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November 15, 2018

The Board of Commissioners of Public Utilities
Prince Charles Building
120 Torbay Road, P.O. Box 21040
St. John's, NL A1A 5B2

Attention: Ms. Cheryl Blundon
Director Corporate Services & Board Secretary

Dear Ms. Blundon:

Re: Cost of Service Methodology Review

Further to the Settlement Agreement to Newfoundland and Labrador Hydro's ("Hydro") 2017 General Rate Application, enclosed please find one (1) original plus thirteen (13) copies of an Application for revisions to Hydro's Cost of Service Methodology for use in the determination of test year class revenue requirements reflecting the inclusion of the Muskrat Falls Project costs upon full commissioning.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Shirley A. Walsh
Senior Legal Counsel – Regulatory
SW/kd

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey
ecc: Dean Porter – Poole Althouse
Van Alexopoulos – Iron Ore Company of Canada
Senwung Luk – Olthuis Kleer Townshend LLP

Dennis Browne, Q.C. – Browne Fitzgerald Morgan & Avis
Denis Fleming – Cox and Palmer
Benoît Pepin – Rio Tinto

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

AND IN THE MATTER OF an Application by Newfoundland and Labrador Hydro (“Hydro”) for approval of revisions to its Cost of Service Methodology pursuant to Section 3 of the *EPCA* (the “Cost of Service Methodology Application”) for use in the determination of test year class revenue requirements reflecting the inclusion of the Muskrat Falls Project costs upon full commissioning.

TO: The Board of Commissioners of Public Utilities (the “Board”)

The Cost of Service Methodology Application of Hydro states that:

A. Background

1. Hydro is a corporation continued and existing under the *Hydro Corporation Act, 2007*, is a public utility within the meaning of the *Act*, and is subject to the provisions of the *Electrical Power Control Act, 1994*.
2. Under the *Act*, the Board has the general supervision of public utilities and requires that a public utility submit for the approval of the Board the rates, tolls, and charges for the service provided by the public utility and the rules and regulations which relate to that service.

3. Section 3(a) of the *EPCA* provides that the rates to be charged, either generally or under specific contracts, for the supply of power within the province should be reasonable and not unjustly discriminatory, and should be such that after December 31, 1999 industrial customers shall not be required to subsidize the cost of power provided to rural customers in the province.
4. In February 1993 the Board provided a report to the Minister of Mines and Energy which provided the foundation for the existing cost of service methodology.
5. In subsequent General Rate Applications (“GRA”), the Board has approved refinements to the methodology established in 1993.
6. Following the 2001 GRA, the Board approved the use of single coincident peak to be the basis for the allocation of distribution demand costs among customer classes, and for generation demand costs for the Labrador Interconnected System in Order No. P.U. 7(2003).
7. In that same Order, the Board found that Hydro’s proposed use of the zero intercept method for classification of distribution system costs is an acceptable method for dividing distribution costs into demand and customer related components. The Board also accepted Hydro’s proposals for treatment of transformer losses, classification of hydraulic plant, and to specifically assign frequency converters to the Industrial Customers.

8. Subsequent to the 2003 GRA, in Order No. P.U. 14(2004), the Board approved Hydro's proposed changes to the cost of service methodology regarding the assignment of Hydro Place costs, Hydro's municipal taxes and Board assessments, as well as the proposed changes to the functionalization of general plant assets.
9. Order No. P.U. 14(2004) also detailed the Board's acceptance of Hydro's proposals to assign generation assets on the Great Northern Peninsula as common plant, and transmission assets to Hydro Rural. The proposal to assign transmission assets on the Doyles – Port aux Basques system specifically to Newfoundland Power was also accepted.
10. Following the 2006 GRA, the Board approved a revision to the treatment of the Newfoundland Power Generation Credit in the cost of service methodology in Order No. P.U. 8(2007), and following the 2013 GRA, the Board approved the use of a revised rural deficit allocation for use in the cost of service methodology in Order No. P.U. 49(2016).
11. Because of the material change in the forecast supply cost mix with the commissioning of the Muskrat Falls Project, Hydro proposed in its Amended 2013 GRA to conduct a Cost of Service Methodology review prior to its next GRA. The Settlement Agreements to the 2013 GRA required Hydro to file a Cost of Service Methodology Review Report with the Board by March 31, 2016.

12. The scope of the Cost of Service Methodology Review, as stated in the Supplemental Settlement Agreement to the Amended 2013 GRA dated September 28, 2015, is as follows:

The Cost of Service Methodology Review to be completed in 2016 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 CDM cost allocation and recovery.

13. The Parties to the Amended 2013 GRA Settlement Agreement also provided that the generation credit agreement between Hydro and Corner Brook Pulp and Paper Limited ("CBPP"), which was approved on a pilot basis by the Board in Order No. P.U. 4(2012), will be reviewed in the cost of service generic hearing.
14. Hydro engaged Christensen Associates Energy Consulting ("CA Energy Consulting") to conduct the cost of service methodology review. Hydro filed a Cost of Service Methodology Review Report on March 31, 2016.
15. In June 2016, it was announced that the Muskrat Falls Project is behind schedule and that full commissioning is not expected until 2020. This removed the requirement for the costs of the Muskrat Falls Project to be recovered through Hydro's 2017 GRA filing.

The delay of the Muskrat Falls Project commissioning delay also resulted in a delay in the cost of service methodology review.

16. The 2017 GRA Settlement Agreement dated April 11, 2018 provided that Hydro would file an application no later than November 15, 2018 for a Cost of Service and Rate Design Methodology Review. The Board confirmed the filing requirement in its October 23, 2018 correspondence to Hydro.

B. Application Requests

17. The Cost of Service Methodology Application proposes changes to the Cost of Service Methodology for use in the determination of test year class revenue requirements reflecting the inclusion of the Muskrat Falls Project costs.
18. Schedule 1 to the Cost of Service Methodology Application provides a revised version of the Cost of Service Methodology Review Report originally filed on March 31, 2016, including Hydro's recommendations. Based on new information being available on system resource requirements post-Muskrat Falls commissioning, Hydro has changed some of the recommendations it made in its 2016 report.
19. Hydro requests that the Board make an Order approving the following changes to the cost of service methodology for use in the preparation of the cost of service 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 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 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 be dealt with through a deferral account mechanism to be developed by Hydro for the Board's review at the next GRA.

DATED at St. John's in the Province of Newfoundland and Labrador this 15th day of November 2018.

NEWFOUNDLAND AND LABRADOR HYDRO



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2018 COST OF SERVICE METHODOLOGY REVIEW REPORT

November 15, 2018

A Report to the Board of Commissioners of Public Utilities



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Exhibit 1 – Equivalent Peaker Detailed Calculations

Exhibit 2 – 2021 Illustrative Cost of Service Study Summary Schedules Recommended Approach

Exhibit 3 – Revenue Requirement Comparison Summary Schedules

Appendix A - Cost of Service Methodology Review prepared by Christensen Associates Energy Consulting

1 **1.0 Background**

2 The completion of the Muskrat Falls Project and the ensuing interconnection of the Island
3 Interconnected System with Labrador will result in a major change in the source of supply of
4 electricity to the Island. For many years, load growth on the Island Interconnected System has
5 been supplied by the Holyrood Thermal Generating Station (“Holyrood”) until capacity growth
6 warranted a generation plant addition.¹ Upon commissioning of the Muskrat Falls Project,
7 supply cost payments to cover the cost of transmission and generation assets will commence
8 under the Transmission Funding Agreement (“TFA”) and Muskrat Falls Power Purchase
9 Agreement (“PPA”), and the role of Holyrood as a generating station will be phased-out.

10
11 The replacement of fuel costs with these supply cost payments has created the need to review
12 the appropriate functionalization, classification and allocation of supply costs among customer
13 classes. At present, fuel costs from Holyrood comprise the largest single portion of the supply
14 costs incurred by Newfoundland and Labrador Hydro (“Hydro”). Prior to the accessibility of off-
15 island purchases, approximately 85% of the test year revenue requirement related to Holyrood
16 was classified as energy-related costs.²

17
18 Because of the material change in the forecast supply cost mix with the commissioning of the
19 Muskrat Falls Project, Hydro proposed in its Amended 2013 General Rate Application (“2013
20 GRA”) to conduct a Cost of Service Methodology review prior to its next GRA. The settlement
21 agreements to the 2013 GRA required Hydro to file a Cost of Service Methodology Review
22 Report with the Board of Commissioners of Public Utilities (the “Board”) by March 31, 2016.

23
24 The scope of the Cost of Service Methodology Review, as stated in the Supplemental
25 Settlement Agreement to the Amended 2013 GRA dated September 28, 2015, is as follows:

¹ Holyrood will function as a fully capable standby facility during the early years of operation of the Muskrat Falls Generating Plant and the Labrador-Island Link between Labrador and Newfoundland. Thereafter, Holyrood will be used as a synchronous condenser.

² 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 approximately 84% of overall Holyrood costs would be classified as energy-related.

1 *The Cost of Service Methodology Review to be completed in 2016 will include a*
2 *review of: (i) all matters related to the functionalization, classification and*
3 *allocation of transmission and generation assets and power purchases (including*
4 *the determination whether assets are specifically assigned and the allocation of*
5 *costs to specifically assigned assets) and (ii) the approach to CDM cost allocation*
6 *and recovery.*

7
8 The Supplemental Settlement Agreement also provides for a review of the generation credit
9 agreement between Hydro and Corner Brook Pulp and Paper Limited (“CBPP”), which was
10 approved on a pilot basis by the Board in Order No. P.U. 4(2012).

11
12 Hydro engaged Christensen Associates Energy Consulting, LLC (“CA Energy Consulting”) to
13 conduct the methodology review. Hydro filed a Cost of Service Methodology Review Report on
14 March 31, 2016.

15
16 In June 2016, it was announced that the Muskrat Falls Project is behind schedule and that full
17 commissioning is not expected until 2020. The delay of the Muskrat Falls Project commissioning
18 resulted in a delay in the cost of service methodology review.³ The 2017 GRA Settlement
19 Agreement dated April 11, 2018 provided that Hydro would file an application no later than
20 November 15, 2018 for a Cost of Service and Rate Design Methodology Review. The Board
21 confirmed the filing requirement in its letter to Hydro, dated October 23, 2018.

22
23 This report provides an updated version of the Cost of Service Methodology Review Report
24 originally filed on March 31, 2016. Based on new information being available on system
25 resource requirements post Muskrat Falls commissioning, Hydro has revised some of the
26 recommendations it made in its 2016 report. An updated CA Energy Consulting report is
27 provided as Appendix A to this report.

³ The Board, in its letter dated September 9, 2016, agreed it was premature to establish a plan at that time but directed Hydro to advise of its plans for the review when it filed its next GRA.

1 **2.0 Legislative Impacts**

2 Legislation and Provincial Government directives on customer rates have a material impact on
3 rates matters in Newfoundland and Labrador. The legislative requirements also have
4 implications for the cost of service methodology to be used to determine the revenue
5 requirement to be recovered from each customer class.

6

7 Legislative impacts include:

- 8 (i) the establishment of rates for rural customers that result in an annual deficit
9 in recovery of the cost of serving those customers (the “Rural Deficit”);
- 10 (ii) the recovery of the Rural Deficit from customers of Newfoundland Power and
11 Hydro Rural customers on the Labrador Interconnected System (and the
12 exclusion of Industrial Customers from the funding of the deficit);
- 13 (iii) the establishment of a Labrador Industrial Rates Policy to promote the
14 development of industrial activity in Labrador;
- 15 (iv) the requirement to defer all costs incurred by Hydro for the use of the
16 Labrador Island Link (“LIL”)⁴ and Labrador Transmission Assets (“LTA”)⁵ during
17 the pre-commissioning period of the Muskrat Falls Project;⁶ and
- 18 (v) the requirement for the cost of supply from Muskrat Falls⁷ including the LIL
19 and the LTA to be recovered in full through Island Interconnected rates with
20 no explicit provision requiring the value of export sales related to Muskrat
21 Falls generation to be credited back to ratepayers to offset the cost of supply
22 from Muskrat Falls.⁸

⁴ 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.

⁵ LTA refers 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.

⁶ See OC2018-213.

⁷ Muskrat Falls refers to the hydroelectric facilities of the Muskrat Falls Project.

⁸ In a letter from the Premier to the Minister of Natural Resources dated December 14, 2015, Government indicated that export sales will be used to mitigate potential increases in electricity rates.

1 Following the commissioning of the Muskrat Falls Project, Newfoundland and Labrador will
2 have an inter-provincial transmission system fully interconnected with Quebec, Nova Scotia,
3 and the broader North American electric grid. This development gives rise to the obligation for
4 Hydro and its affiliated transmission owners to provide open, non-discriminatory access to
5 transmission service on transmission lines used for inter-provincial trade by third parties. This
6 requirement is established by the Federal Energy Regulatory Commission (“FERC”), which is an
7 independent agency that regulates the transmission of electricity in the United States. To meet
8 the FERC requirement of reciprocity, Hydro must provide comparable open access to
9 transmission service over the interprovincial transmission system within Newfoundland and
10 Labrador. From a cost of service perspective, FERC requires that Hydro record its transmission
11 costs in a manner that can be used in the determination of open access transmission tariffs.
12

13 On December 21, 2017, OC2017-380 directed the Board to adopt a policy that the submissions
14 of the Newfoundland and Labrador System Operator (“NLSO”) relating to the transmission of
15 electricity over the Province’s high voltage transmission system be approved on the following
16 terms: (i) the pro-forma Transmission Service Agreements, and attached rates and rate
17 methodology, be approved on an interim basis; and (ii) the Transmission Policies and
18 Procedures and Code of Conduct for transmission system operations to be adopted by the
19 NLSO be approved until such time as the Board reviews the interim proposals.
20

21 In Order No. P.U. 3(2018), the Board approved, on an interim basis, the pro-forma Transmission
22 Service Agreements, the NL Transmission Policies and Procedures and the Code of Conduct for
23 NL Transmission System Operations, effective February 9, 2018.
24

25 The cost of service implications of each item are discussed further in the following sections.
26

27 **2.1 Rural Deficit**

28 The *Electrical Power Control Act, 1994* (“EPCA”) permits the Provincial Government of
29 Newfoundland and Labrador (“Government”) to provide direction to the Board and Hydro with

1 respect to the setting and subsidization of rural rates.⁹ OC2003-347 provides direction to the
2 Board with respect to the establishment of Hydro's Rural Rates.¹⁰

3
4 The EPCA also provides an exemption for Industrial Customers from being required "to
5 *subsidize the cost of power provided to rural customers in the province*".¹¹

7 **2.2 Labrador Industrial Rates Policy**

8 In December 2012, the Government introduced a series of legislative amendments to establish
9 a new electricity rate policy for Industrial Customers on the Labrador Interconnected System.
10 The purpose of the Labrador Industrial Rates Policy is to promote the development of industrial
11 activity in Labrador.¹²

12
13 Under the Labrador Industrial Rates Policy, the generation costs in the Labrador Industrial Rates
14 are established outside the purview of the Board. However, the transmission costs reflected in
15 the Labrador Industrial Rates are approved by the Board,¹³ this approval is expected to occur
16 through a general rate proceeding.

17
18 Prior to the annual publishing of a new rate for Labrador Industrial Customers, Hydro is
19 required to make a submission regarding the proposed rate to the Minister of Natural
20 Resources for review.

22 **2.3 Recovery of Muskrat Falls Costs**

23 In OC2013-343, Government provided a directive setting forth the requirement for the cost of
24 supply from the Muskrat Falls Project (including the LIL and the LTA) to be recovered in full

⁹ See Section 5.1(1) of the *EPCA*.

¹⁰ See response to Request for Information PUB-NLH-077 provided in Hydro's 2013 General Rate Application.

¹¹ See Section 3.0(iv) and 5.1(1) of the *EPCA*.

¹² See Section 3.0(v) and 5.1(1) of the *EPCA*.

¹³ See Section 5.8(2) of the *EPCA*.

