Q. **NLH Evidence, Section 5.2, page 5.6**

Citation:

Nalcor's June 23, 2017 project update stated that average island residential electricity rates would increase to 22.89 cents (¢) (plus HST) per kilowatt hour (kWh) in 2021.

a) Did Hydro assist Nalcor in making this rate projection?

b) If so, does Hydro adopt this projection of average island 2021 electricity rates as its own?

c) If not, has Hydro carried out analyses of the impacts of the integration of the Muskrat Falls Project on Island Interconnected System rates? If so, please provide copies of these analyses.

d) If Hydro has not carried out analyses of the impacts of the integration of the Muskrat Falls Project on Island Interconnected System rates, please explain why it has not done so, and/or when it intends to do so.

e) Did Nalcor also make a projection for Labrador residential and general service rates? If so, please provide it, along with copies of the underlying analyses.

A. a) Hydro provided inputs, such as the existing rates and the load forecast, for Nalcor to use in developing the average residential rate projection.

b) Hydro does not adopt the projection of average island residential electricity rates as its own, as the rate projection was developed by Nalcor. However, Hydro has no reason to consider the rate projection to be unreasonable.

c) Since the previous GRA, Hydro has been preparing for the integration of Muskrat Falls Project costs into customer rates.

On March 31, 2016, Hydro filed its Cost of Service Methodology Review Report with the Board. The report provides options for the Board to consider in allocation of Muskrat Falls Project costs to customer classes. The report also provided illustrative effects on allocated revenue requirements and unit cost of supply from Hydro for the Island Interconnected System post Muskrat Falls commissioning.[1] The Cost of Service Methodology Review filing is provided as LAB-NLH-021, Attachment 1.

Hydro also submitted two reports to the Board with respect to the system marginal costs post-commissioning of the Muskrat Falls Project. Marginal costs are an important element in developing customer rates. Part I of Hydro's marginal cost report focuses on methodology. The discussion provides a detailed review of methodology options, and identifies the methods that are being adopted by Hydro for purposes of estimating marginal cost. The Marginal Cost Report Part II further discusses methodology and provides marginal cost estimates for the Hydro power system. LAB-NLH-021, Attachment 2 provides Part I of the Marginal Cost Study report and LAB-NLH-021, Attachment 3 provides Part II of the Marginal Cost Study report.[2]

On June 15, 2016, Hydro filed a Rate Design Review report with the Board which was prepared by Christensen Associates Energy Consulting and reviewed the rate structure options to apply to Newfoundland Power and Island Industrial

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[1] The Cost of Service Methodology Review Report filed on March 31, 2016, assumed that Muskrat Falls commissioning would be in 2019. It was also based on a total Muskrat Falls Project construction cost of $7.652 billion, plus interest and other carrying charges for a total cost of approximately $9.4 billion.

[2] Part I of the marginal cost study report was filed December 29, 2015 and Part II of the marginal cost study report was filed February 26, 2016.

Customers, giving consideration to generally accepted rate design practices, the Muskrat Falls Power Purchase Agreement, and the Transmission Funding Agreement. LAB-NLH-021, Attachment 4 provides the Rate Design Review report.

On June 15, 2016, Hydro also submitted a Supply Cost Recovery Mechanism Review report to the Board providing a review of the requirements for regulatory mechanisms to deal with variability in supply costs post Muskrat Falls Commissioning. LAB-NLH-021, Attachment 5 provides the Supply Cost Recovery Mechanism Review.

d) Please refer to Hydro's response to part c. Hydro also plans to update its detailed revenue requirement projections in the Cost of Service Methodology review, planned for 2018.

e) In the Cost of Service Methodology Review report, Hydro recommended the cost of service and rates for the Labrador Interconnected System continue to be separate from the Island Interconnected System. Hydro did not prepare a projection of the rates for Labrador interconnected customers that would apply post Muskrat Falls commissioning. Rate changes for customers on the Labrador Interconnected System will depend, to a large extent, on when additional transmission system expansion is required on the Labrador Interconnected System. The requirement for additional transmission is currently under review.

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March 31, 2016

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 Report

Further to the Settlement Agreements to the 2013 GRA, enclosed please find the original and 12 copies of Newfoundland and Labrador Hydro's Cost of Service Methodology Review Report.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Tracey Pennell

Tracey L. Young
Legal Counsel

TLP/bs

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy - Stewart McKelvey Stirling Scales
Thomas J. O'Reilly, Q.C. - Cox & Palmer
Dennis Browne, Q.C. – Browne Fitzgerald Morgan & Avis
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NEWFOUNDLAND AND LABRADOR HYDRO

COST OF SERVICE METHODOLOGY REVIEW REPORT

March 31, 2016

Table of Contents

1.0 BACKGROUND

The completion of the Muskrat Falls Project and the ensuing interconnection of the Island Interconnected System with Labrador will result in a major change in the source of supply of electricity to the Island. For many years, load growth on the Island Interconnected System has been supplied by the Holyrood Thermal Generating Station (Holyrood).[1] Upon the commissioning of the Muskrat Falls Project, supply cost payments will commence under the Transmission Funding Agreement (TFA) and Muskrat Falls Power Purchase Agreement (PPA), and the role of Holyrood as a generating station will be phased-out.

The replacement of fuel costs with supply cost payments to cover the cost of transmission and generation assets has created the need to review the appropriate functionalization, classification and allocation of supply costs among customer classes. At present, fuel costs from Holyrood comprise the largest single portion of the supply costs incurred by Newfoundland and Labrador Hydro (Hydro). Over the past three GRAs, approximately 85%-90% of the revenue requirement related to Holyrood was classified as energy-related costs.[2]

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 General Rate Application (GRA) to conduct a Cost of Service Methodology review prior to its next GRA. The Settlement Agreements to the 2013 GRA requires Hydro to file a Cost of Service Methodology Review Report with the Board of Commissioners of Public Utilities (the Board) by March 31, 2016.

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:

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[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, 90% and 88% 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 85% of overall Holyrood costs would be classified as energy-related.

> *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.*

The Parties also agreed 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.

Hydro has engaged Christensen Associates Energy Consulting (CA Energy Consulting) to conduct the methodology review. The CA Energy Consulting report is provided as Appendix A to this report.

2.0 LEGISLATIVE IMPACTS

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

Legislative impacts include: (i) the establishment of rates for rural customers that result in an annual deficit in recovery of the cost of serving those customers (the Rural Deficit); (ii) the recovery of the Rural Deficit from customers of Newfoundland Power and Hydro Rural customers on the Labrador Interconnected System (and the exclusion of Industrial Customers from the funding of the deficit); (iii) the establishment of a Labrador Industrial Rates Policy to promote the development of industrial activity in Labrador; (iv) the requirement for the cost of supply from Muskrat Falls[3] including the Labrador Island Link (LIL)[4] and the Labrador Transmission Assets (LTA)[5] to be recovered in full through Island Interconnected rates with no explicit provision requiring the value of export sales related to Muskrat Falls generation to be credited back to ratepayers to offset the cost of supply from Muskrat Falls. However, the current Government has indicated that export sales will be used to mitigate potential increases in electricity rates.[6]

Following the commissioning of the Muskrat Falls Project, Newfoundland and Labrador will have an inter-provincial transmission system fully interconnected with Quebec, Nova Scotia, and the broader North American electric grid. This development gives rise to the obligation for Hydro and its affiliated transmission owners to provide open, non-discriminatory access to transmission service on transmission lines used for inter-provincial trade by third parties. This requirement is established by the Federal Energy Regulatory Commission, or FERC, which is an independent agency that regulates the transmission of electricity in the United States. In order to meet the FERC requirement of reciprocity, Hydro must provide comparable open access to transmission service over the interprovincial transmission system within Newfoundland and Labrador.

From a cost of service perspective, FERC requires that Hydro record its transmission costs in a manner that can be used in the determination of open access transmission tariffs. The required process for the approval of transmission tariffs is not yet established.

The cost of service implication of each item is discussed further in the following sections.

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[3] Muskrat Falls refers to the hydroelectric facilities of the Muskrat Falls Project.
[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 letter from the Premier to the Minister of Natural Resources dated December 14, 2015.

2.1 Rural Deficit

The *Electrical Power Control Act* (the EPCA) permits the Provincial Government to provide direction to the Board and Hydro with respect to the setting and subsidization of rural rates.[7] OC2003-347 provides direction to the Board with respect to the establishment of Hydro's Rural Rates.[8]

The EPCA also provides an exemption for Industrial Customers from being required "*to subsidize the cost of power provided to rural customers in the province*".[9]

2.2 Labrador Industrial Rates Policy

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

Under the Labrador Industrial Rates Policy, the generation costs in the Labrador Industrial Rates are established outside the purview of the Board. The transmission costs reflected in the Labrador Industrial Rates are approved by the Board; this approval is expected to occur through a general rate proceeding.[11]

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

[7] See Section 5.1(1) of the *EPCA*.
[8] See response to request for information PUB-NLH-077 provided in Hydro's 2013 General Rate Application.
[9] See Section 3.0(iv) and 5.1(1) of the *EPCA*.
[10] See Section 3.0(v) and 5.1(1) of the *EPCA*.
[11] See Section 5.8(2) of the *EPCA*.

2.3 Recovery of Muskrat Falls Costs

In OC2013-343, Government provided a directive setting forth the requirement for the cost of supply from the Muskrat Falls Project (including the Labrador Island Link and the Labrador Transmission Assets) to be recovered in full through Island Interconnected rates charged to the appropriate classes of ratepayers.[12] This Government direction exempts customers on the Labrador Interconnected System from paying costs related to the Muskrat Falls Project.

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

2.4 Export Sales

Given the policy of the current Government is to use revenue from surplus power sales to mitigate potential increases in electricity rates, Hydro considers it appropriate to recommend an approach to deal with the value to customers of export sales in the Cost of Service Methodology Review.

3.0 COST OF SERVICE RECOMMENDATIONS

3.1 Transition to Muskrat Falls Project Commissioning

Hydro is required to file its next GRA at the end of the first quarter in 2017 based on a 2018 Test Year. To ensure that rates provide reasonable cost recovery beyond one year, Hydro may need to include two test years in its next GRA application.

[12] 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.

For the purposes of the Cost of Service Methodology Review, Hydro has assumed that supply costs from the Muskrat Falls Project will be reflected in the 2019 costs for the full year. However, Hydro is not required to pay the costs of the Muskrat Falls Project until the entire project is commissioned (i.e., generation and transmission assets are fully commissioned). In the event that the new transmission assets are providing service from off the Island in advance of project commissioning, Hydro may have the opportunity to purchase energy to reduce generation at Holyrood.

To reflect this possibility in 2018, Hydro proposes that the existing cost of service methodology be used for the 2018 Test Year with the following two modifications:

(i) All forecast power purchase costs incurred to reduce Holyrood fuel costs should be classified as energy. These may include: Recall power from the Upper Churchill; pre-commissioning power from Muskrat Falls resulting from the availability of the LIL; or imports over the Maritime Link.

(ii) The Holyrood capacity factor used in classification of fixed assets for 2018 should be based on the forecast capacity factor for 2018 rather than the historical 5-year average currently approved in the existing Cost of Service methodology.

3.2 Post Muskrat Falls Project Commissioning

Based on the report of CA Energy Consulting, Hydro makes the following recommendations.

3.2.1 Systemization

Hydro proposes to maintain separate cost of service studies for the Labrador interconnected System and the Island Interconnected System.

3.2.2 Functionalization

(i) Hydro recommends no changes in the functionalization of existing generation and transmission assets with the exception of transmission line TL-248 from Deer Lake to Massey Drive. Hydro recommends the functionalization of this asset change from generation to transmission.

(ii) Hydro recommends that the power purchase costs resulting from the Muskrat Falls Project (Muskrat Falls Generation, LIL and LTA assets) be functionalized as generation.

(iii) Hydro recommends that the frequency converter serving CBPP continue as a specifically assigned asset; and

(iv) Hydro recommends that the transmission assets currently specifically assigned to customers continue to be specifically assigned.

3.2.3 Classification of Functionalized Production/Generation Costs

Hydro's current Cost of Service methodology first classifies generation costs on the basis of demand and energy cost causation, and then allocates to each customer class using a coincident peak allocator in the case of demand costs and an annual energy allocator in the case of energy costs. Cost causation is established based on planners' views as to whether specific costs were incurred to meet peak demands or to supply total energy. There are many methods available to the industry to perform classification and the method chosen can result in material differences in the costs to be recovered from a customer class. For example, classification of a high proportion of costs as energy-related would result in a higher proportion of the costs being allocated to customers who use large amounts of energy relative to their peak demand requirements (i.e., high load factor customers like Hydro's Industrial Customers). Alternatively, classifying a higher proportion of total costs to demand cost would result in a higher allocation of costs to customers who have higher peak demands relative to their energy requirements (i.e., lower load factor customers like Newfoundland Power).

An alternative approach to the various traditional classification methods is to make use of the concept of marginal cost. Marginal generation costs, upon interconnection of the system to the North American grid, will be represented in most hours by wholesale prices of eastern regions of that grid. The use of marginal generation costs in cost allocation would permit Hydro to reflect resource market value in determining how to allocate the financial costs of generation to each class.

Hydro recently completed its Marginal Cost Study based on 2019 forecast costs. The use of this marginal generation cost data allows Hydro to estimate the cost to serve Island Interconnected System classes of customers by applying hourly marginal generation cost profiles to the hourly load profiles for each class served at transmission voltage. Cost shares for each customer class are then derived based on the proportion of the annual total marginal costs that result for each class. This approach gives consideration to the cost of serving each customer class in all the hours of the year, in contrast with traditional CP methods on the demand side that typically make use of a very limited number of peak hours.

The use of marginal cost allocation in the cost of service also aligns with reflecting marginal costs in rate design to promote efficient use of resources by customers. Therefore, Hydro believes it is reasonable for the Board to consider the use of marginal generation costs for allocation of generation costs in the Cost of Service Study.

Classification Alternatives

Hydro presents two alternatives for the Board to consider in the classification and allocation of power purchase costs resulting from the Muskrat Falls Project:

(i) The equivalent peaker methodology be used for classification between demand and energy and a coincident peak approach (3 CP) be used for cost allocation among customer classes; or

(ii) The use of forecast marginal generation capacity and marginal generation energy costs to determine the proportion of power purchase costs to be classified and allocated to each customer class.

If the equivalent peaker methodology is selected for classification of Muskrat Falls Project costs, Hydro proposes few changes in the classification approach for the other functionalized generation assets. The only exception is that Hydro proposes to use a capacity factor for Holyrood based on the Test Year forecast rather than the current approved 5-year historical average. This approach would permit cost allocation to more immediately reflect the role of the plant.

Table 1 below summarizes the proposed generation/production classifications under this option.

Table 1 – Classification of Functionalized Generation Costs – Island Interconnected System

Generation Costs	**Existing**	**Proposed**
Hydraulic Assets	System Load Factor	System Load Factor
Holyrood Assets[13]	5-year average capacity factor	Forecast capacity factor
Gas Turbines/Diesel Assets	100% Demand Related	100% Demand Related
Power Purchases – MF	Not Applicable	Equivalent Peaker (25% D/75% 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	100% Energy

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

If the forecast marginal cost approach is selected, Hydro proposes that all generation costs on the Island interconnected System be classified and allocated based on marginal generation costs. Table 2 below compares the existing and proposed generation cost classifications under this option.

Table 2 – Classification of Functionalized Generation Costs – Island Interconnected System

Generation Costs	**Existing**	**Proposed**
Hydraulic Assets	System Load Factor	Marginal Generation Costs
Holyrood Assets[14]	5-year average capacity factor	Marginal Generation Costs
Gas Turbines/Diesel Assets	100% Demand Related	Marginal Generation Costs
Power Purchases – MF	Not Applicable	Marginal Generation Costs
Other Power Purchases	System Load Factor	Marginal Generation Costs
Holyrood Fuel	100% Energy	Marginal Generation Costs
Gas Turbine/ Diesel Fuel	100% Demand	Marginal Generation Costs
Wind Purchases	100% Energy	Marginal Generation Costs

3.2.4 Classification of Functionalized Transmission Costs

Hydro recommends that all functionalized transmission costs be classified as 100% demand-related. This is consistent with the approach currently used in the Cost of Service Study.

Hydro also proposes to update its annual transmission losses to 5.1% for energy and 7.3% for peak demand for use in the Cost of Service Study.[15] The transmission loss assumption does not vary by customer class as Hydro does not forecast locational losses on the Island Interconnected System.

[14] Ibid.
[15] The loss percentages are expressed as a percentage of customer class load requirements. Hydro will reflect these loss factor updates in its next GRA filing.

3.2.5 Allocation Method

Marginal Cost Approach

In the scenario in which marginal generation costs are used in the classification of generation costs, the allocation calculations are computed in partnership with cost classification. The sharing of generation costs by customer class is determined in the following manner.

Hydro has forecast hourly loads for each of Newfoundland Power, the Island Industrial class and the Hydro Rural bulk load on the Island Interconnected System. The forecast marginal generation cost by hour is applied to the hourly load forecast for each customer group to determine the marginal cost to serve each customer class for each hour. By totaling the marginal generation cost to serve each customer class across all the hours of the year, the total forecast marginal generation cost to serve each customer class is determined for the Test Year. The proportion of the total marginal costs attributable to each customer class in the Test Year is then applied to the total Test Year generation revenue requirement to determine the portion to be allocated to each customer class.

To apply the marginal cost classification and allocation to generation costs of Labrador Interconnected Customers would require class load shapes for each retail class. Hydro plans to continue to apply equal rate changes per class on a go forward basis for the classes on the Labrador Interconnected System until Hydro has reasonable estimates of class load shapes. In its 2013 Amended GRA, Hydro stated it plans to conduct a load research study for the Labrador Interconnected classes.

Traditional Approach

Hydro currently uses a single coincident peak approach to allocate demand costs among customer classes. Hydro has applied the FERC test in evaluating its allocation approach and as a result is recommending 3 CP for allocation of both generation and transmission demand costs.

Hydro considers the application of the FERC test consistent with generally accepted utility practice in the allocation of demand costs.

CA Energy Consulting has recommended that the peak periods for use in applying the CP methodology be based on system peak including the loads for exports. Hydro has concerns with the potential implications of this approach.

On the interconnection with the North American grid in combination with the commissioning of the Muskrat Falls Project, there is material excess capacity available for exports. However, this excess capacity will decrease over time. Including the amount of export load in determining the peak period for cost of service purposes could broaden the system peak period beyond the historical winter peak period. The value for export sales is high in summer periods so it makes sense to maximize export sales in high value periods. Using export sales to determine the cost of service peak period could possibly result in Hydro eventually allocating system demand costs based on a twelve-month average of coincident peak loads instead of just the three winter months.

As native load increases over time, the system may need expansion to meet native peak load requirements. These peak load requirements will continue to be in the coldest days of the winter. Hydro considers the use of export sales in the determination of the peak period to pose possible challenges to the accurate representation of cost causality from a system planning perspective. A material reduction in exports sales capability during a summer period will not cause Hydro to acquire additional capacity. However, a shortage in winter capacity to meet native peak load would cause Hydro to explore least cost approaches to supply the expected increases in native load. Therefore, Hydro believes it is appropriate to determine the times of system peak for the purpose of cost allocation based on native peak load requirements.

Under the current 1 CP approach, Hydro Cost of Service Study reflects that the Island Industrial Customers peak load has an 88% coincidence with system peak factor and the Newfoundland Power peak load has a 99.4% coincidence with system peak. Based on a preliminary analysis, Hydro has not seen any reason to change these coincidence factors under the 3 CP approach. However, Hydro will be conducting further analysis on this matter prior to filing its 2017 GRA.

Hydro currently allocates energy costs based on annual energy use by customer class. If marginal costs are not used for classification and allocation of generation costs, Hydro proposes to continue the current annual energy allocation approach.

3.2.6 Rural Deficit Allocation

Hydro also requested CA Energy Consulting to review the Rural Deficit allocation in the Cost of Service Methodology Review. CA Energy Consulting agreed that Hydro's proposed approach is preferable to the existing method.

Hydro recommends the use of the revenue requirement method for allocation of the Rural Deficit between Newfoundland Power and the Hydro Rural customers on the Labrador interconnected System. This recommendation is consistent with Hydro's proposal in the Amended 2013 GRA.

3.2.7 Conservation and Demand Management

Hydro will discuss with stakeholders the CA Energy Consulting recommendation to allocate CDM costs by customer class on a marginal cost basis. If not acceptable to the stakeholders, Hydro recommends the use of an energy allocation approach as recommended in its 2013 Amended GRA.

Hydro also recommends that, for the Island Interconnected System, Hydro's CDM costs and the CDM costs of Newfoundland Power should be pooled and allocated for recovery among customer classes on the Island Interconnected System.

3.2.8 Specifically Assigned Charges

Hydro recommends that the use of original asset costs as a basis for the allocation of operating and maintenance costs to specifically assigned assets be discontinued. Hydro proposes to engage in discussions with Industrial Customers to enter into an agreement to charge annual operating and maintenance costs to the Industrial Customers based on an as required maintenance approach for specifically assigned assets (including a markup to reflect administrative and general costs).

If this approach is not acceptable to all parties, Hydro recommends using indexed asset costs in operating and maintenance cost allocations in the determination of specifically assigned charges to eliminate the fairness concerns due to asset vintage differences.

3.2.9 Newfoundland Power Generation Credit

Hydro recommends continuation of the portion of Newfoundland Power's generation credit reflecting the operation of its hydraulic generation, as Newfoundland Power normally operates its hydraulic generation during peak periods.

Hydro also recommends that the thermal generation credit for use in the allocation of embedded demand costs not be renewed at the time of reflecting the costs of the Muskrat Falls Project in customer rates. However, Hydro has requested CA Energy Consulting to evaluate the implementation of an alternative credit for capacity availability which is more reflective of the market value of the capacity made available by Newfoundland Power's thermal generation. This issue will be further dealt with in the upcoming rate design review.

3.2.10 CBPP Generation Demand Credit

Similar to the Newfoundland Power generation credit, Hydro recommends the CBPP demand credit approach should be dealt with in the rates review to be filed in June 2016.

3.2.11 Allocation of Export Sales Credit

Due to the uncertainty with respect to the amount of an export sales credit that may be available annually, Hydro recommends that disposition of any export sales credit should be handled through a deferral mechanism outside the Cost of Service Study. Hydro will be filing its proposal for a supply cost deferral account to deal with future annual supply cost variances in June 2016. Hydro will include a detailed proposal on the approach to deal with export sales credits in that report.

4.0 CHANGES IN COST ALLOCATIONS

Hydro has prepared cost of service exhibits showing illustrative forecast 2019 revenue requirement projections for use in methodology evaluation (2019 Illustrative). The 2019 Illustrative revenue requirement allocations are compared to the Proposed 2015 Test Year revenue requirement adjusted to reflect a $64.41 per barrel cost of No. 6 fuel (2015 Proposed).[16]

The cost of service exhibits are provided for the Island Interconnected system as the material cost changes impact that system.[17] Hydro is recommending the cost of service and rates for the Labrador Interconnected System continue to be separate from the Island Interconnected System.

[16] The forecast 2015 Test Year revenue requirement for the Island interconnected System reflecting No. 6 fuel at $64.41 per barrel $CDN is approximately $540 million. See letter to Board dated October 28, 2015. The adjustment to reflect reduce fuel costs reflected $75.9 million reduction in No. 6 fuel and a $1.9 million reduction resulting from the lower forecast cost of No. 2 fuel.

[17] Approval of the recommendation to change from a 1 CP demand allocation to a 3 CP demand allocation would result in a minor reduction in the demand cost allocation to Hydro Rural customers and a minor increase in the demand cost allocation to Labrador Industrial customers.

Hydro has excluded rural deficit allocation in the presentation of results as this is not a relevant issue in evaluating the cost of service methodology for generation and transmission costs. The transmission costs on the Great Northern Peninsula are specifically assigned to Hydro Rural and therefore will not impact classification or allocation of common transmission assets.

The key financial forecast assumptions included in the 2019 Illustrative revenue requirement are:

(i) Muskrat Falls Project, including the Labrador Island Link and Labrador Transmission Assets will be in operation for all of 2019;
(ii) The TFA and PPA payments are consistent with a Nalcor long-term financial plan prepared in the fall of 2015;
(iii) Customer class demand and energy requirements for 2019 are based on Hydro's Spring, 2015 Load Forecast;
(iv) Hydro will continue its five year asset management plan which includes the addition of a 230 kV transmission line from Bay d'Espoir to Western Avalon;
(v) Material reductions in fuel consumption occur on the Island interconnected system;
(vi) Hydro's underlying operating and maintenance expenses are assumed to escalate at a rate of 2.5% per annum; and
(vii) Hydro's allowed return on equity remains at 8.8%.

Attachment 1 to this report provides a comparison of the allocations of the 2015 Proposed and the 2019 Illustrative revenue requirements under Option 1 which uses the equivalent peaker methodology for the classification of the costs of the power purchases related to the Muskrat Falls Project.

Attachment 2 to this report provides a comparison of the allocations of the 2015 Proposed and the 2019 Illustrative revenue requirements under Option 2 which uses a marginal cost approach in the classification and allocation of generation costs.

The differential between the average unit cost to serve Newfoundland Power and the Island Industrial Customers is approximately 1.2¢ per kWh in the 2015 Proposed, with the average cost to serve Island Industrial Customers being lower than the average cost to serve Newfoundland Power.[18] This reflects Island Industrial Customers having a higher load factor and a lower coincidence with system peak than Newfoundland Power.

Under the marginal cost scenario, the average cost differential in 2019 Illustrative relative to the 2015 Proposed is slightly higher by approximately 0.25¢ per kWh. However, under the equivalent peaker scenario, the average cost differential in 2019 Illustrative relative to 2015 Proposed widens by approximately 1¢ per kWh.

The increased average cost differential under the equivalent peaker classification approach primarily results from two factors: (i) the demand-related revenue requirement portion of the Muskrat Falls Project has a higher demand cost classification (25%) than the overall demand-related proportion of Holyrood costs in 2015 Proposed (14%); and (ii) the amount of demand-related revenue requirement in 2019 Illustrative is materially higher than the amount of demand-related revenue requirement in 2015 Proposed. The combination of these two factors increases the cost allocation to Newfoundland Power relative to the Island Industrial Customers when comparing the average unit costs for the 2015 Proposed and the 2019 Illustrative results.

[18] Excludes impact of the Rural Deficit.

NEWFOUNDLAND AND LABRADOR HYDRO
2019 Illustrative Cost of Service
Summary Schedule - Island Interconnected

Attachment 1
Equivalent Peaker

Line No.	1	2	3	4	5	6	7	8	9	10	11
				Revenue Requirement [i]						Average Unit Cost	Differential NP vs Industrial [iii]
		Sales		Demand [ii]		Energy		Total			
		(MWh)	%	($ Millions)	%	($ Millions)	%	($ Millions)	%	($/kWh)	($/kWh)
	2019 Illustrative:										
1	Newfoundland Power	6,169,300	82.7%	298.2	80.3%	402.9	82.2%	701.9	81.5%	0.1138	0.0219
2	Industrial	894,300	12.0%	23.7	6.4%	58.4	11.9%	82.1	9.5%	0.0918	
3	Rural	396,202	5.3%	49.5	13.3%	28.9	5.9%	78.5	9.1%	0.1982	
4	Total	7,459,802		371.4		490.1		861.5			
	2015 Test Year Proposed:										
5	Newfoundland Power	5,924,100	85.0%	153.9	75.3%	241.3	84.4%	395.9	80.8%	0.0668	0.0117
6	Industrial	621,400	8.9%	8.9	4.4%	25.3	8.8%	34.2	7.0%	0.0551	
7	Rural	425,409	6.1%	41.7	20.4%	19.2	6.7%	61.1	12.5%	0.1437	
8	Total	6,970,909		204.5		285.8		490.3			

[i] Customer component of revenue requirement not presented for purposes of this study.
[ii] Includes both production and transmission demand costs.
[iii] Price differential excludes the impacts of the Rural Deficit that is included in the Newfoundland Power wholesale rate.

Assumptions:
1. Equivalent Peaker method deployed to classify Muskrat Falls purchased power only. Allocation is based on the existing 2015 methodology
2. System load factor continues to classify heritage hydraulic generation. Allocation is based on the existing 2015 methodology
3. 2015 CoS methodology for thermal costs is maintained.
4. Combustion Turbine costs are classified as 100% demand and alloacted on a CP methodology.
5. A 3 CP method is used to allocate demand costs.
6. Exploits assets are included as a purchased power at $0.04.
7. Completion of the TWINCo asset transfer has not been included in Rate Base.
8. 2015 Test Year Proposed No 6 fuel priced at $64.41 per barrel.

NEWFOUNDLAND AND LABRADOR HYDRO
2019 Illustrative Cost of Service
Summary Schedule - Island Interconnected

Attachment 2
Marginal Cost

Line No.	1	2	3	4	5	6	7	8	9	10	11
				Revenue Requirement [i]						Average Unit Cost	Differential NP vs Industrial [iii]
		Sales		Demand [ii]		Energy		Total			
		(MWh)	%	($ Millions)	%	($ Millions)	%	($ Millions)	%	($/kWh)	($/kWh)
	2019 Illustrative:										
1	Newfoundland Power	6,169,300	82.7%	159.9	74.9%	534.4	82.5%	695.0	80.7%	0.1127	0.0143
2	Industrial	894,300	12.0%	12.7	5.9%	75.2	11.6%	87.9	10.2%	0.0983	
3	Rural	396,202	5.3%	40.9	19.2%	38.2	5.9%	79.3	9.2%	0.2002	
4	Total	7,459,802		213.5		647.7		861.3			
	2015 Test Year Proposed:										
5	Newfoundland Power	5,924,100	85.0%	153.9	75.3%	241.3	84.4%	395.9	80.8%	0.0668	0.0117
6	Industrial	621,400	8.9%	8.9	4.4%	25.3	8.8%	34.2	7.0%	0.0551	
7	Rural	425,409	6.1%	41.7	20.4%	19.2	6.7%	61.1	12.5%	0.1437	
8	Total	6,970,909		204.5		285.8		490.3			

[i] Customer component of revenue requirement not presented for purposes of this study.
[ii] Includes both production and transmission demand costs.
[iii] Price differential excluded the impacts of the Rural Deficit that is included in the Newfoundland Power wholesale rate.

Assumptions:
1. Marginal Cost ratios are used to classify and allocate all generation costs.
2. Marginal Cost ratios are used to classify and allocate all thermal generating costs.
3. Marginal Cost ratios are used to classify and allocate all Combustion Turbine costs.
4. A 3 CP method is used to allocate demand costs.
5. Exploits assets are included as a purchased power at $0.04.
6. Completion of the TWINCo asset transfer has not been included in Rate Base.

CHRISTENSEN ASSOCIATES ENERGY CONSULTING

Cost-of-Service Methodology Review

for

Newfoundland and Labrador Hydro

by

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March 31, 2016

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CHRISTENSEN ASSOCIATES ENERGY CONSULTING, LLC

March 31, 2016

1. INTRODUCTION

Newfoundland and Labrador Hydro (NLH) requested Christensen Associates Energy Consulting to conduct a review of the utility's cost-of-service (COS) methodology, focusing on the system that is likely to emerge following its transition to integration with the electricity grid of eastern North America. This transition will occur upon completion of several major construction projects and the development work associated with them. The targeted in-service date is the latter half of 2018. The key projects involving NLH are: 1) the new 824 MW Muskrat Falls (MF) hydro dam on the Churchill River in Labrador; 2) the Labrador Transmission Assets (LTA) that will assist in coordinating generation at Muskrat Falls and Churchill Falls; and 3) the Labrador-Island Link (LIL), a direct current (DC) line that connects Muskrat Falls to Soldiers Pond near St. John's. In addition, Nalcor, NLH's parent company, has partnered with Emera to develop the Maritime Link (ML) that will connect Nalcor with Emera's grid in Nova Scotia and points beyond.

