CHRISTENSEN
ASSOCIATES
ENERGY CONSULTING

Cost-of-Service Methodology Review
Revised Version

for

Newfoundland and Labrador Hydro

by

Christensen Associates Energy Consulting, LLC
800 University Bay Drive, Suite 400
Madison, WI 53705-2299
Voice 608.231.2266 Fax 608.231.2108

November 15, 2018

Table of Contents

Cost-of-Service Methodology Review

Revised Version[1]

for

Newfoundland and Labrador Hydro

by

CHRISTENSEN ASSOCIATES ENERGY CONSULTING, LLC

November 15, 2018

[1] The original version of this report was dated March 31, 2016. On September 9, 2016, the Board granted Hydro's request for a delay in the COS methodology review, based on delays in the completion of the Muskrat Falls dam and related projects. The revised version of the report is intended to be submitted as part of the COS methodology review proceeding in 2019.

Summary of Revisions

This report was submitted originally to Newfoundland and Labrador Hydro (“Hydro”) on March 31, 2016. Since that time, some cost issues of that time have been resolved and new issues have arisen, inducing revisions to this report. A list of the main revisions appears below.

Section 3

- Section 3 titles have been reformatted to clarify the section’s topics. These now appear as Sections 3.1 to 3.4.

- Sections 3.1 and 3.2 expand the review of embedded cost-based methods that might be used to classify conventional generation costs. Section 3.2 focuses on alternatives for classifying Muskrat Falls power purchases when the generator’s units come on line.
- Section 3.3 expands the review of marginal cost-based methods. The review documents the absence of marginal cost approaches in Canada and mentions their use in the U.S.

- Section 3.4 has been revised to reflect Hydro’s system planners’ change in perspective on the capacity content of wind generation. The planners have concluded that the purchased power from two wind generators should now be factored in to forecasts of system generating capacity, while previous evidence had suggested to them that wind generation costs might best be classified as 100% energy.

Section 4

- Section 4.2 was simplified by removing analyses of seasonal loss patterns that are now out of date. Updated similar loss information is not available.

Section 5

- Section 5.1 provides updated information on the treatment of the rural deficit in Cost of Service (“COS”).

- Section 5.2 has been updated to reflect the outcome of the review of conservation and demand management (“CDM”) charges in the 2013 General Rate Application (“GRA”), including statements made in the final order [Order No. P.U. 49(2016)].

- Section 5.3 updates the description of Hydro’s investigation of its ability to track operating and maintenance expenditures on specifically assigned transmission facilities of Island Industrial customers.

- Section 5.4 provides a revised discussion of the COS considerations associated with Hydro’s capacity assistance agreements.

- Section 5.5 has been revised to reflect changes in Hydro’s view of the requirement for the Newfoundland Power Generation Credit.

- Section 5.6 provides a more extensive review of export-related costing and revenue recovery options than previously.

1. Introduction

Newfoundland and Labrador Hydro ("Hydro") requested Christensen Associates Energy Consulting to conduct a review of the utility's cost-of-service ("COS") methodology, focusing on the system that is likely to emerge following its transition to integration with the electricity grid of eastern North America. This transition will occur upon completion of several major construction projects and the development work associated with them, anticipated to occur in the latter half of 2020. The key projects involving Hydro are: 1) the new 824 MW Muskrat Falls ("MF") generation facility on the Churchill River in Labrador; 2) the Labrador Transmission Assets ("LTA") that will assist in coordinating generation at Muskrat Falls and Churchill Falls; and 3) the Labrador-Island Link ("LIL"), a direct current ("dc") line that connects Muskrat Falls to Soldiers Pond near St. John's. In addition, Nalcor Energy ("Nalcor"), Hydro's parent company, has partnered with Emera to develop the Maritime Link ("ML") that connects Nalcor with the grid in Nova Scotia and points beyond.

The cost of the MF, LIL, and LTA projects will, by government direction, be borne by customers paying Island Interconnected rates (beginning with the Muskrat Falls Project in-service date) as these facilities are being constructed for them. Additionally, as a result of the arrival of new supply on the Island, Hydro will wind down the Holyrood generation facility, replacing its thermal generation with Muskrat Falls' hydro power.

This COS methodology review is part of a general review process leading up to the in-service date for Muskrat Falls and its associated transmission facilities. The review was anticipated to commence at the conclusion of the 2013 General Rate Application ("GRA") process, during which many COS methodology issues were reviewed. However, due to the delayed in-service date for the Muskrat Falls Project, the cost of service methodology review process was delayed and is now expected to commence in early 2019. This report makes reference to several of these issues and the related discussions and documents from the 2013 GRA and the 2017 GRA.[2]

The COS process is a direct consequence of the dominating presence of common and joint costs in the revenue requirements of electricity services. Large shares of the total costs associated with the provision of service are both common and joint: many consumers are served at the same time—in common; similarly, multiple services such as operating reserves are provided jointly by a single facility—all at the same time. Methodology review is periodically required to resolve issues of how best to attribute the total of common and joint costs to the various classes of consumers when costs cannot be assigned to individual consumers.

The focus of the COS review issues in the 2013 GRA was the methodology to support proposed rates. In contrast, this COS methodology review concentrates on the methodology issues that surround the completion of the new generation and transmission facilities. This review evaluates Hydro's current cost allocation methods in light of the above changes and recommends changes to this methodology where needed. The 2013 GRA Supplemental Settlement Agreement mentions the current review specifically, and states that it will "include a review of: (i) all matters related to the functionalization, classification and allocation of transmission and generation assets and power purchases (including the determination whether assets are specifically assigned and the allocation of costs to specifically assigned assets) and (ii) the approach to conservation and demand management ("CDM") cost allocation and recovery."[3] This report will discuss each of these issues.

The review begins with a "jurisdiction" question, investigating the potential for combining the two previously separate interconnected systems in the Island and Labrador. Sections on

[2] The 2013 GRA *Settlement Agreement* and *Supplemental Settlement Agreement* are untitled documents dated August 14, 2015 and September 28, 2015, respectively. The Final Order is No. P.U. (49)2016, issued Dec. 1, 2016.
[3] *Supplemental Settlement Agreement*, paragraph 13, p. 3.

the core functions of generation and transmission then follow. (The distribution function is not part of this review.) A final section covers a set of topics outside the main functions: the treatment of: 1) the rural deficit; 2) CDM costs; 3) specifically assigned costs; 4) the Newfoundland Power Generation Credit; and 5) the value of export revenues as a rate mitigation initiative that may be used to offset Hydro's cost of supply. An appendix with a separate list of recommendations follows.

2. System Definition

Issue. Hydro will have physically connected its two historically separate integrated systems on the Island and in Labrador. Should Hydro now consider these systems to be a single integrated system for COS purposes?

Background**.** There are technical and institutional considerations to bear in mind in evaluating this issue. From a technical perspective, the interconnection of these two systems is unconventional by North American standards. Unlike circumstances in which a corporate merger brings together two hitherto separate but contiguous service territories in a market with multiple ac transmission lines and points of connection, this event connects two service territories made "contiguous" by means of a pair of high voltage direct current ("HVdc") circuits.

Furthermore, the power flow pattern anticipated for Hydro's physically interconnected system is not conventional when compared with the rest of the Eastern Interconnection.[4] Hydro expects that in virtually all hours, barring an outage at Muskrat Falls or on the LIL, power will flow in one direction, south to the Island and points beyond. This is unconventional for ac-dominated meshed networks, but consistent with conditions in which dc transmission technology is utilized, especially in transporting power over long distances.

[4] The Eastern Interconnection is the largest ac-circuit grid in North America. It covers all of the United States east of the Rocky Mountains, approximately, except for the ERCOT region of Texas, as well as Manitoba, Ontario, and the Maritime Provinces of Canada. Quebec is not part of the Eastern Interconnection.

From an institutional perspective, one can find cases in the Eastern Interconnection in which utilities merge but contiguous service territories are not combined. For example, Emera Maine possesses two contiguous service territories due to a recent merger and, for the moment, maintains separate COS studies. Ameren's subsidiary, Ameren Illinois, preserves three rate zones derived from the boundaries of service territories previously owned by separate utilities.[5] This is partly an artifact of utility regulation, which has preserved a requirement that Ameren submit three separate COS studies. In contrast, Georgia Power acquired Savannah Electric & Power and simply merged their service territory into Georgia Power's, both in terms of cost of service and rate design.

Thus, the technical experience does not strongly suggest that the two regions be combined, and the institutional experience in North America is mixed.

Hydro has a number of external institutional influences that suggest continuation of separate treatment. The Muskrat Falls Exemption Order requires that the costs "shall be recovered in full by Newfoundland and Labrador Hydro in Island Interconnected rates charged to the appropriate classes of ratepayers."[6] This obligation enshrines in law the cost causation underlying the decision to invest: least cost planning of new generation capability to serve the island.[7]

As well, Labrador industrial rates, which serve two large customers, have two components arising from separate sources.[8] The cost of generation services is subject to direction by the Provincial Government and is outside the COS study of Hydro. Transmission costs are within

[5] Ameren Illinois' web site states: "Service territories formerly known as AmerenCIPS, AmerenCILCO and AmerenIP are now referred to as Rate Zone I, II and III, respectively." These service territories cover the southern two-thirds of Illinois.
[6] Order in Council OC2013-343.
[7] The objective of least cost planning is articulated in *Nalcor's Submission to the Board of Commissioners of Public Utilities with Respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project*, Nov. 10, 2011, p. 4.
[8] One of the two, Wabush Mines, has been closed and in receivership, with resulting loads at a very low level. However, Tacora Resources is currently in the process of reopening the mine.

Hydro's COS. This bifurcation would complicate cost allocation for industrial customers in a combined jurisdiction. Creating a single industrial class would require unbundling of pricing.[9] Retaining two separate classes would likely be more sensible, significantly negating the benefits of creating a combined service territory. Another factor suggesting separate treatment would be that the marginal cost to serve the two industrial groups could be quite different at times, given the possibility of transmission constraints separating the two regions temporarily and unexpectedly.

Additionally, Labrador's cost of service and, hence, retail pricing is very low compared to Island rates. In the 2015 COS study, Labrador rural interconnected average cost to serve is just 2.8¢/kWh, while Island average cost to serve is 8.4¢/kWh. The source of the difference is the dominant role in serving Labrador of Churchill Falls power, which currently costs just 0.2¢/kWh. Unifying service territories would likely have significant rate impacts. Such impacts might appear to be cost justified, but the contractual elements providing low-cost Churchill Falls power to the Labrador interconnected System will not be negated by the completion of the LIL.

Discussion/Analysis. It appears that Hydro can resolve this issue in two ways that potentially lead to similar outcomes. First, the COS methodology could retain separate treatment of the two interconnected systems, based on the belief that all new and future assets and expenses will be readily separable by service territory. This would be computationally simple in the short run and would conform to cost assignment requirements. Second, the COS methodology could unify the two areas but retain separate rate classes based on geography, thus retaining the ability to allocate costs in the mandated fashion. This alternative might more readily accept future cost allocation in cases of assets or expenses that both regions must share. If this unification is not performed, then a "jurisdictional" assignment of costs must continue.

[9] See Newfoundland and Labrador Hydro, *2016 Labrador Industrial Rate Submission*, December 22, 2015.

The combination of institutional and technical considerations appears to indicate that combining regions would be challenging, although possible. Costing theory and power flows do not necessarily line up with contractual mandates that assign the resource cost of power from specific locations to specific groups of customers. However, the power flows here appear to reasonably approximate the contractual mandates. It is difficult to see how a combination of regions could improve or simplify the allocation of costs after commissioning of the Muskrat Falls project.

Regarding combination of existing assets, this would not be practical for generation, due to the contractual arrangement in Labrador whereby Churchill Falls Recall Power serves Labrador Industrial customers at a price determined outside the COS and GRA process. Even combining transmission assets would be difficult due to statutory requirements. The LIL and LTA are not cost obligations of Labrador customers, but of Island Interconnected customers only.

***Recommendation*.** We recommend that Hydro retain its practice of separate treatment in COS of the two interconnected regions. Costs shared by the two regions can continue to be separated prior to computation of costs by region, as performed by the current model.

3. Generation

Issues. Hydro's generation mix and regional configuration will change substantially when the Muskrat Falls project is fully commissioned, which is anticipated to occur in the second half of 2020, with 2021 being the projected first full calendar year of service of these facilities. How should this reconfiguration affect Hydro's approach to the classification and allocation of generation costs?

3.1 Classification and Allocation of Current Generation

***Background*.** At present, Hydro classifies and allocates its generation costs in a manner that attempts to recognize each facility's role in generation dispatch. Peaking units are classified as entirely demand-related while other units are recognized as each having an energy and demand component. System load factor is the leading basis for classification for these units. The method of classification varies with the type of generator and region. Table 1 provides a summary.

Table 1
Current Classification and Allocation of Generation Assets

System	Generator Type	Classification	Allocation
Interconnected			
Island	Hydraulic	System Load Factor	D: 1 CP; E: annual Energy
	Holyrood	Capacity Factor (5-yr)	D: 1 CP; E: annual Energy
	Gas Turbines	Demand	1 CP
	Diesel	Demand	1 CP
Labrador	Gas Turbines	Demand	1 CP
	Diesel	Demand	1 CP
Isolated			
Island	Diesel	System Load Factor	D: 1 CP; E: annual Energy
	Other	System Load Factor	D: 1 CP; E: annual Energy
Labrador	Diesel	System Load Factor	D: 1 CP; E: annual Energy
L'Anse au Loup	Diesel	Demand	1 CP

The NARUC COS Manual reveals many different ways to classify generation plant. Some are demand-only in nature and others are a combination of demand and energy, but are termed "energy weighting methods."[10] Since none of the conventional approaches can claim unchallenged superiority, the current Hydro approach of classifying on the basis of generator type, and using both demand-only and energy weighting methods, appears to be within the norms of industry practice.

The system load factor approach to cost classification attributes a share of generation investment cost to energy causation based on the ratio of average to system coincident peak production. This formulation assumes that generation investment to meet average load should be distinguished from generation investment designed to meet peak demand.

[10] The NARUC Electric Utility Cost Allocation Manual, January 1992. Generation cost classification and allocation methods are discussed beginning on p. 39.

System load factor identifies the share of production assumed to be related to base and intermediate generation and that is classified as energy-related. The generation cost not accounted for by energy classification is attributed to peak demand.

Hydro classifies the Holyrood thermal generation facility separately, based on the average capacity factor of the individual plant, as opposed to the load factor of the system, which is based on system peak and system production rather than plant production. (Capacity factor is average quantity generated divided by nameplate unit capacity.) This approach assumes that the energy-related component of a generator is revealed by the degree to which it is utilized. A generator in frequent use has a high capacity factor and should therefore have a high energy share while a peaking generator, being used in fewer hours, has a lower capacity factor and a lower energy share. In brief, the capacity factor approach is akin to applying the system load factor approach (which is based on loss-adjusted sales rather than generation) to an individual generator.

Table 1 displays the classification and allocation of the generation cost elements of rate base, but does not display the role of expenses, especially fuel costs. At present, the dominant component of fuel cost is no. 6 fuel for the Holyrood generating station. No. 6 fuel is classified as entirely energy-related while other fuels are classified in the same manner as the classification of the generator. The effect of this large fuel cost is that approximately 85% of the Holyrood component of revenue requirements is classified as energy-related.[11]

Hydro also currently engages in power purchases. The Island Interconnected system obtains the majority of its purchases from non-utility generation consisting primarily of hydro resources, along with some wind purchases. The hydro purchases are classified in the same

[11] For the 2007 and 2004 Test Years, respectively, 86% and 82% of the Holyrood revenue requirement was classified as energy-related. For the 2015 Test Year adjusted to reflect No. 6 fuel cost at $64.41 per barrel, approximately 84% of overall Holyrood costs would be classified as energy-related.

manner as utility hydro resources (system load factor) and the wind purchases are currently classified as energy-only.

Labrador Interconnected purchases are entirely from Churchill Falls, and are classified on the basis of Labrador system load factor. Isolated system purchases occur mostly at L'Anse au Loup. Those purchases are classified as energy-only due to their non-firm nature. The L'Anse au Loup system also has a diesel unit. It is classified as demand-related since it serves peaking load not covered by power purchases from Hydro-Quebec.

Allocation of energy-related costs occurs on the basis of annual energy, while demand-related cost allocation is based on the 1 CP method, *i.e.* usage by each class in the single highest coincident peak hour of the year. These practices are conventional by industry standards, although utilities use a variety of CP definitions to reflect the seasonality of their peak usage.

It is worth mentioning that the selection of coincident peak measure was the subject of debate in 2001. Hydro and its intervenors debated the relative merits of 1 CP, 2 CP, and 3 or 4 CP as representatives of Hydro's generation peak conditions. Arguments claimed alternatively that February was responsible for preponderant instances of peak demand, that January and February were dominant, and that peaks had been recorded to occur in all four winter months (December through March) if enough years were considered in the review.