1 through Island Interconnected rates charged to the appropriate classes of ratepayers.¹⁴ This
2 Government direction exempts customers on the Labrador Interconnected System from paying
3 costs related to the Muskrat Falls Project.

4
5 OC2013-343 also requires that any expenditures, payments or compensation paid directly or
6 indirectly by Hydro under an agreement or arrangement to which the Muskrat Falls Exemption
7 Order applies, shall be included as costs in Hydro's cost of service, without disallowance, to be
8 recovered through Island Interconnected System customer rates. To enable Hydro to fully
9 recover annual costs resulting from charges related to the Muskrat Falls Project will require
10 Hydro to establish a supply cost recovery mechanism to deal with such cost variances. This
11 matter was reflected in the Supply Cost Mechanism review filed with the Board in June, 2016.
12 Hydro will propose revisions to its supply cost recovery mechanisms in a future GRA along with
13 its proposals to permit the recovery of Muskrat Falls Project costs through customer rates.

14
15 OC2018-213 requires that all costs, expenditures, and payments incurred by Hydro for the use
16 of the LIL and LTA under the Interim Transmission Funding Agreements during the pre-
17 commissioning period of the Muskrat Falls Project be placed in a deferral account with
18 disposition to be addressed by a further order of the Board.

20 **2.4 Export Sales**

21 Hydro forecasts that export revenues will result from available Recapture Energy, ponding
22 activities, exports to avoid spill, and due to the fact that its current forecast load requirements
23 from Muskrat Falls generation are less than its contracted entitlement provided in Schedule 2 of
24 the Muskrat Falls PPA Schedule 2. The sharing of the net revenues from these exports need to
25 be considered in the cost of service methodology. The cost of service methodology does not
26 deal with other rate mitigation funds that may be provided from other sources.

¹⁴ Section 5.1(2) of the *EPCA* sets forth the authority of the Government to direct the Board to implement policies, procedures and directives with respect to the Muskrat Falls Project.

1 **2.5 Open Access Transmission Tariffs**

2 The NLSO transmission tariff defines the terms, conditions and rates under which a
3 Transmission Customer is provided transmission service over the Newfoundland and Labrador
4 Transmission System.

5
6 For Hydro's transmission assets, the NLSO applied the existing approach of determining if any
7 of the high-voltage transmission assets were either functionalized as a generator lead or
8 specifically assigned. The addition of TL-269¹⁵ from Granite Canal to Bottom Brook to support
9 the import and export of energy over the Maritime Link requires a change to the
10 functionalization of Hydro's TL-234 and TL-263 from generator leads to common high-voltage
11 transmission.¹⁶

12
13 **3.0 Cost of Service Recommendations**

14 Based in part on the information provided in the report of CA Energy Consulting, Hydro makes
15 the following recommendations for the cost of service methodology to be applied upon the full
16 commissioning of the Muskrat Falls Project. Many of Hydro's recommendations support the
17 continuation of existing practice while others reflect changes in practice. There are also
18 recommendations to deal with new cost of service issues.

19
20 **3.1 Systemization**

21 Hydro proposes to maintain separate cost of service studies for the Labrador Interconnected
22 System and the Island Interconnected System for use in determining customer rates. This
23 approach is consistent with the Government direction exempting customers on the Labrador
24 Interconnected System from paying costs related to the Muskrat Falls Project.

¹⁵ TL-269 is owned by NSP Maritime Link Incorporated, operated by the NLSO and deemed as a zero rated revenue requirement.

¹⁶ When Hydro filed its cost of service methodology report in 2016, Hydro believed that transmission line TL-248 from Deer Lake to Massey Drive would need to change in functionalization from a generator lead to a common transmission asset. However, because TL-248 is not a portion of a 230 kV loop, the transmission tariff does not consider TL-248 a common transmission asset.

1 **3.2 Functionalization**

- 2 (i) Hydro recommends no changes in the functionalization of existing generation and
3 transmission assets with the exception of Hydro's TL-234 and TL-263. Hydro
4 recommends that the functionalization of these assets change from generation to
5 transmission;
- 6 (ii) Hydro recommends that the power purchase costs resulting from the Muskrat Falls
7 Project (Muskrat Falls Generation, LIL and LTA assets) be functionalized as
8 generation;
- 9 (iii) Hydro recommends that the transmission assets currently specifically assigned to
10 customers continue to be specifically assigned;
- 11 (iv) Hydro recommends that any contributions from customers as a result of
12 implementation of a new network additions policy be deducted from rate base
13 consistent with the current approach used in treating customer contributions in
14 determining rate base for use in the cost of service study; and
- 15 (v) Hydro recommends the functionalization of Holyrood Unit 3 as transmission after
16 the unit is permanently converted into the role of synchronous condenser.

17
18 **3.3 Classification and Allocation of Functionalized Production/Generation Costs**

19 **3.3.1 General**

20 Hydro's current cost of service methodology first classifies generation costs on the basis of
21 demand and energy cost causation, and then allocates to each customer class using a
22 coincident peak allocator (in the case of demand costs) and an annual energy allocator (in the
23 case of energy costs). Hydro's current classification/allocation approach is comparable to the
24 traditional approaches used by most electric utilities.

25
26 An alternative approach to the various traditional classification methods is to make use of
27 marginal costs. Upon interconnection of the system to the North American grid, marginal
28 generation energy and reserve costs will be represented in most hours by wholesale prices
29 from eastern regions of that grid. For the Island Interconnected grid, marginal generation

1 capacity costs will reflect the costs incurred on the island to serve additional capacity due to the
2 potential for transmission constraints applying at times of peak demand.¹⁷ The marginal cost
3 approach gives consideration to the marginal cost of serving each customer class in all the
4 hours of the year. This approach contrasts with the traditional classification approach to
5 determining portions of demand-related costs, energy-related costs and coincident peak
6 methods that typically make use of a very limited number of peak hours in the allocation of
7 demand-related costs.

8
9 Hydro recently completed its Marginal Cost Study providing forecast marginal costs for the
10 period 2021 to 2029.¹⁸ The use of marginal generation cost data allows Hydro to estimate the
11 cost to serve Island Interconnected System classes of customers by applying hourly marginal
12 generation cost profiles to the hourly load profiles for each class served at transmission voltage.
13 Cost shares for each customer class are then derived based on the proportion of the annual
14 total marginal costs that result for each class.

15
16 CA Energy Consulting supports the use of marginal costs in the classification and allocation of
17 production/generation costs in the Cost of Service Study. However, the review determined that
18 the use of marginal costs in cost of service classification and allocation of revenue requirement
19 is not common. There are currently no utilities in Canada applying this approach.¹⁹ Hydro also
20 has concerns with the complexity and understandability of marginal cost derivation relative to
21 the traditional cost of service approaches. Hydro also does not forecast the load requirements
22 for each customer class on an hourly basis. Therefore, Hydro is not recommending the use of
23 marginal generation costs in the classification and allocation of production/generation costs in
24 the Cost of Service Study.

¹⁷ Hydro's "Reliability and Resource Adequacy Study", to be filed in mid-November, 2018, determined given the transmission constraint of the LIL as a source of supply to the island, that it is prudent to incorporate a local capacity requirement for the Island Interconnected System. The study recommended that both the Labrador Interconnected System and the Island Interconnected System should each have sufficient generating capacity to satisfy a Loss of Load Expectation target of not more than 0.1 (i.e., not exceeding 1 day in 10 years).

¹⁸ The Marginal Cost Study for the Island Interconnected System was filed with the Board on November 15, 2018.

¹⁹ The Manitoba Public Utilities Board approved a change from marginal cost classification and allocation for generation functionalized costs to system load factor in Order No. 164/16, issued on December 2016.

1 **3.3.2 Classification Recommendation – Muskrat Falls Project Power Purchases**

2 Hydro recommends the use of the equivalent peaker methodology for classification between
3 demand and energy for the classification of power purchase costs resulting from the Muskrat
4 Falls Project. CA Energy Consulting recommended the equivalent peaker approach rather than
5 the other traditional cost of service classification approaches.

6

7 With respect to the equivalent peaker method, the NARUC Electric Utility Cost Allocation
8 Manual²⁰ states:

9

10 *The premises of this and other peaker methods are: (1) that increases in peak demand*
11 *require the addition of peaking capacity only; and (2) that utilities incur the costs of*
12 *more expensive intermediate and baseload units because of the additional energy load*
13 *they must serve. Thus, the cost of peaking capacity can properly be regarded as peak*
14 *demand-related and classified as demand-related in the cost of service study. The*
15 *difference between the utility's total cost for production plant and the cost of peaking*
16 *capacity is caused by the energy loads to be served by the utility and is classified as*
17 *energy-related in the cost of service study.*

18

19 The equivalent peaker methodology is effectively based on an estimate of the cost per kW of a
20 new peaking unit compared with the cost per kW of the new base load generation unit giving
21 consideration to the life-cycle of the two facilities. The portion of the cost in excess of the cost
22 of the peaking unit is treated as energy related. Table 1 provides a summary of the results of
23 Hydro's equivalent peaker calculation.

²⁰ Electric Utility Cost Allocation Manual, January 1992, National Association of Regulatory Commissioners, pages 52-53.

Table 1
Calculation of Equivalent Peaker Classification of
Muskrat Falls Power Purchases

Generation Source	Levellized annual cost per kW	% Demand Classification C=(A/B)	% Energy Classification 1-C
Gas Turbine (A)	\$249	20%	80%
Muskrat Falls Project (B)	\$1,267		

1 Table 1 shows that the equivalent peaker approach results in approximately 20% of the Muskrat
2 Falls Project being demand related and 80% being energy related. The Muskrat Falls Project was
3 selected as the least cost alternative to replace Holyrood primarily based on the projected fuel
4 costs savings over the long term; therefore from a cost causality approach, it appears reasonable
5 that most of the Muskrat Falls Project costs would be considered energy-related. As indicated
6 earlier, the overall classification of Holyrood costs for the test years in 2004, 2007 and 2015
7 were in the range of 82%-86% energy-related and 14%-18% demand-related.

8
9 Exhibit 1 to this report provides the details supporting the equivalent peaker calculation
10 provided in Table 1.

11

12 **3.3.3 Classification Recommendation – Hydraulic Generation**

13 Hydro proposes to continue to use system load factor for classification of its existing hydraulic-
14 based generation.

15

16 **3.3.4 Classification Recommendation – Other Power Purchases (Excluding Wind)**

17 Hydro proposes to continue to use system load factor for classification of Other Power
18 Purchases (excluding Wind), the largest of which is Exploits generation. From an operational
19 perspective, Hydro operates Exploits assets no differently than if Hydro owned the hydraulic
20 production assets. Hydro has been informed by the Government that the long-term plan is to
21 transfer ownership of the Exploits assets to Hydro. This classification would also apply to
22 Hydro's purchases of Recapture Energy from CF(L)Co.

1 **3.3.5 Classification Recommendation – Holyrood Thermal Generation**

2 Following the completion of Muskrat Falls Project commissioning, Holyrood’s role will change
3 and the plant will cease to perform as a generating unit. The plant may be required to be
4 available for generation for a period of time after Muskrat Falls Project commissioning. In this
5 circumstance, Hydro proposes that Holyrood asset costs be functionalized as generation and
6 classified using a forecast capacity factor. The Holyrood fuel cost is proposed to continue to be
7 classified as an energy cost.

8

9 **3.3.6 Classification Recommendation – Wind Purchases**

10 Hydro recommends that the cost of wind purchases be classified as 22% demand and 78%
11 energy reflecting the “Effective Load Carrying Capability Study” conducted by Hydro’s resource
12 planning group regarding wind availability during peak periods.²¹

13

14 **3.3.7 Classification Recommendation – Diesel and Gas Turbine Generation**

15 Hydro proposes to continue to use the following approaches for the classification of diesel and
16 gas turbine generation.

Table 2
Classification of Diesel and Gas Turbine Generation

System	Assets	Fuel Costs
Island Interconnected and Labrador Interconnected	100% Demand	100% Demand
Isolated Diesel Systems ²² (excluding L’Anse Au Loup)	System Load Factor	100% Energy
L’Anse Au Loup ²³	100% Demand	100% Energy
Power Purchases	Not applicable	100% Energy

²¹ This study is presented in the “Reliability and Resource Adequacy Study” to be filed with the Board in mid-November, 2018.

²² Includes Labrador and Island Isolated diesel systems excluding L’Anse Au Loup.

²³ Because a high percentage of the energy supplied to L’Anse Au Loup comes from secondary energy purchases from Hydro-Quebec, Hydro classifies its diesel assets as 100% demand-related as these assets are required primarily to supply peak periods.

1 **3.3.8 Summary of Recommended Classifications of Production/Generation Costs**

2 Table 3 summarizes the proposed generation/production classifications.

Table 3 – Classification of Functionalized Generation Costs – Island Interconnected System

Generation Costs	Existing	Proposed
Hydraulic Assets	System Load Factor	System Load Factor
Holyrood Assets ²⁴	5-year average capacity factor	Forecast capacity factor
Gas Turbines/Diesel Assets	100% Demand	100% Demand
Power Purchases – MF	Not Applicable	Equivalent Peaker (20% D/80% E)
Other Power Purchases	System Load Factor	System Load Factor
Holyrood Fuel	100% Energy	100% Energy
Gas Turbine/ Diesel Fuel	100% Demand	100% Demand
Wind Purchases	100% Energy	22% Demand/ 78% Energy

3 **3.3.9 Allocation of Functionalized Production/Generation Costs**

4 Hydro currently applies the use of a single coincident peak (“1 CP”) approach in cost allocation
 5 of production/generation costs among customer classes. The 1 CP approach results in
 6 generation demand costs being allocated among customer classes based on the forecast
 7 proportion of the single highest peak attributed to each class in the forecast Test Year.

8
 9 Hydro has reviewed the reasonableness of this approach. As discussed in the CA Energy
 10 Consulting report, the use of the FERC analysis methodology for determining the appropriate
 11 allocation approach concludes that the use of a 12 month CP (“12 CP”) approach would not be
 12 appropriate for allocating demand costs on the Island Interconnected System and 3 month CP
 13 (“3 CP”) approach would be more appropriate.²⁵ However, the FERC test does not evaluate
 14 whether the 1 CP approach, as is used by Hydro, or the 3 CP approach is superior.

²⁴ When Holyrood is converted to a synchronous condenser, it will be converted to a transmission asset and classified as 100% demand.

²⁵ 12 CP reflects the use of the peak demands in all twelve months and 3 CP refers to using the peak demands in the 3 months with the highest peak demands.

1 Under the current 1 CP approach, the Island Industrial Customers peak load has an 88%
2 coincidence with system peak and the Newfoundland Power peak load has a 99.3% coincidence
3 with system peak. These coincidence factors were based on a review of historical coincidence.
4 Based on a preliminary analysis, Hydro does not see a basis to change these coincidence factors
5 for use in the cost of service study.

6
7 Hydro forecasts a single winter peak in its planning process. The system peak can happen in any
8 of the four winter months (December to March). The timing of Hydro's system peak is highly
9 coincident with the system peak of Newfoundland Power. Newfoundland Power's peak
10 forecasting methodology also forecasts a single winter peak with no certainty on which month
11 the system peak will occur. Hydro believes the continued use of 1 CP approach for generation
12 demand classification is reasonable.

13
14 Hydro plans to evaluate if it is practical to employ a peak allocation approach based on the
15 percentage of load by class in the highest 50 hours of the winter season.²⁶ Manitoba Hydro
16 currently uses this approach. This analysis would provide additional information to evaluate the
17 reasonableness of the current 1 CP allocation approach. Hydro plans to report to the Board on
18 the analysis results in its next GRA.

19
20 Hydro currently allocates energy costs based on annual energy use by customer class. Hydro
21 proposes to continue the current energy allocation approach.

22

23 **3.4 Classification of Functionalized Transmission Costs**

24 Hydro recommends that all functionalized transmission costs be classified as 100% demand-
25 related. This is consistent with the approach currently used in the cost of service study.

²⁶ Hydro does not currently forecast load by hour for each customer class. However, Hydro may be able to develop reasonable estimates of class peak responsibility based on an hourly load analysis of previous winter seasons. This hourly load analysis will require applying adjustments to customer load requirements to remove the impacts of load curtailments.

