Review of Existing and Proposed Network Additions Policies for Newfoundland and Labrador Hydro

PREPARED FOR

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Executive Summary

A. Background

The Newfoundland and Labrador Board of Commissioners of Public Utilities ("Board") engaged The Brattle Group ("Brattle") to investigate utility and regulatory practices for network addition policies ("NAP") for new loads as it pertains to transmission interconnection and network upgrades. We have reviewed the utility and regulatory practices of several Canadian provinces and, in the U.S., we examined the relevant policies of the Federal Energy Regulatory Commission ("FERC") and several state Public Utility Commissions ("PUCs").

Based upon this review, as well as our expertise in economic, regulatory, and cost of service principles and practice, the Board requested that we evaluate and provide comments on a NAP proposal by Newfoundland and Labrador Hydro ("Hydro"). Under the current NAP, Hydro generally socializes transmission network upgrade costs, with the costs shared and allocated among all customer classes that use the transmission network upgrades according to Hydro's embedded cost of service.[1] Hydro's proposed NAP will result in the requesting customer bearing greater responsibility for the costs of actual or potential transmission network upgrades. As described by Hydro, the proposed NAP applies to: 1) transmission system extensions to connect new customers or non-utility generators; 2) demand requirement requests that may contribute to transmission network extensions or upgrades; and 3) contributions from customers requesting open access transmission service.[2]

From our review, we find that NAPs for new loads are guided generally by the dual principles of: 1) cost causation; and 2) non-discriminatory mandates to serve, with most NAPs emphasizing the principle of cost causation. For NAPs, the principle of cost causation requires that customers requesting interconnection or increasing their demand requirements are responsible for investments prompted by their request. Typically, it is the immediate or near-term investments prompted by a customer's request that serves as the basis of the costs the requesting customer is responsible for paying—*i.e.*, the investment that "but for" the customer's request would not be required. Following the cost causation principle ensures its corollary holds—the protection of existing customers from costs caused by new customers. A customer that pays for the costs that its actions have caused ensures that other customers are protected.

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1 For ease of discussion, we refer to the currently Board-approved cost of service methodology applied to the transmission system as the "current NAP." Hydro does not have an approved NAP currently.

2 Newfoundland Labrador Hydro, "Labrador Interconnected System Network Additions Policy: Summary Report," December 14, 2018.

A NAP that places greater weight on the non-discriminatory mandate to serve may emphasize the equal treatment of new and existing customers, and thus may not require new customers to bear the cost of network upgrades except for facilities that solely benefit the new customer. A secondary form of the non-discriminatory principle instead requires similar treatment for all new interconnecting customers and customers requesting increases in demand requirements.

Most of the surveyed Canadian jurisdictions adopt the general approach that interconnecting load customers are responsible for network upgrades, and, following the principles of cost causation, the interconnecting load customer is responsible for all costs above and beyond a certain threshold. The NAPs for the Alberta Electric System Operator, B.C. Hydro, Hydro-Québec, and New Brunswick Power require upfront payments from customers for the total cost of network upgrades net of credits to offset some or all of the upfront payment. B.C. Hydro and Hydro-Québec policies provide credits based on anticipated revenues. Similarly, New Brunswick Power charges interconnection customers an upfront capital charge to make up the difference between the incremental cost of service and the rolled-in rate. The Alberta Energy System Operator provides a credit related to the anticipated costs of the network interconnection.

The FERC provides philosophical guidance on the development of NAPs as it pertains to generation interconnections. Hydro's proposal applies to non-utility generation load as well and, thus, the FERC's NAP for generation is relevant to the issues facing Labrador. The FERC has an established policy for generator interconnections, which requires that interconnecting generators finance network upgrades (*i.e.*, pay upfront for network upgrades) with the financing costs credited back to generators over time. This treatment sends locational signals by requiring generators to finance the network upgrades upfront, hopefully resulting in economic choices in site selection. Concerning the question of what rates to charge the interconnecting customer for the use of the transmission network, FERC policy permits charging interconnecting customers the "higher of" embedded or incremental costs. If rolling in the network upgrade investment to the transmission revenue requirement results in lower overall rates to all customers from economies of scale, then the interconnecting customer will pay the same rate for using the transmission network as all other customers. Otherwise, the interconnecting customer's usage charge is related to the incremental costs of the network upgrade.

Regarding the treatment of data centers and cryptocurrency loads that are a driving force behind load growth in Labrador, other jurisdictions that have dealt with an influx of these customer types have developed specific rate classes for them that require a combination of interruptible tariffs and financing or full cost responsibility of network upgrades. For example, interruptible rates specifically for cryptocurrency customers have been developed by Hydro-Québec and two public utility districts ("PUDs") in the state of Washington. These rates require that cryptocurrency customers pay for the full cost of any network upgrades and are not eligible for reimbursements based on revenues received by the utility. In New York, the new high-density load customer ("HDL") rate requires that customers pay for network upgrades and are eligible for refunds over a 10-year time horizon based on demand-related revenues. The Hydro-Québec, Washington PUDs, and New York rate classes include rate increases relative to similarly-sized customers in non-cryptocurrency rate classes.

B. Current and Proposed NAP

In the context of the Labrador Interconnected System ("LIS"), we review the current NAP[3] and Hydro's proposed NAP primarily from the principles of: 1) cost causation; 2) non-discrimination between interconnection of new load types; and 3) rate stability and avoidance of rate shock. Under the current NAP, Hydro fully assesses the customer requesting services for the costs of the directly assigned facilities. This aspect of the current NAP is consistent with cost causation principles. In the context of network upgrades related to new customer loads on the system, however, the current NAP does not follow cost causation principles, a foundational characteristic of electricity and public utility costing and ratemaking. Under the current policy, Hydro socializes the costs of the network upgrades that are required to provide the requesting customer's service reliably, resulting in an inequitable cost allocation among customer classes. The policy imposes network upgrade costs on customers who did not cause the upgrade costs. The current NAP does not provide the correct economic signals to requesting customers because customers do not face the full costs of their decisions; instead, all ratepayers bear the network system upgrade costs. This component of the current NAP potentially leads to new customers requesting more services than are economically optimal, thus requiring Hydro to incur higher investment costs than are economically optimal. Under the current NAP, requesting customers do not take into account the full marginal cost of system upgrades when making requests for services. This situation creates the opportunity for them to "free-ride" off the backs of other customers.

The current policy does fare well in avoiding undue discrimination as it treats all customers uniformly. No customer is required to pay for the network upgrade costs that it causes, and all customers are required to pay for the dedicated facilities that their service requires. On the issue of rate stability and rate shock, the current policy does not fare well. Labrador's potentially substantial demand growth caused by the influx of data centers/cryptocurrency customers may result in significant rate increases to all customer classes.

We have reviewed and assessed Hydro's proposed NAP. Hydro's proposed NAP is an improvement over the current system and a move in the right direction. Nevertheless, we believe there can be further improvements that will balance more fairly the competing regulatory and cost of service interests such as cost causation principles, prevention of undue rate discrimination and rate stability, and prevention of rate shock.

Hydro's proposed NAP for network upgrade facilities separately treats: 1) customers less than 200 kW; 2) customers between 200 kW and 1,500 kW; and 3) customers more than 1,500 kW. For customers less than 200 kW, there are no upstream contribution requirements (*i.e.*, network upgrade charges). For customers between 200 kW and 1,500 kW, the upstream contribution requirement—the Upstream Capacity Charge ("UCC")—is based upon the expansion cost per kW—an estimate of the *potential* transmission upgrades on the LIS that are not reflected in the Transmission Expansion Plan. For customers with maximum demands exceeding 1,500 kW

[3] See footnote 1.

potentially, Hydro conducts a detailed system impact review process. If, as a result of the request, an acceleration of the Transmission Expansion Plan is necessary, the customer is responsible for the costs of accelerating the investments minus the "benefits" to existing customers from the advancement. Those benefits are valued based on the accelerated investment's reduction in expected unserved energy ("EUE"). If no acceleration of the Transmission Expansion plan is identified, then the UCC is determined using the same expansion cost per kW estimate as for customers between 200kW and 1,500 kW.

In our opinion, while Hydro's proposal is an improvement in respect of cost causation principles, it remains deficient in that area in some key respects. One concern is that the upstream connection charges do not tie sufficiently to the actual, immediate investment cost needed to provide the requesting services. Specifically, the upstream contribution requirement is based on the expansion cost per kW, which is an estimate of the costs of a *potential* transmission upgrade that is significantly out in the future. Almost by definition, the expansion cost per kW is not a near-term investment determination, as it is based on the requirements to serve anticipated load levels, levels that go beyond 2043. When the addition of new customers does not create a need for new shared investments, the new customers are required to pay an expansion cost based on potential future investments identified by Hydro. This approach functionally "banks" funds from new customers to fund future investments that may, or may not, be required. While this funding approach protects existing customers to the extent that it produces funds to pay for future lumpy investments, it violates the principle of cost causation. Following the cost causation principle, new customers should be assigned costs using a "but for" approach that identifies the investments that "but for" the customer's request would not have been required and for which the requesting customer is causally responsible.

For customers greater than 1,500 kW and their upstream connection charges, this approach is problematic as it is less bound to the actual costs that Hydro will incur to provide a customer with service. Specifically, the acceleration of the transmission plan can occur long out into the future—much greater than ten years—in which case Hydro would not incur any out of pocket costs until significantly far into the future. That is, for a request that causes an acceleration that takes place twenty years in the future, a customer could face a connection charge today even though Hydro would neither make any investments until twenty years into the future nor would there be any cost of service implications until twenty years into the future.

In this sense, the policy generally fails to reflect cost causation principles adequately. It distorts the price signal that the requesting customer receives and biases that customer's decision-making, as the customer may be asked to pay for costs that its decision did not cause under a "but for" criterion. This policy could result in some potential customers deciding not to request service even though the value they would obtain from the service would be greater than the cost of the request. Other customers would have been better off having the customer take service from Hydro as Hydro's common costs would be shared among a larger group of customers.

At the same time, for those requests that require advancement much closer to the present, the proposed Hydro NAP creates more risk to existing customers than several other load NAPs reviewed because requesting customers are required only to pay for a fraction of total investment costs. Specifically, Hydro's NAP proposal requires the payment of, at most, the full cost of *advancing* the investment rather than the full cost of the investment.

From the jurisdictions surveyed, we find evidence that Hydro's proposed NAP approach is not a common one and would not fall under regulatory best practices. We find the approach that all requesting customers must pay an upstream connection charge even if there are no network upgrade costs required and Hydro "banking" the funds until they are needed to be uncommon in our survey of jurisdiction's NAPs.

C. Summary of Recommendations and Comparisons

We have four recommendations concerning the proposed NAP:

1. We recommend modifying the NAP to reflect more completely the goal of cost causation. We recommend that new and requesting load over a size threshold be given a choice to either pay for the necessary network upgrades or choose an interruptible rate. Specifically, we recommend the following high-level choices:

   - Option A: Be financially responsible for the network upgrades that exceed the customers' anticipated revenues over some fixed period and providing security equal to the anticipated revenues;

     or

   - Option B: Adopt an interruptible rate, which avoids those transmission costs. This choice requires assessing the appropriate level of curtailability/interruptibility to ensure that existing customers do not experience any reduction in the current reliability level.

