to avoiding transmission investments of tens of millions of dollars, or more.

67. In some cases, the capital contribution required under the NAP for a "data centre" project to go ahead would be so great as to make the project uneconomic. Insofar as, without the NAP, such a project would have required substantial additions to the Labrador transmission system that would have imposed large annual costs on existing customers for many years to come, the cancellation of such a project is likely to be in the public interest.

68. In other cases, a "data centre" project may require substantial additions to the Labrador transmission system but, under the terms of the proposed NAP, the capital contribution required of the proponent would be modest. In these cases, the additions required to the Labrador transmission system may nevertheless impose large annual costs on existing customers for many years to come. Under such circumstances, it is far from certain that the proposed project is in the public interest.

69. Pressure on the Labrador transmission system is just one of the complex issues raised by the arrival of cryptocurrency mining activities in Labrador. These activities also have significant implications for generation — in the near term, reducing or eliminating the availability of recall power to displace Holyrood generation on the Island, and, in the longer term, using up the remaining recall power that could otherwise have supplied new

industrial loads in Labrador which would create vastly more employment than do "data centres".

70. The implementation of the proposed NAP, with or without modifications, is unlikely to resolve all of the important issues raised by the arrival of cryptocurrency mining activities in Labrador. It is thus a necessary step, but not a sufficient one to resolve these challenges.

71. The pressure on the Labrador transmission system created by the increase in peak demand due to forecast "data centre" activity could be largely or completely eliminated by an obligation — whether contractual or regulatory in nature — on the part of these customers to curtail their consumption during peak periods. As was amply demonstrated in testimony by leading cryptocurrency companies in the Quebec hearing, such a constraint would constitute at most a minor irritant to these customers.

Recommendation: The Board should undertake, on its own initiative, an examination of whether it can and should create a distinct rate class for cryptocurrency mining in Labrador, and, if so, what constraints should be imposed on services offered to that rate class.

APPENDIX A

EXCERPT FROM CONTRACT BETWEEN A DATA CENTRE AND A MUNICIPAL DISTRIBUTOR IN QUÉBEC[94]

(unofficial translation)

Article 2 : Identification

The parties expressly recognize the validity of the following data, for purposes of the application of the present agreement :

- Business identification number:
- Maximum Allocated Capacity: _____ kVA
- Capacity Reserved for Data Centre: _____ kW
- Capacity Reduction ("Capacité d'abandon de puissance"): 95% of the Capacity Reserved for Data Centre
- Number of Hours for Capacity Reduction: 400 hours annually
- Address of the Data Centre:

Article 6: Supply Constraint

For purposes of the present agreement, the term "Maximum Allocated Capacity" means the percentage of the Capacity Reserved for Data Centre that may be interrupted in whole or in part upon request of the City.

In order to have access to the specified capacity, the Client commits to respect the obligation to reduce a part of its capacity, in accordance with the Capacity Reduction defined in Article 2.

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[94] The original document can be found at http://publicsde.regie-energie.qc.ca/projets/457/DocPrj/R-4045-2018-C-AREQ-0085-Audi-Autre-2018_11_08.pdf.

To do so, the Client must offer an electronic communications interface in order to modulate the reduced capacity or un automatic system for breaking the circuit with the possibility of an interface controlled by the City.

In the event of the Client's failure to respect a Capacity Reduction request formulated by the City, the Client agrees and accepts that the City may cut the electric supply of the data centre, in real time and without advance notice. In such a case, the City shall however respect the Number of Hours for Capacity Reduction specified in Article 2.

The City commits to inform the Client, to the extent possible, when it intends to carry out a Capacity Reduction by virtue of this article.

APPENDIX B

"Energy research for a sustainable future"

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PROFESSIONAL EXPERIENCE

1996- **HELIOS Centre, Executive Director (since 2004)**

An independent, non-profit research organization dedicated to the analysis of energy regulatory or investment options and the design of strategies and policies for the sustainable use and development of energy resources. Responsible for management and development of the Helios Centre, direction of its publication Enjeux-ÉNERGIE (2004-2007), and consulting activities.