1 Hydro can no longer use historical average losses in preparing its cost of service study for the
2 Island Interconnected System. For its next GRA, Hydro will need to model its system losses and
3 provide a forecast for use in the cost of service study. For the subsequent GRAs, Hydro
4 proposes to develop its loss projections based on historical experience.

5

6 **3.5 Allocation of Functionalized Transmission Costs**

7 Hydro proposes to allocate functionalized transmission demand costs following the same
8 approach that it uses to allocate production/generation demand costs.

9

10 **3.6 Rural Deficit Allocation**

11 CA Energy Consulting also reviewed the Rural Deficit allocation in its report. CA Energy
12 Consulting agreed that Hydro's proposed approach is preferable to the previous method.

13

14 Hydro recommends continued use of the revenue requirement method for allocation of the
15 Rural Deficit between Newfoundland Power and the Hydro Rural customers on the Labrador
16 Interconnected System. This recommendation is consistent with Hydro's proposal which was
17 approved by the Board in the 2013 GRA Final Order.²⁷

18

19 **3.7 Conservation and Demand Management ("CDM")**

20 Based on discussions with Newfoundland Power, Hydro is proposing to continue the current
21 approach in recovery of CDM costs among its customer classes.

22

23 **3.8 Specifically Assigned Charges**

24 Consistent with its 2017 GRA filing, Hydro recommends that the use of original asset costs as a
25 basis for the allocation of operating and maintenance costs to specifically assigned assets be
26 discontinued. The use of original assets costs in the allocation of operating and maintenance
27 costs is problematic since direct assignment on the basis of original asset costs appears to be
28 poorly correlated with actual expense patterns over time.

²⁷ Order No. P.U. 49(2016).

1 Hydro plans to report to the Board in its next GRA on whether the tracking of actual operating
2 and maintenance costs by asset provides a reasonable basis for determining the operating and
3 maintenance costs to be used in determining the Test Year operating and maintenance cost
4 allocation for specifically assigned assets.

5
6 Until a reasonable alternative method is developed, Hydro recommends the use of indexed
7 asset costs in operating and maintenance cost allocations in the determination of specifically
8 assigned charges.

10 **3.9 Newfoundland Power Generation Credit**

11 Hydro continues to assume that the existing Newfoundland Power hydraulic and thermal
12 generation assets will continue to provide firm capacity to meet system demand requirements.
13 Therefore, Hydro recommends the continuation of the existing approach of providing a
14 generation credit for both the hydraulic and thermal generation of Newfoundland Power.

15
16 The use of the generation credit provides Newfoundland Power with an estimated coincident
17 peak demand requirement in the cost of service study that is effectively the same as if
18 Newfoundland Power was operating its generation at peak times (with an adjustment for
19 reserves). The provision of the generation credit removes the incentive for Newfoundland
20 Power to operate its thermal generation to minimize its peak demand purchases from Hydro.

21
22 Newfoundland Power runs its thermal generation to meet system load requirements at the
23 request of Hydro. Newfoundland Power also dispatches its hydraulic generation to ensure
24 capacity availability to meet system peak, to the extent reasonable. The generation credit
25 approaches in both the cost of service study and the wholesale rate design are structured to be
26 consistent with the least cost operation of generation resources for both Hydro and
27 Newfoundland Power.

1 Under the existing approach as approved in Order No. P.U. 8(2007)²⁸, the generation credit is
2 calculated as follows:

- 3 (i) the hydraulic generation credit is applied in reducing the Newfoundland Power
4 coincident peak demand at transmission and the Newfoundland Power coincident
5 peak demand at generation;
- 6 (ii) the thermal generation credit is not applied to reduce the Newfoundland Power
7 coincident peak demand at transmission but is applied to reduce the Newfoundland
8 Power coincident peak demand at generation; and
- 9 (iii) the coincident peak at generation used in computing the system load factor does
10 not reflect a reduction for the Newfoundland Power thermal generation.²⁹

11

12 Hydro plans to review the reasonableness of the amount of the Newfoundland Power
13 generation credit. This review will be based on the capacity provided when Newfoundland
14 Power has been requested by Hydro to provide its maximum generation available. Hydro will
15 file the results of this review in its next GRA filing.

16

17 **3.10 CBPP Generation Demand Credit**

18 Since 2009, CBPP has been operating under a piloted generation credit service contract that
19 permits CBPP to maximize the efficiency of its 60 Hz Deer Lake Power generation. The
20 agreement allows Hydro to call on CBPP to maximize its 60 Hz generation prior to increasing
21 generation at Holyrood for system reasons and prior to starting its standby units (i.e., Hydro
22 may make a capacity request to CBPP). Savings are provided to CBPP for providing this
23 additional capacity to the system by permitting CBPP to exceed its firm power requirements
24 and to avoid costs associated with thermal or standby energy rates.

25

26 Under the pilot agreement, capacity is made available to the grid if CBPP's mill loads are
27 reduced and the customer is able to generate in excess of what it requires for its own use. Since

²⁸ See page 22, page 16.

²⁹ The 2017 GRA calculations reflecting the generation credit in the calculation of the Newfoundland Power production and transmission demands are provided in response to request for information IC-NLH-087, Attachment 1, page 1 of 1.

1 the winter of 2014/2015, Hydro has had capacity assistance agreements with CBPP to support
2 system load requirements.

3
4 The benefits to all customers arising from the fuel cost savings that supported the pilot project
5 implementation are not expected to continue upon commissioning of the Muskrat Falls Project.
6 Therefore, Hydro proposes to discontinue the generation credit agreement between Hydro and
7 CBPP upon full commissioning of the Muskrat Falls Project. However, Hydro believes CBPP
8 should have the opportunity to manage its generation as efficiently as possible and, to that end,
9 proposes to work with CBPP in the rate design review planned for 2019 to develop a proposal
10 to achieve this objective.

11

12 **3.11 Allocation of Net Export Revenues**

13 Hydro recommends:

- 14 (i) net export revenues be used to reduce the Muskrat Falls supply costs to be
15 recovered through the rates of customers on the Island Interconnected System;
- 16 (ii) net export revenues be classified in the same manner as the classification of the
17 Muskrat Falls Project costs in the cost of service study; and
- 18 (iii) net export revenues be included in the test year cost of service study for rate making
19 with variations from forecast net export revenues be dealt with through a deferral
20 account mechanism.

21

22 Hydro plans to include any revenues that result from the sale of carbon credits, due to the
23 closure of Holyrood, in net export revenues.

24

25 In June 2016, Hydro filed a report on the requirements for a supply cost deferral account to
26 deal with post Muskrat Falls supply cost variances. Hydro will provide detailed proposals on the
27 required deferral account mechanism at its next GRA.

1 4.0 Changes in Revenue Requirement

2 Table 4 provides a comparison of the 2019 forecast revenue requirement for the Island
3 Interconnected System and the estimated 2021 revenue requirement for the Island
4 Interconnected System reflecting the full commissioning of the Muskrat Falls project.

5
6 Table 4 also provides a separate breakdown of the forecast purchase power costs for each of
7 Muskrat Falls generation, LIL and LTA and assumes that Holyrood generation would conclude in
8 2021.

**Table 4: Change in Revenue Requirements for the Island Interconnected System
Illustrative 2021 vs 2019 Projected Test Year forecast (\$000s)**

	2019 - As filed Oct. 26, 2018	Illustrative 2021	Difference
Operating, Maintenance and Admin.	105,786	112,892	7,106
Fuels - No. 6 Fuel	138,205	41,346 ³⁰	(96,859)
Fuels – Diesel	138	151	13
Fuels - Gas Turbine	7,161	3,286	(3,875)
Total Fuel	145,504	44,783	(100,721)
Power Purchases – Other	62,308	61,615	(693)
Power Purchases – MF	-	293,022	293,022
Net Export Revenues ³¹	-	(53,389)	(53,389)
Power Purchases - LTA Costs	-	52,887	52,887
Power Purchases - LIL Costs	-	379,849	379,849
Power Purchases - Off Island	6,373	1,692	(4,681)
Total Purchased Power	68,681	735,676	666,995
Depreciation	70,939	65,647	(5,292)
Expense Credits	(1,552)	(1,552)	-
Return on Debt	82,696	83,102	406
Return on Equity	34,076	38,622	4,546
			-
Total Revenue Requirement	506,128	1,079,169	573,040

³⁰ The fuel cost in 2021 reflects the generation at Holyrood to eliminate the fuel inventory through the provision of capacity and energy during the first quarter of 2021.

³¹ Includes forecast net revenues from Hydro's exports.

1 Table 4 shows that the projected 2021 revenue requirement for the Island Interconnected
2 System is approximately \$575 million higher (more than double) than that of the projected
3 2019 Test Year revenue requirement. The primary changes are increase in power purchases
4 costs of approximately \$667 million (net of Hydro export revenues), and a decrease in fuel costs
5 of approximately \$100 million. The 2021 projected revenue requirement excludes other rate
6 mitigation that may be provided.

7

8 **5.0 Cost of Service Impacts**

9 Hydro has prepared cost of service summaries showing illustrative 2021 revenue requirement
10 projections for use in methodology evaluation (2021 Illustrative). The 2021 Illustrative revenue
11 requirement allocations are compared to the Projected 2019 Test Year revenue requirements
12 filed on October 26, 2018.

13

14 Exhibit 2 provides the 2021 Illustrative cost of service study summary schedules providing the
15 cost of service revenue requirements based on Hydro's recommended cost of service
16 methodology. The schedules provided in Exhibit 2 assume rates will increase to provide full
17 recovery of the 2021 Illustrative costs and do not reflect rate mitigation.

18

19 The key financial forecast assumptions included in the 2021 illustrative revenue requirement
20 are:

- 21 (i) The Muskrat Falls Project, including the LIL and LTA will be in operation for all of
22 2021 and Hydro will be required to make payments consistent with the TFA and the
23 Muskrat Falls PPA;
- 24 (ii) The TFA and PPA payments estimated for 2021 have been determined consistent
25 with a Nalcor long-term financial plan prepared in September 2018;
- 26 (iii) Customer class demand and energy requirements for 2021 are based on Hydro's
27 2019 GRA forecast;³²

³² Hydro has used the 2019 GRA load forecast to permit isolation of the impact of cost of service methodology changes on revenue requirements by customer.

- 1 (iv) Material reductions in fuel consumption occur on the Island interconnected System
2 in 2021;
- 3 (v) Hydro's forecast net revenues from exports will be applied to reduce the revenue
4 requirement of customers on the Island Interconnected System;
- 5 (vi) Rate mitigation is not reflected in the 2021 costs to be recovered from customers
6 with the exception of Hydro's forecast net export revenues;
- 7 (vii) Hydro's operating and maintenance expenses are assumed to escalate at a rate of
8 approximately 3.4% per annum; and
- 9 (viii) Hydro's allowed return on equity remains at 8.5%.

10

11 Table 5 provides a comparison of the estimated 2019 Projected and the 2021 Illustrative
12 revenue requirements for Newfoundland Power (including rural deficit) and Island Industrial
13 Customers based on Hydro's recommended cost of service methodology approach.

Table 5 – Change in Allocated Revenue Requirements (\$000s)

Customer Class	2019 Projected³³	2021 Illustrative	Difference
Newfoundland Power	\$455,760	\$942,536	\$486,776
Island Industrial	\$38,795	\$92,463	\$53,668

14 Table 6 provides the revenue requirement comparison provided in Table 5 on a unit cost basis.

Table 6 – Change in Unit Costs (cents per kWh)

Customer Class	2019 Projected	2021 Illustrative	Difference
Newfoundland Power	7.81	16.16	8.35
Island Industrial	5.22	12.44	7.22

15 Exhibit 3 to this report, page 1 of 2, provides the detailed revenue requirement allocation
16 summary sheets supporting the calculations in Table 5 and Table 6.

³³ Based on Hydro's 2018 cost Deferral and Interim Rates Application filed October 26, 2018, Schedule 1.3.1, Page 1 of 3.

1 The primary cost of service methodology recommendations with respect to the Muskrat Falls
 2 Project power purchase costs are that (i) the charges incurred through the TFA and Muskrat
 3 Falls PPA should be functionalized as generation and (ii) the equivalent peaker approach should
 4 be used for classification of these costs between demand-related and energy-related costs.
 5
 6 Table 7 provides a comparison of the revenue requirement allocations by customer class for the
 7 2021 Illustrative revenue requirement using Hydro's recommended equivalent peaker
 8 classification for purchase costs from Muskrat Falls and the use of the system load factor
 9 approach that is currently used for classification of hydraulic generation.

**Table 7 – Muskrat Falls Classification Method Impacts on
 2021 Illustrative Revenue Requirements (\$000s)**

Customer Class	Equivalent Peaker	System Load Factor	Difference³⁴
Newfoundland Power	\$942,536	\$949,875	\$7,339
Island Industrial	\$92,463	\$84,549	(\$7,914)

10 Table 7 shows that classification method selected can result in a shift of approximately \$8
 11 million in revenue requirement.

12
 13 Table 8 provides the revenue requirement comparison provided in Table 7 expressed on a unit
 14 cost basis.

**Table 8 – Impact of Muskrat Falls Classification Method
 on 2021 Unit Costs (cents per kWh)**

Customer Class	Equivalent Peaker	System Load Factor³⁵	Difference
Newfoundland Power	16.16	16.28	0.12
Island Industrial	12.44	11.37	(1.07)

³⁴ The Newfoundland Power change is impacted by revenue recovery through rural rates and as a result the dollar difference is not equal between Newfoundland Power and the Island industrial Customers.

³⁵ The use of the system load factor approach reflects a 45.4% demand classification and a 54.6% energy classification.

1 Tables 7 and 8 demonstrate the material impacts the choice of classification can have on class
2 revenue requirements. Classification of a higher proportion of Muskrat Falls power purchase
3 costs as energy-related using the equivalent peaker approach results in an increased proportion
4 of the Muskrat Falls power purchase costs allocated to the higher load factor Island industrial
5 Customers. Classification of a lower proportion of Muskrat Falls costs as energy-related (and a
6 higher proportion demand-related) using the system load factor approach results in an
7 increased proportion of Muskrat Falls power purchase costs allocated to Newfoundland Power,
8 which has a lower load factor.

9
10 Exhibit 3, page 2 of 2 to this report provides the detailed revenue requirement allocation
11 summary sheets supporting the calculations in Table 7 and 8.

12
13 The rates paid by Newfoundland Power customers of must recover the costs incurred by
14 Newfoundland Power to provide service, excluding the cost of purchases from Hydro. For the
15 2019 Test Year, this cost is estimated to be approximately 4.5¢ per kWh for residential
16 customers.³⁶ To estimate average residential rates based on the unit cost estimates for
17 providing service to Newfoundland Power provided in the previous tables requires the addition
18 of 4.5¢ per kWh. The estimated residential rate is projected to be approximately 21¢ per kWh
19 without additional rate mitigation.

20
21 The information provided in this section illustrates that the choice of classification approach for
22 the Muskrat Falls purchase power costs has material impact on class revenue requirements. As
23 discussed earlier, Hydro supports the use of the equivalent peaker approach.

24
25 Hydro has also recommended that charges incurred by Hydro through the TFA and Muskrat
26 Falls PPA be functionalized as generation. This includes the costs related to LIL, LTA and
27 Muskrat Falls generation. If the costs of LIL or LTA are determined to be 100% functionalized as
28 transmission, these costs become demand-related because functionalized transmission costs

³⁶ This amount was estimated based on Newfoundland Power 2016 Cost of Service Study filed with its 2019 GRA evidence.

1 are treated as 100% demand-related. This approach would have similar impacts as those
2 illustrated for the classification approach. The higher the proportion of total costs that are
3 treated as demand-related, the lower the cost allocation to Island Industrial Customers. The
4 lower the proportion of total costs that are treated as demand-related, the lower the cost
5 allocation to Newfoundland Power.