2. For customers that select Option A (accepting financial responsibility for network upgrades), we recommend a policy of holding existing customers fully harmless from the effects of the new load on Hydro's costs. The requirement for customers to pay for the cost of upgrades that exceed anticipated revenues provides protections to existing customers by offsetting rate increases due to increases in rate base. It only partially achieves the hold harmless goal because it leaves uncertain full cost recovery for customers with significant mobility capabilities. Requiring backing the anticipated revenues by a financial security eliminates this uncertainty of whether existing customers are held harmless. The financial security would be decreased based on the customer's actual revenues until fully refunded. The requirements to pay for network upgrades exceeding anticipated revenues and providing security equal to the anticipated revenues would provide greater protection for customers than the existing or proposed policy.

3. For customers that select Option A, we recommend that the required network upgrades should be determined on a "but for" basis through a system integration study of the current system structure, not on a forecasted basis, again to reflect the principle of cost causation.

4. For customers that select Option A, these customers paying for network upgrades should be eligible for additional refunds as additional customers join the system over a pre-determined time horizon. This permits sharing among new customers of network upgrade costs.

Altogether, our four recommendations allow customers to select the most economical rate for their needs by allowing customers to either adopt curtailable/interruptible rates or pay for network upgrades while emphasizing the principles of cost causation and holding existing customers harmless.[4] In Figure 1 below and in the text that follows, we summarize our recommendations for a new NAP relative to Hydro's proposal.

Figure 1: Comparison of Key NAP Recommendations

Guiding Principle	Hydro Proposal	Recommendations
Determination of Upgrade Costs	Acceleration of transmission plan or expansion costs based on potential future investments	"But for" analysis comparing the current system to the system with the new or additional load or generator
Inclusion of Interruptible Rate Option	No	Yes
Policy Differentiation Based on Size	Yes, customers are divided into three categories: • Customers ≤ 200 kW • Customers between 200kW and 1,500 kW • Customers ≥ 1,500 kW	Yes, no specific size recommendation
Refunds Provided for Additional Customer Connections	Yes, the original customer may be eligible for a refund if additional customers connect within ten years	Yes, no specific time horizon recommendation
Credit for Anticipated Revenues	No, except industrial customers	Yes, with security provided to ensure no harm to existing customers if the new customer exits the system before producing the credit for revenues
Inclusion of Reliability Benefits	Yes, to offset the acceleration of transmission plan costs. When included, benefits are calculated based on fuel savings related to projected increased reliability	No, cost causation should be the guiding principle. Hydro's approach to calculating reliability benefits is non-standard
Separate Cryptocurrency Class in NAP	No	Not at this time, possibly appropriate pending experience with new NAP

4 Note that our specific recommendations focus on modifications to the proposed network additions policy related to customer's requests to serve load. The same principles are applicable to a network addition policy for non-utility generation interconnection. In the future, if wholesale competition becomes a policy within the LIS, modifications to our recommendations may be needed to ensure that the generation interconnection policy results in the non-discriminatory treatment of both utility and non-utility generation assets.

II. Introduction

In 2017, Hydro filed its annual capital budget that included the Muskrat Falls to Happy Valley Interconnection project developed to address capacity and reliability issues in the Labrador East system. The Board deferred consideration of the project and directed Hydro to file a proposal for the "provision of reliable service" in Labrador East.[5] In Order No. P.U. 9 (2018), the Board also required that Hydro develop a network additions 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 cost of service or through contributions in aid of construction."[6] In response, Hydro filed its initial report on revising the NAP with a supporting report from Christensen Associates Energy Consulting ("CA Energy Consulting") and initial transmission expansion study for the Labrador Interconnected System in October 2018. Hydro filed its full proposal for a new network additions policy ("Proposed NAP") in December 2018.[7]

Cryptocurrency customers, referred by Hydro as "data centers," have increasingly joined or are anticipated to join the LIS and are one of the driving factors for future load growth. Cryptocurrency customers are relatively unique in their demand density (*i.e.*, small facility with high electrical loads) combined with potential impermanence. In the 2018 Transmission Expansion Planning Study, Hydro developed sensitivities around the potential for new cryptocurrency customers, which could result in a 51.5 MW increase in peak demand in Labrador West.[8] In Labrador West, data centers represented 2% of total peak load in 2018, and as shown in Figure 2, could represent almost 15% of total peak load by 2022, according to Hydro's forecast. Similarly, as shown in Figure 3, Hydro's sensitivity to cryptocurrency customers in Labrador East considered a 28.4 MW increase in peak demand in Labrador East due to new cryptocurrency customers. In 2018, cryptocurrency customers represented 8% of total peak load and, based on Hydro's sensitivity case, could represent more than 30% of total peak load by 2022.

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[5] In 2018, Hydro filed its proposal that included a moratorium on new service connections or service upgrades for load requirements greater than 100kW, which was approved in October 2018.

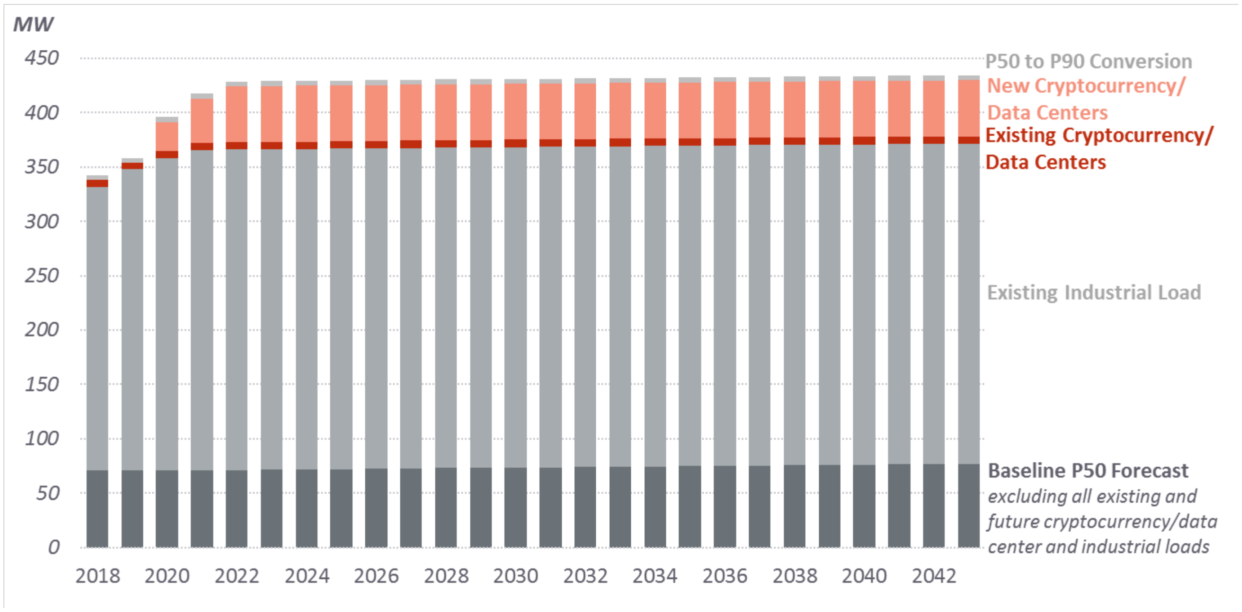
[6] Newfoundland and Labrador Board of Commissioners of Public Utilities, Order No. P.U. 9 (2018), p. 9.

[7] Newfoundland Labrador Hydro, "Labrador Interconnected System Network Additions Policy: Summary Report," December 14, 2018.

Newfoundland Labrador Hydro, "Network Additions Policy—Labrador Interconnected System," December 14, 2018.

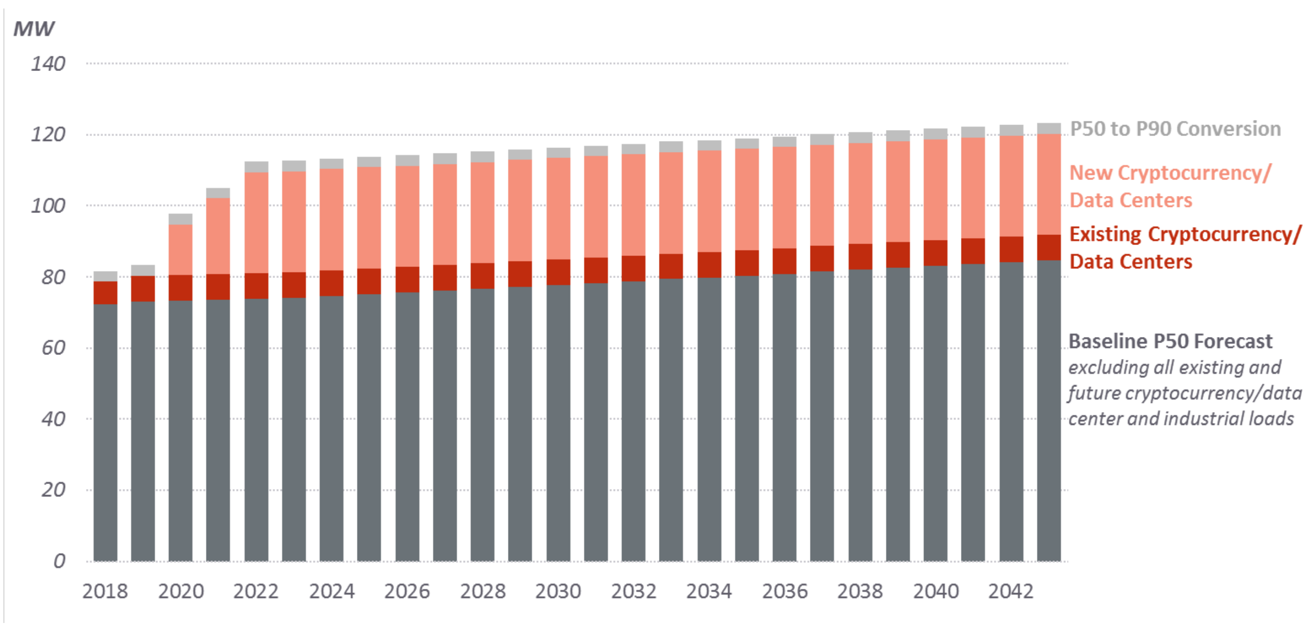
[8] Newfoundland Labrador Hydro, "Labrador Interconnected System Transmission Expansion Study," October 31, 2018 (Revised April 3, 2019), Section 3.

Figure 2: Labrador West Peak Load Forecast



Source: Newfoundland Labrador Hydro, Labrador Interconnected System Transmission Expansion Study, October 31, 2018 (Revised April 3, 2019) and LAB-NLH-074.

Figure 3: Labrador East Peak Load Forecast



Sources: Newfoundland Labrador Hydro, Labrador Interconnected System Transmission Expansion Study, October 31, 2018 (Revised April 3, 2019) and LAB-NLH-074.

Notes: "New Cryptocurrency/Data Centers" based on Labrador East Data Center Development Case.

The Brattle Group was engaged by the Board to review Hydro's proposed NAP, including a comparison between Hydro's proposed NAP and NAPs in other jurisdictions, describing if and how the proposed NAP protects the existing load and addressing related questions about the proposed NAP. The report discusses NAPs in other jurisdictions in Section III, followed by a review of Hydro's existing and proposed NAP in Section IV. Finally, Section V provides our analysis and recommendations. The Appendix provides additional information on the treatment of cryptocurrency customers across other jurisdictions.