The cost of these investments is significant, and MF, LIL, and LTA costs will, by government direction, be borne by customers paying Island Interconnected rates (beginning with the

Muskrat Falls in-service date) as these facilities are being constructed for them. Additionally, as a result of the arrival of new supply on the Island, NLH will wind down the Holyrood generation facility, replacing its thermal generation with Muskrat Falls' hydro power.

This COS methodology review is part of a general review process leading up to the in-service date for Muskrat Falls and its associated transmission facilities. The review is occurring at the conclusion of the 2013 General Rate Application (GRA) process, during which many COS methodology issues were reviewed. This report makes reference to several of these issues and the related discussions, and follows recent issuance of a Settlement Agreement and Supplemental Settlement Agreement.[1]

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

[1] The *Settlement Agreement* and *Supplemental Settlement Agreement* are untitled documents dated August 14, 2015 and September 28, 2015, respectively.

The focus of COS review in the 2013 proceeding was the methodology to support currently proposed rates. In contrast, this COS methodology review concentrates on the methodology issues that surround the completion of the new generation and transmission facilities. This review evaluates NLH's current cost allocation methods in light of the above changes and recommends changes to this methodology where needed. The Supplemental Settlement Agreement mentions the current review specifically, and states that it will "include a review of: (i) all matters related to the functionalization, classification and allocation of transmission and generation assets and power purchases (including the determination whether assets are specifically assigned and the allocation of costs to specifically assigned assets) and (ii) the approach to CDM cost allocation and recovery."[2] This report will discuss each of these issues.

The review begins with a "jurisdiction" question, investigating the potential for combining the two previously separate interconnected systems in the Island and Labrador. Sections on the core functions of generation and transmission then follow. (The distribution function is not part of this review.) A final section covers a set of topics outside the main functions: the treatment of: 1) the rural deficit; 2) conservation and demand management (CDM) costs; 3) specifically assigned costs; and 4) the frequency converter at Corner Brook Pulp and Paper. An appendix with a separate list of recommendations follows.

[2] *Supplemental Settlement Agreement*, paragraph 13, p. 3.

2. SYSTEM DEFINITION

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

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

Furthermore, the power flow pattern anticipated for NLH's physically interconnected system is not conventional when compared with the rest of the Eastern Interconnection.[3] NLH expects that in virtually all hours, barring an outage at Muskrat Falls or on the LIL, power will flow in one direction, south to the Island and points beyond. This is unconventional for AC-dominated meshed networks, but consistent with conditions in which DC transmission technology is utilized, especially in transporting power over long distances.

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

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

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

NLH has a number of external institutional influences that suggest continuation of separate treatment. The Muskrat Falls Exemption Order requires that the costs "shall be recovered in full by Newfoundland and Labrador Hydro in Island Interconnected rates charged to the appropriate classes of ratepayers."[5] This obligation enshrines in law the cost causation underlying the decision to invest: least cost planning of new generation capability to serve the island.[6]

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[4] 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.
[5] Order in Council 2013-343.
[6] 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.

As well, Labrador industrial rates, which serve two large customers, have two components arising from separate sources.[7] The cost of generation services is subject to direction by the Provincial Government and is outside the COS study of NLH. Transmission costs are within NLH's COS. This bifurcation would complicate cost allocation for industrial customers in a combined jurisdiction. Creating a single industrial class would require unbundling of pricing.[8] Retaining two separate classes would likely be more sensible, significantly negating the benefits of creating a combined service territory. Another factor suggesting separate treatment would be that the marginal cost to serve the two industrial groups could be quite different at times, given the possibility of transmission constraints separating the two regions temporarily and unexpectedly.

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

Discussion/Analysis. It appears that NLH can resolve this issue in two ways that potentially lead to similar outcomes. First, the COS methodology could retain separate treatment of

[7] One of the two, Wabush Mines, is closed and in receivership, with resulting loads at a very low level.
[8] See Newfoundland and Labrador Hydro, *2016 Labrador Industrial Rate Submission*, December 22, 2015.

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

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

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

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

3. GENERATION

Issues. NLH's generation mix and regional configuration will change substantially at the time that Muskrat Falls and its associated transmission links, which is anticipated to be put in service in the second half of 2018, with 2019 being the projected first full calendar year of service of these facilities. How should this reconfiguration affect the allocation of generation costs?

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

Current Classification and Allocation
Of Generation Assets of NLH

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

The system load factor approach to cost classification attributes a share of generation investment cost to energy causation, based on the assumption that generation investment to meet average load should be distinguished from generation investment designed to meet peak demand. NLH uses system load factor to identify the share of production assumed to be base and intermediate generation-related. The generation cost not accounted for by energy classification is attributed to peak demand.

NLH classifies the Holyrood thermal generation facility separately, based on its average historical and forecasted capacity factor. The 2015 Test Year historical average five-year net capacity factor of 24% indicates the generator’s use primarily to meet demand needs as opposed to energy supply. Isolated systems use versions similar to the interconnected system methods.

NLH also engages in power purchases currently. The Island Interconnected system obtains the majority of its purchases from non-utility generation consisting primarily of hydro resources, along with some wind purchases. The hydro purchases are classified in the same manner as utility hydro resources (system load factor) and the wind purchases are classified as energy-only.

Labrador Interconnected purchases are entirely from Churchill Falls, and are classified on the basis of Labrador system load factor. Isolated system purchases occur mostly at L'Anse au Loup. Purchases are classified as energy-only due to their non-firm nature. Due to these purchases, that system's diesel unit is classified as demand-related.

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

The table above displays the classification and allocation of the generation cost elements of rate base. It does not display the dominant element of generation cost in COS: fuel costs. At present, these costs are the most significant element in revenue requirements, and the dominant component of fuel cost is no. 6 fuel for the Holyrood generating station. No. 6 fuel is classified as entirely energy-related while other fuels are classified in the same manner as the generator that they supply. The effect of this large fuel cost is that Holyrood revenue requirement is classified between 85-90% as energy.

The composition of NLH's generation assets and expenses will change significantly after 2018, with the introduction of Muskrat Falls' 824 MW of new hydraulic capacity, linked to the Island and to the Eastern Interconnection by undersea DC lines. The addition of Muskrat Falls to the NLH system facilitates the eventual retirement of the Holyrood thermal generation unit. The introduction of new DC interties to the mainland also raises the possibility of additional wind generation.

NLH will pay for the new generation services of Muskrat Falls via a stream of power purchases scheduled to recover the full costs of the new generation source over a fifty-year period. Payments will be predominantly monthly lump sum charges covering capital cost and operations and maintenance (O&M) expenses. The contractual agreements between NLH and MF also include periodic true-up payments covering the difference between actual and forecasted O&M costs and the cost of sustaining capital.

Classification and Allocation

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

The NARUC COS Manual reveals many different ways to classify generation plant, some demand-only in nature and others, a combination of demand and energy, are termed “energy weighting methods.”[9] Since none of the conventional approaches can claim unchallenged superiority, the NLH approach, which is a variant of the energy weighting methods, appears to be within the norms of industry practice.

This approach might, at first look, be feasible with the introduction of Muskrat Falls. NLH would treat the new facility in the same manner as other hydro facilities, by classifying on the basis of SLF. At current SLF levels of about 55%, a sizable portion of the facility would be treated as energy-related. However, one implication of the substitution of Muskrat Falls for Holyrood generation under the assumption of SLF classification is that the demand composition of generation revenue requirements may rise substantially. As mentioned, Holyrood’s revenue requirement has historically been approximately 90% energy-related while that of Muskrat Falls under SLF would be approximately 55% energy-related.

A significant change in the makeup of generation capability can be expected to change system operations such that existing classification methods may be rendered out of date. While applying the SLF method to a new hydro unit may appear sensible, the shift in demand and energy components may misrepresent system operations as a whole.

An alternative approach to SLF of classifying the costs of Muskrat Falls might be to use the *equivalent peaker* methodology. This approach postulates that any cost per unit of capacity

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

that exceeds that of a peaking unit should be classified as energy-related, while the peaking unit cost component is classified as demand-related. Baseload and intermediate units are typically more expensive to build than peaking units, and that extra expense is viewed as being energy-driven. That extra cost is incurred in order to save fuel cost relative to peaking unit production, with generation investment occurring to attain least cost production.

The equivalent peaker method is viewed by some as giving formal recognition to the generation planner's selection of a range of plants to serve the system. (The argument is that generation must meet peak demand, but that generation planning is caused by a need to meet varying load durations.) Muskrat Falls is a baseload unit with costs imposed as a lump sum on Island Interconnected customers. This approach recognizes that fact by treating much of its cost as being energy-related.

To implement this approach, the utility develops an estimate of the current cost per kW of a peaking unit, and compares that with the cost per kW of the new generation unit, being careful to use the same vintage as the plant under study. The actual computations can be complex, since they allow for plant vintage and financial cost details. However, it is possible to illustrate this approach in simplified form here. Suppose that the discounted revenue requirements for Muskrat Falls and its associated transmission investments of LIL and LTA approximate \$870 per kW, while the charges for CT capacity are \$219 per kW, stated in \$CAD.[10] The demand share of Muskrat Falls would be \$219 /\$870, or about 25%. The energy share would be the residual 75%, which is below the 90% share of Holyrood revenue

[10] These calculations are provisional, based on NLH's informal estimates.

requirement. Based on this estimate, it may be that the final shares developed by the equivalent peaker approach will better account for the main reason underlying the resource choice favoring Muskrat Falls—very large fuel costs savings over future decades. NLH's longstanding SLF approach, would likely obtain an approximate 45/55 split between demand and energy, a result which seems out of step with Muskrat Falls' envisioned purpose of serving base load and, in so doing, producing substantial fuel cost savings.

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

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

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

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

Marginal Cost-Based Cost Allocation

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

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

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

However, marginal costs can serve to develop an allocator that can be applied to embedded costs.

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

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

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

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

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

Applying the marginal cost method requires hourly marginal cost and class load profile data sufficient to represent the range of likely market conditions that may apply in the service territory. NLH already has transmission-level hourly profiles for its NP and industrial customers, and for its aggregate rural customers on the Island and in Labrador. The utility has been developing forecasted hourly wholesale price/marginal cost scenarios for the forecasted early years of Muskrat Falls service, and is thus well on the way to operationalizing this approach.

Marginal cost-based allocation of embedded costs may seem to be novel, but variants of this approach have been in use for many years in a number of regulatory jurisdictions. West coast U.S. utilities have used this approach for twenty years.[11] In Canada, Manitoba Hydro applies a marginal cost-based allocation to generation services and utilizes a variant of the process in allocating transmission costs.[12]

Marginal cost-based allocation has sometimes been criticized for producing greater variability in allocator shares over time than embedded cost-based methods. Analysis of historical marginal costs can shed light on this issue. Concerns with respect to variation can generally can be resolved by the use of multiple scenarios for the development of marginal cost estimates over forward periods. As forecasts change, expected marginal cost levels and patterns change, and these changes can be incorporated within cost shares for consumer

[11] Example utilities include Pacific Gas & Electric, Southern California Edison, and Portland General Electric.
[12] 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.

classes. Such changes reflect in a timely manner expected changes in cost to serve. For example, a strongly peak-coincident class might see an increase in cost share if peak marginal costs/wholesale prices rise relative to off-peak. Conversely, a relative smoothing of price patterns would reduce the cost share of the class.

Under marginal cost-based cost allocation, NLH would first assemble its generation cost financial data and then assign costs to the five service regions. The three isolated regions would then have costs classified and allocated in the same manner as is currently applied, due to current data availability. To allocate each of the two interconnected regions' costs, NLH would develop hourly load profiles for its customers under various marginal cost scenarios and, summing across hours and scenarios, develop total marginal costs for each class in each region. Allocation would then be based on the shares of the total marginal cost to serve.[13] Allocator values would then be applied to aggregated generation assets and to generation-related expenses of each region.

One key issue will be determining how to treat the power purchases from Muskrat Falls. The payments are the form of lump sum capacity and O&M charges. Transmission lease payments that accompany Muskrat Falls charges for purchased power are also lump sum in nature, but are not broken down into capacity and O&M components. These charges will not vary with loads or peak demands, and resemble other generation fixed costs. Under a marginal cost-based approach, the lump sum of purchased power and transmission lease

[13] At present, NLH 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.

payments could be allocated on the basis of marginal cost-weighted usage, in the same manner as other generation-related costs.

On the periphery of the main cost allocation issues is the question of how to allocate the costs of wind generation. NLH has access to some wind at present, but independent wind generation might increase significantly in the future. Wind generation advocates sometimes argue that wind can have a capacity element and should not be classified as energy-only. NLH's system planners state wind is not available to meet system peak requirements. While originally conceived as substituting for Holyrood generation, that relationship no longer applies. This view underpins the utility's 2013 recommendation to treat wind generation as 100% energy-related.[14] This approach is common in the industry, although contribution to capacity has begun to be introduced. Additionally, after the commencement of Muskrat Falls service, new wind generation would most likely contribute to exports, as opposed to meeting peak demand of NLH customers. If marginal cost-based methods are introduced, wind generation purchases can be included in the allocation of the overall generation portfolio.

Recommendations. We recommend that NLH introduce marginal cost-based allocation of embedded generation costs for the Island Interconnected system beginning with the implementation of rates that recover revenue to cover payments by NLH for Muskrat Falls and its associated transmission facilities. This change will avoid the need to allocate each generation asset or cost on its own and relates cost to serve to an objective market-based

[14] See NLH, *2013 Amended General Rate Application*, Section 4.3.2.

value of generation services that recognizes cost to serve by each rate class in each hour. It appears that NLH can undertake this approach, as the utility already possesses the costing capabilities to generate the requisite marginal cost scenarios.

Marginal cost-based allocation can be used in the Labrador Interconnected system as well, following the Muskrat Falls in-service date. For Labrador, projections of marginal cost will be developed from the same process as used for the Island Interconnected system.

Until the Muskrat Falls project is included in the cost of service, we recommend that NLH continue its current generation cost allocation methodology, with modifications agreed upon in the 2013 Supplemental Settlement Agreement, specifically with regard to the treatment of Holyrood fuel and wind generation as 100% energy-related.

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

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

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

We recommend that wind resources be allocated in the same manner as other generation facilities if marginal cost-based cost allocation is adopted. If not, then we recommend that NLH adopt a classification method based on NLH planners' forecasts. Current forecasts indicate that wind generation does not contribute to the ability to meet peak demand and should therefore be classified as 100% energy-related.

4. TRANSMISSION

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

4.1 Capacity Costs

Transmission Facility Categories

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

- *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 NLH 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; relays; reactors, capacitor banks and static var compensators to maintain/control voltage and provide stability; switches and protection gear;
- *Terminal Stations:* substations, transformers, switchgear, meters, and monitoring equipment; and,
- *Special Facilities:* an array of transmission facilities such as frequency converters and phase shifters. The relevant special purpose facilities for NLH include long direct current (DC) facilities such as NLH's Labrador Island Link (LIL) and associated rectifiers situated within the Muskrat Falls switchyard and the inverters situated at the Soldiers Pond substation, integrated within NLH's high voltage network on the Avalon Peninsula.

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

Subfunctionalization

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

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

Special Purpose Transmission Facilities. Special purpose facilities are constructed for, or primarily because of, the provision and facilitation of least cost generation. Least cost generation plans reflect real-world constraints: generation cannot necessarily be sited near load centers. Large-scale generation, including hydraulic facilities, nuclear stations, and wind farms, often requires sizable properties, selected according to geographical features, available resources, and societal externalities and constraints.[15] These sites can be remote locations, thus requiring extended transmission leads in order to bring power supply into meshed transmission networks and load centers.

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

Also, transmission can substitute for local generation, in selected cases. For example, the recent expansion of transmission capability in Southwest Connecticut and along California's Path 15 rather dramatically improved flows, thus reducing the costs of generation by significantly lowering congestion costs, specifically costs related to out-of-merit generation

[15] *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.

dispatch. Conversely, special purpose transmission facilities often accompany generation and special circumstances with respect to geography and opportunities to exploit and favorably employ natural resources.

The NLH system includes two major special purpose transmission facilities:

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

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

The transfer capability of the LIL is 900 MW. Because of capital indivisibility, the LIL can be utilized, especially in its early years, to serve out-of-province loads in addition to native loads. In combination, MF and LIL provide the capability for significant power exports through Maritime Link during the early years of the life of capital. However, capability for power exports is largely incidental: Nalcor's commitment to Muskrat Falls in combination with Labrador Island Link is for NLH electricity consumers—the Province as a whole.

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

The second approach is to assign the LIL facility to generation and transmission. Arguably, because the LIL creates a DC-dominated transmission loop on the fringe of the Eastern Interconnection, in which flows in both directions are at least theoretically possible, the LIL can be viewed as an example of joint-use facilities. In this case, the LIL could be assigned jointly to the generation and transmission functions, at least for the near term. Functionalization could occur based on some measure of native load and export shares of LIL transportation. The native load share would be classified as generation and the export share would be classified as transmission, since that is the share that will make use of the loop configuration.[16] (Note that this does not mean that a share of costs will be allocated to export load.)

[16] 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.

However, this second approach creates conceptual difficulties for NLH given the structure of its agreements facilitating the LIL. The Order in Council that sets out the Muskrat Falls Exemption Order states that all costs are to be paid by NLH native load customers, since the LIL and MF are being constructed based on the supply needs of the Island without consideration of export opportunities.[17]

Subfunctionalization Recommendations.

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

The special purpose facilities which comprise the Labrador Transmission Assets (LTA) should be assigned to the generation function for the reasons discussed above—facilitation of efficient use of hydro facilities along the Churchill River, including the Churchill Falls and Muskrat Falls stations. We recommend that the LIL facility, including its converter facilities, be functionalized as generation, in harmony with the formal cost designation of the facility as providing service to the Island.

[17] Reference the Order in Council 2013-343.

Classification and Allocation

Generator Interconnection Facilities. The previous section set out the alternatives for classification and allocation of generation facilities. NLH will presumably wish to classify and allocate the generator interconnection facilities in the same manner as other generation facilities. The options include retaining the current approach, in which classification and allocation by generator type occurs, or moving to the marginal cost-based approach, in which marginal cost-weighted shares of annual energy are the basis for both steps.

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

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

<u>General Purpose Transmission Cost Classification Alternatives.</u> The CP approach is reinforced by the policy of the FERC. In the case of broadly defined general use facilities, all-in total costs of transmission facilities are recovered as monthly $/kW access charges, determined according to load ratio shares based on coincident demands and, on occasion, non-coincident demands in the case of subtransmission.[18] In other words, in this consensus view, it is the expected level of peak demands which have, over decades, driven ongoing investment in transmission and, thus, cost allocation.

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

[18] 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 NLH would need to use a 12 CP approach.)
[19] Not mentioned is the impact of restructured wholesale electricity markets, which have given rise to changes in flow patterns and thus revealing, in the process, the need for further grid expansion to better manage congested networks. A salient example is the expansion of Path 15 in California's wholesale market.

This view of transmission investment is open to challenge on causality grounds in that the factor of transport distances is clearly a cost driver for transmission.[20] (The longer the line, the greater the amount of equipment.) However, for electricity transactions, the dimension of distance is not easily measured or observable, notwithstanding the locational pricing inherent in unbundled wholesale markets, where the price differences reflect network congestion and marginal line losses. Even if the relationship between costs and transport distances is understood, the cost allocation process would need to attribute transport distances, and thus costs, to consumer groups with sufficient accuracy. In brief, billing consumer groups for electric transport distances, on an embedded cost basis would undoubtedly prove to be daunting and highly unwieldy. Such an approach would constitute a major departure from the demand-only classification convention and, if implemented, might lead to significant changes in assignable costs across consumer groups.

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

[20] 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.

distances, such an approach would face clear challenges in the form of complexity, cost ambiguity, and uncertainty of stability over time.

Another alternative is to conceive of general transport facilities as no more than an extension of generation. If so, these facilities would then be viewed by utilities using a method of classification into demand- and energy-related cost as having a similar mixed demand-energy causation. However, this view of transmission is not common relative to the demand-only perspective.

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

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

- *<u>Conventional Coincident Peak Method.</u>* NLH would determine the class shares of demand in peak hours using an appropriate measure of coincident peak. Hitherto NLH has utilized a 1 CP approach. Often utilities prefer some form of CP calculation that relies on more than the single hour peak hour of the year in order to avoid statistical anomalies from such a small sample. The U.S. FERC has been using a test in its cost allocation proceedings for some years. This test, applied to NLH peak demands, suggests that a 3 CP measure would be preferable to a 12 CP measure, even after 2019. Please see the note below for details.
- *<u>Peak Load Frequency.</u>* This method uses the frequency in which the hour and month where peak loads are expected to occur. Peak load frequency serves

as the basis to determine hourly weights which, by definition, sum to one over an annual period;[21] or,

- *Pro Rata Peak Load distribution.* Based on a max function algorithm, shares of an annual revenue requirement for transmission are assigned to system-level peak load hours *pro rata*. The max function algorithm is also used to estimate marginal capacity costs.[22]

The remaining costs shares[23] are then classified accordingly to energy. For general purpose transport facilities, the energy share basis of allocation can, potentially, weight hourly loads by marginal costs (both in hourly frequency).

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

[21] For NLH, 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.

[22] 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.

[23] 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.

demand costs on a 3 CP basis which assumes the system will peak during the three months with the highest peaks.

As mentioned, NLH currently applies a 1 CP method to transmission cost allocation. This approach has been widely used in the past, for the good reason that the single hour of highest use is the benchmark for system planning.[24] Other time periods, though, have been considered for a number of reasons. First, for many utilities (but not NLH), summer and winter peaks are not far apart and the class shares can differ significantly by season. Giving weight to peak hours in both seasons avoids possibly dramatic changes in cost shares over time. Second, measuring cost shares using a single hour of system peak can be statistically unreliable. As a result, utilities, even strongly seasonal utilities, have gravitated toward a 3 CP alternative to 1 CP.

In an effort to manage the seasonality issue, the FERC has developed three tests of seasonality of peak demands as guides to selection between 3 CP and 12 CP.[25] The three tests are:

- <u>The On- and Off-Peak test.</u> Compute two quotients: average system peaks during the peak season/annual peak demand and average system peaks during the non-peak season/annual peak demand. If the difference between these quotients is less than 19%, the conclusion on this test is that the utility is best represented by a 12 CP measure.
- <u>The Low to Annual Peak test.</u> Compute the quotient of the lowest monthly peak demand and annual peak demand. If that quotient is greater than 66%, the conclusion on this test is that the utility is best represented by a 12 CP measure.

[24] Reference the NARUC *Electric Utility Cost Allocation Manual*, January, 1992, p. 77.
[25] The tests are described in FERC opinion Golden Spread *et al* v. Southwestern Public Service Company, opinion no. 501, dockets EL05-19-002 and ER05-168-001, issued April 21, 2008, at paragraph 76*ff*.

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

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

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

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

FERC Tests of NLH Seasonality
2019-2020

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

If these tests are to be accepted as guidelines, it is not strictly necessary to evaluate which column should serve as the reference point. However, given that the "including exports" results are less than fully conclusive, it is worth reviewing the issue of scenario selection. In our view, the shares allocated to NLH's customer classes ought to be measured with reference to the times when the system is at or near peak usage. This suggests that the full utilization of the system matters. Consider a hypothetical case in which a system's native load customers peak in the winter but that overall use of the system peaks in the summer. When should the shares of customer class usage be measured? If the system is built, either by design or due to project indivisibilities, such that the peak usage is in the summer, then contribution to the summer peak should be determinative.

Note that the preference for the inclusion of export loads in the determination of the peak season does not mean that export loads are included in cost allocation. It is assumed that regardless of the presence of exports, the transmission system is designed to serve native load. The approach recognizes the role of exports in determining the level and timing of system loading, but continues to allocate costs based on native load shares at the time(s) of coincident peak.

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

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

Special Purpose Transmission Facilities. Classification and allocation of these facilities depends upon decisions regarding functionalization. For facilities classified as generation-related, which treats the DC lines of the LTA and LIL as generation leads, allocation compatible with the allocation of other generation assets is appropriate.

Classification and Allocation Recommendations

Generator Interconnection Facilities. We recommend that NLH classify and allocate the costs of Generator Interconnection Facilities in the same manner as their related generation facilities. If NLH adopts marginal cost-based allocation of embedded generation costs, then marginal costs would apply to the financial costs of generator interconnection as well. If NLH retains its existing allocation methods, we recommend that NLH assign interconnection facilities costs with each specific generator and allocate costs in the established manner.[26]

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

Demand-related costs should be allocated based on one of the three methods proposed. The Peak Load Frequency and *Pro Rata* Peak Load Distribution methods offer improved accuracy and stability over time, as well as an hourly analysis approach similar to that

[26] 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.

recommended for generation cost allocation. However, they require more analysis than the traditional CP method. If the traditional CP method is selected, we recommend that NLH adopt a 3 CP approach in preference to the traditional 1 CP approach, for reasons of statistical reliability. (Note that this does not suggest that planners deprecate the importance of the single annual peak for planning purposes but simply use more than one hour for cost allocation.)

Terminal Stations. The charges on capital and O&M costs (revenue requirements) associated with Terminal Stations should be classified as demand-related and allocated according to one of the methods described above.

Special Purpose Transmission Facilities. Assuming that the LTA is functionalized as generation, we recommend that its costs be classified and allocated in the same manner as other generation assets. (Our recommendation under this assumption would be that the LTA be allocated in the same manner as Muskrat Falls, based on marginal cost or, alternatively, equivalent peaker methods.)

If the LIL is functionalized as generation as well, it should be treated in the same fashion as the LTA. If, instead, the LIL is functionalized as jointly generation and transmission, the generation component can be classified and allocated in the same manner as Muskrat Falls. The transmission component would then be viewed as general purpose transmission facilities and classified and allocated in the approved manner.

4.2 Transmission Line Losses

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

1. Interconnection between the Labrador and Island power systems facilitated by the Labrador Island Link (LIL), a dual circuit DC facility (900 MW capability);
2. Coordination of energy management between Churchill Falls and Nalcor's new Muskrat Falls hydro facility (MF or Lower Churchill), facilitated by Labrador Transmission Assets (LTA), a dual circuit 315 kV AC facility (approximately 900 MW capability);
3. Interconnection of the Island system with the Eastern Interconnection, thus facilitating power transactions with the organized power markets of the Northeast through the Maritime Link, a dual circuit DC facility (approximately 500 MW capability); and,
4. Investment in the NLH's high voltage AC network (230 kV) in order to satisfy reliability standards associated with increased power flows across the NLH power system.

The NLH power system is currently comprised of high voltage (230 kV) and lower voltage (66 kV–138 kV) facilities configured within meshed and radial networks. NLH's transmission network spans fairly long distances in order to serve the sizable urban area residing on the Avalon Peninsula (St. John's) as well as rural communities and towns located throughout the Province. Restructuring includes major additions to the NLH network, as identified above. Coupled with the commercial operation of Muskrat Falls and significantly expanded export sales, the impacts on the NLH power system are twofold: flow patterns on key facilities will materially change, most likely; and the overall magnitude of average and marginal losses will likely rise.

Within transmission, system-wide average losses are often tabulated from observed power flows within networks, metered in hourly or monthly frequency. These data provide a historical record: determining total and average transmission losses involves adjusting observed historical quantities (MWh), for application within COS studies.[27] Beginning in 2019 however, major restructuring of the Newfoundland-Labrador Hydro (NLH) system will likely cause significant changes in both the profile and level of average and marginal losses. As a consequence, observed historical losses cannot be readily utilized within COS, following 2018. Thus, the issue: how should line losses be determined for purposes of cost allocation for 2019 forward, in view of the resource changes under way?[28]

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

- Transmission losses are predominantly thermal losses, resulting from line resistances. Larger conductors will generally have lower losses.
- Transmission losses decline significantly with higher conductor voltages, as currents are lower by similar magnitudes.
- Line losses are approximately linear with respect to the length of circuits.
- Power system losses vary with respect to temperature: total and average losses decline under lower ambient temperatures, other factors constant.

Most importantly, thermal losses can change dramatically with respect to changes in load level and flow configuration on circuits. The Company has recently conducted a sizable set

[27] Average losses are non-linear with respect to load level.
[28] 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.

of load flow simulations covering selected seasons and load conditions including: *Winter: Peak, Moderate, and Off-Peak Loads*; *Spring-Fall: Peak and Off-Peak Loads; Cool-Summer: Peak and Off-Peak Loads*; *Warm-Summer: Peak and Off-Peak Loads*.[29] Load flow-based thermal and non-thermal losses resulting from these simulations are as follows:

Load Flow Estimates of Average Losses for the NLH Transmission Network, for Selected Season and Load Scenarios, for 2019
System-Wide Average Power Losses

Winter	
Peak	6.15%
Moderate	6.16%
Off-Peak	4.59%
Spring/Fall	
Peak	6.17%
Off-Peak	4.58%
Cool Summer	
Peak	8.19%
Off-Peak	5.95%
Warm Summer	
Peak	6.43%
Off-Peak	5.47%

The load flow studies[30] reveal some unusual patterns of loss levels across seasons. Specifically, percentage losses do not necessarily decline significantly during off-peak summer periods, although retail loads of the NLH power system vary significantly between the winter peak periods and the summer off-peak season. Sizable power flow withdrawals

[29] *Winter* season refers to the second half of November and December—March; *Spring/Fall* season refers to April, the first half of May, the second half of September, October, and the first half of November; *Cool-Summer* season refers to the second half of May, June, and the first half of September; Warm-Summer refers to July and August.

[30] The results shown above incorporate modifications to the load flow cases in to order to appropriately take account of expectations of differences in dispatch patterns to accommodate non-native loads. The result is improved estimates of energy losses with respect to changes in native loads—which is the relevant context for the immediate study.

at the Bottom Brook network location within the Island system alter the longstanding winter peak-summer off-peak load differences.

As shown above, energy losses within the Island AC 230 kV network can, under selected circumstances, rise during the off-peak summer season, reaching sizable levels. Although retail loads for summer decline, total loads may not be significantly lower in certain regions of the NLH network. Importantly, the power loading on lines within the Island AC high voltage system west of the West Avalon substation, because of the long distances—approaching 500 kilometers—can result in average losses above those of the winter season.

Recommendations

Following the in-service date for MF and its associated transmission links, NLH should estimate average losses with load flow analysis. Load flow study results can then be utilized to parameterize a losses algorithm based on the well-known I^2R approximation. The algorithm is directly applicable to the hourly loads utilized within COS studies, including energy and demand loss factors. For purposes of example, the table below presents estimates of average energy losses arising from recently conducted forecast hourly loss analytics. Shown as percentages of native loads, these average loss estimates are somewhat below—though close to—the losses obtained from the load flow cases. Specifically, average line losses for peak and off-peak hours are as follows:

Average Line Loss Percentage Estimates
NLH Power System for 2019

Month	Peak	Off-Peak	All-Hours	Maximum	Minimum
Jan	6.20%	5.49%	5.87%	7.18%	4.46%
Feb	6.34%	5.79%	6.06%	7.18%	4.82%
Mar	6.13%	6.10%	6.11%	7.31%	5.09%
Apr	6.12%	5.38%	5.77%	7.01%	4.64%
May	4.66%	4.18%	4.43%	5.64%	3.43%
Jun	4.66%	3.40%	4.06%	5.14%	2.88%
Jul	4.75%	3.27%	4.14%	5.12%	2.74%
Aug	4.53%	3.13%	3.93%	4.86%	2.46%
Sep	4.69%	3.41%	4.11%	5.47%	2.79%
Oct	5.05%	4.21%	4.66%	5.64%	3.38%
Nov	5.23%	4.78%	5.00%	6.30%	3.66%
Dec	5.93%	4.59%	5.31%	7.21%	3.10%
Annual	5.44%	4.70%	5.09%	7.31%	2.46%

The monthly average losses shown above were derived from an hourly losses algorithm, as parameterized according to a selection of load flow cases for 2019. As implied, the losses algorithm can be used to obtain estimates of peak and off-peak losses for monthly timeframes. Because of resource restructuring, it may be appropriate, for COS, to estimate and apply regional losses to selected areas of the NLH power system such as Labrador, Avalon Peninsula, and the Island AC network west of the Sunnyside substation.[31] Once sufficient historical experience under the restructured resources has accrued—say, two years—NLH can again utilize observed metered loads as the basis for estimating line losses (transmission energy costs).