Selected projects:

- ***Régie de l'énergie:*** Expert testimony on behalf of the Regroupement national des conseils régionaux de l'énvironnement du Québec (RNCREQ), l'Union de consommateurs, the Fédération des commissions scolaires du Québec, and other groups (including the Groupe de la charge locale), in hearings concerning:
  - Hydro-Québec Distribution's avoided costs (R-4057-2018);
  - Hydro-Québec's transmission tariff (R-3401-98, R-3493-04, R-3605-06; R-3549 phase 2, R-3640-07 and R-3669-08 phase 1; R-3669-08 phase 2 (harmonization with Order 890); R-3738-10);
  - the framework agreement between HQ-Production and HQ-Distribution (R-3622-06),

- the need for a balancing contract for wind energy (R-3550-04 and R-3648-07),
- Hydro-Québec's security of supply (concerning its resource plans R-3470-01 and R-3550-04, its interruptible tariffs in R-3518, and its Suroît project in R-3526-04),
- Hydro-Québec's energy efficiency plan and avoided costs (R-3473, R-3519 and R-3708-09),
- sustainable development criteria (R-3525-04), and
- acquisition of power from small hydro developers (R-3410).

- ***Commission of Inquiry Respecting the Muskrat Falls Project:***
  - Testimony with respect to project justification and water management
- ***Newfoundland and Labrador Public Utilities Board:***
  - Expert testimony on behalf of Labrador Interconnected Group, NL Hydro, 2017 General Rate Application and related matters (2017-)
  - Expert testimony on behalf of Innu Nation, NL Hydro, Amended General Rate Application 2013 (2014-2015)
  - Expert testimony on behalf of Grand Riverkeeper, Muskrat Falls Inquiry (2012)
- ***Manitoba Public Utilities Board:***
  - Expert testimony on behalf of Assembly of Manitoba Chiefs, Manitoba Hydro General Rate Application 2017/18 and 2018/19, before the Manitoba Public Utilities Board (2017 -)
- ***British Columbia Utilities Commission:***
  - Expert testimony on behalf of the BC Sustainable Energy Association and Sierra Club BC, Fortis BC Rate Design Proposal, before the BC Utilities Commisison (2018)
  - Submissions on behalf of the University of British Columbia Program on Water Governance, Site C Inquiry (2017)
- ***University of British Columbia — Program on Water Governance:***
  - Reassessing the Need for the Site C Hydroelectric Project (2017)
- ***Small hydro producers:***
  - Expert litigation support in confidential arbitration proceedings with respect to avoided costs (2016 – 2017)

* ***NEB Modernization Expert Panel:***
  * Critical review of the NEB's role in electricity regulation and energy information on behalf of the Front commun pour la transition énergétique *(2017)*
* ***Peace Valley Landholders' Association:*** Expert affidavit in injunction proceeding *(2016)*
* ***Treaty 8 Tribal Association:***
  * Expert affidavits in support of judicial review and injunction applications *(2014 - 2015)*
  * Expert testimony in the Environmental Assessment of the Site C Hydroelectric Project *(2013 - 2014)*
* ***Grand Riverkeeper Labrador :*** Expert testimony on the justification for the proposed Lower Churchill Project (2011); Testimony before the Public Utilities Board of Newfoundland and Labrador regarding the Muskrat Falls Reference (2012); Affidavit In support of Federal Court File No. T-2060-11 (judicial review of Joint Panel Report (2012); Comments on the justification of the proposed Labrador-Island Transmission Link (2012)
* ***Technocentre éolien* –** Étude sur l'énergie éolienne et les exportations d'électricité (2014)
* ***Low Power Rates Alliance:*** Expert testimony before the Nova Scotia Utility and Review Board concerning the compliance filing of NSPI *(2013)*
* ***CanWEA (Canadian Wind Energy Association):***
  * Expert testimony before the Nova Scotia Utility and Review Board concerning the proposed Maritime Link and related agreements.
  * Study on rate impacts of wind energy in Quebec (*L'impact de l'énergie éolienne sur les tarifs d'Hydro-Québec Distribution)* (2013)
* ***Canmet ÉNERGIE:*** Review of regulatory policies relevant to Smart Grid development in Canada's provinces and territories (2012)
* ***Natural Resources Defence Council :*** Power supply issues concerning the Champlain Hudson Power Express (2010)
* ***SPG Hydro inc. :*** Market study on in-stream hydropower *(Étude de marché sur la filière de l'hydrolienne fluviale) (2008)*
* ***Service d'actions entrepreneuriales Manicouagan :*** Étude sur les coûts de revient de la nouvelle filière de l'hydraulienne fluviale. *(2008)*
* ***Communauté innue d'Ekuanitshit :*** Conseils sur les enjeux énergétiques et économiques du Complexe La Romaine *(2008)*