III. Network Addition Policies Across Jurisdictions

NAPs are tailored for specific contexts and frequently differ based on the interconnecting customer's location (*e.g.*, transmission or distribution), customer type (*e.g.*, generation or load), and size or customer end-use. Similarly, NAPs may vary between investments providing benefits to a single region or multiple regions. Thus, providing a benchmark between Hydro's existing and proposed NAPs is challenging and requires identifying similar contexts for comparison. As we understand that new loads are the driving factor to develop a new NAP, we have focused on reviewing Canadian NAPs focused on new load. To provide context on how interconnections, in this case, generator interconnections, are addressed by the FERC, we give an overview of existing policies. Given that Hydro's proposed NAP applies to non-utility generators as well as load, the FERC's generation interconnection policies are applicable to the case of Hydro.

NAPs typically treat interconnection facilities separately from network upgrades. Interconnection facilities connect the customer's facility and the transmission provider's existing system. These facilities' costs generally are assigned directly to the interconnecting customer. Network upgrades include only facilities at or beyond the point where the interconnecting customer connects to the existing transmission provider's system. The costs of network upgrades frequently are allocated to the interconnecting customer but may be socialized in whole or in part.

A. Load NAPs in Canada

The network addition policies for load in the six jurisdictions reviewed in Canada most commonly reflect the principle of cost causation, with network upgrades based on a "but-for" analysis, and include provisions for reallocation of costs if new customers join the system. A "but-for" analysis identifies those investments required for providing service to the requesting customer that "but-for" the customer's request would not have been required. As summarized in Figure 4, five out of the six jurisdictions use a "but-for" analysis to determine the network upgrades needed due to an interconnecting load customer.

In five of six jurisdictions, customers are explicitly required to pay for some portion of the network upgrades. Importantly, these network upgrade payments are in addition to the standard transmission rates, which generally are treated as a separate stand-alone issue. Two of the jurisdictions allow for a credit or refund (upfront or over time) to reduce the costs of network upgrades based on the anticipated revenues, and the refunds are based either on realized customer revenues, or monitoring is put in place to check the anticipated versus realized revenues. Finally, in three of the jurisdictions, costs of network upgrades are eligible for reallocation if new users join the system across timespans ranging from 7 years (B.C. Hydro) to 20 years (Alberta Electric System Operator). Additional detail on each policy follows in subsequent subsections.

Figure 4: Summary of Reviewed Canadian Network Addition Policies for Load

	Cost allocation follows cost-causation approach?	Upfront payment (or security) for some portion of network upgrades?	Is the customer eligible for revenue-based credits or refunds to reduce the upfront payment?	Reallocation of costs for incremental customers? (maximum timespan considered for incremental customers)
AESO [1]	Yes, but-for analysis used to determine network upgrades	Yes	No (Maximum Local Investment credit based on anticipated interconnection costs)	Yes (20 years)
B.C. Hydro [2]	Yes, but-for analysis used to determine network upgrades	Yes	Yes (approximately seven years of revenues that are securitized; security refunded over time based on actual revenues)	Yes (7 years)
New Brunswick Power [3]	Yes, but-for analysis used to determine network upgrades	Yes	N/A	Yes (10 years)
Ontario Energy Board (Network Facilities) [4]	Mixed, beneficiary pay used as guiding principle, network facilities that serve as "connection facilities" may require a capital contribution	Yes, if required	No *(for connection facilities, based on economic analysis with 5-25 year time horizons; includes true-ups)*	No *(for connection facilities15 years)*
Hydro Québec [5]	Yes, but-for analysis or pre-calculated costs for projects not requiring an engineering study	Yes	Yes (demand monitored for five years)	No (applicable to distribution but not transmission facilities)
SaskPower [6]	Yes, but-for analysis used to determine network upgrades	Yes (Determined at SaskPower's discretion)	No (however, customer eligible to be refunded upfront costs through a credit against future transmission rates)	No

Notes: Detailed sources provided in subsequent sections.

1. Alberta (AESO, Unbundled Market)

At the transmission level in Alberta, connecting load customers are responsible for interconnection and network upgrade costs above a maximum local investment. The Albertan policies for interconnection and network upgrade costs are determined by the Alberta Electric System Operator ("AESO"), which divides connection costs into "participant-related" costs, allocated to the interconnecting customer, and "system-related" costs. Participant-related costs include interconnection facilities, a share of existing transmission facilities built within the past 20 years to connect another market participant, and the advancement of radial transmission facilities that are planned to be networked within five years.[9] System-related costs include facilities that increase the number of electrical paths between any two substations and facilities above the minimum size required to service the market participant.[10] The participant-related costs are reduced by the "Maximum Local Investment."[11] The Maximum Local Investment represents an estimate of interconnection cost based on historical analysis.[12] The Alberta Utility Commission has stated that the Maximum Local Investment should reflect interconnection costs rather than anticipated customers' revenues to avoid incentives for customers to pursue higher standards of connection facilities and thus avoid unnecessary upward pressures on rates.[13] If additional customers make use of the transmission facilities paid for by the connecting customer within 20 years, the original connecting customer may be eligible for a refund.[14]

Interconnecting generators are required to pay set fees based on the area of the transmission system. These costs, outlined in Section 10 of the tariff, range from $10,000/MW to $50,000/MW. These contributions then are refunded over nine years.[15]

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9 The full set of facilities included as participant-costs is defined in Section 8, 3(2) of the AESO tariff (effective 2019-01-01). The radial facilities included are defined in Section 8, 3(3)(b) as:

"radial transmission facilities which, within five (5) years of commercial operation, are planned to become looped as part of a critical transmission development or regional transmission system project: (i) in the ISO's most recent long-term transmission system plan; (ii) in a needs identification document filed with the Commission; or (iii) as the ISO reasonably expects will be required in the future…."

10 AESO ISO Tariff Section 8:3(3)

11 In addition to the Maximum Local Investment, facilities in excess of good practice and a reduction for transformers are subtracted.

AESO ISO Tariff Section 8:4 and Section 8:5(2).

12 EUB Decision 2007-106, pp. 91–96, December 21, 2007.

13 EUB Decision 2005-096, p. 44, August 28, 2005

14 AESO ISO Tariff Section 8:4 and Section 9:5

15 The refund amounts are contingent upon meeting performance criteria set in the AESO rules, and the refund amounts increase over time with 5.6% refunded in years 1–4, 11.2% refunded in year 5, and 16.6% refunded in years 6–9.

AESO ISO Tariff Section 10:5.

2. British Columbia (B.C. Hydro, Vertically Integrated)

B.C. Hydro's policy requires customers to contribute to reinforcements of the existing system prompted by interconnection based on the difference between the investment costs and anticipated revenues from the customer. The utility responds to a request for new service by a permanent transmission customer (served at 60 kV or higher) by preparing a detailed estimate of a cost study paid for by the customer that results in agreed-upon maximum cost of system reinforcement.[16, 17] Rather than pay upfront for the detailed cost study, which produces a maximum total cost, a customer may decide to have the total cost based on the actual costs that B.C. Hydro incurs.[18] System Reinforcements are defined by B.C. Hydro to be:[19]

> Additions and alterations to existing B.C. Hydro Facilities, required to supply the Electricity to a Transmission Connection. Where an existing Transmission Connection supplies at least one other Customer, or other B.C. Hydro customers whose combined power demand exceeds five percent of the Nominal Capacity of the Transmission Connection, any additions and alterations shall be considered System Reinforcement. System Reinforcement shall not include any additions or alternations to generation plant and associated transmission, or transmission lines at 500kV and over, unless the new or incremental loads exceed 150 MVA.

We interpret this definition to mean that upgrade costs to existing infrastructure, including existing transmission lines' costs that previously would have been allocated to existing customers, are treated as System Reinforcement costs, subject to the five percent constraint.

The total cost paid for by a permanent customer is net of a credit, called the "B.C. Hydro Offset" that reflects anticipated customer revenues, customer-required operating and maintenance ("O&M") expenditures, depreciation, and other benefits to the system:[20]

System Reinforcement Customer Cost = Total Cost – (R – E) / 0.135 – D – B, where:

- R = the incremental revenue as calculated by B.C. Hydro from the estimated incremental load during the first year of normal operations;
- E = the estimated incremental O&M expense of supplying the incremental load during the first year of normal operations;

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16 A transmission customer is a customer who takes or is proposing to take electricity from B.C. Hydro pursuant to an Electricity Supply Agreement on the terms and conditions of Rate Schedule 1821 (Source: Tariff Supplement No 6, p.11)

17 B.C. Hydro, Electric Tariff Supplement 6, Appendix 1, Section 4 (pdf p.14).

18 B.C. Hydro, Electric Tariff Supplement 6, Appendix 1, Section 5 (pdf p.15).

19 B.C. Hydro, Electric Tariff Supplement 6, Appendix 1, Section 2.

20 B.C. Hydro, Electric Tariff Supplement 6, Appendix 1, Section 5 (pdf p.15–18).

- D = one-half the annual depreciation associated with the estimated total costs of System Reinforcement; and
- B = other benefits to the B.C. Hydro system, as determined by B.C. Hydro.

The customer must pay upfront the net cost of the project (full project cost minus B.C. Hydro Offset) and security equal to the B.C. Hydro Offset. To date, we understand that the offsets have been higher than the capital cost of the project; thus, customers have not been required to make cash payments toward system reinforcement costs. The security is refunded over time as customers produce revenues, which historically has occurred over the first few years of a customer's operation and may be refunded more quickly if additional customers make use of the system upgrade.[21] If B.C. Hydro determines that a subsequent customer will make use of the system reinforcement during the first five years of service, it recalculates the customer's payment based on the combined loads and refunds the appropriate amount to the first customer.[22] Subsequent customers are not required to make a capital contribution to the cost of the network upgrades and are not required to provide security. B.C. Hydro has a similar policy about sharing of initial costs related to the construction and operation of a radial transmission line between the existing B.C. Hydro system and the new customer, providing that B.C. Hydro owns and operates the line.[23]

3. New Brunswick (New Brunswick Power, Vertically Integrated)

In New Brunswick, customers are responsible for directly assigned costs and a share of the capital costs for additional upgrades, subject to credits related to anticipated customer revenues. New Brunswick Power defines the two types of costs as "Direct Assignment Facilities," which serve a

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21 Before the Customer's Plant is in "normal operation", the customer is required to provide security equal to the B.C. Hydro offset. The security for costs may include an irrevocable letter of credit, a contract bond, a guarantee by a corporation other than the Customer, a bank term deposit to be deposited in trust for B.C. Hydro, a negotiable bearer bond that is government guaranteed at face value, or a prepayment on account.

B.C. Hydro Electric Tariff Supplement 6, Section 5(e) (pdf p.18).

22 The subsequent customers are not required to provide security and thus free ride on the first customer's investments. The increased reimbursement to the first customer is available only while security is outstanding.

B.C. Hydro Electric Tariff Supplement 6, Section 5(e) (pdf p.18).

23 B.C. Hydro, Electric Tariff Supplement 6, Appendix 1, Section 10.

single customer,[24] and "Network Upgrades," which are for the "general benefit of all customers."[25] As outlined in Attachment K of the Open Access Transmission Tariff ("OATT"), the interconnecting customer ("Connection Applicant") is first required to pay for a feasibility study and, if required, a broader system impact study.[26] For new loads, the customer is responsible only for the difference between the tariff rate and the incremental carrying charges if the new connection costs exceed the average rolled-in costs of facilities. The difference between the incremental carrying charges and average rolled-in costs is paid through an upfront capital contribution.