[31] 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.

5. OTHER ISSUES

5.1 Rural Deficit

Issue. NLH charges its rural customers at rates based on those of Newfoundland Power, rates which fail to cover the cost of service, which tends to be high in isolated locations. NLH makes up the deficit with supplementary volumetric charges on Newfoundland Power and rural Labrador Interconnected system (RLIS) customers. The methodology of deficit allocation has been under review in the latest GRA, although stakeholders have not agreed on a change advocated by NLH. Does a superior approach recommend itself? Should NLH's proposed allocation based on revenue requirements be adopted in preference to the current approach, based on a representation of cost of service? Given the size of the deficit, should NLH customers continue to be the exclusive source of funds?

Background. Subsidizing rural customers has been a longstanding feature of service in the Province, and the practice of subsidizing small numbers of customers in remote locations is common in other provinces of Canada. In the Province of Newfoundland and Labrador, the subsidy was at one time covered by the Provincial Government but since 2002 the responsibility has been borne by some of NLH's non-rural customers. The customers benefiting from the subsidy are found in four groups: Island rural interconnected (about 23,700 customers) Island isolated (about 800) Labrador isolated (about 2,700) and L'Anse au Loup (about 1,000) totaling about 28,300 customers.[32]

[32] As recorded in NLH's COS model, 2015.

The cost burden of the rural deficit is allocated to NP and to Labrador Interconnected customers, Island industrial customers having been exempted from responsibility in 1999.[33] The Electric Power Control Act mandates that these two customer groups fund the subsidy, but does not prescribe how it is to be allocated.[34] Until recently, the allocation was based on an "equal unit cost" allocation mechanism developed in 1993 by the Board's witness, Mr. George C. Baker.[35] Under this mechanism, NLH classified the deficit total among demand, energy and customer categories based on the total costs in each classification for the NP and Labrador Interconnected rural customers combined. The classified amounts of the deficit were then applied to the combined groups' unit costs for each classification to determine the deficit share for each of the two groups of customers. Essentially, this approach has been viewed as allocating the deficit using a mini-COS study.

The difficulty with this approach is that it allocates relatively large amounts per customer to Labrador customers (who are significantly higher users of energy than Island customers, chiefly due to relatively colder weather and consequent heavy use of electric heating). This approach produced much higher revenue/cost (R/C) ratios for RLIS customers than for NP—1.42 vs. 1.12—as revealed by NLH's recent analysis.[36]

[33] Order-in-Council 2003-347 also specifies that NP customers and Labrador rural interconnected customers are to fund the rural deficit. See NLH, *2013 General Rate Application, Final Submission*, revision 1, p. 14. The 1999 date regarding the Island industrial customers is referenced on p. 15.
[34] 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.
[35] Board of Commissioners of Public Utilities, *Report on … the Proposed Cost of Service Methodology…* February 1993, Appendix 1.
[36] NLH, *2013 Amended General Rate Application*, Section 4.3.1, reference Table 4.2 for the R/C ratios.

NLH analyzed the impact of this approach in response to customer concerns about the impact of the resulting charge, and concluded that it was sensible to modify the approach. After considering options, the utility selected a revenue requirements-based allocation whose purpose is to equalize R/C ratios, and whose effect is to shift the deficit burden in the direction of NP customers and away from Labrador Interconnected customers.

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

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

These methods lead to annual average costs per customer numbers that are very similar between the two groups of subsidizing customers, NP and Labrador Interconnected.[37] In contrast, the established method, based on equalized unit costs, imposes an annual bill increase of $653 on RLIS customers and just $217 on NP customers, due to differences in consumption levels. Even with impact equalization by means of the alternative approaches, subsidizing customers would have $207-$235 added to their annual bills.

The 2013 GRA process resulted in commentary on NLH's analysis and proposed change. Most intervenors, and the Board's consultant, Mr. John Wilson, supported a change. The exception, Mr. Larry Brockman, representing NP, felt that the change was unwarranted and that the min-COS methodology was sound.[38] Another intervenor, Dr. James Feehan, participating on behalf of several Labrador towns, suggested four alternative approaches to allocating the rural deficit, including one similar to NLH's customer-based alternative.[39]

In the absence of a cost-causative criterion for allocation of the rural deficit, or of a single best indicator of fairness, the choice of an allocator may be influenced by criteria such as simplicity and by acceptability of outcome to stakeholders. These criteria place the equal unit cost method at a disadvantage on both counts.

NLH's revenue requirements method has the virtue of simplicity of computation and comprehensibility of outcome, relative to its predecessor, the equal unit cost method. The

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[37] NLH, *2013 Amended General Rate Application*, Section 4.3.1, p. 4.10. See Table 4.3 for results.
[38] These views are summarized in NLH's *2013 General Rate Application, Final Submission*, revision 1, p. 71*ff*.
[39] Dr. J. Feehan, *op. cit.*, pp. 7-10.

revenue requirements method also avoids the apparent problem of significant differences in R/C ratios that arises with the equal unit cost method, and the consequent price distortions away from unit cost that arise with R/C ratios of 1.42 for rural Labrador interconnected customers and 1.12 for NP customers.

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

NLH's proposed approach appears well suited to manage the transition process that will occur beginning in 2018 and provide effective guidance in allocation of the rural deficit thereafter. The advantages of this approach are: 1) a perception of fairness based on a sensible and measurable benchmark; and 2) computational simplicity via the R/C ratio. Other suggestions, including the current method, all appear to have identifiable weaknesses in the form of differential price distortions or questionable benchmarks (such as the count of customer numbers) or computational complexity. While fairness itself does not necessarily produce a clear favorite, the combination of influences and the recognized problems of the current method suggest that a change in methods is both justified and timely.

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

5.2 Conservation and Demand Management

Issues. Conservation and Demand Management (CDM) costs tend not to be driven by the specific decisions of individual customers but instead by the program scale decisions of the utility, subject to regulatory approval. Accordingly, there is debate about how CDM costs should be allocated.

Additionally, NLH plans its CDM activities in conjunction with Newfoundland Power (NP). NP customers pay NP CDM costs and are also charged for some NLH CDM costs. Thus, there is concern about double billing for CDM expenses for NP customers. How should costs be allocated to avoid double billing, if it is occurring?

Another consideration is whether the changes introduced to the NLH landscape by the completion of the MF and LIL investments should alter CDM activities and the way CDM costs are allocated.

Background. Like most utilities, NLH undertakes expenditures to induce its customers to undertake cost-effective measures that reduce total consumption and peak demand. Relative to other categories of utility expense, the amounts are not large, but the cost allocation process still produces controversy due the absence of agreement regarding allocation method. NLH's CDM costs are divided into two categories: 1) expenditures dedicated to particular programs, and 2) general CDM program administration costs. NLH treats the latter as conventional O&M costs and allocates them in the same manner as other O&M expenditures.

As proposed by NLH in the 2013 GRA, and as endorsed by parties to the recent Settlement Agreements, specific actual program costs for each year are to be aggregated for the year and are made subject to deferral in equal amounts over a seven-year period. Costs for the period 2009 to 2015 are proposed for recovery. Once deferred, each year's cost recovery is based on the previous year-end's balance of the resulting CDM Deferral Account, which consists of the deferred amounts that apply to that year and true-up amounts from the previous year.

Deferral appears to play two roles. It distributes revenue recovery over a period in which the conservation measures are most likely to be affecting consumption, and smooths the time pattern of cost recovery should expenditures vary significantly across years. The use of deferral accounting and the time period of deferral are not issues in this review.[40]

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

Cost recovery will occur through an add factor or tracker called the CDM Cost Recovery Adjustment, charged against each customer's energy consumption.[41] The Adjustment value is to be differentiated by class as a result of cost allocation/assignment plans. Island Industrial customers will face a different rate from that facing NP and its customers. Conservation program costs associated with the Labrador interconnected system are excluded from this account and charged to NLH income.[42]

NLH does not have to specify formally how its CDM program costs are functionalized or classified, as they are removed from the COS study. However, some indication of the utility's attitude regarding the purpose of CDM programs can be gleaned from the documentation related to the 2013 GRA. NLH has promoted conservation programs whose focus appears to be overall energy conservation, as opposed to peak demand reduction.[43] Additionally, energy savings from CDM programs in the past have been seen as reducing the need for use of the Holyrood thermal generating station.[44]

The current CDM program cost allocation plan begins with segmentation of CDM costs among Island Interconnected, Rural Isolated and Labrador Interconnected categories. The Island Interconnected amount is allocated among NP, IC, and Rural Island Interconnected customers on the basis of the previous year's energy sales. Energy sales are defined as

[41]*NLH 2013 Amended General Rate Application*, Vol. I, Rates Schedules, p. 18 of 46.
[42]*NLH 2013 Amended General Rate Application*, Vol. I, Rates Schedules, p. 18 of 46; and Vol. I, Sec. 3, Finance Schedule V, p. 1.
[43] *NLH 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.
[44] 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.

utility firm and firmed-up secondary and industrial firm invoiced energy, plus rural bulk island interconnected transmission energy. Rural Island Interconnected and Rural Isolated CDM amounts are then re-allocated to NP and Labrador Interconnected customers according to the Rural Deficit allocation rule.[45] As mentioned above, Labrador Interconnected CDM costs are initially allocated to Labrador Interconnected customers, but are written off.

Additionally, NP has its own CDM expenditures, which it allocates to its customers on the basis of annual energy consumption. Thus NP customers pay these costs and are also allocated substantial CDM costs from NLH.[46]

Discussion/Analysis. Although CDM expenses are not caused by the traditional cost causative factors (customer numbers, energy consumption, or peak demand) they might be thought of in terms of the costs that they intend to avoid. One could, potentially, review each CDM program individually and determine whether its focus is overall energy reduction or peak demand reduction or some combination. Views reported by experts during the 2013 GRA suggest that NLH's focus has been exclusively on energy reduction. For example, Lummus Consulting, in its 2013 review of COS methodology stated that, "the justification of the Utilities' CDM programs has been on system energy savings that benefit all customers on the Island interconnected System."[47] Similarly, Bowman and Najmidinov, in expert

[45] *NLH 2013 Amended General Rate Application*, Vol. I, Rates Schedules, p. 18 of 46.
[46] J.W. Wilson, *op. cit.*, p. 36.
[47] *NLH 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.

testimony on behalf of industrial customers, say that "Hydro's focus is on fuel savings through CDM. As a result, Hydro has developed programs targeting energy savings. There are no Hydro programs currently designed to reduce system peak."[48] If true, this objective helps to justify an energy-only cost classification scheme, and the use of an energy allocator in some form, at least for the present.

This perspective may not hold for the future, of course, and NLH should not feel constrained to engage in conservation practices that save energy but do not focus on peak demand. In particular, CDM programs have made efforts to reduce isolated system consumption. (Since these customers' costs exceed the rates charged, CDM programs that improve these customers' energy efficiency help to reduce the rural deficit.) At some point the marginal value of additional consumption spending for this class may fall relative to the value of incremental spending for other classes and other programs. Thus, a system of cost allocation that is flexible enough to deal with program variability is desirable.

Industry practice regarding cost allocation is variable. Some jurisdictions such as North Carolina attempt to distinguish between program objectives and then use demand and energy allocators to allocate separately classified costs.[49] Others are content to use energy-only allocation regardless of the purpose of CDM programs. A NARUC report from 1993, though somewhat dated, provides a useful summary of methodological issues and cost

[48] P. Bowman and H. Najmidonov, *Updated Pre-filed Testimony*, June 4, 2015, p. 62.
[49] North Carolina Utilities Commission, *The Results of Cost Allocations for Electric Utilities…, Part 2. Demand-Side Management and Energy Efficiency Costs.* P. 7*ff*.

allocation practices.[50] The report notes that some jurisdictions directly assign CDM costs to customer classes, and subsequently allocate them based on a variety of allocators, while others simply allocate CDM cost based on energy consumption regardless of cost classification. The policy of direct assignment of each program's costs to its target class stems partly from a principle that one ought not to burden a class with costs when its customers derive no direct benefit from them. The counter-argument, apparently shared by NLH, is that all classes benefit from energy conservation, regardless of the source, and thus should share the burden of paying those costs.

The report views CDM costs as being equivalent to the costs of new generation: both are aimed at meeting the supply needs of all customers. On the basis of cost causation, then, allocation based on some measure of class responsibility for demand and energy should occur, rather than on the basis of the alternative hypothesis of avoiding burdens on classes not eligible to participate in a specific program.

NLH's unusual circumstances may influence its approach. Instead of the conventional mix of residential, commercial, and industrial customers with roughly similar shares of consumption found at most utilities, NLH's usage is dominated by sales to NP, with residual sales to industrial and rural customers. NLH's CDM expenditures are focused on rural and isolated customers, with some expenditure on the Industrial class. These classes benefit from those expenditures but NP's customers also benefit from CDM-related consumption

[50] 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.

reductions. NP's CDM expenditures likewise benefit NLH customers. NP's customers pay all their own CDM costs, allocated on the basis of annual energy. Presumably NLH's (interconnected) customers also benefit from the conservation efforts of NP customers since they are part of the same grid.

NLH and NP jointly plan their CDM activities and expenditures, and the customers of both utilities appear to benefit from the programs that result from this joint planning. The utilities already share costs for one initiative, the takeCharge program, which serves isolated diesel-served communities, along with some other costs.[51]

PUB expert John Wilson argues that NLH should modify its CDM allocation approach to avoid the apparent double-counting involved in NP's CDM allocation.[52] He proposes excusing NP from the initial allocation while retaining the rural deficit-based reallocation. By his computation, more than $300,000 of CDM costs would shift from NP to Island Industrial customers, while NLH would absorb a small increase in Labrador cost allocation.

It is useful to ask how costs would be allocated were the Province served by a single utility. Combined CDM costs would either be directly assigned by program to their target classes or perhaps classified to energy and allocated by means of annual energy. In fact, the latter approach is being considered at present by NLH and NP, with combined cost recovery occurring through a single rider. The approach differs from the Wilson suggestion in that the

[51] *NLH 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.
[52] J.W. Wilson, *op. cit.*, p. 37.

pooled costs allocated to NP before reallocation might not equal NP's current costs. The pooled cost method would simplify computation while still permitting the rural customer CDM cost reallocation to NP and Labrador interconnected customers, and would likely achieve an effect similar to that of the Wilson suggestion.

Another approach that eliminates NP sharing of NLH CDM costs would be to use the intra-class direct assignment method within each utility. NP customers would pay only their costs. This would terminate the rural customer reallocation of CDM costs. This plan would drive up the NLH rural subsidy, producing an offsetting increase in costs that would subsequently need to be reallocated to NP customers. Clarity regarding the size of the subsidy would be improved, though.

The NARUC report suggests an alternative to energy-based allocation. The report indicates that American states that use marginal costing for generation cost allocation appear to avoid the controversy of embedded cost-based jurisdictions. This approach involves allocation of CDM costs based on a marginal cost-based allocator for generation function costs. This is an attractive alternative for NLH following 2019, especially since, as we argue elsewhere in this report, the generation function's costs might best be allocated based on each class's share of load-weighted marginal costs. The approach would allow NLH to view CDM costs, which chiefly avoid generation costs, in the same light as generation.

Under this approach, total NLH CDM costs would be allocated based on NLH's computation of marginal cost. NP could adopt a similar approach, extending marginal cost-based allocation to its own customer classes, or it could retain energy consumption unweighted by marginal cost as its allocator internally if it did not wish to use marginal cost itself. The rural deficit would still reallocate the extra costs of serving rural customers to NP and Labrador customers.

An additional complication for the future is that conservation expenditures will serve not so much to reduce energy use and, hence, generation costs but, in the absence of transmission constraints on the Maritime Link and LIL, to enable increased exports. Ideally, NLH and NP will jointly plan CDM program scale to optimize use of system resources (and to minimize uneconomic use of fossil fuel generation) with an eye to profitable export sales. Thus, if prices in the ISO of New England (ISONE) are forecast to be high on average in coming years, indicating tight resources in the Eastern Interconnection, it would be cost effective to increase CDM expenditures, while low ISONE price expectations would reduce the value of CDM programs.

A marginal cost-based allocation of CDM costs would be a useful and compatible element of this environment. Additionally, the use of marginal cost-based allocation finesses the issue of whether a program is focused on energy or demand, since all CDM costs are allocated based on the generation-related cost shares of the various NLH classes.

Additionally, NLH is seeking to recover CDM costs incurred over the period 2009–2015, with cost recovery deferred over a seven-year period. The question may arise as to whether one cost allocation approach should be preferred over another, especially when the system itself will change significantly in the near future. The deferral does not appear to change the cost-causative relationships involved in that the stream of benefits from these programs takes place over a number of years. Those benefits appear to be best expressed in terms of weighted marginal costs in the current period. The energy-based allocation approach currently in use may not be notably inferior, however, depending on the marginal costs that are used in the future.

Lastly, NLH's cost allocation issues for the future include the degree to which reallocation of costs occurs between classes. Currently, NLH reallocates some allocated CDM costs, based on the reallocation structure of the rural deficit. That allocation may change as a result of the establishment of DC transmission links between the two interconnected areas of Labrador and the Island. However, the changes that are expected in 2019 do not rule out the reallocations mandated at present, provided that Island and Labrador industrial customers are not combined into a single class. Other contractual features make such a combination unlikely.

Recommendations. NLH should continue its current CDM cost allocation approach for the near future. Industry practice admits of both direct assignment by program to class and allocation on the basis of cost causation of the need for supply, usually expressed as energy allocation, but sometimes including both demand and supply. In NLH's case, energy-only allocation seems to have been appropriate in the past, given the energy conservation focus of past programs, but this approach may not necessarily be appropriate in the future.

NLH should consider converting to a marginal cost-based allocation system following the in-service date of Muskrat Falls and its associated transmission assets. This approach avoids classification issues and improves upon an energy-only allocation by virtue of its use of cost weighting. Additionally, marginal cost-based cost allocation is compatible with our recommended future generation cost allocation approach and with the concept of CDM costs as avoiding generation costs primarily.

If acceptable to NP, NLH should adopt the pooled CDM cost computation immediately. This system will simplify computations and clarify NP's share in advance of the reallocation of the rural CDM share. If this approach proves not to be workable, then an approach which allocates each utility's costs within its own customer classes, prior to reallocation of rural costs, would be a feasible second-best.

Regardless of the cost allocation mechanism selected, NLH does not need to revise its revenue recovery scheme of deferred cost recovered through the CDM Cost Recovery Adjustment. The marginal cost-based approach would utilize rate-specific pricing in a manner similar to that currently proposed.

5.3 Specifically Assigned Charges

Issue. Four Island Industrial Customers are assigned a number of specific charges because each of the customers is served by assets that are deemed to serve them alone.[53] The central issue, identified in the most recent GRA, pertains to the allocation of Operating and Maintenance (O&M) costs. Currently O&M costs are allocated to these customers based on asset share, with asset value defined in terms of original cost. Periodic investment in new or

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

upgraded facilities results in variation in shares over time across customers due to variations in age of plant.

Background. The issues surrounding specific cost assignment have grown in the past decade as the value of the charges has increased. Charges for the 2007 Test Year were $0.7 million while those for the 2015 Test Year were $1.7 million, spread across four customers: Corner Brook Pulp and Paper (CBPP), North Atlantic Refining, Ltd. (NARL), Teck, and Vale Newfoundland and Labrador Limited (Vale).[54] O&M, depreciation expense, and return on debt and equity are the bulk of the charges, in declining order, with O&M constituting somewhat more than half in aggregate. Customers who paid for their assigned assets through contributions in aid of construction (CIAC) pay for O&M only.

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

Assignment of a share of O&M expenses to the Island Industrial class and to its customers requires use of a sharing mechanism applied to total O&M. The basis for identifying O&M costs assigned to the customer group is the group's share of transmission plant in service,

[54] Vale was connected in 2012 and does not currently pay a specifically assigned charge.

with plant valued at original cost. Similarly, allocation of O&M assigned to these four customers is based on their shares of transmission assets, again valued at original cost.

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

As a consequence, direct assignment of transmission assets is not widespread, but NLH may fit the pattern of having significant assignable assets. The Industrial customers with directly assigned transmission assets consume about 10% of Island sales at present and are assigned a little more that 10% of transmission assets in 2015.

Even among utilities that engage in direct assignment, the practice of directly assigning O&M costs is not uniform. Xcel Energy in Minnesota simply allocates all its transmission-related O&M costs on the basis of the CP allocator that it uses for transmission expenses generally. This approach is arguably less precise in allocating O&M costs to direct assignment customers but likely avoids swings in O&M charges to those customers in response to equipment upgrades. More generally, though, it appears that direct assignment of assets leads to direct assignment of expenses, and that assignment is based on original cost.

One customer, (Vale) responsible for roughly $500,000 of directly assigned costs for the 2015 Test Year, proposed an improvement to the determination of O&M charges. Their expert, Mr. Melvin Dean, advocated and set out the steps for development of allocation based on current cost.[55] This technique makes use of Handy-Whitman indexes, which are available for sufficiently detailed segments of the electric utility industry to produce reliable cost indexation over many years.

NLH investigated this approach and found it to be feasible.[56] The utility also found that the outcome of its calculations confirmed Mr. Dean's belief: the relatively newer transmission assets directly assigned to customers, when compared with other transmission assets, produced a reduced O&M cost allocation for the direct assignment customers.[57]

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

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[55] Melvin Dean, *Expert's Report on Newfoundland and Labrador Hydro's Amended General Rate Application*, June 4, 2015, p. 3*ff*.
[56] See V-NLH-083, rev. 1, for a description of the method.
[57] NLH, *2013 General Rate Application, Closing Submissions*, Dec. 23, 2015, p. 76.

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

An alternative might be to track actual expenses associated with each customer's dedicated transmission assets and bill the customer directly, while in addition charging them for their share of remaining transmission-related expenses on the basis of the standard transmission allocator. Under this system, a customer who is directly assigned high asset costs for new or upgraded transmission assets would also have the lower expenses associated with new equipment. NLH would need to investigate whether its accounting systems would find this approach to be cost effective. Directly assigned O&M costs would be removed from the COS, although customers would continue to be allocated their share of common transmission-related O&M costs. The outcome of this approach is fairly allocated cost for the share of the transmission system common to all customers plus charges for actual repair costs. Depreciation and return on investment on the dedicated assets would still be based on original cost, in conformance with charges for other assets.

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

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

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

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

The current method of allocation of O&M expenses is correctly viewed by customers and NLH as problematic, since direct assignment on the basis of original cost appears to be poorly correlated with actual expense patterns over time. There appears to be a feasible improvement, based on determination of test-year transmission asset value via Handy-Whitman indexes.

If NLH finds that keeping separate accounts for each industrial customer's transmission repair expenses is feasible, then the utility could adopt a simpler approach than that of indexing by charging each customer for their actual expenses and allocating remaining utility transmission O&M costs via the established allocator for such costs. This approach recognizes that assets of lesser vintage likely are associated with lower repair costs. Allocation of other costs arising from direct assignment of assets (depreciation and return on investment) can be derived from original cost.

We also recommend that NLH adopt the process of separate accounting of actual O&M expenses for each customer, if feasible in terms of internal accounting processes. The charges for services would include a markup for A&G services. If this approach is not feasible, using current-year (or "constant dollar") costs for direct allocation of O&M expenses would provide a partial remedy to perceived excessive charging for O&M expenses. If that approach still appears to NLH to allocate excessive costs relative to actual costs, then abandoning direct allocation of O&M expenses would be an acceptable strategy.

5.4 Frequency Converter

Issue. Corner Brook Pulp and Paper Limited's (CBPP) paper mill load is served partly through a frequency converter (FC) through the conversion of some of its 50 Hz generation to 60 Hz. The customer faces a number of cost allocation and pricing issues arising from the presence of the converter. As a specifically assigned asset, capital expenditure on the FC induces increases in O&M and other costs allocated to the customer through a specifically assigned charge which is updated each GRA. Underlying the issue of the cost allocation mechanism for specifically assigned charges is a question raised by the customer as to whether the unit should in fact be treated as common rather than directly assigned. The customer's relationship with NLH is affected as well by its piloted Generation Credit service contract and Capacity Assistance Arrangements. While rate design issues will be reviewed in the future, the core issue here is whether the FC is properly directly assigned to the customer. Rate design issues spill over into COS, though, since the customer's power requirements can be reduced by up to 90 MW under the Capacity Assistance Agreements during the winter months.

Background. The CBPP Mill is the last remaining facility on the Island with load served at the 50 Hz frequency. The customer owns and operates hydro plants with a combined installed capacity of approximately 135 MW. The hydro plants generate electricity at both 50 and 60 Hz and the mill site uses energy at both frequencies. Some of the 50 Hz generation produced at the customer's hydro facilities is converted to 60 Hz[58] at the NLH frequency converter to serve its mill load.

Originally, the frequency converter provided services not just to the host customer but to the system as a whole. However, the expansion of the Island interconnected system reduced their contribution to the provision of voltage control for the local mill system, and for conversion of 50 Hz power to 60 Hz for use on site. This change in function over time was the basis for the conversion to specific assignment of the assets in 2001.[59]

Since 2009, CBPP has been operating under a piloted Generation Credit service contract that permits CBPP to maximize the efficiency of its 60 Hz Deer Lake Power generation. The agreement allows Hydro to call on CBPP to maximize its 60 Hz generation (including the frequency converter) prior to increasing generation at Holyrood for system reasons and prior to starting its standby units (i.e., a "capacity request"). However, capacity is only made available to the grid in this manner if Mill loads are reduced and CBPP is able to generate in excess of what it requires for its own use. Otherwise, if the Mill is using its maximum power requirements, there is no excess generation made available to the grid under this provision[60]. Savings are provided to CBPP for providing this additional capacity to the

[58] Approximately 18 MW.
[59] See 2001 General Rate Application, IC-NLH-32 Revised.
[S] See RFI IC-NLH-186.

system by permitting CBPP to exceed its firm power requirements and to avoid costs associated with thermal or standby energy rates.[61,62].

Prior to the winter of 2014/2015, Hydro entered into Capacity Assistance and Supplementary Capacity Assistance agreements with CBPP[63]. Under these arrangements and on rare occasions the facility provides emergency capacity to the grid.[64] This is achieved through load interruption of up to 90 MW at the Corner Brook mill when system generation reserves are low[65]. NLH compensates CBPP for services under these arrangements through fixed winter fees and usage payments.

After the commission of the Muskrat Falls Project, NLH may find that the opportunities for the frequency converter to be used for system support such as capacity assistance may be reduced, since the NLH system will be long in generation with the arrival of Muskrat Falls power. Should an outage occur on the LIL, NLH feels that under certain circumstances such as temporary unavailability of sufficient 10-minute reserves, the capacity assistance may be a consideration. The amount of extra capacity required would be uncertain. If the Capacity Assistance Arrangements were in place, it would provide a platform for payment to CBPP. Considering that there are only transmission constraint issues, CBPP's value of services

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[61] Reference NLH 2015 Amended Exhibit 4, Section 3.3.1 pg.'s 12-13 and Table 8 pg. 21.
[62] See IC-NLH-059 Rev 1.
[63] See IC-NLH-186.
[64] Bowman and Najmidinov, Updated Pre-Filed Testimony, NLH 2013 Amended General Rate Application, June 4, 2015, p. 58.
[65] Net to the system is approximately 80 MW as this level of load interruption at the mill would effectively shut down production from the CBPP cogeneration unit. There are two contractual arrangements for providing capacity: one for Capacity Assistance (up to 60 MW) and another for Supplemental Capacity Assistance (up to an additional 30 MW). There are fixed fees for the Capacity Assistance arrangements only.

provided may drop from its current level, which may be reflected in any future contract payments.

The frequency converter is relatively old, having been placed in service in 1967. It is owned and maintained by NLH. NLH has undertaken significant investment at the FC since Hydro's last GRA. Direct assignment of these costs to CBPP has significantly increased their cost, which is proposed to amount to $891 thousand in the 2015 Test Year. This cost is a combination of $329 thousand of O&M cost, $185 thousand of depreciation, with the residual being predominantly return on debt and equity. Due partly to a reduction in consumption of NLH power, CBPP expects its share of its bill due to directly assigned costs rise to 21%.[66]

NLH maintains, in the most recent GRA, that the "Corner Brook Frequency Converter remains of primary benefit to Corner Brook Pulp and Paper Limited ."[67] Capital expenditures at the FC are subject to the standard Public Utility Board Capital Budget Application process, and customers (including CBPP) are given an opportunity to review and question the Capital Budget Application on a project-by-project basis[68]. Thus, there appear to be questions of interpretation about the role of the frequency converter and associated cost responsibility that interact with the overall issue of specifically assigned charges.

[66] Bowman and Najmidinov, o*p. cit.*, p. 53.
[67] See IC-NLH-186.
[68] See IC-NLH-100 Rev 1.

Discussion/Analysis. Regarding the issue of how to treat the frequency converter, there are a variety of views in discussion in the most recent rate case. Some support the current arrangement. Mr. Patrick Bowman, representing industrial customers, argues for adjusted treatment of the CBPP FC unit on four grounds.[69] First, he believes that the technical limit of 18 MW ought to result in a reduction in the value of the rate base that should be allocated to the customer. Second, he joins others in arguing about improper O&M cost allocation due to the vintage issue.[70] (See the section on direct assignment for a discussion of this issue, including NLH's proposal to allocate on the basis of current rather than original cost.) He also feels that all increases in O&M responsibility since 2007 should be eliminated. Third, he questions the core issue of whether the unit delivers benefits to the NLH system, claiming that the FC unit permits improvements in system stability and the occasional delivery of energy during emergency situations. If benefits are conferred upon the system, then some costs should be allocated in common, arguably. Fourth, he states that the technical constraint on the FC unit forces peak consumption of CBPP (and thus industrial customers as a class) upward by about 4.5 MW. More generally, Mr. Bowman objects to the imposition of expenses to maintain the FC, arguing that these have not improved its operation as was expected.

For the longer term, Mr. Bowman would like to explore changes in ownership of the unit, presumably to alleviate its cost burden. Thus by reducing the asset share of the customer

[69] See Bowman and Najmidinov, op. cit., p. 59*ff*.
[70] In fact, in oral testimony, Mr. Bowman suggests that the direct assignment of O&M charges to specific customers might occur very rarely in the industry, and that a cursory investigation failed to turn up an example. Transcript of Hydro GRA, Sept. 5, 2015, p. 145.

and revising the O&M allocation methodology, Mr. Bowman believes that CBPP and industrial customer cost assignment should be significantly reduced.

The unique 50 Hz situation and the ongoing requirement to convert 50 Hz generation to 60 Hz to supply mill load, suggests that the unit's purpose is predominantly, if not exclusively, to serve CBPP. This suggests that the unit fulfills the basic criterion of direct assignment: facilities that provide service exclusively to a particular customer (or customers).[71] This view is in line with that formed by the Board in its final ruling in the 2001 GRA, which supported the conversion to direct assignment. CBPP is compensated for its services in providing emergency capacity support to the grid under the Capacity Assistance Arrangements.