* ***Groupe Pacific:*** Electric supply options for a new residential community on Montreal Island. *(2008)*
* ***Hydro-Québec / ACDI / Électricité d'Haïti:*** Études sur le potentiel et la mise en œuvre des énergies renouvelables en Haïti
    - Survol des technologies d'énergie renouvelable et technologies d'appoint (2007)
    - Options pour l'intégraiton des énergies renouvelables dans le réseau de Jacmel *(2007)*
* ***Centre local de développement Manicouagan:*** Étude sur les coûts de l'Entente entre le gouvernement du Québec et Alcan *(2007)*
* ***Association québécoise des consommateurs industriels d'électricité:*** Étude sur l'évolution des prix disponibles sur les marchés d'exportation d'Hydro-Québec Production *(2007)*
* ***Latin American Energy Organization (OLADE):*** Competition in Energy Markets: An Analysis of the Relevance of North American Experiences to the Latin American and Caribbean Region. Project leader and principal consultant (with Peter Bradford). Project includes an in-depth review of the impact on restructuring on electricity and natural gas consumers in the U.S. and Canada, with an emphasis on regulatory policy concerning transmission, guidance and oversight of case studies of electricity restructuring experience in Brazil, Chile, Peru and Trinidad and Tobago, and the development of policy guidelines to regulate energy markets in the public interest in Latin America and the Caribbean. *(2003 - 07)*
* ***Law Offices of Scott Hempling* (Washington, D.C. law firm specializing in energy regulatory matters):** Senior policy advisor. *(2005-06)*
* ***Hydro-Québec, Direction Réseaux Autonomes:*** Renewable energy potential in off-grid communities *(2005-06)*
* ***National Grid USA: Economic Development and Environmental Imacts of Narragansett Electric's Energy Efficiency Programs:*** Analysis of avoided cost component (for the Goodman Group) *(2006)*
* ***Cree Nations of Nemaska, Waskaganish and Chisasibi:*** Comments on the Justification of the Eastmain -1A/Rupert Diversion Project *(2006)*
* ***Cree Nation of Nemaska:*** Advice concerning wind energy development and community energy planning (*2005-06)*
* ***Canadian Wind Energy Association:*** Submission to the Ontario Power Authority's Supply Mix Consultation (with Hélimax Énergie inc.) *(2005)*

* ***National Roundtable on the Economy and the Environment:*** Background paper on the role of hydropower in a carbon-constrained energy future for Canada *(2005)*

* ***Federal Review Commission, Eastmain 1A/Rupert Hydroelectric Project:*** *Report on the conformity of the Eastmain 1A/Rupert Environmental Impact Study, with respect to project justification (2005)*

* ***Institut d'énergie et de l'environnement de la Francophonie (IEPF):*** Editorial supervision and co-author, *Mettre en Place Une Autorité Nationale Désignée pour le MDP: Pourquoi et Comment?,* presentation at COP-11 in Montreal; Profiles of the Clean Development Mechanism potential of the developing countries in the Francophonie (with Helios staff). Presentation at COP-10 in Buenos Aires. *(2004)*

* ***Mushkegowuk Council (Ontario):*** Critical review of power supply options (including transmission upgrades) for De Beers' Victor diamond mine (CEAA environmental assessment process). *(2004)*

* ***Pemex – Refinación:*** Co-facilatator with Jay Ogilvy and Napier Collyns of Global Business Network of a strategic planning scenario workshop for the company's management. *(2004)*

* ***Nuclear Waste Management Organization:*** Expert participant in inter-disciplinary scenarios team for long-term management of high-level reactor waste in Canada. *(2003)*

* ***Energy Foundation:*** Proposed eligibility criteria for hydropower in the New York State Renewables Portfolio Standard. *(2003)*

* ***Low Impact Hydropower Institute:*** Principal consultant for pilot project to develop an international green standard for small-scale hydropower, funded by North American Fund for Environmental Cooperation. *(2002-03)*

* ***Commission for Environmental Cooperation:*** Expert reviewer for *Environmental Challenges and Opportunities of the Evolving Continental Electricity Market. (2002)*

* ***Pimicimak Cree Nation:*** Research on hydropower mitigation costs and operations reviews. *(2002)*

* ***Hydro-Québec-Recouvrement/ARC/CACQ/FACEF :*** Review of low-income customer assistance programs in U.S. *(2001)*

* ***International Rivers Network:*** Commissioned book-length study: *Restructured Rivers: Hydropower in the Era of Competitive Markets*. *(2001)*

* ***Low Impact Stakeholders Alliance (Ontario):*** Options paper on environmental rating of electricity; consultations on certification of hydroelectric facilities for green power market. *(2000-01)*