For large industrial customers, New Brunswick Power will extend the transmission system to the customer. In exchange for the extension, the industrial customer must provide a guarantee (cash, letters of guarantee, bonds, *etc.*) equal to the cost of the extension minus contributions to capital described previously.[27] The guarantee is reduced annually by 10% of the total prior 12-months paid energy and demand, and if after five years the guarantee has not been reduced to zero, the customer will be required to pay the outstanding balance.[28]

The amount that a customer funds may be decreased if New Brunswick Power identifies additional benefits of the upgrades or multiple new customers who will benefit from the upgrades, and customers may receive a refund if other customers make use of the upgrades. If multiple service requests benefit from a system upgrade, costs are shared based on the relative usage of the upgraded facilities on a 12CP basis based on a load flow study.[29] Further, the transmission provider may identify system benefits that reduce the customer's cost contribution.[30] Customers may be eligible for refunds if subsequent customers connect within the first ten years, and the refund amount is

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24 Direct Assignment Facilities are defined as: "Facilities or portions of facilities that are constructed by a Transmitter for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Board approval."

New Brunswick Power Corporation, Open Access Transmission Tariff, Section 1.12.

25 New Brunswick Power Corporation, Open Access Transmission Tariff, Section 1.29.

26 New Brunswick Power Corporation, Open Access Transmission Tariff, Attachment K, Section 5.2.6 and 5.2.7.

27 Energie NB Power, NB Power Rate Schedules and Policies, Revised September 1, 2019. Schedule H-6.

28 *Ibid.*

29 New Brunswick Power Corporation, Open Access Transmission Tariff, Attachment K, Section 5.2.6 and 5.6.4.

30 The customer's cost contribution would be net the net present value of the system benefits. These additional benefits are not identified in Attachment K.

Ibid.

proportional to the segment of the transmission assets used by each customer and in proportion to the capacity of the assets relative to the economic life.[31]

4. Ontario (Ontario Energy Board, Unbundled Market)

For cost allocation purposes, the Ontario Energy Board defines "network facilities" and "connection facilities" as separate cost categories. Network facilities are the transmission facilities shared by all customers in Ontario and include all 500kV lines, 230 and 115kV lines not tapped to supply load customers, as well as other facilities.[32] The primary function of connection facilities is to connect one or more customers to the network.

Upgrades to transmission network facilities are allocated to the transmission owner—which means that the costs are socialized among transmission customers—unless the network facility upgrades are determined to provide a connection function, in which case the customer may be required to make a capital contribution. The Transmission System Code requires that customers not be required to make a capital contribution to accommodate new or modified connections except under "exceptional circumstances."[33] Compliance Bulletin 200606 describes these "exceptional circumstances" as being related to meeting minimum connection requirements:[34]

> It is my view that, in keeping with the TSC requirement that connecting customers be allocated the cost of connection, connecting customers are responsible for costs that are directly related to the physical interface connection with the transmission system regardless of where, on the transmission system, the connection occurs. It is my view that the costs of these "minimum connection requirements" are to be borne by the connecting customer even when the assets necessary to achieve the minimum connection requirement will be located within the transmitter's *network* facilities. It is also important to note that in some cases, all or some of the minimum connection requirement may be physically located away from the actual connection interface point for practical or economic reasons.

With regard to connection facilities, a feature of the Ontario Energy Board cost allocation is the use of a Proportional Benefit Approach/Beneficiary Pays approach. This approach recovers a portion of connection facilities cost from all ratepayers when the connection facilities address a

31 New Brunswick Power Corporation, Open Access Transmission Tariff, Attachment K, Section 5.2.6 and 5.6.6.

32 Ontario Energy Board, "Board Staff Discussion Paper: Regulatory Framework for Regional Planning for Electricity Infrastructure," EB-2011-0043, November 2011.

33 Ontario Energy Board, Transmission System Code, Last Revised December 18, 2018, Originally Issued on July 14, 2000. Section 6.3.5.

34 Ontario Energy Board, Compliance Bulletin 200606, September 2006.

broader network system need, such as overall reliability. The Ontario Energy Board refers to this as being consistent with the beneficiary pays principle, "since both the customer(s) that caused the need for the investment and the broader system benefit."[35]

The Ontario Energy Board directs transmission asset owners/operators to analyze the connection costs incurred by new and modified interconnections and requires them to pay an upfront capital charge if the projected revenues, with adjustments, do not equal the capital expenses. When a load customer applies for a new interconnection request, the transmission owner is first responsible for the performance of an evaluation study to determine the need for new investments and subsequently is responsible for performing an "economic evaluation" to determine the need for an upfront capital charge. The need for new investments can include new facilities, upgrades to existing facilities, and the advancement costs of planned facilities.

The economic evaluation assesses the cost and revenue implications of the new transmission project, and any shortfall in net revenue is charged to the customer. The economic evaluation compares the present value of revenues plus an allowance for a "Capital Cost Allowance Tax Shield" less the capital expenditures and projected O&M. The time horizon for the economic evaluation varies from 5 to 25 years based on the customer's risk, with longer time horizons used for less risky customers. For new or modified connection facilities, transmission asset owners carry out a true-up calculation, based on actual customer load, with the frequency varying based on customer risk and the related horizon. There can be multiple customers in the application process, with costs shared based on non-coincident peak demand. The interconnection customer is required to pay for the transmission project before construction starts through either a cash payment or a security deposit. The interconnection customer receives its security deposit back once the new facility is connected to the transmission system, and all capital contributions have been paid. If a new customer emerges in the subsequent 15 years, the interconnection customer is entitled to receive a refund for part of its investment.[36]

5. Québec (Hydro Québec, Vertically Integrated)

The connection costs calculated by Hydro Québec are based on a system study and include a credit or "allowance" related to anticipated customer revenues on the system. Hydro Québec segregates the connection costs by size but applies the same general approach. Similar to other utilities, Hydro

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35 Ontario Energy Board, "Notice of Proposal to Amend a Code: Proposed Amendment to the Transmission System Code and the Distribution System Code to Facilitate Regional Planning," EB-2-10-003, September 21, 2017.

36 Ontario Energy Board, Transmission System Code, Last Revised December 18, 2018, Originally Issued on July 14, 2000.

Québec performs a study to determine the costs required for the customer's upgrades.[37] The customer is responsible for the total costs less an allowance, calculated as a per kW charge ($363/kW in the most recent report) multiplied by the anticipated demand.[38,39] For the five years following the interconnection, Hydro Québec monitors the customers to ensure that the actual customer demand is at least the amount used to calculate the allowance.[40]

6. Saskatchewan (SaskPower, Vertically Integrated)

In Saskatchewan, customers are responsible for directly assigned costs and a share of the capital costs for additional upgrades, subject to credits related to anticipated customer revenues. Saskatchewan defines the two types of costs as "Direct Assignment Facilities," which serve a single customer,[41] and "Network Upgrades."

For customers seeking to use SaskPower's system at 72 kV or above, the cost of network upgrades is allocated between the customer and SaskPower based on the changes in investment relative to a "baseline assessment." To determine the network upgrades, SaskPower uses a "baseline assessment," which includes all investments in its 5-year business plan as well as network upgrades due to other customers higher in the interconnection queue, and compares those needs relative to a case with the interconnecting customer (excluding the investments included in the baseline).[42] In its comparison, SaskPower analyzes the network upgrades that would not be incurred "but for" the existence of the customer as well as needs to advance planned investments and the ability to defer investments.[43] The allocated charge is based upon the following formula:[44]

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37 It is unclear whether these costs include only costs directly related to the interconnection (*e.g.*, extension of distribution lines to the customer's site) or system-wide costs. The costs calculated are in excess of a pre-defined "basic service."

Hydro-Quebec, Conditions of Service, April 1, 2019 Edition, Section 9.1 (Calculation of the Amount to Be Paid for Work Not Included in Basic Service).

38 Hydro-Quebec, Conditions of Service, April 1, 2019 Edition, Section 19.1 (Connection request for 5 MVA or more, including installed load, at medium voltage).

39 Hydro-Quebec, Conditions of Service, April 1, 2019 Edition, Section 20 (Costs and Charges), Table II-M.

40 Hydro-Quebec, Conditions of Service, April 1, 2019 Edition, Section 19.2 (Customer commitments for 5 MVA or more, including installed load, at medium voltage).

41 Direct Assignment Facilities are defined as: "Facilities or portions of facilities that are constructed by SaskPower for the sole use/benefit of a particular customer".

SaskPower Generator Interconnection and Transmission Service Customer Charge Policy, Section 1.4.2.

42 SaskPower Generator Interconnection and Transmission Service Customer Charge Policy, Section 3.3.

43 *Ibid.*

44 *Ibid.*

> Allocated charge = Actual cost of network upgrades (allocated to the customer) – Deferral benefit + Advancement cost

Network upgrade facilities are constructed only for interconnection customers who have executed a long-term transmission agreement, and customers are eligible for transmission service credits, which may be applied against future transmission rates up to the total allocated cost for network upgrades.[45]

B. FERC's Network Addition Policies for Generator Interconnection

The FERC's generation interconnection policies are developed to ensure open access to the transmission network and to further the goals of wholesale competition and allow generators to compete on an equal playing field. To that end, the FERC has two complementary policies: 1) in addition to the facilities needed for physically interconnecting the generation to the transmission network, interconnecting generation customers are responsible for *financing* network upgrades, with the financing refunded over a pre-determined time period; and 2) in terms of usage of the transmission network once the generator has been interconnected, transmission customers may be charged the "higher of" the embedded cost rate (including network upgrades) or the incremental cost rate based on the required network upgrades.

In the FERC's generator interconnection context, customers are anticipated to remain on the system for many years and are expected to produce revenues equivalent to the network upgrade costs within five years. If connection customers are charged the "higher of" rate, it may reasonably be expected that those customers will provide sufficient revenues to cover the cost of the network upgrades before departing from the system.

The FERC's "higher of" policy was outlined in its 1994 Transmission Pricing Policy:

> In order to provide new or expanded transmission service, a utility may be required to add expensive transmission assets, which can result in an increase in rolled-in embedded cost rates. To address this possibility, the Commission has allowed a utility to charge transmission-only customers the higher of embedded costs (for the system as expanded) or incremental expansion costs, but not the sum of the two.[7]
>
> Footnote 7: This current pricing policy is based on three goals that the Commission adopted in the Northeast Utilities case: (1) to hold native load customers harmless, (2) to provide the lowest reasonable cost-based price to third-party firm

[45] SaskPower Generator Interconnection and Transmission Service Customer Charge Policy, Section 4.

> transmission customers, and (3) to prevent the collection of monopoly rents by transmission owners and promote efficient transmission decisions.[46]

In Orders 2003 and 2006, the FERC laid out the rationale for the refunding of network upgrade costs based on avoiding double-charging interconnecting generators. FERC Order 1000, which addressed interregional transmission planning, explicitly does not address interconnection costs, which are treated separately.[47] In FERC Order 2003, the FERC re-affirmed its policy for the payment of upgrades:[48]

> The Commission determined that it is appropriate for the Interconnection Customer to pay initially the full cost of Interconnection Facilities and Network Upgrades that would not be needed but for the interconnection, but once the Generating Facility commences operation and delivery service begins, it must receive transmission service credits for the cost of the Network Upgrades.