Regarding cost control, one can understand CBPP's concern for cost effective repairs to an aging unit. From NLH's perspective, ownership imposes the obligation to maintain the unit, and decisions on the scale and cost of the expenditures reside first with the utility. Modifications in the method by which O&M costs are allocated to specific assignment customers may offer some degree of relief to CBPP (as suggested in the section of this report on specific assignment). However, about $550 thousand of annual costs associated with depreciation and return are unavoidable without further action.

Two other issues raised by Mr. Bowman, and mentioned above, pertain to the technical limit of 18 MW on the operation of the FC. CBPP views the limit as having been imposed

[71] Reference NARUC's *Electric Utility Cost Allocation Manual*, p. 74. "For cost of service purposes, these [radial] facilities may be directly assigned to specific customers on the theory that these facilities are not used or useful in providing service to customers not directly connected to them."

upon it by NLH. However, a study by General Electric for Bowater Newfoundland, Ltd. (CBPP's predecessor) recommended the 18 MW limit.[72] This review offers no opinion on this technical topic. It has COS implications through the 4.5 MW impact on peak demand. Since the customer is the source of this limit, it appears that the customer would need to make a technical argument for its adjustment.

Recommendations. We recommend that the FC unit continue to be assigned directly to CBPP, due to its apparent use almost solely by the customer and the availability of compensation for service that is provided from time to time. The questions of demand credit fairness and the appropriateness of the structure of the Capacity Assistance Agreement are a matter for the upcoming rate review which will include an inquiry into the rate structure and pricing methodology. This study cannot pass an opinion on the technical issues surrounding benefit limitations pertaining to the 18 MW technical limit on capacity or on the question of cost effectiveness of repairs.

5.5 Newfoundland Power Generation Credit

Issue. Newfoundland Power owns both thermal and hydraulic generation facilities that contribute to the Island Interconnected supply. While many pricing issues surround this capability, one element concerns the cost of service: the size of the capacity that is credited by NLH to reduce the Newfoundland Power native peak in the current COS study. The COS issue relates to the value to NLH of the generation given as compared to the embedded cost allocation impact of simply reducing the Newfoundland Power native peak requirements to

[72] See IC-NLH 194, Rev. 1.

reflect the generation availability. Upon commissioning of the Muskrat Falls Project, marginal capacity costs on the system are forecast to decline to a low level, whereas the embedded demand costs reflected in the COS study can be materially higher (depending on the classification methodology). The issue thus becomes determining what credit value should be provided to Newfoundland Power for making its capacity available to meet system requirements.

Background. NLH's current COS methodology credits NP for making its generation available to reduce its contribution to system peak under the terms of NLH's Utility tariff. NP annually demonstrates its ability to run its generation to meet the capacity credit reflected in the cost of service study and in the Utility tariff. At the most recent GRA, the 2015 Test Year reflected a generation credit, adjusted for reserves, of 119.3 kW, of which 83 kW is for hydraulic capacity and 36 kW is for thermal generation. The picture is complicated by the presence of interruptible load deliverable by NP customers upon request. NLH also provides a curtailable credit in the tariff to cover provision of curtailment. The result is that NP's "minimum billing demand is computed as maximum native load less these two credited amounts (and a small downward adjustment to reflect an energy conservation incentive).

Discussion. A full discussion of how rates and credits might operate following the Muskrat Falls in-service date is properly set in the upcoming rate review. For the present, the issue of importance is whether NLH will value NP's generation at peak times to the same degree as it currently does (i.e., based on the value of embedded cost). For the first few years, NLH will be long in generation, with reduced need to request supply from NP, in all likelihood, with the exception of supply interruption on the LIL. This situation is analogous to wholesale markets in which increases in net supply are reflected in capacity and reserves market price reductions.

For the moment, it is sufficient to review the anticipated patterns of usage of the NP generation that NLH is likely to call. NLH expects that the increase in available generation supply from Muskrat Falls will reduce the need to call upon NP generation. NP currently operates its hydraulic supply to maximize its hydraulic generation on an annual basis and does so (as requested by Hydro) at daily peak times. Therefore, NP's system peak requirements already reflect the operation of its hydraulic generation. So it is appropriate for NP's native load during system peak times be reduced to reflect the operation of its Hydraulic generation.

The current generation credit for NP's thermal generation in the COS study and the Utility tariff remove the incentive for Newfoundland Power to run its thermal generation to reduce its billing demand. NP is reimbursed for its fuel costs when requested to operate its thermal generation which makes it more expensive for Hydro to call upon than NP's hydraulic services. NLH expects that the utility will not need to call upon NP's thermal generation support to meet native load requirements after Muskrat Falls begins providing energy. Given the reduced need for support, the expectation of need for thermal generation disappears, at least in the early years of Muskrat Falls operation.

For the years following the introduction of Muskrat Falls supply, NLH anticipates less need for NP's generation supply. Under these circumstances, one might anticipate that the thermal generation credit might not be renewed, at least for a period of time.

Recommendations. We recommend that NLH review expectations regarding likely demand for NP's two forms of supply. For testing purposes, eliminating the thermal capacity from the credit would provide a preliminary reflection of the possible outcome of the arrival of Muskrat Falls power.

For the longer term, though, it might be worth investigating a separate pricing arrangement in which the credits are eliminated altogether and a separate arrangement for delivery of supply by the NP generators developed. This would obviate the need to agree on a credit kW amount. Instead, the arrangement would offer a credit for availability, agreed upon each year based on expected net supply conditions and market-quoted capacity value. The agreement would also provide for payment based on some function of marginal costs for the actual delivery of supply upon request. This recommendation is preliminary, but suggests an alternative for future contracting and rate design that offers market-based compensation for both availability and response. This approach is subject to further review in upcoming rate design review.

5.6 Export Revenues/Credits

Issue. There are no requirements in the financing agreements to state that NLH will receive revenues from potential Muskrat Falls export sales power to customers outside the Province. Interconnected customers are, however, required to pay all the costs of the facility and all costs of the LIL and LTA. Instead, all revenues will redound to Nalcor and its shareholder, the Province of Newfoundland and Labrador. NLH customers will receive partial reimbursement under this system by way of reduced taxation relative to what it would otherwise be to sustain provincial government revenues. However, it is worth asking how export revenues could be credited to NLH Island Interconnected customers if the Province were to devise a crediting mechanism to offset the large increases in customer bills that will be necessary to cover the costs of the new facilities. What alternatives are available for allocation of credits in such an event?

Background. The apparent asymmetry between cost and revenues facing Island Interconnected customers (payment of all costs, receipt of no export revenues) is due to the investment decision made to develop these facilities: provide secure supply for Island customers. Under current policy, export revenues are accorded to the people of the Province for use in the manner judged most productive. It is not obvious that credits are automatically due to electricity consumers who will pay for the facilities, but instead is a policy decision of the government.

If the government chooses to provide export revenues partially to NLH customers, there is no cost basis that obviously serves to provide a rebate. An obvious rebate method, though, is a rebate in proportion to allocated costs. This simple approach proportionally reduces costs according to the same rules that allocate the new generation-related costs. Proportional reduction does not alter the shares of costs paid, with the shares being based on some cost-based method of cost allocation. For example, a marginal cost-based allocation of distribution costs would not be affected by this proportional credit mechanism.

Credits likely would take two forms, a base rate rebate for expected exports, and a credit adjustment taking the form of a class-specific energy credit/debit for export overages/shortfalls relative to expectations.

If the credit is large, there might be some issues regarding the relative level of prices and marginal costs. That issue concerns another Canadian utility, Manitoba Hydro. There, under some circumstances, export rebates can bring price close to or below marginal cost. However, the cost-price relationships likely will be different here. At any rate, the key point is that a credit system, if the credit is a sizable share of export revenues, will need to evaluate the likely impact on price.

Naturally, this approach might expect criticism. For example, some may object that NLH exports are likely to be the residual of all system supply that is made available. For example, some may ask why exports should provide credits to Island Interconnected customers only. The allocation rule relies on the assumption that all exports are derived from Muskrat Falls only. The credit could make room for Labrador customers who pay energy charges too.

Recommendation. It is somewhat speculative to inquire about how to allocate a currently hypothetical rebate. In addition, the timing of any export amount may require that it be handled through a deferral mechanism outside the COS study. However, a first review suggests that a rebate proportional to Muskrat Falls and related transmission investment cost allocation is simple and non-distortionary, but could be revised depending on what classes are viewed as entitled to a share of the rebate. Fairness rather than cost causation would figure in such a review.

APPENDIX: SUMMARY OF RECOMMENDATIONS

System Definition

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

Generation

- We recommend that NLH introduce marginal cost-based allocation of embedded generation costs for the Island Interconnected system beginning with the institution of rates that recover revenue to cover payments by NLH for Muskrat Falls and its associated transmission facilities. This change will avoid the need to allocate each generation asset or cost on its own and relates cost to serve to an objective market-based value of generation services that recognizes cost to serve by each rate class in each hour. It appears that NLH can undertake this approach, as the utility already possesses the costing capabilities to generate the requisite marginal cost scenarios.
- Marginal cost-based allocation can be used in the Labrador Interconnected system as well following the Muskrat Falls in-service date. Marginal cost forecasts will be produced by the same process as used for the Island Interconnected system.
- Until the Muskrat Falls project is included in the cost of service, we recommend that NLH continue its current generation cost allocation methodology, with modifications agreed upon in the 2013 Supplemental Settlement Agreement, specifically with

regard to the treatment of Holyrood fuel and wind generation as 100% energy-related.

- If marginal cost-based cost allocation of generation is not adopted for the period after the Muskrat Falls in-service date, the current system, as modified, could be retained after the transition, but with classification of Muskrat Falls costs via the equivalent peaker methodology. It appears that this approach might prove more in line with generation planning practice, and might better reflect the base load role of the unit than would an SLF approach.
- After Holyrood is converted into the role of synchronous condenser, then the plant should be subfunctionalized as transmission and its costs allocated in the same manner as general purpose transport facilities (described in the next section). The reduced fuel costs should continue to be allocated on the basis of energy.
  - If the plant does not immediately come to be used as a synchronous condenser, then it should be retained as generation and functionalized according to marginal cost-based cost allocation. In the event that marginal cost-based allocation is not adopted and the plant is still treated as generation, then the current capacity factor methodology, altered by the use of forecast-only capacity factors, would suffice.
- We recommend that wind resources be allocated in the same manner as other generation facilities if marginal cost-based cost allocation is adopted. If not, then we recommend that NLH adopt a classification method based on NLH planners'

forecasts. Current forecasts indicate that wind generation does not contribute to the ability to meet peak demand and should therefore be classified as 100% energy-related.

Transmission

<u>Capacity Costs</u>

Subfunctionalization

- **Generator Interconnection Facilities.** NLH should continue to assign (functionalize) to generation the costs of generator interconnection facilities.
- **General Purpose Transport Facilities and Terminal Stations.** General purpose transport facilities and terminal stations should be assigned to the transmission function.
  - The converter facilities located at the Muskrat Falls and Soldiers Pond stations should be functionalized in the same manner as the LIL facility.
- **Special Purpose Transmission Facilities.** The special purpose facilities which comprise the Labrador-Transmission Assets (LTA) should be assigned to the generation function due to their role in facilitation of efficient use of hydro facilities along the Churchill River, including the Churchill Falls and Muskrat Falls stations. We recommend that the LIL facility, including its converter facilities, be functionalized as generation, in harmony with the formal cost designation of the facility as providing service to the Island.

Classification and Allocation

- **Generator Interconnection Facilities.** We recommend that NLH classify and allocate the costs of Generator Interconnection Facilities in the same manner as their related generation facilities.
    - If NLH adopts marginal cost-based allocation of embedded generation costs, then marginal costs would apply to the financial costs of generator interconnection as well.
    - If NLH retains its existing allocation methods, we recommend that NLH assign interconnection facilities costs with each specific generator and allocate costs in the established manner.
- **General Purpose Transport Facilities.** We recommend that NLH retain the demand-only classification approach due in part to the absence of an analytically preferable or cost effective alternative, and partly to its acceptance by system planners of its ability to approximate their thought processes.
- Demand-related costs should be allocated based on one of the three methods proposed.
    - The Peak Load Frequency and *Pro Rata* Peak Load Distribution methods offer improved accuracy and stability over time, as well as an hourly analysis approach similar to that recommended for generation cost allocation. However, they require more analysis than the traditional CP method.

- If the traditional CP method is selected, we recommend that NLH adopt a 3 CP approach in preference to the traditional 1 CP approach, for reasons of statistical reliability. (Note that this does not suggest that planners deprecate the importance of the single annual peak for planning purposes but simply use more than one hour for cost allocation.)

- **Terminal Stations.** The charges on capital and O&M costs (revenue requirements) associated with Terminal Stations should be allocated to peak loads, determined according to one of the methods listed above.
- **Special Purpose Transmission Facilities.** Assuming that the LTA is functionalized as generation, we recommend that its costs be classified and allocated in the same manner as other generation assets.
  - If the Lil is functionalized as generation as well, it should be treated in the same fashion as the LTA.
  - If, instead, the LIL is functionalized as jointly generation and transmission, the generation component can be classified and allocated in the same manner as Muskrat Falls. The transmission component would then be viewed as general purpose transmission facilities and classified and allocated in the approved manner.

<u>Line Losses (Transmission Energy Costs)</u>

- Following the in-service date for MF and its associated transmission links, NLH should estimate average losses with load flow analysis. Load flow study results can then be utilized to parameterize a losses algorithm based on the well-known I^2R approximation. The algorithm is directly applicable to the hourly loads utilized within COS studies, including energy and demand loss factors.

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

Other Issues

Rural Deficit

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

Conservation and Demand Management

- NLH should continue its current CDM cost allocation approach for the near future. Industry practice admits of both direct assignment by program to class and allocation on the basis of cost causation of the need for supply, usually expressed as energy allocation, but sometimes including both demand and supply. In NLH's case, energy-only allocation seems to have been appropriate in the past, given the energy conservation focus of past programs, but this approach may not necessarily be appropriate in the future.

- NLH should consider converting to a marginal cost-based allocation system following the in-service date of Muskrat Falls and its associated transmission assets. This approach avoids classification issues and improves upon an energy-only allocation by virtue of its use of cost weighting. Additionally, marginal cost-based cost allocation is compatible with our recommended future generation cost allocation approach and with the concept of CDM costs as avoiding generation costs primarily.
- If acceptable to NP, NLH should adopt the pooled CDM cost computation immediately. This system will simplify computations and clarify NP's share in advance of the reallocation of the rural CDM share.
  - If this approach proves not to be workable, then an approach which allocates each utility's costs within its own customer classes, prior to reallocation of rural costs, would be a feasible second-best.
- Regardless of the cost allocation mechanism selected, NLH does not need to revise its revenue recovery scheme of deferred cost recovered through the CDM Cost Recovery Adjustment. The marginal cost-based approach would utilize rate-specific pricing in a manner similar to that currently proposed.

<u>Specifically Assigned Charges</u>

- We recommend that the transmission assets directly assigned to industrial customers continue to be so assigned due to their use solely by the individual customers and their apparent importance within the Island's transmission assets.
- The current treatment of O&M expenses is correctly viewed by customers and NLH as problematic, since direct assignment on the basis of original cost appears to be poorly correlated with actual expense patterns over time. There appears to be a feasible improvement, based on determination of test-year transmission asset value via Handy-Whitman indexes.
- If NLH finds that keeping separate accounts for each industrial customer's transmission repair expenses is feasible, then the utility could adopt a simpler approach than that of indexing by charging each customer for their actual expenses and allocating remaining utility transmission O&M costs via the established allocator for such costs. This approach recognizes that assets of lesser vintage likely are associated with lower repair costs. Allocation of other costs arising from direct assignment of assets (depreciation and return on investment) can be derived from original cost.
- We also recommend that NLH adopt the process of separate accounting of actual O&M expenses for each customer, if feasible in terms of internal accounting processes.

- If that approach still appears to allocate excessive costs relative to actual costs, then abandoning direct allocation of O&M expenses would be an acceptable strategy.

<u>Frequency Converter</u>

- We recommend that the FC unit continue to be assigned directly to CBPP, due to its apparent use almost solely by the customer and the availability of compensation for service that may be provided to NLH from time to time. The questions of demand credit fairness and the appropriateness of the structure of the Capacity Assistance Agreement are a matter for the upcoming rate review.

<u>Newfoundland Power Generation Credits</u>

- We recommend that NLH review expectations regarding likely demand for NP's two forms of supply. For testing purposes, eliminating the thermal capacity from the credit would provide a preliminary reflection of the possible outcome of the arrival of Muskrat Falls power.
- For the longer term, though, it might be worth investigating a separate pricing arrangement in which the credits are eliminated altogether and a separate arrangement for delivery of supply by the NP generators developed.

Export Revenues/Credits

- It is somewhat speculative to inquire about how to allocate a currently hypothetical rebate. However, a first review suggests that a rebate proportional to Muskrat Falls and related transmission investment cost allocation is simple and non-distortionary, but could be revised depending on what classes are viewed as entitled to a share of the rebate. Fairness rather than cost causation would figure in such a review.

CHRISTENSEN ASSOCIATES ENERGY CONSULTING

MARGINAL COST REPORT, PART I

METHODOLOGY: ESTIMATION OF MARGINAL COSTS OF GENERATION AND TRANSMISSION SERVICES for 2019

prepared for:

NEWFOUNDLAND LABRADOR HYDRO

developed by:

CHRISTENSEN ASSOCIATES ENERGY CONSULTING

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December 29, 2015

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1.0 INTRODUCTION

This report reviews the proposed methods for the estimation of the marginal cost of generation and transmission services (G&T services) provided by Newfoundland and Labrador Hydro ("NLH" or "Company"). Marginal cost refers to the change in total costs associated with a change in the level of services provided. For infrastructure industries, electric power in particular, marginal cost is broadly recognized as the appropriate basis to value incremental resources used in the provision of services. For electricity services, viable estimates of marginal costs assume strategic importance, serving as the basis for short-and long-term resource decisions, cost allocation, and efficient tariff prices. As envisioned, NLH's estimates of marginal costs of G&T services will provide guidance for:

- the allocation of financial costs (revenue requirements) to industrial customers and power distributors (Newfoundland Power); and,
- design of wholesale tariffs for G&T services, where the end result is price incentives for consumers to use electricity efficiently.

Marginal costs reflect incremental costs incurred by NLH to produce and deliver electricity services, at the numerous delivery points across NLH's lower voltage transmission network, the 66kV-138kV network, where the Company's industrial customers and Newfoundland Power receive service. Marginal G&T costs will be estimated in hourly frequency for 2019, and will include energy and reliability cost components.

This report provides a brief review of marginal cost methodology, clarifies the proposed marginal cost estimation for NLH, and concludes with a summary of observations. Estimates of marginal costs for 2019 will be provided in a supplemental report, *Marginal Cost Report, Part II*, soon to follow.

2.0 MARGINAL COST METHODOLOGY

Marginal cost is the change in total cost with respect to a change in the level of output, where output refers to the production and delivery of goods and services. Marginal costs are highly specific to industry and underlying production technology, and the goods and services that are produced and provided. Generally speaking, the provision of retail electricity service is a bundle of upstream services, including:

- *generation services*, in the form of electric energy and reserves;

- *transmission services*, in the form of capacity to provide the long-distance transport of power (energy, reserves) between production locations (generator sites) and delivery locations, including power distribution[1] and large industrial consumers. Transmission services are provided by high voltage electrical networks, configured as either meshed[2] or radial circuits; and,
- *interconnection services* involving the electrical interconnection of generator sites, power distribution, and large consumers with the transmission network. Interconnection involves voltage transformation, often carried out at the various points of delivery. For NLH, this can include both large-scale pad mount transformers and associated control equipment, as well as large substations.[3]

Marginal cost analysis draws upon s*hort-* and *long-run* concepts.[4] The most relevant definition for costing and pricing electricity services is *Short-Run Marginal Cost* ("SRMC"), as estimated for either near real-time or forward periods. As a practical matter, however, short-run marginal costs for transmission and interconnection services are not readily observable, typically.[5] Thus, for these services, estimates of *Long-*

[1] Locations of power distribution would include substations where distributors such as Newfoundland Power take delivery of generation and transmission services.

[2] The term "meshed systems" refers to parallel path electrical systems where power flows from production locations to delivery locations over multiple paths, including single loop circuits and the many parallel paths that constitute vast interconnected networks such as those that make up the Eastern Interconnection.

[3] For estimation of marginal costs, *interconnection* may imply power transactions and the measurement and billing of both the quantities of supply (power generation) and quantities of demand (electricity usage by retail consumers).

[4] Short-run marginal cost is the change in short-run variable costs with respect to a change in load. Some costs remain unchanged in the short run, and are thus referred to as fixed costs. That is, the timeframe – *e.g.,* day ahead – is too short for physical facilities currently in place (the stock of physical capital) to be altered or adjusted. In the short run, the capital-related charges and fixed operations and maintenance costs (FOM) associated with physical facilities do not vary as load varies.

Under LRMC all costs including capital charges and FOM associated with physical resources vary in response to a change in load level. This means that, in the long run, a change in the expected load level precipitates adjustments to physical facilities in order to obtain the desired (least total cost) resource configuration and mix. In the context of the real world, long-run adjustments – *i.e.*, the implementation of adjustments to the resource pool in order to obtain the least cost configuration – may take a very long time, years or a decade. Indeed, the process of implementing long-run adjustments to realize the optimal configuration is likely to be taking place *as the optimal configuration is also evolving*. As a practical matter, then, the LRMC definition of marginal cost is most relevant as a conceptual view. In brief, LRMC is the change in total cost with respect to a change in load if all resources could be adjusted to the optimal configuration *overnight*.

In summary, the most useful marginal cost metric is forward-looking (*ex ante*) short-run marginal cost, where forward-looking SRMC embody expected long-run adjustments. Accordingly, the immediate discussion is confined to SRMC although capacity cost proxies, which are essentially LRMC adjustments to SRMC, are incorporated in the analysis. These cost proxies, in the form of marginal capacity costs are incorporated within SRMC as a surrogate for reliability costs, for both generation and power delivery (Transmission and Distribution, or T&D). Power delivery for the immediate marginal cost study is limited to transmission, however.

[5] The exception is unbundled locational electricity markets, wherein the short-run marginal costs of transmission is equal to the sum of the incremental impacts on locational prices (which incorporate marginal congestion and line

Run Marginal Costs ("LRMC") can often serve as viable proxies for forward-looking short-run marginal costs.

2.1 GENERATION SERVICES

Marginal generation costs consist of *energy* and *reserves*. Reserves provide additional capability to ensure that electricity services are provided with the appropriate level of reliability; hence, the marginal costs of reserves are associated with *marginal reliability costs*. *Marginal energy cost* refers to the incremental fuel and variable operating and maintenance costs associated with a change in load level.

Marginal Reliability Cost refers to the costs associated with unexpected power interruptions – the likelihood and magnitude of electricity demand not served because of power outages. Reliability costs can be measured in several ways including the direct costs incurred as a consequence of unexpected power failures, referred to as *Consumer Outage Costs.* However, outage costs are difficult to objectively measure for forward looking periods, though estimates of outage costs can be drawn from survey results. An alternative approach, referred to as *Capacity Costs*, determines reliability costs according to the incremental costs of generating capacity. In the presence of competitive wholesale markets, incremental capacity costs can be set equal to the observed market prices for generation capacity, as obtained from regional capacity auctions.

2.1.1 Marginal Energy Cost

Forward-looking estimates of marginal energy costs can be obtained in two ways, including *Internal Marginal Production Costs*, and *Market-Based Opportunity Costs*.

<u>*Internal Production Costs*</u>*:* An internal cost approach utilizes estimates of loads including hourly peak and off-peak demands along with primary fuel prices and parameters describing the individual units of the generation fleet such as installed capacity, maintenance schedules, and availability of generation units.[6] Least cost dispatch procedures are simulated, thus obtaining internal production costs over future timeframes.[7] In the case of energy-limited hydraulic power systems, marginal cost involves estimating the likelihood that incremental service to contemporary loads (next hour, day, or week) will impose higher costs on consumers in prospective periods.

<u>*Opportunity Costs*</u>*:* The alternative approach to cost estimation, opportunity cost, sets marginal energy cost according to the expected electricity prices, as estimated for wholesale electricity markets over forward periods. Generally speaking, electricity prices so determined are the result of competitive auction

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losses) among the relevant locations. Essentially, a change in load at a specific location gives rise to changes in costs at multiple locations.

[6] The full set of parameters incorporated in power system simulations can include, for individual units, effective capacity, marginal heat rates, fuel costs, variable operations and maintenance costs (VOM), maintenance time, forced outage rates, time to repair, and ramp rates.

[7] For a simulation, the marginal energy cost in some hour of, say 2019, is the marginal running cost of the highest cost unit dispatched in order to satisfy the total system load in the hour.

procedures, and reflect the highest-valued use of the participating generator units, for the market as a whole. Properly designed, auctions obtain, simultaneously, least-cost short-run supply *and* set prices equal to the marginal cost of supply.

Under least-cost dispatch, internal production costs rise with increased demand. Competitive wholesale power markets present cost-minimizing opportunities not otherwise available: participating service providers and independent generators can maximize the value of their generation resources thus obtaining least total cost for the market as a whole. This result is obtained through 1) the sale of power under the condition when internal costs are less that than auction prices; and 2) the purchase of power from markets when internal costs are above auction prices. In the case of condition 1), it is appropriate to sell power up to the point where the internal marginal production cost approximates auction prices (*i.e.*, the market price). In the case of condition 2), it is appropriate to purchase power up to the point where the internal production cost savings approximates market prices.

In short, in the presence of competitive wholesale markets, the prices obtained reflect opportunity costs, the highest-valued use of marginal resources, such result is fully consistent with least cost dispatch. Generally speaking, an opportunity cost approach is the preferred methodology when service providers are actively engaged in competitive markets. As a practical matter, when applied over forward periods, the opportunity cost approach also involves dispatch simulation,[8] as applied to hourly loads and generation in the regional market. In this way, market prices are marginal costs – hence, the notion of opportunity costs.

Proposed Approach: The 2016 Marginal Cost Study of NLH will adopt the second approach, opportunity cost. For the forward year 2019, generation dispatch is simulated for the relevant regional markets, including those of the New York Independent System Operator (NYISO) and the Independent System Operator of New England (ISO NE). The result is estimates of hourly marginal energy prices, which are then compressed into average prices for the peak and off-peak commercial periods common to regional wholesale electricity markets of North America. Also, hourly marginal energy costs can be organized into peak and off-peak loads specific to the NLH system.[9]

[8] The simulation of forward-looking marginal energy costs is most applicable to thermal systems, and can involve modest-scale Monte Carlo simulation. The analysis procedures can include maintenance scheduling, where individual units are scheduled for maintenance within the year according to the principle of least cost impact. Once generator maintenance is scheduled, the algorithm then commits units on the basis of startup costs and the current status as a matter of chronology. For units which are committed, each model iteration represents a different forced outage realization for the various units individually, leading to different sets of generators and reserve levels across hours. The set of available generators is then ordered into a supply function according to running costs (fuel and VOM). Marginal energy cost – measured at the generator bus bar – is equal to the intersection of the estimated level of demand and the supply function. Note that the simulation of wholesale market prices of generation is similar to the simulation of internal production costs.

[9] The relevant marginal cost of energy is internal NLH, under the condition of flow constraints along the transmissions paths to Northeast markets.

2.1.2 Marginal Reliability Cost

Marginal reliability cost refers to the change in the likelihood of power outage and the associated costs incurred by consumers, as a consequence of a change in load. Outage costs rise with respect to increases in load level, and decline with respect to load decreases. As mentioned above, reliability costs can be measured in three ways including *Consumer Outage Costs*, *Incremental Cost of Capacity* internal to the service provider, and *Capacity Auction Prices* in the presence of competitive wholesale markets for unbundled services. Marginal capacity cost refers to the annual charges related to the installation of capacity. Capacity cost is essentially the shadow price of consumer outage costs, providing that generation supply reasonably approximates least total cost. Marginal generation costs are of course load-related costs.

<u>*Consumer Outage Costs:*</u> Outage cost refers to the value or economic worth foregone by consumers as a consequence of not having electricity service available on demand.[10] Marginal outage cost is measured as $/kWh not served. Annual outage cost can be measured as the product of two metrics: the *Expected Unserved Energy* (EUE) or *Loss of Load Hours* (LOLH), and the costs incurred during power outages, referred to as *Value of Lost Load* (VOLL). In the context of hourly frequency, consumer outage cost is often measured as the product of the likelihood of an outage event, typically measured as *Loss of Load Probability* (LOLP) and *Loss of Load Expectation* (LOLE); and VOLL. Generally speaking, EUE is the preferred outage cost metric for purposes of cost estimation, insofar as the frequency, duration, and depth of power outages (MWs) are implicitly captured.

<u>*Internal Capacity Costs:*</u> Marginal capacity cost refers to the costs associated with incremental changes in expected peak demands. Marginal capacity cost is measured as $/kW-year; charges associated with marginal generating capacity are distributed to those hours in an annual period where reliability standards are not fully satisfied on an expected value basis. Power systems consist of large, highly-specialized facilities and equipment, implemented on a large scale. Because of the sheer scale of the investment, substantial planning and analysis underscore resource decisions. Properly executed, resource decisions are driven by least cost principles: expand total capacity up to the point where, over forward years, the

[10] This definition advances a comparatively narrow interpretation of generation reliability, where the level of realized reliability is measured with respect to load level – essentially, realized reliability is a function of total capacity installed with reference to peak demands. However, reliability can be viewed more broadly to include:

- committed units are capable of satisfying operating reserve requirements – total generation matches real time load changes (ramp speed);
- sufficient network observability such that system operators understand the status of the power system in real time;
- satisfaction of real-time operating parameters, such that supply-side events do not precipitate transient oscillations that challenge system-wide stability limits; and,
- realized voltages that remain within acceptable operating limits, both during peak and off-peak timeframes.

It is useful to mention that, historically, the observed breach of reliability often takes place during timeframes of comparatively modest load levels.

decline in expected outage costs incurred by consumers is just enough to offset the increase in total resource costs. In essence, the notion of least cost planning is an inherently marginal cost concept

Decisions to commit resources are based on expectations of the demand for and cost of capacity, *ex ante*. Necessarily, resource commitments are made in advance, and involve considerable risk with respect to electricity demand and, to a lesser extent, capacity costs. As with all decisions regarding costs and benefits in the future, resource decisions by electricity service providers are subject to forecast error. For generation capacity, resource commitment may take place several years prior to installation. At the time of installation and availability to provide power, demand levels – driven by regional economic activity and weather – may prove to be higher or lower than expectations at the time of commitment. As a consequence, realized outage costs of consumers, and the value of incremental capacity to arrest power outages, may deviate substantially from expectations implicit to expansion plans – for both the current period and near-term years following the installation (or acquisition) of new capacity.[11]

Capacity Auction Prices: This third alternative approach to reliability costs draws upon, where available, capacity auction prices as the basis for marginal capacity costs. The use of capacity prices obtained from competitive auction processes is a conceptually plausible basis to determine the economic worth of capacity insofar as both the New York ISO and ISO New England have organized capacity auctions. As a practical matter, the use of auction prices as the basis for generation capacity costs involves two dimensions: 1) accounting for line losses and, 2) ensuring that transmission capacity is in fact available to import reserve power along the two relevant transmission paths through Quebec and Nova Scotia-New Brunswick for markets of the New York ISO and ISO New England, respectively.