* ***Innu Nation (Labrador):*** Overview of Quebec and U.S. energy policy issues. *(2000)*

* ***Grand Council of the Crees (of Quebec) :*** Orientations for a Cree Energy Policy *(2009)*

  Drafting project justification section of *Draft Directives for the Preparation of the Impact Statement for the Eastmain-1A and Rupert Diversion Project* (for COMEV, the tripartite Evaluating Committee under the JBNQA). *(2003)*

  Expert testimony before U.S. Court of Appeal (D.C. Circuit) on role of exports in Hydro-Québec planning; technical analysis for FERC consultation on Regional Transmission Organizations and for the World Commission on Dams. *(1999)*

  Assistance in preparation of technical affidavits submitted to the Federal Energy Regulatory Commission concerning the application by Hydro-Québec U.S. Inc. for energy marketer status. *(1997)*

* ***HéliMax Inc. :*** Report on the Implications of the Kyoto Protocol for Renewable Energy Projects in Developing Countries (1999)

* ***World Bank:*** Critical review of French translation of *Environmental Assessment Sourcebook,* chapter on economic analysis of projects and policies. (*1999*)

* ***Option consommateurs :*** Study on traditional and incentive ratemaking approaches in electricity regulation (1998)

  Study on electricity market restructuring options and rate impacts. *(1997)*

* ***Standing Committee on the Economy and Labour, National Assembly of Quebec:***

  Analysis of Hydro-Québec's Strategic Plan 2000-2004. *(2000)*

  Analysis of Hydro-Québec's Strategic Plan in relation to the Committee's June 1997 recommendations; drafting of questions. *(1998)*

  Expert assistance in oversight hearings concerning Hydro-Québec, especially with respect to market restructuring and energy efficiency, including drafting introductory texts, seminars with committee members, drafting report. *(1997)*

* ***Rivers Canada :*** Preliminary study on the implications of the restructuring of electricity markets in North America for the preservation of Canada's rivers. *(1997)*

* ***Quebec Forestries Industries Association:*** Workshop on electricity market restructuring and competition, and their impacts on Quebec electricity rates, energy efficiency and biomass generation. *(1997)*

* ***Averyt and Associates (for Green Mountain Power) :*** Report on Native issues in the context of Quebec energy policy. *(1996)*

* ***Ad hoc working group of American and Canadian environmental groups :*** Design of legislative mechanisms to reduce the environmental impacts of electricity restructuring. *(1996)*

1995- **Independent energy analyst**

Environnement Jeunesse *(1996-97)*

Representative at the *Commission of inquiry into Hydro-Québec's purchase policy for private producers.*

Université de Montréal *(1995)*

Coordination of a lecture series on *Energy and Resources at the Dawn of the 21st Century.* Lectures by David Freeman (then CEO of New York Power Authority), Allen Kupcis (CEO of Ontario Hydro) and Victoria Yegorova (Donetsk Research Institute, Ukraine).

Government of Québec: Natural Resources Department *(1995)*

Study on approach used for the regulation of energy in British Columbia and on the interest of this model for Quebec, published for the Quebec Public Debate on Energy.

Government of Canada: Environment Department *(1995)*

Quebec chapter of a study on the treatment of externalities (social costing methodologies) in Canada, under subcontract from Passmore Associates.

Grand Council of the Crees (of Québec) *(1995-)*

Expert assistance on costs and benefits of different generating technologies, alternative solutions, and methodologies for taking externalities into account in competitive energy markets.

1992-95 **Deputy Scientific Coordinator**
Great Whale Public Review Support Office

- Member of the support staff for the committees and commissions responsible for the assessment of the Great Whale project.
- Responsible for analyses concerning project justification.
- Drafting of preparatory documents and preliminary versions of reports; selection and oversight of consultants.

- Co-author, with James Litchfield and Roy Hemmingway, of a study on integrated resource planning and its application to the project.
- Editor of study on mitigation measures at the La Grande hydroelectric complex.
- Assisted in editing and publishing of 9 other studies on issues related to the project (mercury, dam safety, traditional ecological knowledge, etc.)
- Involved in designing, planning and carrying out all aspects of the public review process.

1987-92 **Freelance science journalist**

- Articles on energy, science and medicine in *Science*, *The New Scientist, The Medical Post* and other specialized publications.