This debate mirrors debate in the industry about the choice of demand allocator. Theory suggests that a single annual CP value is the best measure of how classes contribute to peak demand. However, single values can be prone to variability over time and instances of anomalous behavior by a class that can skew results. Multiple-month averages are more stable, but dilute the peak nature of the signal. Additionally, the seasonality of the utility matters, with single-season utilities favoring a 3 CP or 4 CP measure and non-seasonal utilities preferring a twelve-month average. The NARUC COS Manual contains a discussion of this issue, but offers no general recommendation.[12] In Hydro's case, the Newfoundland and Labrador Board of Commissioners of Public Utilities (Board) concluded in 2002 that 1 CP was simple and that other measures had not proved demonstrably preferable.[13]

In Hydro's case, peak periods usually occur in periods of sustained extreme cold. A CP allocator that utilized multiple months *e.g.* a 4 CP allocator that averaged values for the winter months of December through March would likely capture one hour of each winter's coldest period, but then dilute the measure with three other hours that are much less extreme and thus feature lower peak demand than many other hours of the cold "snap". An alternative might be to use a method applied at Manitoba Hydro, which makes use of the fifty highest demand hours of the winter. Such a measure requires recording and averaging much more data, but is likely to be stable and to capture behavior in the many hours associated with peak demand. Taking this approach to its logical conclusion, one might consider utilizing a marginal cost-based combined classification and allocation approach, which includes all hours, and uses marginal cost to value each hour. Section 3.3 discusses this approach.

3.2 Classification and Allocation of Muskrat Falls

***Discussion/Analysis*.** The composition of Hydro's generation assets and expenses will change significantly after 2020, with the introduction of Muskrat Falls' 824 MW of new installed hydraulic capacity (790 MW of firm capacity), linked to the Island and to the Eastern Interconnection by undersea dc lines. The addition of Muskrat Falls to the Hydro system facilitates the eventual retirement of the Holyrood thermal generation unit.

[12] NARUC, Electric Utility Cost Allocation Manual, January 1992, Chapter 4, p. 41*ff*.
[13] Various sources include: Public Utility Board, Order No. P.U. 7 (2002-2003), Direct and 2nd Supplemental Testimony of Larry Brockman (August 2001, November 2001), Pre-Filed Supplementary Testimony of C.F. Osler, and Supplementary Evidence of J.A. Brickhill. (All documents supplied by Hydro.)

Muskrat Falls and the associated transmission links are being constructed because they were deemed the least cost means to satisfy projections of the energy and reliability needs of the Island. The expected export of wholesale power through Nova Scotia to the competitive wholesale markets of the U.S. Northeast increases the potential utilization of Muskrat Falls capacity, thus improving the viability of Hydro's overall resource package. The practical operation of these facilities is expected to fulfill this strategy, with power flows south forecasted to approach the limit of transmission capacity in many hours.

Hydro will pay for the new generation services of Muskrat Falls via a stream of power purchases scheduled to recover the full costs of the new generation source over a fifty-year period. Payments will be predominantly monthly lump sum charges covering capital cost and operations and maintenance ("O&M") expenses. These payments will occur at the start of every month, covering deliveries for that month. This practice is out of the ordinary in that payment for energy usually occurs following delivery. The pre-payment plan has implications for Hydro in that it will need to incorporate this pattern into its estimates of working capital. The contractual agreements between Hydro and MF also include periodic true-up payments covering the difference between actual and forecasted O&M costs and the cost of sustaining capital.

How should Hydro classify and allocate the significant generation costs associated with the Muskrat Falls project? The project is very large and appears materially different from the leading generation source that it is replacing, Holyrood. Hydro does not have an obvious approach suggested by industry practice or its existing generation, or perhaps even regulatory precedent in the province due to the project's novel characteristics. Hydro could try to proceed as it does with its current generation units by selecting an appropriate generator-specific method that would reflect the plant's baseload role in supplying energy. Alternatively, Hydro could revise its practice for all its units, and bundle them all together into a single allocation mechanism.

First, Hydro could classify the costs of the new facility in the same manner as other hydro facilities, namely on the basis of SLF. This approach assumes that Muskrat Falls would be operated in the same manner as Island hydro generation, and would play the same role in generation dispatch. However, Muskrat Falls is on the mainland, connected to the Island's customers via an HVdc line that may encounter transmission constraints. Additionally, the new facility is large relative to other Hydro facilities once the associated transmission costs are included. The contractual aspects of the power are unusual as well: lump sum monthly charges that are not strictly dependent upon volume.

Another consideration associated with the SLF approach is the impact of the approach on the demand/energy split in generation costs. At recent SLF levels of about 55%,[14] a sizable portion of Muskrat Falls would be treated as energy-related. In contrast, Holyrood, which Muskrat Falls will largely replace, has historically had a revenue requirement that has been approximately 85 to 90% energy-related due to the preponderant expense of fuel cost. One implication of the substitution of Muskrat Falls for Holyrood generation under the assumption of SLF classification is that the demand composition of generation revenue requirements may rise substantially. This change may or may not reasonably represent the change in cost causality due to the substitution of Muskrat Falls for Holyrood but it would likely shift the cost burden in the direction of peak-coincident classes or customers.

Yet another classification alternative is the *equivalent peaker* methodology. This approach postulates that any cost per unit of capacity that exceeds that of a peaking unit should be classified as energy-related, while the peaking unit cost component is classified as demand-related. Baseload and intermediate units are typically more expensive to build than peaking units, and that extra expense is viewed as being energy-driven. That extra cost is incurred in order to save fuel cost relative to peaking unit production, with generation investment occurring to attain least cost production.

[14] SLF value used in 2015 test year COS model.

The *equivalent peaker* method is viewed by some as giving formal recognition to the generation planner's selection of a range of plants to serve the system. (The argument is that generation planners must design their system to meet not only peak demand, but also the full range of load durations, and to do so at least cost. Costs not incurred to meet peak load are deemed to be incurred to supply energy.)[15] Muskrat Falls is designed to operate as a baseload unit. The equivalent peaker approach would recognize that fact by treating much of its cost as being energy-related.

To implement this approach, the utility develops an estimate of the cost per kW of a peaking unit, and compares that with the cost per kW of the new generation unit, being careful to use the same vintage as the plant under study. The actual computations can be complex, since they allow for plant vintage and financial cost details. It is possible to illustrate this approach in simplified form here. The levelized annual revenue requirement for Muskrat Falls generation and its associated transmission investments of LIL and LTA is approximately $1,249 per kW, while the estimated levelized annual cost for a new CT is $248 per kW, stated in CDN$.[16] The demand share of Muskrat Falls would be $248/$1,249, or about 20%. The energy share would be the residual 80%, which is slightly below the 85% historical share of Holyrood's revenue requirement that is classified as energy-related. Based on this estimate, it may be that the final shares developed by the equivalent peaker approach will better account for the main reason underlying the resource choice favoring Muskrat Falls—very large fuel costs savings over future decades. In contrast, Hydro's longstanding SLF approach would likely obtain an approximate 45/55 split between demand and energy, a result which seems out of step with Muskrat Falls' envisioned purpose of serving base load and, in so doing, producing substantial fuel cost savings. (Note that the Holyrood demand percentage is not a target, since Muskrat Falls' operation may differ somewhat from that of Holyrood in the past. Modest changes in classification suggest

[15] NARUC, *Electric Utility Cost Allocation Manual*, January 1992, page 53*ff*.
[16] These calculations are provisional, based on Hydro's informal estimates.

modest changes in cost allocation are likely. Whether a modest change reflects cost causation, though, is the key question.)

The NARUC Utility Cost Allocation Manual describes the equivalent peaker approach that includes a subsection entitled, “A Digression on System Planning with Reference to Cost Allocation”. The equivalent peaker method is thus tied to the system planner’s perspective on generation. On this basis, the equivalent peaker approach may merit review.
The equivalent peaker methodology received serious consideration by the Board in the 1992 COS methodology review. The approach was ultimately rejected for reasons of computational challenge, and plant vintage and valuation issues. However, those issues apply with less force now, since the peaking unit computations pertain to a plant of current vintage. As a result, this approach may deserve renewed consideration for its application to the classification approach for Muskrat Falls.

Additionally, if the equivalent peaker approach, with its grounding in system planning, appeals conceptually to Hydro, the utility may wish to consider applying this approach to its entire fleet of Interconnected generation. The theoretical advantage is that each unit is judged for its demand and energy components under the same set of assumptions. The challenge is to compute the current value of each generation unit. (Indexes like the Handy-Whitman are available for this purpose.)

Following the introduction of Muskrat Falls power to the Island, Holyrood’s role will change and the plant will eventually cease to perform as a generating unit. In the interim, the plant’s net book value and fuel purchases will be reduced sharply in significance. Under the current methodology, the plant’s capacity factor will fall gradually as its usage rate declines. The cost allocation implications will involve a reduction in fuel cost (classified as energy, of course) and a resulting shift in the direction of demand-related costs. With the plant coming to be used more for peaking purposes, serving in a standby role in its last years, this shift will be sensible. Another variant of this approach would be to shift the five-year average capacity factor to a forecast-only approach, causing cost allocation to reflect immediately the plant's changed role.

Holyrood's change in usage eventually will amount to Hydro using the unit as a synchronous condenser, available for system stability but not supplying energy. At that point, it would begin to be treated as transmission rather than a generation facility. Hydro could sub-functionalize it as such and then classify it in the same manner as general-purpose transport services. (Please see the next section for a discussion of the classification and allocation of this type of transmission facilities.)

Hydro's current generation cost allocation methods, as mentioned, utilize a 1 CP approach for demand-related costs and annual energy for energy-related costs. Both approaches are long-established and well recognized in the industry. In the transmission section, below, the report discusses several approaches to demand cost allocation. One of these arises from a U.S. Federal Energy Regulatory Commission ("FERC") review of transmission cost allocation practice. It raises the issue of whether the 1 CP measure is preferable for cost allocation. Certainly, this measure is appealing in theory: it identifies class shares at the single hour of highest usage in the year, when the level that system planners recognize as the level of service to attain is recorded. Its weakness is the risk of anomalous behavior that might create variability over time. The issue is reviewed in the transmission section. The recommendation there—consideration of a 3 CP approach—may also be applicable here.

3.3 Marginal Cost-Based Cost Allocation

The upcoming transformation of the system and the advance of costing capabilities in North America and at Hydro offer an opportunity to expand the range of costing methodologies relative to traditional demand-energy classification. The demand-energy approach, applied according to a variety of methods, attempts to compartmentalize costs in some sensible manner between costs incurred to meet peak demands and costs incurred to supply total energy. Its virtue is the effective use of limited available data to impute cost causation. Its weaknesses are that the information utilized is limited and there is no single preferred method of classification.

Marginal cost is defined as the change in total costs associated with a small change in the level of service provided. The concept is important because the price in a competitive market, where demand equals supply, is the marginal cost of providing the good or service. Marginal costs serve as highly desirable benchmarks of resource value because they communicate to all parties the economic worth of electricity services provided in particular timeframes, where services include energy and reserves. For regulated industries that in the past have not been viewed as workably competitive, marginal cost of service is a vital costing and pricing guideline for regulators.

Marginal costs have not been widely used for cost allocation in the past due to their computational challenges and the fact that total marginal costs do not necessarily equal the embedded costs that are the object of revenue recovery, subject to regulatory approval. However, marginal costs can serve to develop an allocator that can be applied to embedded costs.

Marginal cost-based methods of cost allocation are particularly attractive for two institutional reasons. First, regulators seek methods, as a matter of public policy, that yield prices for public services that obtain improvements in resource efficiency. Thus, regulated prices should reflect the economic resource costs associated with regulated utility services, subject to the need to ensure revenue recovery. Second, with the development of wholesale markets, marginal costs are directly observable in wholesale prices. Thus, marginal costing offers the opportunity to link cost allocation, which guides regulated retail pricing, to wholesale market prices. As a result, marginal cost is playing an increasingly important role in wholesale and retail pricing, including cost allocation. The integration of marginal costs into cost allocation provides the basis to obtain improved efficiency. As a consequence, the allocation result has the potential to more closely adhere to the efficient outcomes that would result from competitive markets.

Marginal cost-based methods take advantage of the emergence of sophisticated techniques for measuring or estimating cost over hourly (and even finer) time intervals. The development of wholesale markets for energy, reserves services, and capacity, along with advances in internal cost computation advances, provide the means to project marginal costs over forward periods. This means that estimating the cost to serve a class of customers can be calculated by developing hourly marginal costs and applying them to hourly load profiles. The result is an annual total marginal cost for each class (and then a sum across classes representing the utility as a whole). By calculating each class's share of the utility total, one can derive a cost allocator applicable to generation services.

Using this approach, it is no longer necessary to infer demand and energy classification results. Instead, the derived marginal cost shares are applied directly to financial costs of generation. From a conceptual or methodological point of view, this approach has a virtue of taking account of customer behavior in all the hours of the year, in contrast with traditional CP methods on the demand side that typically make use of a very limited number of hours.

In summary, the incorporation of marginal cost analytics within cost allocation captures the economic worth of the resources used in the provision of service. This result is both fair and efficient, and holds for both the internal cost and market-based marginal cost framework. Marginal cost-based COS provides cost foundation and detail by timeframe that is not available through conventional methods.

Thus, the marginal cost perspective provides the means to capture explicitly the components of generation services (including energy and reserves) attributable to each class. Classes that tend to have high but variable usage at times of high marginal reserves cost have their costs for the full year recorded. A utility that opts for marginal cost-based allocation of embedded costs can thus avoid classification debates (energy and demand shares of costs) and debates as to which measure of peak demand is most appropriate (*e.g.* 1 CP vs. 3 CP vs. 12 CP) but then must meet the challenge of modeling marginal cost.

Applying the marginal cost method requires hourly marginal cost and class load profile data sufficient to represent the range of likely market conditions that may apply in the service territory. Hydro already has transmission-level hourly profiles for its NP and industrial customers, and for its aggregate rural customers on the Island and in Labrador. The utility has been developing forecasted hourly wholesale price/marginal cost scenarios for the forecasted early years of Muskrat Falls service, and is thus well on the way to operationalizing this approach. These forecasts include not only Hydro jurisdiction capacity conditions but also external market conditions.

Marginal cost-based allocation of embedded costs may seem to be novel, but variants of this approach have been in use for many years in a number of regulatory jurisdictions. West coast U.S. utilities have used this approach for twenty years.[17]

The Canadian practice of generation cost classification and allocation is summarized in Table 2 for large, vertically integrated utilities. At present, no utility or jurisdiction makes use of marginal cost in cost allocation. All utilities apply some form of energy and demand allocator method to classify generation cost. Cost allocation occurs via coincident peak (“CP”) demand allocators and annual usage energy allocators.

Most utilities apply the same classification approach as Hydro in that they use different approaches for different types of generation, rather than combining all generation costs and allocating them collectively.

[17] Example utilities include Pacific Gas & Electric, Southern California Edison, and Portland General Electric.

Table 2

Classification and Allocation of Generation Costs by Major Canadian Utilities [18, 19]

Jurisdiction	Utility/Type of Gen.	E/D Classification E=energy, D=demand	Allocation	
			Demand	Energy
British Columbia	**BC Hydro**			
	Hydro	45% E, 55% D	4 CP	Ann. kWh
	Thermal	by generator: SLF 60%E, 40%D for key interconnected unit		
	IPP - PP	100% E		
	Fortis BC	based on PP contract 80% E, 20% D	2 CP	Ann. kWh
Saskatchewan	**SaskPower**			
	generation rate base	equivalent peaker	2 CP	Ann. kWh
	Purchased Power	contract-based		
	Fuel	energy		
Manitoba	**Manitoba Hydro**			
	most generation	SLF currently; previously "weighted energy" (MC of energy)	top 50 Winter hours (kW) = "Winter CP"	Ann. kWh
	wind, water rentals	100% energy		
Quebec	**Hydro-Quebec**			
	all purchased power	direct assignment		
New Brunswick	**NB Power**	Peak and Average	3 CP (winter months)	Ann. kWh
Nova Scotia	**Nova Scotia Power**			
	conventional gen	SLF	3 CP	Ann. kWh
	wind	90% E, 10% D		
	Purchased Power	wind PP like owned wind; fossil fuel PP like owned fossil fuel		

[18] Information is of varying vintage: BC Hydro (2015 presentation); Fortis BC (2009 COS); SaskPower (2017 COS); Manitoba Hydro (2017); NB Power (2017); Nova Scotia Power (2013 COS Methodology proceeding).

[19] Notes: BC Hydro thermal refers to Prince Rupert generating station. SaskPower purchased power classification varies by purchased power contract. Hydro-Quebec Distribution purchases power and uses class-specific unit costs to compute class allocations. NB Power: "peak and average" is a combined demand-and-energy methodology. The NARUC COS Manual provides a description at page 57*ff* in the section entitled "Judgmental Energy Weightings". Nova Scotia Power: the utility treats its purchased power in the same manner as other generation, by type. Purchased conventional generation is classified in the same manner as owned conventional generation; purchased wind is classified in the same manner as owned wind.