The FERC stated that its policy is intended to prohibit customers from paying twice for their use of the transmission system and, in the case that the interconnecting generator is interconnecting into a vertically-owned utility's system, to create a level playing field:

> …However, the Commission instituted this policy to achieve a number of important goals. First, consistent with the Commission's long-held policy of prohibiting "and" pricing[111] for transmission service, the crediting policy ensures that the Interconnection Customer will not be charged twice for the use of the Transmission System. This ensures that the Interconnection Customer will not ultimately have to pay both incremental costs and an average embedded cost rate for the use of the Transmission System. Second, the Commission's crediting policy helps to ensure that the Interconnection Customer's interconnection is treated comparably to the interconnections that a non-independent Transmission Provider completes for its own Generating Facilities.
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> Footnote 111: When a Transmission Provider must construct Network Upgrades to provide new or expanded transmission service, the Commission generally allows the Transmission Provider to charge the higher of the embedded costs of the

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46 Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act, Policy Statement, 59 FR 55031 at 55037 (Nov. 3, 1994), FERC Stats. & Regs. ¶ 31,005 at 31,146, 1994. (FERC Transmission Pricing Policy Statement)

47 In FERC Order 1000, which focuses on regional and interregional planning, the FERC explicitly excluded discussion of generator interconnection, stating, "The Commission agrees with the California ISO and other commenters that issues related to the generator interconnection process and to interconnection cost recovery are outside the scope of this rulemaking…This Final Rule does not set forth any new requirements with respect to such procedures for interconnecting large, small, or wind or other generation facilities."

FERC Order 1000; ¶ 760.

48 FERC Order 2003; ¶ 694.

> Transmission System with expansion costs rolled in, or incremental expansion costs, but not the sum of the two. Hence, "and" pricing is not permitted.

In FERC Order 2006, the FERC applied the same framework for small generators, requiring that small generators similarly pay for interconnection facilities, upgrades to the distribution system, and network upgrades, with a subsequent refund for network upgrades:[49]

> We recognize that the Interconnection Facilities, Distribution Upgrades, and Network Upgrades required to interconnect a generator can be costly. Indeed, such costs can be a significant portion of the total project costs. Nevertheless, each Generating Facility, whether large or small, must bear its fair share of the cost of the facilities and Upgrades from which it benefits; otherwise, the facility simply does not make economic sense.
>
> …Among other things, this means that the Interconnection Customer must bear the cost of necessary Interconnection Facilities and Distribution Upgrades. Also, the Interconnection Customer must initially fund the cost of Network Upgrades, but is entitled to credits against its charges for transmission delivery service equal to the amount funded, plus interest."

The use of a cost causation "but for" case to determine the network upgrades is explicit in the FERC's guidance and is reflected in ISO and RTO Open Access tariffs. For example, the Southwest Power Pool's tariff states that:[50]

> Each impact amount shall be determined by first establishing a set of initial seasonal base cases that excludes flows associated with all requests included in the Cluster Study. Then each request will be added to the models and the change in flow across such Network Upgrades shall be determined for each request included in the Cluster Study.

In some regions, the network upgrades, or a portion of network upgrades, may be treated separately such that only a share must be paid upfront by the interconnecting customer.

C. The Beneficiary Pays Approach

The topic of a "beneficiary pays" approach in assessing cost responsibility for network additions has been raised by Hydro in its application. Hydro states that, based on a Christensen Associates Energy Consulting report, there is an "emergence of the use of beneficiary pays."[51] Hydro's position is that the beneficiary pays approach applies to the NAP issues in this proceeding, and its proposal is guided, in part, by this concept.

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49 FERC Order 2006; ¶ 424–425.

50 Southwest Power Pool OATT, Attachment V, §4.2.5(b).

51 Newfoundland Labrador Hydro, "Network Additions Policy Review," October 1, 2018, Section 1.

The beneficiary pays approach, while related in part to cost causation principles, is, in our opinion, less relevant and useful in this context of network additions policies. Concerning network upgrades, the beneficiary pays concept is not well defined and is lacking clear foundational rules, implementation methodologies, and proposed calculations and formulas. Its application within the context of network upgrades and additions would be problematic, challenging, and unduly subjective. From a regulatory economics perspective, regulations and rules should provide clear guidance, be understandable and predictable, and straightforwardly implementable, the absence of which leads to uncertainty for market participants, stakeholders, and policymakers and an overall loss in economic efficiency. We do not believe that the beneficiary pays "rule" meets these standards nor that application of the rules would result in superior outcomes compared to the more traditional cost-causer approach that we favour and discuss further below.

We have reviewed the submissions of Philip Raphals on behalf of the Labrador Interconnected Group and are in general agreement that the beneficiary pays concept seems to be more applicable to situations that are not the main issue in this proceeding.[52] That is, to the extent that there is an "emergence of the use of the beneficiary pays" approach, it seems to be reflected more in transmission planning procedures and transmission investments that create benefits in different areas within and between RTOs and ISOs and that are used as the basis for cost allocation.[53] We agree with Mr. Raphals that the beneficiary pays concept is less applicable to network upgrade policies carried out by a jurisdictional utility applying its own FERC-compliant OATT.[54]

At a high level, we do not find the merits of NHL's interpretation of the beneficiary pays concept sufficient to deviate significantly from applying cost causation principles to the issue of optimal network upgrade policies. The cost causer, by definition, benefits from the action; otherwise, it would not have requested the service. It could be the case that other customers also benefit from that investment, but this does not lessen the principle that it is the entity that requested the service and caused the costs of the network upgrades that should, in general, be responsible for the costs.[55] If the cost causation principle is not followed, incorrect price signals are given to the customer

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52 See, Philip Raphals, "Newfoundland and Labrador Hydro's Proposed Network Addition Policy and Transmission Expansion Study—Supplemental Report," submitted to the NL Public Utilities Board on behalf of the Labrador Interconnected Group, June 21, 2019, p. 4.

53 In general, our observation is that transmission allocation usually is performed on a basis that is <u>broadly</u> consistent with the concept of beneficiary pays but practically results in a less complex allocation approach. One of the most common approaches for allocation of transmission costs are "postage stamp" approaches, where costs are allocated based on their proportion ("load share ratio") of peak, noncoincident peak, or energy. This approach is used, for example, by the Alberta Electric System Operator, the MidContinent ISO, and the Southwest Power Pool, amongst others.

54 See, Philip Raphals, "Newfoundland and Labrador Hydro's Proposed Network Addition Policy and Transmission Expansion Study—Supplemental Report," submitted to the NL Public Utilities Board on behalf of the Labrador Interconnected Group, June 21, 2019, p. 4.

55 There may be exceptions to this general rule. However, we would anticipate that those exceptions are relatively rare.

requesting the service and the amount of interconnection and network upgrade requests and services would not be optimal.

Finally, based on our review of network addition policies, in our opinion, the beneficiary pays approach applied to network additions policy is not a best practice and is not widely or commonly used in the United States or Canada to allocate the costs of transmission network investments made in response to a new or expanded interconnection request. From our review of the jurisdictions surveyed, we did not find many examples where a beneficiary pays approach is the principal methodology used to allocate the costs of network upgrade costs for new or expanded load interconnections.

IV. Hydro Proposed Changes to the Network Additions Policy

A. Current NAP Review

Hydro's current NAP at the transmission level treats investments that benefit more than one customer as shared and allocates those costs across ratepayers. To determine the necessary investments to accommodate a new load request, Hydro performs a facilities study, which determines the nature of the investments and estimates the total cost.[56] According to the summary of the policy provided by Hydro, the only costs from that facilities study specifically assigned to a customer are those facilities dedicated only to one customer and that benefit only that customer and which are deemed to be "material."[57] We understand this to mean that, in effect, all costs are treated as shared, excluding interconnection facilities, which would benefit only a single customer. This sharing of costs is limited to the extent that interconnection costs with impacts deemed to be "local" may be shared across multiple requesting customers rather than shared across the full system.[58] Under the current NAP, a contribution is required from the customer for specifically assigned facilities, and, as the facility is not shared with other customers, the costs of the facilities are the full responsibility of the customer. As a result, there are no credits or refunds based on revenues paid into the system. The customer is responsible for the costs related to sustaining capital, the end of life replacement cost of the asset, and the estimated annual O&M costs of the specifically assigned asset.[59]

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56 Newfoundland Labrador Hydro, "Network Additions Policy Review," October 1, 2018, Section 3.2.

57 Newfoundland Labrador Hydro, "Network Additions Policy Review," October 1, 2018, Section 2.2 and Section 3.2.

58 Newfoundland Labrador Hydro, "Network Additions Policy Review," October 1, 2018, Section 3.2.

59 Newfoundland Labrador Hydro, "Network Additions Policy Review," October 1, 2018, Section 2.2.

Hydro's analogous policies for distribution level costs are more nuanced, with consideration of factors such as the primary beneficiary of network upgrades, whether the load is permanent or temporary, and whether the costs of upgrades are supported by anticipated revenues from the customer. As summarized in Figure 5, the distribution policy distinguishes between General Service and Residential Customers. For General Service Customers, load interconnection costs are treated as shared up to the anticipated revenues from a combination of the customer and other potential load growth connected to the upgraded facilities. Interconnection costs above that threshold are directly assigned to the customer and may be refunded if another customer connects within ten years.[60] Concerning upstream effects (*i.e.*, network upgrades), the customer is not required to pay for upgrades previously identified within a five-year plan.[61]

60 CIAC Policy for Domestic Customers, Section 5.d.

CIAC Policy for General Service Customers, Section 5.c.

61 Newfoundland Labrador Hydro, "Network Additions Policy Review," October 1, 2018, Section 2.1.

Figure 5: Summary of Hydro's Current Transmission and Distribution NAPs

	Transmission	Distribution Contribution in Aid of Construction ("CIAC")
Specifically Assigned Assets	• Costs related to assets that benefit only one customer and are deemed to be "material" resulting from a facilities study • Upgrades with "local" impacts may be allocated between multiple requesting customers	• Dependent upon whether the load is temporary or permanent and if primary benefits accrue to requesting customer or other ratepayers; Hydro will not consider paying for an investment if the customer will have electric service for at least three years • For permanent customers, assets are not treated as specifically assigned; upgrade costs are calculated according to the description in row labelled "Upgrade Cost Required from Customer."
Upgrade Costs Required from Customer	• Upgrades benefiting multiple customers are socialized	• **Residential:** Customer pays for additional cost not included in Hydro's fixed-asset investment, which consists of a basic investment (fixed length of line and plant directly associated with it, transformation and metering) and an additional investment (single-phase mainline extensions if revenue from future growth along the mainline can support the costs to construct and maintain the extensions) • **General Service:** required to pay any additional costs not covered by Hydro's basic, growth-based, and load-based investments outlined by CIAC Policy; basic investment includes a fixed length of line, transformation and metering; growth-based investment provided if revenue from future growth along the mainline extension can support the costs to construct and maintain the extension; load-based investment provided if it can be recovered from revenue generated by the customer(s) requesting the extension • If the upgrade is previously included in the 5-year capital plan, no charge is assigned to the interconnecting customer • Board approval required when customer contributions toward the asset's capital > CAD 50,000
Credits and Refunds Related to Specifically Allocated Costs	• None	• Betterment credit reduces the amount charged to customers if new asset provides benefits to the customer and general customer base • Under certain circumstances, a refund is provided if a new customer connects within ten years of original customer connection

Sources and Notes: Network Additions Policy Review, pp. 2–7, October 1, 2018. CIAC Policy for Domestic Customers, Sections 3–5 and 10. CIAC Policy for General Service Customers, Sections 3–6 and 10.

B. Proposed NAP Revision

1. Specifically Assigned Asset Cost Recovery

For specifically assigned assets, Hydro's proposal would continue its current approach of requiring a full capital cost contribution from customers to offset the initial capital investment.[62] Hydro's proposal also calls for the customer to contribute to the sustaining capital associated with the specifically assigned asset as well as the replacement at the end of life. Hydro's past practice was financing the sustaining capital and asset replacement, but the risk of cost recovery from customers who may discontinue operations compelled Hydro to alter this aspect of the policy.