ÉDUCATION

1976 M. Music (performance), Boston University

1974 B.A., *cum laude*, in philosophy, Yale University. Minor in biological sciences.

LANGUAGES

- **English, French and Spanish** (written and spoken fluently)
- **German and Italian** (limited comprehension)

CONFERENCE PRESENTATIONS

Integrated Resource Planning and the Site C Project: Implications for Newfoundland and Labrador, Muskrat Falls Public Symposium, Labrador Institute, Happy Valley – Goose Bay, Labrador, Thursday, February 22, 2018.

Present Value Analysis of the Site C Hydroelectric Project. Presentation to British Columbia Utilities Commission, Site C Inquiry, Technical Session, October 14, 2017.

Rencontre expert sur les surplus d'électricité. Commission sur les enjeux énergétiques du Québec. Montréal, le 21 octobre 2013.

Greenhouse gas emissions and hydropower. 13th Annual Waterkeeper Alliance Conference, Northwestern University, Evanston, Illinois, June 24, 2011.

Invited testimony, Senate Standing Committee on Energy, the Environment and Natural Resources. February 2011.

La filière hydrolienne : Une introduction. AQPER Colloque — Québec: Carrefour des énergies renouvelables octobre 2009.

L'avenir énergétique au Québec et ailleurs : structures institutionnelles et les nouvelles technologies d'énergie verte. Réseau des ingénieurs du Québec, Congrès annuel des ingénieurs, 25 novembre 2008.

Tarification sur la base des coûts, ou des coûts d'opportunité ? Réplique au Groupe de travail sur la tarification des services publics (Groupe Montmarquette), Forum québécois sur l'électricité, 14 mai 2008.

La filière de l'hydraulienne fluviale : un premier regard sur les coûts, Ocean Renewable Energy Group, Spring Symposium, Canada's Ocean Energy Future: New Partnerships and Wider Opportunities, Québec, 21 avril 2008 (à venir).

Les coûts de l'Entente Alcan: un deuxième regard, Conférence sur le développement durable dans l'industrie de l'aluminium (Céddi-AL), Baie-Comeau, Québec, September 20, 2007.

The Restructuring of North American Energy Markets, Seminario regional de OLADE sobre el future de los mercados energéticos en Latinoamérica y el Caribe, Buenos Aires, March 8, 2007.

Des monopoles aux marchés concurrentiels : Implications environnementales de la restructuration des marchés, 3e conférence internationale sur la mise à niveau environnementale : Entreprise et économie d'eau et d'énergie, CITET, Tunis, le 8 décembre 2006.

Technologies émergentes de production d'électricité, AQPER Colloque sur l'énergie éolienne … et autres énergies vertes30 octobre 2006.

politiques européennes sur les énergies renouvelables, l', 9 juin 2006.

L'application conjointe : un outil méconnu mais prometteur, Les énergie traditionnelles, les énergies nouvelles, les énergies de demain », November 4, 2005.

La sécurité énergétique et les sources alternatives de production d'énergie : oui mais à quel prix ? », (Montreal, April 18, 2005).

« Le MDP dans la Francophonie: Fiches d'information sur le potentiel et les opportunités dans les pays de la Francophonie », présentation aux représentants de la Francophonie en marge de 10e Conférence des parties de la Convention sur le climat (Buenos Aires, December 2004).

"Toward an International Green Standard for Small-Scale Hydropower, ," World Renewable Energy Conference, Denver, Colorado (September 2, 2004).

"The Role of Hydropower in Green Power Markets," Ontario Green Power Trade Show, (Toronto, Oct. 2002)

"Creating Value by Working with NGOs," HydroVision (Portland, Oregon, August 2002)

"Quebec Energy Policy," Environmental Law McGill Forum on James Bay and Sustainable Development (Montreal, March 2002)

"Approaches to Green Power Certification," Ontario Green Power Trade Show, (Toronto, Nov. 2001)

Guest Lecturer, Hydropower and Sustainable Energy Policy, Yale School of Forestry and Environmental Sciences, FES 850b (Energy Policy and Environmental Protection, 2001-02)

North American Commission for Environmental Cooperation, Symposium on Understanding the Linkages between Trade and the Environment (discussant). (Washington, D.C., October 2000)

Harvard Electricity Policy Group, Special Session: Retail and Wholesale Transmission Markets: Can They Be Unified? Defining the Issues and the Ramifications (Invited participant) (Washington, D.C., March 19, 1999)

Ontario Low Impact Stakeholders' Alliance, Public Workshop, *Environmental Ranking of Hydropower Facilities in Canada*. (Toronto, May 2000)

Canadian Association of Members of Public Utility Tribunals, annual meeting. Lecture on the implications of electricity deregulation for the evironment. (1997, *Whistler, B.C.)*