Manitoba Hydro constitutes an interesting special case. Until recently the utility applied a "weighted energy" allocator to generation costs, which consists of marginal cost-based allocation of generation services. (Manitoba Hydro also utilized a variant of the process in allocating transmission costs.)[20] In a recent COS methodology proceeding, the utility argued for retention of its weighted energy allocator. However, the Public Utilities Board of Manitoba (Manitoba Board) found that the allocator lacked elements of demand, a shortcoming that it felt was determinative.[21] As a result, it required Manitoba Hydro to adopt a system load factor approach. The demand allocator that it recommended is a "winter CP" formulation in which usage in the fifty winter hours with the highest demand is to be averaged to produce class peak period usage totals. Curiously, the weighted energy (marginal cost) approach could readily have been retained had marginal cost included both energy and reserves instead of energy alone.

The Manitoba Hydro example, though terminated by regulatory ruling, is useful in that it provides evidence that marginal cost-based cost allocation has been used in Canada. Manitoba Hydro argued that its weighted energy allocator was based on market prices in the Midcontinent ISO ("MISO") and that these prices were augmented by a capacity adder based on the utility's own capacity costs as developed for its Curtailable Rate Program. Intervenors, incidentally, largely supported the weighted energy allocator, although they questioned the need for a capacity adder, out of concern that it might double count capacity costs already present in MISO reserve prices. One intervenor, large customers, preferred a separate demand allocator but use of weighted energy as an energy allocator.

The Manitoba Board did not address the merits of Manitoba Hydro's proposed approach, but stated its preference for a separate representation of demand and energy.[22] They chose

[20] The Manitoba Hydro method makes use of hourly marginal costs and loads in all hours of the year, by class for generation cost allocation. The utility additionally uses loads in many hours, the 50 highest-demand hours each in summer and winter, for transmission cost allocation.
[21] Manitoba Public Utilities Board, *Order 164/16. Order in Respect of a Review of Manitoba Hydro's Cost-of-Service Study Methodology*, December 20, 2016.
[22] *Ibid*, p. 53.

a "top 50 Winter Coincident Peak hours" demand allocator and unweighted energy for an energy allocator. The demand allocator is an improvement upon a conventional CP allocator since it uses more hours and will strongly represent demand recorded in an interval of extreme weather.

The rejected approach appears to be within Hydro's capabilities as they will exist upon completion of the Muskrat Falls project. The utility will have access to both historical and forecast wholesale market data from ISONE and NYISO, and will have its own estimates of internal capacity cost that might be used to supplement wholesale market prices.[23] Additionally, it does not appear that the Manitoba Board ventured criticism of the methodology, but instead simply expressed preference for its own separate classification and allocation scheme.

The U.S. experience illustrates how limited the application of marginal cost-based cost allocation has been. Other than a few west-coast utilities in California, Oregon, and Washington, this approach is found in Maine and New Hampshire, and a few other jurisdictions such as Nevada. California is perhaps the best-known proponent of the approach, since marginal cost-based cost allocation is applied to all functions, not just generation.

It is worth mentioning, as well, that North American jurisdictions that have deregulated their generation and retail services functions offer additional examples of marginal cost-based cost allocation. This occurs as a natural outcome of the process of wholesale purchases by retail energy providers. The cost of wholesale energy and reserves is applied to the forecasted loads of any contract and a weighted marginal cost determines the purchase price. Retail providers then resell energy to retail customers at competitively determined prices that cover providers' load-weighted marginal costs. From this

[23] Historical data are available typically in hourly form while forecast data are usually available by day type. This means that the hourly pattern of historical loads and wholesale prices/marginal costs must then be related to future test year patterns.

perspective, significant shares of both U.S. and Canadian retail sales take place competitively with (implicit) allocation of generation costs on the basis of marginal cost.

Marginal cost-based allocation has sometimes been criticized for producing greater variability in allocator shares over time than embedded cost-based methods. Analysis of historical marginal costs can shed light on this issue. Concerns with respect to variation can generally can be resolved by the use of multiple scenarios for the development of marginal cost estimates over forward periods. As forecasts change, expected marginal cost levels and patterns change, and these changes can be incorporated within cost shares for consumer classes. Such changes reflect in a timely manner expected changes in cost to serve. For example, a strongly peak-coincident class might see an increase in cost share if peak marginal costs/wholesale prices rise relative to off-peak. Conversely, a relative smoothing of price patterns would reduce the cost share of the class.

Under marginal cost-based cost allocation, Hydro would first assemble its generation cost financial data and then assign costs to the five service regions. The three isolated regions would then have costs classified and allocated in the same manner as is currently applied, due to current data availability. To allocate each of the two interconnected regions' costs, Hydro would develop hourly load profiles for its customers under various marginal cost scenarios and, summing across hours and scenarios, develop total marginal costs for each class in each region. Allocation would then be based on the shares of the total marginal cost to serve.[24] Allocator values would then be applied to aggregated generation assets and to generation-related expenses of each region.

One key issue will be determining how to treat the power purchases from Muskrat Falls. The payments are in the form of lump-sum charges for capacity and O&M costs. Transmission lease payments that accompany Muskrat Falls charges for purchased power

[24] At present, Hydro has hourly data for the combined set of interconnected rural customers in Labrador. Proxy hourly loads could be developed for the various rural classes based on billing data. Alternatively, the current method could be retained.

are also lump-sum in nature, but are not broken down into capacity and O&M components. These charges will not vary with loads or peak demands, and resemble other generation fixed costs. Under a marginal cost-based approach, the lump sum of purchased power and transmission lease payments could be allocated on the basis of all-in marginal cost-weighted usage, in the same manner as other generation-related costs.

In summary, marginal cost-based cost allocation is an established, if not widely used, approach to the classification and allocation of generation costs. The approach eliminates the issues of 1) classification of generation costs into demand and energy compartments, and 2) the selection of a demand allocator. The approach presents the technical challenges of 1) marginal cost and class load development and 2) the possibly more variable cost shares than are found in embedded costing. U.S. jurisdictions demonstrate the feasibility of the approach. Hydro appears to have the information and the technical capability to adopt marginal cost-based cost allocation, although timing of the adoption of this approach should be based on Hydro's assessment of its internal capabilities as well as public review and approval of the approach.

3.4 Classification and Allocation of Wind Generation

On the periphery of the main cost allocation issues is the question of how to classify and allocate the costs of wind generation. Hydro has access to some wind at present, via power purchases from two wind farms with peak capacity of 54 MW. Although wind currently is not a significant component of the generation resources available to Hydro, it is possible that independent wind generation might increase in the future.[25] It is appropriate, then, that the scope of review includes the cost classification and allocation issue.

Under marginal cost-based cost allocation, the classification issue does not arise. Marginal cost-weighted class load profiles yield total marginal costs whose shares determine each class's cost share of all generation, including wind (either owned or purchased). However, if

[25] Newfoundland and Labrador, *Focusing Our* Energy, Energy Plan, 2006, Pages 6 and 36.

marginal cost-based cost allocation is not adopted, then wind classification and allocation would be required.

As a non-dispatchable resource, wind is not an obvious candidate for classification according to the same methods applied to other generation resources. If dispatch is a critical element in determination of wind's contribution to capacity, then wind is not available to meet an increase in peak demand and should have no capacity component. Thus, it can be argued that wind should be classified as an energy-only generation cost.

Alternatively, one might argue that that the demand component of wind generation cost should be gauged based on the presence of wind generation at times of system peak. That is, the level of wind capacity rather than its availability to meet a load increase, might be seen as the proper criterion for cost classification. Under these circumstances, a combined demand and energy classification outcome is possible. However, this outcome is not guaranteed for two reasons. First, system planners may view wind as not contributing to system peaks for planning purposes. Planners can reasonably conclude that availability "on average" at peak times is not a good guide for planning. This argument relies on the concept that planners' views are logically prior to observed wind generation patterns, either at Hydro or in other jurisdictions.

Second, it may be that wind generation is simply not available in peak hours. For example, Hydro's system planners have observed that during past peak periods, which typically have occurred in winter during periods of extreme cold, wind was often not available due to the need to shut down wind turbines when winds are high. Both theory and past experience, then, supported Hydro's system planners' recommendation in 2013 that the utility treat wind generation as 100% energy-related.[26]

Having recently established a connection to the continent's grid, Hydro's operational perspective has changed. While wind will still not be dispatchable, the planners see the

[26] See Newfoundland and Labrador Hydro, *2013 Amended General Rate Application*, Section 4.3.2.

interconnection and resulting seasonal change in peak period as materially affecting their perspective on wind's capacity value.[27]

If the planners now see a possible capacity role for wind, then it makes sense to examine evidence of the role of wind in meeting capacity needs. Hydro has recently investigated the issue of capacity value, applying a methodology recommended by NERC,[28] an Electric Load Carrying Capacity ("ELCC") study.[29] The methodology applies probabilistic assessment to the system that allows for a range of possible reliability outcomes. Hydro found that its current wind resources yield an ELCC ratings of about 22%. This value is in line with industry values that range from 5 to 20%.

Hydro's result is comparable to results found in other Canadian utilities as well. During the review of Hydro's 2013 GRA, Vale witness Mr. Melvin Dean referenced previous Hydro research indicating that North American industry practice is varied, sometimes resulting in the classification of wind as energy-only, while at other times granting wind generation a capacity role. Referencing NP-NLH-280, he finds that a high proportion of utilities split wind costs between demand and energy. Many use a percentage of nameplate wind generator capacity as a basis for determining shares.

Witness Dean then presents, for six utilities that report classification shares between energy and demand, information on the relationship between capacity factor and demand share. Two utilities (BC Hydro and Austin Energy) classify wind generation as 100% energy-related, while four other utilities accept a demand component. Three of these classify wind as between 9 and 20% demand-related. A fourth utility, MidAmerican Energy of Ohio, has a

---

[27] Telephone conversation with Hydro staff, October 18, 2018.

[28] NERC *Reliability Assessment Guidebook*, Version 3.1, August 2012. Acquired at: https://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%20DL/Reliability%20Assessment%20Guidebook/Reliability%20Assessment%20Guidebook%203%201%20Final.pdf

[29] Newfoundland and Labrador Hydro, *Reliability and Resource Adequacy Study, Volume I: Study Methodology and Proposed Planning Criteria*, November 15, 2018. (Wind capacity results are reported in Section 4.2.4, Variable Energy Resources.)

demand component of (1 – load factor), resulting in a value likely higher than any of the other three.[30] He also observes that the St. John's area has higher average wind speeds than Saskatchewan and that SaskPower accords a 20% demand share to wind generation. He suggests that this should be a floor for Hydro, with a proper choice of share needing to be dependent on a future study for this purpose.[31]

Previously, Hydro argued that its system planners' perspective and the use by some utilities of energy-only allocation indicated that Hydro would be justified in also adopting an energy-only perspective. Hydro now believes that interconnection with eastern North America suggest that its wind assets appear to have a capacity component. In the absence of marginal cost-based cost allocation, Hydro would use the results of its ELCC study to classify wind generation as 22% capacity-driven. Industry practice supports the use of such a value. Assuming that the system planners would factor wind power into its capacity planning, such a percentage seems sensible.

Recommendations. We recommend that Hydro introduce marginal cost-based allocation of embedded generation costs for the Island Interconnected system beginning with the implementation of rates that recover revenue to cover payments by Hydro for Muskrat Falls and its associated transmission facilities, subject to Hydro's mastery of the technical challenges of marginal cost development. This change will avoid the need to classify each generation asset or cost on its own and relates cost to serve to an objective market-based value of generation services that recognizes cost to serve by each rate class in each hour. It appears that Hydro can undertake this approach, as the utility already possesses the costing capabilities to generate the requisite marginal cost scenarios.

[30] Melvin Dean, *Expert's Report on Newfoundland and Labrador Hydro's Amended 2013 General Rate Application*, June 4, 2015, page 14.
[31] *Ibid*, pp. 14-15.

Marginal cost-based allocation can be used in the Labrador Interconnected system as well, following the Muskrat Falls in-service date. This would require that projections of marginal cost for Labrador be developed, presumably based on a process similar to that used for the Island Interconnected system.

If marginal cost-based allocation of generation costs is not adopted for the period after the Muskrat Falls in-service date, the current system, with some modifications, could be retained after the transition. We recommend in that case that Hydro undertake classification of Muskrat Falls costs based on the equivalent peaker methodology. It appears that this approach might prove more in line with generation planning practice, and might better reflect the base load role of Muskrat Falls than would an SLF allocation approach.

Regarding generation cost allocation in the event that marginal cost-based allocation is not adopted, we recommend that Hydro consider an allocator that makes use of peak demand data in periods of extreme cold, such as the 1 CP – top 50 hours approach of Manitoba Hydro. This approach requires forecasts that make use of historical hourly data, but it avoids reliance on a single hour. That said, Hydro's current 1 CP approach can be retained assuming that the utility is confident that such a measure reliably produces allocator shares that are close to a measure that makes use of many hours.

After Holyrood is converted into the role of synchronous condenser, the plant should be sub-functionalized as transmission and its costs allocated in the same manner as general-purpose transport facilities (described in the next section). The reduced fuel costs incurred at Holyrood prior to the conversion to transmission should continue to be allocated on the basis of energy.

If the plant does not immediately come to be used as a synchronous condenser, then it should be retained as generation and functionalized according to marginal cost-based cost allocation. In the event that marginal cost-based allocation is not adopted and the plant is still treated as generation, then the equivalent peaker method or the continued use of the forecasted capacity factor methodology would suffice.

We recommend that wind resources be allocated in the same manner as other generation facilities if marginal cost-based cost allocation is adopted. If not, then we recommend that Hydro adopt a classification method based on Hydro planners' forecasts. As a result of interconnection with eastern North American, Hydro's forecasts now indicate that wind generation contributes to the ability to meet peak demand and should be classified as about 20% demand-related.

4. Transmission

Transmission costs, in their familiar form, consist of capacity costs recorded as fixed capital and operations and maintenance costs. Utility and regulatory practitioners are also familiar with transmission line losses, which are short-term variable and fixed transmission costs, and are recorded as variable energy costs. This section discusses each of these types of costs, focusing first on the treatment of capacity costs. Line losses are not always discussed as part of the process of reviewing a utility's COS methodology. However, in this case, projections of line losses associated with the new transmission investments help to highlight the nature of the changes that will take place in the system. The pattern of losses has implications for capacity cost allocation issues discussed below.

4.1 Capacity Costs

Transmission Facility Categories

Transmission facilities consist of conductors, poles, towers, transformers, substations, relays, meters, voltage support equipment, switchgear, monitoring gear to facilitate real time observability, and specialized equipment such as long-distance dc circuits and associated conversion equipment including rectifiers and inverters. This equipment, which together comprises transmission networks, can be categorized, for purposes of addressing cost allocation issues for the Hydro power system, into four facility types:

- *<u>Generator Interconnection Facilities</u>:* sometimes referred to as generator leads, interconnection facilities consist of a dedicated equipment bundle associated with the interconnection of generators to the Hydro transmission network. This equipment includes lines, substations, step-up transformers, switchgear, and monitoring equipment;

- *<u>General-Purpose Transport Facilities</u>:* transport facilities include the equipment bundles which are most observable and recognizable as transmission: conductors, towers, poles, insulators, hangers; reactors, capacitor banks and static var compensators to maintain/control voltage and provide stability; switches, relays, and protection gear;

- *<u>Terminal Stations</u>:* substations, transformers, switchgear, meters, and system monitoring equipment; and,

- *<u>Special Facilities</u>:* an array of transmission facilities such as frequency converters and phase shifters. The relevant special purpose facilities for Hydro include long dc facilities such as Hydro's LIL and associated rectifiers situated within the Muskrat Falls switchyard and the inverters situated at the Soldiers Pond substation, integrated within Hydro's high voltage network on the Avalon Peninsula.

Additionally, some utilities, Hydro included, assign transmission facilities that serve a single customer directly to that customer. This study reviews Hydro's treatment of specific assignment in a separate section of the report.

Sub-functionalization

Generator Interconnection Facilities. In the past, utilities have often functionalized generator interconnection facilities and their associated costs as transmission. However, more recently, some electricity service providers have been assigning all-in financial costs to the generation function. Additionally, the U.S. FERC has set up specific features for the assignment of all-in costs of interconnection facilities to the individual generators obtaining interconnection services. Such functional assignment is facilitated by a bright line of demarcation that is immediately observable: Interconnection facilities are built to connect generation to the grid; flows are one way; facilities are sized according to the capability of the relevant station.

General Purpose Transport Facilities and Terminal Stations. These facilities inherently belong to the transmission function as a matter of definition and purpose. However, even among these quintessential transmission facilities, there is an exception: the converter facilities located at the Muskrat Falls and Soldiers Pond stations that serve as the terminal points of the LIL. These highly specialized facilities, include rectifiers, inverters, and associated equipment. As a component of the LIL, they are probably best functionalized in the same manner as the LIL, a special purpose facility discussed immediately below.