2. Network Upgrades

For transmission network upgrades that under the current policy Hydro considers as common—and thus recovered from all customers through the particulars of the cost of service study—Hydro proposes to implement a contribution requirement to new and existing customers requesting significant load additions. Hydro's proposed NAP differs primarily from the previous policy in that network upgrade costs—that are not dedicated assets used by one customer only—are not entirely treated as shared from a cost allocation perspective. In essence, under certain conditions, the requesting customer is now responsible for paying for some of the network upgrade costs caused by the customer or contributing financially to investments beyond Hydro's planned investments through a standardized $/kW "Expansion Cost per kW." The Expansion Cost per kW represents an estimate of the cost of *potential* transmission upgrades as calculated by Hydro.[63] The capital charge, either acceleration of planned investments or the Expansion Cost per kW, is referred to as the "Upstream Capacity Charge." Hydro states that funds paid through the Upstream Capacity Charge will be used to "reduce customer impacts that would occur as new transmission investments are required…."[64]

The new policy creates three tranches of customers based on peak demand. For customers with a peak demand of less than 200 kW, network upgrades continue to be shared. For customers with a demand of greater than 200 kW but less than 1,500 kW, a standard Expansion Cost per kW applies to all demand exceeding 200 kW, not to be refunded by Hydro over time. Finally, for customers of 1,500 kW or greater, a system integration study will be performed, and the load/customer allocated either the cost of advancing investments identified by Hydro minus a calculation of

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62 Newfoundland Labrador Hydro, "Labrador Interconnected System Network Additions Policy Summary Report," December 14, 2018, Section 2.2.

63 Newfoundland and Labrador Hydro, "Network Additions Policy—Labrador Interconnected System" December 14, 2018, p. 5.

64 Newfoundland and Labrador Hydro, "Network Additions Policy—Labrador Interconnected System" December 14, 2018, p. 4.

benefits attributed to existing customers or, if no acceleration of the transmission investments is required, levied a charge based on the Expansion Cost per kW. Also, industrial customers, which are defined to have a peak of 5,000 kW or more, are eligible for a "Demand Revenue Credit," which can further reduce the upfront charge.[65]

The Expansion Cost per kW represents, in essence, a contribution from new customers toward transmission investments that may be needed in the future. The investments used to calculate the Upstream Capacity Charge, shown in Figure 6, are those identified by Hydro in its 2018 Transmission Expansion Plan needed to meet load beyond the baseline load forecast through 2043.[66] The load "triggers" or total demand levels at which new investment would be needed in Labrador East are shown in Figure 7. The trigger for the Labrador West project is load growth of 383 MW.[67]

Figure 6: Derivation of Expansion Costs per kW
(Reproduction of Table 1)

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**

Source: Newfoundland and Labrador Hydro, "Labrador Interconnected System: Network Additions Policy: Summary Report," December 14, 2018. p. 5.

65 Newfoundland and Labrador Hydro, "Network Additions Policy—Labrador Interconnected System" December 14, 2018, p. 4.

66 Newfoundland and Labrador Hydro, "Network Additions Policy—Labrador Interconnected System" December 14, 2018, p. 5; and LAB-NLH-093.

67 Newfoundland and Labrador Hydro, "Labrador Interconnected System Transmission Expansion Study," December 14, 2018, p. 31.

Figure 7: Labrador East—Investments Included in Expansion Cost per kW
(Reproduction of Table 10)

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

Source: Newfoundland and Labrador Hydro, "Labrador Interconnected System Transmission Expansion Study," December 14, 2018. p. 30. The Muskrat Falls to Happy Valley (MF to HVY Interconnection) is designated as a need to meet baseline load by Hydro and thus not included in the calculation of the Expansion Cost per kW.

For customers with a load above 1500 kW, the Upstream Capacity Charge is calculated using either the Expansion Cost per kW or the cost to accelerate planned investments, the "Expansion Advancement Cost." The Expansion Advancement Cost is defined to be "the difference between the cost of acceleration of the Transmission Expansion Plan and the value to existing Customers from accelerating the Transmission Expansion Plan."[68] Based on the language of the proposed NAP and examples provided by Hydro, the acceleration applies to all investments, including investments that are not immediately required to provide service to the new customer and investments that were previously not included in the transmission expansion plan.[69] The proposed "value to existing Customers" reflects reductions in expected unserved energy ("EUE") valued at the approximate cost of projected gas turbine fuel use.[70] The proposed benefit from reductions in EUE is capped at 50% of the cost to accelerate planned transmission investments.[71]

Under the proposed policy, industrial customers are eligible to receive the Demand Revenue Credit, which reflects Hydro's assumptions that future demand revenues will be sustained for the long term and provide revenues to materially offset the additional cost of the required investment in common assets. The Demand Revenue Credit is determined by multiplying a customer's anticipated peak demand by the "Demand Revenue Credit per kW," the present value of the forecast demand revenues to be paid by Labrador Industrial Customers on a per kW basis. The Demand Revenue Credit per kW assumes an Industrial Customer has a service life of 25 years and is reduced by 3.0% for each year that the estimated life of the customer is less than 25 years. The proposed credit is calculated based on the proposed Labrador Industrial Transmission Demand Charge of $1.38 per kW per month reflected in Hydro's 2017 GRA filing of October 26, 2018.

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68 Newfoundland and Labrador Hydro, "Labrador Interconnected System Network Additions Policy," December 14, 2018, p. 3.

69 See, for example, LAB-NLH-101.

70 Newfoundland and Labrador Hydro, "Labrador Interconnected System: Network Additions Policy: Summary Report," December 14, 2018, p. 6.

71 Newfoundland and Labrador Hydro, "Labrador Interconnected System: Network Additions Policy: Summary Report," December 14, 2018, p. 7.

A summary of the main features of the current NAP and the proposed NAP is contained in Figure 8 below.

Figure 8: Current vs Proposed NAPs

	Current NAP	Proposed NAP
Interconnection facilities	• Benefit only one customer • Costs specifically assigned to the customer	• Benefit only one customer • Costs specifically assigned to the customer
Network Upgrades	• Benefit more than one customer • All costs considered shared; no charges for interconnecting customer	• Customer ≤ 200 kW: No additional charges • Customer < 1.5 MW: "expansion cost per kW" applied to all demand exceeding 200 kW. First 200 kW treated as shared and paid for by Hydro ("Basic Capacity Investment Credit," calculated as "expansion cost per kW" x 200 kW) • Customers ≥ 1.5 MW: Customer contribution determined through a system integration study; the customer is allocated either the cost of advancing investments identified by Hydro minus a calculation of benefits attributed to existing customers; if no acceleration of the transmission investments is required, the customer is charged based on the "expansion cost per kW."
Network Upgrades: Credits and Refunds	• No reduction in contribution based on customer revenues	• Industrial customers are eligible for a "Demand Revenue Credit." • If a new customer is served by the specifically assigned assets within ten years, the original customer is eligible for a refund

Sources and Notes: Network Additions Policy Review, pp. 2–7, October 1, 2018. CIAC Policy for Domestic Customers, Sections 3–5 and 10. CIAC Policy for General Service Customers, Sections 3–6 and 10.

C. Potential Protection Offered by Proposed NAP to Existing Load

Hydro's proposed policy offers better protection to existing customers than the current NAP as interconnecting customers would be required to contribute to either the cost of assets required by the interconnecting customer or potential future upgrade needs. If the interconnecting customer creates the need to advance investments, the interconnecting customer is required to pay for a portion of the advancement cost. The advancement cost may relate to network upgrades needed immediately to accommodate the new customer or advancement of future investments. Under the existing policy, the cost of network upgrades needed immediately to accommodate the new customer would be shared. Similarly, under the existing policy, new customers would not be required to pay for the advancement costs of network upgrades not immediately needed for their interconnection.

By requiring customers to pay for advancement costs of network upgrades needed in future years (*i.e.*, not required immediately to accommodate the new customer), Hydro will accumulate a pool of funds that may be used to offset the cost to existing ratepayers. The proposed NAP requires customers with demand over 1,500 kW to pay for the advancement of transmission infrastructure included in Hydro's 25-year planning horizon—a time horizon that includes significant uncertainty as to if or when the assets may be needed. While investments that are within the next 3–5 years are reasonably sure, investments planned for 25 years in the future are likely to be impacted in timing, scale, and scope by changes in technology, economic growth, and public policy, amongst other drivers.

The load investments included in Hydro's proposed Expansion Cost per kW are based on load "triggers." Peak load forecasts are inherently challenging and may give rise to significant uncertainty even for relatively short periods of 5–10 years, let alone 25 years. For example, Figure 9 shows actual load growth in the U.S.'s PJM ISO compared to the annual peak load forecast projected by PJM. As can be seen in the figure, PJM consistently over forecasted demand between 2007 and 2014.

Figure 9: PJM Summer Peak Load Forecast

By forecasting over such an extended period, Hydro has cast a wide net over investments that are includable for acceleration. Shortening the time horizon, for example, to ten years as used in Hydro's baseline expansion plan,[72] would provide greater certainty in the forecasted investments. For customers that do not create the need to advance planned transmission assets, the proposed policy requires that customers pay based on Expansion Cost per kW in anticipation of, sometimes, distant future needs. By requiring this payment, Hydro will have a pool of funds that can be used

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to pay for future investment needs that would otherwise be paid for by existing customers. Hydro's proposed policy diminishes the protection for existing customers when the new interconnecting customer is an industrial load, which is eligible for a reduction in contribution based on anticipated revenues. If the projected revenues for an industrial load are at least equal to the customer's Upstream Capacity Charge, then the industrial customer will not be required to make an upfront contribution. In this case, the total cost of the network upgrades will be treated as shared, which is the same outcome as under Hydro's current policy.

D. Potential Risks to Existing Load in the Proposed NAP

1. Treatment of Reliability Benefits

A risk to the existing customers is paying for "benefits" through reductions in expected unserved energy that are not commensurate with customer value. Power systems are planned to an acceptable level of performance, including the weighing of customer benefits due to decreased outages against the capital costs required to achieve them. A transmission plan thus includes the cost level required to increase reliability to be commensurate with its benefit. Increasing reliability beyond this level will result in a cost level not necessarily comparable with its benefits. An acknowledgement of this tradeoff is discussed in Hydro's transmission expansion planning study:[73]

> The Labrador East transmission system is classified as a Radial Transmission System, and the Labrador West transmission system is classified as a Local Network. In contrast to the PTS [Primary Transmission System], these systems distribute power to specific customers and are designed to meet the reliability requirements and balance customer cost impacts. If there was a strict application of transmission planning criteria on the LIS, significant expansion of the transmission system would be required.

If the Board finds it appropriate to measure customer benefits due to increased reliability, a standard measure is the value of lost load ("VOLL"). VOLLs estimate the monetary value that customers would pay to avoid an outage in the face of an impending outage event. However, VOLL values are not universally understood, nor are they always accepted as accurate representations of customer values. VOLL typically is used as a guiding factor for system reliability but is not typically used as the basis for payments to customers for shortfalls in service or to "charge" customers for increased reliability.

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[73] Newfoundland and Labrador Hydro, Labrador Interconnected System Transmission Expansion Study, Revised April 3, 2019, p.9.

Unlike VOLL, which is a widely used measure, we are unaware of any jurisdictions where the benefits of improving reliability are measured based on back-up fuel costs. In its report, Hydro states that:[74]

> Given the high cost of backup generation, there is a potential that the calculated reliability benefits associated with a new interconnection may reach or exceed its capital cost.