National Forum on Markets, Regulation and the Future for Canadian Energy Utilities. Talk on IRP in a competitive market. (1995, *Whistler, B.C.*)

Quebec Public Debate on Energy : presentations on the application of integrated resource planning in the Quebec context and on resource portfolio analysis. (1995, *Montreal*)

COMMITTEES, BOARDS AND AWARDS

2015 Finalist, R.J. Templin Award (CanWEA)

2010- Choeur de chambre Tactus, Board of Directors (Chair)

1999- Low Impact Hydropower Institute, Renewable Markets Advisory Panel (Chair 2003-)

1997- Helios Centre, Board of Directors (Vice President and Secretary)

2009-10 Ecologo Advisory Committee, Renewable Low-Impact Electricity

2008 Expert Review Panel, National Centres for Excellence, Centres of Excellence for Commercialization and Research (CECR).

2007-08 Comité d'Experts francophones, Stratégies nationales de développement durable des pays africaines, Délégation au développement durable de la France.

2005 Conseil de la science et de la technologie du Québec, Groupe de travail sur les défis en énergie.

2004-05 Quebec Climate Change Action Centre, Advisory Committee

2003-04 National Roundtable for Energy and the Environment, Ecological Fiscal Reform and Energy Program, Advisory Committee on Energy Efficiency

1995-98 Working Group on Methodology, Focalisation, Evaluation and Scope of Environmental Impact Assessment (NATO *Committee on Challenges to Modern Society*)

1995-97 Environnement Jeunesse, Board of Directors

PUBLICATIONS

ACADEMIC AND TECHNICAL PRESS

Hendriks, R., Raphals, P., Bakker, K. and Christie, G. (2017) First Nations and Hydropower: The Case of British Columbia's Site C Dam Project, Items (SSRC) (items.ssrc.org).

Christie, G., Hendriks, R., Raphals, P. and K. Bakker (2017) Site C: It's not too late to hit pause. *Policy Options,* April 19, 2017.

Hendriks, R., Raphals, P. and K. Bakker (2017) Reassessing the Need for Site C. Program on Water Governance, University of British Columbia: Vancouver.

P. Raphals and R. Hendriks, Towards a Sustainable Low-Carbon Electric System: Challenges and Opportunities, in Potvin, C., et al. (eds.), *Acting on Climate Change: Extending the Dialogue Among Canadians,* UNESCO-McGill Chair for Dialogues on Sustainability, 2015 (in press).

P. Raphals and R. Hendriks, Vers un système électrique sobre en carbone et durable : défis et opportunités, in Potvin, C., et al. (eds.), *Agir sur les changements climatiques : vers un dialogue elargi à la societe civile canadienne,* UNESCO-McGill Chair for Dialogues on Sustainability, 2015 (in press).

P. Dunsky and P. Raphals, Challenges for Effective Competition in Large Hydro-Dominated Markets — The Case of Québec, in Zaccour, Georges (ed.), *Deregulation of Electric Utilities*, (Boston : Kluwer Academic Publishers), 1998

P. Dunsky and P. Raphals, « Pour une fiabilité énergétique accrue — Quelques leçons à tirer de la récente tempête de verglas », in L'Énergie au Québec : Quels sont nos choix? (Montréal : ÉcoSociété, 1998), pp. 85-98.

P. Raphals and P. Dunsky, Ouverture des marchés de l'électricité au Québec — Modèles, impératifs d'une réelle concurrence et implications pour les prix globaux, Option consommateurs, October 1997

M.A. Bouchard and P. Raphals, *Mécanismes et méthodologies d'évaluation d'impacts dans le cadre de la restructuration du marché de l'électricité*, Association québécoise pour l'évaluation des impacts, June 1997

■ TESTIMONY

Bélanger, J. et Raphals, P. (14 janvier 2019). Demande relative au Plan directeur de Transition Énergétique Québec : L'approbation des programmes et mesures sous la responsabilité des distributeurs — Rapport d'analyse, on behalf of Option Consommateurs and the RNCREQ, dossier R-4043-2018 de la Régie de l'énergie.

Raphals, P. (1er novembre 2018). Analyse du Programme proposé sur l'Usage cryptographique appliqué aux chaînes de blocs, on behalf of RNCREQ, dossier R-4045-2018 de la Régie de l'énergie.

Cormier, P. et Raphals, P. (22 août 2018). Programme GDP Affaires, on behalf of RNCREQ, dossier R-4041-2018 de la Régie de l'énergie.