Special Purpose Transmission Facilities. Special purpose facilities are constructed for, or primarily because of, the provision and facilitation of least cost generation. Least cost generation plans reflect real-world constraints: generation cannot necessarily be sited near load centers. Large-scale generation, including hydraulic facilities, nuclear stations, and wind farms, often requires sizable properties, selected according to geographical features, available resources, and societal externalities and constraints.[32] These sites can be remote

[32] *Geographical features* can include suitable sites within large river basins such as that of the Churchill River or remote locations with sufficient wind velocities for wind farms; *available resources* can refer to water sources to satisfy the cooling requirements of nuclear power stations (*e.g.*, Georgia Power's Plant Vogtle Units 3 and 4, currently under development) or nearby rail and gas pipelines; *societal externalities* can refer to siting rules and regulations which delimit the available routes to site new transmission lines.

locations, thus requiring extended transmission leads in order to bring power supply into meshed transmission networks and load centers.

This is particularly the case with remotely sited hydraulic facilities where, because of the distances involved, dc facilities are the preferred technology choice. Under these conditions, the commitment of specific generation facilities is a resource choice involving joint generation and transmission—akin to a fixed proportions production function: generation provides no value in isolation of transmission; similarly, transmission provides little to no value in isolation of generation.

Also, transmission can substitute for local generation, in selected cases. For example, the recent expansion of transmission capability in Southwest Connecticut and along California's Path 15 rather dramatically improved flow capability, thus reducing the costs of generation by significantly lowering congestion costs, specifically costs related to out-of-merit generation dispatch. Conversely, special purpose transmission facilities often accompany generation and special circumstances with respect to geography and opportunities to exploit and favorably employ natural resources.

The Hydro system includes two major special purpose transmission facilities:

- *Labrador Transmission Assets:* The LTA facilities are being put in place in order to enable least cost operation of the combined Churchill Falls and Muskrat Falls generation facilities. The LTA facilities will improve network reliability while also facilitating energy transfers outside the Province.

- *Labrador-Island Link:* The LIL is a 1,100 km dc transmission line, stretching from Muskrat Falls in Labrador across the Strait of Belle Isle, then southeast to Soldiers Pond on the Avalon Peninsula. The LIL and MF constitute an integrated resource strategy where the net economic benefits of the strategy are jointly determined. The incremental economic value of the LIL is compromised absent MF; and similarly for MF, absent LIL.

The transfer capability of the LIL is 900 MW. Because of capital indivisibility, the LIL can be utilized, especially in its early years, to serve out-of-province loads in addition to native loads. In combination, MF and the LIL provide the capability for significant power exports through Maritime Link particularly during the early years of the life of the facility. However, capability for power exports is largely incidental with respect to cost allocation: Nalcor's commitment to Muskrat Falls in combination with Labrador Island Link is for electricity consumers served by the Island Interconnected System.[33]

The LIL can be sub-functionalized in two different ways. One approach is to treat the LIL as a "generation lead" that stretches from Muskrat Falls to Soldiers Pond, thereby functionalizing the facility as generation. Other Canadian utilities (BC Hydro, Manitoba Hydro, and Hydro-Quebec) make use of this approach for the dc connections from remote hydro generation sites to load centers.

The second approach is to assign the LIL facility jointly to generation and transmission. Arguably, because the LIL creates a dc-dominated transmission loop on the fringe of the Eastern Interconnection, in which flows in both directions are at least theoretically possible, the LIL can be viewed as an example of joint-use facilities. In this case, the LIL could be assigned jointly to the generation and transmission functions, at least for the near term. Functionalization could occur based on some measure of native load and export shares of LIL transportation. The native load share would be classified as generation and the export share would be classified as transmission, since that is the share that will make use of the

[33] Note that a portion of the LIL is dedicated to firm exports to Nova Scotia. This portion is excluded from the cost allocation review in consequence.

loop configuration.[34] (Note that this does not mean that a share of costs will be allocated to export load).

However, this second approach creates conceptual difficulties for Hydro given the structure of its agreements facilitating the LIL. The Order in Council that sets out the Muskrat Falls Exemption Order states that all costs are to be paid by Hydro native load customers, since the LIL and MF are being constructed based on the supply needs of the Island without consideration of export opportunities.[35]

Sub-functionalization Recommendations

Hydro should continue to assign (functionalize) to generation the costs of generator interconnection facilities. General purpose transport facilities and terminal stations should be assigned to the transmission function. The converter facilities located at the Muskrat Falls and Soldiers Pond stations should be functionalized in the same manner as the LIL facility.

The special purpose facilities which comprise the LTA should be assigned to the generation function for the reasons discussed above—facilitation of efficient use of hydro facilities along the Churchill River, including the Churchill Falls and Muskrat Falls stations. We recommend that the LIL facility, including its converter facilities, be functionalized as

[34] The shares of the revenue requirements associated with the LIL facility—which are in the form of monthly lease payments—can be determined in two ways, as follows:

- *Rated Path Method:* shares of LIL revenue requirements ("RR") are assigned to generation and transmission according to the 12-month average of the expected flows over the LIL facility attributable to native loads and to export sales. The flows attributable to native loads are assigned to generation, where the remaining share of revenue requirements (for LIL facilities) is assigned to transmission. The rated path method is described in section *MOD-029* within the "White Paper on the MOD A Standards", *North American Electric Reliability Corporation*, July 3, 2013.

- *Native Peak Loads and Export Sales:* the share of the annual revenue requirement attributed to generation is the load ratio share of native loads within total system loads including export sales. The remaining share, attributed to transmission, is the load ratio share of export sales in total system sales.

[35] Order in Council OC2013-343.

generation, in harmony with the formal cost designation of the facility as providing service to the Island.

Classification and Allocation

Generator Interconnection Facilities**.** The previous section set out the alternatives for classification and allocation of generation facilities. Hydro will presumably wish to classify and allocate the generator interconnection facilities in the same manner as other generation facilities.

General Purpose Transport Facilities**.** Much of transmission cost classification and allocation is more complicated than generator interconnection; a cost allocation bright line is not easily discerned, since network operations are characterized by measurable externalities. Current industry practice is typically to classify general purpose transport facilities, terminal stations, and non-assignable special facilities as demand-related and then allocate costs to customer groups according to coincident peak demands. For this broadly defined facility pool (general purpose transport, substations, special equipment), such an approach is based on planners' longstanding assumptions that transmission costs are more or less exclusively a function of peak demand.

The longstanding approach of Hydro is compatible with this practice. The utility classifies much of its transmission costs as demand-driven and allocates transmission-related costs according to a 1 CP allocator. Some Hydro generation-related transmission costs are classified in the same manner as their associated generation assets; in so doing, Hydro resolves the issue of functionalization of generator interconnection costs: even if not assigned to generation, these costs are classified and allocated as extensions of their associated generators.

Table 3 provides a summary of Canadian classification and allocation practices regarding common transmission facilities. With three exceptions, the utilities investigated classify transmission assets as 100% demand-related. The first exception is Nova Scotia Power, which has a tradition of treating its common transmission assets as an extension of its generation facilities. Since they use an SLF allocator for generation, they also use it for common transmission. The second exception relates to the specialized transmission assets used to connect Manitoba Hydro to U.S. markets. These are classified according to system load factor. Discussion below describes why these assets are not viewed by the regulator as similar to other common transmission assets. Absent this exception, industry classification practice is uniform in using demand-only classification.

The third exception, Hydro-Quebec, disaggregates transmission costs into four groups. Network and customer connection costs are classified as demand-related, but other costs have both energy and demand components. (The first line presents an aggregate share.)

Table 3
Classification and Allocation of Transmission Costs by Major Canadian Utilities

Jurisdiction	Utility	E/D Classification E=energy, D=demand	Allocation	
			Demand	Energy
British Columbia	**BC Hydro**	100% D	4 CP	
	Fortis BC	100% D	2 CP: W/S	
Saskatchewan	**SaskPower**	100% D	2 CP	
Manitoba	**Manitoba Hydro**			
	AC system	100% D	"1 CP": top 50 winter hours	
	US Interconnections	SLF		Ann. kWh
Quebec	**Hydro-Quebec**	25% E, 75% D	52% 1 CP, 23% 1 NCP	Ann. kWh
	Production-related	57%E, 43% D	1 CP	
	Network	100% D		
	Interconnections	57%E, 43% D		
	Customer Connection	100% D	1 NCP	
New Brunswick	**NB Power**	100% D	1 CP	
Nova Scotia	**Nova Scotia Power**	SLF (like generation)	3 CP	Ann. kWh

Allocation practices are not particularly uniform, except to state that utilities rely mostly on coincident peak measures and are seasonal. A range of CP allocators is in use: 2 CP, 4 CP, and an instance of 1 CP at Manitoba Hydro that turns out to consist of the peak 50 winter hours of Winter, which parallels their allocation of generation demand-related cost. 2CP allocation is essentially seasonal 1 CP allocation, with utilities like Fortis recognizing both a winter and summer peak. In contrast, 3 CP and 4 CP allocators are single-season in focus, with winter being the peak season.

Hydro-Quebec makes use of an annual non-coincident peak allocator (1 NCP) for connections to distribution services. The 1 NCP allocator is in use at the distribution level at many utilities and its appearance here is not out of the ordinary.

General Purpose Transmission Cost Classification Alternatives. The CP approach is reinforced by the policy in the U.S. of the FERC. In the case of broadly defined general use facilities, all-in total costs of transmission facilities are recovered as monthly $/kW access charges, determined according to load ratio shares based on coincident demands and, on occasion, non-coincident demands in the case of subtransmission.[36] In other words, in this consensus view, it is the expected level of peak demands which have, over decades, driven ongoing investment in transmission and, thus, cost allocation.

The use of demand-only allocation is broadly applied in contemporary systems in North America, a practice partly justified additionally by the mature state of the grid. To a large extent, power networks have been more or less fully developed, at least notwithstanding grid development to transport power produced by renewable resources situated in areas remote from load centers.[37] For developed systems, investment to increase capability is necessary largely to satisfy year-over-year growth in peak demands: accordingly, demand-based allocation is arguably appropriate for power systems that are substantially *built out*, either as meshed, loop, or radial systems.

[36] Generally, load ratio shares are based on observed loads and firm transmission reservations over a recent twelve-month period (12 observations of loads *pro rata*) or according to projected loads and reservations over a forward period. (This does not imply that Hydro would need to use a 12 CP approach.)
[37] Not mentioned is the impact of restructured wholesale electricity markets, which have given rise to changes in flow patterns and thus revealing, in the process, the need for further grid expansion to better manage congested networks. A salient example is the expansion of Path 15 in California's wholesale market.

This view of transmission investment is open to challenge on causality grounds in that the factor of transport distances is clearly a cost driver for transmission.[38] (The longer the line, the greater the amount of equipment.) However, for electricity transactions, the dimension of distance is not easily measured or observable, notwithstanding the locational pricing inherent in unbundled wholesale markets, where the price differences reflect network congestion and marginal line losses. Even if the relationship between costs and transport distances is understood, the cost allocation process would need to attribute transport distances, and thus costs, to consumer groups with sufficient accuracy. In brief, billing consumer groups for electric transport distances, on an embedded cost basis would undoubtedly prove to be daunting and highly unwieldy. Such an approach would constitute a major departure from the demand-only classification convention and, if implemented, might lead to significant changes in assignable costs across consumer groups.

Is there any alternative to demand-only classification of general transmission facilities that bears consideration? One might explore this by categorizing transmission expenditures into major categories by type or purpose, such as replacement-, reliability-, extension-, and load-related activities, and then applying transmission planners' expertise to classify historical expenditures in each category. Some expenditures might be clearly peak demand-related, while others could be viewed as reliability reinforcement, or replacement and thus assigned to energy for purposes of cost allocation. While not explicitly accounting for transport distances, such an approach would face clear challenges in the form of complexity, cost ambiguity, and uncertainty of stability over time.

Another alternative is to conceive of general transport facilities as no more than an extension of generation. If so, these facilities would then be viewed by utilities using a method of classification into demand- and energy-related cost as having a similar mixed

[38] At the most basic level, electric transmission is a transport service similar to air freight and long-haul rail services. For freight media, the costs of transport services are determined by both load (tons of freight) and distances (kilometers). Hence, freight of all types is typically billed according to ton-km/ton-mile metrics.

demand-energy causation. However, this view of transmission is not common relative to the demand-only perspective.

At Hydro, the plain fact of COS methodology continuity suggests retention of demand-only classification, in the absence of an alternative method that can improve on the established method.

General Purpose Transmission Cost Allocation. The cost share of real expenditures attributable to peak demands requires some means of measurement. Peak loads can be determined in one of three ways.

- *Conventional Coincident Peak Method.* Hydro would determine the class shares of demand in peak hours using an appropriate measure of coincident peak. Hitherto Hydro has utilized a 1 CP approach. Often utilities prefer some form of CP calculation that relies on more than the single peak hour of the year in order to avoid statistical anomalies from such a small sample. The U.S. FERC has been using a test in its cost allocation proceedings for some years. This test, applied to Hydro peak demands, suggests that a 3 CP measure would be preferable to a 12 CP measure, even after 2019. Please see the note below for details.

- *Peak Load Frequency.* This method uses the frequency in which the hour and month where peak loads are expected to occur. Peak load frequency serves as the basis to determine hourly weights which, by definition, sum to one over an annual period;[39] or

[39] For Hydro, prior to the in-service date of Muskrat Falls, the determination of peak load frequency requires simulation analysis, where expected export sales are combined with observed historical peak loads, both measured in MW. Export sales can markedly alter the frequency distribution of peak loads from the observed historical pattern for native loads alone.

- *Pro Rata Peak Load Distribution.* Based on a max function algorithm, shares of an annual revenue requirement for transmission are assigned to system-level peak load hours *pro rata*. The max function algorithm is also used to estimate marginal capacity costs.[40]

The remaining costs shares[41] are then classified accordingly to energy. For general purpose transport facilities, the energy share basis of allocation can, potentially, weight hourly loads by marginal costs (both in hourly frequency).

A Note on the FERC's CP Allocation Tests. FERC typically uses a coincident peak method to allocate demand costs, allocating based on each customer class's demand at the time of system peak demand. The coincident peak may be based, for example, on a single peak month (1 CP), the average of three peak months (3 CP), or the average of peaks in all twelve months (12 CP). The 1 CP method reflects traditional planners' views on the significance of the single highest peak of the year. In contrast, COS tends to seek a broader picture of peak demand. A utility that has a relatively flat demand requirement throughout the year would typically allocate demand costs on a 12 CP basis, recognizing the relatively constant peak demand requirements. A winter- or summer-peaking utility would more typically allocate demand costs on a 3 CP basis which assumes the system will peak during the three months with the highest peaks.

As mentioned, Hydro currently applies a 1 CP method to transmission cost allocation. This approach has been widely used in the past, for the good reason that the single hour of highest use is the benchmark for system planning.[42] Other time periods, though, have been considered for a number of reasons. First, for many utilities (but not Hydro), summer and

[40] The results of the max function algorithm, as a matter of practical application, prove to be unusually sensitive to the defined allocation parameter (referred to as simply α, and assumes a value within the interval $0 < \alpha < 1$) over certain parameter ranges.

[41] Note that a share of reinvestment to replace aging capital will be in the service of peak loads, insofar as the share of the historical investment in legacy assets is driven by the expected peak loads, at the time of investment.

[42] Reference the NARUC *Electric Utility Cost Allocation Manual*, January 1992, p. 77.

winter peaks are quite similar and the class shares can differ significantly by season. Giving weight to peak hours in both seasons avoids possibly dramatic changes in cost shares over time. Second, measuring cost shares using a single hour of system peak can be statistically unreliable. As a result, utilities, even strongly seasonal utilities, have gravitated toward a 3 CP alternative to 1 CP.

In an effort to manage the seasonality issue, the FERC has developed three tests of seasonality of peak demands as guides to selection between 3 CP and 12 CP.[43] The three tests are:

- The On- and Off-Peak test. Compute two quotients: average system peaks during the peak season/annual peak demand and average system peaks during the non-peak season/annual peak demand. If the difference between these quotients is less than 19%, the conclusion on this test is that the utility is best represented by a 12 CP measure.

- The Low to Annual Peak test. Compute the quotient of the lowest monthly peak demand and annual peak demand. If that quotient is greater than 66%, the conclusion on this test is that the utility is best represented by a 12 CP measure.

- The Average to Peak test. Compute the quotient of the average of the 12 monthly peaks and the annual peak demand. If that quotient is greater than 81%, the conclusion on this test is that the utility is best represented by a 12 CP measure.

While some utilities are clearly quite seasonal, with all measures resulting in a 3 CP determination, and others are clearly less seasonal, with a 12 CP determination, still others provide mixed verdicts. The tests are used as guidelines, rather than rules, with an understanding that utility results can be close to the test boundaries.

[43] The tests are described in FERC opinion Golden Spread *et al* v. Southwestern Public Service Company, opinion no. 501, dockets EL05-19-002 and ER05-168-001, issued April 21, 2008, at paragraph 76*ff*.