Exhibit 1

Equivalent Peaker Detailed Calculations

Equivalent Peaker Detailed Calculations

The equivalent peaker methodology 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. Table 1 provides a summary of the results of Hydro's equivalent peaker calculation.

Table 1
Calculation of Equivalent Peaker Classification for
Muskrat Falls Power Purchases

Generation Source	Levellized annual cost per kW	% Demand Classification C=(A/B)	% Energy Classification 1-C
Gas Turbine (A)	\$249	20%	80%
Muskrat Falls Project (B)	\$1,267		

Table 1 shows that the equivalent peaker approach results in approximately 20% of the Muskrat Falls Project being demand related and 80% being energy related. 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; therefore from a cost causality approach, it appears reasonable that most of the Muskrat Falls Project costs would be considered energy-related. Page 2 of this Exhibit provides the derivation of the levellized annual cost of the gas turbine, while page 3 provides the levellized annual cost for the Muskrat Falls power purchases.

**Exhibit 1 - Equivalent Peaker Detailed Calculations
Derivation of Gas Turbine Levelized Cost per kW**

Investment Cost	Parameters	Investment Costs per kW	Charges on Capital (\$/kW-year)
Direct Facility Investment ⁽¹⁾		3,114.60	169.86
General Plant /Common ⁽²⁾	8.98%	279.64	18.34
Materials and Supplies ⁽²⁾	1.16%	36.17	1.97
Fuel Inventory ⁽²⁾		24.04	1.31
Working Capital (%/FO&M) ⁽²⁾	1.76%	0.72	0.04
			Cost Elements (\$/kW-year)
Charge Rates	Parameters		
Carrying Charges, Direct ⁽³⁾	5.45%		173.19
Carrying Charges, General Plant/Common ⁽⁴⁾	6.56%		18.34
Insurance Costs ⁽⁵⁾	0.11%		3.74
FOM Rate (\$/kW-year) ⁽⁶⁾	35.63		35.63
A&G Cost Rate (% O&M) ⁽⁷⁾	15.01%		5.35
Total Cost/kW-year:			236.26
Forced Outage Rate⁽⁸⁾		5.03%	12.51
Adjusted Total Cost/kW-year:⁽⁹⁾			248.77

Notes:

- ¹ Direct Facility investment is based on a 58.5 MW gas turbine with a capital cost of \$182.2 million (2019 dollars) financed at Hydro's long-term WACC of 5.9%.
- ² Rate base adjustments consistent with the 2019 Test Year as filed in the Cost Deferral and Interim Rates Application filed with the Board on October 26, 2018.
- ³ Revenue requirement reflecting the economic carrying charge to recover the capital investment of \$182.2 million.
- ⁴ To reflect the economic carrying charge of associated general plant.
- ⁵ To forecast insurance charges based on 2019 Test Year ratio.
- ⁶ To include direct operating and maintenance costs consistent with the 2019 Test Year gas turbine operating cost filed as filed in the Cost Deferral and Interim Rates Application filed with the Board on October 26, 2018 (see Schedule 1.3.1).
- ⁷ To include administration and overhead allocation as per the 2019 Test Year Cost of Service Study.
- ⁸ Reflects the forecast forced outage rate per Hydro's Reliability and Resource Adequacy Study.
- ⁹ Resulting total cost per kW-year.

**Exhibit 1 - Equivalent Peaker Detailed Calculations
Derivation of Muskrat Falls Project Levelized Cost per kW**

Investment Cost (\$/kW)	Parameters	NPV of Revenue Requirement (\$)
Muskrat Falls Generation ⁽¹⁾		10,491,670
LTA Transmission Assets ⁽¹⁾		1,820,777
LIL Transmission Assets ⁽¹⁾		5,816,521
Total Muskrat Falls Project⁽¹⁾		18,128,968
NPV of Generation Capacity (MW) ⁽²⁾		13,995
NPV of Transmission Capacity (MW) ⁽³⁾		15,286
Discount rate ⁽⁴⁾	5.90%	
Charge Rates		Cost Elements (\$/kW-year)
Carrying Charges, Generation ⁽⁵⁾		749.66
Carrying Charges, LTA ⁽⁵⁾		119.11
Carrying Charges, LIL ⁽⁵⁾		380.51
	Total Cost/kW-year:	1,249.28
Forced Outage Rate		
Generation ⁽⁶⁾	1.93%	14.75
Transmission ⁽⁶⁾	0.56%	2.81
Adjusted Total Cost/kW-year:⁽⁷⁾		1,266.85

Notes:

- ¹ A discounted cash flow approach was used. The net present value ("NPV") of the annual revenue requirement for each major asset class was determined using Hydro's long-term WACC of 5.9%.
- ² Represents the NPV of the capacity generated (824 MW annually).
- ³ Represents the NPV of the capacity transmitted (900 MW annually).
- ⁴ Hydro's long-term weighted average cost of capital.
- ⁵ The levelized equal charge is determined (i.e., MF Generation/NPV of Generation Capacity)
- ⁶ Reflects the long-term forecast forced outage rate per Hydro's Reliability and Resource Adequacy Study for each of generation and transmission.
- ⁷ Resulting total cost per kW-year.

Exhibit 2

2021 Illustrative Cost of Service Study Summary Schedules Recommended Approach

NEWFOUNDLAND AND LABRADOR HYDRO
2021 Illustrative Cost of Service Study - Recommended Approach
Total System Revenue Requirement

Line No.	1 Description	2 Total Amount (\$)	3 Island Interconnected (\$)	4 Island Isolated (\$)	5 Labrador Isolated (\$)	6 L'Anse au Loup (\$)	7 Labrador Interconnected (\$)	8 Basis of Proration
	Revenue Requirement							
	Expenses							
1	Operating, Maintenance and Admin.	150,374,985	112,891,671	7,467,527	16,474,628	1,639,348	11,901,810	Detailed Analysis
2	Fuels - No. 6 Fuel	41,346,120	41,346,120	-	-	-	-	Detailed Analysis
3	Fuels - Diesel	19,718,496	151,060	2,414,900	16,451,500	655,400	45,636	Detailed Analysis
4	Fuels - Gas Turbine	3,566,784	3,285,533	-	-	-	281,251	
5	Fuel Supply Deferral	-	-	-	-	-	-	
6	Power Purchases -CF(L)Co	1,490,325	-	-	-	-	1,490,325	Detailed Analysis
7	Power Purchases - Other	65,248,655	61,614,658	210,500	-	3,423,496	-	Detailed Analysis
8	Power Purchases - MF	293,021,738	293,021,738	-	-	-	-	Detailed Analysis
9	Total Exports	(53,388,712)	(53,388,712)	-	-	-	-	Detailed Analysis
10	Power Purchases - LTA Costs	52,887,301	52,887,301	-	-	-	-	Detailed Analysis
11	Power Purchases - LIL Costs	379,849,000	379,849,000	-	-	-	-	Detailed Analysis
12	Power Purchases - Off Island	1,691,700	1,691,700	-	-	-	-	Detailed Analysis
13	Depreciation	77,147,362	65,646,886	823,757	4,683,316	927,534	5,065,869	Detailed Analysis
	Expense Credits:							
14	Sundry	(456,000)	(342,335)	(22,645)	(49,958)	(4,971)	(36,091)	Total O&M Expenses
15	Building Rental Income	(15,600)	(15,600)	-	-	-	0	Detailed Analysis
16	Tax Refunds	-	-	-	-	-	-	Total O&M Expenses
17	Suppliers' Discounts	(39,600)	(29,729)	(1,967)	(4,338)	(432)	(3,134)	Total O&M Expenses
18	Pole Attachments	(1,598,389)	(1,151,878)	(23,750)	(103,327)	(68,522)	(250,912)	Detailed Analysis
19	Wheeling Revenues	-	0	-	-	-	-	Island Interconnected
20	Application Fees	(24,680)	(12,200)	(300)	(1,654)	(406)	(10,120)	Detailed Analysis
21	Meter Test Revenues	-	0	-	-	-	-	Weighted Customers
22	Total Expense Credits	(2,134,269)	(1,551,742)	(48,661)	(159,277)	(74,331)	(300,258)	
23	Subtotal Expenses	1,030,819,483	957,445,212	10,868,023	37,450,167	6,571,447	18,484,634	
24	Disposal Gain/Loss	-	-	-	-	-	-	Detailed Analysis
25	Subtotal Rev Req Excl Return	1,030,819,483	957,445,212	10,868,023	37,450,167	6,571,447	18,484,634	
26	Return on Debt	94,151,480	83,101,721	805,803	4,202,229	711,102	5,330,625	Rate Base
27	Return on Equity	43,757,085	38,621,688	374,499	1,952,994	330,486	2,477,418	Rate Base
28	Total Revenue Requirement	1,168,728,048	1,079,168,621	12,048,325	43,605,390	7,613,035	26,292,677	

NEWFOUNDLAND AND LABRADOR HYDRO
2021 Illustrative Cost of Service Study - Recommended Approach
Total System
Return on Rate Base

Line No	1	2	3	4	5	6	7	8
	Total \$	Island Interconnected \$	Island Isolated \$	Labrador Isolated \$	Labrador Isolated \$	L'Anse au Loup \$	Labrador Interconnected \$	Basis of Proration
Rate Base:								
1	Average Net Book Value	2,306,167,365	2,036,334,531	19,637,535	101,548,908	17,399,731	131,246,660	Schedule 2.3
2	Cash Working Capital	9,320,000	8,229,515	79,362	410,393	70,318	530,412	Prorated on Average Net Book Value - L. 1
3	Fuel Inventory - No. 6 Fuel	13,838,000	13,838,000	-	-	-	-	Specifically Assigned - Holyrood
4	Fuel Inventory - Diesel	4,023,924	1,082,000	363,540	2,420,572	94,956	62,856	Detailed Fuel Analysis
5	Fuel Inventory - Gas Turbine	857,084	632,000	-	-	-	225,084	Detailed Fuel Analysis
6	Inventory/Supplies	36,391,000	32,230,621	212,292	1,478,524	340,179	2,126,473	Prorated on Total Plant in Service, Schedule 2.2
7	Deferred Charges: Holyrood	-	-	-	-	-	-	Detailed Analysis
8	Deferred Charges: Foreign Exchange Loss and Regulatory Costs	75,958,000	67,070,543	646,800	3,344,706	573,093	4,322,858	Prorated on Average Net Book Value - L. 1
9	Retired Asset Pool	11,710,730	10,340,517	99,720	515,666	88,356	666,471	Prorated on Average Net Book Value - L. 1
10	Total Rate Base	<u>2,458,263,192</u>	<u>2,169,757,727</u>	<u>21,039,249</u>	<u>109,718,770</u>	<u>18,566,633</u>	<u>139,180,813</u>	
11	Less: Rural Portion	-	-	-	-	-	-	Schedule 2.6, L. 9
12	Rate Base Available for Equity Return	<u>2,458,263,192</u>	<u>2,169,757,727</u>	<u>21,039,249</u>	<u>109,718,770</u>	<u>18,566,633</u>	<u>139,180,813</u>	
Corporate Targets:								
13	Capital Structure: Percent of Debt	75.42% ⁽¹⁾						
14	Return	<u>5.08%</u>						
15	Weighted Average Return: Debt	<u>3.83%</u>						
16	Capital Structure: Percent of Equity	20.95% ⁽¹⁾						
17	Return	<u>8.50%</u>						
18	Weighted Average Return: Equity	<u>1.78%</u>						
19	Weighted Average Cost of Capital	<u>5.61%</u>						
Return on Rate Base by System (%):								
20	Return on Rate Base - Debt Component	-	3.83%	3.83%	3.83%	3.83%	3.83%	
21	Return on Rate Base - Equity Component	-	1.78%	1.78%	1.78%	1.78%	1.78%	
Return on Rate Base (\$):								
22	Return on Debt	94,151,480	83,101,721	805,803	4,202,229	711,102	5,330,625	Schedule 2.6, L.13
23	Return on Equity	43,757,085	38,621,688	374,499	1,952,994	330,486	2,477,418	Schedule 2.6, L.14
24	Return on Rate Base (\$)	<u>137,908,565</u>	<u>121,723,409</u>	<u>1,180,302</u>	<u>6,155,223</u>	<u>1,041,588</u>	<u>7,808,044</u>	Schedule 2.6, L.15
Return on Total Rate Base (%):								
25	Return on Rate Base - Debt Component	3.83%	3.83%	3.83%	3.83%	3.83%	3.83%	L. 22 divided by L.10
26	Return on Rate Base - Equity Component	1.78%	1.78%	1.78%	1.78%	1.78%	1.78%	L. 23 divided by L.10
27	Return on Rate Base (%)	<u>5.61%</u>	<u>5.61%</u>	<u>5.61%</u>	<u>5.61%</u>	<u>5.61%</u>	<u>5.61%</u>	L. 24 divided by L.10

⁽¹⁾ Debt and equity weightings reflect a 3.64% funded ARO and 3.09% component for Employee Future Benefits at 0% cost.

NEWFOUNDLAND AND LABRADOR HYDRO
2021 Illustrative Cost of Service Study - Recommended Approach
Total System
Comparison of Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues (\$)	3 Cost of Service Before Deficit and Revenue Credit Allocation (\$)	4 Revenue Credits (\$)	5 Deficit (\$)	6 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) (\$)	7 Revenue to Cost Coverage (Col.2/3)
Total System							
1	Newfoundland Power	945,678,522	878,437,211	-	67,247,790	945,685,001	
2	RSP Activity	-	-	-	-	-	
2	Subtotal Newfoundland Power	945,678,522	878,437,211	-	67,247,790	945,685,001	1.08
3	Island Industrial	92,765,659	92,771,198	-	-	92,771,198	1.00
4	Unallocated RSP Hydraulic Variation	-	-	-	-	-	-
4	Labrador Industrial	6,896,887	6,898,089	-	-	6,898,089	1.00
5	CFB - Goose Bay Secondary	-	-	-	-	-	-
6	Rural Labrador Interconnected	20,899,895	19,394,588	-	1,484,731	20,879,319	1.08
Rural Deficit Areas							
7	Island Interconnected	81,531,777	107,960,211	-	(26,428,434)	81,531,777	0.76
8	Island Isolated	2,335,646	12,047,966	-	(9,712,320)	2,335,646	0.19
9	Labrador Isolated	13,640,522	43,605,390	-	(29,964,868)	13,640,522	0.31
10	L'Anse au Loup	4,986,137	7,613,035	-	(2,626,898)	4,986,137	0.65
11	CFB Revenue Credit Applied to Deficit	-	-	-	-	-	-
12	Subtotal	102,494,081	171,226,602	-	(68,732,521)	102,494,081	0.60
13	Total	1,168,735,044	1,168,727,690	-	-	1,168,727,690	1.00

NEWFOUNDLAND AND LABRADOR HYDRO
2021 Illustrative Cost of Service Study - Recommended Approach
Island Interconnected
Comparison of Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues (\$)	3 Cost of Service Before Deficit and Revenue Credit Allocation (\$)	4 Revenue Credit (\$)	5 Deficit Allocation (\$)	6 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) (\$)	7 Revenue to Cost Coverage (Col.2/3)
Island Interconnected							
1	Newfoundland Power	945,678,522	878,437,211	-	67,247,790	945,685,001	
2	Subtotal Newfoundland Power	945,678,522	878,437,211	-	67,247,790	945,685,001	1.08
3	Industrial - Firm	92,765,659	92,771,198	-		92,771,198	
4	Industrial - Non-Firm	-	-	-		-	
5	Subtotal Industrial	92,765,659	92,771,198	-	-	92,771,198	1.00
Rural							
6	1.1 Domestic	22,404,991	32,499,342	-	(10,094,351)	22,404,991	0.69
7	1.12 Domestic All Electric	28,230,278	38,279,829	-	(10,049,550)	28,230,278	0.74
8	1.3 Special	32,730	104,119	-	(71,388)	32,730	0.31
9	2.1 General Service 0-100 kW	14,644,230	18,399,607	-	(3,755,377)	14,644,230	0.80
10	2.3 General Service 110-1,000 kVa	9,383,558	11,023,264	-	(1,639,706)	9,383,558	0.85
11	2.4 General Service Over 1,000 kVa	5,144,100	6,059,886	-	(915,787)	5,144,100	0.85
12	4.1 Street and Area Lighting	1,691,888	1,594,164	-	97,724	1,691,888	1.06
13	Subtotal Rural	81,531,777	107,960,211	-	(26,428,434)	81,531,777	0.76
14	Total Island Interconnected	1,119,975,958	1,079,168,621	-	40,819,355	1,119,987,976	1.04