Proposed Reliability Cost Approach: Marginal reliability costs of the NLH 2016 Marginal Cost Study will utilize an internal cost approach, where capacity costs are set according to the internal costs incurred by NLH to provide incremental capacity. Annual capacity costs ($/kW-year) can be distributed to hours according to the approximate distribution of reliability costs across hours. As mentioned, capacity costs are essentially the shadow prices of consumer outage costs, providing that generation supply reasonably approximates least total cost. In our view, this approach is most relevant for the purposes at hand: cost allocation process and tariff design – tariff prices that remain largely unchanged over an annual period.[12]

Marginal generation capacity costs are, of course, exclusively load-related costs and, generally, are vanishingly small at off-peak load levels *on an expected value basis*: a change in load level has no

[11] Recent history chronicles several timeframes with supply-demand imbalance, including the comparative capacity-short position of the Eastern Interconnection during 1997-2001, California during 2002-2003, ERCOT during 2011-2015, and New England since 2004; and the comparative capacity-long position of the overall Eastern Interconnection for 2009 forward. Energy prices, scarcity rents, and capacity prices follow accordingly, with observed short-term wholesale prices reaching exceptional levels (*e.g.*, >$700/MWh) in capacity-short conditions.

[12] Dynamic, short-run marginal cost pricing of electricity, where the marginal prices facing consumers change frequently – *e.g.*, hourly real time pricing, critical peak pricing – take account of short-term changes in supply-demand balance, as a consequence of weather, generator unit outages, and other random events.

measurable impact on the capability of the system to satisfy total loads. However, changes in load levels, either load increases or decreases, can have a pronounced impact on realized reliability under unexpected circumstances. Even at modest load levels, changes in system conditions – *e.g.*, loss of large generator units, or unexpectedly high levels of load during off-peak seasons – can give rise to reliability concerns. At the end of the day, load-related reliability is a matter of available supply with reference to load level, regardless of whether the loads as a matter of magnitude are peak or off-peak. But certainly under expected value conditions, for both load level and available supply, reliability costs with respect to loads are concentrated during peak load timeframes.

Under the condition of complete foresight and knowledge regarding the future need for capacity and the costs of resources, and where resource indivisibility is not present, optimal least cost planning yields marginal capacity costs which approximate marginal outage costs. However, resource indivisibility is often present, insofar as the process of sizing facilities often favors, during the process of construction, oversizing beyond that which is needed during the early years of capacity life, as doing so reduces total facility costs in the long run – over extended future years. Other considerations often weigh on resource decisions and may, appropriately, influence the issue of least cost and, thus, estimates of marginal costs.[13]

It is useful to mention that, in lieu of internal capacity costs, estimates of capacity auction prices for 2019 could seemingly be utilized as the measure of reliability costs, but for practical considerations in the form of delivery constraints: the NLH system is not contiguous to the footprint of the regional wholesale markets with organized capacity auctions. Largely for this reason, the approach options available to the immediate study are limited to internal capacity costs though outage costs could also be estimated through simulation.

2.2 TRANSMISSION SERVICES

__Introduction__: Marginal costs of transmission services, like those of generation, include energy and reliability cost elements, with reliability costs expressed in terms of the outage cost-capacity cost paradigm. Unlike generation, marginal energy costs for transmission are in the form of network congestion and losses.

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[13] The concerns and views of regulatory authorities and interested stakeholders may favor certain resource choices, when compared to the resource set determined with even the most sophisticated analytical tools. As an example, strong social externalities may surface with respect to the announced siting of new generation in some locales.

Finally, risks associated with potential outcomes matter considerably; resource choices that obtain somewhat higher total costs, stated on an expected value basis, may be preferred to alternative lower cost choices, providing that the dimensions of risks are lower. Moreover, risks may be highly asymmetric and laced with low probability-high cost events. To the degree that these events are uncertain and not easily observably within historical experience, it is appropriate for resource decisions to be founded on 1) model results obtained from well-grounded analytical methods, as well as 2) informed intuition and *ad hoc* analysis and peripheral studies where relevant. In short, resource decisions need not necessarily be driven exclusively by the formal analysis implicit to generation planning tools and methods.

As described earlier, transmission services refer to the capability to transport energy from the locations where it is produced – generator sites – to locations where it is consumed – load centers. Generally speaking, generator locations can be described as *points of injection* of electricity into the transmission network; similarly, consumer locations, referred to as delivery points, can be described as *points of withdrawal* of electricity from the network. Transmission facilities can assume both radial and parallel path configurations; parallel paths can be in the form of either loop or meshed networks.

Marginal Transmission Cost, A Definition: The short-run marginal costs of transmission networks consists of energy costs, congestion, and reliability and are specific to time and location. Power systems are dominated by strong network externalities: a change in load (increase or decrease) at a specific location will have impacts on the total costs of serving all locations within the network. Furthermore, the locational cost impacts are specific to timeframe (hour, day, or year). Most remarkably, the marginal cost of transmission is unique to each location. This result, location-specific marginal costs, is a consequence of the physical properties of power systems.

Similar to generation, transmission service providers operate transmission networks in a manner that satisfies established reliability criteria – reliability standards identified by the North American Electric Reliability Corporation and adopted by regional regulatory authorities. Reliability standards are expressed in terms contingency survival and transient stability. Studies gauge the capability of networks to satisfy standards under expected future states of the network, which include expected peak load conditions. The proper expansion of transmission network increases the capability of the network at least cost, given that reliability standards are satisfied. Network expansion can also involve – *i.e.*, can be driven by – the expansion of generation including, as in the case of NLH, a major reconfiguration of power supply. Transmission investment costs complementary to generation are not on the margin with respect to changes expected peak loads and, arguably, should be excluded from marginal costs.

Transmission capability, in contemporary timeframes, is determined predominantly by loads and the spatial configuration of load centers and generation sites. Transmission capacity is expanded in order to satisfy expected peak loads, to reduce line losses, and to mitigate congestion, prospectively. In the case of line losses and congestion, the capability of the network will be expanded up to the point that the decrease in total energy costs associated with a decline in line losses and congestion approximates the incremental costs of expanding the network. In this context, the marginal capacity cost of transmission is the shadow price of reliability, and of energy in the form of line losses and congestion.

In principle, marginal transmission capacity cost is similar to generation as a matter of approach options. Accordingly, marginal capacity costs of transmission can be approached directly through simulation: estimating the impacts associated with the change in loads, including reliability, line loss, and congestion cost effects. Alternatively, marginal transmission costs can be measured in terms of shadow prices, a marginal capacity cost metric.

Proposed Study Approach: The immediate study assumes a capacity cost approach, for determination of peak-load related marginal transmission costs of the NLH system. For the prospective years 2018-2023, marginal transmission costs, stated on $/kW-year basis, are estimated from NLH's transmission expansion plans, and expected peak loads. For the defined period, the marginal transmission capacity cost is equal to the incremental investment costs (stated in 2019 $CAD) associated with peak loads, with respect to projected increases in peak loads.

3.0 SUMMARY OF PROPOSED METHODS

To summarize, the Company's 2016 Marginal Cost study will be based on the following proposed methodology:

3.1 Marginal Costs of Generation Services

Energy Cost based on Opportunity Costs: Energy costs set according to projections of marginal energy prices of regional markets including the New York ISO and ISO New England.

Reliability Cost set according to Internal Capacity Costs of NLH: Reliability costs are based on the incremental capacity costs of an oil-fired combustion turbine generator, situated on a greenfield site near NLH load centers.

3.2 Marginal Costs of Transmission Services

Energy Costs (Losses) Estimated through Simulation Studies: Marginal line losses for transmission services will be estimated from a set of load flow studies. Load flow studies will reflect expected loads and the configuration of the NLH transmission system in 2019.

Reliability Costs Based on Capacity Costs: Estimates of marginal reliability costs of transmission will be determined from the Company's peak-load related expenditures (capacity) for transmission, as planned for forward years through 2023.

4.0 OBSERVATIONS, OUSTANDING ISSUES

Determination of marginal costs necessarily involves a fairly detailed understanding of the underlying power system and market context, at the outset. Our review of the Company's system and markets served reveals highly unusual features which, together, give rise to key challenges for cost estimation. First, the NLH system consists of integrated and isolated systems, where the isolated systems (diesel-powered systems) are likely to have markedly higher average costs. Second, the interconnected system is characterized by very low levels of load density; in addition, generation resources are separated from load centers by long distances. Third, NLH is putting in place a major reconfiguration of its generation and transmission resources – a transformation, literally. The end result: the selection of method(s) for marginal cost estimation must be approached cautiously, paying close attention to how intermediate studies (load flows, capacity cost estimates) are conducted. We harbor several concerns, highlighted by key observations as follows:

- *Energy Valued According to Opportunity Cost:* As discussed, opportunity cost is an appropriate basis for determining the economic value of energy, where service providers participate in formal auction-based markets for energy and reserves. This is the case for the Nalcor system beginning in 2019; as a consequence, the immediate marginal cost study utilizes estimates of market prices for this forward year ('19). Estimates of forward prices implicitly contain a substantial level of uncertainty in the form of energy price risk.

- *Line Losses (Transmission Energy Costs) Based on Load Flow Results:* Energy losses are unusually high, and marginal losses are higher still, because of key properties of the NLH power system including long lines and sparse load concentration. Marginal losses averaged across delivery points will, most likely, significantly differentiate all-in marginal costs according to season and between peak and off-peak timeframe. Marginal losses can vary dramatically with respect to system configuration and the location of the marginal generation (Labrador or Island).

- *G&T Capacity Costs:* For modest-sized power systems such as NLH, physical capital – particularly transmission – is often installed in sizable increments and thus characterized by high levels of indivisibility. As a result, the short-run cost impact arising from modest changes in load level (*e.g.*, < 5.0 MW) cannot be directly associated with incremental capacity. The proposed methodology, referred to as forward-looking short-run marginal costs, can be interpreted as an estimate of the average of the incremental costs that are likely to be incurred over several years, with respect to a change in load. The proposed method has inherent long-run cost elements. At issue is how best to attribute marginal capacity costs to hourly loads.

- *Labrador and Island Loads:* year 2019 is assumed to be the first full year of integration of NLH's Labrador and Island power systems. While the proposed study will provide a load-weighted average of marginal costs for the integrated system, the incremental costs to serve the Labrador loads will likely be much different from the Island loads during some timeframes.

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February 26, 2016

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: Marginal Cost Study – Part II

Further to our correspondence of February 19, 2016, please find attached the original and 12 copies of the above referenced report.

We trust this to be satisfactory. However, should you have any questions, please feel free to contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Geoffrey P. Young
Senior Legal Counsel

GPY/bds

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey Stirling Scales
Sheryl Nisenbaum – Praxair Canada Inc.
Thomas Johnson – Consumer Advocate
Thomas J. O'Reilly, Q.C. – Cox & Palmer

CHRISTENSEN ASSOCIATES ENERGY CONSULTING

MARGINAL COST REPORT, PART II

ESTIMATION: MARGINAL COSTS OF GENERATION AND TRANSMISSION SERVICES for 2019

prepared for:

NEWFOUNDLAND LABRADOR HYDRO

developed by:

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February 26, 2019

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MARGINAL COST REPORT, PART II

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February 25, 2019

[1] Principal investigator and primary author.

1.0 INTRODUCTION

This Part II Report presents estimates of the marginal costs of generation and transmission services (G&T services) provided by Newfoundland and Labrador Hydro ("NLH" or "Company"), for forward year 2019. Part II carries out the marginal cost methods identified in Section 3.0 of the Part I Report[2], *Summary of Methods*. As identified in the Part I Report, NLH's estimates of marginal costs of G&T services provide guidance for:

- the allocation of financial costs (revenue requirements) to industrial customers and power distributors (Newfoundland Power); and,
- the design of tariffs providing G&T service to Island and Labrador customers of NLH, where the end result satisfies fairness criteria while simultaneously providing consumers with price incentives to use electricity most efficiently.

Marginal cost refers to the change in cost with respect to a change in the level of electricity services provided. For NLH, G&T services are provided at numerous points of delivery across NLH's lower voltage transmission system, referred to as the 66kV-138kV network. Marginal costs include energy and reliability cost elements, where reliability refers to the costs incurred by consumers as a consequence of the loss of power supply, referred to as *consumer outage costs*.

Marginal costs can be estimated for G&T services in combination, or separately for generation and for transmission. The 2019 estimates of marginal costs reported herein follow the latter approach: marginal costs are estimated and reported separately for generation and transmission services, then combined to obtain estimates of the *All-In Marginal Costs* including, for generation, marginal costs of energy, operating reserves, and capacity and, for transmission, marginal costs of energy (line losses) and capacity. Cost elements for NLH's generation and transmission functions involve short- and long-run cost elements, and are estimated as follows:

1.1 GENERATION SERVICES

<u>Energy Cost based on Opportunity Costs</u>*:* Marginal energy costs set according to projections of marginal energy prices for regional markets including the New York ISO and ISO New England.

<u>Reliability Cost measured according to 1) Internal Capacity Costs or 2) Opportunity Costs</u>*:*

- *Internal Capacity Costs* refers to the incremental costs of oil-fired combustion turbine generators, situated on a greenfield site near NLH load centers. (Model 1)
- *Capacity Auction Prices (Opportunity Cost)*, as determined by the capacity markets of the Northeast wholesale markets.[3] (Model 2)

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[2] "Marginal Cost Report, Part I, Methodology: Estimation of Marginal Costs of Generation and Transmission Services for 2019", dated December 29, 2015 and filed with the Public Utilities Board December 30, 2015.

[3] Operating reserve prices are included within the reported marginal energy costs, under the Opportunity Cost approach (Model 2).

For purposes of reporting herein, the *Opportunity Cost* of generation capacity (Auction Prices) is the primary, though not exclusive, measure of all-in marginal costs estimates. We anticipate that, for the applications identified above (cost allocation, tariff design), NLH will generally utilize all-in marginal costs inclusive of the New England ISO (NE ISO) auction price of generation capacity for 2019.

1.2 TRANSMISSION SERVICES

Energy Costs (Losses) Estimated through Simulation Studies: Marginal line losses for transmission services are determined from a set of transmission load flow simulation studies. These transmission studies reflect the expected loads of the Island and Labrador service regions, as well as the configuration of the NLH transmission system for 2019

Reliability Costs Based on Capacity Costs: Estimates of marginal reliability costs of transmission will be determined from the Company's peak-load related expenditures (capacity) for transmission, as planned for forward years through 2023.

As described, estimates of the 2019 NLH marginal costs utilize a combination of short- and long-run marginal cost concepts. The 2019 marginal costs are estimated in hourly frequency. For purposes of reporting, the results are presented in monthly frequency, and for peak and off-peak timeframes.

2.0 ESTIMATES OF 2019 MARGINAL COSTS[4]

GENERATION: Marginal Cost of Energy and Reserves: Marginal cost of generation including energy and operating reserves are based on the opportunity costs, determined through the competitive power auctions organized by Northeast U.S. regional transmission organizations, the New York ISO and the New England ISO. These market auction procedures take account of the demand for and supply of generation resource, resulting in market prices for energy and reserves. Market prices capture the market worth of power generation insofar as, by definition, competitive auction-based market prices are equivalent to marginal cost for wholesale electricity markets as a whole. Within unbundled markets, energy and reserve prices are estimated in hourly frequency for same-day (real time) and day-ahead timeframes. Although not reported separately, the marginal costs of operating reserves cover, in total, regulation, spin, and non-spin operating reserves; reserve prices are scaled to 4.5% of the reserve prices paid to generators, in order to reflect the net price paid by loads.[5]

As identified above, *Marginal Cost of Reliability* can be based on estimates of the internal costs of capacity incurred by NLH to provide reliability (Model 1), or according to opportunity costs – capacity auction prices (Model 2). As discussed in the Part I Report, under plausible long-term planning

[4] The marginal costs reported herein are non-weighted averages of the estimates of hourly marginal cost.

[5] The cost of reserves is small, averaging $0.70/MWh, stated in Canadian dollars. Arguably, reserve prices should not be incorporated within marginal costs under the internal capacity cost approach, insofar as they are implicit within the marginal costs of generating capacity.

assumptions, capacity costs approximate the shadow prices of consumer outage costs – the true value of reliability.

TRANSMISSION: Marginal Energy Cost is in the form of line and transformer loss percentages as determined through power system simulation tools (load flow analysis). *Marginal Transmission Reliability Costs*, like generation, are in the form of capacity cost proxies.

ALL HOURS: Presented below are 2019 estimates of marginal generation and transmission costs for Newfoundland-Labrador Hydro.

Table 1: Estimates of Marginal Generation and Transmission Costs for NLH, by Month for 2019 (CAD/MWh)

Average Hourly Marginal Costs (CAD/MWh)

		Energy and Reserve Costs		**Capacity Costs**		**All-In Marginal Costs including Energy, Capacity, Reserves, Losses**	
All Hours		NE ISO	NY, Zone A	Gen	Trans	NE ISO	NY, Zone A
Month	Jan	49.27	51.45	10.00	10.39	67.94	70.14
	Feb	45.04	45.55	8.71	15.19	67.42	67.94
	Mar	33.06	38.63	5.26	16.23	53.63	59.21
	Apr	32.76	32.62	2.04	7.66	42.11	41.97
	May	35.88	33.50	3.48	0.00	38.87	36.49
	Jun	37.34	38.00	9.97	0.00	45.96	46.63
	Jul	44.67	47.91	22.83	0.00	64.39	67.67
	Aug	41.33	45.01	11.13	0.00	50.98	54.68
	Sep	34.24	34.98	6.19	0.00	39.59	40.33
	Oct	37.54	38.12	3.26	0.00	40.32	40.90
	Nov	40.31	41.04	5.29	0.20	44.98	45.72
	Dec	44.51	49.27	10.14	4.51	57.55	62.33
	Annual	39.66	41.36	8.21	4.45	51.10	52.81

The marginal energy and reserve costs for Northeastern wholesale electricity markets (NE ISO; NY ISO, Zone A) reflect estimates of market prices available to NLH from the sale of energy (and reserves) into the respective market. These 2019 marginal cost estimates (opportunity cost-based prices) are non-weighted, adjusted for the estimated Canadian-US exchange rate (1.212), and incorporate charges for transmission line losses along the two regional "paths to markets" available to NLH through Nova Scotia/New Brunswick and through Hydro Quebec, respectively. Also, transmission access fees are incorporated in the marginal cost estimates derived from the markets of the NE ISO.

Several noteworthy observations can be drawn from Table 1, as follows:

- Average monthly prices for energy are only modestly higher during the summer months of July and August, than for the average across the year. This pattern follows directly from load patterns. Over the most recent four years (2012-2015), electricity consumption across months demonstrates that summer peak loads are only modestly higher than winter peak loads, within Northeast electricity markets.

- Inclusion of generation capacity costs (determined under the opportunity cost method – i.e., auction price-basis – within marginal costs causes July marginal costs to rise significantly above the annual average. This result is not surprising: the demand for generating capacity rises non-linearly, as peak loads over the calendar year – i.e., the summer peak loads of July stated on expected value basis – are approached.
- Because the loads and prices of Northeast markets are comparatively high in summer, NLH is in a favorable position for the profitable sale of power during summer months. This is a direct result of the countervailing electricity consumption patterns for Newfoundland and Labrador, where energy consumption is sharply concentrated during winter months.

PEAK HOURS: Shown below are marginal costs for the widely-followed commercial peak period of wholesale electricity markets, week-day hours ending 7am–10pm, as established by the North American Energy Standards Board (NAESB).

Table 2: Estimates of Peak Period Marginal Generation and Transmission Costs for NLH, by Month for 2019 ($CAD/MWh)

Average Hourly Marginal Costs (CAD/MWh)

		Energy and Reserve Costs		Capacity Costs		All-In Marginal Costs including Energy, Capacity, Reserves, Losses	
Peak Hours		NE ISO	NY, Zone A	Gen	Trans	NE ISO	NY, Zone A
Month	Jan	53.88	59.18	12.53	17.74	81.94	87.26
	Feb	50.75	51.50	10.49	23.57	82.94	83.71
	Mar	37.61	42.02	6.86	16.35	59.62	64.04
	Apr	36.48	34.49	2.50	13.98	52.52	50.54
	May	39.86	35.53	4.77	0.00	43.94	39.62
	Jun	44.44	42.80	10.62	0.00	53.48	51.86
	Jul	58.88	59.43	24.61	0.00	79.82	80.40
	Aug	50.51	53.47	13.65	0.00	62.17	65.15
	Sep	38.09	35.82	8.06	0.00	44.96	42.71
	Oct	43.31	41.73	4.20	0.00	46.87	45.29
	Nov	45.25	45.08	6.61	0.40	51.22	51.07
	Dec	50.63	54.01	11.88	9.47	69.95	73.35
	Annual	45.89	46.34	9.78	6.69	60.81	61.28

The analysis results presented above for the peak period largely conform to the *all hours* marginal cost patterns shown in Table 1: opportunity cost-based marginal costs are comparatively high during summer peak load timeframes. The week-day peak period constitutes a 48% share of the total hours of a typical month but a larger share of total energy – thus, higher average loads. As a consequence, capacity costs on the margin are concentrating during peak period hours, leading to higher all-in marginal costs, for summer months in particular. This is evidenced above: for NE ISO and NY ISO respectively, annual marginal energy costs per MWh rise from $39.66 and $41.36 to $45.89 and $46.346 per MWh during peak hours – an increase of 13.9% across the two Northeast markets. In contrast, all-in marginal cost for the NE ISO and NY ISO – which includes energy and capacity – rise from an average annual level of $51.10 and $52.81 per MWh to $60.81 and $61.28 for peak period hours, an increase of 17.5% – a difference of about 26%.[6] In short, capacity costs are strongly centered during peak load hours. Generation capacity cost – for (and only for) the auction-price basis of generation capacity cost – fall almost exclusively during the summer months of June through early September; transmission capacity costs are concentrated during the winter months of January through March and to a lesser extent, April.

OFF-PEAK HOURS: Below are shown 2019 marginal costs for the commercial off-peak hours, including hours ending 11pm–6am for week days and the 24 hours of each of the two weekend days, for a total of 88 hours of the 168 hours that comprise a week.[7]

Table 3: Estimates of Off-Peak Period Marginal Generation and Transmission Costs for NLH, by Month for 2019 (CAD/MWh)

Average Hourly Marginal Costs (CAD/MWh)

		Energy and Reserve Costs		Capacity Costs		All-In Marginal Costs including Energy, Capacity, Reserves, Losses	
Off-Peak Hours		NE ISO	NY, Zone A	Gen	Trans	NE ISO	NY, Zone A
Month	Jan	44.75	43.88	7.53	3.19	54.24	53.38
	Feb	39.85	40.14	7.08	7.57	53.30	53.60
	Mar	29.31	35.83	3.95	16.13	48.70	55.23
	Apr	29.20	30.83	1.60	1.61	32.16	33.78
	May	31.99	31.51	2.21	0.00	33.91	33.43
	Jun	31.66	34.16	9.44	0.00	39.94	42.45
	Jul	30.76	36.63	21.09	0.00	49.30	55.21
	Aug	33.10	37.43	8.87	0.00	40.93	45.27
	Sep	30.88	34.24	4.55	0.00	34.89	38.25
	Oct	31.89	34.60	2.34	0.00	33.91	36.61
	Nov	35.99	37.50	4.13	0.02	39.52	41.04
	Dec	39.01	45.01	8.59	0.05	46.42	52.43
	Annual	33.98	36.81	6.79	2.41	42.25	45.10

The typical level of off-peak marginal costs for comparable months are lower than the annual average marginal cost, by definition; the substantive questions are matters of magnitude and differences in relative cost patterns over months. For both the energy and reserves, and the all-in marginal cost metrics, the percentage differences are similar. Two observations are as follows:

- For the all-in marginal cost metric, the absolute percent difference in off-peak marginal costs compared to the average, is somewhat less than the percentage difference between peak period marginal costs and the average.
- The lower percentage difference between off-peak and average marginal costs, compared to the difference between on-peak and average marginal costs, also holds true for marginal energy and operating reserves. This is also not surprising, as marginal operating costs rise non-linearly as loads rise.

[6] That is, 17.53% is 26.1% above 13.9%.

[7] It is useful to note that, for months, the total of peak hours and off-peak hours are specific to the calendar year insofar as the share of week days and weekend days within each month can vary from one year to another.

For the all-in measure of marginal cost, the differences are largely attributable to the presence of capacity costs, for both generation and transmission in peak period hours, as shown above. This is most evident in the averages across months. For the annual period,[8] the average cost of capacity is $8.21/MWh and $4.45/MWh for generation and transmission, respectively. Within peak period hours, capacity costs rise to $9.780/MWh and $6.69/MWh, for generation and transmission respectively. Owing predominantly to variation in daily load patterns, comparatively small shares of G&T marginal capacity costs frequent off-peak periods. Thus, while at substantially lower cost levels, capacity costs are nonetheless also present during off-peak hours: $6.79/MWh and $2.41/MWh for generation and transmission respectively.

3.0 VARIATION IN 2019 MARGINAL COST PATTERNS

Within months, hourly and average daily marginal energy prices vary considerably as a consequence of variation in loads and, on occasion, abrupt loss in available supply in the form of unexpected forced outages of generator units and, for transmission, in the form of occasional loss of critical-path transmission circuits. Variation can be expressed with commonly applied metrics of statistical distribution. Below are shown two measures of variation: the standard deviation of hourly estimates of marginal costs and, second, the differences between the maximum and average marginal energy costs, shown graphically. Each measure of distribution is presented for peak and off-peak time frames, by month. The first measure of variation, standard deviation, is as follows for peak and off-peak periods across months:

Table 4: Variation in Hourly Marginal Costs during Peak Period Hours for NLH, by Month for 2019 (CAD/MWh)

Hourly Standard Deviations of Marginal Costs (CAD/MWh)

		Energy and Reserve Costs		Capacity Costs		All-In Marginal Costs including Energy, Capacity, Reserves, Losses	
Peak Hours		NE ISO	NY, Zone A	Gen	Trans	NE ISO	NY, Zone A
Month	Jan	7.85	10.00	11.75	15.65	19.40	20.43
	Feb	8.57	8.53	1.07	15.21	18.95	19.23
	Mar	3.83	2.03	0.00	16.88	17.49	17.30
	Apr	2.84	1.27	0.00	13.25	13.25	13.08
	May	3.18	1.56	21.36	0.00	19.04	18.51
	Jun	5.85	5.63	61.11	0.00	51.75	51.53
	Jul	15.10	13.60	123.29	0.00	103.54	103.14
	Aug	8.86	9.38	32.28	0.00	26.93	26.57
	Sep	5.11	4.17	43.32	0.00	37.29	37.20
	Oct	5.01	3.27	0.00	0.00	5.01	3.27
	Nov	6.13	4.06	0.00	2.17	6.74	4.65
	Dec	8.02	7.02	13.60	14.27	20.51	19.41
	Annual	10.18	11.20	49.80	12.86	45.39	45.80

[8] To reaffirm, all analyses are conducted in hourly frequency.

As shown in Table 4 above, standard deviations across the average hourly marginal energy and reserve prices follow relative load levels across months. The relationship is strongly non-linear, as evidenced by the differences between the variation for the off-peak months of April and May and variation during peak load months of July and August.

Table 5: Electricity Consumption across Months for the New England ISO during 2012-2013 (GWh)

New England ISO: Monthly Energy Across Months		
	2012	**2013**
Jan	11,322	11,639
Feb	10,151	10,349
Mar	10,188	10,664
Apr	9,425	9,461
May	10,164	9,940
Jun	10,822	11,022
Jul	13,052	13,840
Aug	12,982	11,734
Sep	10,307	10,256
Oct	9,849	10,003
Nov	10,213	10,295
Dec	11,101	11,701
Total	129,576	130,903

When assessed with respect to variation in energy consumption across months, presented above, the sensitivity of variation in marginal energy costs and prices to loads becomes starkly evident. Energy consumption increases by approximately 32% between the off-peak months of April and May and the peak load months of July and August, for Northeast U.S. markets. For these two timeframes, statistical variation – i.e., the standard deviation of the distribution of hourly marginal cost of energy and reserves – increases by approximately fourfold for the NE ISO and eight times for the NY ISO. Note that the relative increases in variation within hourly all-in marginal costs (including G&T capacity costs), between May-June and July-August, rise by a similar magnitude (though somewhat less).

As presented below, a similar pattern of variation is found for off-peak timeframes though, as expected, the differences in hourly variation in marginal energy and reserve prices are remarkably less, generally speaking.

(reference following page)

Table 6: Variation in Hourly Marginal Costs during Off-Peak Period Hours for NLH, by Month for 2019 (CAD/MWh)

Hourly Standard Deviations of Marginal Costs (CAD/MWh)

		Energy and Reserve Costs		Capacity Costs		All-In Marginal Costs including Energy, Capacity, Reserves, Losses	
Off-Peak Hours		NE ISO	NY, Zone A	Gen	Trans	NE ISO	NY, Zone A
Month	Jan	5.31	5.41	7.19	7.29	12.72	12.23
	Feb	4.99	3.29	6.07	11.89	16.03	14.94
	Mar	2.02	3.82	4.67	17.24	18.35	19.36
	Apr	2.80	1.88	2.55	5.15	6.12	5.81
	May	2.92	2.84	4.67	0.00	4.67	4.52
	Jun	4.15	3.95	10.29	0.00	9.54	9.07
	Jul	5.41	4.93	14.60	0.00	12.89	12.40
	Aug	5.20	4.41	8.25	0.00	7.62	6.91
	Sep	3.68	3.28	7.01	0.00	6.79	6.21
	Oct	3.37	2.57	3.02	0.00	4.12	3.63
	Nov	5.31	4.36	4.87	0.35	6.57	5.62
	Dec	9.73	9.78	7.14	0.63	11.35	11.25
	Annual	6.78	6.26	8.96	8.16	13.03	13.23

As observed, the standard deviation in the hourly energy and reserve prices between warm summer (July, August) and April and May increases by 86% and 98% for the NE ISO and NY ISO, respectively – a comparatively modest differential. However, in contrast with marginal costs within peak load hours, the differences in the variation in all-in marginal costs, for off-peak months of April and May compared to the peak load months of July and August, is higher: for off-peak hours, statistical variation rises by approximately 50% during July and August, a direct consequence of the presence of sizable levels of marginal generation capacity costs within selected off-peak hours during July.[9]

The charts below present the differences between average and marginal energy prices, as estimated for 2019.

(reference following page)

[9] The comparatively high variation in the December off-peak energy and reserves costs is significantly impacted by an anomalous, high reserve price during one hour.

