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August 5, 2019

Ms. G. Cheryl Blundon
Director of Corporate Services and Board Secretary
Newfoundland and Labrador Board of Commissioners
of Public Utilities
120 Torbay Road
P.O. Box 21040
St. John's, NL A1A 5B2

Dear Ms. Blundon:

Re: Newfoundland and Labrador Hydro – Application for Revisions to Cost of Service Methodology – Expert Report

Further to the above-noted matter, enclosed please find the original and eight (8) copies of the report of Andrew McLaren, filed on behalf of the Island Industrial Customers Group.

We trust you will find this to be in order.

Yours very truly,

Denis J. Fleming

DJF/js
Encl.

c.c. <u>Newfoundland and Labrador Hydro</u>
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Newfoundland and Labrador Hydro
Cost of Service Methodology
Review Application

Pre-filed Testimony
of Andrew McLaren

Submitted to:
The Board of Commissioners of Public Utilities
on behalf of
Island Industrial Customers Group

InterGroup
CONSULTANTS

August 5, 2019

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1.0 INTRODUCTION

This testimony has been prepared for three Island Interconnected Industrial Customers (known collectively as the "IIC Group")[1] of Newfoundland and Labrador Hydro ("Hydro" or "NLH") by Mr. Andrew McLaren, Principal and Consultant with InterGroup Consultants Ltd. ("InterGroup"). This evidence is submitted in relation to the public hearing into the Cost of Service Methodology Review Application (the "Application") by Hydro to the Board of Commissioners of Public Utilities ("Board" or "PUB") on November 15, 2018.

The IIC Group includes three large industrial companies currently operating in Newfoundland and Labrador. These companies are:

- Corner Brook Pulp and Paper Limited ("CBPP");
- NARL Refining Limited Partnership ("NARL"); and
- Vale Newfoundland and Labrador Limited ("Vale").

Mr. McLaren's qualifications are set out in Appendix A.

InterGroup was initially retained in June 2001 to assist in addressing the 2001 Hydro Rate Review, and subsequently assisted the IIC in the 2003, 2006, 2013 and 2017 rate reviews, as well as the 2009 review of the Rate Stabilization Plan ("RSP"), submitting evidence for each application. InterGroup also provided limited advice in the 2012 review of depreciation methodology, but did not provide evidence.

In preparation for this testimony, the following information was reviewed:

- The Cost of Service Methodology Review Application filed by Hydro on November 15, 2018, including a report provided by Christensen Associates Energy Consulting ("Christensen Associates") which is part of Hydro's Application;
- Request for Information ("RFI") responses from Hydro to the requests of the IIC Group;
- A number of the responses from Hydro to RFIs posed by the Board and other Intervenors;
- The Brattle Group, Inc. ("Brattle Group") report prepared for the Board and filed on May 3, 2019 and subsequent amendment filed on June 27, 2019;
- RFI responses from the Brattle Group to the requests of the IIC Group and the other Intervenors; and
- Regulatory filings and decisions from the PUB's website and certain other publicly available information.

[1] This evidence refers to all industrial customers in the Island Interconnected system as Industrial Customers, or IC.

InterGroup has been asked to identify and evaluate issues of interest to industrial customers, taking into account normal regulatory review procedures and principles appropriate for Canadian electric power utilities.

2.0 SUMMARY OF RECOMMENDATIONS

The following recommendations are made for the reasons set out in the discussion and analysis in this report.

Functionalization and Classification of the Muskrat Falls Project (Section 6)

- InterGroup recommends functionalizing the Muskrat Falls Generation Project to generation and the LIL and LTA to transmission, consistent with the recommendation of the Brattle Group.
- InterGroup recommends that Muskrat Falls Generation be classified using the system load factor approach, consistent with other existing hydraulic generation assets on Hydro's system.
- InterGroup recommends classifying the LTA 100% to demand, consistent with other transmission assets on Hydro's system.
- In InterGroup's view, it may be appropriate to classify the LIL using the system load factor, the same method used for Hydro's existing hydraulic generation assets and recommended for Muskrat Falls Generation.

CBPP Generation Credit Pilot Agreement (Section 7)

- The Board should not approve the discontinuation of the CBPP pilot agreement at this time. The CBPP pilot agreement should be continued until a replacement agreement is available.
- The current cost of service treatment for the CBPP pilot agreement remains reasonable and should be approved by the Board.

Demand Allocation (Section 8)

- The Board should approve the continued use of a 1CP allocator for demand.
- The Board should direct Hydro to review the contribution of different customer classes to the uncertainty parameters in its planning studies, and ensure the calculation of peaks used in the COS study appropriately reflect the contribution of the different customer classes to this uncertainty.

Functionalization and Classification of Transmission Lines (Section 9.1)

- Hydro's proposal to functionalize TL-234 and TL-263 as transmission and classify them 100% to demand is reasonable and should be approved by the Board.

Conservation Demand Cost Allocation (Section 9.2)

- The Board should direct Hydro to review the capacity and energy benefits of its CDM programs and classify them consistent with those benefits at the time of the next GRA.

Allocation of Specifically Assigned Charges (Section 9.3)

- The Board should direct Hydro to provide a report on the feasibility of using actual O&M data for specifically assigned assets as the basis for cost allocation at the time of the next GRA.

Functionalization and Classification of Holyrood Assets (Section 9.4)

- Hydro's proposal to use a forecast capacity factor instead of the historic 5-year average to classify the Holyrood assets is reasonable and should be approved by the Board.
- Hydro's proposal to functionalize the Holyrood Unit 3 assets to transmission once they are converted to synchronous condenser operations and classify them 100% to demand is reasonable and should be approved by the Board.

Diesel and Gas Turbine Fuel Costs (Section 9.5)

- The Board should approve Hydro's proposal to classify IIS diesel and gas turbine generation unit assets and fuel costs 100% to demand.

Wind Purchases (Section 9.6)

- The Board should approve Hydro's proposed classification for wind purchases.

Marginal Cost Based Allocation (Section 9.7)

- The Board should accept Hydro's recommendation not to use the marginal cost study as the basis for cost allocation in the COS study at this time.

Allocation of Net Export Revenues (Section 9.8)

- Hydro's proposal to provide proposed allocation and recovery methodologies with its next GRA is reasonable and should be approved by the Board.

NP Generation Credit (Section 9.9)

- The Board should direct Hydro to file a report on the reasonableness of the NP Generation Credit at the time of the next GRA.

3.0 THE INTERGROUP ASSIGNMENT

InterGroup was retained to focus on issues of interest to Industrial Customers generally, and to the IIC Group in particular.

3.1 OVERVIEW OF ISLAND INDUSTRIAL CUSTOMERS GROUP

The members of the IIC Group are large energy consumers who are presently in production and operate with high load factors (i.e. they have relatively comparable levels of energy use throughout the day and throughout the year).

There are two other Hydro industrial customers who are proposed to be part of the same industrial class (Teck and Praxair). During the review of Hydro's 2017 GRA, Hydro stated the energy purchases for Teck reflect continued mine site reclamation and environmental protection requirements as Teck's mine closure activities are continuing. Hydro also confirmed that Teck is purchasing power at transmission voltage and will continue to be treated as an industrial customer.[2] Praxair represents about 7% of total IC load.

The customers that comprise the IIC Group have a forecast of 691 GW.h of firm electricity in 2019 (about 10% of the total firm energy delivered by Hydro to the Island Interconnected system). The entire industrial class (i.e. including Teck and Praxair) has a forecast firm load of 743 GW.h for the 2019 test year, with $45.7 million in total allocated costs (an average unit cost of 6.14 cents/kW.h).[3]

Island industrial customers are engaged in capacity assistance and load curtailment agreements with Hydro that are used to minimize disruptions of load to all IIS customers in the event of a contingency or to maintain sufficient level of operating reserves for reliable operation of the grid.[4]

Industrial Customer concerns are normally focused around the following:

- Long-term stability and predictability in electricity rates;
- Fair allocation of costs between the various customer classes to be served;
- Flexibility to tailor electrical service options to suit their operation, so as to achieve an appropriately firm supply at the lowest cost for the load being served (i.e. using a mix of self-generation, Hydro firm power, Hydro interruptible power, curtailable service, etc.);
- Continued reliability of power supply for Island Interconnected customers; and
- Lowest cost for power that can be achieved within the above considerations.

[2] 2017 GRA, IC-NLH-080.

[3] Based on Hydro's 2017 GRA Compliance Filing, 2019 Test Year Cost of Service Study, Schedule 1.3.1.

[4] Hydro's 2017 GRA Volume I, page 3.25.

The concerns of the IIC Group reflect the size of their capital investments in Newfoundland and Labrador, the long-term perspective essential to such investments, and the major stake that a customer with these investments typically has in continued large-scale power purchases from Hydro.

InterGroup's assignment focuses on a review of the cost of service methodology proposed by Hydro, including a detailed review of proposed functionalization, classification and allocation components.

4.0 APPLICATION OVERVIEW

4.1 BACKGROUND

Hydro is a public utility and is subject to the provisions of the *Electrical Power Control Act, 1994* (the "*Act*"). The Board has general supervisory responsibilities for public utilities and requires that rates, tolls and charges for services provided by public utilities and the rules and regulations which relate to those services be submitted for the approval of the Board. A cost of service ("COS") study is an analytical tool used by utilities to determine a fair allocation of costs to the different customer classes.

The Board has reviewed Hydro's COS study methodology on several occasions. Such periodic reviews are necessary because appropriate COS methods must reflect the way the system is planned, built and operated. COS methods that were once appropriate may need to be changed in light of changes to the utility's systems. The commissioning of the Muskrat Falls Project introduces major changes to the costs and operations of Hydro. The current Application arises pursuant to the 2017 General Rate Application settlement agreement that provided that Hydro would file an application for a COS methodology review no later than November 15, 2018.