NEWFOUNDLAND AND LABRADOR HYDRO
2021 Illustrative Cost of Service Study - Recommended Approach
Island Isolated
Comparison of Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues (\$)	3 Cost of Service Before Deficit and Revenue Credit Allocation (\$)	4 Revenue Credit (\$)	5 Deficit (\$)	6 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) (\$)	7 Revenue to Cost Coverage (Col.2/3)
Island Isolated							
1	1.2 Domestic Diesel	1,292,683	9,244,022		(7,951,339)	1,292,683	0.14
2	1.2G Government Domestic Diesel	-	-		-	-	-
2	1.23 Churches, Schools & Com Halls	104,463	362,510		(258,048)	104,463	0.29
3	2.1 General Service 0-10 kW	296,106	960,396		(664,289)	296,106	0.31
4	2.2 GS 10-100 kW	571,302	1,240,415		(669,113)	571,302	0.46
5	4.1 Street and Area Lighting	64,769	229,635		(164,866)	64,769	0.28
6	4.1G Gov't Street and Area Lighting	6,323	10,988		(4,665)	6,323	0.58
7	Total	2,335,646	12,047,966		(9,712,320)	2,335,646	0.19

NEWFOUNDLAND AND LABRADOR HYDRO
2021 Illustrative Cost of Service Study - Recommended Approach
Labrador Isolated
Comparison of Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues (\$)	3 Cost of Service Before Deficit and Revenue Credit Allocation (\$)	4 Revenue Credit (\$)	5 Deficit (\$)	6 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) (\$)	7 Revenue to Cost Coverage (Col.2/3)
Labrador Isolated							
1	1.2 Domestic Diesel	5,065,575	23,495,398		(18,429,823)	5,065,575	0.22
2	1.2G Government Domestic Diesel	658,137	632,185		25,952	658,137	1.04
3	1.23 Churches, Schools & Com Halls	458,120	1,274,283		(816,163)	458,120	0.36
4	2.1 General Service 0-10 kW	1,874,329	4,278,139		(2,403,810)	1,874,329	0.44
5	2.2 GS 10-100 kW	4,631,949	10,067,547		(5,435,598)	4,631,949	0.46
6	2.3 GS 110-1,000 kVa	396,655	1,594,196		(1,197,541)	396,655	0.25
7	2.4 General Service Over 1,000 kVa	358,118	1,837,749		(1,479,630)	358,118	0.19
8	4.1 Street and Area Lighting	188,774	415,934		(227,160)	188,774	0.45
9	4.1G Gov't Street and Area Lighting	8,864	9,958		(1,094)	8,864	0.89
10	Total	13,640,522	43,605,390		(29,964,868)	13,640,522	0.31

NEWFOUNDLAND AND LABRADOR HYDRO
2021 Illustrative Cost of Service Study - Recommended Approach
L'Anse au Loup
Comparison of Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues (\$)	3 Cost of Service Before Deficit and Revenue Credit Allocation (\$)	4 Revenue Credit (\$)	5 Deficit (\$)	6 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) (\$)	7 Revenue to Cost Coverage (Col.2/3)
L'Anse au Loup							
1	1.1 Domestic	908,603	1,579,580		(670,977)	908,603	0.58
2	1.12 Domestic All Electric	2,179,806	3,521,804		(1,341,998)	2,179,806	0.62
3	2.1 General Service 0-100 kW	1,361,601	1,844,600		(482,999)	1,361,601	0.74
3	2.3 General Service 110-1,000 kVa	503,905	615,138		(111,233)	503,905	0.82
4	4.1 Street and Area Lighting	32,222	51,913		(19,691)	32,222	0.62
5	Total L'Anse Au Loup	4,986,137	7,613,035		(2,626,898)	4,986,137	0.65

NEWFOUNDLAND AND LABRADOR HYDRO
2021 Illustrative Cost of Service Study - Recommended Approach
Labrador Interconnected
Comparison of Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues (\$)	3 Cost of Service Before Deficit and Revenue Credit Allocation (\$)	4 Revenue Credit (\$)	5 Deficit Allocation (\$)	6 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) (\$)	7 Revenue to Cost Coverage (Col.2/3)
Labrador Interconnected							
1	Labrador Industrial Firm	6,896,887	6,898,089	-	-	6,898,089	1.00
2	Labrador Industrial Non-Firm	-	-	-	-	-	-
3	Subtotal Industrial	6,896,887	6,898,089	-	-	6,898,089	
4	CFB - Goose Bay Secondary	-	-	-	-	-	-
Rural							
5	1.1 Domestic	94,465	208,097	-	15,930.61	224,027	0.42
6	1.1A Domestic All Electric	10,303,040	11,200,649	-	857,453	12,058,103	0.85
7	2.1 General Service 0-10 kW	351,143	360,613	-	27,606	388,219	0.90
8	2.2 General Service 10-100 kW	2,176,656	1,780,078	-	136,272	1,916,350	1.14
9	2.3 General Service 110-1,000 kVa	3,616,334	2,543,684	-	194,729	2,738,413	1.32
10	2.4 General Service Over 1,000 kVa	3,996,993	2,996,062	-	229,360	3,225,422	1.24
11	4.1 Street and Area Lighting	361,265	305,405	-	23,380	328,785	1.10
12	Subtotal Rural	20,899,895	19,394,588	-	1,484,731	20,879,319	
13	Total Labrador Interconnected	27,796,782	26,292,677	-	1,484,731	27,777,408	

NEWFOUNDLAND AND LABRADOR HYDRO
2021 Illustrative Cost of Service Study - Recommended Approach
Total System
Rural Deficit Allocation

Line No.	1	2
		<u>Deficit Allocation</u> Allocated on Revenue Requirement (\$)

ALLOCATION OF DEFICIT:

1	Island Interconnected	67,247,790	
2	Labrador Interconnected	1,484,731	
3	Allocated Totals	<u><u>68,732,521</u></u>	

CUSTOMER DEFICIT ALLOCATION:

		Amount	Revenue Requirement	Percent
	Island Interconnected:			
4	Newfoundland Power	<u>67,247,790</u>	878,437,211	97.8%
	Labrador Interconnected:			
5	Rural Labrador Interconnected	<u>1,484,731</u>	19,394,588	<u>2.2%</u>
6	Total	<u><u>68,732,521</u></u>		<u>100.0%</u>

Exhibit 3

Revenue Requirement Comparison Summary Schedules

Comparison of Revenue Requirement Allocations (Pre- and Post- Muskrat Falls)

	Revenue Requirement Excluding Rural Deficit ⁽¹⁾					Revenue Requirement Including Rural Deficit			
	Sales (MWh)	Demand ⁽²⁾ (\$ million)	Energy (\$ million)	Total (\$ million)	Percent of Total (%)	Average Unit Cost (¢/kWh)	Total (\$ million)	Percent of Total (%)	Average Unit Cost (¢/kWh)
Post-Muskrat Falls									
2021 Recommended Approach (Equivalent Peaker)									
Newfoundland Power	5,833,600	317,308	558,204	875,512	82.5	15.01	942,536	91.1	16.16
Industrial	743,300	21,359	71,105	92,463	8.7	12.44	92,463	8.9	12.44
Rural	413,405	49,675	43,667	93,342	8.8	22.58			
Total	6,990,305	388,341	672,976	1,061,317			1,034,999		
Pre-Muskrat Falls									
2019 (Current Approach)⁽³⁾									
Newfoundland Power	5,833,600	187,964	205,508	393,471	80.3	6.74	455,760	92.2	7.81
Industrial	743,300	12,623	26,172	38,795	7.9	5.22	38,795	7.8	5.22
Rural	413,405	41,326	16,181	57,507	11.7	13.91	-		
Total	6,990,305	241,913	247,860	489,773			494,555		

(1) Specifically assigned customer component of revenue requirement not included in calculations.

(2) Includes both production and transmission demand costs.

(3) Cost Deferral and Interim Rates Application filed with the Board on October 26, 2018

Comparison of Revenue Requirement Allocations (Muskrat Falls Cost Classification)

	Revenue Requirement Excluding Rural Deficit ⁽¹⁾					Revenue Requirement Including Rural Deficit			
	Sales (MWh)	Demand ⁽²⁾ (\$ million)	Energy (\$ million)	Total (\$ million)	Average Unit Cost % (¢/kWh)	Total (\$ million)	Average Unit Cost %	Average Unit Cost (¢/kWh)	
2021 Recommended Approach (Equivalent Peaker)									
Newfoundland Power	5,833,600	317,308	558,204	875,512	82.5	15.01	942,536	91.1	16.16
Industrial	743,300	21,359	71,105	92,463	8.7	12.44	92,463	8.9	12.44
Rural	413,405	49,675	43,667	93,342	8.8	22.58			
Total	6,990,305	388,341	672,976	1,061,317			1,034,999		
2021 Alternative Approach (System Load Factor)									
Newfoundland Power	5,833,600	467,387	416,302	883,688	83.3	15.15	949,875	91.8	16.28
Industrial	743,300	31,516	53,033	84,549	8.0	11.37	84,549	8.2	11.37
Rural	413,405	60,511	32,570	93,081	8.8	22.52			
Total	6,990,305	559,413	501,905	1,061,318			1,034,424		

(1) Specifically assigned customer component of revenue requirement not included in calculations.

(2) Includes both production and transmission demand costs.

Appendix A

Cost of Service Methodology Review
prepared by Christensen Associates Energy Consulting

**Cost-of-Service Methodology Review
Revised Version**

for

Newfoundland and Labrador Hydro

by

Christensen Associates Energy Consulting, LLC

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Madison, WI 53705-2299

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November 15, 2018

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Cost-of-Service Methodology Review

Revised Version¹

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.

1 **Summary of Revisions**

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

6

7 **Section 3**

- 8 • Section 3 titles have been reformatted to clarify the section’s topics. These now
9 appear as Sections 3.1 to 3.4.
- 10
- 11 • Sections 3.1 and 3.2 expand the review of embedded cost-based methods that
12 might be used to classify conventional generation costs. Section 3.2 focuses on
13 alternatives for classifying Muskrat Falls power purchases when the generator’s
14 units come on line.
- 15 • Section 3.3 expands the review of marginal cost-based methods. The review
16 documents the absence of marginal cost approaches in Canada and mentions their
17 use in the U.S.
- 18
- 19 • Section 3.4 has been revised to reflect Hydro’s system planners’ change in
20 perspective on the capacity content of wind generation. The planners have
21 concluded that the purchased power from two wind generators should now be
22 factored in to forecasts of system generating capacity, while previous evidence had
23 suggested to them that wind generation costs might best be classified as 100%
24 energy.

25

26 **Section 4**

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

29

1 **Section 5**

- 2 • Section 5.1 provides updated information on the treatment of the rural deficit in
3 Cost of Service (“COS”).
4
- 5 • Section 5.2 has been updated to reflect the outcome of the review of conservation
6 and demand management (“CDM”) charges in the 2013 General Rate Application
7 (“GRA”), including statements made in the final order [Order No. P.U. 49(2016)].
8
- 9 • Section 5.3 updates the description of Hydro’s investigation of its ability to track
10 operating and maintenance expenditures on specifically assigned transmission
11 facilities of Island Industrial customers.
12
- 13 • Section 5.4 provides a revised discussion of the COS considerations associated with
14 Hydro’s capacity assistance agreements.
15
- 16 • Section 5.5 has been revised to reflect changes in Hydro’s view of the requirement
17 for the Newfoundland Power Generation Credit.
18
- 19 • Section 5.6 provides a more extensive review of export-related costing and revenue
20 recovery options than previously.

1 **1. Introduction**

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

14
15 The cost of the MF, LIL, and LTA projects will, by government direction, be borne by
16 customers paying Island Interconnected rates (beginning with the Muskrat Falls Project in-
17 service date) as these facilities are being constructed for them. Additionally, as a result of
18 the arrival of new supply on the Island, Hydro will wind down the Holyrood generation
19 facility, replacing its thermal generation with Muskrat Falls’ hydro power.

20
21 This COS methodology review is part of a general review process leading up to the in-service
22 date for Muskrat Falls and its associated transmission facilities. The review was anticipated
23 to commence at the conclusion of the 2013 General Rate Application (“GRA”) process,
24 during which many COS methodology issues were reviewed. However, due to the delayed
25 in-service date for the Muskrat Falls Project, the cost of service methodology review process
26 was delayed and is now expected to commence in early 2019. This report makes reference

1 to several of these issues and the related discussions and documents from the 2013 GRA
2 and the 2017 GRA.²

3

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

12

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

24

25 The review begins with a “jurisdiction” question, investigating the potential for combining
26 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.

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

7

8 **2. System Definition**

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

12

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

20

21 Furthermore, the power flow pattern anticipated for Hydro’s physically interconnected
22 system is not conventional when compared with the rest of the Eastern Interconnection.⁴
23 Hydro expects that in virtually all hours, barring an outage at Muskrat Falls or on the LIL,
24 power will flow in one direction, south to the Island and points beyond. This is
25 unconventional for ac-dominated meshed networks, but consistent with conditions in which
26 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.

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

10

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

13

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

20

21 As well, Labrador industrial rates, which serve two large customers, have two components
22 arising from separate sources.⁸ The cost of generation services is subject to direction by the
23 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.

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

8

9 Additionally, Labrador's cost of service and, hence, retail pricing is very low compared to
10 Island rates. In the 2015 COS study, Labrador rural interconnected average cost to serve is
11 just 2.8¢/kWh, while Island average cost to serve is 8.4¢/kWh. The source of the difference
12 is the dominant role in serving Labrador of Churchill Falls power, which currently costs just
13 0.2¢/kWh. Unifying service territories would likely have significant rate impacts. Such
14 impacts might appear to be cost justified, but the contractual elements providing low-cost
15 Churchill Falls power to the Labrador interconnected System will not be negated by the
16 completion of the LIL.

17

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

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

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

8

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

15

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

19

20 **3. Generation**

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

26

27 **3.1 Classification and Allocation of Current Generation**

28 **Background.** At present, Hydro classifies and allocates its generation costs in a manner that
29 attempts to recognize each facility's role in generation dispatch. Peaking units are classified

1 as entirely demand-related while other units are recognized as each having an energy and
 2 demand component. System load factor is the leading basis for classification for these units.
 3 The method of classification varies with the type of generator and region. Table 1 provides a
 4 summary.

Table 1
Current Classification and Allocation of Generation Assets

System	Generator Type	Classification	Allocation
<i>Interconnected</i>			
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
<i>Isolated</i>			
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

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

11

12 The system load factor approach to cost classification attributes a share of generation
 13 investment cost to energy causation based on the ratio of average to system coincident
 14 peak production. This formulation assumes that generation investment to meet average
 15 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.

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

4

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

15

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

23

24 Hydro also currently engages in power purchases. The Island Interconnected system obtains
25 the majority of its purchases from non-utility generation consisting primarily of hydro
26 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.

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

3

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

9

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

15

16 It is worth mentioning that the selection of coincident peak measure was the subject of
17 debate in 2001. Hydro and its intervenors debated the relative merits of 1 CP, 2 CP, and 3 or
18 4 CP as representatives of Hydro's generation peak conditions. Arguments claimed
19 alternatively that February was responsible for preponderant instances of peak demand,
20 that January and February were dominant, and that peaks had been recorded to occur in all
21 four winter months (December through March) if enough years were considered in the
22 review.