Chart 1: Average and Maximum Marginal Energy Price Estimates during Peak Hours New England ISO and New York ISO Zone A for 2019, USD/MWh

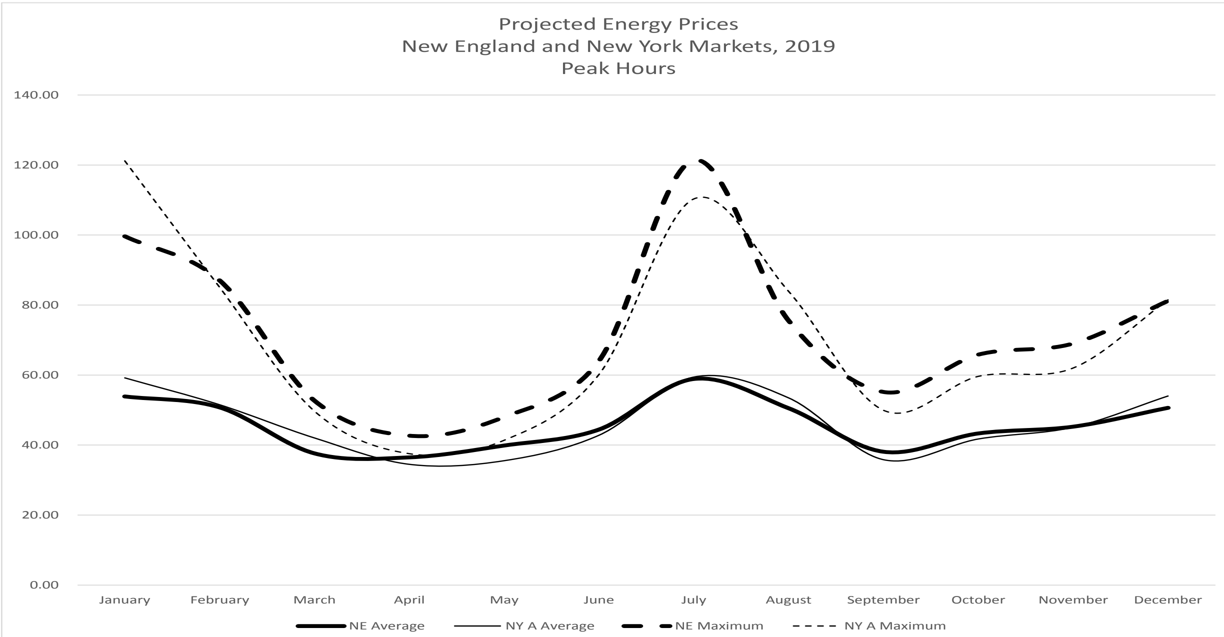
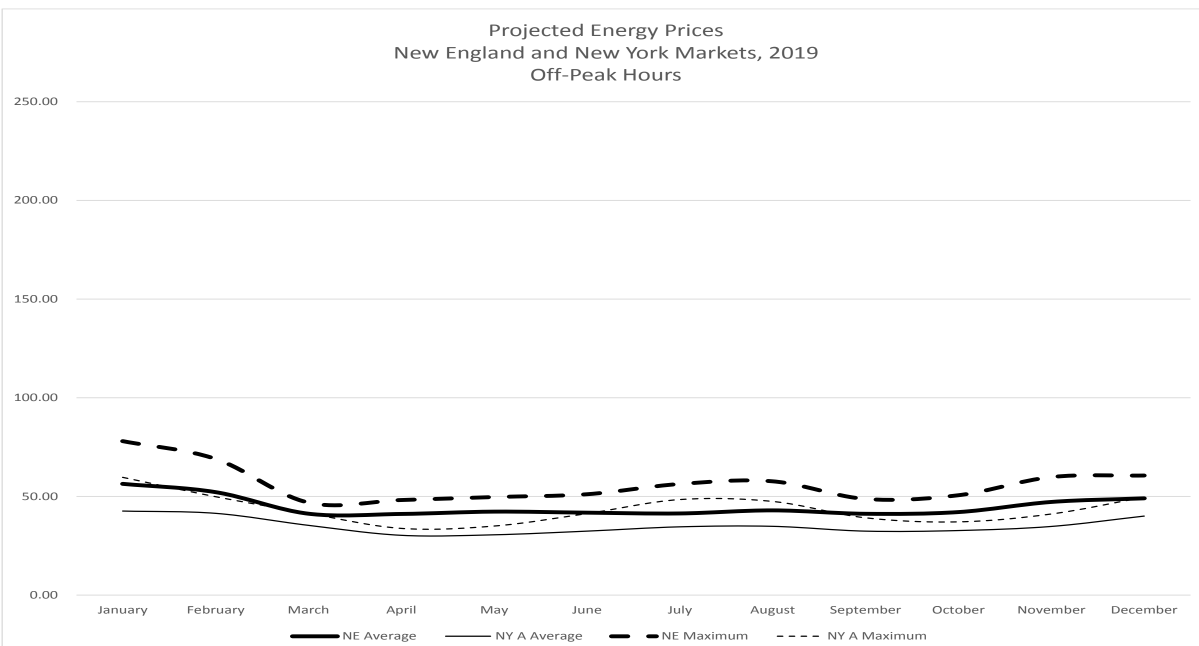


Chart 2: Average and Maximum Marginal Energy Price Estimates during Off-Peak Hours, New England ISO and New York ISO Zone A for 2019, USD/MWh



The marginal energy cost patterns revealed above are common to electricity markets, and are driven by a key feature of electricity markets – non-storability[10] on a meaningful scale. As a consequence, the demand for, and supply of, electricity must be balanced exactly in high levels of frequency (i.e., five minute intervals). Because of non-storage, electricity cannot be readily arbitraged – produced during low-cost hours when supply is plentiful, stored, and then provided during high-value timeframes. The above charts reinforce the evidence presented in the above tables: marginal costs – and, similarly, competitive market clearing prices – often vary greatly from one day to another. As demands approach total supply, non-restricted market prices can approximate consumer outage costs, reaching well beyond $2,000/MWh.

As shown in Chart 1 (Peak Period Hours), for marginal energy prices in both NE ISO and NY ISO markets, the differences between the estimates of the hourly maximum and the average monthly prices expand by factors nearing 4 to 1 between off-peak seasons and the summer peak month, July. Add to this capacity costs, and the differences between average and maximum level prices narrow, because of the fourfold increases the maximum-average differences for the off-peak season, while the July maximum-average difference declines somewhat.

Off-peak prices (marginal energy costs) revealed in Chart 2 are strongly juxtaposed to the peak period energy prices presented in Chart 1. For January, comparatively modest differences are observed between the maximum and the average monthly prices: January maximum-average differences appear to be 3-5 times greater than the maximum-average price differences for the off-peak seasons (April, May). Further, the inclusion of capacity costs causes the marginal costs differences between peak and off-peak timeframes to decline somewhat, a result largely attributable the seasonal energy differences and the frequency with which loads approach capacity constraints across months.

In summary, day-to-day and monthly variation in estimates of marginal costs generally increase with the inclusion of capacity costs – as expected. The differences are comparatively large and, for this reason, it is appropriate for NLH to explore the development of tariff options based on dynamic pricing, where the marginal prices facing consumers are based on short-run marginal costs, set accordingly to market-based opportunity costs. Such approach, when hedged under the structure of a two-part tariff – i.e., a forward-spot combination – provides the means to significantly improve market efficiency: increased reliability while simultaneously lowering the overall level of prices to ultimate consumers.

4.0 GENERAL STRUCTURE OF NLH MARGINAL COSTS

The hourly estimates of the 2019 marginal costs for NLH are based on the second of two potential model structures, as follows.

[10] Notwithstanding the energy storage capability of pondage and pumped-storage hydraulic facilities.

4.1 Model 1: Market-Based Energy Costs and Internal Generation Capacity Costs

The marginal costs under the Model 1[11] construct are defined as follows:

$$All\ In\ Marginal\ Cost\ = MEC * LL^{Network} + GenCap^{Internal\ Cost} * LL^{Peak} + TransCap$$

where,

$$MEC = marginal\ energy\ cost\ (competitive\ market\ prices)$$
$$GenCap^{Internal\ Cost} = generation\ capacity\ costs\ of\ NLH$$
$$TransCap = transmission\ capacity\ costs$$
$$LL^{Network} = marginal\ loss\ factors, NLH\ network\ and\ transmission\ paths\ to\ wholesale\ markets$$
$$LL^{Peak} = marginal\ losses\ at\ peak\ loads$$

4.2 Model 2: Market-Based Energy and Opportunity Costs of Generation Capacity

The definition of marginal costs under Model 2 is as follows:

$$All\ In\ Marginal\ Cost\ = (ME\_RC + GenCap^{Market}) * LL^{Network\ and\ Path} + TransCap$$

where,

$$ME\_RC = marginal\ energy\ and\ operating\ reserve\ costs\ (competitive\ market\ price)$$
$$GenCap^{Market} = generation\ capacity\ auction\ prices\ of\ competitive\ markets$$
$$TransCap = transmission\ capacity\ costs$$
$$LL^{Network\ and\ Path} = marginal\ loss\ factors, NLH\ network\ and\ transmission\ paths\ to\ wholesale\ markets$$[12]

Hourly generation and transmission costs are stated as $/kW-year and, as discussed in the Part I Report, can be assigned to hours in several ways, including estimates of the statistical distribution of *loss of load hours* (LOLH) or *expected unserved energy* (EUE) among hours. The immediate study, however, assigns annual generation and transmission capacity costs ($/kW-year) to hours using two alternatives, as follows:

Parameterized Max Function, which distributes annual capacity costs *pro rata* to the highest hourly loads, as selected by the function. Selection can be fairly narrow or broad, depending on the model parameters.

Statistical Distribution of Peak Demands, where the historical frequency of peak load occurrences within months and hours serve as the basis to distribute annual costs to hours.

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[11] Reference Appendix A for a more complete specification of marginal costs under Models 1 and 2.

[12] Note that, in the case of the Opportunity Cost framework under export conditions, line losses are negative, thus reducing the value of internal resources. However, line losses reverse under the import case, thus raising the marginal value of resources. For NLH, only under rare circumstances does the import case hold.

While both methods are highly plausible, we are attracted to the parameterized max function approach, because of flexibility. In addition, it is common to find that the limits of the available supply of capacity is approached much more broadly across hours than is often suggested by planning models. It is nonetheless useful to draw upon the analytics reached through generation planning tools to determine the appropriate parameters for use within the Max Function, as applied.

5.0 COST ESTIMATES, GENERATION AND TRANSMISSION COMPONENTS

As identified above, the 2019 estimates of marginal costs include energy and capacity components for each function, generation and transmission. Estimates of the various cost components are presented in the following discussions.

5.1 MARGINAL GENERATION COSTS

Marginal energy costs are measured as opportunity costs, and set equal to estimates of market prices for energy and reserves, as determined by regional wholesale electric markets including the NE ISO and the NY ISO. Marginal generation capacity costs reflect two methods: the all-in bus bar costs of the Company's planned capacity additions (marginal cost Model 1); estimates of capacity auction prices, opportunity costs (marginal cost Model 2).[13] Marginal energy costs and capacity costs are reviewed separately below.

5.1.1 Marginal Energy Costs, Generation

As mentioned above, estimates of marginal energy costs assume an opportunity cost basis, where hourly energy costs ($/MWh) are based on the 2019 electricity market outlook of Nalcor Energy for the two U.S. wholesale electricity market regions in which Nalcor Energy will market hydro power, including the markets operated by the New York ISO and ISO New England. As a matter of structure, these two regional energy markets are highly similar: bid-based simultaneous auctions to determine real-time and day-ahead generation prices (spot, forward) for energy and operating reserves.

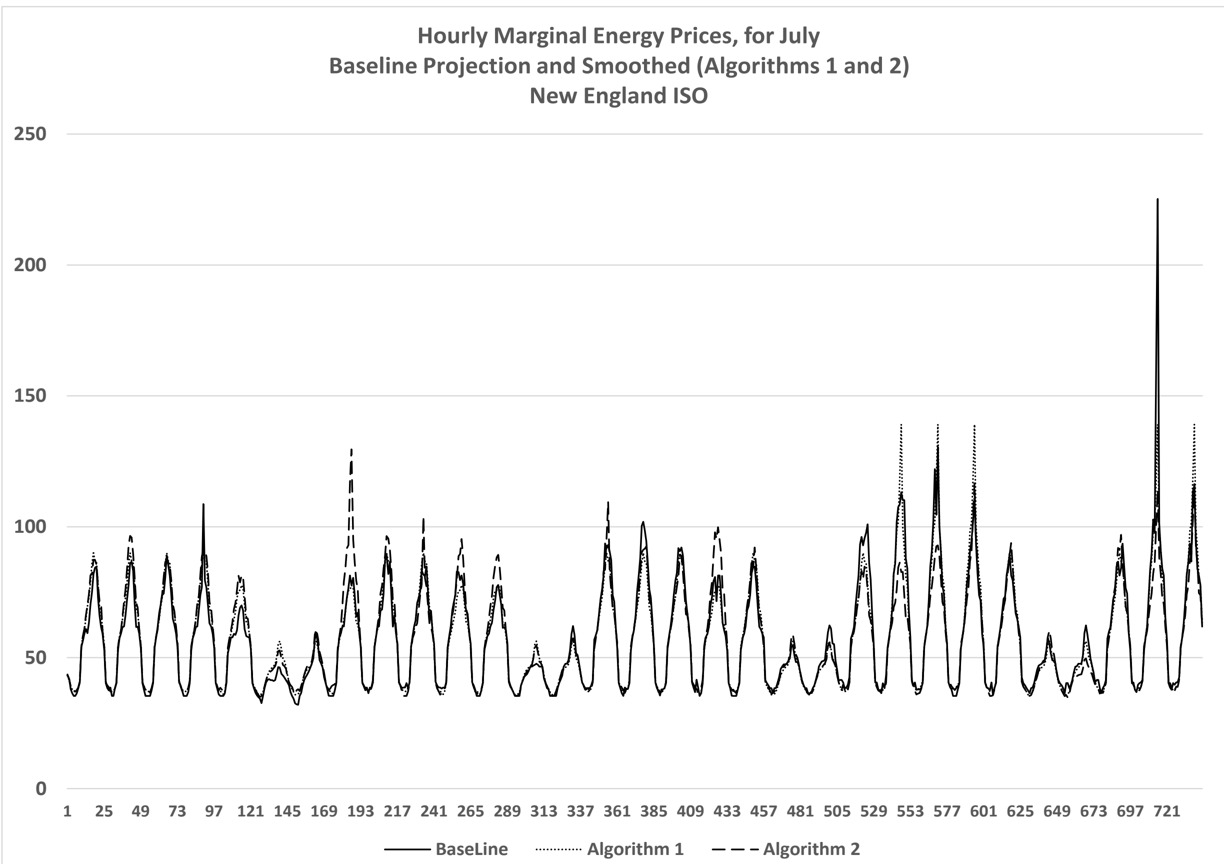
Projections of energy prices across these two markets can be determined through market simulation: for each region, projections of electricity demand are aligned with electricity supply (i.e., generation dispatch curve), as simulated. For each region, projections of marginal energy cost take account of plans for, and forecasts of, new generators, projections of fuel prices, and various generator unit parameters including heat rates and unit availability (EFOR). Analysis procedures take account of expected maintenance time, where individual units are scheduled for maintenance within the year according to the principle of least cost impact. Once generator maintenance is scheduled, the algorithm then commits units on the basis of startup costs and current operating status. Following commitment, each model iteration obtains a different availability (forced outage realization) for each of the various generator units, leading to different sets of generators and reserve levels across hours. The set of

[13] As mentioned, the marginal costs of generating capacity, incorporated within the estimates of all-in marginal costs, are based on opportunity costs (Model 2).

available generators is then ordered into a supply function according to running costs (fuel and variable operations and maintenance expenses). Marginal energy cost – measured at the reference bus plus marginal line losses and congestion for the relevant market zone/area – is equal to the intersection of the estimated level of demand and the supply function.[14] For the immediate study, marginal reserve prices (regulation, spin, and non-spin reserves) are drawn from observed hourly prices over several years, and then scaled to the demand side of wholesale electricity markets.[15]

As mentioned, marginal energy costs can vary greatly within short-run timeframes. Day-to-day variation within estimates of hourly prices for the New England ISO are shown below.

Chart 3: Estimates of Hourly Marginal Energy Costs, New England ISO, for July 2019 (USD/MWh)



[14] Note that the simulation of wholesale market prices of generation is similar to the simulation of internal production costs.

[15] The scaling parameter, set equal to 4.5%, can be revisited and potentially reset. Generally speaking, system operators will vary the physical quantities of reserves held, depending on system conditions. Reference *OP-8 – Operating Reserve and Regulation*, within the operating procedures of ISO New England.

Restated in brief, the statistical variation in hourly and daily marginal energy costs (and reliability costs also) can be exploited with the appropriate tariff mechanisms – e.g., short-run marginal cost-based dynamic pricing – where the end result is substantial gains in the form of reduced costs and improved reliability for ultimate consumers.

5.1.2 Marginal Generation Reliability Costs

5.1.2.1 Marginal Capacity Costs Internal to NLH (Model1)

For Model 1, NLH reliability costs for the generation function are based on the costs of the combustion turbine (CT) supply technology. CTs are well recognized as the least-cost basis by which electricity service providers satisfy generation reliability, and estimates of CT capacity costs, sometimes referred to as the *cost of new entry*, are commonly used as the basis to determine marginal reliability costs for generation services. This standard approach is not without reason: high flexibility, capable of high ramp rates, short construction times, and modest-sized footprint. In addition, combustion turbine generating units are available in a wide range of capacity sizes. Driven in part by the increased availability and a lower expected path of petroleum and natural gas fuel prices, CTs have represented a sizable share of the total capacity additions in North American over recent years.

Stated on a \$/kW-year basis, CT capacity costs vary considerably, owing largely to differences in the specifications of units, site-specific factors, and scale economies favoring larger units. For this reason, capacity cost estimates are drawn from NLH's planned expenditures for incremental CT capacity. The cost estimate of NLH's oil-fueled CT capacity, planning-based proxy units, serve as the foundation for the estimation of internal marginal generation capacity cost, and is specified as follows:

$$Capacity\ Cost_{CT} = \left(I_{CT} + I_{M\&S} + I_{F\_Inv} + WK\right) * ECC + I_{GP} * ECC_{GP} + OM_{CT} + A\&G_{wrt\ OM} + Ins_{K,Ops}$$

where,

$Capacity\ Cost_{CT} = total\ annual\ direct\ and\ indirect\ cost\ of\ CT\ technology$
$I_{CT} = direct\ CT\ investment\ expenditure\ including\ interest\ during\ construction$
$I_{GP} = investment\ expenditure\ in\ indirect\ plant\ and\ equipment$
$I_{M\&S} = investment\ expenditure\ for\ materials\ and\ supplies\ inventory$
$I_{F_{Inv}} = investment\ expenditure\ in\ fuel\ inventory$
$WK = working\ capital\ associated\ with\ fixed\ O\&M\ and\ fuel\ inventory$
$ECC = economic\ carrying\ charge\ rate, generation(CT\ expected\ capital\ life)$
$ECC_{GP} = economic\ carrying\ charge\ rate, general\ plant$
$OM_{CT} = annual\ expenditure\ for\ operations\ and\ maintenance$
$A\&G_{wrt\ OM} = annual\ expenditure\ for\ administrative\ and\ general\ expenses$
$Ins_{K,Ops} = annual\ expenditure\ for\ insurance, plant\ and\ operations$

As presented above, generation capacity costs, in total, include the carrying charges on capital and operating costs, stated annually. Capital-related cost is equal to the sum of the direct investment expenditures, general plant, fuel inventory, materials and supplies (M&S), and working capital, multiplied by the carrying charge rate. The carrying charges are based on the *economic carrying charge* approach (ECC),[16] sometimes referred to as trended real capital costs.[17] ECC-based charges rise with respect to shorter capital life; as presented below, the ECC rate for general plant is substantially higher than the ECC rates for generation or transmission capacity– the cost of which is discussed subsequently.

As mentioned, direct investment expenditures are based on NLH's planned for costs associated with the installation of two 25MW CTs at a greenfield site situated on the Avalon Peninsula. These costs, stated in 2015 Canadian dollars, are escalated to 2018-2019 dollars based upon expected inflation, where the historical relationship between gas-fueled generation, simple and combined cycle generators, and observed inflation is accounted for. Further, the capacity cost estimates presume that NLH's CT generators are constructed over a two-year construction cycle, with 27.8% of expenditures occurring during the first year and the remaining share of the total expenditures (72.2%) taking place during the subsequent year. Interest is capitalized during construction at a 7.0% weighted average cost of capital.

Investment in general plant is drawn from the historical relationship, for years 2008-2014, between NLH's capital investment in general and common plant and investment in generation and transmission facilities, measured in real terms, net of economic depletion (depreciation). The materials and supplies inventory associated with NLH's CTs is based on the level of materials and supplies associated with gas-fueled generation, for a sample of several modest-sized U.S. electricity utilities during 2013.[18]

Fuel inventory is set at a sufficient level to cover NLH's expectations for continuous or near-continuous running hours for the planned CT over one week (168 hours), an expected heat rate of 9430/kWh, and energy content of 5.8 MMBTU per barrel. The CTs will utilize No. 2 fuel oil. Prices for No. 2 oil are for

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[16] Economic Carrying Charge refers to the annual "all-in" carrying charges on capital including depreciation, payback of principal, interest charges, corporate income taxes where appropriate, and return on capital including investor perceptions of risk. The ECC rate can be calculated as:

$$I \{[(k-i+t)(1+i-t)^n] / (1+k)\}\{(1+k)^m / [(1+k)^m + (1+i-t)^m]\}$$

where *I=investment*, *k=capital charge rate*, *i=expected inflation*, *t=technological advance*, *n=year*, and *m=expected life of capital*. CA Energy Consulting has this approach automated within a computer program for expedient calculation of the ECC rate.

[17] The economic carrying charge method, for the determination of capital charges, reflects the expected escalation in the costs of new investment over time. Under the condition of rising prices for capital, the economic carrying charges rise over the life of the capital. Thus, the ECC path for capital charges over the life of assets is in sharp contrast to declining capital charges over time, under conventional original cost accounting. Importantly, the discounted value of economic carrying charge over time equal that of the charges under original cost accounting. Under the condition of no escalation in prices over time, the ECC approach is equivalent to levelized fixed charges over the life of capital.

[18] M&S is determined as the ratio of M&S to gross plant, measured in nominal terms. Across the sample of utilities, the average of the beginning and ending amounts for M&S are divided by gross plant, also measured as the average of the beginning and ending balances for year 2013. The sample of utilities include Duke Energy Indiana and Kentucky; Entergy Arkansas, Louisiana, and Mississippi; Kentucky Utilities, Gulf Power, Louisville Gas and Electric Mississippi Power, Old Dominion, and South Carolina Electric and Gas.

2019, based on the settled prices for July 2019, as observed for January 5, 2016 on the Chicago Mercantile Exchange (CME Group).[19] U.S. futures prices are exchange rate adjusted.[20] Costs for transportation are accounted for.

Operating costs comprise direct operating expenses including both fixed and variable costs (O&M), indirect administrative and general expenses (A&G), and insurance charges (Ins). Fixed and variable O&M is based on the Company's estimates, equal to $11.73/kW-year for an installed unit. The average level of A&G expenses is equal to 64.14% of direct operations and maintenances for NLH, estimated over years 2008-2014. Marginal A&G is likely to be substantially less than average A&G because of economies of scale across many of the various support functions and activities which constitute A&G; a review of the Company's recent resource cost history tends to confirm this result. For the immediate study, marginal A&G expenses are set accordingly: one half the Company's average A&G cost level. Insurance costs are set equal to 0.1% of the carrying charges on the Company's CT investment and incremental general and common plant.[21, 22]

Stated on a $/kW-year basis, the capital-related charges total to $138.71 and operating expenditures total $17.76, obtaining a total cost of $156.47/kW-year. The recognition of a reserve margin of 15% adds further to capacity costs in the amount of $23.86/kW-year; similarly, expected forced outage rates (EFOR) of 7% amounts to $13.76/kW-year. Altogether, the estimate of marginal generation capacity cost for NLH during 2019 is $193.48/kW-year.

This marginal capacity cost estimate reflects an installed all-in cost result and may not, for several reasons, necessarily satisfy least-cost supply requirements. First, generation supply for modest-sized power systems often confront a certain conundrum in resource sizing: generation is installed in lumpy increments of physical capital; thus, supply is highly indivisible. Yet, adherence to long-run cost minimization principles suggests that it is appropriate to install capacity additions in sizable increments in order to realize economies of scale in the process of construction and installation. As a consequence, however, supply-demand balance equilibria may not be fully satisfied during the near-term years

[19] For many years, futures contracts for oil and other commodities traded on New York Mercantile Exchange (NYMEX) were often referenced and used as the basis of expected market prices. NYMEX merged with the Chicago Mercantile Exchange to form CME Group in 2007.

[20] The adjustment reflects the average 2015 Canadian-US exchange rate of 1.2888, as reported by the Federal Reserve Bank of St. Louis.

[21] Arguably, insurance costs should cover both materials and supplies as well as fuel inventory.

[22] Substantial quantitative analysis is associated with estimates for A&G and general plant. This work involves the simulation of the real capital stock and real operations and maintenance costs including A&G for NLH over years 1997-2014. This analysis reaches further back, referencing historical cost and service level records from the late 1960s; incorporates Handy Whitman cost indexes relevant to Canada based on estimates of purchasing power parity, and takes account of capital depletion based on a geometric decay function. The simulation of the real capital stock was alternatively estimated using historical exchange rates, and historical cost indexes for Canada's electric power sector, obtained from Statistics Canada.

following installation. Specifically, near-term years may very well constitute a *capacity-long* condition, where the incremental costs of generation capacity exceed marginal reliability costs, measured in terms of outage costs associated with expected loss of load.

A capacity-long condition is expected to hold for NLH during 2019: the NLH power system is not expected to fully utilize 50MW of capacity (two 25MW CTs) to satisfy peak load reliability requirements, even though such additions may well prove appropriate in terms of least total costs over extended years. Accordingly, the immediate study adjusts the all-in cost estimate of generation capacity for NLH downward by 60%, ($118.00) in order to better match load-related reliability requirements for 2019. The end result, for purposes of the Company's 2019 marginal cost study, is generation capacity cost of $77.39/kW-year.

To summarize, the computation of the 2019 marginal generation capacity costs for NLH (Model 1) is shown below:

Table 7: Estimate of the Marginal Cost of Generation Capacity, Newfoundland-Labrador Hydro, 2019 (CAD/kW-year)

Estimate: 2019 Marginal Cost of Generating Capacity
Newfoundland-Labrador Hydro

Investment Cost ($/kW)	Parameters	Investment Costs per kW	Charges on Capital ($/kW-year)
Direct Facility Investment		2,123.7	124.04
General/Common	6.76%	143.55	10.49
Materials and Supplies	2.24%	47.57	2.78
Fuel Inventory		22.92	1.34
Working Capital (%/FOM)	6.16%	0.95	0.06

Charge Rates (%)	Parameters		Cost Elements ($/kW-year)
Carrying Charges, Direct	5.84%		128.22
Carrying Charges, Gen/Com	7.31%		10.49
Insurance Costs	0.10%		2.27
FOM Rate ($/kW-year)	11.73		11.73
A&G Cost Rate (% OM)	32.1%		3.76
	All-In Total Cost/kW-year:		**156.47**
Costs of Reserves (% of Supply)		15.00%	23.47
Cost Effect of E(Forced Outage)		7.00%	13.54
Adjustment for *Capacity-Long* Condition:			(116.09)
	Marginal Cost of Generation Capacity at Bus Bar ($/kW-year)		**77.39**

5.1.2.2 Market-Based Capacity Costs (Opportunity Costs, Model2)

Unbundled wholesale electricity markets, organized under the auspices of regional transmission groups, referred to as either Regional Transmission Organizations (RTOs) or Independent System Operators (ISOs), obtain highly granular market prices, by type of service [23] and by timeframe and location. Within the U.S., unbundled electricity markets can assume either of two general types including *Energy Only* and *Energy plus Capacity* configurations. Both markets involve highly structured procedures to determine market prices for the relevant generation services. While there are a number of nuances associated with the design of auctions, electricity auctions involve two general types including *uniform price sealed bid* auction design for energy markets and, for capacity, *uniform price sealed bid multi-round* and *descending clock* auction structures.

As alluded to, much of the regional wholesale electricity markets of North America are organized under the auspices of RTOs. RTO markets integrate generation and transmission services. Moreover, the procedures to determine prices for services – the process of price discovery – under RTOs are remarkably different from that of contract path market regimes. In the case of RTOs, prices are determined through formal auction procedures; in contrast, the provision for price discovery under contract path markets is often limited to largely informal over-the-counter procedures or, for longer-term transactions, sealed bid discriminatory auctions.

Under an Energy Only market structure, the marginal cost of generation capacity is implicitly financed by the scarcity rent content in prices. The working premise underlying Energy Only markets presumes that wholesale electricity prices for energy, along with reserves, would clear at levels above the running costs of the marginal generator during peak load periods in order to cover capacity costs. Over the course of an annual period, the scarcity rent content within energy prices, summed across hours, would be sufficient to cover the marginal cost of capacity. This view holds that the competitive process would obtain, across multiple suppliers, an aggregate level of installed capacity which would result in sufficient scarcity rents to cover capacity on a going forward basis. Too much capacity begets comparatively low prices, causing suppliers to shed capacity. Too little capacity results in comparatively high prices and improved profitability through higher scarcity rents; in turn, generation suppliers install more capacity up to the point that the total scarcity rent content is closely balanced to capacity costs – an equilibrium condition. Scarcity rents constitute the shadow price of the marginal cost of capacity and, conceptually,

[23] Service types include electric energy, voltage control and reactive power, operating reserves including regulation, spin and non-spin reserves, transmission congestion and line losses (reflected as differences in locational energy prices). Prices are determined with hourly frequency for same-day and day-ahead timeframes (referred to as dual settlements) and for numerous locations within transmission networks. In the case of the Midcontinent ISO (MISO), for example, hourly locational marginal cost-based prices (LMP) are solved for over 2,440 buses which, in turn, are aggregated into hub and zonal prices.

are not far removed from consumer outage costs providing that organizing agents of markets, the RTOs, set planning-based reserves for generation capacity at appropriate levels – perhaps 12-15%.[24]

The fundamental difficulties with Energy Only markets are twofold. First, regulatory authorities tend to cap the prices (price or bid caps); thus, energy prices are not allowed to clear at unconstrained high levels. Because it is the high prices, realized during timeframes of limited supply, which contain much of scarcity rent content over annual timeframes, generators often may not cover total capacity costs stated on an all-in cost basis. Second, historical evidence demonstrates that scarcity rent content within energy prices varies greatly from one year to another. As a consequence, generation suppliers have been exposed to considerable risk of not covering capacity costs.[25] The reasons for sizable departures from well-balanced supply-demand conditions are several – weather, performance of the macro-economy, and unexpected changes in demand as a result of market entry by renewable resources, to name a few.

In brief, high year-over-year variation in scarcity rent content along with constraints on price levels can result in chronic revenue shortages to cover capacity costs. Thus, capacity auctions have been organized in the Eastern RTOs including New England, New York, and PJM.[26] These auctions can be for both short-term forward periods in the case of the Installed Capacity (ICAP) market of the New York ISO, or for longer-forward periods, up to four years in advance of installed commercial availability.

Capacity auctions may involve several rounds of price determination, thus allowing participants to delist and to adjust positions and, for the market as a whole, ultimately reaching market equilibrium price levels. Generators accepted in capacity auctions have bid prices equivalent to or below the relevant market-clearing prices, which are specific to territorial zones within RTO footprints. Winning generators (those within the auction solution) are compensated at the market clearing auction price ($/kW-year). Auction price results reflect levels of compensation that closely approximate the all-in incremental costs (cost of new entry or CONE), net of the revenues that a pure peaking generator would realize from participating in energy and ancillary services markets.

Prices for capacity are determined by the intersection of supply and demand curves associated with generation capacity. The supply function is the extant set of offers: the MW quantities and associated offer prices advanced by the resources participating in capacity auctions. The demand curves are

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[24] For a more complete discussion, please reference *Ensuring Adequate Power Supply for Tomorrow's Electricity Needs*, Mathew Morey, Laurence Kirsch, Kelly Eakin, and Robert Camfield, June 16, 2014, published by the Electricity Markets Research Foundation.

[25] Supply-demand equilibrium is obtained when the marginal costs of capacity ($/kW-year) are equal to marginal outage costs, equal to the product of expected unserved energy (EUE) and value of lost load (VOLL) to retail consumers. Contemporary surveys suggest that VOLL resides within the range of $3.00 to $12.00 per kWh, for most economic sectors. A well-known Canadian researcher, Roy Billinton, has published numerous studies which report outage cost survey results.