4.2 HYDRO'S APPLICATION

Hydro filed its Application on November 15, 2018. Hydro notes the COS methodology review application filed on November 15, 2018 is a revised version to the report originally filed on March 31, 2016. Hydro also notes it has changed some of the recommendations made in the 2016 report based on new information on system resource requirements post-Muskrat Falls.[5]

Hydro's Application requests approval of the following changes to its COS methodology, for use in the preparation of the COS study required to be filed upon proposing inclusion of Muskrat Falls Project costs in test year revenue requirements:

a) functionalization of Hydro's TL-234 and TL-263 change from generator leads to common high-voltage transmission;

b) functionalization of Holyrood Unit 3 as transmission after the unit is permanently converted into the role of synchronous condenser;

c) power purchase costs resulting from the Muskrat Falls Power Purchase Agreement and the Transmission Funding Agreement be functionalized as generation;

d) classification between demand and energy for the power purchase costs resulting from the Muskrat Falls Power Purchase Agreement and the Transmission Funding Agreement to be

[5] Lines 23 through 27 on page 13 of 144 of the Application PDF document.

20% demand-related and 80% energy related based on the equivalent peaker methodology;

e) classification between demand and energy for the power purchase costs to the Island Interconnected system for Recapture Energy be based on system load factor;

f) classification between demand and energy for the Holyrood Thermal Generation asset costs should be based on a forecast test year capacity factor and its fuel cost would continue to be classified as an energy cost;

g) classification of the cost of wind purchases be 22% demand-related and 78% energy-related;

h) the use of indexed asset costs in operating and maintenance cost allocations in the determination of specifically assigned charges subject to a further review in the next GRA;

i) to discontinue the generation credit agreement between Hydro and CBPP upon full commissioning of the Muskrat Falls Project;

j) that net export revenues available will:

   i. be used to reduce the Muskrat Falls supply costs to be recovered through the rates paid by of customers on the Island Interconnected System;

   ii. be classified in the same manner as the classification of the charges from the Transmission Funding Agreement and the Muskrat falls PPA included in the cost of service study; and

   iii. be included in the test year cost of service study for rate making with variations from forecast net revenues to be dealt with through a deferral account mechanism to be developed by Hydro for the Board's review at the next GRA.[6]

The Board retained the Brattle Group to review Hydro's Application. The Brattle Group filed its report to the Board on May 3, 2019 and an amendment was filed on June 27, 2019. The following sections address key proposals and recommendations from Hydro's Application as well as the Brattle Group report.

[6] Pages 6 and 7 of the Application.

5.0 COST OF SERVICE PRINCIPLES AND METHODS

A COS study is a tool used by utilities to help evaluate the reasonableness of their existing rates and rate proposals. A COS study seeks to allocate costs to customers based on cost causation principles, that is, in proportion to the degree to which each customer class contributes to the need for a utility to incur a particular cost. This information can be used to determine if rates for each rate class appropriately recover the costs to serve each rate class. A COS study is not by itself fully determinative of whether rates are fair and reasonable. Utilities and regulators can consider other factors as part of rate design. However, a COS study is often consider an important input into evaluating whether rates are fair and reasonable.

A typical COS study requires a number of inputs including the utility's forecast revenue requirement for a particular test year, the selection of customer classes, and sales forecasts. The National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual[7] ("NARUC manual") is often cited as a key reference in developing and evaluating COS studies and methodologies. The typical steps in a COS study include:

- **Functionalization:** the process of assigning company revenue requirements to specific utility functions such as Production, Transmission, Distribution, Customer and General.[8]
- **Classification**: the separation of functionalized costs by the components of utility service being provided. The three principal cost classifications for an electric utility are demand costs (costs that vary with the kW demand imposed by the customer), energy costs (costs that vary with the energy or kWh that the utility provides, and customer costs (costs that are related to the number of customers served).[9]
- **Allocation**: the classified costs are distributed to different customer classes based on class characteristics. Demand related costs are allocated on the basis of demands imposed on the system, energy related costs are allocated on the basis of energy in kWh and customer related costs are allocated on the basis of number of customers or weighted number of customers.[10]

While these are the basic building blocks of a typical COS study, there is considerable flexibility in deciding how to apply these steps, depending on the unique characteristics of each utility. The NARUC manual notes a number of examples where such flexibility may be implemented including:

[7] Electric Utility Cost Allocation Manual. National Association of Regulatory Utility Commissioners. January 1992.

[8] Page 33 of the NARUC manual.

[9] Page 20 of the NARUC manual

[10] Page 22 of the NARUC manual.

- Functionalization will generally follow accounting categories. At times, however, there will be exceptions. In such cases the purpose of functionalization, not the accounting treatment, must drive the distribution of the functional costs for the cost study.[11]
- Plant reclassification of some assets because of their functional characteristics may occur.[12] As an example, the NARUC manual discusses a situation when a power generator feeds directly into the distribution system. In such cases assets that are normally considered distribution may be determined to be performing a transmission function.[13]
- Subfunctionalization, or distinguishing the functions in more detail, is an optional, but potentially valuable, step in cost of service analysis. Subfunctionalization may enable COS analysts to classify and allocate costs more directly.[14]
- Classification is often integrated with functionalization; some analysts do not distinguish it as an independent step in the assignment of revenue requirement.[15] In fact, the NARUC manual chapter on transmission specifically addresses only functionalization and allocation, it does not specifically address the classification step.[16] However, the NARUC manual also states:

> "After transmission costs are separated into appropriate demand or energy allocation categories, it is necessary to then select a method of assigning cost allocation responsibility to various customers".[17]

The process of separating costs into demand and energy categories would often be understood to occur in the classification step, although the NARUC manual does not explicitly state this in its discussion of transmission assets. The NARUC manual also provides a chart showing an integrated functionalization/classification scheme that suggests the transmission function could have costs classified to any of demand, energy or customer.[18]

In evaluating Hydro's proposed methods, InterGroup has applied the following general principles:

1. Assets should generally be functionalized consistent with their accounting treatment. Where an asset is clearly intended to perform a function that is different than suggested by its accounting treatment, it may be reasonable to refunctionalize the asset to a different functional category.

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[11] Summarized from page 19 of the NARUC manual.

[12] See for example page 70 of the NARUC manual.

[13] Summarized from page 74 of the NARUC manual.

[14] Summarized from page 33 of the NARUC manual.

[15] Page 34 of the NARUC manual.

[16] The heading of Chapter 5 on page 69 of the NARUC manual is "Funcationalization and allocation of transmission plant".

[17] Page 75 of the NARUC manual.

[18] Refer to the table on page 34 of the NARUC manual.

2. Subfunctionalization is useful for allowing different classification of groups of assets within a function and better accuracy in cost tracking.
3. In InterGroup's view, it is preferable to consider the functionalization and classification steps separately in order to improve clarity and consistency throughout the COS study.

6.0 MUSKRAT FALLS PROJECT

6.1 OVERVIEW

The Muskrat Falls Project includes three elements:

- The Muskrat Falls Generating Project (“Muskrat Falls Generation”) is an 824 megawatt (MW) hydroelectric generating facility at Muskrat Falls on the lower Churchill River, approximately 30 km west of Happy Valley-Goose Bay, Labrador.[19]
- The Labrador Island Link (“LIL”) refers to the transmission line and all related components to be constructed between the Muskrat Falls hydroelectric plant on the Churchill River and Soldier's Pond including converter stations, synchronous condensers, and terminal, telecommunications, and switchyard equipment.[20] The LIL is a 1,100 km ±350 kV 900 MW HVDC transmission line.[21]
- The Labrador Transmission Assets (“LTA”) refer to the transmission facilities of the Muskrat Falls Project to be constructed between the Muskrat Falls hydroelectric plant on the Churchill River and the generating plant located at Churchill Falls.[22] The LTA include two, 250 km 315kV HVAC transmission lines.[23] The Christensen Associates report states the LTA are being put in place in order to enable least cost operation of the combined Churchill Falls and Muskrat Falls generation facilities and that the LTA facilities will improve network reliability while also facilitating energy transfers outside the Province.[24]

Figure 6-1 provides an overview of the Muskrat Falls Project. Hydro proposes to treat the Muskrat Falls Project as a package for cost of service purposes. However, the Brattle Group recommends treating the components of the Project separately and differently. In InterGroup’s view it is reasonable to consider the appropriate functionalization and classification of the components separately and differently, consistent with the principles discussed in section 5.

[19] Nalcor Energy, Muskrat Falls Project. http://muskratfalls.nalcorenergy.com/project-overview/muskrat-falls-hydroelectric-generation-facility/ [accessed on July 23, 2019].

[20] Hydro’s 2018 Cost of Service Methodology Review Report, Footnote 4 on page 14 of 144 of the PDF document.