Raphals, P. (July 2018). Moratoria Applied to Cryptocurrency Loads in Low-Cost Jurisdictions, on behalf of the Labrador Interconnected Group, regarding an application by NLH for temporary service in Labrador West, before the Newfoundland and Labrador Public Utilities Board.

Raphals, P. (July 2018). Expert Testimony on the Fortis BC Rate Design Proposal, on behalf of the BC Sustainable Energy Association and Sierra Club BC, before the British Columbia Utilities Commission.

Cormier, P. and Raphals, P. (22 août 2018). Programme GDP Affaires : Rapport d'analyse externe, on behalf of the RNCREQ, dossier R-4041-2018 de la Régie de l'énergie.

Raphals, P. (December 2017). Commentaires sur le dossier tarifaire 2017-2018 d'Hydro-Québec Distribution : Stratégie tarifaire et Mesurage net, on behalf of the RNCREQ, dossier R-4011-2017 de la Régie de l'énergie.

Raphals, P. (December 2017). Comments on the 2017 General Rate Application of Newfoundland Labrador Hydro, on behalf of the Labrador Interconnected Group.

Raphals, P. (October 2017). Implications of Manitoba Hydro's General Rate Application, on behalf of the Assembly of Manitoba Chiefs.

Raphals, P. and Hendriks, R. (October 2017). An Updated Present Value Cost Analysis of the Site C Project, submitted to the BCUC Site C Inquiry on behalf of the University of British Columbia Program on Water Governance.

Raphals, P. and Hendriks, R. (August 2017). Submission to the British Columbia Utilities Commission regarding the Site C Hydroelectric Project, on behalf of the University of British Columbia Program on Water Governance.

Les achats de court terme d'Hydro-Québec Distribution, rapport d'analyse externe préparé pour le RNCREQ dans le cadre du dossier R-3986-2016 de la Régie de l'énergie du Québec, sur le Plan d'approvisionnement 2017-2026 d'HQ Distribution, 4 avril 2017.

Avis de la Régie de l'énergie sur les mesures susceptibles d'améliorer les pratiques tarifaires dans le domaine de l'électricité et du gaz naturel, Rapport d'analyse externe pour le RNCREQ, dossier R-3972-2016 de la Régie de l'énergie, 18 janvier 2017.

Costs and benefits to ratepayers of delaying the construction and commissioning of the Site C Hydroelectric Project, expert testimony submitted to the Supreme Court of British Columbia in reply to an injunction proceeding, February 11, 2016.

Commentaires sur le dossier tarifaire 2016-17 d'Hydro-Québec Distribution, Régie de l'énergie du Québec, témoignage pour le RNCREQ, Régie de l'énergie du Québec, R-3933-2015, 10 novembre 2015.

Costs and benefits of delaying the construction and commissioning of the Site C Hydroelectric Project, expert testimony submitted to the Supreme Court of British Columbia in support of a judicial review petition and injunction application of the Prophet River and West Moberly First Nations, July 7, 2015.

Comments on the Amended 2013 General Rate Application of Newfoundland Labrador Hydro, expert testimony submitted to the Public Utilities Board of Newfoundland and Labrador on behalf of the Innu Nation, June 23, 2015.

Bénéfices potentiels des compteurs « intelligents » pour répondre aux besoins en puissance, Régie de l'énergie du Québec, R-3864-2013, Plan d'approvisionnement d'Hydro-Québec Distribution, pour le RNCREQ, 21 mai 2014.

Comments on the 2013 General Rate Application of Newfoundland Labrador Hydro, expert testimony submitted to the Public Utilities Board of Newfoundland and Labrador on behalf of the Innu Nation, April 28, 2014

Response to BC Hydro Rebuttal Evidence, submitted to the Joint Review Panel for the Site C Hydroelectric Project on behalf of the Treaty 8 Tribal Association, January 18, 2014

Need for, Purpose of and Alternatives to the Site C Hydroelectric Project, submitted to the Joint Review Panel for the Site C Hydroelectric Project on behalf of the Treaty 8 Tribal Association, November 25, 2013.

Conformity of the Maritime Link Compliance Filing with the NSUARB Condition Concerning Market-Priced Energy, expert testimony submitted to the Nova Scotia Utility And Review Board on behalf of the Low Power Rates Alliance, November 7, 2013.

Comments on the Proposed Maritime Link Project, expert testimony submitted to the Nova Scotia Utility and Review Board on behalf of the Canadian Wind Energy Association (CanWEA), April 17, 2013.