[26] Reference *Centralized Capacity Market Design Elements*, Commission Staff Report AD13-000, August 23, 2013, Federal Energy Regulatory Commission.

administratively estimated by the RTOs, determined according to the expected level of realized reliability at various levels of installed capacity: as simulated, consumer outage costs decline rapidly with progressively higher levels of installed capacity. Capacity auctions are typically held for market zone within the territorial footprint of the RTO. In the event of failure to perform – e.g., failure to start when called by system operators – accepted resources may be penalized and may be liable to pay for replacement capacity.

The Forward Capacity Market (FCM) of the New England ISO has a mandatory centralized capacity market. The auction for new capacity together with existing capacity satisfies the Installed Capacity Requirement (ICR). The capacity auction results in guaranteed capacity prices for up to five years.[27] The FCM auction begins at fairly high prices, thus yielding more capacity than the ICR. Over the course of the various auction rounds, capacity prices are steadily reduced under the structure of the declining clock auction procedures. Market clearing capacity prices are settled once the ICR requirements of each zone are satisfied. Existing capacity resources are price-takers, clearing the auction automatically;[28] of course, new capacity resources must provide quantity and price bids in order to ultimately receive capacity-based compensation. Capacity and capacity prices are differentiated by zone. Load serving entities (LSEs) can bilaterally trade capacity for up to three years in advance.

The cost of new entry (CONE) for the New England ISO Forward Capacity Market involves several cost elements for the *Gross Cone* and *Net Cone* cost benchmarks. The gross cost of new entry is computed as:

$$C_{gross} = K + FOM$$

where,

K = capital cost ($/kW month)[29]
FOM = fixed O&M cost ($/kW month)

The Net Cone cost benchmark is computed as:

$$C_{net} = C_{gross} – E – AS – PFP/PER$$

where,

E = revenues earned from the energy market
AS = revenues earned from the ancillary services markets
PFP/PER = revenues (or costs, in which case the values are negative) associated with the Pay for Performance program and Peak Energy Rents

[27] New York auction procedures include voluntary monthly and six-month auctions for summer and winter timeframes, referred to as “capability period”. Offers by capacity suppliers include quantities (MWs) and prices; offers are accepted up to the point that the resulting supply curve satisfies the demand for capacity, as determined with planning simulation tools. Load Serving Entities (LSEs) are allowed to self-supply capacity obligations. Capacity and capacity prices are differentiated by zone. As with New England, load serving entities (distributors) trade capacity up to one month in advance.

[28] Existing capacity resources can influence the market clearing price by exiting the auction, referred to as delisting.

[29] The benchmark capital costs are estimated for specific CT generators including, for example, the LM6000 series or Frame 7 series combustion turbo generators of General Electric.

The net cone value is used to determine the inflection point, where the demand for capacity is downward sloping to the right.

The New England ISO's most recent auction under the Forward Capacity Market covers the market's installed capacity requirements (ICR) for forward year 2019.[30] The auction was conducted on February 10, 2016, covering the NE ISO system as a whole as well as several transmission interfaces, each separately recognized. The interfaces included the New York ISO interfaces of the Cross Sound Cable and the NY ISO-NE ISO bundle of Tie Lines; New Brunswick; and Hydro Quebec interfaces of Phase I/II and High Gate. Auction price results were announced on the following day February 11,[31] and are as follows:

Table 8: Capacity Auction Price Results,
New England ISO for 2019, USD/kW-year

	System Wide	Interfaces with NE ISO	
	Capacity Auction Price	All Other Interfaces	New Brunsick Link
Round 1	$17.30-$14.50	Eq Price	Eq Price
Round 2	$14.50-$11.50	Eq Price	Eq Price
Round 3	$11.50-$8.50	Eq Price	Eq Price
Round 4	$8.50-$5.50	Eq Price	Eq Price
Round 5			$5.50-$2.75

"Eq Price" refers to interface prices equivalent to the system-wide capacity auction price.

The above system-wide auction result, $5.50-$2.75 translates into an annual price of approximately $48.00/kW-year,[32] stated in USD or, equivalently, $58.18/kW-year in Canadian dollars. The capacity auction price is not adjusted for the expected forced outage rate (EFOR) or capacity reserves (≈15%). Insofar as the relevant marginal cost is the differential of total costs with respect to Island and Labrador loads, these adjustments are appropriate: accounting for EFOR obtains a marginal generation capacity cost of $62.55/kW-year; incorporation of planning reserve margins results in a marginal capacity cost of $71.94/kW-year.

5.2 MARGINAL TRANSMISSION COSTS

Marginal transmission costs, like generation, include energy and capacity components, where energy costs are in the form of physical losses, expressed as a percent of load. Marginal transmission losses include the charges for losses within the two transmission paths to Northeast markets, NE ISO, and NY ISO. Each transmission cost component is reviewed below.

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[30] Reference *Parameters for the Tenth Forward Capacity Auction (FCA #10) Capacity Commitment Period 2019-2010*, New England ISO, July 2015.

[31] Reference *Forward Capacity Market (FCA 10) Result Report*, New England ISO, February 11, 2016.

[32] Based on a close-to-midpoint value of $4.00/kW-month.

5.2.1 Marginal Energy Costs, Transmission (Line Losses)

Marginal energy costs for transmission are the physical energy losses within transmission networks. Physical losses include charging losses and thermal losses, often referred to as I^2R losses, where *I* refers to 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.

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

- Power system losses vary with respect to temperature: total and average losses decline under lower ambient temperatures, other factors constant.
- Transmission losses are predominantly thermal losses, resulting from line resistances. Larger conductors will generally have lower losses.
- Transmission losses decline significantly with higher conductor voltages, as currents are lower by similar magnitudes.
- Line losses are approximately linear with respect to the length of conductors.

Most important for the purpose of the immediate study: Thermal losses change non-linearly with respect to changes in the level of loads on circuits. Specifically, marginal losses rise at twice the rate of change of load within power circuits. In support of the Study, the Company conducted a sizable set of load flow simulations covering selected seasons and load conditions, including *Winter: Peak, Moderate, and Off-Peak Loads*; *Spring-Fall: Peak and Off-Peak Loads; Cool-Summer: Peak and Off-Peak Loads*; *Warm-Summer: Peak and Off-Peak Loads*.[33] Each season and load condition is assessed for *Baseline*, *+1%*, and *-1%* cases – 27 cases in all. The load flow cases designated as *+1* and *-1* refer to the percentage change in load level with respect to the corresponding baseline case. Marginal losses are estimated by gauging the change in total losses across the cases (*Baseline, +1, -1*).[34] For the load difference cases (*+1, -1*), net power flows out (exports) of the NLH power system are held constant: load changes are exclusively in the form of differentials in power withdrawals from the Company's 66-138kV system. Across all cases, the marginal generator is located at NLH's new generation facility, Muskrat Falls.

[33] *Winter* season refers to the second half of November and December – March; *Spring/Fall* season refers to April, the first half of May, the second half of September, October, and the first half of November; *Cool-Summer* season refers to the second half of May, June, and the first half of September; Warm-Summer refers to July and August.

[34] Note that the true marginal losses are derivatives of underlying power flow solution, and will be somewhat above the losses calculated as change case differentials.

Table 9: Load Flow Estimates of Incremental Losses for the NLH Transmission Network, for Selected Season and Load Scenarios

System Wide Incremental Power Losses Differences from Baseline Cases			
Winter		+%1	-1%
	Peak	8.33%	12.75%
	Moderate	15.48%	13.33%
	Off-Peak	5.79%	8.26%
Spring/Fall			
	Peak	11.48%	17.70%
	Off-Peak	5.88%	9.91%
Cool Summer			
	Peak	18.18%	16.28%
	Off-Peak	4.17%	8.45%
Warm Summer			
	Peak	9.78%	10.11%
	Off-Peak	5.36%	5.56%

The load flow studies[35] reveal markedly different loss levels with respect to season and load level. Specifically, percentage losses do not necessarily decline significantly during off-peak summer periods, though retail loads of the NLH power system vary significantly between the winter peak periods and the summer off-peak season. Sizable power flow withdrawals at the Bottom Brook network location within the Island system alter the longstanding winter peak-summer off-peak load differences. While summer domestic loads are at comparatively low levels, export sales through Nova Scotia, served by either Island generation or Muskrat falls, increase flows on lines during off-peak seasons. On an expected value basis, Nalcor Energy anticipates that Island resources will often serve exports to NE ISO, in which case marginal and average losses are at moderate levels. On occasion, however, Muskrat Falls may serve as the marginal source of generation, where power flows southeast across the Labrador Island Link to Soldier's Pond situated on the Avalon Peninsula, and then west to Bottom Brook. Differences in line losses across load flow scenarios are as follows:

(reference following page)

[35] The results shown above incorporate modifications to the load flow cases in to order to appropriately take account of expectations of differences in dispatch patterns to accommodate non-domestic loads. The result is improved estimates of marginal line losses with respect to changes in domestic loads – which is the relevant context for the immediate study.

Table 10: Estimated Loads, Exports, and Island High Voltage Line Losses for Peak and Off-Peak Seasons during 2019, NLH Power System

Selected Baseline Load Flow Case Results (MW)			
	Avalon Loads	Exports Sales	Losses, Island 230kV Network
Muskrat Falls on the Margin			
Winter Peak	821.6	158.0	22.9
Winter Off Peak	524.6	158.0	12.0
Warm Summer Off-Peak	272.3	500.0	39.2
Bay D'Espoir on the Margin			
Cool Summer Peak	510.9	158	15.6
Cool Summer Peak	508.9	250	22.6

As shown above, line losses within the Island AC 230kV network can, under selected circumstances, rise during the off-peak summer season, reaching sizable levels. Though retail loads for summer decline, total loads may not be significantly lower in certain regions of the NLH network. Importantly, the power loading on lines within the Island AC high voltage system west of the West Avalon substation; because of the long distances – approaching 500 kilometers – losses can be above that of the winter season.

For purposes of marginal costs contained in the immediate study, line losses are estimated using the well-known I^2R approximation. Specifically, the analytics underlying the hourly marginal cost estimates are parameterized such that the marginal losses, averaged across hours, approximate – but are somewhat below – load flow results, notwithstanding load flows for the cold summer season. Specifically, marginal line losses for peak and off-peak hours are as follows:

Table 11: Parameterized Peak and Off-Peak Marginal Loss Percentages, Estimates for the NLH Power System, 2019

Marginal Loss Percentage					
Month	Peak	Off Peak	All-Hours	Max	Min
Jan	12.4%	11.0%	11.7%	14.4%	8.9%
Feb	12.7%	11.6%	12.1%	14.4%	9.6%
Mar	12.3%	12.2%	12.2%	14.6%	10.2%
Apr	12.2%	10.8%	11.5%	14.0%	9.3%
May	9.3%	8.4%	8.9%	11.3%	6.9%
Jun	9.3%	6.8%	8.1%	10.3%	5.8%
Jul	9.5%	6.5%	8.3%	10.2%	5.5%
Aug	9.1%	6.3%	7.9%	9.7%	4.9%
Sep	9.4%	6.8%	8.2%	10.9%	5.6%
Oct	10.1%	8.4%	9.3%	11.3%	6.8%
Nov	10.5%	9.6%	10.0%	12.6%	7.3%
Dec	11.9%	9.2%	10.6%	14.4%	6.2%
Annual	10.9%	9.4%	10.2%	14.6%	4.9%

As shown, marginal line losses average 10.2%, and reach a maximum of slightly above 14% and a minimum of just less than 5%. Compared to the load flow results, the hourly marginal cost model is calibrated to obtain closely approximate but somewhat lower marginal line losses for two reasons: the load flow studies reflect exceptionally high and low load levels, and are not necessarily reflective of typical load levels of peak and off-peak timeframes across seasons. Second, the native loads of the Island are concentrated on the Avalon Peninsula; consequently, the high levels of average and marginal losses within the AC high voltage system west of West Avalon are less impacted. In essence, a change in load on the Avalon Peninsula is not likely to precipitate marginal losses, measured in percentage terms, at the loss levels obtained in the load studies for the west of West Avalon network.

5.2.2 Marginal Transmission Capacity Costs

The key features of transmission capacity costs are twofold: First, transmission networks are characterized by very large economies of scale: the differences in flow capability between 115kV and 230kV lines can approximate four times, while cost differences may be measurably less – e.g., a factor of 1.5 times – other factors constant. Second, transmission capacity costs, measured in load capability (MWs), change more-or-less one-to-one with respect to transport distances.[36]

Marginal transmission capacity costs are, by definition, load-related costs: the change in total (transmission) costs with respect to a change in load-carrying capability (MW). Over years, however, ongoing investment in transmission is a function of reinvestment (replacement) and, particularly in recent years, upgraded reliability, unrelated to load level. While transmission capability is, often, more stressed during high load periods, power system outage events often take place during moderate load levels, industry history suggests.

Like generation, the marginal capacity cost of transmissions is stated on a $/kW-year basis. For the immediate study, marginal transmission capacity costs are based on forward-looking costs and load changes. The starting point is the Company's estimated budget expenditures associated with NLH transmission expansion plans and estimated growth in peak loads for years 2018-2023. Properly executed and appropriately attenuated, this *change in cost-change in load* approach for estimation obtains plausible transmission marginal cost estimates.

The Company's expected budget expenditures follow directly from transmission plans which, in turn, are driven by the near-term capital plans for three categories of facility needs, including:

- Replacement of aging transmission facilities (replacement);

[36] The main exception to the relationship between distance and total costs is voltage: comparatively long AC transmission lines require voltage support in the form of series compensation-providing technology such as static capacity banks placed along the circuits of long transmission lines in order to manage the inductive capacitance inherent to the facilities.

- Reliability updates to existing network facilities in order to conform to reliability criteria; and,
- Increased capacity to satisfy expected changes in peak demands.

These categories of capital expenditures for transmission are not completely separable. Ratings of transmission lines to handle load is not exclusively determined by voltage; conductor size, conductor material, voltage support over extended distances, and span lengths all contribute to the overall capability transmission circuits, expressed as line ratings. As a consequence, replacement of existing facilities with new equipment often results in improved reliability and, to a lesser extent, increased load carrying capability; this holds true for reliability driven expenditures. As an example, investment in equipment such as static var compensators (SVC) may provide for improved transient stability. But because networks are somewhat more susceptible to transient events during high-load levels, capacity benefits are also obtained. Nonetheless, for purposes of marginal cost analysis – i.e., the *change in cost-change in load* paradigm – load-related transmission expenditures by the Company, as planned over 2018-23, serve as the *cost basis*. Similarly, the Company's forecast path for peak loads for the integrated Island-Labrador system over these years serves as the *load basis*.

Stated on $/kW-year basis, estimates of transmission capacity costs are not specific to any single transmission facility or expenditure, but may include several facilities and a number of individual expenditures over the relevant years. In this respect, load-related transmission capacity cost can be described as an average of incremental expenditures and costs. More specifically, the marginal cost of transmission capacity is determined as follows:

$$\begin{aligned} Capacity\ Cost_{Trans} \\ &= \left(I_{Trans} + I_{M\&S_{TR}} + WK\right) * ECC_{Trans} + I_{GP} * ECC_{GP} + OM_{Trans} \\ &+ A\&G_{wrt\ OM} + Ins_{K,Ops} \end{aligned}$$

where,

$Capacity\ Cost_{Trans} = total\ annual\ direct\ and\ indirect\ cost\ of\ transmission$
$I_{Trans} = direct\ investment\ expenditure, transmission$
$I_{GP} = investment\ expenditure\ in\ indirect\ plant\ and\ equipment$
$I_{M\&S_{TR}} = investment\ expenditure\ for\ materials\ and\ supplies\ inventory, transmission$
$WK = working\ capital\ associated\ with\ FOM$
$ECC_{Trans} = economic\ carrying\ charge\ rate, transmission$
$ECC_{GP} = economic\ carrying\ charge\ rate, general\ plant$
$OM_{Trans} = annual\ expenditure\ for\ operations\ and\ maintenance$
$A\&G_{wrt\ OM} = annual\ expenditure\ for\ administrative\ and\ general\ expenses$
$Ins_{K,Ops} = annual\ expenditure\ for\ insurance, plant\ and\ operations$

The structure of the $/kW-year estimate of transmission capacity cost is highly similar to the methodology utilized to determine the internal cost of generation capacity, and includes carrying charges on capital and operating costs. Capital-related cost is equal to the sum of the direct investment expenditures, general plant, materials and supplies (M&S), and working capital, multiplied by the carrying charge rate.

The carrying charges are based on the *economic carrying charge* approach, sometimes referred to as *trended real capital costs*. As described earlier, the economic carrying charge (ECC) method essentially captures the expected escalation in the costs of new investment over time; under the condition of rising costs for new physical facilities, as expected, economic carrying charges rise accordingly over the life of the facilities.[37] ECC-based charges rise with respect to shorter capital life. For this reason, the ECC rate for general plant is substantially higher than the ECC rates for either generation or transmission capacity.

Estimates of incremental investment in general plant associated with marginal transmission capacity, follows the same methodology used to determine estimates of the internal cost-based generation capacity. Restated, estimates of incremental investment for general plant costs are drawn from the historical relationship between NLH's capital investment in general and common plant and investment in generation and transmission facilities for years 2008-2014, net of economic depletion (depreciation) and measured in real terms. The materials and supplies inventory associated with transmission is based on the level of materials and supplies associated with gas-fueled generation, for a sample of several modest-sized U.S. electricity utilities during 2013 (listed previously in footnote 8).

Operating costs for transmission, similar to generation, include the annual direct operating expenses, indirect administrative and general expenses (A&G), and insurance charges (Ins). Fixed O&M is based on a historical assessment of the Company's O&M expenditures with reference to the real capital stock, for transmission assets. As previously mentioned, the development of the real capital stock draws on the Company's energy sales experience reaching back to the late 1960s, and gross and net plant records over years 1997 – 2014. For years 2008-2014, O&M costs per unit of real capital stock are equal to 3.03% – a result which largely conforms to the cost experience of other electric utilities. As discussed before, A&G expenses are measured with respect to direct O&M and stated on an *average A&G rate of cost basis*, are equal to 64.14%, an analysis result estimated, also, over years 2008-2014. As discussed earlier, marginal A&G is likely to be substantially less than average A&G[38] and, for the immediate study, marginal A&G expenses are set accordingly: one half the Company's average A&G cost level. As mentioned within the discussion of generation, Insurance costs are set (parameterized) at a level of 0.1% of the carrying charges on investment in physical facilities, including general and common plant.

[37] An exception to this general rule is to account for scale economies and productivity within production processes. In the case of electricity, productivity, as typically measured, appears to be near zero or declining for the industry as a whole, over recent years.

[38] This is a consequence of substantial economies of scale which are often availing for the many support functions and activities within A&G; a review of the Company's recent resource cost history tends to confirm this result.

Estimates of the marginal cost of transmission capacity are presented below. Note that the direct transmission investment cost, $412.97, is set equal to 40% of the incremental load-related investment costs for study years 2018-2023. In other words, the calculated result is attenuated in order to account for two major factors: capital indivisibility common to electricity facilities and, second, the impacts of scale economies in transmission. In brief, for these forward years, the Company does not anticipate that the prospects for growth in peak loads will be sufficient to fully utilize the *planned-for* expansion of capacity, in transmission. The capacity adjustment, equal to a downward adjustment of $58.53/kW-year, is similar to the adjustment for generation.

To summarize, the estimate of the marginal cost of transmission capacity is as follows:

Table 12: Estimate of the Marginal Cost of Transmission Capacity, Newfoundland-Labrador Hydro, 2019 (CAD/kW-year)

Investment Cost ($/kW)	Parameters	Investment Costs per kW	Charges on Capital ($/kW-year)
Direct Facility Investment		1,032.42	48.11
General/Common	6.76%	69.79	5.10
Materials and Supplies	0.72%	7.43	0.35
Working Capital (% OM)	6.16%	2.63	0.19

Charge Rates (%)	Parameters		Cost Elements ($/kW-year)
Carrying Charges, Direct	4.66%		48.65
Carrying Charges, Gen/Com	7.31%		5.10
Insurance Costs	0.10%		1.10
FOM Rate ($/kW-year)	3.13%		32.33
A&G Cost Rate (% OM)	32.1%		10.37
Total Costs ($/kW-year)			97.54
Adjustment for *Capacity-Long* Condition:			(58.53)
		Marginal Cost of Transmission ($/kW-year)	**$39.02**

As shown above, the proposed cost attenuation reduces the marginal cost of transmission capacity from $97.54/kW-year to $39.02/kW-year.

6.0 CONCLUDING COMMENTS

The restructuring of electricity resources currently underway assumes two overarching dimensions: Newfoundland-Labrador Hydro's (NLH) power system will be largely integrated, thus drawing upon a common pool of generation resources with thermal capacity assuming a smaller role; the Island system will be interconnected to the Eastern Interconnection, facilitating wholesale market participation. As a consequence, the level and pattern of economic costs will be measurably altered. First, marginal energy costs (and reserves) will be determined by market value, rather than internal costs – with the market value the lesser of internal costs in virtually all timeframes. Second, transmission will play a much more prominent role in day-to-day operations, market transactions, and resource decisions over long-term forward periods.

The Company's immediate study of marginal costs for 2019 is conceptually well founded, technically articulate, and resides empirically on the best information available – which should be updated periodically. Accordingly, the 2019 study results can be used for the purposes intended: analytical basis for cost allocation, resource evaluation, and tariff prices geared to obtain gains resource efficiency. Moreover, the analytics underlying the study are well suited to further development such as extension over forward timeframes beyond 2019 in a manner that accounts for (i.e., explicitly models) risks inherent to the future worth of resources.

At a technical level, we wish to conclude with a few comments, as follows:

1. *Attenuation of Capacity Costs to Account for Capacity-Long Condition:* Though it is often appropriate to fully invest in larger-sized facilities because of economies of scale, such resource decisions can gives rise to an inherently capacity-long condition over near-term years. For this reason, and because the purpose of the study is to provide guidance for the development of appropriate price signals over the long term, it is appropriate to attenuate calculated capacity costs on a $/kW basis to better reflect the long-term supply-demand balance wherein expanded capacity can be more fully utilized. Accordingly, it is appropriate for Newfoundland-Labrador Hydro to consider the attenuation of marginal capacity costs for both generation and transmission within marginal costs covering contemporary years – note that the marginal cost of generation capacity internal to NLH, as attenuated, is not far from market value. Going forward, we can anticipate that the appropriate degree of cost attenuation will likely decline as the NLH power system can more fully utilize the installed capacity. This can be explored through scenario analysis, benchmarked to model results obtain from formal generation planning tools.

2. *Line Losses Subject to Further Analysis:* As discussed, the parameters for line losses, incorporated within the marginal costs reported herein, are drawn from load flow studies. NLH line losses appear to be sensitive to line loading within the Island high voltage AC network. To this end, we recommend that NLH explore further line loss estimates, for purposes of marginal costs. Also, with the appropriate load flow parameters, an hourly algorithm can applied to selected periods within the annual 2019 timeframe.

3. *Projections of Marginal Energy Costs:* The marginal energy costs consist of a single vector of hourly marginal energy prices (marginal cost of energy) for Northeast markets, including

markets operated by the NE ISO and the NY ISO. The vector of estimated prices is plausible. NLH may wish to commission further analysis, obtaining a set of projected prices in order to capture uncertainty associated with the worth of resources.

4. *Parameterization:* The marginal cost estimates are generally sensitive to wholesale markets and underlying system conditions. Through the parameterization of marginal cost models, it is useful to explore sensitivities, in order to more fully understand and capture inherent uncertainty over future timeframes. NLH may wish to explore the sensitivity of projections of estimates of marginal costs.

APPENDIX A

SPECIFICATION OF MARGINAL COST MODELS, NEWFOUNDLAND-LABRADOR HYDRO

MODEL #1

$$M\_Cost_h^{NLH,J} = \left(MEP_h^{market\ J} + MRP_h^{market\ J}\right) * LF_{Path\ J} * LF_h^{NLH} + MC_{G\_Cap_h}^{AP} * LF_h^{AP} + M_{T\_Cap_h}^{NLH}$$

where,

$MEP_h^{market\ J} = marginal\ energy\ price, hour\ h, market\ J$

$MRP_h^{market\ J} = marginal\ reserve\ price, hour\ h, market\ J * operating\ reserve\ \%^{NLH\ System}$

${M_{G\_Cap}}_h^{AP} = marginal\ generation\ capacity\ cost_{kW-year}^{Avalong\ Peninsula} * allocation\ factor_h^{Gen\_Cap^{AP}}$

${M_{T\_Cap}}_h^{NLH} = marginal\ transmission\ capacity\ cost/_{kW-year} * allocation\ factor_h^T$

$LF_{Path\ J} = \left(1 - loss\ percentage_{Path\ to\ Market\ J}\right)$

$LF_h^{NLH} = \left(1/\left(1 - marginal\ losses\ percentage_h^{NLH\ System}\right)\right)$

$LF_h^{AP} = \left(1/\left(1 - marginal\ losses\ percentage_h^{Avalon\ Peninsula}\right)\right)$

$Allocation\ Factor_h^{Gen\_Cap^{AP}} = generation\ cost\ allocation\ share, hour\ h$

$Allocaiton\ Factor_h^T = transmission\ cost\ allocation\ share, hour\ h$

Regions, Paths:

$J = 1\ for\ Quebec\ to\ New\ York\ ISO; 2\ for\ Nova\ Scotia/New\ Brunswick\ to\ New\ England$

MODEL #2

$$M\_Cost_h^{NLH,J} = \left(MEP_h^{market\ J} + MRP_h^{market\ J} + G\ A\_Price^{market\ J}\right) * LF_{Path\ J} * LF_h^{NLH} + M_{T\_Cap_h}^{NLH}$$

where,

$MEP_h^{market\ J} = marginal\ energy\ price, hour\ h, market\ J$

$MRP_h^{market\ J} = marginal\ reserve\ price, hour\ h, market\ J * operating\ reserve\ \%^{NLH\ System}$

$G\ A\_Price^{market\ J} = generation\ auction\ price, market\ J$

$M_{T\_Cap}{}_h^{NLH} = marginal\ transmission\ capacity\ cost/_{kW-year} * allocation\ factor_h^T$

$LF_{Path\ J} = \left(1 - loss\ percentage_{Path\ to\ Market\ J}\right)$

$LF_h^{NLH} = \left(1/\left(1 - marginal\ losses\ percentage_h^{NLH\ System}\right)\right)$

$Allocation\ Factor_h^T = transmission\ cost\ allocation\ share, hour\ h$

Regions, Paths:

$J = 1\ for\ Quebec\ to\ New\ York\ ISO; 2\ for\ Nova\ Scotia/New\ Brunswick\ to\ New\ England$

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June 15, 2016

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: Rate Design Review for Newfoundland Power and Island Industrial Customers

Further to the 2013 GRA Settlement Agreement and Hydro's Final Submission, please find enclosed the original and 12 copies of the above-noted report prepared by Christensen Associates Energy Consulting, LLC at the request of Hydro.

Should you have any questions, please contact the undersigned.

NEWFOUNDLAND AND LABRADOR HYDRO

Tracey L. Pennell
Senior Counsel, Regulatory

TLP/bds
Encl.

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey Stirling Scales
Sheryl Nisenbaum – Praxair Canada Inc.
Thomas Johnson – Consumer Advocate
Thomas J. O'Reilly, Q.C. – Cox & Palmer
Larry Bartlett – Teck Resources Limited

CHRISTENSEN ASSOCIATES ENERGY CONSULTING

Rate Design Review

for

Newfoundland and Labrador Hydro

by

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June 15, 2016

Table of Contents

EXECUTIVE SUMMARY

Context

This report reviews the need to modify Newfoundland and Labrador Hydro's (NLH's) Island Interconnected rates in response to its transition to interconnection with eastern North America and power sourced from the Muskrat Falls (MF) project. The review is part of a larger transition preparation process.

The key change in NLH's circumstances affecting rate design is the shift in the mix of costs away from variable costs (chiefly fuel costs for the Holyrood Thermal Generating Station (TGS) and toward fixed costs (in the form of lump-sum payments for the MF project to Nalcor affiliates. This shift creates a mismatch between costs and current rate structures, which are in good part volumetric.

Design Objectives and Current Designs

NLH's leading objectives in rate design include revenue recovery and stability, pricing efficiency to reveal to customers the cost of increased electric resource use, and practical objectives such as simplicity and minimization of controversy.

NLH currently uses rates that can be characterized as a mixture of embedded cost pricing and marginal cost pricing. Variability in No. 6 fuel costs (NLH's largest single portion of supply cost) incurred at the Holyrood TGS is managed via a Rate Stabilization Plan (RSP).

- The Utility rate consists of a demand charge and a two-block energy charge, with the customer reaching the second block in almost all months. The second block is priced to reflect the marginal cost of fuel at the Holyrood TGS. The demand charge is set to reflect a price that reasonably reflects marginal capacity costs. The 1st block price is set to recover remaining revenue requirement.
- The standard Industrial rate reflects an embedded cost rate design to recover firm energy requirements from customers. The demand charge and energy charge are outputs of the approved Test Year cost of service study. If a customer exceeds its firm demand requirements and utilizes interruptible load, the additional energy usage while

using interruptible load is priced at the marginal cost of the fuel to provide the interruptible load.

- The industrial rate for Corner Brook Pulp and Paper (CBPP) currently reflects a pilot project permitting CBPP to exceed its firm demand without incurring a charge for non-firm energy.
- Customer-owned generation is supported by demand credits and compensation for fuel costs incurred when requested to operate to provide system benefits. The capability of Newfoundland Power's customers to curtail load is supported by a demand credit.

Design Alternatives

NLH seeks designs that recover its largely fixed costs and provide marginal cost-based prices as guides to additional consumption. Blocked designs and two-part pricing appear to meet this need.

<u>Blocked Designs</u>

Blocked designs modeled on current tariffs require modification to reflect the increased share of fixed costs. Cost changes can be expected to transform the Utility rate into a declining block structure with a high first-block price. The current Industrial rate requires modification to create the opportunity to use the second block regularly.

The existing Utility rate could be modified by: 1) making the demand charge depend on the customer's forecasted demand; 2) increasing the block boundaries by making them a fixed percentage of forecasted monthly usage; and 3) making the tail block price seasonal and variable between rate cases, to keep up with changes in marginal cost. This change would not affect revenue recovery significantly. These modifications would eliminate variability in demand charge revenues; provide certainty in recovering revenue requirement; and improve on the marginal cost signal currently reflected in rates. This approach would, however, require changes to the entire rate structure when the tail block is adjusted.

The current Industrial rate could be modified by 1) introducing a blocking component based on energy; 2) pricing the firm demand and energy to recover the embedded revenue requirement; and 3) pricing all increases in firm demand and interruptible energy at marginal cost using a tail block rate. The tail block rate could be seasonal and variable between rate cases, to keep up with changes in marginal cost.

<u>Two-Part Pricing</u>

A two-part design consists of a Base Bill (revenue requirement divided by contract/forecasted consumption) and an Incremental Energy Charge (IEC) (marginal cost-based price multiplied by the difference between actual and forecasted consumption). The customer nominates contractual usage (the Customer Baseline Load (CBL)) before the contract period. NLH apportions annual values of energy and demand to billing months. The Base Bill collects full revenue requirements. The IEC covers the cost of incremental usage. The IEC's price can be hourly, seasonal, or annual. The prices should be updated regularly, as with the tail block price of the blocked design.