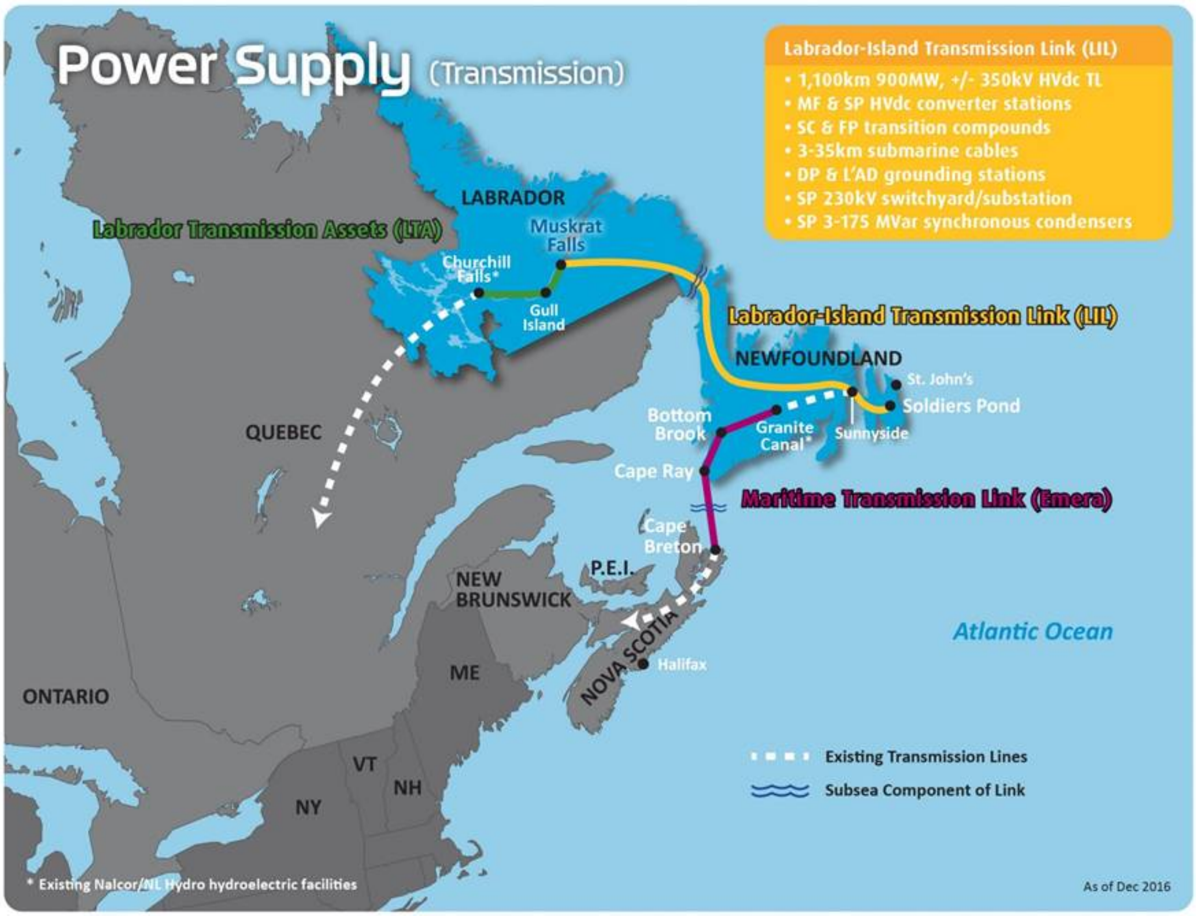
[21] Lines 11 and 12, page 5 of 105 of the Brattle Group amended report PDF document.

[22] Hydro’s 2018 Cost of Service Methodology Review Report, Footnote 5 on page 14 of 144 of the PDF document.

[23] Line 14. Page 5 of 105 of the Brattle Group amended report PDF document.

[24] Christensen Associates report, page 34. Lines 21 through 24 on page 90 of 144 of the Application PDF document.

Figure 6-1: Location of Muskrat Falls Project[25]



6.2 FUNCTIONALIZATION

6.2.1 Hydro's Recommendation

Hydro recommends the power purchase costs resulting from the Muskrat Falls Generation, LIL and LTA be functionalized as generation.[26] To support this approach, Hydro references recommendation 15 from the PUB's 1993 Cost of Service Report:

[25] Nalcor Energy, Muskrat Falls Project. https://muskratfalls.nalcorenergy.com/wp-content/uploads/2017/03/ [accessed on July 23, 2019].

[26] Line 6 through 8 on page 19 of 144 of the Application PDF document.

> That transmission lines and substations in the Island Interconnected System used solely or dominantly for the purpose of connecting remotely located generation to the main transmission system be classified in the same manner as the generating stations they serve.[27]

Hydro notes its practice has been to functionalize and classify radial transmission assets connecting generation to the bulk grid in the same manner as the associated generation assets.[28]

6.2.2 The Brattle Group's Recommendation

The Brattle Group recommends the LTA and LIL be functionalized as transmission and provides several reasons in support of this treatment including:

- The LTA and LIL meet the US FERC definition of transmission system assets.[29]
- The Newfoundland-Labrador System Operator has preliminarily included these lines in its Open Access Transmission Tariff.[30]
- The North American Electric Reliability Corporation requires that generators with significant transmission lines register as transmission owner/operators and that such high voltage lines conform to its reliability standards for transmission systems. Given the voltage level and the significant length of the LIL and LTA, it seems reasonable to conform to this approach.[31]

The Brattle Group notes the National Association of Regulatory Utility Commissioners Electric Utility Cost Allocation Manual ("NARUC Manual") describes a subfunctionalization approach for transmission assets. The Brattle Group notes the subfunctionalization approach allows the utility to identify different subcomponents of the system that may not be used by all customer classes and also that in some instances portions of a transmission network should be functionalized as something other than transmission.[32]

6.2.3 InterGroup's Observations

Hydro notes the PUB's 1993 Cost of Service Report does not explicitly state the approach for functionalization of transmission connecting remotely-located generation, only that they should be classified in the same manner as the related generation assets.[33] There are two potential approaches to accomplish this, as discussed in section 5:

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[27] PUB-NLH-034. Page numbered 2 of 6.

[28] PUB-NLH-034. Lines 3 through 7 on page numbered 3 of 6.

[29] Brattle Group Embedded and Marginal Cost of Service Review. Lines 4 through 14 on page 16.

[30] Brattle Group Embedded and Marginal Cost of Service Review. Lines 12 through 13 on page 18.

[31] Brattle Group Embedded and Marginal Cost of Service Review. Line 14 on page 18 through line 2 on page 19.

[32] Summarized from Brattle Group Embedded and Marginal Cost of Service Review, pages 16 and 17.

[33] PUB-NLH-034. Lines 1 through 3 of page numbered 3 of 6.

- **Refunctionalization:** under this approach, assets that are normally considered transmission assets are refunctionalized as generation, so that they are subsequently classified and allocated as though they are generation assets.
- **Subfunctionalization:** under this approach, transmission assets are subfunctionalized into different categories so that they may later be classified and allocated differently from other transmission subfunctions. For example, both generation leads (or generation integration transmission) and network transmission assets could be sub-functions of transmission, but generation leads could later be classified in the same manner as generation assets, while network transmission assets could be classified as 100% demand related.

Hydro's proposal to functionalize generation leads (such as the LIL) as generation is consistent with the treatment of generation integration transmission assets in other jurisdictions. For example the Manitoba Public Utilities Board ("MBPUB") found that Manitoba Hydro's Bipoles I and II HVDC transmission assets connect northern generation with southern load centres and therefore act as extensions of the northern generators, not as networked transmission. On that basis the MBPUB determined that Bipoles I and II should be functionalized as generation.[34] The Christensen Associates report notes that BC Hydro and Hydro Quebec also treat dc connections from remote hydro generation sites to load centers as generation.[35]

However, it is important to note that, ordinarily, the refunctionalization and subfunctionalization approaches could lead to similar cost allocation outcomes so that the distinction between the two approaches does not particularly matter. In the context of the Hydro system, there is an added complication due to the NP Generation credit. The application of the NP Generation Credit means that it matters whether assets are called transmission or generation, even if they are subsequently classified in the same way. The 2006 Stone and Webster report noted that NP's thermal generation is not forecast to be run during system peak and there is no avoided transmission cost associated with NP thermal generation.[36] Hydro states in the Application, that under the existing approach as approved in Order No. P.U. 8(2007), the thermal generation credit is not applied to reduce the Newfoundland Power coincident peak demand at transmission, but is applied to reduce the coincident peak demand at generation.[37] As an example, Hydro provided information that indicates functionalizing the LTA and LIL assets to transmission instead of generation would reduce the IC revenue requirement by about $600,000 even with the assets classified 100% to demand in both cases due to the treatment of the NP generation credit the COS study.[38] The Brattle Group report

[34] Page 56, Manitoba Public Utilities Board Order 164/16.

[35] Lines 14 through 16. Page 91 of 144 of the Application PDF document.

[36] Page 22. Review of Newfoundland and Labrador Hydro's Treatment of Newfoundland Power's Generation. Stone & Webster Management Consultants Inc. Dated February 3, 2006.

[37] Lines 6 through 8 of the Application on page 28 of 144 of the PDF.

[38] IC-NLH-007.

also notes that the Newfoundland-Labrador System Operator has preliminarily included the LTA and LIL in its Open Access Transmission Tariff.[39]

InterGroup agrees the Muskrat Falls Generation Project should be functionalized to generation. InterGroup understands the LTA and LIL are considered transmission assets for accounting purposes and are also generally performing a transmission function of transporting power from a point of origin to a load center. For these reasons, InterGroup recommends functionalizing the LIL and LTA to transmission, consistent with the recommendation of the Brattle Group. The appropriate breakdown of costs between demand and energy can be considered in the classification step.

6.3 CLASSIFICATION

6.3.1 Hydro's Recommendation

Hydro recommends using the equivalent peaker methodology to classify the Muskrat Falls Project (inclusive of the Muskrat Falls Generation, LIL and LTA). Hydro notes this method is effectively based on an estimate of the cost per kW of a new peaking unit compared with the cost per kW of the new base load generation unit giving consideration to the life-cycle of the two facilities. The portion of the cost in excess of the cost of the peaking unit is treated as energy related. Hydro estimated that using the Equivalent peaker method would result in 20% of the costs being classified as demand and 80% as energy. Hydro states the Muskrat Falls Project was selected as the least cost alternative to replace Holyrood primarily based on the projected fuel costs savings over the long term and that, therefore, it appears reasonable that most of the Muskrat Falls Project would be considered energy-related. By contrast, Hydro currently uses the system load factor to classify its existing hydraulic generation and proposes to continue using this method for existing hydraulic generation. Hydro also proposes to continue to use system load factor for the classification of power purchases from Exploits generation and Recapture Energy from CF(L)Co. [40] The system load factor classification results in a demand/energy classification of approximately 45%/55%.[41]

In support of using the equivalent peaker methodology, the Christensen Associates report states:

> 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. Muskrat Falls is designed to operate as

[39] Page 22 of 105 of the Brattle Group Amended Report PDF document.