23

24 This debate mirrors debate in the industry about the choice of demand allocator. Theory
25 suggests that a single annual CP value is the best measure of how classes contribute to peak
26 demand. However, single values can be prone to variability over time and instances of
27 anomalous behavior by a class that can skew results. Multiple-month averages are more
28 stable, but dilute the peak nature of the signal. Additionally, the seasonality of the utility
29 matters, with single-season utilities favoring a 3 CP or 4 CP measure and non-seasonal

1 utilities preferring a twelve-month average. The NARUC COS Manual contains a discussion
2 of this issue, but offers no general recommendation.¹² In Hydro’s case, the Newfoundland
3 and Labrador Board of Commissioners of Public Utilities (Board) concluded in 2002 that 1 CP
4 was simple and that other measures had not proved demonstrably preferable.¹³

5

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

18

19 **3.2 Classification and Allocation of Muskrat Falls**

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

25

¹² NARUC, Electric Utility Cost Allocation Manual, January 1992, Chapter 4, p. 41ff.

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.)

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

8

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

19

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

29

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

9

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

20

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

¹⁴ SLF value used in 2015 test year COS model.

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

8

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

¹⁵ NARUC, *Electric Utility Cost Allocation Manual*, January 1992, page 53ff.

¹⁶ These calculations are provisional, based on Hydro's informal estimates.

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

3

4 The NARUC Utility Cost Allocation Manual describes the equivalent peaker approach that
5 includes a subsection entitled, “A Digression on System Planning with Reference to Cost
6 Allocation”. The equivalent peaker method is thus tied to the system planner’s perspective
7 on generation. On this basis, the equivalent peaker approach may merit review.

8 The equivalent peaker methodology received serious consideration by the Board in the
9 1992 COS methodology review. The approach was ultimately rejected for reasons of
10 computational challenge, and plant vintage and valuation issues. However, those issues
11 apply with less force now, since the peaking unit computations pertain to a plant of current
12 vintage. As a result, this approach may deserve renewed consideration for its application to
13 the classification approach for Muskrat Falls.

14

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

21

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

1 capacity factor to a forecast-only approach, causing cost allocation to reflect immediately
2 the plant’s changed role.

3

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

10

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

22

23 **3.3 Marginal Cost-Based Cost Allocation**

24 The upcoming transformation of the system and the advance of costing capabilities in North
25 America and at Hydro offer an opportunity to expand the range of costing methodologies
26 relative to traditional demand-energy classification. The demand-energy approach, applied
27 according to a variety of methods, attempts to compartmentalize costs in some sensible
28 manner between costs incurred to meet peak demands and costs incurred to supply total
29 energy. Its virtue is the effective use of limited available data to impute cost causation. Its

1 weaknesses are that the information utilized is limited and there is no single preferred
2 method of classification.

3

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

12

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

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

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

10

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

17

18 In summary, the incorporation of marginal cost analytics within cost allocation captures the
19 economic worth of the resources used in the provision of service. This result is both fair and
20 efficient, and holds for both the internal cost and market-based marginal cost framework.

21 Marginal cost-based COS provides cost foundation and detail by timeframe that is not
22 available through conventional methods.

23

24 Thus, the marginal cost perspective provides the means to capture explicitly the
25 components of generation services (including energy and reserves) attributable to each
26 class. Classes that tend to have high but variable usage at times of high marginal reserves
27 cost have their costs for the full year recorded. A utility that opts for marginal cost-based
28 allocation of embedded costs can thus avoid classification debates (energy and demand

1 shares of costs) and debates as to which measure of peak demand is most appropriate (*e.g.*
2 1 CP vs. 3 CP vs. 12 CP) but then must meet the challenge of modeling marginal cost.

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

11

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

15

16 The Canadian practice of generation cost classification and allocation is summarized in Table
17 2 for large, vertically integrated utilities. At present, no utility or jurisdiction makes use of
18 marginal cost in cost allocation. All utilities apply some form of energy and demand
19 allocator method to classify generation cost. Cost allocation occurs via coincident peak
20 (“CP”) demand allocators and annual usage energy allocators.

21

22 Most utilities apply the same classification approach as Hydro in that they use different
23 approaches for different types of generation, rather than combining all generation costs
24 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 57ff 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.

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

13

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

23

24 The Manitoba Board did not address the merits of Manitoba Hydro’s proposed approach,
25 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.

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

5

6 The rejected approach appears to be within Hydro’s capabilities as they will exist upon
7 completion of the Muskrat Falls project. The utility will have access to both historical and
8 forecast wholesale market data from ISONE and NYISO, and will have its own estimates of
9 internal capacity cost that might be used to supplement wholesale market prices.²³

10 Additionally, it does not appear that the Manitoba Board ventured criticism of the
11 methodology, but instead simply expressed preference for its own separate classification
12 and allocation scheme.

13

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

20

21 It is worth mentioning, as well, that North American jurisdictions that have deregulated
22 their generation and retail services functions offer additional examples of marginal cost-
23 based cost allocation. This occurs as a natural outcome of the process of wholesale
24 purchases by retail energy providers. The cost of wholesale energy and reserves is applied
25 to the forecasted loads of any contract and a weighted marginal cost determines the
26 purchase price. Retail providers then resell energy to retail customers at competitively
27 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.

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

3

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

14

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

24

25 One key issue will be determining how to treat the power purchases from Muskrat Falls.
26 The payments are in the form of lump-sum charges for capacity and O&M costs.
27 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.

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

6

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

17

18 **3.4 Classification and Allocation of Wind Generation**

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

25

26 Under marginal cost-based cost allocation, the classification issue does not arise. Marginal
27 cost-weighted class load profiles yield total marginal costs whose shares determine each
28 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.

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

3

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

9

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

20

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

27 Having recently established a connection to the continent’s grid, Hydro’s operational
28 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.

1 interconnection and resulting seasonal change in peak period as materially affecting their
2 perspective on wind’s capacity value.²⁷

3
4 If the planners now see a possible capacity role for wind, then it makes sense to examine
5 evidence of the role of wind in meeting capacity needs. Hydro has recently investigated the
6 issue of capacity value, applying a methodology recommended by NERC,²⁸ an Electric Load
7 Carrying Capacity (“ELCC”) study.²⁹ The methodology applies probabilistic assessment to the
8 system that allows for a range of possible reliability outcomes. Hydro found that its current
9 wind resources yield an ELCC ratings of about 22%. This value is in line with industry values
10 that range from 5 to 20%.

11
12 Hydro’s result is comparable to results found in other Canadian utilities as well. During the
13 review of Hydro’s 2013 GRA, Vale witness Mr. Melvin Dean referenced previous Hydro
14 research indicating that North American industry practice is varied, sometimes resulting in
15 the classification of wind as energy-only, while at other times granting wind generation a
16 capacity role. Referencing NP-NLH-280, he finds that a high proportion of utilities split wind
17 costs between demand and energy. Many use a percentage of nameplate wind generator
18 capacity as a basis for determining shares.

19
20 Witness Dean then presents, for six utilities that report classification shares between energy
21 and demand, information on the relationship between capacity factor and demand share.
22 Two utilities (BC Hydro and Austin Energy) classify wind generation as 100% energy-related,
23 while four other utilities accept a demand component. Three of these classify wind as
24 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.)

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

6

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

15

16 **Recommendations.** We recommend that Hydro introduce marginal cost-based allocation of
17 embedded generation costs for the Island Interconnected system beginning with the
18 implementation of rates that recover revenue to cover payments by Hydro for Muskrat Falls
19 and its associated transmission facilities, subject to Hydro’s mastery of the technical
20 challenges of marginal cost development. This change will avoid the need to classify each
21 generation asset or cost on its own and relates cost to serve to an objective market-based
22 value of generation services that recognizes cost to serve by each rate class in each hour. It
23 appears that Hydro can undertake this approach, as the utility already possesses the costing
24 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.

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

5

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

12

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

20

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

26 If the plant does not immediately come to be used as a synchronous condenser, then it
27 should be retained as generation and functionalized according to marginal cost-based cost
28 allocation. In the event that marginal cost-based allocation is not adopted and the plant is

1 still treated as generation, then the equivalent peaker method or the continued use of the
2 forecasted capacity factor methodology would suffice.

3

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

10

11 **4. Transmission**

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

21

22 **4.1 Capacity Costs**

23 **Transmission Facility Categories**

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

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- Generator Interconnection Facilities: 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;
- General-Purpose Transport Facilities: 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;
- Terminal Stations: substations, transformers, switchgear, meters, and system monitoring equipment; and,
- Special Facilities: 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.

1 **Sub-functionalization**

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

11
12 **General Purpose Transport Facilities and Terminal Stations.** These facilities inherently
13 belong to the transmission function as a matter of definition and purpose. However, even
14 among these quintessential transmission facilities, there is an exception: the converter
15 facilities located at the Muskrat Falls and Soldiers Pond stations that serve as the terminal
16 points of the LIL. These highly specialized facilities, include rectifiers, inverters, and
17 associated equipment. As a component of the LIL, they are probably best functionalized in
18 the same manner as the LIL, a special purpose facility discussed immediately below.

19
20 **Special Purpose Transmission Facilities.** Special purpose facilities are constructed for, or
21 primarily because of, the provision and facilitation of least cost generation. Least cost
22 generation plans reflect real-world constraints: generation cannot necessarily be sited near
23 load centers. Large-scale generation, including hydraulic facilities, nuclear stations, and
24 wind farms, often requires sizable properties, selected according to geographical features,
25 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.

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

3

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

10

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

18

19 The Hydro system includes two major special purpose transmission facilities:

20

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

25

26 • Labrador-Island Link: The LIL is a 1,100 km dc transmission line, stretching from
27 Muskrat Falls in Labrador across the Strait of Belle Isle, then southeast to Soldiers
28 Pond on the Avalon Peninsula. The LIL and MF constitute an integrated resource
29 strategy where the net economic benefits of the strategy are jointly determined. The

1 incremental economic value of the LIL is compromised absent MF; and similarly for
2 MF, absent LIL.

3

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

11

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

17

18 The second approach is to assign the LIL facility jointly to generation and transmission.
19 Arguably, because the LIL creates a dc-dominated transmission loop on the fringe of the
20 Eastern Interconnection, in which flows in both directions are at least theoretically possible,
21 the LIL can be viewed as an example of joint-use facilities. In this case, the LIL could be
22 assigned jointly to the generation and transmission functions, at least for the near term.
23 Functionalization could occur based on some measure of native load and export shares of
24 LIL transportation. The native load share would be classified as generation and the export
25 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.

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

3

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

9

10 **Sub-functionalization Recommendations**

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

16

17 The special purpose facilities which comprise the LTA should be assigned to the generation
18 function for the reasons discussed above—facilitation of efficient use of hydro facilities
19 along the Churchill River, including the Churchill Falls and Muskrat Falls stations. We
20 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.

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

3

4 **Classification and Allocation**

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

9

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

19

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

27

28 Table 3 provides a summary of Canadian classification and allocation practices regarding
29 common transmission facilities. With three exceptions, the utilities investigated classify

1 transmission assets as 100% demand-related. The first exception is Nova Scotia Power,
 2 which has a tradition of treating its common transmission assets as an extension of its
 3 generation facilities. Since they use an SLF allocator for generation, they also use it for
 4 common transmission. The second exception relates to the specialized transmission assets
 5 used to connect Manitoba Hydro to U.S. markets. These are classified according to system
 6 load factor. Discussion below describes why these assets are not viewed by the regulator as
 7 similar to other common transmission assets. Absent this exception, industry classification
 8 practice is uniform in using demand-only classification.

9
 10 The third exception, Hydro-Quebec, disaggregates transmission costs into four groups.
 11 Network and customer connection costs are classified as demand-related, but other costs
 12 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		
	Network	100% D	1 CP	
	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

13 Allocation practices are not particularly uniform, except to state that utilities rely mostly on
 14 coincident peak measures and are seasonal. A range of CP allocators is in use: 2 CP, 4 CP,
 15 and an instance of 1 CP at Manitoba Hydro that turns out to consist of the peak 50 winter

1 hours of Winter, which parallels their allocation of generation demand-related cost. 2CP
2 allocation is essentially seasonal 1 CP allocation, with utilities like Fortis recognizing both a
3 winter and summer peak. In contrast, 3 CP and 4 CP allocators are single-season in focus,
4 with winter being the peak season.

5

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

9

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

17

18 The use of demand-only allocation is broadly applied in contemporary systems in North
19 America, a practice partly justified additionally by the mature state of the grid. To a large
20 extent, power networks have been more or less fully developed, at least notwithstanding
21 grid development to transport power produced by renewable resources situated in areas
22 remote from load centers.³⁷ For developed systems, investment to increase capability is
23 necessary largely to satisfy year-over-year growth in peak demands: accordingly, demand-
24 based allocation is arguably appropriate for power systems that are substantially *built out*,
25 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.

1

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

14

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

24

25 Another alternative is to conceive of general transport facilities as no more than an
26 extension of generation. If so, these facilities would then be viewed by utilities using a
27 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.

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

3

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

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

10

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

20

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

25

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.

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

5 The remaining costs shares⁴¹ are then classified accordingly to energy. For general purpose
6 transport facilities, the energy share basis of allocation can, potentially, weight hourly loads
7 by marginal costs (both in hourly frequency).

8

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

20

21 As mentioned, Hydro currently applies a 1 CP method to transmission cost allocation. This
22 approach has been widely used in the past, for the good reason that the single hour of
23 highest use is the benchmark for system planning.⁴² Other time periods, though, have been
24 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.

1 winter peaks are quite similar and the class shares can differ significantly by season. Giving
2 weight to peak hours in both seasons avoids possibly dramatic changes in cost shares over
3 time. Second, measuring cost shares using a single hour of system peak can be statistically
4 unreliable. As a result, utilities, even strongly seasonal utilities, have gravitated toward a
5 3 CP alternative to 1 CP.

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

9

- 10 • The On- and Off-Peak test. Compute two quotients: average system peaks during the
11 peak season/annual peak demand and average system peaks during the non-peak
12 season/annual peak demand. If the difference between these quotients is less than
13 19%, the conclusion on this test is that the utility is best represented by a 12 CP
14 measure.
- 15
- 16 • The Low to Annual Peak test. Compute the quotient of the lowest monthly peak
17 demand and annual peak demand. If that quotient is greater than 66%, the
18 conclusion on this test is that the utility is best represented by a 12 CP measure.
- 19
- 20 • The Average to Peak test. Compute the quotient of the average of the 12 monthly
21 peaks and the annual peak demand. If that quotient is greater than 81%, the
22 conclusion on this test is that the utility is best represented by a 12 CP measure.

23

24 While some utilities are clearly quite seasonal, with all measures resulting in a 3 CP
25 determination, and others are clearly less seasonal, with a 12 CP determination, still others
26 provide mixed verdicts. The tests are used as guidelines, rather than rules, with an
27 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 76ff.

1

2 Hydro computed these tests, making use of forecasted peak demands for 2019 and 2020.⁴⁴

3 They tested their system both including and excluding export sales. The results of the tests

4 appear in Table 4. Each cell presents the number of the above-mentioned tests that

5 supported either the 3 CP or 12 CP construction. There are three test results for each of the

6 two years, six in all. The tests are performed for two scenarios, one in which load totals are

7 comprehensive, including export flows, the other in which exports are excluded from the

8 computation.

9

10 The tests appear to support the conclusion that the utility, at least in the early stages

11 following the Muskrat Falls in-service date, is best represented by a 3 CP representation as

12 opposed to 12 CP. If exports are excluded, all six tests (three per year) support the 3 CP

13 conclusion. If exports are included, two of three tests support the 3 CP conclusion in each

14 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

15 If these tests are to be accepted as guidelines, it is not strictly necessary to evaluate which

16 column should serve as the reference point. However, given that the “including exports”

17 results are less than fully conclusive, it is worth reviewing the issue of scenario selection.

18 The shares allocated to Hydro’s customer classes ought to be measured with reference to

19 the times when the system is at or near peak usage. This suggests that the full utilization of

20 the system matters.

21

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.