Hydro computed these tests, making use of forecasted peak demands for 2019 and 2020.[44] They tested their system both including and excluding export sales. The results of the tests appear in Table 4. Each cell presents the number of the above-mentioned tests that supported either the 3 CP or 12 CP construction. There are three test results for each of the two years, six in all. The tests are performed for two scenarios, one in which load totals are comprehensive, including export flows, the other in which exports are excluded from the computation.

The tests appear to support the conclusion that the utility, at least in the early stages following the Muskrat Falls in-service date, is best represented by a 3 CP representation as opposed to 12 CP. If exports are excluded, all six tests (three per year) support the 3 CP conclusion. If exports are included, two of three tests support the 3 CP conclusion in each year, for totals of four 3 CP outcomes and two 12 CP outcomes.

Table 4
FERC Tests of Hydro Seasonality 2019-2020

Seasonality	Including Exports	Excluding Exports
3 CP	4	6
12 CP	2	0

If these tests are to be accepted as guidelines, it is not strictly necessary to evaluate which column should serve as the reference point. However, given that the "including exports" results are less than fully conclusive, it is worth reviewing the issue of scenario selection. The shares allocated to Hydro's customer classes ought to be measured with reference to the times when the system is at or near peak usage. This suggests that the full utilization of the system matters.

[44] These tests were performed in 2016, before the announced delay in completion of the Muskrat Falls project. Similar results would presumably apply today, for delayed forecasted years.

In order to understand what "full utilization" means it is necessary to consider the type of export contract that Hydro might offer. A firm export contract might be treated differently from a non-firm contract, in keeping with the typical treatment of non-firm load: exclusion from the imposition of capacity charges. A Canadian example of this practice can be found at Manitoba Hydro. They have two types of exports: Dependable and Opportunity. The utility allocates capacity costs to the former but not the latter. A demand computation could then be expected to include Dependable exports but not Opportunity exports.

In Hydro's case, system demand excluding exports is winter peaking, with peaks driven by sales to NP and Hydro's own small number of domestic interconnected customers. While generation offers more capability for exports in summer, limitations on transmission export potential would likely retain winter peaks in excess of summer peaks, although the differential including exports narrows relative to that excluding exports. The uncertainties associated with capacity help to limit firm exports as well. If the utility can choose not to export in summer or is limited in its ability to commit to firm exports, then the peak that counts is in winter, when firm load peaks at a higher level than in the summer.

The FERC seasonality issue highlights the challenge of understanding and measuring transmission cost drivers. As mentioned in the generation classification section, a pure CP approach is theoretically appealing in that it connects the notion of system development directly with a simple measure of peak usage. However, a consideration of the issue of the relative merits of 1 CP vs. multiple CP measures for Hydro runs into the problem of cold snaps, when the winter's peaks are all clustered in a short period of time, perhaps a week or two.

The other measures proposed—Peak Load Frequency and *Pro Rata* Peak Load Distribution—offer an alternative to the CP approach by taking advantage of greater data availability and statistical sophistication to measure the probability with which peak demands occur in individual hours, and distribute the class responsibility for transmission cost based on hourly loads and probability of setting a peak. In spirit, these methods are close to the marginal cost-based computation recommended for generation cost allocation. These methods use more data than the traditional method but offer perhaps greater stability of measure given the use of information in more hours. Additionally, these methods also may reduce the issue of determining utility seasonality in borderline cases (*e.g.* 3 vs. 12 CP) by objectively weighting the relative importance of each hour. Over time these weights may change, but significant changes in cost weights are unlikely.

***Terminal Stations*.** Terminal stations provide interconnection among the various branches of meshed and radial transmission systems, and include equipment to transform voltage, provide voltage control, relays, switchgear, and various automated monitoring and control equipment, and phase shifters. Broadly speaking, investment in terminal stations is determined by peak loads and the amount of transformation, viewed at a system-wide level. Industry practice, as with general purpose transport facilities, is to classify costs related to these facilities as demand-related. Hydro currently subscribes to this approach. Allocation typically takes place in the industry by means of a CP demand measure, although the use of annual noncoincident peak (1 NCP) is not uncommon. The CP measure selected can be the same as that used for general purpose transmission facilities.

***Special Purpose Transmission Facilities*.** Classification and allocation of these facilities depends upon decisions regarding functionalization. If these facilities are functionalized as generation-related, *i.e.* the dc lines of the LTA and the LIL are treated as generation leads, allocation compatible with the allocation of the generation assets for which the generator lead is provided seems sensible. Alternatively, if the facilities are functionalized as split between generation and transmission, then the generation-related facilities should be classified and allocated as stated above and the transmission-related facilities should be classified and allocated in the manner of common transmission facilities.

Classification and Allocation Recommendations

***Generator Interconnection Facilities*.** We recommend that Hydro classify and allocate the costs of Generator Interconnection Facilities in the same manner as their related generation facilities. If Hydro adopts marginal cost-based allocation of embedded generation costs, then marginal costs would apply to the financial costs of generator interconnection as well. If Hydro retains its existing allocation methods, we recommend that Hydro assign interconnection facilities costs with each specific generator and allocate costs in the established manner.[45]

***General Purpose Transport Facilities*.** We recommend that Hydro retain the demand-only classification approach due in part to the absence of an analytically preferable or cost-effective alternative, and partly to its acceptance by system planners of its ability to approximate their thought processes.

Demand-related costs should be allocated based on one of the three methods proposed. The Peak Load Frequency and *Pro Rata* Peak Load Distribution methods offer improved accuracy and stability over time, as well as an hourly analysis approach similar to that recommended for generation cost allocation. However, they require more analysis than the traditional CP method. If the traditional CP method is selected and used for generation classification as well, we recommend that Hydro retain its traditional 1 CP approach, for reasons of harmonization with generation classification, and despite its statistical limitations.

***Terminal Stations*.** The reserve requirements for capital and O&M costs associated with Terminal Stations should be classified as demand-related and allocated according to one of the methods described above.

[45] In theory, one could allocate generation costs, including those of generator interconnection, according to the marginal energy and capacity costs during the timeframes that the maximum level of output of each of the respective generation stations is approached. For some generation stations, high levels of production can occur in many hours; for others, only a few.

Special Purpose Transmission Facilities**.** Assuming that the LTA is functionalized as generation, we recommend that its costs be classified and allocated in the same manner as Muskrat Falls, based on marginal cost or, alternatively, equivalent peaker methods. If the LIL is functionalized as generation as well, it should be treated in the same fashion as the LTA. If, instead, the LIL is functionalized as jointly generation and transmission, the generation component can be classified and allocated in the same manner as Muskrat Falls. The transmission component would then be viewed as general purpose transmission facilities and classified and allocated in the approved manner for transmission.

4.2 Transmission Line Losses

Hydro's grid is undergoing major restructuring, including large-scale investment in generation and transmission facilities, and participation in wholesale electricity markets. Key features of these changes are taking place in transmission, as follows:

1. Interconnection between the Labrador and Island power systems facilitated by the LIL, a dual circuit dc facility (900 MW capability);

2. Coordination of energy management between Churchill Falls and Nalcor's new Muskrat Falls hydro facility (MF or Lower Churchill), facilitated by the LTA, a dual circuit 315 kV ac facility (approximately 900 MW capability);

3. Interconnection of the Island system with the Eastern Interconnection, thus facilitating power transactions with the organized power markets of the Northeast through the Maritime Link, a dual circuit dc facility (approximately 500 MW capability); and

4. Investment in the Hydro's high voltage ac network (230 kV) in order to satisfy reliability standards associated with increased power flows across the Hydro power system.

The Hydro power system is currently comprised of high voltage (230 kV) and lower voltage (66 kV to 138 kV) facilities configured within meshed and radial networks. Hydro's transmission network spans fairly long distances in order to serve the sizable urban area residing on the Avalon Peninsula (St. John's) as well as rural communities and towns located throughout the Province.

Coupled with the commercial operation of Muskrat Falls and significantly expanded export sales, the impacts on the Hydro power system are twofold: flow patterns on key facilities will materially change, most likely; and the overall magnitude of average and marginal losses will likely rise.

Within transmission, system-wide average losses are often tabulated from observed power flows within networks, metered in hourly or monthly frequency. These data provide a historical record: determining total and average transmission losses involves adjusting observed historical quantities (MWh), for application within COS studies.[46] Beginning in 2020 however, major restructuring of the Hydro system will likely cause significant changes in both the profile and level of average and marginal losses. As a consequence, observed historical losses cannot be readily utilized within COS. Thus the issue: how should line losses be determined for purposes of cost allocation for 2020 forward, in view of the resource changes under way?[47]

It is perhaps useful to clarify key factors that determine transmission losses, which occur predominantly in the conductors that constitute transmission lines, as follows:

[46] Average losses are non-linear with respect to load level.

[47] Energy costs for transmission are the physical loss of energy within transmission networks. Physical losses include charging losses and thermal losses, the latter often referred to as I^2R losses, where I describes electrical current flows within circuits, and R refers to resistance of the physical mass and related characteristics of conductors. Charging losses are associated with conductors and transformers and do not change with respect to load levels.

- Transmission losses are usually predominantly thermal losses, resulting from line resistances. Larger conductors will generally have lower losses. However, in this case dc converter/inverter losses and synchronous condenser losses will contribute materially to station service losses.[48]

- Transmission losses decline significantly with higher conductor voltages, as currents are lower by similar magnitudes.

- Line losses are approximately linear with respect to the length of circuits.

- Power system losses vary with respect to temperature: total and average losses decline under lower ambient temperatures, other factors constant.

Most importantly, thermal losses can change dramatically with respect to changes in load level and flow configuration on circuits.

In addition to changes in the level and variability of losses upon completion of the Muskrat Falls project, and the conversion of Holyrood, there will be a change in the way losses are recorded. Currently the losses associated with Holyrood are netted out by reducing the Holyrood conversion factor, thereby altering energy cost. These energy-related losses will be reduced while, at the same time, LIL losses will be introduced. As noted, depending on how the LIL is functionalized, these losses may be partly demand-related.

Recommendations

Following the in-service date for MF and its associated transmission links, Hydro's loss levels, patterns, and variability will change significantly, requiring that Hydro abandon its historical average losses for the cost of service. Hydro should estimate average losses either

[48] Note that these losses can be either generator-related or jointly transmission-related, depending on how the special transmission resources described in Section 4.1 are functionalized.

via observations of the difference between hourly generation and metered loads or with load flow analysis. Load flow study results can be utilized to parameterize a losses algorithm based on the well-known I^2R approximation. The algorithm is directly applicable to the hourly loads utilized within COS studies, including energy and demand loss factors.[49] Once sufficient historical experience under the restructured resources has accrued—say, two years—Hydro can again utilize observed metered loads as the basis for estimating line losses (transmission energy costs).

5. Other Issues

5.1 Rural Deficit

***Issue*.** Hydro charges its rural customers at rates either equal to or partially reflective of the rates of Newfoundland Power. These rates fail to cover Hydro's cost of service, which tends to be high in isolated locations. Hydro makes up the deficit with supplementary volumetric charges on Newfoundland Power and Rural Labrador Interconnected System ("Rural LIS") customers. The methodology of deficit allocation was reviewed in the 2013 GRA and the Board approved the use of a "revenue requirement" method as proposed by Hydro. Page 105 of Order No. 49 (2016) states: "The Board expects that Hydro will address the rural deficit allocation methodology in its cost of service report and all parties will have a further opportunity to have input as part of the review of that report."[50] This section undertakes that review task.

***Background*.** Subsidizing rural customers has been a longstanding feature of service in the Province, and the practice of subsidizing small numbers of customers in remote locations is common in other provinces of Canada. In the Province of Newfoundland and Labrador, the subsidy was at one time covered by the Provincial Government but since 2002 the

[49] Loss measures of this sort are also compatible with the loss measure to be used in transactions with Emera via the Maritime Link. That measure utilizes a rolling 12-month average of measured losses which is likely to be quite close to the test year loss measure of total grid flows. See the Energy and Capacity Agreement, Schedule 3.

[50] The revenue requirement approach was also accepted in the 2017 GRA Supplemental Settlement Agreement, point 20. Public Utility Board, Consent #3, Filed July 16, 2018.

responsibility has been borne by some of Hydro's non-rural customers. The customers benefiting from the subsidy are found in four groups: Island rural interconnected (about 22,900 customers) Island isolated (about 800) Labrador isolated (about 2,700) and L'Anse au Loup (about 1,000) totaling about 27,400 customers.[51]

The cost burden of the rural deficit is allocated to NP and to Labrador Interconnected customers, Island industrial customers having been exempted from responsibility in 1999.[52] The Electric Power Control Act mandates that these two customer groups fund the subsidy, but does not prescribe how it is to be allocated.[53] Until recently, the allocation was based on an "equal unit cost" allocation mechanism developed in 1993 by the Board's witness, Mr. George C. Baker.[54] Under this mechanism, Hydro classified the deficit total among demand, energy and customer categories based on the total costs in each classification for the NP and Labrador Interconnected rural customers combined. The classified amounts of the deficit were then applied to the combined groups' unit costs for each classification to determine the deficit share for each of the two groups of customers. Essentially, this approach has been viewed as allocating the deficit using a mini-COS study.

The difficulty with this approach is that it allocates relatively large amounts per customer to Labrador customers (who are significantly higher users of energy than Island customers, chiefly due to relatively colder weather and consequent heavy use of electric heating). This approach produced much higher revenue/cost ("R/C") ratios for Rural LIS customers than for NP—1.42 vs. 1.12—as revealed by Hydro's recent analysis in 2013.[55]

---

[51] As recorded in Hydro's COS model, 2015, excluding street and area lighting.
[52] Order-in-Council 2003-347 also specifies that NP customers and Labrador rural interconnected customers are to fund the rural deficit. See Newfoundland and Labrador Hydro, *2013 General Rate Application, Final Submission*, revision 1, p. 14. The 1999 date regarding the Island industrial customers is referenced on p. 15.
[53] See Dr. J. Feehan, *Report on the Allocation of the Rural Deficit*, prepared for Miller& Hearn, representing the towns of Labrador City, Wabush, Happy Valley-Goose Bay, and North West River, p. 1, footnote 1.
[54] Board of Commissioners of Public Utilities, *Report on … the Proposed Cost of Service Methodology…* February 1993, Appendix 1.
[55] Newfoundland and Labrador Hydro, *2013 Amended General Rate Application*, Section 4.3.1, reference Table 4.2 for the R/C ratios.

Hydro analyzed the impact of this approach in response to customer concerns about the impact of the resulting charge, and concluded that it was sensible to modify the approach. After considering options, the utility selected a revenue requirements-based allocation whose purpose is to equalize R/C ratios, and whose effect is to shift the deficit burden in the direction of NP customers and away from Labrador Interconnected customers. The Board approved the change to the new approach as of January 1, 2014 in its decision P.U. 49(2016). The resulting target R/C ratio in the 2017 GRA application for 2019 is 1.15 for both classes.[56]

Discussion/Analysis. Extensive debate over the years since the 1993 COS methodology review has revealed general agreement that there is no solid theoretical basis for allocating the rural deficit burden. Since the deficit has no association with any of the costs of the subsidizing customers, there is no clear cost allocation method available to recommend from a perspective of costing theory. Additionally, industry practice does not have much to offer, since smaller subsidies are less noticeable and do not create debate as a result.

In the absence of cost-related guidance, Hydro gravitated to a notion of fairness based on results, a departure from standard costing practice, and hampered by the difficulty in defining what constitutes fairness. That search for improved fairness caused the utility to explore two alternatives to the established method of allocating the rural deficit. They assessed an equal R/C ratio approach based on revenue requirements, as well as an approach that relies on number of customers. Arguably, achieving equal R/C ratios after imposition of the rural deficit charge is a desirable criterion for allocation. However, a case can be made for equal customer bill impact as well.

[56] Newfoundland and Labrador Hydro, *2017 General Rate Application*, vol. 3, revised July 4, 2018, Exhibit 15, page 3 of 107., Schedule 1.2, col. 6.

These methods lead to annual average costs per customer numbers that are very similar between the two groups of subsidizing customers, NP and Labrador Interconnected.[57] In contrast, the established method, based on equalized unit costs, imposes an annual bill increase of $653 on Rural LIS customers and just $217 on NP customers, due to differences in consumption levels. Even with impact equalization by means of the alternative approaches, subsidizing customers would have $207-$235 added to their annual bills.

The 2013 GRA process resulted in commentary on Hydro's analysis and proposed change. Most intervenors, and the Board's consultant, Mr. John Wilson, supported a change. The exception, Mr. Larry Brockman, representing NP, felt that the change was unwarranted and that the mini-COS methodology was sound.[58] Another intervenor, Dr. James Feehan, participating on behalf of several Labrador towns, suggested four alternative approaches to allocating the rural deficit, including one similar to Hydro's customer-based alternative. [59] In the absence of a cost-causative criterion for allocation of the rural deficit, or of a single best indicator of fairness, the choice of an allocator may be influenced by criteria such as simplicity and by acceptability of outcome to stakeholders. These criteria place the equal unit cost method at a disadvantage on both counts.