[40] Summarized from pages 21 and 22 of 144 of the Application PDF document.

[41] Line 22 on page 72 of 144 of the Application PDF document.

a baseload unit. The equivalent peaker approach would recognize that fact by treating much of its cost as being energy-related.[42]

6.3.2 The Brattle Group's Recommendation

The Brattle Group notes both the equivalent peaker and the system load factor approach to classification are energy-weighted approaches that recognize that energy loads are an important driver of production plant costs and that both approaches are reasonable ways to implement an energy-weighted approach to classification.[43] The Brattle Group recommends using the system load factor approach for Muskrat Falls Power Purchases for the following reasons:

- Hydro uses the system load factor approach for its existing hydraulic generation as well as other power purchases (excluding wind). In the absence of evidence that the equivalent peaker approach is unequivocally superior there are benefits to treating all of Hydro's hydraulic assets similarly.
- The system load factor approach is more straightforward to implement and not dependent and sensitive to key assumptions and input values. The Brattle Group highlights assumptions necessary to implement the equivalent peaker method and notes issues related to the use of cost estimates. The Brattle Group also notes issues with including the LIL and LTA in the equivalent peaker calculation.
- The energy component of the equivalent peaker approach is a residual. As such, unusually high or low baseload investment may distort the energy portion of the classification.
- The equivalent peaker approach assigns less of the Muskrat Falls costs to demand which dilutes peak-reducing price signals.
- Payments that Hydro makes to the Muskrat Falls Corporation are not related to the amount of energy Hydro purchases. [44]

The Brattle Group recommends the LIL be classified as 100% demand related regardless of whether it is functionalized as transmission or generation noting that the underlying cost characteristics of the LIL are such that the main cost driver is demand.[45] The Brattle Group recommends the LTA be classified as 100% demand related noting this is common COS practice and consistent with Hydro's recommendation for functionalized transmission costs.[46]

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[42] Lines 1 through 7 on page 72 of 144 of the Application PDF document.

[43] Embedded and Marginal Cost of Service Review. The Brattle Group. Page 32. Lines 4 through 7.

[44] Summarized from pages 32 through 37 of the Brattle Group report. Embedded and Marginal Cost of Service Review.

[45] Lines 4 through 7 on page 49 of 105 of the Brattle Group Amended Report PDF document.

[46] Lines 16 on page 45 through line 2 of page 50 of 105 pages in the Brattle Group Amended Report PDF document.

6.3.3 InterGroup's Observations

It is reasonable to evaluate the appropriate classification for the Muskrat Falls Generation, LIL and LTA separately, given the different characteristics of each group of assets. Hydro provided responses to information requests assuming different classification treatment for these different components that are useful in understanding the potential outcomes of such scenarios.

For Muskrat Falls Generation, the use of the equivalent peaker method should not be justified simply because it more closely approximates the historic classification ratios of Holyrood. The Christensen Associates report seems to acknowledge this stating that the Holyrood demand percentage is not a target, since Muskrat Falls' operation may differ somewhat from that of Holyrood in the past.[47] In InterGroup's view, the equivalent peaker method can only be justified if it more accurately reflects cost causation than other methods and can be calculated in a reliable and consistent way.

The Christensen Associates report notes the equivalent peaker method was reviewed in the 1992 methodology review and rejected by the Board for reasons of computational challenge and plant vintage and valuation issues. The Christensen Associates report states those issues apply with less force now, since the peaking unit computations pertain to a plant of current vintage.[48] However, in InterGroup's view, these vintage issues will also affect calculations in the future. It seems likely the Board's previously expressed concerns will be an issue in subsequent COS studies if the equivalent peaker method is adopted.

The Brattle Group also identifies a number of issues with the underlying data and assumptions used in the equivalent peaker methodology, including that the method compares Class 5 capital cost estimates for the gas turbine peaking unit with levelized costs of the Muskrat Falls Project that include the LIL and the LTA as well as material cost overruns.[49]

InterGroup recommends that Muskrat Falls Generation be classified using the system load factor approach, consistent with other existing hydraulic generation assets on Hydro's system for the following reasons:

- It is not reasonable to assume that the cost classification for Muskrat Falls should be required to confirm to the classification of Holyrood costs.
- The equivalent peaker approach proposed by Hydro mixes different types of cost data comparing Muskrat Falls actual costs that include significant transmission assets as well as material cost overruns to high level budget estimates for a gas turbine peaking unit.

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[47] Lines 24 through 26 on page 72 of 144 of the Application PDF document.

[48] Lines 8 through 12. Page 74 of 144 of the Application PDF document.

[49] Summarized from line 20 on page 38 through line 16 on page 39 of 105 of the Brattle Group Amended Report PDF document.

- Hydro will encounter the same issues related to vintage cost data and valuation issues in applying the equivalent peaker approach in future cost of service studies that led the Board to reject that approach in the 1992 methodology review.

For transmission assets, the Brattle Group notes it is common practice to classify functionalized transmission costs as 100% demand related.[50] This is consistent with InterGroup's experience. The LTA is a high voltage AC asset. The Christensen Associates report states the LTA facilities are being put in place to enable least cost operation of the combined Churchill Falls and Muskrat Falls generation facilities and that they will improve network reliability while facilitating energy transfers outside the Province.[51] The fact that the LTA improves network reliability suggests it has characteristics in common with network transmission assets, rather than simply being a generation lead. For those reasons, InterGroup recommends classifying the LTA 100% to demand, consistent with Hydro's other transmission assets.

The LIL is an HVDC line that connects the Muskrat Falls generation to a load center on the Island. The Christensen Associates report notes that the LIL and Muskrat Falls generation constitute an integrated resource strategy where the net economic benefits are jointly determined.[52] In InterGroup's view, these characteristics mean there is some merit in considering a different classification for the LIL than typical network transmission assets. Other Canadian hydroelectric utilities classify similar generation leads or generation integration transmission assets in the same manner as the related generation. Therefore, it may be appropriate to classify the LIL using the system load factor, the same method used for Hydro's existing hydraulic generation assets and recommended for Muskrat Falls Generation.

[50] Line 17, page 49 of 105 of the Brattle Group Amended Report PDF document.

[51] Lines 21 through 24 on page 90 of 144 of the Application PDF document.

[52] Lines 28 and 29. Page 90 of 144 of the Application PDF document.

7.0 CBPP GENERATION CREDIT PILOT AGREEMENT

Since 2009, CBPP has been operating under a pilot generation credit service contract that permits CBPP to maximize the efficiency of its Deer Lake Power Generation. The agreement allows Hydro to call on CBPP to maximize CBPP generation prior to increasing generation at higher cost units such as Holyrood or standby units.[53] Hydro is proposing to discontinue the CBPP generation credit agreement upon full commissioning of the Muskrat Falls Project stating that the fuel cost savings are not expected to continue upon commissioning of the Muskrat Fall Project. However, Hydro states it believes CBPP should have the opportunity to manage its generation as efficiently as possible and proposes to work with CBPP in the rate design review planned for 2019 to develop a proposal to achieve this objective.[54]

The CBPP generation credit is intended to better achieve generation efficiency on the Island consistent with provincial policy as set out in the *Act* at Section 3(b)(i):

> 3. It is declared to be the policy of the province that …
>
> b) all sources and facilities for the production, transmission and distribution of power in the province should be managed and operated in a manner …
>
> i. that would result in the most efficient production, transmission and distribution of power,

As of the 2013 Amended GRA, Hydro supported continuation of the pilot project[55], noting that the agreement had, over the period 2009-2012, resulted in net savings of 21,000 barrels of oil for the Island to the benefit of all customers, and with no net cost to any other customer class. The savings arose from more efficient production of power on the integrated Island hydraulic generation system than would arise without the agreement. InterGroup agrees that the economic relationships will be different following the Labrador infeed, and may need to be reassessed in the future. However, any such revision would need to be structured to retain incentives to operate Deer Lake Power Generation in a manner that results in the most efficient production of power.

The Board should not approve the discontinuation of the CBPP pilot agreement at this time. Absent the pilot project, CBPP will effectively be economically incented (by way of the existing industrial contract and rate design) to operate its hydro generation in a manner that is inefficient and unnecessary under a properly structured agreement such as the pilot project provides. The CBPP pilot agreement should be continued until a replacement agreement is available. In InterGroup's view the only issue to be determined in the current proceeding is the proper COS treatment of the CBPP pilot agreement and other capacity agreements.

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[53] Lines 18 through 22 on page 28 of 144 of the Application PDF document.

[54] Lines 4 through 10, page 29 of 144 of the Application PDF document.

[55] 2013 Amended GRA, Exhibit 4.

The Christensen Associates report recommends 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.[56]

The Brattle Group report states:

> Non-firm capacity assistance agreements and programs are common in utilities. The CBPP agreement is a form of non-firm, capacity assistance program but one where Hydro can call upon CBPP's own self-supply generation resources. To provide Hydro with capacity, CBPP must reduce its load requirement. Hydro treats the costs of capacity assistance program as being demand related, which we agree with as the programs are meant to lower consumption during peak demand periods.[57]

InterGroup agrees the current cost of service treatment for the CBPP pilot agreement remains reasonable and should be approved by the Board.

[56] Lines 26 through 29 on page 71 of 144 of the Application PDF document.

[57] Lines 8 through 13 on page 64 of 105 of the Brattle Group Amended Report.