It is unclear why Hydro selected a proxy that would produce benefits that indicate that the value of a transmission investment is higher than its costs. This use of fuel costs as a proxy appears to be inconsistent with Hydro's earlier acknowledgement that the transmission expansion plan already reflects a balance between customer rates and reliability. While Hydro states that the fuel costs serve as a "proxy" for reliability to customers,[75] it does not provide a discussion of why fuel costs are an appropriate proxy or how fuel costs compare to other potential measures of customer reliability, such as VOLL, that may reflect the balance of customer costs and benefits included in the transmission expansion plan.

2. Use of Advancement Costs

While the proposed NAP provides greater protections to existing load than the current policy, existing customers will likely continue to be responsible for the majority of immediate network upgrade costs caused by new load customers. For new customers with 1,500 kW of demand that require immediate network upgrades, the new customers will pay for the advancement of that infrastructure rather than the total cost. Consider the hypothetical example where a new customer comes online in 2020 and requires the advancement of a network upgrade previously scheduled for 2025. The new customers would be responsible for advancing the network from 2025 to 2020, which will only be a fraction of the total asset cost.

V. Analysis and Recommendations

A. Analysis of current and proposed NAP

Our economic analysis of the current NAP, as well as Hydro's proposed NAP, is guided by cost causation principles—customers that cause a cost to be incurred should be responsible for paying the costs. We believe economic efficiency is improved whenever cost causation principles play a

[74] Newfoundland and Labrador Hydro, "Network Additions Policy—Labrador Interconnected System" December 14, 2018, p. 21.

[75] *Ibid.*

major role in cost allocation. Indeed, the idea of cost causation is a bedrock principle of cost of service studies and is a common feature of competitive markets.

Requiring customers to be responsible for the cost their actions and decisions cause ensures that the customer makes correct economic decisions. Under cost causation principles, decisions to connect to Hydro's network or to increase demand are based on whether the value and the benefits the customer receives exceeds the costs that Hydro incurs to provide the connection and the needed upgrades. This calculus is necessary to ensure the proper allocation of scarce economic resources. In this particular case with the emergence of data centers/cryptocurrency mining sites to the region, customers must be exposed to the costs that their decisions impose on the Hydro network. Key characteristics of data centers/cryptocurrency customers are that they have large energy demand requirements, have uncertain permanency given their mobility, lack sunk costs into the local economy, and have the mobility to enter and exit geographic markets that are served by different electricity companies with different tariffs and NAPs. Electricity supply is a crucial input for these customers, and they are vulnerable to the "boom and bust" cycles of global cryptocurrency market conditions and prices. Serving these customer types is risky and requires economically efficient costing and price signals to ensure the attainment of appropriate decision-making and economic efficiency.

A corollary of the cost causation principle, and one that we believe is good regulatory policy, is protecting existing customers from costs that they did not cause and that are caused by new customers. This is sometimes known as a "hold harmless" policy and is the basis of the FERC generation interconnection policy discussed previously. Two other regulatory principles and general regulatory practices that play a role in guiding our overall analysis and recommendation on this topic are the practice—and in most cases requirement—that whatever policy is implemented should not be unduly discriminatory and should not result in significant and dramatic changes in customer rates, *i.e.*, rate stability and prevention of "rate shock".

The current NAP, as it pertains to directly assigned facilities, is generally consistent with cost causation principles, as the customer causing the facilities that are dedicated to it is responsible for the full costs. As it pertains to network upgrades related to new customer connections, however, or increases in existing customer load, the current NAP fails to reflect cost causation principles. Existing customers who do not cause the network upgrades pay the vast majority of the network upgrade costs, as the cost causer is assigned a relatively small share of the costs, a share that is in proportion to its demand requirement relative to the entire system demand. Existing customers are particularly vulnerable to being responsible for 100% of the network upgrade if the cost-causing customer leaves Hydro's territory and locates somewhere else or shuts down operations entirely.

Concerning undue discrimination, the current NAP fares well in this regard. While we believe the policy fares poorly in respect of cost causation, the current policy applies to all customer classes equally; there is no special treatment or consideration given for any particular group of customers. As it pertains to rate stability and rate shock considerations, the current NAP fares poorly as the potential impact on customer rates from the increased load growth is significant. Load growth that is “primarily due to the arrival of data centers/cryptocurrency mining sites to the region” is the reason for proposing a new NAP.[76]

As discussed above, Hydro’s proposed NAP for non-dedicated facilities is divided among customers requesting less than 200 kW, customers requesting between 200 kW and 1,500 kW, and customers requesting more than 1,500 kW. For customers under 200 kW, from a cost causation perspective, Hydro’s NAP does not fare well conceptually as all network upgrade costs that are caused by customers falling into this category are socialized. From a practical perspective, however, the treatment of customers in this category may be justified based upon the fact that the cost impact of these customers' connection requests likely tends to be generally lower than for larger customers in the other categories. It also may be the case that the regulatory and transaction costs of applying these rules to these smaller customers outweigh the benefits derived from improved pricing signals. In terms of rate stability and rate shock, the policy fares well as customers in this group are protected from sizeable one-time connection charges. Prevention of rate shock is especially relevant for smaller customer groups, who tend to have fewer alternatives or choices than customer groups in the higher categories. In terms of undue discrimination, the policy does advantage these smaller customer types in comparison to the other customers. But, for reasons just discussed, such a result seems justifiable in this case.

For customers between 200 kW and 1,500 kW, Hydro’s proposed NAP is an improvement and better reflects cost causation principles than the current approach that socializes all network upgrades. Some costs that previously were socialized will be the responsibility of the requesting customer, the cost causer, and this provides improved price signals for that customer’s decision-making. Nevertheless, the policy is lacking in an important respect. The contribution requirement (the Upstream Capacity Charge) is based upon the expansion cost per kW, which is an estimate of the costs of a *potential* transmission upgrade. Moreover, how the expansion cost per kW is determined is almost by definition not near-term investments as they look to serve loads levels beyond what is expected for 2043. Thus, the policy is not tied to the actual network upgrade costs that a customer causes to be incurred by its request. All customers in this category must pay the Upstream Capacity Charge irrespective of whether the customer was, in fact, the cost causer of the request and irrespective of *when* Hydro will spend the money or how much it will spend. Hydro may not make these investments for a significant period, further removing the customer’s action (the request for the service) from the costs that the action brought about. In this sense, the policy fails to reflect cost causation principles adequately. This distorts the price signal that the requesting customer receives and biases the customer’s decision-making as the customer may be asked to pay for costs that its decision did not cause. This could result in some potential customers deciding not to request service even though the value they would obtain from the service would be greater than the cost of the request. Existing customers would also have been better off having the customer connect and take service from Hydro as Hydro’s common costs would be shared among a large group of customers.

76 Newfoundland Labrador Hydro, “Network Additions Policy Review,” October 1, 2018 at 1.

Looked at it another way, the Upstream Capacity Charge is not tied to the actual costs that Hydro incurs to upgrade the network charge to accommodate the request of the cost-causing customer. It serves as a form of "banking," essentially lending Hydro the money until it makes the upgrades. We find this approach uncommon in our review of regulatory jurisdictions, not in line with our view of cost causation principles and complicating the problem needlessly.

The proposed policy does protect existing customers compared to the current NAP, where all non-dedicated assets are socialized and fully paid by all customers, including those customers not responsible for the costs. The policy helps achieve rate stability and helps prevent rate shock for existing customers who are not responsible for the network upgrades. The policy may, however, lead to unnecessary one-time charges for customers who are not causing network upgrade costs. Further, the funds paid through the Upstream Capacity Charge may not be spent for a long time. We do not believe these charges are consistent with rate stabilization and prevention of rate shock for those customers.

For customers that are greater than 1,500 kW, our analysis and conclusions of Hydro's proposed NAP are similar to our review and findings for the customers between 200 kW and 1,500 kW. It is an improvement and better reflects cost causation principles than the current approach that socializes all network upgrades. The potential mismatch in timing between the customer's request for service (the "action" of the cost-causing customer) and the actual incurrence of the network upgrade costs are similarly problematic. The approach for these customers is not bound tightly to the actual costs that Hydro will incur to provide the customer with the service, as the acceleration of the transmission plan can occur long out into the future—much greater than ten years—and Hydro would not incur any costs until that time as well. That is, for an acceleration that takes place twenty years in the future, a customer would face a connection charge today, but Hydro would not make any investments until twenty years into the future, and there would be no cost of service implication until twenty years into the future.

A concrete example is given in one of Hydro's responses to an RFI.[77] The RFI shows a hypothetical example of Hydro needing to advance the upgrade of the Happy Valley power transformers to 2042 as a result of a 10 MW load addition in 2021. This means that Hydro will not need to invest until 2042 and given the extended time frame, there is significant uncertainty on the anticipated transmission cost. Nevertheless, the requesting customer is responsible today for $4.4 million. Similar to the policy for the customers between 200 kW and 1,500 kW, the policy for these customer types fails to reflect cost causation principles adequately and distorts the price signal that the requesting customer receives, biasing the customer's decision-making. There may be potential customers deciding not to request service even though the value they would obtain from the service would be higher than the cost of the request.

A feature of Hydro's proposed NAP that applies to all industrial customers greater than 200 kW is providing industrial customers with a revenue-based investment credit to offset the Upstream Capacity Charge. Hydro describes the purpose of the demand revenue credit as reflecting that

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"Hydro anticipates additional future demand revenues from the industrial Customer will be sustained for the long-term and will provide revenues that are expected to materially offset the additional cost of the required investment in common assets, thereby reducing the rate impacts on other customers."[78] This uniquely treats industrial customers and may not be consistent with preventing undue discriminatory preferences not founded on cost considerations.

B. Recommendations

We have four recommendations concerning the proposed NAP:

1. We recommend modifying the NAP to more completely reflect the goal of cost causation. We recommend that new and requesting load over a size threshold be given a choice to either pay for the necessary network upgrades or choose an interruptible rate. Specifically, we recommend the following high-level choices:

    - Option A: Be financially responsible for the network upgrades that exceed the customers' anticipated revenues over some fixed period and providing security equal to the anticipated revenues;

      or

    - Option B: Adopt an interruptible rate, which avoids those transmission costs. This choice requires assessing the appropriate level of curtailability/interruptibility to ensure that existing customers do not experience any reduction in the current reliability level.

2. For customers that select Option A (accepting financial responsibility for network upgrades), we recommend a policy of holding existing customers fully harmless from the effects of the new load on Hydro's costs. The requirement for customers to pay for the cost of upgrades that exceed anticipated revenues provides protections to existing customers by offsetting rate increases due to increases in rate base. It only partially achieves the hold harmless goal because it leaves uncertain full cost recovery for customers with significant mobility capabilities. Requiring backing the anticipated revenues by a financial security eliminates this uncertainty of whether existing customers are held harmless. The financial security would be decreased based on the customer's actual revenues until fully refunded. The requirements to pay for network upgrades exceeding anticipated revenues and providing security equal to the anticipated revenues would provide better protection for customers than the existing or proposed policy.

3. For customers that select Option A, we recommend that the required network upgrades should be determined on a "but for" basis through a system integration study of the current system structure, not on a forecasted basis, again to reflect the principle of cost causation.

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78 Newfoundland Labrador Hydro, "Labrador Interconnected System Network Additions Policy: Summary Report," December 14, 2018 at 7.

4. For customers that select Option A, these customers paying for network upgrades should be eligible for additional refunds as additional customers join the system over a pre-determined time horizon. This permits sharing among new customers of network upgrade costs.

Altogether, our four recommendations allow customers to select the most economical rate for their needs by allowing them to either adopt curtailable/interruptible rates or pay for network upgrades while emphasizing the principles of cost causation and holding existing customers harmless.