Hydro's revenue requirements method has the virtue of simplicity of computation and comprehensibility of outcome, relative to its predecessor, the equal unit cost method. The revenue requirements method also avoids the apparent problem of significant differences in R/C ratios that arises with the equal unit cost method, and the consequent price distortions away from unit cost that arise with R/C ratios of 1.42 for rural Labrador interconnected customers and 1.12 for NP customers.

[57] Newfoundland and Labrador Hydro, *2013 Amended General Rate Application*, Section 4.3.1, p. 4.10. See Table 4.3 for results.
[58] These views are summarized in Hydro's *2013 General Rate Application, Final Submission*, revision 1, p. 71*ff*.
[59] Dr. J. Feehan, *op. cit.*, pp. 7-10.

Additionally, the revenue requirements approach may have an advantage over the customer approach. The customer approach is initially appealing: equal charges to all customers. However, customers vary significantly in size and average bill between NP and rural Labrador interconnected groups, and the approach imposes a small distortion in R/C ratios. A rate designer striving for parity would automatically move rates against the allocation and in the direction of the equal R/C ratios of the revenue requirements method. In that case, it may make sense not to affect R/C ratios in the first place, and undertake the slightly more complicated revenue requirements computation.

In its review of the issue, the Board had similar key findings. First, they stated that there is no satisfactory measure of fairness. Second, they acknowledged that both the arguments for change and for the then-current method have merits. In particular, the Board noted Newfoundland Power's argument that their customers have access to more expensive generation than do the Labrador customers, and that the revenue requirements method does not account for this.[60] In contrast, the previous method burdened Labrador Interconnected System customers with costs due to the extra energy cost of the Labrador climate.

The Board also did not accept a suggestion by the Consumer Advocate that the Rural Deficit be partly absorbed by Hydro's shareholder, the provincial government, through the device of covering some of the deficit with Hydro's return. The Board concluded, after review, that the legislation authorizing collection of the rural deficit does not offer discretion sufficient to consider this approach.[61]

Hydro's revenue requirements approach appears well suited to manage the transition process that will occur beginning in 2020 and provide effective guidance in allocation of the rural deficit thereafter. The advantages of this approach are: 1) a perception of fairness

[60] Newfoundland and Labrador Board of Commissioners of Public Utilities, *Decision and Order of the Board*, P.U. 49 (2016), Sec. 14.3, p. 101.
[61] *Ibid*, p. 98 *ff*.

based on a sensible and measurable benchmark; and 2) computational simplicity via the R/C ratio. Other suggestions, including the current method, all appear to have identifiable weaknesses in the form of differential price distortions or questionable benchmarks (such as the count of customer numbers) or computational complexity. While the fairness criterion itself does not necessarily produce a clear favorite, the combination of influences and the recognized problems of the current method suggest that the change in methods approved by the Board is both justified and timely.

Recommendations. We recommend that Hydro retain its new allocation method based on revenue requirements. The criterion of equalizing R/C ratio across regions and the concomitant avoidance of price distortion appear to be desirable features of this approach. The relative simplicity of the calculation method, when compared with the existing approach, is an additional advantage.

5.2 Conservation and Demand Management

***Issues*.** Like most utilities, Hydro provides incentives to its customers to undertake cost-effective measures that reduce total consumption and peak demand. The costs of these incentives must be recovered in some manner from customers. This cost recovery task creates several issues. Some of these have been reviewed and resolved recently, while others may deserve additional future review with the commissioning of Muskrat Falls.

First, CDM costs are not directly associated with the standard measures used in cost classification (usage, peak demand, and number of customers). Therefore, utilities need guidance as to how CDM costs should be classified and allocated.

A second issue arises from Hydro's and Newfoundland Power's (NP's) separation within the Island jurisdiction but enjoyment of shared benefits from each other's CDM activities. Hydro plans its CDM activities in conjunction with NP. NP customers pay their own CDM costs and are also charged for some Hydro CDM costs. Thus, there may be a concern about NP's customers being allocated more than a reasonable share of the overall CDM expenses incurred by Hydro and NP.

A third consideration is whether completion of the MF and LIL investments should alter CDM activities and the way CDM costs are allocated.

***Background*.** Relative to other categories of utility expense, CDM amounts are not large, but the cost classification and allocation process still has the potential to produce controversy. Hydro's CDM costs are divided into two categories: 1) expenditures dedicated to particular programs, and 2) general CDM program administration costs. Hydro treats the latter as conventional O&M costs and allocates them in the same manner as other O&M expenditures. Controversy is associated with the first category.

As proposed by Hydro in the 2013 GRA, and as endorsed by parties to its Settlement Agreements, and by the Board's Final Order, specific actual program costs for each year are to be aggregated for the year and are made subject to deferral in equal amounts over a seven-year period. Costs for the period 2009 to 2016 were approved for recovery beginning with 2017. Once deferred, each year's cost recovery is based on the previous year-end's balance of the resulting CDM Deferral Account, which consists of the deferred amounts that apply to that year and true-up amounts from the previous year.

Deferral appears to play two roles. It distributes revenue recovery over a period in which the conservation measures are most likely to be affecting consumption and smooths the time pattern of cost recovery should expenditures vary significantly across years. The use of deferral accounting and the time period of deferral are not issues in this review.[62]

[62] Expert testimony in the 2013 GRA review noted that other Canadian provinces that use deferral accounting elect to use longer deferral periods. See P. Bowman and H. Najmidonov, *Updated Pre-filed Testimony*, June 4, 2015, p. 63, footnote 137.

Cost recovery occurs through an add factor or tracker called the CDM Cost Recovery Adjustment, charged against each customer's energy consumption.[63] The Adjustment value is to be differentiated by class as a result of cost allocation/assignment plans. Island Industrial customers will face a different rate from that facing NP and its customers. Conservation program costs associated with the Labrador interconnected system are excluded from this account and charged to Hydro income.[64]

Hydro does not have to specify formally how its CDM program costs are functionalized or classified, as they are removed from the COS study. However, some indication of the utility's attitude regarding the purpose of CDM programs can be gleaned from the documentation related to the 2013 GRA. Hydro has promoted conservation programs whose focus appears to be overall energy conservation, as opposed to peak demand reduction.[65] Additionally, energy savings from CDM programs in the past have been seen as reducing production from the Holyrood thermal generating station.[66]

The current CDM program cost allocation plan operates outside the COS study, as mentioned. Allocation begins with segmentation of CDM costs among Island Interconnected, Rural Isolated and Labrador Interconnected categories. The Island Interconnected amount is allocated among NP, IC, and Rural Island Interconnected customers on the basis of the previous year's energy sales. Rural Island Interconnected and Rural Isolated CDM amounts are then re-allocated to NP and Labrador Interconnected customers according to the Rural Deficit allocation rule.[67]

---

[63]Newfoundland and Labrador Hydro, *2013 Amended General Rate Application*, Vol. I, Rates Schedules, p. 18 of 46.
[64]Newfoundland and Labrador Hydro, *2013 Amended General Rate Application*, Vol. I, Rates Schedules, p. 18 of 46; and Vol. I, Sec. 3, Finance Schedule V, p. 1.
[65] Newfoundland and Labrador Hydro, *2013 Amended General Rate Application*, Vol. II, Exhibit 9; Lummus Consultants, *Cost of Service Study/Utility and Industrial Rate Design Report,* July 7, 2013, p. 19.
[66] J.W. Wilson, *Updated Report to The Newfoundland and Labrador Board of Commissioners of Public Utilities on Cost Allocation and Rate Design Issues in the Newfoundland and Labrador Hydro ("Hydro") November 10, 2014 Amended General Rate Application*, June 1, 2015, p. 36.
[67] Newfoundland and Labrador Hydro, *2013 Amended General Rate Application*, Vol. I, Rates Schedules, p. 18 of 46.

Additionally, NP has its own CDM expenditures, which it recovers from its customers through its customer rates. Thus, NP customers pay the NP CDM costs and are also allocated some of Hydro's CDM costs.[68]

***Discussion/Analysis*.** Regarding CDM cost classification, CDM expenses are not caused directly by the traditional cost causative factors (customer numbers, energy consumption, or peak demand). However, they might be classified in terms of the costs that they intend to avoid. CDM programs are initiated typically by planners who seek to secure customer assistance in limiting the growth of total energy consumption or peak demand over time. One could, potentially, review each CDM program individually and determine whether its focus is overall energy reduction or peak demand reduction or some combination, and then classify costs on that basis.

Views reported by experts during the 2013 GRA suggest that Hydro's focus has been exclusively on energy reduction. For example, Lummus Consulting, in its 2013 review of COS methodology stated that, "the justification of the Utilities' CDM programs has been on system energy savings that benefit all customers on the Island interconnected System."[69] There are no Hydro programs currently designed to reduce system peak."[70] If true, this objective helps to justify an energy-only cost classification scheme, and the use of an energy allocator in some form, at least for the present. This perspective may not hold for the future, of course, and Hydro should not feel constrained to engage in conservation practices that save energy but do not focus on peak demand. One possible consideration along these lines is the development of new service requests in Labrador. If these are expected to press capacity, then peak demand-focused CDM programs may prove beneficial.

[68] J.W. Wilson, *op. cit.*, p. 36.
[69] *Newfoundland and Labrador Hydro 2013 Amended General Rate Application*, Vol. II, Exhibit 9; Lummus Consultants, *Cost of Service Study/Utility and Industrial Rate Design Report,* July 7, 2013, p. 19.
[70] P. Bowman and H. Najmidonov, *Updated Pre-filed Testimony*, June 4, 2015, p. 62.

Industry practice regarding cost classification and allocation is variable. Some jurisdictions such as North Carolina attempt to distinguish between program objectives and then use demand and energy allocators to allocate separately classified costs.[71] Others are content to use energy-only allocation regardless of the purpose of CDM programs. A NARUC report from 1993, though somewhat dated, provides a useful summary of methodological issues and cost allocation practices.[72] The report notes that some jurisdictions directly assign CDM costs to customer classes, and subsequently allocate them based on a variety of allocators, while others simply allocate CDM cost based on energy consumption regardless of cost classification. The policy of direct assignment of each program's costs to its target class stems partly from a principle that one ought not to burden other classes with costs when their customers derive no direct benefit from the program. The counter-argument, apparently shared by Hydro, is that all classes benefit from energy conservation, regardless of the source, and thus should share the burden of paying those costs. This would be the case on the Island Interconnected System as Hydro's CDM activities for Hydro Rural Interconnected customers and Island Industrial customers are intended to reduce the supply cost to all customers on the system, including NP's customers.

For past programs, classification of CDM programs as energy-only and allocation on the basis of annual usage appears to have matched program objectives. In the future, if capacity-directed programs are initiated and are perceived to be material in size of outlay, Hydro might want to classify new program costs based on their purpose and then allocate the demand and energy components to class on the basis of its generation allocators, since the programs arguably will delay generation expense predominantly. (If the utility elects to pursue marginal cost-based cost allocation, then CDM costs could be allocated in this fashion too.)

[71] North Carolina Utilities Commission, *The Results of Cost Allocations for Electric Utilities…, Part 2. Demand-Side Management and Energy Efficiency Costs.* P. 7*ff*.
[72] National Association of Regulatory Utility Commissioners, Committee on Energy Conservation, *Cost Allocation for Electric Utility Conservation and Load Management Programs*, February 1993. See the executive summary for a quick review of the conclusions.

Regarding the issue of how to harmonize Hydro and NP CDM programs, it should be noted that the utilities already jointly plan their CDM activities and expenditures, and the customers of both utilities appear to benefit from the programs that result from this joint planning. The utilities already share costs for one initiative, the takeCharge program, which serves isolated diesel-served communities, along with some other costs.[73]

PUB expert John Wilson argues that Hydro should modify its CDM allocation approach to avoid double-counting involved in NP's CDM allocation.[74] He proposes excusing NP from the initial allocation while retaining the rural deficit-based reallocation. By his computation, more than $300,000 of CDM costs would shift from NP to Island Industrial customers.

It is useful to ask how costs would be allocated were the Province served by a single utility. Combined CDM costs would either be directly assigned by program to their target classes or perhaps classified to energy and allocated by means of annual energy. The two utilities are collaborating in conservation planning, having produced one planning document and pledged to develop a successor.[75] This process yields agreed-upon programs and CDM outlays but preserves the current payment structure in which each utility recovers its costs from its customer base. However, an agreement on pooling costs for recovery through Hydro would address Dr. Wilson's concerns.

Regarding the possible impact of the Muskrat Falls project completion, conservation expenditures will serve not only to reduce energy use and postpone the need for new capacity, but to enable increased exports. Ideally, Hydro and NP will jointly plan CDM program scale to optimize use of system resources to manage peak demand, with the incidental benefit of possibly enhancing profitable export sales. Thus, if prices in the ISO of

[73] *Newfoundland and Labrador Hydro 2013 Amended General Rate Application*, Vol. I, p. 1.14. See also P. Bowman and H. Najmidonov, *Updated Pre-filed Testimony*, June 4, 2015, p. 62.
[74] J.W. Wilson, *op. cit.*, p. 37.
[75] Newfoundland and Labrador Hydro and Newfoundland Power, *Five-Year Energy Conservation Plan: 2016-2020*. A successor for 2021-25 is expected by the Board. See Newfoundland and Labrador Board of Commissioners of Public Utilities, *Decision and Order of the Board*, No. P.U. 49(2016), Section 18.2, p. 124.

New England (ISONE) are forecast to be high on average in coming years, indicating tight resources in the Eastern Interconnection, it would be cost effective to increase CDM expenditures, while low ISONE price expectations would reduce the value of CDM programs in terms of export promotion.

***Recommendations*.** Hydro should continue its current CDM cost classification (all-energy) and allocation approach for the near future. If programs focusing on demand are introduced, and if the dollar amounts are material, Hydro can classify programs based on anticipated avoidance of demand or energy growth and allocate the demand and energy amounts to class based on the utility's generation allocators.

Given that Hydro and NP jointly plan conservation activities for the province, they should discuss if they should modify the current CDM cost recovery approach to address any concern that NP's customers are allocated more than a reasonable share of the overall CDM expenses incurred by Hydro and NP.

With the completion of the Muskrat Falls project, Hydro and NP should base CDM program decisions on the relative value of demand and energy, including influences on these values of external markets.

5.3 Specifically Assigned Charges

***Issue*.** Four Island Industrial Customers are assigned a number of specific charges because each of the customers is served by assets that are deemed to serve them alone.[76] The central issue, identified in the 2013 GRA, pertains to the allocation of O&M costs. Currently O&M costs are allocated to these customers based on asset share, with asset value defined

[76] Costs are also specifically assigned to Newfoundland Power for lines and terminal stations that connect them to the Hydro grid. Hydro's definition of specifically assigned plant is "*that equipment and those facilities which are owned by Hydro and used to serve the customer only*." Newfoundland and Labrador Hydro *2013 Amended General Rate Application*, Schedule A, Article 1.01(ee).

in terms of original cost. Periodic investment in new or upgraded facilities results in variation in shares over time across customers due to variations in age of plant.

Background**.** The issues surrounding specific cost assignment have grown in the past decade as the value of the charges has increased. Charges for the 2007 Test Year were $0.7 million while those for the 2015 Test Year were $1.7 million, spread across four customers: Corner Brook Pulp and Paper ("CBPP"), North Atlantic Refining, Ltd. (NARL), Teck, and Vale Newfoundland and Labrador Limited ("Vale").[77] O&M, depreciation expense, and return on debt and equity are the bulk of the charges, in declining order, with O&M constituting somewhat more than half in aggregate. Customers who paid for their assigned assets through contributions in aid of construction ("CIAC") pay for O&M only.[78]

The assets that generate the charges are solely transmission-related, consisting mostly of lines and terminal stations that connect the customers to the grid. The CBPP facility is different from the others in that the customer has some facilities that operate at 50 Hz instead of the 60 Hz common to the rest of the grid. Additionally, the customer has a small hydro plant that provides generation services to its site. Issues related to the frequency converter that transforms 50 Hz power into 60 Hz are discussed in the next section.

Assignment of a share of O&M expenses to the Island Industrial class and to its customers requires use of a sharing mechanism applied to total O&M. The basis for identifying O&M costs assigned to the customer group is the group's share of transmission plant in service, with plant valued at original cost. Similarly, allocation of O&M assigned to these four customers is based on their shares of transmission assets, again valued at original cost.

Analysis**.** Some US jurisdictions deem virtually all transmission assets, including connections to large customers, as common property, to be allocated by the utility's transmission cost

[77] Vale was connected in 2012 and does not currently pay a specifically assigned charge.
[78] Since the 2015 test year, Hydro has brought on line significant common transmission investments that have reduced the share of specifically assigned transmission cost.

allocation rule. These utilities tend to be large, with the result that no single customer is a significant share of total sales and no assets that might be directly assigned are a significant share of the total. For example, Georgia Power Company has many large customers, but the utility does not engage in direct assignment of transmission costs because the system as a whole has a capacity of over 17,000 MW. Smaller utilities that serve one or more customers whose loads are an appreciable share of total sales are more likely than other utilities to engage in direct assignment of transmission costs in cases in which the transmission assets serve the individual customer only.