8.0 DEMAND ALLOCATION

8.1 HYDRO'S RECOMMENDATION

Hydro currently uses a single coincident peak (1CP) approach to allocate generation costs among customer classes based on the forecast proportion of the single highest peak attributed to each class in the forecast test year.[58]

Hydro also notes that under the current 1CP approach, the Island Industrial Customer peak load has an 88% coincidence with system peak and the Newfoundland Power peak load has a 99.3% coincidence with system peak. These coincidence factors were based on a review of historical coincidence. Hydro states it does not see a basis to change these coincidence factors for use in the cost of service study.[59]

Hydro states the class load requirements by hour for the Test Year are based on a 2015 load profile which Hydro believes reasonably reflects a normal load profile. The hourly profile is scaled using the weather normalized monthly peak and monthly energy to develop an hourly profile for the Test Year.[60]

8.2 THE BRATTLE GROUP'S RECOMMENDATION

The Brattle report recommends the continued use of the 1CP allocator for the allocation of demand-related production and transmission classified costs. The Brattle report notes that Hydro forecasts a single winter peak in its planning process. The Brattle report also provided an analysis that indicated the use of a 3CP allocator would not be expected to materially change the allocations.[61]

8.3 INTERGROUP'S OBSERVATIONS

Hydro and the Brattle Group both recommend continued use of a 1CP allocator for generation and transmission demand allocations. InterGroup agrees this approach is reasonable and the Board should approve the continued use of a 1CP allocator for demand.

However, the calculation of the customer class CPs used in the test year COS study merits additional consideration. In its 2018 reliability and resource adequacy study, Hydro discusses two forecast approaches:

- In a P50 forecast, the actual peak demand is expected to be below the forecast number 50% of the time and above 50% of the time (i.e. the average forecast).

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[58] Lines 4 through 7. Page 24 of 144 of the Application PDF document.

[59] Lines 1 through 5. Page 25 of 144 of the Application PDF document.

[60] PUB-NLH-002 lines 14 through 18.

[61] Summarized from pages 51 through 55 of 105 of the Brattle Group Amended Report.

- In a P90 forecast, the actual peak demand is expected to be below the forecast number 90% of the time and above the forecast 10% of the time. While in this case there is a smaller chance of the actual peak demand exceeding the forecast peak demand, it requires planning to have more generation available, which increases costs.[62]

Hydro notes in the 2018 Reliability and Resource Adequacy Study that planning to meet a P90 peak demand forecast would increase the peak forecast by 60 MW plus the reserve margin – if the desired reserve margin is 13%, planning for the P90 peak demand would increase system requirements by 67.8MW over the P50 peak demand. Hydro notes the Board directed Hydro to use the P90 weather variable as the base case in all reporting to the Board for supply planning decisions related to the IIS but Hydro is proposing the P50 peak demand forecast be used for evaluating resource additions.[63]

Hydro states in its 2018 Reliability and Resource Adequacy study that load forecast uncertainty models how a system's peak load can vary by providing an uncertainty range. Hydro applies a load forecast uncertainty parameter against the expected peak demand. A range of economic conditions are considered in the development of long-term resource plans while probabilistic modelling of weather variability is considered in setting the planning reserve margin.[64]

It is important to note that customer classes contribute differently to the changes in the peaks between the P50 forecast and the P90 forecast. Figure 8-1 provides a comparison of 2019/20 coincident demands by customer class for P50 and P90 scenarios. Figure 8-1 shows that under both the P50 and P90 load scenarios, coincident demands for industrial customers are the same, reflecting the flatter load profile of the industrial customers. However, the peak demand for Newfoundland Power and Rural customers increases.

If customer classes contribute differently to the uncertainty included in developing planning criteria, and this drives Hydro to incur additional costs, it would be appropriate to reflect this in the calculation of peaks for cost allocation purposes. The Board should direct Hydro to review the contribution of different customer classes to the uncertainty parameters in its planning studies, and ensure the calculation of peaks used in the COS study appropriately reflect the contribution of the different customer classes to this uncertainty.

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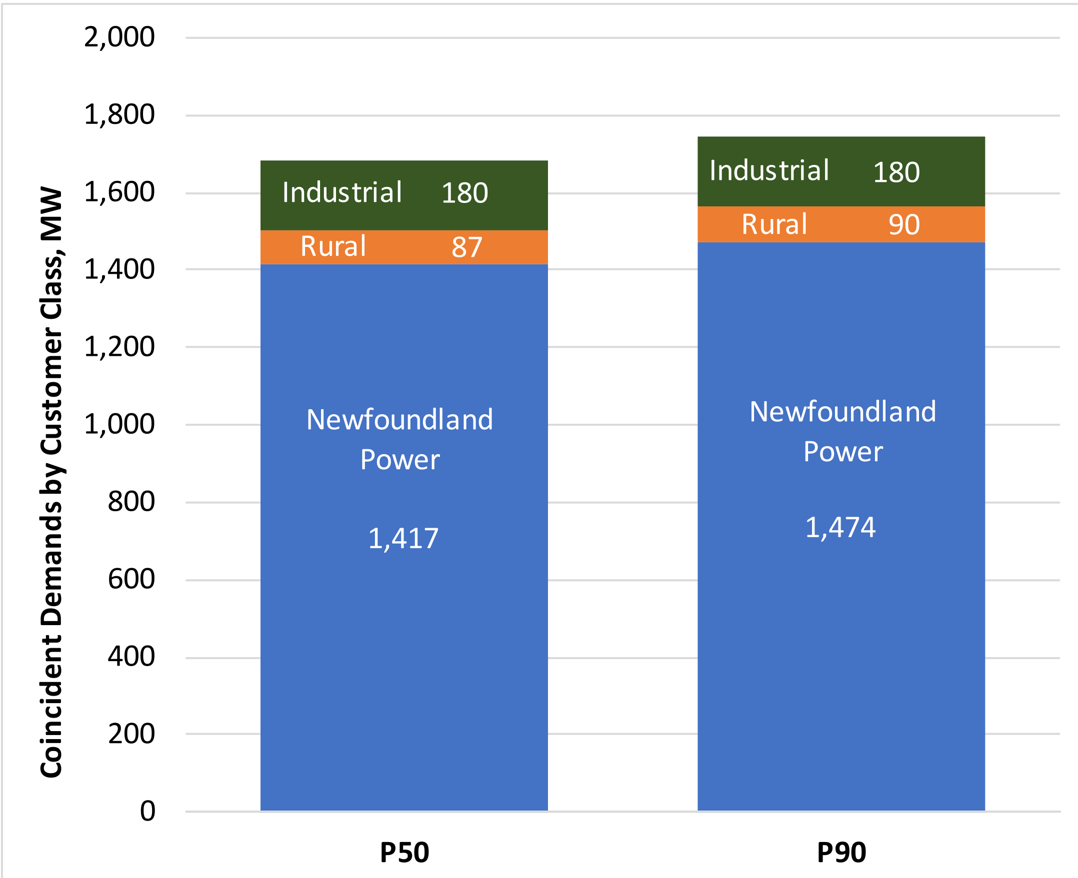
[62] NLH Reliability and Resource Adequacy Study. November 2018. Page 18 of 620 of the PDF document.

[63] Summarized from pages 49 and 50 of 620 of the NLH Reliability and Resource Adequacy Study dated November 16, 2018.

[64] Section 4.2.1.1 of the November 2018 Reliability and Resource Adequacy Study. Pages 56 and 57 of the PDF document.

Figure 8-1: 2019/20 Coincident Demands by Customer Class, MW[65]



[65] Figure prepared by InterGroup based on Hydro's response to IC-NLH-028 in the Review of Island Interconnected System Supply Issues and Power Outages proceeding. The figure does not include transmission losses and Holyrood station service.

9.0 OTHER TOPICS

9.1 FUNCTIONALIZATION AND CLASSIFICATION OF OTHER TRANSMISSION LINES

Hydro recommends changing the functionalization of transmission lines TL-234 and TL-263 from generation to transmission.[66] Hydro states TL 234 and TL 263 were previously considered generator leads and functionalized as generation. The addition of TL 269 from Granite Canal to Bottom Brook to support the import and export of energy over the Maritime Link creates a 230 kV transmission loop which includes TL 234 and TL 263.[67] Hydro also recommends that all functionalized transmission costs be classified as 100% demand related. The Brattle Group agrees with Hydro's proposal to modify the functionalization of TL-234 and TL-263.[68]

Both Hydro and the Brattle Group recommend functionalizing TL-234 and TL-263 as transmission and classifying them 100% to demand. This change is reasonable and should be approved by the Board.

9.2 CONSERVATION DEMAND MANAGEMENT COST ALLOCATION

Hydro states that based on discussions with Newfoundland Power, Hydro is proposing to continue the current approach in recovery of CDM costs among its customer classes.[69] Hydro's CDM program costs are currently excluded from the COS study and allocated for recovery from customer classes based on energy. Hydro states that it anticipates a change in CDM focus toward peak demand management will be reflected in the CDM potential study currently being prepared for the Island Interconnected System.[70] The Christensen Associates report recommends Hydro continue its current CDM cost classification but if programs focusing on demand are introduced and the dollar amounts are material, Hydro can classify programs based on anticipated avoidance of demand or energy growth.[71]

The Brattle Group notes that, in the 2013 GRA, Hydro's justification of its CDM programs was system energy savings that benefit all customers. However, Hydro and NP are conducting a CDM potential study to identify cost-effective electric energy and demand management measures to reduce or shift peak demand. The Brattle Group report states that, in future proceedings, it may be appropriate to assign some CDM costs to demand.[72]

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[66] Lines 2 through 5 on page 19 of 144 of the Application PDF document.

[67] PUB-NLH-006. Lines 5 through 8.

[68] Line 17 on page 23 of 105 of the Brattle Group Amended Report PDF document.