Appendix: Strategies to Manage Cryptocurrency Interconnection Requests

To provide context for how other jurisdictions with cryptocurrency customers have accommodated the new load and network upgrades, we reviewed four jurisdictions with large cryptocurrency customers that have prompted regulator intervention: Québec, Alberta, New York, and Washington.

In 2019, Hydro-Québec created a new interruptible rate class for cryptocurrency miners, with a cap on the total capacity available to cryptocurrency customers, and a requirement for the customers to pay upfront for connection requirements. In Alberta, a 42 MW cryptocurrency facility was accommodated through a ten-year electricity agreement that includes a provision for interrupting the load and a provision for economic development through a local investment of $100 million. Due to concerns of increased prices to native customers in New York, the New York Public Service Commission approved a new rate class for cryptocurrency customers that includes a marginal cost approach to electricity pricing—*i.e.*, rate class customers pay for incremental electricity costs related to meeting their load—and upfront payment for upgrades required to the system. Unlike in Québec, cryptocurrency customers served under the new rate class in New York are eligible for reimbursement of all or part of the upgrade costs. Finally, in Washington, two districts developed unique rate classes for cryptocurrency customers that require customers to pay for network upgrades and do not allow for refunds of network upgrades.

A. Québec

Hydro-Québec started offering cryptocurrency miners a rate of $0.0394/kWh in January of 2018, but miners responded quickly, and one month later, February, Hydro-Québec had over 100 inquiries.[79] Hydro-Québec became overwhelmed and ceased processing inquiries in March 2018.[80] Before a final determination on policy, Hydro-Québec tripled the prices it originally offered to new miners and implemented a moratorium on new miners.[81]

After a year of deliberating, in April 2019, Hydro-Québec's regulator (the Régie de l'énergie) issued a decision to provide a new 300 MW block to be allocated to new entrants on an interruptible

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79 See Congressional Research Service, "Bitcoin, Blockchain, and the Energy Sector", August 9, 2019, p. 14.

80 *Id.*, p. 15

81 *Ibid.*

rate.[82] This 300 MW block reserved for new cryptocurrency miners is in addition to the 158 MW granted to existing miners approved by Hydro-Québec and the 210 MW approved by municipal distributors. The new 300 MW block is open for applications from new entrants, and new entrants will be evaluated using the following criteria and weightings:[83]

- Number of direct jobs in Québec per MW: 30%
- Total payroll of direct jobs in Québec per MW: 30%
- Investment in Québec per MW: 30%
- Heat recovery: curtailed electricity use/total electricity use: 10%

Further, the creation of the reserved block allows Hydro-Québec to curtail electricity use during peak hours on request (up to a maximum of 300 hours a year), and customers must pay upfront for the total cost of the work related to the connection request, with no possibility of reimbursement.[84]

B. Alberta

Currently, Alberta has no special rate classes or tariff changes for cryptocurrency mining companies. However, the city of Medicine Hat developed an agreement to accommodate an additional 42 MW of cryptocurrency mining. In March 2018, the city of Medicine Hat, and Hut 8 Mining, the world's largest public Bitcoin miner, came to an agreement that would supply Hut 8 with 42 MW of electric energy and leased land for a ten-year term to build Hut 8's mining facility.[85] The electric agreement includes a provision for interruptibility.[86] In return, Hut 8 Mining has committed to investing $100 million into the project and surrounding community, which expands its current 18.7 MW operation in Drumheller, Alberta, to a total of 60.7 MW.[87]

C. New York, United States

During January and February 2018, Plattsburg, NY residents experienced electricity bills up to $300 higher than usual due to the combination of increased energy use from the cold and costs

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82 See Hydro Quebec Press Release, "The Régie de l'énergie hands down its decision in the blockchain file", April 29, 2019.

83 *Ibid.*

84 https://www.hydroquebec.com/data/chaines-de-blocs/pdf/R-4045-2018-B-0130-Demande-Piece-2019_05_23.pdf,

85 See Hut Mining Corp., "Hut 8 Mining Corp. Announces Electricity Supply Agreement with City of Medicine Hat", March 19, 2018, p. 1.

86 https://www.cbc.ca/news/business/hut8-medicine-hat-bitcoin-mining-1.4834027.

87 *Ibid.*

from additional power purchases, attributable in part to cryptocurrency mining loads.[88] In response, the New York Municipal Power Agency (NYMPA)[89] filed a rate-tariff amendment proposal to implement a new class: Rider A—Rates and Charges for High Density Load Service.[90] NYMPA requested that the State of New York Public Service Commission (PSC) implement emergency adoption of the new rate class to target high-density load (HDL) customers.[91] NYMPA classified the need for an emergency adoption because "HDL customers may use an exorbitant amount of resources, which harms the public welfare by shifting costs to municipal ratepayers while providing no general benefit."[92] The PSC accepted and temporarily implemented the new rate class (Rider A) outlined by NYMPA's tariff, on March 23, 2018,[93] and permanently on June 14, 2018.[94] In its Order, the PSC characterized HDL customers as those which "…impose capital and commodity costs on NYMPA members because of their unusually high energy demands while not maintaining a long-term presence in the community…increasing costs for all NYMPA members and their ratepayers while providing no corresponding benefit to the community."[95]

Customers under the HDL rate class are required to pay for a system interconnection ("feasibility") study and the entire cost of any new facilities necessary to supply the requested service as well as pay an increased volumetric electricity rate.[96] The new rate class distinguishes customers by their total load "density," exceeding 250kWh/ft^2/year, and maximum demand used or requested exceeding 300kW.[97] Further, the customers that qualify for the New York Authority Municipal and Rural Cooperative Economic Development Program do not qualify for the HDL rate class.[98] The payment for new facilities is required in cash before new facilities will be constructed and may be refunded over time. For the first ten years of service, the customer receives a refund equal to the lesser of the annual non-supply related revenues from the customer, or one-tenth of the cost

88 Congressional Research Service, "Bitcoin, Blockchain, and the Energy Sector", August 9, 2019, pg. 11.

89 NYMPA is composed of 36 municipal electric utilities, which abide by the rules and regulations set forth by the NYMPA tariff, see Case 18-E-0126, "Order Approving Tariff Amendments with Modifications", issued March 19, 2018, p. 1.

90 See Case 18-E-0126, "Order Approving Tariff Amendments with Modifications", issued March 19, 2018.

91 NYMPA claims that HDL customers are high volume data processing companies for cryptocurrencies, see Case 18-E-0126, "Order Approving Tariff Amendments with Modifications", issued March 19, 2018, p. 3.

92 Case 18-E-0126, "Order Approving Tariff Amendments with Modifications", issued March 19, 2018, p. 5.

93 *Id.*, p. 10.

94 Case 18-E-0126, "Order Adopting Action and Tariff Amendments on a Permanent Basis", issued June 15, 2018.

95 *Id.*, p. 2.

96 *Id.*, pp. 96–97.

97 New York Municipal Power Agency Generic Tariff, p. 96.

98 *Ibid.*

contribution paid by the customer.[99] The energy rate (per kWh) paid by HDL customers reflects the increased cost incurred to serve the HDL customers.[100]

D. Washington, United States

1. Grant County Public Utility District

Grant County has seen an increase in requests for power from cryptocurrency mining companies since the summer of 2017. Over 2,000 MW of power has been requested—75% of which comes from crypto mining companies.[101] Due to an increase in demand for power and the stress on the system to current non-high use power customers, Grant County PUD conducted a half-year analysis via staff outreach to current mining companies, presentations, public meetings, and additional independent research.[102]

After their analysis, Grant County PUD developed a new rate class for "evolving industries" customers and passed a three-phase rate increase for this rate class starting on April 1, 2019.[103] In its findings, the commission emphasized protecting ratepayers and differentiated cryptocurrency mining from data centers. Commissioner Tom Flint referred to the cryptocurrency customers as "unregulated and high risk," and stated that the rate increases were "the best way to ensure our ratepayers are not impacted by this unregulated, high-risk business."[104] The new rate class is defined as a customer that meets the requirement for "Concentration Risk" and one of the other two criteria:

1. Regulatory Risk—Risk of detrimental changes to regulation with the potential to render the industry inviable within a foreseeable time horizon.
2. Business Risk—Potential for cessation or significant reduction of service due to a concentration of business risk, in an evolving or unproven industry, in the value of the customer's primary output.
3. Concentration Risk—Potential for significant load concentration within Grant County PUD's service territory resulting in a meaningful aggregate impact and corresponding future risk to Grant County's revenue stream. The evaluation would begin to occur when the industry concentration of existing and additional customer loads in the service request queue exceeds 5% of Grant County PUD's total load.

99 *Id.*, p. 97.

100 *Ibid.*

101 See Grant County PUD Public Affairs, "Commission Recap: August 28, 2018", p. 3.

102 See Grant County PUD Public Affairs, "Commission Recap: August 28, 2018", p. 1.

103 *Ibid.*

104 *Ibid.*

The rate increases include a 15-percent increase in April 2019, a 35-percent increase in 2020, and a 50-percent increase in 2021. Because customers are transitioning to the new higher rates, each annual increase will be calculated on the difference between what the evolving-industry customer is currently paying and the higher target rate.[105] The decision requires that evolving-industry customers must pay upfront the cost for lines, poles, transformers, studies, and other equipment needed to expand or connect.

2. Chelan County Public Utility District

Due to an increase in demand for power from cryptocurrency mining companies, Chelan County PUD accepted a new rate for crypto mining customers starting April 1, 2019, and thus lifting the moratorium on new requests.[106] Chelan County PUD spent time reviewing risks, costs, and public feedback from various public meetings before coming to a solution that "protects existing PUD customers-owners and maintains opportunities for this emerging industry."[107] Schedule 36 is the new rate class that "strives to have operators carry the cost and risks—operational and financial—of providing them power [and] the rate will allow the District to serve cryptocurrency operations while protecting other customers from the uncertainty and volatility of the cryptocurrency industry."[108]

Schedule 36 rate class is defined as any customer "involved in computing or data processing load related to cryptocurrency mining, Bitcoin, blockchain, proof-of-work, or other loads having, in the District's determination, similar characteristics" of the following:[109]

1. High energy use density
2. High load factor
3. Highly variable load growth
4. High sensitivity to volatile commodity or asset prices
5. An industry with potential to become a large concentration of power demand

Customers in this rate class must pay an upfront capital charge based on the requested size of the new or increased amount of electric load.[110] However, the upfront capital charge does not apply to load amounts "approved by the District prior to the effective date of this schedule where":[111]

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105 *Ibid.*

106 See Chelan County PUD News, "Board approves new cryptocurrency rate effective April 1, 2019", December 3, 2018.

107 *Id.,* p. 1.

108 *Ibid.*

109 Chelan County PUD, "Electric Rate Schedules", p. 23.

110 Chelan County PUD, "Electric Rate Schedules", p. 23.

111 *Ibid.*

1. The customer has properly obtained District approval of the load prior to the effective date of this schedule
2. Load has not changed materially in load factor, size, or otherwise from the load approved by the District
3. The customer has fully complied and continues to fully comply with the District's rules, policies, and regulations
4. Load is transferred onto this schedule as of the effective date of the schedule.

The upfront capital charge is a one-time, dollars per kilowatt charge, and customers will be responsible for any line extension costs and applicable fees.[112] Customers under 5 MW are required to pay either $325/kW or $720/kW based on the substation location, and the capital charge for customers over 5 MW will be based on an engineering study.[113]

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112 Chelan County PUD, "Fees and Changes", p. 6.

113 *Ibid.*

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