This perspective is borne out by research that CA Energy Consulting conducted in 2017. The resulting memorandum appears an appendix to this report. That memorandum reviewed Canadian and U.S. treatment of O&M related to dedicated transmission assets. The investigation found that direct assignment is relatively more common in Canada than in the U.S. We found five Canadian utilities that directly assign transmission assets serving individual customers to those customers. We found four U.S. investor-owned utilities, one federally-owned utility (Bonneville Power) and three municipal/public power district utilities who engage in direct assignment. While the inquiry was not systematic, it was clear from telephone interviews that the practice is not widespread in the U.S.

The utilities engaging in direct assignment do not appear to have a single dominant approach to the treatment of O&M related to these dedicated transmission facilities. Large Canadian and U.S. utilities often bundle these costs with other transmission costs and allocate such common costs using the utility’s transmission cost allocator. Xcel Energy in Minnesota simply allocates all its transmission-related O&M costs on the basis of the CP allocator that it uses for transmission expenses generally. This approach is arguably less precise in allocating O&M costs to direct assignment customers but likely avoids swings in O&M charges to those customers in response to equipment upgrades.
Other large utilities develop a means of sharing directly assigned costs across direct assignment customers, with sharing usually based on original asset cost. Smaller U.S. firms

directly assigned either actual or estimated costs of each facility to the customer that the facility serves.

Direct assignment of transmission assets is not widespread, but Hydro may fit the pattern of having significant assignable assets. The Industrial customers with directly assigned transmission assets consume about 9% of Island sales at present and are assigned a little more that 11% of transmission assets in 2015. [79]

One customer, (Vale) responsible for roughly $500,000 of directly assigned costs for the 2015 Test Year, proposed an improvement to the determination of O&M charges. Their expert, Mr. Melvin Dean, advocated and set out the steps for development of allocation based on current cost.[80] This technique makes use of Handy-Whitman indexes, which are available for sufficiently detailed segments of the electric utility industry to produce reliable cost indexation over many years.

Hydro investigated this approach and found it to be feasible.[81] The utility also found that the outcome of its calculations confirmed Mr. Dean's belief: the relatively newer transmission assets directly assigned to customers, when compared with other transmission assets, produced a reduced O&M cost allocation for the direct assignment customers.[82] In its 2017 GRA, Hydro proposed to implement this change beginning January 1, 2018.[83] The Handy-Whitman approach was subsequently agreed upon in the 2017 GRA Settlement Agreements and awaits Board approval.[84]

[79] Based on 2013 Amended GRA COS Study. Sales share: Schedule 1.3.2, column 3, page 1 of 3, (Exhibit 13, p. 17 of 109) Asset share: Schedule 2.2A, line 22 (Exhibit 13, p. 26 of 109.)
[80] Melvin Dean, *Expert's Report on Newfoundland and Labrador Hydro's Amended General Rate Application*, June 4, 2015, p. 3*ff*.
[81] See V-NLH-083, rev. 1, for a description of the method.
[82] Newfoundland and Labrador Hydro, *2013 General Rate Application, Closing Submissions*, Dec. 23, 2015, p. 76.
[83] Newfoundland and Labrador Hydro, *2017 General Rate Application*, Vol. I, Revised Nov. 27, 2017, p. 5.11
[84] Public Utility Board, *Settlement Agreement*, Consent #1, April 16, 2018, see point 15.

The Handy-Whitman approach has a parallel in distribution cost classification. Minimum system studies classify the minimum system needed by a utility as customer-related and the remainder as demand-related. Such computations resort to conversion of assets to test year value to avoid biased outcomes, due perhaps to smaller assets being of older vintage. Thus, it seems reasonable to consider test year dollar valuation in transmission as a reasonable approach.

Critics might object that even test year dollar valuation may not capture the full impact of age. Two identical transmission lines, one built in 2015 and another built in 2005 might have the same 2015 dollar value, but the ten-year-old line would likely be associated with higher O&M costs. Attaining this degree of accuracy in an index would require knowledge of the relationship of O&M cost to vintage, which would be very challenging.

An alternative might be to track actual expenses associated with each customer's dedicated transmission assets and bill the customer directly, while in addition charging them for their share of remaining transmission-related expenses on the basis of the standard transmission allocator. Under this system, a customer who is directly assigned high asset costs for new or upgraded transmission assets would also have the lower expenses associated with new equipment.

In response to an inquiry by the PUB, Hydro investigated whether the customer-specific billing of actual expenses would be feasible or cost effective.[85] The utility found that it would not be costly to record separately the costs of transmission O&M on dedicated transmission lines for the Industrial customers with specifically assigned assets, and intends to implement this approach in 2018. However, Hydro also noted that it would be a challenge to prepare a specifically assigned charge for submission with each GRA based on forecasted annual O&M costs. Discrepancies between actual and forecasted costs would

[85] PUB-NLH-078.

need to be resolved as well. At present, Hydro lacks a history of customer-specific O&M, which likely would be vital for forecasting. In its response to the above inquiry, Hydro pledged to provide information on its cost tracking experience in the next GRA.

Directly assigned O&M costs would be removed from the COS, although customers would continue to be allocated their share of common transmission-related O&M costs. The outcome of this approach is fairly allocated cost for the share of the transmission system common to all customers plus charges for actual repair costs. Depreciation and return on investment on the dedicated assets would still be based on original cost, in conformance with charges for other assets.

An additional alternative is available. Instead of directly assigning O&M costs, Hydro could allocate all transmission-related O&M costs, including those that would have been directly assigned, via the standard transmission-related cost allocator. That is, no O&M costs would be directly assigned. As noted above, this method is used by Xcel Energy in the United States (whose directly assigned costs are not as significant a share of cost as at Hydro). This approach would shield individual customers against large, unexpected repair costs by "socializing" the costs across the utility. However, this approach is a second-best method due to its failure to recognize differences in asset vintage among customers, and between direct assignment customers and other customer groups.

Lastly, direct assignment also affects the treatment of administrative and general expenses in that the allocation of the various categories of A&G expenses is typically prorated based on shares of underlying assets. Specifically assigned transmission-related A&G thus depends on gross transmission plant assets. Hydro proposed in their 2013 GRA submission to modify A&G allocation to match proportionally the modification in direct assignment of O&M expenses. This methodology is applied to all categories of A&G expenses, with a proposed saving to direct assignment customers outside the direct impact of the change in O&M methodology. This appears to be a consistent extension of that methodology.

If Hydro were to adopt the alternative approach of charging for actual O&M expenses, there is a question as to the treatment of A&G expenses. The customers with specifically assigned assets would still be allocated a share of A&G costs based on the allocation of common transmission costs. The issue would then be whether additional charges should be due based on actual O&M expenses which are separately billed. If 5% of all transmission O&M costs were related to specifically assigned facilities, for example, one would expect the charge to reflect not merely direct labor and materials costs but additional elements to cover A&G. Hydro would then use company accounting data to develop such a rate so that the share of A&G in total transmission maintenance cost would carry over into charges for specifically assigned asset maintenance costs.

Recommendations. We recommend that the transmission assets directly assigned to industrial customers continue to be so assigned due to their use solely by the individual customers and their apparent importance within the Island's transmission assets.

We also support Hydro's plan to adopt the process of separate accounting of actual O&M expenses for each customer, and to develop a history of cost tracking to guide subsequent policy. We note also that the charges for services would include a markup for A&G services.

5.4 Capacity Assistance Agreements

***Issue*.** Like many other utilities, Hydro makes use of non-firm load contracting to provide potential capacity at times of low reserves. Hydro obtains capacity from Island Industrial customers via curtailment and, in two cases, provision of energy and capacity from customer site generation. In its COS study, Hydro makes provision for forecasted capacity assistance payments as part of its purchased power. The issue for Hydro is whether such contracts and payments should continue to exist after Muskrat Falls enters service. This is essentially a rates question, but there is an underlying question as to how capacity assistance should be represented in COS in order to ensure recovery of whatever cost is incurred in the future.[86]

***Background*.** Hydro has capacity assistance agreements with two customers, CBPP and Vale. They provide customer-controlled curtailable load upon request and are also able to provide customer-site generation. Total forecasted available capacity assistance for the winter of 2018-19 amounts to 118.6 MW, of which 105 MW is provided by CBPP. Vale provides 6 MW of curtailable load and 7.6 MW of diesel generation upon request. CBPP and Vale have contracts through 2022.

Each agreement provides Hydro with purchased power upon request, with the number and frequency of requests limited by the contract. Customers receive a credit of approximately $28 per kW-year to make their capacity available under the contracts' terms.[87] Customers also receive payments for energy actually provided at times of capacity requests.

These capacity assistance agreements are part of a broader effort to control peak demand growth. Hydro has also recently implemented an interruptible service agreement for the 2018-2019 winter season with a large General Service customer on the Labrador Interconnected System. The customer receives a fixed credit of approximately $10 per kW-winter month for 4 months to make their capacity available under the contract terms.

Hydro includes the value of the capacity assistance agreement payments in COS in its purchased power totals. These payments are classified as demand-only and allocated to class using the same CP allocator as other generation demand-related costs.

The CBPP contracts, which dominate the capacity assistance agreements, deserve specific reference. Since 2009, CBPP has been operating under a piloted Generation Credit service

[86] The questions of demand credit fairness and the appropriateness of the structure of the Capacity Assistance Agreement are discussed in CA Energy Consulting's Rate Design Review dated June 15, 2016.
[87] More accurately, the capacity payment is for availability for peak months.

contract that permits CBPP to maximize the efficiency of its 60 Hz Deer Lake Power generation. The agreement allows Hydro to call on CBPP to maximize its 60 Hz generation prior to increasing generation at Holyrood for system reasons and prior to starting its standby units (i.e., Hydro may make a capacity request to CBPP). However, capacity is only made available to the grid in this manner if CBPP's mill loads are reduced and the customer is able to generate in excess of what it requires for its own use. Otherwise, if the mill is using its maximum power requirements, there is no excess generation made available to the grid under this provision.[88] Savings are provided to CBPP for providing this additional capacity to the system by permitting CBPP to exceed its firm power requirements and to avoid costs associated with thermal or standby energy rates.[89,90].

Prior to the winter of 2014/2015, Hydro entered into Capacity Assistance and Supplementary Capacity Assistance agreements with CBPP[91]. Hydro has proposed an Amended and Restated Agreement for 105 MW for the 2018-19 winter season. Under these arrangements, on rare occasions the facility will continue to provide emergency capacity to the grid.[92] This is achieved through load interruption of up to 105 MW at the Corner Brook mill when system generation reserves are low[93]. As noted above, Hydro compensates CBPP for services under these arrangements through fixed winter fees and usage payments.

***Discussion/Analysis*.** Hydro's treatment of its agreement-related demand in COS appears to provide sensible underpinning for cost recovery. The approach of classifying capacity payments as demand-related and allocating costs on a standard CP basis reflects the theory that capacity relief is purchased for the benefit of the entire system and should be allocated

[88] See RFI IC-NLH-186.
[89] Reference Newfoundland and Labrador Hydro, *2015 Amended Exhibit 4*, Section 3.3.1 pg.'s 12-13 and Table 8 pg. 21.
[90] See IC-NLH-059 Rev 1.
[91] See IC-NLH-186.
[92] Bowman and Najmidinov, Updated Pre-Filed Testimony, Newfoundland and Labrador Hydro *2013 Amended General Rate Application*, June 4, 2015, p. 58.
[93] Net to the system is approximately 97 MW as this level of load interruption at the mill would effectively shut down production from the CBPP cogeneration unit.

based on responsibility for peak demand. Additionally, because these contracts are medium-term in nature, it is possible to obtain a value for capacity from capacity markets or marginal cost forecasts and use these for valuation during the life of a period between rate classes.

Looking ahead past the completion of the Muskrat Falls project, the value of the demand made available by the agreements may change, and that value may become more variable over time. As a result, the pilot program structure and related payment system may need updating. Even though the pilot agreements might not be continued, an alternative pricing agreement, supported by reference to market prices and internal capacity valuation may prove valuable to Hydro. A stable cost classification and allocation approach would benefit Hydro and its customers by enabling recovery from customers of capacity assistance payments under the current and successor contractual agreements.

Hydro's energy payments/credits for load reduction at times of capacity requests are currently excluded from COS. Hydro incurs this cost and does not achieve recovery when payments are made. Hydro has not included the energy payments for capacity assistance in COS in the past as the utility does not forecast the use of capacity assistance on the Island.

If Hydro were to recover these costs via rate stabilization payments, in line with the variability in volume and value of such payments or credits, it could be made whole. This structure would parallel that of wholesale markets where separate payments for capacity and energy secure available capacity in advance of shortages and reimburse demand response as needed.

Recommendations. We recommend that Hydro retain a contracting structure such as capacity assistance agreements as a valuable step in securing capacity at times of shortage. We also recommend that Hydro retain its approach to capacity assistance agreement payment classification and allocation in its COS methodology.

5.5 Newfoundland Power Generation Credit

Issue. NP owns both thermal and hydraulic generation facilities that contribute to Island Interconnected supply. Hydro currently provides credits to NP in the form of capacity reductions from native peak load in the COS study to recognize this contribution. The issue is whether or how Hydro should reflect the value of NP's generation in its cost of service for purposes of developing rates.

Background**.** Hydro's current COS methodology credits NP for making its generation available to reduce its contribution to the Island Interconnected system peak. The credits reduce NP's net peak demand, thereby reducing the demand charge under the terms of Hydro's Utility tariff. NP annually demonstrates its ability to run its generation to meet the capacity credit reflected in Hydro's COS study and in the Utility tariff. In the 2017 GRA, the 2019 Test Year reflects a generation credit, adjusted for reserves, of 118 MW, of which 83 MW is for hydraulic capacity and 35 MW is for thermal generation. The result of this approach is that NP's minimum billing demand is computed as maximum native load less these two credited amounts.[94,95]

Hydro dispatches these two types of generation units and includes them in its system planning. NP maintains the units and its customers pay the costs of the units, with Hydro contributing to the cost coverage via its demand credits. The result of the credit, then, is that NP does not get charged for generation capacity that they themselves provide. Hydro

---

[94] Newfoundland and Labrador Hydro, *Schedule of Rates, Rules and* Regulations, Effective January 1, 2019, p. UT-1.

[95] The impact of the credit is somewhat more complicated than it first appears. The credit provides NP with an estimated coincident peak demand requirement in COS that is effectively the same as if NP was operating its generation at peak times. The credit removes the incentive for NP to operate its thermal generation to minimize its peak demand purchases from Hydro. Instead, NP runs its thermal generation to meet system load requirements at the request of Hydro. NP also dispatches its hydraulic generation to ensure capacity availability to meet system peak, to the extent reasonable. Thus, the generation credit is structured to be consistent with the least cost operation of generation resources for both Hydro and NP.

also pays the direct fuel costs when it calls upon NP's thermal generation. Hydro does not pay for energy from hydraulic generation.

NP uses these generation units, subject to Hydro dispatch, to meet NP distribution system needs in the event of an outage, planned or unplanned. Hydro uses the units to contribute to system capacity as needed. Since Hydro cannot count on peaking capacity from outside the system due to the potential for transmission constraints and remote supply availability, NP's generators provide a contribution to system reserves. If the NP generation was not available, Hydro would have to add an offsetting amount of its own generation.

***Discussion*.** The current generation credit performs the useful task of negating any incentive that NP would have to manage its generation to minimize its peak demand, and its revenue obligation to Hydro. This provides a stable basis for contracting between the two parties but does not establish whether Hydro is under- or overpaying for this capacity. Alternative arrangements are conceivable and may provide a basis for evaluation of the current credit structure.

First, consider a situation in which Hydro and NP merged. There would be no impact on the dispatch of NP's units, since they are already dispatched by Hydro to maximize value to the Island system. This value might change, of course, once the Muskrat Falls project has been completed. In this situation, the cost of the units would be billed to all customers on an embedded basis that is fairly close to the current arrangement. NP customers' share of demand-related costs might rise or fall slightly depending on whether the NP generators' demand cost average exceeded or fell short of Hydro's average. NP fuel costs would be shared across all Hydro Island customers, shifting a small amount of fuel costs away from current NP customers. In brief, relatively little would change.

Second, consider a situation in which the Hydro demand discount is terminated and Hydro and NP enter into a power purchase agreement in which Hydro purchases all the usage of the plants. Under this arrangement, NP would not be able to use its generation to reduce the peak demand established by its customers. NP's allocation of demand costs would rise with the loss of the discount, but NP would be reimbursed for hydraulic water value, fuel (as it is now) and capacity payments for availability. Those capacity payments would perhaps be market-based, but more likely would be valued at Hydro's estimate of capacity value in the presence of transmission constraints. In brief, higher bills from Hydro would be offset, in whole or in part, by increased payments for use of the plants.