[69] Lines 20 and 21 on page 26 of 144 of the Application PDF document.

[70] Lines 24 through 26. CA-NLH-040.

[71] Lines 6 through9 on page 188 of 144 of the Application PDF document.

[72] Summarized from lines 1 through 18 on page 60 of 105 of the Brattle Group Amended Report PDF document.

InterGroup agrees that CDM programs with capacity benefits should have a portion of their costs classified to demand. The Board should direct Hydro to review the capacity and energy benefits of its CDM programs and classify them consistent with those benefits at the time of the next GRA.

9.3 ALLOCATION OF SPECIFICALLY ASSIGNED CHARGES

Hydro is proposing to discontinue using original asset costs as the basis for the allocation of operating and maintenance ("O&M") costs to specifically assigned costs as it tends to be poorly correlated with actual expense patterns over time.[73] Hydro plans to report to the Board in its next GRA on whether tracking of actual O&M costs by asset is a reasonable approach to use for cost allocation for specifically assigned assets. Until a reasonable alternative method is developed, Hydro recommends the use of indexed asset costs in the determination of specifically assigned charges.[74]

Hydro has confirmed it has the ability to track actual O&M expenses for all Island Interconnected specifically assigned assets.[75] Hydro states that it plans to make the results available at its next GRA, but it is premature to make any recommendation regarding this option before gathering complete data.[76] Christensen Associates state they support Hydro's plan to develop a history of cost tracking to guide subsequent policy.[77] The Brattle Group report states it is preferable to have Hydro track actual O&M expenses associated with each customer's dedicated assets and to bill the customer directly.[78]

In InterGroup's view, the Handy Whitman indexed approach is superior compared to an allocation on the basis of original asset costs. The original asset cost data are unavoidably burdened by the impacts of differing vintages of assets and the inflation that has occurred between the dates in which they went into service. However, there can be cases where even the indexed approach does not lead to fair allocations. If Hydro can accurately track actual O&M expenses for specifically assigned assets it would be preferable to use that data as the basis for test year cost allocations. The Board should direct Hydro to provide a report on the feasibility of using actual O&M data for specifically assigned assets as the basis for cost allocation at the time of the next GRA.

9.4 HOLYROOD ASSETS

Hydro notes that Holyrood's role will change following the commissioning of the Muskrat Falls Project. Once the LIL and ML are in-service, Hydro expects to reduce Holyrood production by importing energy from off-island supply. Hydro will continue to use Holyrood to provide reliable service to customers, and as satisfactory operating experience is obtained over the LIL and the

[73] Lines 24 through 28 on page 26 of 144 of the Application PDF document.

[74] Lines 1 through 8 on page 27 of 144 of the Application PDF document.

[75] IC-NLH-020.

[76] Lines 19 through 27 of CA-NLH-024.

[77] Lines 17 through 19 on page 124 of 144 of the Application PDF document.

[78] Lines 17 through 19. Page 61 of 105 of the Brattle Group Amended Report PDF document.

ML, the Holyrood units will be placed in standby mode.[79] Hydro is proposing to change the classification for Holyrood assets from a 5-year average capacity factor to the forecast capacity factor for the test year.[80] The Brattle Group agrees with Hydro's recommendation.[81] In InterGroup's view, classification should reflect the way the asset is planned to be used during the test year. Following the addition of the Muskrat Falls Project, Holyrood will be operated differently, and therefore, the historic data will no longer reflect how the asset is forecast to be used in the test year. Hydro's proposal to use a forecast capacity factor instead of the historic 5-year average to classify the Holyrood assets is reasonable and should be approved by the Board.

Hydro recommends that Holyrood Unit 3 be functionalized as transmission and classified as 100% demand after the unit is permanently converted into the role of synchronous condenser.[82] The Christensen Associates report notes the unit will be used as a synchronous condenser, available for system stability but not supplying energy.[83] Hydro states that as a synchronous condenser Holyrood Unit 3 will not have a prime mover attached to the shaft and therefore will be unable to generate energy. The synchronous condenser will consume power and energy from the transmission system and is only able to generate or absorb reactive power to/from the transmission system.[84]

The Brattle Group report recommends that the portion of rate base and depreciation associated with Holyrood's use as a generator continue to be functionalized as generation, but that the capital additions and operations and maintenance costs associated with the use as a synchronous generator be functionalized as transmission.[85] For classification, the Brattle Group report recommends that the portion of rate base and depreciation associated with prior use to provide generation be classified as demand while the capital additions and operations and maintenance costs associated with Holyrood Unit 3's use as a synchronous generator be classified as energy.[86] Hydro states it has not provided revenue requirement impacts for Brattle's recommendation because it is unclear on how to apply these recommendations.[87]

In a report to the PUB dated June 2010, Hydro provided the following description of Holyrood Unit 3's function as a synchronous condenser:

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[79] Lines 6 through 11 on page 146 of 431 of Hydro's 2019 Capital Budget Application – Revision 1 dated October 9, 2018.

[80] Lines 2 through 7 on page 23 of 144 of the Application PDF document.

[81] Line 11. Page 42 of 105 of the Brattle Group Amended Report.

[82] Lines 15 and 16. Page 19 of 144 of the Application PDF document.

[83] Lines 4 and 5. Page 74 of 144 of the Application PDF document.

[84] PUB-NLH-038 Lines 18 through 30.

[85] Lines 13 through 17 of page 24 of 105 of the Application PDF document.

[86] Lines 17 through 20 on page 42 of 105 of the Application PDF document.

[87] Lines 21 through 22. NP-NLH-001.

In addition to being operated as a generator of electrical power and energy, the Unit 3 generator at Holyrood has the capability of operating as a synchronous condenser. Each year Holyrood Unit 3 is converted to operate as a synchronous condenser during the offpeak generation period which typically occurs between April and November. A synchronous condenser is a specialized synchronous motor whose purpose is not to produce mechanical power, but to adjust electrical conditions on an interconnected power grid system. Synchronous condensers provide voltage control in the form of MVAR injection/absorption to/from the system when power is transmitted over long distances on an interconnected power grid system.

In the case of Holyrood Unit 3, the synchronous condenser consists of a relatively small induction motor that is coupled to a gearbox (or speed increaser) which, in turn, is mechanically connected to the generator via a clutch system. During operation of Unit 3 as a synchronous condenser, the generator assembly is de-coupled from the turbine. The 230 kV transmission system east of Bay d'Espoir can be characterized as a heavily loaded system and consequently experiences significant voltage drop during peak load conditions. As a result, this portion of the system requires voltage support in the form of MVAR injection in order to bring system voltages up to minimum acceptable levels. The Holyrood Thermal Generating Station, the Hardwoods Gas Turbine operating as a synchronous condenser and shunt capacitor banks at long Harbour, Hardwoods and Oxen Pond Terminal Stations provide the MVAR injection into the 230 kV system to counteract the voltage drop. During the April to November time frame there is sufficient hydroelectric capacity on the Island Interconnected system to supply the system load. Subsequently, the generating units at Holyrood are not required and the plant is shut down. Therefore, with all generating resources located off the Avalon Peninsula, voltage control on the 230 kV transmission system east of Bay d'Espoir is of concern during the April to November period. Operation of Holyrood Unit 3 in synchronous condenser mode ensures acceptable voltage levels on the Avalon Peninsula during both normal operation and under line out contingencies.[88]

While the Holyrood Unit 3 assets may originally have been put in place to perform a generation function, when operating in synchronous condenser mode it appears they are primarily serving a functional role in addressing a transmission constraint. Further, capital spending has been undertaken as far back as 1986 to support the unit’s role as a synchronous condenser.[89] In InterGroup’s view, this is a situation where refunctionalization of the assets from generation to transmission may be appropriate. Hydro’s proposal to functionalize the Holyrood Unit 3 assets to transmission once they are converted to synchronous condenser operations and classify them 100% to demand is reasonable and should be approved by the Board.

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[88] Pages 1 and 2 of a report to the PUB on the Holyrood Unit 3 Synchronous Condenser Upgrade. Dated June 2010. Available: http://pub.nf.ca/applications/NLH2011Capital/files/application/NLH2011Application-Report8.pdf. Accessed July 29, 2019.

[89] Lines 9 through 11 on page 144 of 431 of Hydro’s 2019 Capital Budget Application – Revision 1 dated October 9, 2018.

9.5 DIESEL AND GAS TURBINE FUEL COSTS

Hydro proposes to continue to classify IIS diesel and gas turbine generation unit assets and fuel costs 100% to demand.[90] The Brattle Group recommends that IIS diesel and gas turbine variable fuel costs be classified as energy since the amount of fuel required varies with the amount of energy produced.[91]

Hydro notes that typically gas turbines and diesel units are operated on the IIS for system reliability considerations and that this is consistent with the classification as demand-related.[92] In the 2017 GRA, Hydro states:

> The requirements for the gas turbines are determined in consideration of thermal and hydraulic forced outage rates, and in consideration of the peak load forecast and Hydro's typical load duration curve.

The Island Interconnected System gas turbines and diesel production also assumes that each plant is exercised at rated output for one hour per month during the non-winter period for testing and for ensuring availability. These units are assumed to be exercised for four hours during each winter month (approximately once per week) for winter readiness and storm preparedness.

The reduced production forecast for Hydro's Island Interconnected System gas turbines and diesels for 2017 through to the 2019 Test Year reflect the reliability benefit of the planned in service of a third transmission line from Bay d'Espoir to Western Avalon (TL267).[93]

Christensen Associates states that, in practice, since these generators do not perform a conventional load following role but instead are tied to transmission system reliability, continuation of the use of demand appears justifiable.[94] In InterGroup's view, it is reasonable to continue classifying diesel and gas turbine fuel costs to demand, given the role they play in supporting peak demand and that these costs are reduced by the addition of transmission infrastructure. The Board should approve Hydro's proposal to classify IIS diesel and gas turbine generation unit assets and fuel costs 100% to demand.