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

8

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

17

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

25

26 The other measures proposed—Peak Load Frequency and *Pro Rata* Peak Load
27 Distribution—offer an alternative to the CP approach by taking advantage of greater data
28 availability and statistical sophistication to measure the probability with which peak
29 demands occur in individual hours, and distribute the class responsibility for transmission

1 cost based on hourly loads and probability of setting a peak. In spirit, these methods are
2 close to the marginal cost-based computation recommended for generation cost allocation.
3 These methods use more data than the traditional method but offer perhaps greater
4 stability of measure given the use of information in more hours. Additionally, these
5 methods also may reduce the issue of determining utility seasonality in borderline cases
6 (e.g. 3 vs. 12 CP) by objectively weighting the relative importance of each hour. Over time
7 these weights may change, but significant changes in cost weights are unlikely.

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

18

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

27

28 **Classification and Allocation Recommendations**

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

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

12
13 Demand-related costs should be allocated based on one of the three methods proposed.
14 The Peak Load Frequency and *Pro Rata* Peak Load Distribution methods offer improved
15 accuracy and stability over time, as well as an hourly analysis approach similar to that
16 recommended for generation cost allocation. However, they require more analysis than the
17 traditional CP method. If the traditional CP method is selected and used for generation
18 classification as well, we recommend that Hydro retain its traditional 1 CP approach, for
19 reasons of harmonization with generation classification, and despite its statistical
20 limitations.

21
22 **Terminal Stations.** The reserve requirements for capital and O&M costs associated with
23 Terminal Stations should be classified as demand-related and allocated according to one of
24 the methods described above.

25

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.

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

9 **4.2 Transmission Line Losses**

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

13

- 14 1. Interconnection between the Labrador and Island power systems facilitated by the
15 LIL, a dual circuit dc facility (900 MW capability);
16
- 17 2. Coordination of energy management between Churchill Falls and Nalcor's new
18 Muskrat Falls hydro facility (MF or Lower Churchill), facilitated by the LTA, a dual
19 circuit 315 kV ac facility (approximately 900 MW capability);
20
- 21 3. Interconnection of the Island system with the Eastern Interconnection, thus
22 facilitating power transactions with the organized power markets of the Northeast
23 through the Maritime Link, a dual circuit dc facility (approximately 500 MW
24 capability); and
25
- 26 4. Investment in the Hydro's high voltage ac network (230 kV) in order to satisfy
27 reliability standards associated with increased power flows across the Hydro power
28 system.

1

2 The Hydro power system is currently comprised of high voltage (230 kV) and lower voltage
3 (66 kV to 138 kV) facilities configured within meshed and radial networks. Hydro's
4 transmission network spans fairly long distances in order to serve the sizable urban area
5 residing on the Avalon Peninsula (St. John's) as well as rural communities and towns located
6 throughout the Province.

7

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

12

13 Within transmission, system-wide average losses are often tabulated from observed power
14 flows within networks, metered in hourly or monthly frequency. These data provide a
15 historical record: determining total and average transmission losses involves adjusting
16 observed historical quantities (MWh), for application within COS studies.⁴⁶ Beginning in
17 2020 however, major restructuring of the Hydro system will likely cause significant changes
18 in both the profile and level of average and marginal losses. As a consequence, observed
19 historical losses cannot be readily utilized within COS. Thus the issue: how should line losses
20 be determined for purposes of cost allocation for 2020 forward, in view of the resource
21 changes under way?⁴⁷

22

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

25

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.

- 1 • Transmission losses are usually predominantly thermal losses, resulting from line
2 resistances. Larger conductors will generally have lower losses. However, in this case
3 dc converter/inverter losses and synchronous condenser losses will contribute
4 materially to station service losses.⁴⁸
5
- 6 • Transmission losses decline significantly with higher conductor voltages, as currents
7 are lower by similar magnitudes.
8
- 9 • Line losses are approximately linear with respect to the length of circuits.
10
- 11 • Power system losses vary with respect to temperature: total and average losses
12 decline under lower ambient temperatures, other factors constant.
13

14 Most importantly, thermal losses can change dramatically with respect to changes in load
15 level and flow configuration on circuits.
16

17 In addition to changes in the level and variability of losses upon completion of the Muskrat
18 Falls project, and the conversion of Holyrood, there will be a change in the way losses are
19 recorded. Currently the losses associated with Holyrood are netted out by reducing the
20 Holyrood conversion factor, thereby altering energy cost. These energy-related losses will
21 be reduced while, at the same time, LIL losses will be introduced. As noted, depending on
22 how the LIL is functionalized, these losses may be partly demand-related.
23

24 **Recommendations**

25 Following the in-service date for MF and its associated transmission links, Hydro's loss
26 levels, patterns, and variability will change significantly, requiring that Hydro abandon its
27 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.

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

8

9 **5. Other Issues**

10 **5.1 Rural Deficit**

11 **Issue.** Hydro charges its rural customers at rates either equal to or partially reflective of the
12 rates of Newfoundland Power. These rates fail to cover Hydro’s cost of service, which tends
13 to be high in isolated locations. Hydro makes up the deficit with supplementary volumetric
14 charges on Newfoundland Power and Rural Labrador Interconnected System (“Rural LIS”)
15 customers. The methodology of deficit allocation was reviewed in the 2013 GRA and the
16 Board approved the use of a “revenue requirement” method as proposed by Hydro. Page
17 105 of Order No. 49 (2016) states: “The Board expects that Hydro will address the rural
18 deficit allocation methodology in its cost of service report and all parties will have a further
19 opportunity to have input as part of the review of that report.”⁵⁰ This section undertakes
20 that review task.

21

22 **Background.** Subsidizing rural customers has been a longstanding feature of service in the
23 Province, and the practice of subsidizing small numbers of customers in remote locations is
24 common in other provinces of Canada. In the Province of Newfoundland and Labrador, the
25 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.

1 responsibility has been borne by some of Hydro’s non-rural customers. The customers
2 benefiting from the subsidy are found in four groups: Island rural interconnected (about
3 22,900 customers) Island isolated (about 800) Labrador isolated (about 2,700) and L’Anse
4 au Loup (about 1,000) totaling about 27,400 customers.⁵¹

5

6 The cost burden of the rural deficit is allocated to NP and to Labrador Interconnected
7 customers, Island industrial customers having been exempted from responsibility in 1999.⁵²

8 The Electric Power Control Act mandates that these two customer groups fund the subsidy,
9 but does not prescribe how it is to be allocated.⁵³ Until recently, the allocation was based

10 on an “equal unit cost” allocation mechanism developed in 1993 by the Board’s witness,
11 Mr. George C. Baker.⁵⁴ Under this mechanism, Hydro classified the deficit total among
12 demand, energy and customer categories based on the total costs in each classification for
13 the NP and Labrador Interconnected rural customers combined. The classified amounts of
14 the deficit were then applied to the combined groups’ unit costs for each classification to
15 determine the deficit share for each of the two groups of customers. Essentially, this
16 approach has been viewed as allocating the deficit using a mini-COS study.

17

18 The difficulty with this approach is that it allocates relatively large amounts per customer to
19 Labrador customers (who are significantly higher users of energy than Island customers,
20 chiefly due to relatively colder weather and consequent heavy use of electric heating). This
21 approach produced much higher revenue/cost (“R/C”) ratios for Rural LIS customers than
22 for NP—1.42 vs. 1.12—as revealed by Hydro’s recent analysis in 2013.⁵⁵

23

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.

1 Hydro analyzed the impact of this approach in response to customer concerns about the
2 impact of the resulting charge, and concluded that it was sensible to modify the approach.
3 After considering options, the utility selected a revenue requirements-based allocation
4 whose purpose is to equalize R/C ratios, and whose effect is to shift the deficit burden in
5 the direction of NP customers and away from Labrador Interconnected customers. The
6 Board approved the change to the new approach as of January 1, 2014 in its decision P.U.
7 49(2016). The resulting target R/C ratio in the 2017 GRA application for 2019 is 1.15 for
8 both classes.⁵⁶

9

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

16

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

25

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.

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

7
8 The 2013 GRA process resulted in commentary on Hydro's analysis and proposed change.
9 Most intervenors, and the Board's consultant, Mr. John Wilson, supported a change. The
10 exception, Mr. Larry Brockman, representing NP, felt that the change was unwarranted and
11 that the mini-COS methodology was sound.⁵⁸ Another intervenor, Dr. James Feehan,
12 participating on behalf of several Labrador towns, suggested four alternative approaches to
13 allocating the rural deficit, including one similar to Hydro's customer-based alternative.⁵⁹
14 In the absence of a cost-causative criterion for allocation of the rural deficit, or of a single
15 best indicator of fairness, the choice of an allocator may be influenced by criteria such as
16 simplicity and by acceptability of outcome to stakeholders. These criteria place the equal
17 unit cost method at a disadvantage on both counts.

18
19 Hydro's revenue requirements method has the virtue of simplicity of computation and
20 comprehensibility of outcome, relative to its predecessor, the equal unit cost method. The
21 revenue requirements method also avoids the apparent problem of significant differences
22 in R/C ratios that arises with the equal unit cost method, and the consequent price
23 distortions away from unit cost that arise with R/C ratios of 1.42 for rural Labrador
24 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. 71ff.

⁵⁹ Dr. J. Feehan, *op. cit.*, pp. 7-10.

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

9

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

18

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

24

25 Hydro's revenue requirements approach appears well suited to manage the transition
26 process that will occur beginning in 2020 and provide effective guidance in allocation of the
27 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.

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

8

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

14

15 **5.2 Conservation and Demand Management**

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

21

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

25

26 A second issue arises from Hydro's and Newfoundland Power's (NP's) separation within the
27 Island jurisdiction but enjoyment of shared benefits from each other's CDM activities. Hydro
28 plans its CDM activities in conjunction with NP. NP customers pay their own CDM costs and
29 are also charged for some Hydro CDM costs. Thus, there may be a concern about NP's

1 customers being allocated more than a reasonable share of the overall CDM expenses
2 incurred by Hydro and NP.

3

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

6

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

13

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

21

22 Deferral appears to play two roles. It distributes revenue recovery over a period in which
23 the conservation measures are most likely to be affecting consumption and smooths the
24 time pattern of cost recovery should expenditures vary significantly across years. The use of
25 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.

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

7
8 Hydro does not have to specify formally how its CDM program costs are functionalized or
9 classified, as they are removed from the COS study. However, some indication of the
10 utility's attitude regarding the purpose of CDM programs can be gleaned from the
11 documentation related to the 2013 GRA. Hydro has promoted conservation programs
12 whose focus appears to be overall energy conservation, as opposed to peak demand
13 reduction.⁶⁵ Additionally, energy savings from CDM programs in the past have been seen as
14 reducing production from the Holyrood thermal generating station.⁶⁶

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

⁶³Newfoundland and Labrador Hydro, *2013 Amended General Rate Application*, Vol. I, Rates Schedules, p. 18 of 46.

⁶⁴Newfoundland 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.

1 Additionally, NP has its own CDM expenditures, which it recovers from its customers
2 through its customer rates. Thus, NP customers pay the NP CDM costs and are also
3 allocated some of Hydro’s CDM costs.⁶⁸
4

5 **Discussion/Analysis.** Regarding CDM cost classification, CDM expenses are not caused
6 directly by the traditional cost causative factors (customer numbers, energy consumption,
7 or peak demand). However, they might be classified in terms of the costs that they intend
8 to avoid. CDM programs are initiated typically by planners who seek to secure customer
9 assistance in limiting the growth of total energy consumption or peak demand over time.
10 One could, potentially, review each CDM program individually and determine whether its
11 focus is overall energy reduction or peak demand reduction or some combination, and then
12 classify costs on that basis.
13

14 Views reported by experts during the 2013 GRA suggest that Hydro’s focus has been
15 exclusively on energy reduction. For example, Lummus Consulting, in its 2013 review of COS
16 methodology stated that, “the justification of the Utilities’ CDM programs has been on
17 system energy savings that benefit all customers on the Island interconnected System.”⁶⁹
18 There are no Hydro programs currently designed to reduce system peak.”⁷⁰ If true, this
19 objective helps to justify an energy-only cost classification scheme, and the use of an energy
20 allocator in some form, at least for the present. This perspective may not hold for the
21 future, of course, and Hydro should not feel constrained to engage in conservation practices
22 that save energy but do not focus on peak demand. One possible consideration along these
23 lines is the development of new service requests in Labrador. If these are expected to press
24 capacity, then peak demand-focused CDM programs may prove beneficial.
25

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.

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

17

18 For past programs, classification of CDM programs as energy-only and allocation on the
19 basis of annual usage appears to have matched program objectives. In the future, if
20 capacity-directed programs are initiated and are perceived to be material in size of outlay,
21 Hydro might want to classify new program costs based on their purpose and then allocate
22 the demand and energy components to class on the basis of its generation allocators, since
23 the programs arguably will delay generation expense predominantly. (If the utility elects to
24 pursue marginal cost-based cost allocation, then CDM costs could be allocated in this
25 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. 7ff.

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.

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

6
7 PUB expert John Wilson argues that Hydro should modify its CDM allocation approach to
8 avoid double-counting involved in NP's CDM allocation.⁷⁴ He proposes excusing NP from the
9 initial allocation while retaining the rural deficit-based reallocation. By his computation,
10 more than \$300,000 of CDM costs would shift from NP to Island Industrial customers.

11
12 It is useful to ask how costs would be allocated were the Province served by a single utility.
13 Combined CDM costs would either be directly assigned by program to their target classes or
14 perhaps classified to energy and allocated by means of annual energy. The two utilities are
15 collaborating in conservation planning, having produced one planning document and
16 pledged to develop a successor.⁷⁵ This process yields agreed-upon programs and CDM
17 outlays but preserves the current payment structure in which each utility recovers its costs
18 from its customer base. However, an agreement on pooling costs for recovery through
19 Hydro would address Dr. Wilson's concerns.

20
21 Regarding the possible impact of the Muskrat Falls project completion, conservation
22 expenditures will serve not only to reduce energy use and postpone the need for new
23 capacity, but to enable increased exports. Ideally, Hydro and NP will jointly plan CDM
24 program scale to optimize use of system resources to manage peak demand, with the
25 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.

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

5

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

11

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

16

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

20

21 **5.3 Specifically Assigned Charges**

22 **Issue.** Four Island Industrial Customers are assigned a number of specific charges because
23 each of the customers is served by assets that are deemed to serve them alone.⁷⁶ The
24 central issue, identified in the 2013 GRA, pertains to the allocation of O&M costs. Currently
25 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).

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

3

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

12

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

19

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

25

26 **Analysis.** Some US jurisdictions deem virtually all transmission assets, including connections
27 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.

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

9

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

19

20 The utilities engaging in direct assignment do not appear to have a single dominant
21 approach to the treatment of O&M related to these dedicated transmission facilities. Large
22 Canadian and U.S. utilities often bundle these costs with other transmission costs and
23 allocate such common costs using the utility's transmission cost allocator. Xcel Energy in
24 Minnesota simply allocates all its transmission-related O&M costs on the basis of the CP
25 allocator that it uses for transmission expenses generally. This approach is arguably less
26 precise in allocating O&M costs to direct assignment customers but likely avoids swings in
27 O&M charges to those customers in response to equipment upgrades.

28 Other large utilities develop a means of sharing directly assigned costs across direct
29 assignment customers, with sharing usually based on original asset cost. Smaller U.S. firms

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

3

4 Direct assignment of transmission assets is not widespread, but Hydro may fit the pattern of
5 having significant assignable assets. The Industrial customers with directly assigned
6 transmission assets consume about 9% of Island sales at present and are assigned a little
7 more than 11% of transmission assets in 2015.⁷⁹

8

9 One customer, (Vale) responsible for roughly \$500,000 of directly assigned costs for the
10 2015 Test Year, proposed an improvement to the determination of O&M charges. Their
11 expert, Mr. Melvin Dean, advocated and set out the steps for development of allocation
12 based on current cost.⁸⁰ This technique makes use of Handy-Whitman indexes, which are
13 available for sufficiently detailed segments of the electric utility industry to produce reliable
14 cost indexation over many years.