The virtue of the second alternative would be that it would make valuation of the plants explicit, potentially more reflective of publicly revealed values of capacity and energy. These values, influenced by market conditions and determined by contractual formulation, would have the virtue of providing regular updates, subject to regulatory review, of what amount to independent power purchase prices. The problem with this approach is its complexity relative to the current demand discount, which requires no more than an annual verification of NP's ability to deliver upon request. Additionally, NP's IPP would be selling into a market that potentially has just one buyer, Hydro, and the objective establishment of capacity value might be contentious.

***Recommendations*.** We recommend, for the present, that Hydro and NP continue the current generation demand credit arrangement due to its generator management incentive properties. If either party objects to the agreement, the parties could explore the alternative of an IPP approach in place of the credit. The parties would then need to agree upon means of occasionally establishing capacity and energy prices by negotiation or with reference to objective, observable values that would reflect conditions in the Island.

5.6 Export Revenues/Credits

***Issues*.** The cost of the Muskrat Falls project and the associated anticipated increase in rates to defray this cost has raised a number of issues regarding how net export revenues should be treated, since the project creates an enhanced opportunity for Hydro to earn additional revenues through expanded exports. The first issue is whether all customers should receive the rebate or whether it should be restricted to the customer classes that will pay for the Muskrat Falls project. Second, Hydro faces the issue of how to treat the rebate in the cost of service and then how to provide it through rates and/or a rider. Third, within COS, the issue arises as to how to classify and allocate net export revenues.

***Background*.** Upon completion of the Muskrat Falls project, Hydro will find itself with an exportable surplus of energy and new outlets for those exports, thanks to construction of the LIL and ML dc lines. By contractual requirement, Island Interconnected customers must pay all the costs of these facilities. Operationally, Hydro will determine how much power Nalcor Energy Marketing (NEM) will have available for export. NEM will sell the power and remit the net revenues from the sale to Hydro.

***Discussion*.** "Export" revenues are a common feature of utilities interconnected to their neighbors. Power purchases and sales of varying duration take place regularly, many of them through the ISOs' wholesale markets. Power purchases are common generation expenses and sales are sources of revenue set against revenue requirements.

Hydro may have some discretion to recommend to the Board or the government how a net export revenues credit should be shared. The contractual obligation to pay for the Muskrat Falls project lies with the Island Interconnected customers and it is they whose rates will rise relative to others when the project enters rate base. Thus, these customers are obvious candidates for the rebate.

However, others may argue that exports are derived from the exportable surplus of the entire utility and that the actual source of power to support individual export contracts cannot be determined. The relatively low prices of Labrador customers and the subsidies provided to rural customers suggests that rebates to these groups might seem unfair to other customers or might create rate reductions where marginal prices are below marginal cost. While reasoning on the basis of outcome is not desirable in COS methodology, the absence of a theoretical basis for rebates suggests that reference to rate impacts might be sensible.

Regarding the issue of how a net export credit should be treated in terms of cost of service and rate design, there appear to be two available approaches. One alternative is to include forecasted net export revenues in cost of service and then use a rider or deferral account to rectify any difference between actual and forecasted net revenues. The other alternative is to exclude net export revenues from COS and simply use a rider to disburse all revenues.

Note that these alternatives parallel those available to utilities regarding fuel cost recovery. Some recover forecasted fuel through rates and use a fuel adjustment clause to recover or rebate departures from forecast. Other utilities recover all fuel costs via a fuel cost recovery rider. The choice is up to the utility, subject to regulatory approval. Regardless of the approach taken, net export revenues are like fuel costs in that they have the potential to meet the requirements of a rider: materiality, variability, and being beyond the utility's control.

Two leading Canadian utilities with significant exports, BC Hydro and Manitoba Hydro, include their costs in rates. Other utilities treat off-system sales in a similar manner. As a result, Hydro appears to have discretion in how to proceed. Operationally, inclusion of the credit on COS requires the development of a net export forecast. However, this approach also provides an adjustment to rates that results in a rider or deferral account with an expected value of zero. Cosmetically, base rates appear lower than they otherwise would. As well, inclusion of the credit in COS may permit greater flexibility in classification and allocation than would be possible in a deferral account (where the basis of reimbursement would likely be energy only).

Another consideration that would be available to Hydro, regardless of its choice of credit mechanism, would be whether or how to smooth the potentially variable pattern of export revenues. As with fuel cost recovery, the utility can choose the frequency with which it alters its rider value. Unlike fuel, the utility might also want to spread the pattern of recovery or reimbursement over time to further limit swings in value. Forecasted average revenues and a balancing fund might reduce any rate variability that swings due to weather or market prices might impose.

The third issue for net export revenue credits is how to undertake classification and allocation. From a theoretical perspective, there is no basis for cost classification and allocation that is obviously best suited to support a rebate. Exports are produced by increments to generation costs (and transmission costs as well). However, net export revenues are an increment in revenue resulting from a sale that takes place in a competitive market in which multiple buyers and sellers are establishing prices. Their connection to the embedded costs of the utility is tenuous. [96]

The costing methodologies of several Canadian utilities provide examples of how significant export revenues can be managed, but do not suggest a single clear recommended approach.

BC Hydro engages in exports and imports at varying times of the day and seasons of the year. The utility has a wholly-owned subsidiary, Powerex, through which it conducts all its export transactions. BC Hydro earns income on its sales to Powerex and on other surplus sales, and then reaps net income from Powerex activity (margins on sales and purchases in wholesale markets). The utility classifies sales to Powerex and other surplus sales as being 100% energy-related and allocates these revenues to its customer classes on the basis of annual usage. However, it classifies its receipts on its Powerex subsidiary's net income on

[96] The losses discussion notes that measured (and thus forecasted) losses might increase as the Muskrat Falls project comes into service. Another consideration might be that loss variability might increase. This additional element of risk might increase the risk associated with exports.

the basis of its aggregate generation classification. In 2012 this produced a 31% share for demand and a 69% share for energy. This Powerex net income is a relatively small share of gross income, so the reductions in revenue requirements are not substantial.[97]

Manitoba Hydro is a significant net exporter of power to the U.S. In their case their exports are held within the regulated utility rather than conducted through a subsidiary. They effectively create an export "class" in that they allocate both costs and revenues to exports, and then allocate net export revenues to rate classes. They recognize two types of exports: Dependable, characterized by firm sales contracts of a year's duration or more, and Opportunity, featuring shorter duration and less firm commitment.[98] The utility allocates fixed costs to Dependable exports and variable costs to both types of exports.

Manitoba Hydro's exports have been so significant that the size of its net export revenues has created issues upon rebate. The utility has experimented with a couple of allocation mechanisms, settling upon class shares of combined generation, transmission, and distribution costs. The difficulty has been that the credit has been large enough to reduce some classes' energy prices to the level of, or even below, marginal cost. Exports rebates, then, can distort customer pricing. (Hydro is unlikely to experience this issue to the same degree due to the relatively large embedded costs of the Muskrat Falls project.)

Hydro-Quebec's experience is slightly different from that of the other two utilities. As mentioned, this utility has separate subsidiaries for its three main functions. Hydro-Quebec Production ("HQP") manages generation and wholesale sales while Hydro-Quebec Distribution ("HQD") undertakes retail sales. HQD purchases all its energy from HQP, paying a weighted price for a combination of inexpensive heritage generation and more expensive market-priced generation, with most of the weight on the heritage side. This structure

[97] BC Hydro, *2015 Rate Design Application, Appendices, Appendix C-2C, Draft F2016 Cost of Service (COS) Model*, p. 1113 of 4457. Powerex Net Income is $110 million. Revenue requirements are $4,560 million.
[98] In fact, they also recognize a "hybrid" type as well, in which the recipient of the export provides the firm commitment, instead of Manitoba Hydro.

distances export sales from retail customers. Although sales margins at HQP could theoretically be used to reduce HQD's costs, net export revenues are returned to the provincial government. In this structure, HQD sees only a purchased power cost. There are no export revenues available to allocate to customer classes.

It appears that industry practice is admittedly arbitrary due to the poor connection between net export revenues and underlying costs. However, both BC Hydro and Manitoba Hydro appear to favor an approach that ties classification and allocation either to overall generation costs or to an allocator based on the costs of all the major functions. As seen in the case of Manitoba Hydro, a constraint worth remembering is to develop a system that avoids setting energy prices below marginal cost.

Recommendations. We recommend that Hydro, if permitted by the Board, provide the rebate to Island Interconnected customers due to the potential for rate relief from the contractual obligation to pay for the Muskrat Falls project.

We recommend as well that Hydro consider including forecasted net export revenues in the COS study. A rider will facilitate true-ups in this case. A deferral account could be an added feature if Hydro anticipates large variability in export revenues.

We also recommend that the credit be classified and allocated in a manner similar to Hydro's generation services. That approach could involve marginal costs, the current classification and allocation system (aggregated across units) or an equivalent peaker approach for classification, followed by current allocation mechanisms for demand and energy.

Appendix A:

Summary of Recommendations

System Definition

- We recommend that Hydro retain its practice of separate treatment in COS of the two interconnected regions. Costs shared by the two regions can continue to be separated prior to computation of costs by region, as performed by the current model.

Generation

- We recommend that Hydro introduce marginal cost-based allocation of embedded generation costs for the Island Interconnected system beginning with the institution of rates that recover revenue to cover payments by Hydro for Muskrat Falls and its associated transmission facilities. This change will avoid the need to classify each generation asset or cost on its own and relates cost to serve to an objective market-based value of generation services that recognizes cost to serve by each rate class in each hour. It appears that Hydro can undertake this approach, as the utility already possesses the costing capabilities to generate the requisite marginal cost scenarios.

- Marginal cost-based allocation can be used in the Labrador Interconnected system as well following the Muskrat Falls in-service date. Marginal cost forecasts will be produced by the same process as used for the Island Interconnected system.

- If marginal cost-based cost allocation of generation is not immediately adopted for the period after the Muskrat Falls in-service date, the current system, as modified, could be retained after the transition. We recommend in that case that Hydro undertake classification of Muskrat Falls costs via the equivalent peaker methodology. It appears that this approach might prove more in line with generation planning practice, and might better reflect the base load role of the unit than would an SLF approach.

- Regarding generation cost allocation in the event that marginal cost-based allocation is not adopted, we recommend that Hydro consider an allocator that makes use of peak demand data in periods of extreme cold, such as the 1 CP – top 50 hours approach of Manitoba Hydro. This approach requires forecasts that make use of historical hourly data, but it avoids reliance on a single hour. That said, Hydro's current 1 CP approach can be retained assuming that the utility is confident that such a measure reliably produces allocator shares that are close to a measure that makes use of many hours.

- After Holyrood is converted into the role of synchronous condenser, the plant should be sub-functionalized as transmission and its costs allocated in the same manner as general-purpose transport facilities (described in the next section). The reduced fuel costs should continue to be allocated on the basis of energy.

    - If the plant does not immediately come to be used as a synchronous condenser, then it should be retained as generation and functionalized according to marginal cost-based cost allocation. In the event that marginal cost-based allocation is not immediately adopted and the plant is still treated as generation, then the equivalent peaker method or the current capacity factor methodology, altered by the use of forecast-only capacity factors, would suffice.

- We recommend that wind resources be allocated in the same manner as other generation facilities if marginal cost-based cost allocation is adopted. If not, then we recommend that Hydro adopt a classification method based on Hydro planners' forecasts. As a result of interconnection with eastern North American, Hydro's forecasts now indicate that wind generation contributes to the ability to meet peak demand and should therefore be classified as about 20% demand-related.

Transmission

<u>Capacity Costs</u>

Sub-functionalization

- **Generator Interconnection Facilities.** Hydro should continue to assign (functionalize) to generation the costs of generator interconnection facilities.

- **General Purpose Transport Facilities and Terminal Stations.** General purpose transport facilities and terminal stations should be assigned to the transmission function.

    - The converter facilities located at the Muskrat Falls and Soldiers Pond stations should be functionalized in the same manner as the LIL facility.

- **Special Purpose Transmission Facilities.** The special purpose facilities which comprise the LTA should be assigned to the generation function due to their role in facilitation of efficient use of hydro facilities along the Churchill River, including the Churchill Falls and Muskrat Falls stations. We recommend that the LIL facility, including its converter facilities, be functionalized as generation, in harmony with the formal cost designation of the facility as providing service to the Island.

Classification and Allocation

- **Generator Interconnection Facilities.** We recommend that Hydro classify and allocate the costs of Generator Interconnection Facilities in the same manner as their related generation facilities.

    - If Hydro adopts marginal cost-based allocation of embedded generation costs, then marginal costs would apply to the financial costs of generator interconnection as well.

- If Hydro retains its existing allocation methods, we recommend that Hydro assign interconnection facilities costs with each specific generator and allocate costs in the established manner.

- **General Purpose Transport Facilities.** We recommend that Hydro retain the demand-only classification approach due in part to the absence of an analytically preferable or cost-effective alternative, and partly to its acceptance by system planners of its ability to approximate their thought processes.

- Demand-related costs should be allocated based on one of the three methods proposed.

    - The Peak Load Frequency and Pro Rata Peak Load Distribution methods offer improved accuracy and stability over time, as well as an hourly analysis approach similar to that recommended for generation cost allocation. However, they require more analysis than the traditional CP method.

    - If the traditional CP method is selected and used for generation classification as well, we recommend that Hydro retain its traditional 1 CP approach, for reasons of harmonization with generation classification, and despite its statistical limitations.

- **Terminal Stations.** The charges on capital and O&M costs (revenue requirements) associated with Terminal Stations should be allocated to peak loads, determined according to one of the methods listed above.

- **Special Purpose Transmission Facilities.** Assuming that the LTA is functionalized as generation, we recommend that its costs be classified and allocated in the same manner as other generation assets.

- If the Lil is functionalized as generation as well, it should be treated in the same fashion as the LTA.

- If, instead, the LIL is functionalized as jointly generation and transmission, the generation component can be classified and allocated in the same manner as Muskrat Falls. The transmission component would then be viewed as general purpose transmission facilities and classified and allocated in the approved manner for transmission.

Line Losses (Transmission Energy Costs)

- Following the in-service date for MF and its associated transmission links, Hydro's loss levels, patterns, and variability will change significantly, requiring that Hydro abandon its historical average losses for the cost of service. Hydro should estimate average losses either via observations of the difference between hourly generation and metered loads or with load flow analysis. Load flow study results can then be utilized to parameterize a losses algorithm based on the well-known I^2R approximation. The algorithm is directly applicable to the hourly loads utilized within COS studies, including energy and demand loss factors.

- Once sufficient historical experience under the restructured resources has accrued—say, two years—Hydro can again utilize observed metered loads as the basis for estimating line losses (transmission energy costs).

Other Issues

Rural Deficit

- We recommend that Hydro adopt its proposed allocation method based on revenue requirements. The criterion of equalizing R/C ratio across regions and the concomitant avoidance of price distortion appear to be desirable features of this approach. The relative simplicity of the calculation method, when compared with the existing approach, is an additional advantage.

Conservation and Demand Management

- Hydro should continue its current CDM cost classification (all-energy) and allocation approach for the near future. If programs focusing on demand are introduced, and if the dollar amounts are material, Hydro can classify programs based on anticipated avoidance of demand or energy growth and allocate the demand and energy amounts to class based on the utility's generation allocators.

- Given that Hydro and NP jointly plan conservation activities for the province, they should discuss if they should modify the current CDM cost recovery approach to address any concern that NP's customers are allocated more than a reasonable share of the overall CDM expenses incurred by Hydro and NP.

- With the completion of the Muskrat Falls project, Hydro and NP should base CDM program decisions on the relative value of demand and energy, including influences on these values of external markets.

Specifically Assigned Charges

- We also support Hydro's proposed, and now agreed plan to adopt the process of separate accounting of actual O&M expenses for each customer, and to develop a history of cost tracking to guide subsequent policy. We note also that the charges for services would include a markup for A&G services.

Capacity Assistance Agreements

- We recommend that Hydro retain a contracting structure such as capacity assistance agreements as a valuable step in securing capacity at times of shortage. We also recommend that Hydro retain its approach to capacity assistance agreement payment classification and allocation in its COS methodology.

Newfoundland Power Generation Credits

- We recommend, for the present, that Hydro and NP continue the current demand discount arrangement. If either party objects to the agreement, the parties could explore the alternative of an IPP approach in place of the discount. The parties would then need to agree upon means of occasionally establishing capacity and energy prices by negotiation or with reference to objective, observable values that would reflect conditions in the Island.

Export Revenues/Credits

- We recommend that Hydro, if permitted by the Board, provide the rebate to Island Interconnected customers due to the potential for rate relief from the contractual obligation to pay for the Muskrat Falls project.

- We recommend as well that Hydro consider including forecasted net export revenues in the COS study. A rider will facilitate true-ups in this case. A deferral account could be an added feature if Hydro anticipates large variability in export revenues.

- We also recommend that the credit be classified and allocated in a manner similar to Hydro's generation services. That approach could involve marginal costs, the current system (aggregated across units) or an equivalent peaker approach for classification, followed by current allocation mechanisms for demand and energy.