Comments on the Justification for the Lower Churchill Transmission Project (Labrador-Island Transmission Link), submitted to the Canadian Environmental Assessment Agency — Comprehensive Study on the Lower Churchill Transmission Project and to the Government of Newfoundland and Labrador, Department of Environment and Conservation, expert testimony on behalf of Grand Riverkeeper Labrador Inc., June 12, 2012.

Demande d'approbation du Projet de Lecture à Distance, Phase I d'Hydro-Québec Distribution, Régie de l'énergie du Québec, R-3770-2011, *Mémoire* du RNCREQ (with Christian Martel), December 6, 2012.

Expert Testimony before the Public Utilities Board of Newfoundland Labrador on the Muskrat Falls Reference, February 23, 2012.

Affidavit before the Federal Court of Canada concerning the judicial review of the Joint Panel Report on the Lower Churchill Generation Project (Court File No. T-2060-11), February 1, 2012.

Comments on the Justification for the Lower Churchill Generation Project, submitted to the Joint Review Panel for the Lower Churchill Generation Project, on behalf of Grand Riverkeeper Labrador Inc., February 28, 2011.

La politique d'ajouts : L'application du concept de neutralité tarifaire à la Charge Locale (Témoignage expert pour UC, ACEFO, FCEI, UMQ et ACEFQ), Régie de l'énergie du Québec, R-3738-2010, 15 novembre 2010.

La modification des Tarifs et conditions de TransÉnergie en fonction de l'Ordonnance 890, Régie de l'énergie du Québec, R-3669-08 phase 2 (témoignage expert pour le RNCREQ et UC), 15 juin 2009 ; v. rév. 23 sept. 2010.

La proposition du Transporteur concernant les Services de compensation des écarts de livraison et de réception, Régie de l'énergie du Québec, R-3669-08 phase 2 (témoignage expert pour le RNCREQ et UC), 19 juin 2009 ; v. rév. 23 sept. 2010.

Les coûts évités d'Hydro-Québec Distribution, Régie de l'énergie du Québec, R-3708-09 (témoignage expert pour le RNCREQ), 3 novembre 2009.

La tarification des Services de compensation des écarts de livraison et de réception, Régie de l'énergie du Québec, Régie de l'énergie du Québec, R-3669-08 (témoignage expert pour le RNCREQ), 4 novembre 2008.

The Fixed Charge in Hydro-Québec Distribution's Domestic Rates, Régie de l'énergie du Québec, R-3677-08 (pour le RNCREQ), 28 octobre 2008.

L'énergie éolienne, l'équilibrage et la demande à la pointe, dans le contexte du contrat patrimonial, Régie de l'énergie du Québec, R-3648-07 (témoignage expert pour le ROEÉ et le RNCREQ), 28 mars 2008.

Reforming the rate structure to better reflect marginal costs : Comments on Hydro-Québec Distribution's 2008 Rate Proposal (Testimony of Jim Lazar, in collaboration with Philip Raphals), Régie de l'énergie du Québec, R-3644-07, October 30, 2007.

P. Raphals, Allocation of transmission costs in Hydro-Québec Distribution's 2008 rate filing, Régie de l'énergie du Québec, R-3644-07, October 30, 2007.

Commentaires sur la demande tarifaire 2008 d'Hydro-Québec TransÉnergie, Régie de l'énergie du Québec, témoignage expert pour le RNCREQ, Régie de l'énergie du Québec, R-3640-07, 15 octobre 2007 (en anglais).

Commentaires sur l'entente cadre 2006 entre Hydro-Québec Distribution et Hydro-Québec Production, Régie de l'énergie du Québec, R-3622-06, April 18, 2007.

TransÉnergie's *Tarifs et conditions*: comments concerning rates, discounts, interconnection costs and generation imbalance service, Régie de l'énergie du Québec, R-3549 phase 2, Expert testimony, October 18, 2005.

Implications pour Hydro-Québec Distribution de l'ajout des parcs éoliens en Gaspésie, Régie de l'énergie du Québec, R-3550-04, témoignage expert, May 25, 2005.

Témoignage expert sur la demande tarifaire 2005 de TransÉnergie, Régie de l'énergie du Québec, R-3549-04, 22 décembre 2004.

La contribution du projet Suroît à la sécurité des approvisionnements en électricité d'Hydro-Québec Production, Régie de l'énergie du Québec, R-3526-04, 22 avril 2004.

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OTHER ACTIVITIES

Professional cellist

Voces Boreales (a cappella chamber choir)