15

16 Hydro investigated this approach and found it to be feasible.⁸¹ The utility also found that
17 the outcome of its calculations confirmed Mr. Dean's belief: the relatively newer
18 transmission assets directly assigned to customers, when compared with other transmission
19 assets, produced a reduced O&M cost allocation for the direct assignment customers.⁸² In
20 its 2017 GRA, Hydro proposed to implement this change beginning January 1, 2018.⁸³ The
21 Handy-Whitman approach was subsequently agreed upon in the 2017 GRA Settlement
22 Agreements and awaits Board approval.⁸⁴

23

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. 3ff.

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.

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

7
8 Critics might object that even test year dollar valuation may not capture the full impact of
9 age. Two identical transmission lines, one built in 2015 and another built in 2005 might have
10 the same 2015 dollar value, but the ten-year-old line would likely be associated with higher
11 O&M costs. Attaining this degree of accuracy in an index would require knowledge of the
12 relationship of O&M cost to vintage, which would be very challenging.

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

19
20 In response to an inquiry by the PUB, Hydro investigated whether the customer-specific
21 billing of actual expenses would be feasible or cost effective.⁸⁵ The utility found that it
22 would not be costly to record separately the costs of transmission O&M on dedicated
23 transmission lines for the Industrial customers with specifically assigned assets, and intends
24 to implement this approach in 2018. However, Hydro also noted that it would be a
25 challenge to prepare a specifically assigned charge for submission with each GRA based on
26 forecasted annual O&M costs. Discrepancies between actual and forecasted costs would

⁸⁵ PUB-NLH-078.

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

4

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

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

20

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

1

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

12

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

16

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

20

21 **5.4 Capacity Assistance Agreements**

22 **Issue.** Like many other utilities, Hydro makes use of non-firm load contracting to provide
23 potential capacity at times of low reserves. Hydro obtains capacity from Island Industrial
24 customers via curtailment and, in two cases, provision of energy and capacity from
25 customer site generation. In its COS study, Hydro makes provision for forecasted capacity
26 assistance payments as part of its purchased power. The issue for Hydro is whether such
27 contracts and payments should continue to exist after Muskrat Falls enters service. This is
28 essentially a rates question, but there is an underlying question as to how capacity

1 assistance should be represented in COS in order to ensure recovery of whatever cost is
2 incurred in the future.⁸⁶

3

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

10 Each agreement provides Hydro with purchased power upon request, with the number and
11 frequency of requests limited by the contract. Customers receive a credit of approximately
12 \$28 per kW-year to make their capacity available under the contracts' terms.⁸⁷ Customers
13 also receive payments for energy actually provided at times of capacity requests.

14

15 These capacity assistance agreements are part of a broader effort to control peak demand
16 growth. Hydro has also recently implemented an interruptible service agreement for the
17 2018-2019 winter season with a large General Service customer on the Labrador
18 Interconnected System. The customer receives a fixed credit of approximately \$10 per kW-
19 winter month for 4 months to make their capacity available under the contract terms.

20

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

24

25 The CBPP contracts, which dominate the capacity assistance agreements, deserve specific
26 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.

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

11

12 Prior to the winter of 2014/2015, Hydro entered into Capacity Assistance and
13 Supplementary Capacity Assistance agreements with CBPP⁹¹. Hydro has proposed an
14 Amended and Restated Agreement for 105 MW for the 2018-19 winter season. Under these
15 arrangements, on rare occasions the facility will continue to provide emergency capacity to
16 the grid.⁹² This is achieved through load interruption of up to 105 MW at the Corner Brook
17 mill when system generation reserves are low⁹³. As noted above, Hydro compensates CBPP
18 for services under these arrangements through fixed winter fees and usage payments.

19

20 **Discussion/Analysis.** Hydro's treatment of its agreement-related demand in COS appears to
21 provide sensible underpinning for cost recovery. The approach of classifying capacity
22 payments as demand-related and allocating costs on a standard CP basis reflects the theory
23 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.

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

5

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

14

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

19

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

25

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

1

2 **5.5 Newfoundland Power Generation Credit**

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

8 **Background.** Hydro's current COS methodology credits NP for making its generation
9 available to reduce its contribution to the Island Interconnected system peak. The credits
10 reduce NP's net peak demand, thereby reducing the demand charge under the terms of
11 Hydro's Utility tariff. NP annually demonstrates its ability to run its generation to meet the
12 capacity credit reflected in Hydro's COS study and in the Utility tariff. In the 2017 GRA, the
13 2019 Test Year reflects a generation credit, adjusted for reserves, of 118 MW, of which
14 83 MW is for hydraulic capacity and 35 MW is for thermal generation. The result of this
15 approach is that NP's minimum billing demand is computed as maximum native load less
16 these two credited amounts.^{94,95}

17

18 Hydro dispatches these two types of generation units and includes them in its system
19 planning. NP maintains the units and its customers pay the costs of the units, with Hydro
20 contributing to the cost coverage via its demand credits. The result of the credit, then, is
21 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.

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

3

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

10

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

17

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

27

28 Second, consider a situation in which the Hydro demand discount is terminated and Hydro
29 and NP enter into a power purchase agreement in which Hydro purchases all the usage of

1 the plants. Under this arrangement, NP would not be able to use its generation to reduce
2 the peak demand established by its customers. NP's allocation of demand costs would rise
3 with the loss of the discount, but NP would be reimbursed for hydraulic water value, fuel (as
4 it is now) and capacity payments for availability. Those capacity payments would perhaps be
5 market-based, but more likely would be valued at Hydro's estimate of capacity value in the
6 presence of transmission constraints. In brief, higher bills from Hydro would be offset, in
7 whole or in part, by increased payments for use of the plants.

8

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

18

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

25

26 **5.6 Export Revenues/Credits**

27 **Issues.** The cost of the Muskrat Falls project and the associated anticipated increase in rates
28 to defray this cost has raised a number of issues regarding how net export revenues should
29 be treated, since the project creates an enhanced opportunity for Hydro to earn additional

1 revenues through expanded exports. The first issue is whether all customers should receive
2 the rebate or whether it should be restricted to the customer classes that will pay for the
3 Muskrat Falls project. Second, Hydro faces the issue of how to treat the rebate in the cost of
4 service and then how to provide it through rates and/or a rider. Third, within COS, the issue
5 arises as to how to classify and allocate net export revenues.

6

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

13

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

18

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

24

25 However, others may argue that exports are derived from the exportable surplus of the
26 entire utility and that the actual source of power to support individual export contracts
27 cannot be determined. The relatively low prices of Labrador customers and the subsidies
28 provided to rural customers suggests that rebates to these groups might seem unfair to
29 other customers or might create rate reductions where marginal prices are below marginal

1 cost. While reasoning on the basis of outcome is not desirable in COS methodology, the
2 absence of a theoretical basis for rebates suggests that reference to rate impacts might be
3 sensible.

4

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

10

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

18

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

28

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

8

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

16

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

20

21 BC Hydro engages in exports and imports at varying times of the day and seasons of the
22 year. The utility has a wholly-owned subsidiary, Powerex, through which it conducts all its
23 export transactions. BC Hydro earns income on its sales to Powerex and on other surplus
24 sales, and then reaps net income from Powerex activity (margins on sales and purchases in
25 wholesale markets). The utility classifies sales to Powerex and other surplus sales as being
26 100% energy-related and allocates these revenues to its customer classes on the basis of
27 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.

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

4

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

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

19

20 Hydro-Quebec’s experience is slightly different from that of the other two utilities. As
21 mentioned, this utility has separate subsidiaries for its three main functions. Hydro-Quebec
22 Production (“HQP”) manages generation and wholesale sales while Hydro-Quebec
23 Distribution (“HQD”) undertakes retail sales. HQD purchases all its energy from HQP, paying
24 a weighted price for a combination of inexpensive heritage generation and more expensive
25 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.

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

5

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

12

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

16

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

20

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

26

Appendix A:
Summary of Recommendations

1 **System Definition**

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

6

7 **Generation**

- 8 • We recommend that Hydro introduce marginal cost-based allocation of embedded
9 generation costs for the Island Interconnected system beginning with the institution
10 of rates that recover revenue to cover payments by Hydro for Muskrat Falls and its
11 associated transmission facilities. This change will avoid the need to classify each
12 generation asset or cost on its own and relates cost to serve to an objective market-
13 based value of generation services that recognizes cost to serve by each rate class in
14 each hour. It appears that Hydro can undertake this approach, as the utility already
15 possesses the costing capabilities to generate the requisite marginal cost scenarios.
- 16
- 17 • Marginal cost-based allocation can be used in the Labrador Interconnected system
18 as well following the Muskrat Falls in-service date. Marginal cost forecasts will be
19 produced by the same process as used for the Island Interconnected system.
- 20
- 21 • If marginal cost-based cost allocation of generation is not immediately adopted for
22 the period after the Muskrat Falls in-service date, the current system, as modified,
23 could be retained after the transition. We recommend in that case that Hydro
24 undertake classification of Muskrat Falls costs via the equivalent peaker
25 methodology. It appears that this approach might prove more in line with
26 generation planning practice, and might better reflect the base load role of the unit
27 than would an SLF approach.

- 1 • Regarding generation cost allocation in the event that marginal cost-based allocation
2 is not adopted, we recommend that Hydro consider an allocator that makes use of
3 peak demand data in periods of extreme cold, such as the 1 CP – top 50 hours
4 approach of Manitoba Hydro. This approach requires forecasts that make use of
5 historical hourly data, but it avoids reliance on a single hour. That said, Hydro’s
6 current 1 CP approach can be retained assuming that the utility is confident that
7 such a measure reliably produces allocator shares that are close to a measure that
8 makes use of many hours.
9
- 10 • After Holyrood is converted into the role of synchronous condenser, the plant
11 should be sub-functionalized as transmission and its costs allocated in the same
12 manner as general-purpose transport facilities (described in the next section). The
13 reduced fuel costs should continue to be allocated on the basis of energy.
14
- 15 ○ If the plant does not immediately come to be used as a synchronous
16 condenser, then it should be retained as generation and functionalized
17 according to marginal cost-based cost allocation. In the event that marginal
18 cost-based allocation is not immediately adopted and the plant is still treated
19 as generation, then the equivalent peaker method or the current capacity
20 factor methodology, altered by the use of forecast-only capacity factors,
21 would suffice.
22
- 23 • We recommend that wind resources be allocated in the same manner as other
24 generation facilities if marginal cost-based cost allocation is adopted. If not, then we
25 recommend that Hydro adopt a classification method based on Hydro planners’
26 forecasts. As a result of interconnection with eastern North American, Hydro’s
27 forecasts now indicate that wind generation contributes to the ability to meet peak
28 demand and should therefore be classified as about 20% demand-related.

1 **Transmission**

2 Capacity Costs

3 *Sub-functionalization*

- 4 • **Generator Interconnection Facilities.** Hydro should continue to assign
5 (functionalize) to generation the costs of generator interconnection facilities.
6
- 7 • **General Purpose Transport Facilities and Terminal Stations.** General purpose
8 transport facilities and terminal stations should be assigned to the transmission
9 function.
- 10
- 11 ○ The converter facilities located at the Muskrat Falls and Soldiers Pond
12 stations should be functionalized in the same manner as the LIL facility.
13
- 14 • **Special Purpose Transmission Facilities.** The special purpose facilities which
15 comprise the LTA should be assigned to the generation function due to their role in
16 facilitation of efficient use of hydro facilities along the Churchill River, including the
17 Churchill Falls and Muskrat Falls stations. We recommend that the LIL facility,
18 including its converter facilities, be functionalized as generation, in harmony with
19 the formal cost designation of the facility as providing service to the Island.
20

21 *Classification and Allocation*

- 22 • **Generator Interconnection Facilities.** We recommend that Hydro classify and
23 allocate the costs of Generator Interconnection Facilities in the same manner as
24 their related generation facilities.
25
- 26 ○ If Hydro adopts marginal cost-based allocation of embedded generation
27 costs, then marginal costs would apply to the financial costs of generator
28 interconnection as well.

- 1 ○ If Hydro retains its existing allocation methods, we recommend that Hydro
2 assign interconnection facilities costs with each specific generator and
3 allocate costs in the established manner.
4
- 5 • **General Purpose Transport Facilities.** We recommend that Hydro retain the
6 demand-only classification approach due in part to the absence of an analytically
7 preferable or cost-effective alternative, and partly to its acceptance by system
8 planners of its ability to approximate their thought processes.
9
- 10 • Demand-related costs should be allocated based on one of the three methods
11 proposed.
12
- 13 ○ The Peak Load Frequency and Pro Rata Peak Load Distribution methods offer
14 improved accuracy and stability over time, as well as an hourly analysis
15 approach similar to that recommended for generation cost allocation.
16 However, they require more analysis than the traditional CP method.
17
- 18 ○ If the traditional CP method is selected and used for generation classification
19 as well, we recommend that Hydro retain its traditional 1 CP approach, for
20 reasons of harmonization with generation classification, and despite its
21 statistical limitations.
22
- 23 • **Terminal Stations.** The charges on capital and O&M costs (revenue requirements)
24 associated with Terminal Stations should be allocated to peak loads, determined
25 according to one of the methods listed above.
26
- 27 • **Special Purpose Transmission Facilities.** Assuming that the LTA is functionalized as
28 generation, we recommend that its costs be classified and allocated in the same
29 manner as other generation assets.

- 1 ○ If the Lil is functionalized as generation as well, it should be treated in the
2 same fashion as the LTA.
3
4 ○ If, instead, the LIL is functionalized as jointly generation and transmission,
5 the generation component can be classified and allocated in the same
6 manner as Muskrat Falls. The transmission component would then be viewed
7 as general purpose transmission facilities and classified and allocated in the
8 approved manner for transmission.
9

10 Line Losses (Transmission Energy Costs)

- 11 • Following the in-service date for MF and its associated transmission links, Hydro's
12 loss levels, patterns, and variability will change significantly, requiring that Hydro
13 abandon its historical average losses for the cost of service. Hydro should estimate
14 average losses either via observations of the difference between hourly generation
15 and metered loads or with load flow analysis. Load flow study results can then be
16 utilized to parameterize a losses algorithm based on the well-known I^2R
17 approximation. The algorithm is directly applicable to the hourly loads utilized within
18 COS studies, including energy and demand loss factors.
19
20 • Once sufficient historical experience under the restructured resources has accrued—
21 say, two years—Hydro can again utilize observed metered loads as the basis for
22 estimating line losses (transmission energy costs).
23

24 **Other Issues**

25 Rural Deficit

- 26 • We recommend that Hydro adopt its proposed allocation method based on revenue
27 requirements. The criterion of equalizing R/C ratio across regions and the
28 concomitant avoidance of price distortion appear to be desirable features of this

1 approach. The relative simplicity of the calculation method, when compared with
2 the existing approach, is an additional advantage.

3

4 Conservation and Demand Management

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

10

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

15

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

19

20 Specifically Assigned Charges

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

25

26 Capacity Assistance Agreements

27 • We recommend that Hydro retain a contracting structure such as capacity assistance
28 agreements as a valuable step in securing capacity at times of shortage. We also

1 recommend that Hydro retain its approach to capacity assistance agreement
2 payment classification and allocation in its COS methodology.

3

4 Newfoundland Power Generation Credits

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

11

12 Export Revenues/Credits

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

16

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

21

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

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

AND IN THE MATTER OF an Application by Newfoundland and Labrador Hydro ("Hydro") for approval of revisions to its Cost of Service Methodology pursuant to Section 3 of the EPCA (the "Cost of Service Methodology Application") for use in the determination of test year class revenue requirements reflecting the inclusion of the Muskrat Falls Project costs upon full commissioning.

AFFIDAVIT

I, Kevin Fagan, of St. John's in the Province of Newfoundland and Labrador, make oath and say as follows:

1. I am Director, Regulatory Affairs of Newfoundland and Labrador Hydro, the Applicant named in the attached Application.
2. I have read and understand the foregoing Application.
3. I have personal knowledge of the facts contained therein, except where otherwise indicated, and they are true to the best of my knowledge, information and belief.

SWORN at St. John's in the)
Province of Newfoundland and)
Labrador, this 15 day of)
November 2018, before me:)



Barrister – Newfoundland and Labrador



Kevin Fagan