9.6 WIND PURCHASES

Hydro is proposing to classify wind purchases as 22% demand/78% energy based on a study conducted by its resource planning group regarding wind availability during peak periods.[95] The Brattle Group reviewed Hydro's proposal and confirmed Hydro's methodology is consistent with other approaches to calculating the load carrying capability of wind units but noted these

[90] Section 3.3.7 on page 23 of 144 of the Application PDF document.

[91] Lines 9 through 11 on page 48 of 105 of the Brattle Group amended report.

[92] Lines 19 through 22. Page 1 of the response to PUB-NLH-039.

[93] Lines 4 through 18. Page 3.25. Volume 1. NLH 2017 General Rate Application. Revision 5.

[94] Lines 7 through 10. Page 2 of the response to PUB-NLH-039.

[95] Lines 10 through 12 of 144 of the Application PDF document.

methodologies can be case specific and dependent upon the type of data and system models that are available. The Brattle Group undertook additional analysis of wind output and concluded that a 22% demand classification is not an unreasonable estimate.[96]

It is reasonable to classify some costs of wind generation to demand where they can be demonstrated to have some firm load carrying capability. The Board should approve Hydro's proposed classification for wind purchases.

9.7 MARGINAL COST BASED ALLOCATION

Hydro notes the Christensen Associates report supports the use of marginal costs in the classification and allocation of generation costs.[97] Hydro is not recommending the use of marginal generation costs in the classification and allocation of generation costs in the COS study and notes the following with respect to the use of marginal costs for cost allocation studies:

- There are currently no utilities in Canada applying this approach;
- Hydro has concerns with the complexity and understandability of marginal cost derivation relative to the traditional cost of service approaches; and
- Hydro does not forecast load requirements for each customer on an hourly basis.[98]

The Brattle Group report agrees it is economically appropriate to use a marginal COS study to either directly set rates based upon study results (with a reconciliation to ensure that rates are sufficient to recover embedded costs) or to use as a component within the embedded COS study. However, the Brattle Group noted that, in their view, it is premature to pursue this methodology in the present proceeding given the lack of experience with marginal COS studies with Hydro in Newfoundland and Labrador and additional issues Brattle identified in the marginal COS study.[99]

InterGroup agrees that it is premature for Hydro to use marginal cost approaches in its COS study at this time. Questions around the accuracy and reliability of the marginal cost studies would need to be resolved as well as concerns about the potential volatility of the results in the future. The Board should accept Hydro's recommendation not to use the marginal cost study as the basis for cost allocation in the COS study at this time.

9.8 ALLOCATION OF NET EXPORTS REVENUES

Hydro recommends that net export revenues be used to reduce Muskrat Falls supply costs to be recovered through the rates of customers on the Island Interconnected System; that net export revenues be classified in the same manner as the classification of the Muskrat Falls Project costs in the cost of service study; and that net export revenues be included in the test year cost of

[96] Summarized from pages 46 through 48 of 105 of the Brattle Group Amended Report PDF document.

[97] Lines 16 and 17 on page 20 of 144 of the Application PDF document.

[98] Lines 16 through 24 on page 20 of 144 of the Application PDF document.

[99] Summarized from lines 10 through 18 of page 68 of 105 of the Brattle Group Amended Report.

service study for rate making with variations from forecast net export revenues to be dealt with through a deferral account mechanism.[100] Hydro states it will provide deferral account definitions, including proposed allocation and recovery methodologies, with its next GRA.[101]

The Brattle Group report notes that Island Interconnected customers are required to pay for the facilities of Muskrat Falls and that export sales are to be credited to Island Interconnected customers as a matter of government policy.[102] The Brattle Group recommends the export credit be classified and allocated in the same manner as the Muskrat Falls generation. The Brattle Group further recommends the use of a rider to facilitate true-ups between rate cases.[103]

InterGroup agrees that net export revenues should be functionalized and classified in the same manner as the assets that give rise to those revenues. With respect to the true-up of differences between actual and forecast net export revenues, Hydro's proposal to provide proposed allocation and recovery methodologies with its next GRA is reasonable and should be approved by the Board.

9.9 NP GENERATION CREDIT

Hydro states it continues to assume that the existing Newfoundland Power hydraulic and thermal generation assets will continue to provide firm capacity to meet system demand requirements. Therefore, Hydro recommends the continuation of the existing approach of providing a generation credit for both the hydraulic and thermal generation of Newfoundland Power.[104]

Under the existing approved approach, the hydraulic generation credit is applied in reducing NPs coincident peak demand at transmission and generation. The thermal generation credit is applied to reduce NP's coincident peak at generation, but not the coincident peak for transmission. The coincident peak at generation used in computing the system load factor does not reflect a reduction for NP's thermal generation.[105]

Hydro states it plans to review the reasonableness of the amount of the NP generation credit based on the capacity provided when Newfoundland Power has been requested by Hydro to provide it maximum generation available. Hydro states it will file the results of this review in its next GRA.[106]

Both the Christensen Associates report and the Brattle Group report recommend continuing the current generation credit arrangement. Christensen Associates notes that, if either party objects to the agreement, alternatives could be explored.[107] InterGroup notes the value of the NP generation assets could be different with the inclusion of Muskrat Falls and it is appropriate to

[100] Lines 13 through 20 on page 29 of 144 of the Application PDF document.

[101] IC-NLH-014.

[102] Summarized from line 20 on page 64 through line 3 of page 65 of 105 of the Brattle Group Amended report.

[103] Summarized from lines 4 through 11 on page 65 of 105 of the Brattle Group Amended report.

[104] Lines 11 through 14. Page 27 of 144 of the Application PDF Document.

[105] Summarized from lines 1 through 10 on page 28 of 144 of the Application PDF document.

[106] Lines 12 through 15 on page 28 of 144 of the Application PDF document.

[107] Summarized from lines 19 through 22 of page 130 of 144 of the Application PDF document.

review the credit. The Board should direct Hydro to file a report on the reasonableness of the NP Generation Credit at the time of the next GRA.

APPENDIX A:
Resume

InterGroup CONSULTANTS

ANDREW McLAREN

PRINCIPAL AND CONSULTANT

AREAS OF EXPERIENCE:

- Utility Regulation
- Socio-economic and Environmental Assessment
- Economic Impact Assessments, Feasibility Studies and Program Evaluations
- Fee Setting and Policy Advice for Environmental Stewardship Programs in Canada

EDUCATION:

- MNRM (Master of Natural Resources Management), Natural Resources Institute, University of Manitoba, 1999
- Bachelor of Science (Environmental Science), University of Manitoba, 1996

PROFESSIONAL EXPERIENCE:

InterGroup Consultants Ltd., Winnipeg, Manitoba

2000 – Present – Research Analyst / Research Consultant / Consultant / Principal

Utility Regulation

- **For Northwest Territories Power Corporation (2000-Present):** Provided technical support and analysis during the Corporation's 2001/03 Phase I and Phase II General Rate Applications; 2006/08 Phase I and Phase II General Rate Application; 2010 rate rebalancing application; 2012/14 Phase II General Rate Application and 2016/19 Phase I and Phase II General Rate Applications. Other responsibilities have included assisting with preparing rate stabilization fund rider applications and applications for major project permits. Prepared evidence and provided expert testimony on revenue requirement, cost of service and rate design topics before the Northwest Territories Public Utilities Board in the NTPC 2016/19 Phase I and Phase II General Rate Applications.
- **For Qulliq Energy Corporation (QEC) (2008-Present):** Lead consultant responsible for assisting QEC with preparation of the 2010/11 Phase I General Rate Application. Provided

advice on proposed return on equity, reasonableness of revenue requirement and rate design. Lead consultant responsible for assisting QEC with preparation of the 2010/11 Phase II General Rate Application. This was the first Phase II application undertaken by the Corporation since separating from the Northwest Territories Power Corporation. Provided advice on classification and allocation methods for the Corporation's cost of service study and rate design options. Lead consultant responsible for assisting QEC with preparation of the 2014/15 Phase I General Rate Application. Other responsibilities have included preparing fuel rider applications and capital project permit applications. Lead consultant responsible for assisting QEC with preparation of the 2018/19 Phase I and Phase II General Rate Application.

- **For Saskatchewan Rate Review Panel (2013-Present):** Technical advisor to the Panel with respect to SaskEnergy's 2013 delivery service rate application. Prepared an independent report analyzing SaskEnergy's application and made recommendations to the Panel. Topics addressed included load forecasts, reasonableness of operations and maintenance expense forecasts and rate design. Technical advisor to the Panel with respect to SaskEnergy's 2014 commodity rate application. Topics addressed included reasonableness of commodity rate forecast and rate design. Technical advisor to the Panel with respect to SaskPower's 2016 and 2017 rate application. Technical advisor with respect to SaskPower's 2018 rate application. Prepared consultant reports reviewing the reasonableness of SaskPower's revenue requirement and rate design proposals.
- **For City of Penticton (2015-Present):** Technical consultant on utility financial planning, cost of service and rate proposals for the City's electric, water, sewer and stormwater utilities. Prepared financial forecasts and rate design options for review by City staff, ratepayers and City Council.
- **For Town of Ponoka (2018-2019):** Undertook a review of the cost of service, rates and financial performance of the Town's electric distribution system.
- **For Regional District of Okanagan-Similkameen (2016):** Prepared a technical memo on rate options for the community of West Bench for moving from a fixed charge water rate structure to a rate structure that included a variable component. Participated in a public consultation session with local residents and made a presentation to the District Council.
- **For North Salt Spring Island Water District (2016):** Prepared a technical report on revising the parcel tax for the district to recover a portion of the costs of operating the utility. Made a presentation to the water district board recommending new parcel tax categories.
- **For Towns of Chestermere and Cochrane, City of Airdrie and Strathmore County (2012-2014):** Provided technical analysis support to municipalities who receive water and wastewater service from the City of Calgary with respect to the City of Calgary's financial forecast, cost of service study and proposed rate design. Responsibilities included reviewing material provided by the City of Calgary, drafting briefing notes and participating in negotiation meetings with municipal officials.
- **For BC First Nations Energy and Mining Council (2011-2013):** Represented BCFNEMC on the Technical Advisory Committee (TAC) for BC Hydro's 2013 Integrated Resource Plan.

Responsibilities included preparing briefing notes for BCFNEMC executives and preparing submissions to BC Hydro on First Nations perspectives on the IRP process and recommendations.

- **For Manitoba Industrial Power Users Group (MIPUG) (2001-2012):** Prepared analysis for regulatory proceedings before the Manitoba Public Utilities Board representing large industrial energy users during Manitoba Hydro's 2001 Status Update Filing and 2004 General Rate Application. Prepared evidence and provided expert testimony on cost of service and rate design methods before the Manitoba Public Utilities Board in the 2006 Cost of Service Study hearing. Prepared evidence and provided expert testimony on revenue requirement, cost of service and rate design topics (with Patrick Bowman) before the Manitoba Public Utilities Board in the Manitoba Hydro 2008 General Rate Application. Prepared evidence and provided expert testimony on revenue requirement and rate design topics (with Patrick Bowman) before the Manitoba Public Utilities Board in the Manitoba Hydro 2010 General Rate Application.
- **For Industrial Customers of Newfoundland and Labrador Hydro (2001-2008):** Prepared analysis related to Newfoundland Hydro's 2001 and 2003 General Rate Applications on behalf of large industrial energy users. Topics addressed included revenue requirement issues and rate design. Submitted pre-filed testimony (with Patrick Bowman) on behalf of the Island Industrial Customers in regards to the Newfoundland and Labrador Hydro 2006 General Rate Review before the Board of Commissioners of Public Utilities. Topics addressed included revenue requirement development, cost-of-service and rate design studies. Lead consultant for the Industrial Customers in a working group with Newfoundland and Labrador Hydro in 2008 to develop and review a marginal cost based rate proposal.

Socio-economic and Environmental Assessment

- **For Lake and Peninsula Borough (Alaska) (2018-2019):** Lead consultant preparing a socio-economic and fiscal impact assessment of the proposed Pebble mine. Undertook community consultations and prepared report analysing potential socio-economic effects of the project on the Borough.
- **For Manitoba Hydro – Conawapa Project (2012-2014):** Overall responsibility for day to day management of the socio-economic studies and public engagement programs for the proposed Conawapa generation project, a 1,300 MW hydro-electric generation project in Northern Manitoba. Planning for the Conawapa project is currently suspended.
- **For Manitoba Hydro – Keeyask Transmission Project (2011-2012):** Lead consultant on the socio-economic effects assessment for the Keeyask Transmission Project. Prepared socio-economic technical study and drafted sections of the environmental assessment report.
- **For two Northern British Columbia First Nations (2003-2009):** Provided strategic advice and analysis on settlement claims for damages related to the development of the Williston reservoir and the GM Shrum hydro-electric generation project. Included community consultations on agreements and planning for new electricity supply.
- **For Yukon Energy Corporation (2009):** Provided senior advice on approach to

environmental assessment for the proposed Mayo B Hydro Project. Responsibilities included advising on approach to selection of valued components and assessment methods.

- **For Manitoba Floodway Authority (2003-2005):** Managed the field program for the socio-economic impact assessment of the Floodway Expansion, a $600 million infrastructure project to improve flood protection for the City of Winnipeg. Responsibilities included planning, conducting and supervising field work, analysis of potential socio-economic pathways of environmental effects and drafting the socio-economic chapter of the environmental impact statement.
- **For Province of Manitoba (2003):** Conducted analysis related to recreation and tourism benefits of summer water level regulation in the City of Winnipeg. Responsibilities included quantitative and qualitative assessments of potential benefits of water level regulation.
- **For Province of Manitoba (2000-2002):** Conducted quantitative and qualitative assessment of socio-economic impacts related to proposed flood control alternatives for the City of Winnipeg, including key-person interviews with stakeholders and presentation of results at public meetings.

Economic Impact Assessments, Feasibility Studies and Program Evaluations

- **For the Manitoba Motion Picture Industry Association (2004)**: Researched and wrote an economic impact study for the film industry in Manitoba. Analysis included interviews with creative and technical workers in the film industry, as well as producers and industry service providers. The assessment included employment estimates, an analysis of spending and Gross Domestic Product as well as revenues flowing to the provincial government.
- **For the Manitoba Industrial Power Users Group (MIPUG) (2006):** Conducted an economic impact assessment of the operations of the members of MIPUG, comprising the largest industrial operations in Manitoba. Analysis included spending and GDP benefits, as well as tax and employment impacts for various levels of government.

Fee Setting and Policy Advice for Environmental Stewardship Programs in Canada

- **Electronics Recycling Fees and Tire Recycling Fee Studies (2009–2018):** Project study director for numerous reviews since 2009 of Environmental Handling Fees and Tire Recycling Fees for electronics and tire stewardship programs in Nova Scotia, Quebec, Manitoba, Saskatchewan and British Columbia. Projects included broad consultation with industry and government stakeholders related to the calculation of fees.
- **Performance Indicators Study:** Project study director for a 2010 study developing performance measurement indicators for public reporting for stewardship programs. Indicators included operational, financial, public awareness and accessibility and environmental indicators.
- **Generic Tire Fee Setting Manual:** Project study director for the development of a generic fee design manual for scrap tire stewardship programs in Canada.

Andrew McLaren Utility Regulation Experience

Utility	Proceeding	Work Performed	Before	Client	Year	Testimony
NTPC	2001/03 Phase I General Rate Application	Analysis and Case Preparation	NWTPUB	NTPC	2000-02	No
NTPC	2001/03 Phase II General Rate Application	Analysis, Assisted with preparation of Company Rate Design Evidence	NWTPUB	NTPC	2002	No
Newfoundland Hydro	2004 General Rate Application	Analysis, assisted with preparation of Intervenor Evidence	NLPUB	Newfoundland Industrial Customers	2003	No
Manitoba Hydro	2004 General Rate Application	Analysis, Assisted with Preparation of Intervenor Evidence	MPUB	MIPUG	2004	No
Nunavut Power (Qulliq Energy)	2004 General Rate Application	Analysis, Preparation of Intervenor Submission	Nunavut Utility Rate Review Commission (URRC)	NorthWest Company (commercial customer intervenor)	2004	No
Manitoba Hydro	Cost of Service Methodology	Analysis, Preparation of Intervenor Evidence and Expert Testimony with Patrick Bowman	MPUB	MIPUG	2006	Yes
Newfoundland Hydro	2006 General Rate Application	Analysis, Preparation of Intervenor Evidence with Patrick Bowman	Board of Commissioners of Public Utilities of Newfoundland and Labrador (NLPUB)	Newfoundland Industrial Customers	2006	No - Negotiated Settlement
NTPC	2006/08 General Rate Application Phase I and Phase II	Analysis, Assisted with Preparation of Company Evidence	NWTPUB	NTPC	2006-08	No
Manitoba Hydro	2008 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony with Patrick Bowman	MPUB	MIPUG	2008	Yes
Manitoba Hydro	2008 Energy Intensive Industrial Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony with Patrick Bowman	MPUB	MIPUG	2008	Yes
NTPC	Rate Rebalancing Application	Analysis and assisted with preparation of application	NWTPUB	NTPC	2010	No
Qulliq Energy Corporation	2010/11 General Rate Application	Analysis, Lead Consultant for Preparation of Company Evidence	Utility Rates Review Panel (URRC)	QEC	2010-11	No
Manitoba Hydro	2010/11 and 2011/12 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony with Patrick Bowman	MPUB	MIPUG	2010-11	Yes
SaskEnergy	2013/14 and 2014/15 Delivery Service Rates	Lead Technical Advisor to SK Rate Review Panel (SRRP)	SRRP	SRRP	2013	No
Qulliq Energy Corporation	2014/15 General Rate Application	Analysis, Lead Consultant for Preparation of Company Evidence	URRC	QEC	2014-15	No
SaskEnergy	2014 Commodity Rate Application	Lead Technical Advisor to SK Rate Review Panel (SRRP)	SRRP	SRRP	2014	No
SaskEnergy	2014/15 Delivery Service Rates Update	Lead Technical Advisor to SK Rate Review Panel (SRRP)	SRRP	SRRP	2014	No
NTPC	2012/14 Phase II General Rate Application	Analysis, Advisor on Company Evidence	NWTPUB	NTPC	2015	No
SaskEnergy	2015/16 Delivery and Commodity Rate Application	Lead Technical Advisor to SK Rate Review Panel (SRRP)	SRRP	SRRP	2015	No
SaskPower	2016 and 2017 Rate Application	Lead Technical Advisor to SK Rate Review Panel (SRRP)	SRRP	SRRP	2016	No
NTPC	Phase I and Phase II 2016/19 General Rate Application.	Lead witness on load forecasts, cost of service study and rate design.	NWTPUB	NTPC	2017	Yes
SaskPower	2018 Rate Application	Lead Technical Advisor to SK Rate Review Panel (SRRP)	SRRP	SRRP	2018	No
Qulliq Energy Corporation	2018/19 General Rate Application	Analysis, Lead Consultant for Preparation of Company Evidence	URRC	QEC	2017-18	No
Enmax Energy Corporation	2017-2020 RRO Non-energy tariff	Lead consultant to Utilities Consumer Advocate (UCA)	Alberta Utilities Commission	UCA	2018-onging	In progress

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