Additional Design Features

NLH needs to offer support for existing tariff features not supported by the general designs summarized above. The two contractual elements currently offered to either or both of these classes is: 1) interruptible service; and 2) customer-owned site generation. As well, NLH would improve its tariff accuracy by securing approval for regular revenue recovery target updates between rate cases.

For both interruptible and customer owned support services, optional tariff riders based on occasional real-time pricing (ORTP) appear to be useful. ORTP customers are signaled at short notice about special circumstances (unusually tight reserves, but possibly spill conditions as well) at which time RTP prices, based on NLH's forecast at short notice of hourly marginal cost, apply to departures from preapproved CBL values.

Design Recommendations

Given NLH's current designs with their segmentation of revenue recovery and marginal cost pricing, and the shift to fixed costs, blocked and two-part designs are appropriate vehicles for revised tariffs. The two-part design appears simpler due to its full bifurcation between revenue recovery and marginal pricing, and its bill simplicity (but not necessarily administrative simplicity). The two-part structure is novel, but close in theme to blocked designs, and appears within the capabilities of the utility and all customers.

- **Utility Rate:**
  - The two-part design appears to be advantageous, for reasons of theory (separation of revenue recovery and marginal pricing) and practical simplicity. The designs are similar enough that two-part pricing should not be entirely novel. Additionally, the two-part design appears simpler in both revenue recovery and pricing.
  - Seasonal marginal pricing is advisable, as is regular updating of these prices.
  - An ORTP design appears to meet Newfoundland Power's needs regarding interruptible and customer site generation support. Payment for performance rather than availability is a material improvement for both groups.
  - NLH may wish to explore a possible improvement in pricing with Nalcor affiliates for ORTP service.
- **Industrial Rate:**
  - The two-part design appears to have an advantage in providing a simpler product for customers and NLH. Both products offer customers marginal cost-based pricing for all or almost all hours.
  - Again, ORTP would support both interruptibility, should customers be interested, and site generation.
  - In the case of Corner Brook Pulp and Paper, a two-part RTP design might facilitate energy management at the customer site and provide better signals of system conditions which, in extreme cases, would call forth interruption and additional supply in a cost effective manner.

Rate Design Review

for
Newfoundland and Labrador Hydro

by
CHRISTENSEN ASSOCIATES ENERGY CONSULTING, LLC

June 15, 2016

1. INTRODUCTION

As part of its preparation for the completion of the Muskrat Falls (MF) project, including the generation site and its associated transmission links, Newfoundland and Labrador Hydro (NLH) is conducting a review of its rate designs. Its rates were intended to meet objectives developed at a time when NLH had no links to the rest of the North American grid and when fossil fuel generation played a significant role in its electric power generation. With the completion of the MF project and the Maritime Link, however, NLH's Island Interconnected system will have reduced need for its own fossil fuel generation. Instead, having established links with the Eastern Interconnection via Nova Scotia and Quebec, NLH will be able to export surplus power and to import power in times of shortfalls.

This review is part of a much larger process undertaken to prepare NLH for this. The recent 2013 GRA and Settlement Agreement make reference to this and other studies, including a marginal cost review, a cost-of-service (COS) methodology review, and a Rate Stabilization Plan evaluation, culminating in a GRA in early 2017.[1]

NLH engaged Christensen Associates Energy Consulting to conduct the rate review. The focus of the review is on rates for Island Interconnected customers, specifically the Utility tariff that serves Newfoundland Power Inc. and the Industrial tariff covering Island Industrial customers.[2] The review does not cover the rates faced by the Island's Rural Interconnected customers

[1] NLH, *Settlement Agreement,* August 14, 2015, paragraph 23.

[2] The Industrial tariff is supported by industrial customer service agreements that provide additional contract detail.

because these are, for the most part, determined based on Newfoundland Power's retail tariffs. Revenue shortfalls arising from those rural rates, including those in Rural Diesel areas, are recovered through a Rural Deficit amount primarily assigned to Newfoundland Power, Industrial customers having been exempted from this responsibility.

Section 2 of this report reviews how the completion of the MF project will affect the NLH costs that must ultimately be recovered from customers. Section 3 then provides a review of NLH's current rates. Section 4 begins with a discussion of NLH's rate design objectives, and then reviews possible rate design alternatives, including their features and incentives, strengths and weaknesses, and their ability to meet NLH's rate design objectives. The closing section provides rate design recommendations for NLH and its customers. An appendix provides information on marginal cost patterns that will help to guide pricing decisions.

This report does not dwell upon cost recovery outside base rates. Currently NLH's Rate Stabilization Plan (RSP) smooths recovery of variable costs—particularly No. 6 fuel costs at the Holyrood Thermal Generating Station (Holyrood TGS)—that are outside NLH's control. Following completion of the MF project, the RSP will be replaced by a new deferral account recovery mechanism, the details of which are reviewed by a companion report by NLH.

2. IMPENDING CHANGES IN NLH'S POWER SYSTEM AND COSTS

The MF project consists of the Muskrat Falls hydraulic generation project, providing 824 MW of generation capability; the Labrador-Island Link, a high voltage direct current (HVDC) transmission line of 900 MW carrying capacity connecting Muskrat Falls with Soldiers Pond in the vicinity of St. John's; and the Labrador Transmission Assets, which connect Muskrat Falls with Churchill Falls and transmission lines through Quebec. This project, combined with the virtual retirement of the Holyrood TGS, will significantly affect NLH's costs.

Because of Nalcor's substantial capital investments associated with the MF project, NLH's overall costs will rise with the completion of the project. Furthermore, there will be a substantial shift in the mix of costs away from variable costs (chiefly fuel costs for the Holyrood TGS) and toward fixed costs (through NLH's payments under the utility's Power Purchase

Agreement with Muskrat Falls Corporation (the MF PPA) and Transmission Funding Agreement with Labrador island Link Operating Corporation (TFA) payments). Consequently, NLH's overall rates will increase significantly; and in the interests of stability in revenue recovery and to avoid increasingly using volumetric pricing to recover fixed costs, NLH will want to modify its rate design to shift revenue recovery toward fixed charges and still provide customers a pricing signal to promote efficiency.

Additionally, the basis for volumetric pricing at times when NLH has used a measure of marginal cost can be expected to change. The Holyrood TGS has historically been NLH's marginal generating unit. System marginal energy cost was thus based on that unit's fuel price, operating efficiency, and system losses.[3] This was expressed in stable tariff prices supplemented by a variable fuel cost component in the RSP. With the establishment of DC links to the mainland, marginal cost, in the absence of transmission constraints, will depend on the regional wholesale market's prices for energy, reserves, and capacity. A recent review of expected marginal costs with the MF project in operation produced marginal costs with noticeable seasonality and some variation over the course of the day.[4] In practice, hourly marginal costs can be quite variable, from effectively zero (during water spill conditions, for example) to $1.00 per kWh (under conditions of extremely low reserves). These marginal costs are the basis on which Nalcor will be valuing its trades, and NLH would benefit from having the same valuation approach as its parent company. While such marginal costs might not be the basis for recovery of embedded costs from customers, they would be essential guidelines for marginal cost based pricing, whether hourly, seasonal, or annual.

Once the project is ready for commercial operation, NLH will commence regularly scheduled payments to other Nalcor subsidiaries for energy and transmission services, and will receive allocations of energy as defined in the PPA by the combination of the Initial Load Forecast and

[3] Holyrood TGS marginal cost underpins the current Utility tariff's tail block rate of $0.0903/kWh.

[4] A potentially complicating factor in marginal costing for NLH is the nature of the contracts that govern the MF project. These contracts imply that, under certain circumstances, NLH's marginal costs can be zero even when the market prices of electricity services are positive: apparently, NLH's utilization of Muskrat Falls power can change with no accompanying change in its payments for that power.

Base Block Energy. These allocations increase annually. Inevitably, actual requirements will differ from the pre-determined allocation. In the event that its actual Island Native Load is in excess of the Initial Load Forecast, NLH can draw on Supplemental Energy from the MF project. The Supplemental Energy amount is adjusted over time by the variation in the Base Block Energy due to positive and negative variations in the total NLH production requirement from the Muskrat Falls plant. Thus, NLH can utilize less or more than the Base Block energy in any given year to ensure that the utility meets its customers' supply needs. Unused allocations can be deferred for future use. The notable implication for cash flow is that to the extent that increases in the Base Block energy are less than its Supplemental Block and Deferred Energy when that power is available, NLH makes no additional payment. However, in cases in which a change in NL hydraulic production and/or load causes NLH to take Muskrat Falls power in excess of its current period Supplemental Energy allowance and prior periods NLH Deferred Energy, NLH experiences an increase in costs.

More generally, though, NLH experiences a change in costs or availability of future hydro resources whenever its load changes. Customers' load increases can be met with either: 1) increased utilization of the MF project allocation; 2) increased utilization of other hydro generation at NLH; or 3) increased power purchases. Changes in the utilization of the MF project allocation result in decreased exports or increased imports by Nalcor and a matching reduced NLH allocation of MF project power in the future. Thus, while no apparent immediate *contractual* cost change may occur from a load increase by a customer, a cost change equivalent to the product of marginal cost and the quantity of the change will effectively occur. This is an important factor in rate design from the perspective of pricing to promote efficient use.

3. NLH'S CURRENT RATES AND RIDERS

3.1 Rate and Rider Descriptions

NLH serves three classes of customers on the Island Interconnected System (IIS):

- The Utility class, consisting of a single customer, Newfoundland Power;

- The Industrial class, consisting of five customers; and
- The Rural "class", consisting of residential and small commercial customers in several subclasses, served by NLH under prices established by Newfoundland Power for similar classes of their own customers.

Because Rural customers' rates on the IIS are set to equal Newfoundland Power's rates, the scope of this report is limited to review of the Utility and Industrial customer tariffs on the IIS.

3.1.1 Utility Tariff

The Utility tariff recovers revenue via an energy charge and a demand charge. The Utility rate consists of a demand charge and a two-block energy charge, with the customer reaching the second block in almost all months. The block boundary was set in the past at a level equivalent to the total consumption of the lowest-usage month so that the customer would see the marginal price in almost all months. The second block is priced to reflect the marginal cost of fuel at the Holyrood TGS. The first block price is set to recover remaining revenue requirement.

Since the Holyrood TGS was considered always at the margin, the marginal costs of Holyrood TGS were deemed to constitute marginal cost in all hours. The result based on the most recently approved test year in 2007 was an inverted block tariff with block prices of 3.226 ¢/kWh for the first block and 8.805 ¢/kWh for the tail block as of July 1, 2015.[5] In the Settlement Agreement in NLH's 2013 General Rate Application (GRA), the parties agreed to continue to base the tail block energy charge on the 2015 Test Year No. 6 fuel cost that was approved in the final GRA Order.[6]

The demand charge recovers some, but not all, demand-related costs. The price from the 2007 Test Year is $4.00/kW of billing demand. The demand charge was negotiated to reflect a balance between high embedded demand costs and low marginal capacity costs at the time of

[5] The PUB approved an 8% interim rate increase to all components of the NP base rate effective July 1, 2015. The tariff also includes an additional firming-up energy charge to permit NP's purchases of excess hydraulic self-generation of Corner Brook Pulp and Paper through a Secondary Energy Rate. The current price of this supply is 0.908 ¢/kWh.

[6] NLH, *Supplemental Settlement Agreement, September 28, 2015*, p. 3, sec. 10(ii).

the 2007 GRA. In the Settlement Agreement in the 2013 NLH GRA, the parties negotiated an increase in the demand charge to $5.50 per kW per month.

Billing demand is determined based on the weather-adjusted native peak less credits for Newfoundland Power generation and curtailment capability, where the weather-adjusted native peak has a Minimum Billing Demand set at 99% of the test year Native Load. Because the weather adjustment is determined after the conclusion of the winter season, the billing demand for the remainder of the year is trued-up to recover the difference between the billing demands applied during the winter season and the weather-normalized billing demand established at the conclusion of the winter season.

The block energy charge structure of the Utility tariff created a vehicle for reliable recovery of costs allocated to Newfoundland Power, combined with a marginal cost-based price that reflects the short-term cost to NLH of additional usage based on the previous Test Year No. 6 fuel cost at the Holyrood TGS. Cost variances from the Test Year No. 6 fuel cost are recovered through the RSP.

The Utility tariff includes two demand credits, one for generation and one for curtailable load capability. Both credits are priced at the Utility demand price since the demand levels are deducted directly from Native Load. The demand credits enable NLH to use Newfoundland Power’s generation and demand-side resources when they are most valuable to the island system.

Newfoundland Power operates its generation at the request of NLH when required to meet customer load requirements. The generation demand credit reimburses Newfoundland Power for demonstrated capability to provide capacity from its hydraulic and thermal generation facilities upon request by NLH. Capability is determined at the time of each general rate application and confirmed annually during the peak winter season. NLH reimburses

Newfoundland Power for the additional cost incurred to operate its thermal generation when requested by NLH.[7]

The curtailable credit operates in a similar fashion to the generation credit. Newfoundland Power customers demonstrate their ability to deliver load reductions annually in December. NLH informs Newfoundland Power when to request curtailments from their participating customers.

The provision of the generation credit and the curtailable credit in the Utility Rate is consistent with the peak demand for generation used in the test year COS study allocation of the revenue requirement. That is, the native peak for Newfoundland Power is reduced to reflect that Newfoundland Power serves part of its load during peak conditions.

3.1.2 Industrial Tariff

The costs of meeting the firm energy requirements of Industrial customers are recovered under a traditional embedded cost-based rate design. The demand and energy charges are derived from embedded demand-related and energy-related unit costs of service and are set to fulfill the test year revenue requirements. The Industrial Customer rate also includes a customer-specific customer charge ("specifically assigned charge") designed to recover the costs of transmission facilities specific to providing service to each customer.[8]

Each customer nominates a firm power contract demand called "Power on Order," the terms of which are specified in its Industrial Service Agreement. Power on Order is set no later than October 1 of the current calendar year for the following calendar year. The Power on Order request may provide for one or more successive increases at specified times during the service

[7] The additional cost reflects the difference between the end block wholesale energy rate and NP's thermal fuel costs.

[8] Unlike many large industrial customer rates elsewhere, there is no customer charge for customer-related costs, but this is due to the lack of customer-driven costs found in the NLH COS study.

year, but may not provide for a decrease other than a decrease to take effect on January 1st of that following calendar year.

The customer pays a Demand Charge in each billing period based on their firm power. If customers' demand requirements exceed their Power on Order plus their interruptible demand, they establish a new billing demand based on the new peak demand less its interruptible demand.

The customer pays a monthly Firm Energy Charge for firm power consumed up to the demand level of Power on Order. Consumption recorded during the period when firm demand is in excess of Power on Order is billed at the applicable marginal fuel rate. If not for the RSP, increases or decreases in Industrial Customer firm energy requirements would create material earnings impacts as a result of the embedded energy charge being materially lower than the marginal cost of No. 6 fuel at the Holyrood TGS. For the 2007 Test Year, the embedded energy cost was 3.676₵ per kWh and the Holyrood TGS fuel cost was 8.805₵ per kWh. The RSP has a provision to avoid the financial impact of this approximate 5₵ per kWh differential on NLH resulting from load variations.

If non-firm demand is available, the customer can pay a Non-Firm Energy Charge to acquire energy. The non-firm energy price is based upon the fuel cost of the thermal energy source then at the margin, serving as a representation of marginal cost. The non-firm price depends upon the unit deemed to be at the margin, of which there are three types: Holyrood TGS, gas turbines, and diesel. The industrial rate for Corner Brook Pulp and Paper (CBPP) currently reflects a pilot project permitting CBPP to exceed its firm demand without incurring a charge for non-firm energy.

NLH also has optional capacity assistance agreements with two customers, under which customers provide interruptible load relief upon request by the utility. These agreements offer a "capacity fee" for capacity made available for interruption, and also offer a payment for load relief delivered.

- One customer, Vale Newfoundland & Labrador Limited, has a contractual amount of up to 15.8 MW of capacity available in the form of thermal (standby diesel) generation. NLH provides a $28 per kW winter credit for availability and reimburses the fuel costs for load relief delivered.
- A second customer, CBPP, offers up to 60 MW of interruptible capacity in the form of 9 MW of load reduction at its mill and 51 MW of the customer's hydraulic generation. The agreement divides this capability into 20 MW parcels for purposes of calls for reduction. NLH pays CBPP a lump sum of $1,680,000 per winter for availability (which amounts to $28 per kW for its 60 MW of interruptible capacity) and $0.20 per kW per hour for load relief.[9]
- A supplemental capacity assistance agreement with CBPP yields another 22 MW of net capacity obtained by further load reduction. CBPP is provided compensation for this agreement on a ₵ per kW per hour basis if called upon to provide service.[10]

The use that NLH can make of this interruptible capacity is circumscribed by rules on frequency and duration of interruption that are found in most interruptible rates and riders. Interruptions cannot exceed 100 hours per winter, no more than two calls per day, and normally have durations of between three and six hours.

In the 2015–16 winter season NLH called upon both customers for load relief. In CBPP's case, this amounted to two calls for a total of eleven hours, while Vale was called upon eleven times for a total of about 30 hours.[11]

3.1.3 Rate Stabilization Plan

The No. 6 fuel costs incurred at the Holyrood TGS that are deemed to be beyond the control of NLH, particularly due to variations in customer load, hydroelectric production, and world oil prices, are recovered via the RSP. While the demand, energy, and specifically assigned charges of the Utility and Industrial rates are designed to recover the full *forecast* embedded costs of each class, NLH uses the RSP to ensure recovery from customers of the differences between actual and forecast test year costs due to particular causes. Those causes are variations in: 1)

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[9] Details are found in the Capacity Assistance Agreements, Articles 1-3. Payment occurs in two installments: half at the end of January and half at the end of March.

[10] This net capacity takes the form of a 30 MW plant reduction less the loss of 8 MW of cogeneration capacity.

[11] NLH, *Capacity Assistance Report, Winter 2015-2016*, April 2016.

hydroelectric production; 2) Holyrood TGS fuel costs; and 3) customer loads. For each of these causes, differences between actual and test year values are accumulated in balancing accounts, which are used to smooth cost recovery over time according to specific formulas.

The RSP also accumulates changes in NLH's Rural revenue requirements that follow changes in Newfoundland Power rates between NLH's test years. The RSP rate adjustments are implemented on an annual basis, on July 1 with Newfoundland Power, and on January 1 with Industrial Customers.[12]

The Holyrood TGS will cease to provide significant power soon after the MF project comes into use, so fossil fuel cost recovery will become much less significant than it has in the past. Nonetheless, other costs that are arguably beyond the control of NLH will accompany completion of the MF project, implying the need for a revised revenue recovery and rate stabilizing mechanism. Consequently, NLH intends to replace the RSP with an updated deferral account recovery mechanism. The cost variations to be recovered through this mechanism are addressed separately in a report filed by NLH on the same date as this report.[13]

3.2 Rate Design Issues

3.2.1 Main Design Considerations

The completion of the MF project will create challenges to the current designs arising from three main sources. First, the level of fixed costs will rise in both absolute terms and on a per-kWh basis. The increase in total costs and revenue requirements is a common outcome at utilities that replace aging plant with new plant. The timing and final capital cost of the MF project, coupled with decisions regarding the distribution of export revenues will affect the

[12] RSP balances resulting from fuel cost variations produced by hydraulic production variations are recovered/refunded over a four-year period based on rolling balances.

[13] Newfoundland and Labrador Hydro, *Supply Cost Mechanism Review*, June 15, 2016.

absolute level of such increases but will not negate the necessity to review and alter the NLH rate structures.

Second, because the bulk of MF project-related costs are capital costs, the proportion of fixed costs in total costs will rise. In particular, the variable fuel costs of the Holyrood TGS are going to be replaced by the fixed obligation of payments for the MF project. NLH's fixed obligation for payments to provide recovery of embedded costs does not decline if customer load is less than the Base Block Energy reflected in the MF PPA, although loads themselves will vary with economic conditions, weather, and other factors. NLH can, however, defer or monetize any such customer load reductions to partially offset the fixed obligations. A rate design goal for NLH might then be to try to match these fixed costs with fixed billing charges to the degree possible, shifting rate design in the direction of fixed charges.

Third, the eventual transition of the Holyrood TGS from energy generation to grid support services will substantially reduce NLH's fuel costs, thus mitigating most of the need for the RSP and thereby meriting review of the purpose and scope of this cost tracker. However, for the first few years during the transition to MF project power, Holyrood TGS annual cost will still be uncertain.

3.2.2 The Role of Marginal Costs

Prices are most efficient when they equal marginal costs; but many traditional utility tariffs make little or no use of marginal cost. Instead, retail electricity prices are generally derived from embedded customer-, demand-, and energy-related unit costs of service, and are set to fully recover these costs. For the structure of NLH's costs once the MF project is complete, a relatively simple Utility rate would consist of a large per-kW demand charge and a small per-kWh energy charge, with no seasonal variation. The current Island Industrial Customer rate has a similar structure for recovery of firm load revenue requirements.

However, NLH has a history of utilizing marginal cost to signal incremental cost to customers (specifically in the Utility Rate), an approach found in many utilities that use block pricing or other rate designs that afford the opportunity to use marginal cost for some pricing. NLH's past use of marginal cost pricing has been based on the cost of operating a limited number of generation units, particularly Holyrood TGS. With the establishment of links to the Eastern Interconnection, the "marginal unit" and, hence, marginal cost, will be no longer be linked to a specific NLH generating unit. Instead, NLH will face the challenge of forecasting marginal costs as a basis for price development for its tail block rates and other applications. Not only will the new marginal costs be less predictable in advance, but they will also be more variable than they were in the past. In the absence of real-time pricing (RTP), NLH will need to announce marginal cost-based prices in rate submissions, or in some other form approved by the Public Utilities Board (PUB), far in advance of the time periods to which the prices will apply, raising issues of cost coverage and under- or over-recovery of revenues. Additionally, because of increased marginal cost variability, it will be necessary to review whether seasonal and/or time-of-use pricing should be used to better match price with cost.

3.2.3 Customer Site Generation Resources

The Base Block of energy available to NLH from the MF project was developed based on the assumption that existing non-utility generation, and wind resources, plus customer site generation capability will continue to function as they do presently, at least for the near term. Customer sites include Newfoundland Power's hydraulic and thermal generation and the hydraulic and cogeneration capacity of CBPP.[14] At present, informal agreements and contract provisions combine to induce these units to operate in a least-cost manner. [15] NLH calls upon Newfoundland Power's generation at times of low system reserves, and Newfoundland Power maintains its units' availability to serve this role. It is desirable that this dispatch coordination continue for the purpose of minimizing Newfoundland and Labrador's overall net power generation and procurement costs. Therefore, NLH will need to put processes in place to

[14] CBPP's cogeneration (as opposed to hydraulic) generation facility is due to shut down in 2022.

[15] Newfoundland Power obtains a demand charge discount based on its generation capabilities rather than its actual use of generation services at times of the utility's peak usage. Before 2009, CBPP operated its generation to minimize its peak demand, but pilot contracting since then has allowed the customer to operate it to improve the efficiency of its 60 Hz hydraulic resources as well as providing capacity to the grid (to the extent that it is available) when called upon by NLH.

ensure that the customer site generation resources are operated optimally from a system perspective (*e.g.*, to minimize spill). This factor requires consideration in implementing rate design.

Hitherto, pricing of customer site resources has included demand charge discounts and compensation of thermal generation for fuel costs. As links to competitive wholesale markets are established, market prices offer benchmarks for pricing not previously available. Customer site pricing that makes use of hourly wholesale price variation, and that uses peaks in pricing to induce supply availability and delivery, would serve NLH's needs and would compensate customer generation based on its market value. A real-time price, objectively determined, offers the opportunity to improve upon contracting that offers a substantial demand charge for availability and relatively little for actual delivery of energy. Such an approach would also avoid the potential distortion of pricing that can occur with a demand charge.

4. ALTERNATIVE DESIGN CANDIDATES

4.1 NLH's Rate Design Objectives

The classic industry taxonomy of rate design objectives can be found in Bonbright.[16] His list can be summarized as follows:

- Revenue-related objectives
  - Recover total revenue requirements
  - Provide *revenue* stability, so that small changes in costs or sales do not lead to large changes in revenues
  - Achieve *rate* stability, which means avoiding rate designs that require frequent pricing modifications
- Cost-related objectives:
  - Encourage efficient use of energy and ongoing innovation in energy efficiency
  - Reflect present and future private and social costs and benefits
  - Appear to be fair in apportioning costs
  - Avoid undue discrimination
- Practical objectives

[16] J.C. Bonbright, A.L. Danielsen, D.R. Kamerschen, *Principles of Public Utility Rates*, c. 1988, Public Utility Reports, Inc., pp. 381–84.

- Be simple, understandable, and acceptable
- Minimize controversy

Taken as a whole, these objectives encourage utilities, regulators, and intervenors to agree upon rate structures that permit a utility to recover its costs, including a return to investors, while setting prices that induce customers to use energy efficiently, where efficiency is defined by some measure of marginal cost, and to offer rates that customers and others can understand.

Naturally, fulfilling these objectives involves tradeoffs. For example, efficient pricing is achieved by setting prices at levels determined by marginal costs. However, marginal costs generally differ from average costs, so that prices based on marginal cost will generally over-or under-collect required revenues. Additionally, pricing that attempts to convey marginal costs with accuracy may lead potentially to complex rates due, for example, to multiple pricing periods that can confuse customers.

Like other utilities, NLH faces the challenge of balancing these objectives. In striving to recover required revenues, NLH has provided its customers with blocked pricing that compartmentalizes revenue recovery and pricing efficiency. The base block or firm power recovers embedded cost-based revenue requirements; and the tail block price in the Utility tariff and the non-firm power price in the Industrial tariff are based upon marginal costs in both the existing Utility and Industrial tariffs. Upon completion of the MF project, NLH's rate objectives do not require change, although the composition of costs will change. A first challenge will continue to be recovery of costs, increased and shifted in the direction of fixed costs by the MF project. A second challenge will be revision of NLH's system operations and marginal pricing methods, at both wholesale and retail, in response to its establishment of links to the Eastern Interconnection.

NLH's rate design challenges are unusual in some respects relative to those of other utilities. First, NLH's customers are uniformly large and relatively sophisticated, and can tolerate some measure of rate complexity. Second, NLH's costs, as influenced by the preponderance of hydraulic generation and the paucity of fuel costs, are disproportionately fixed in comparison with other utilities. Third, the rural deficit involves significant cross subsidies that, if financed through volumetric rates, will increase pressures for prices to stray far from marginal costs. Fourth, NLH's marginal costs, due to the MF project contractual arrangements, can differ from those of the parent company, Nalcor. In other words, a change in consumption by an NLH customer can cause cost changes that are shared among NLH and its affiliates in ways that are determined by the contracts among the affiliates.

These NLH-specific challenges, though, do not detract from NLH's overall need to pursue its general rate design objectives of full revenue recovery of its embedded costs and efficient pricing at the margin. In particular, with respect to marginal costs, it is worthwhile to ensure that NLH reflects in the marginal prices of its tariffs some representation of the prices that Nalcor faces in its dealings with the wholesale market. Prices designed in this manner guide customers in their own consumption decisions to enhance the likelihood of least cost service in the short and long term.

4.2 Alternative I. Modified Current Rate Structures

The current Utility and Industrial rate structures already accomplish much of what NLH wishes to achieve in rates. A base block or contract quantity recovers a large portion of fixed costs, while an incremental block priced near marginal cost mainly recovers variable costs and signals the cost of load changes to customers whose load carries them into the tail block. Below are proposed variants of those rates.

4.2.1 Utility Rate

Option A. Current Structure, Modified Prices. The current Utility rate collects fixed costs via both the demand charge and the first block of the energy charge. The block boundary is established in the tariff, and is currently set at 250 million kWh monthly. The tail block energy charge collects the substantial costs of fuel from Holyrood TGS. Since Newfoundland Power uses enough energy to cover the first block in virtually all months, the energy charge for this block becomes a lump sum from both the customer's and NLH's perspective. The demand charge, which recovers some demand-related fixed costs, operates on revenue recovery in two ways. First, it recovers additional revenue as Newfoundland Power's customer base and peak demand grow between rate cases. Second, variations in peak demand over time tend to create earnings volatility. This volatility is mitigated by the use of a demand ratchet, a weather normalization mechanism, and by maintaining a relatively low demand price.

If no changes are made to this tariff structure, but prices are modified to reflect cost changes, a large portion of cost will move into the first block of the energy charge, and the tail block charge will diminish due to lower future marginal costs upon completion of the MF project and Maritime Link, assuming that the tail block price is set to reflect forecasted annual average marginal cost. As an option, the demand price could be moved up to recover an increased share of demand-related fixed costs.

This first block would be priced to recover the embedded, approved costs of NLH, as determined by a regular COS study. The remaining load would constitute a second block. That tail block would be priced based on marginal cost. The first block price would be calculated as: 1) the total class forecasted embedded cost less the forecast revenue to be recovered by the demand charge and the forecast revenue from the second block sales priced at marginal cost; divided by 2) a proportion of forecasted class load to be determined by NLH (either the current block boundary or a revised level).[17]

Even with minimal changes to structure, there will need to be a change in tail block pricing. Currently, the generation source for load following is chiefly the Holyrood TGS. NLH posts a tail block price based on forecasted fuel prices and recovers any cost discrepancy in the RSP. With the interconnection to the mainland, marginal cost becomes somewhat more complicated to forecast, and takes on a time-varying dimension not previously experienced. It appears that some degree of time variation in price might be necessary to convey to Newfoundland Power the cost of incremental generation.[18] Additionally, marginal costs are likely to vary as time passes between rate cases. Therefore, it will be advisable for NLH to consider mechanisms for

[17] Option C, below, describes an alternative to the current annual boundary.

[18] Please see the next section for a discussion of marginal cost patterns.

regular updating of marginal cost. Such changes will have little influence on revenue recovery, which takes place primarily in the first block.

The advantages of this structure are that expected embedded costs are recovered fully, demand-related costs are recovered in a demand charge, changes in load are priced at marginal cost, and the structure is familiar to the customer, NLH, and the PUB. A leading disadvantage is that the demand charge, if set to recover demand-related costs in full, would introduce variability in revenue recovery that may be poorly related to cost variability.

Additional to the disadvantage of possible over-collection of required revenues is the impact of a demand price on the marginal price of consumption. NLH would like to send Newfoundland Power price signals that indicate incremental cost. A high demand price will be perceived by Newfoundland Power as imposing a strong signal to control peak demand, a signal that they will need to pass on to their customers. Until completion of the MF project, Newfoundland Power's winter peaks will likely continue to be strongly correlated with Island system peaks and marginal costs. However, this link may be significantly weakened by interconnection with summer (or joint winter-summer) peaking regions of eastern North America. There is a risk that this price signal will not reflect system conditions well.

This structure also has a disadvantage in that variations over time in tail block price will have a small effect on the base block price if such variations occur seasonally or with the passage of time generally. Since the first block price is derived by deducting demand cost and marginal cost multiplied by second block sales from revenue requirements, a change in second block price will affect the first block price. This change can be handled as part of the cost deferral accounting.

Option B. Modification to Option A: Disconnect the Demand Charge from Actual Billing Demand. Retention of the demand charge, especially if the price is allowed to rise to demand-related unit cost, poses challenges of fixed cost recovery variability and marginal price distortion. NLH can stabilize revenue recovery by charging for peak demand on the basis of forecasted peak demand, with the forecast being derived from Newfoundland Power's annually forecasted usage and historical load factor. An even simpler alternative representation is to charge a lump-sum amount based on revenue requirement as developed in NLH's COS study for the test year, less energy-related revenue recovery in the base block. This charge could be distributed evenly across the year or shaped into a monthly pattern based on past patterns of monthly peak demand.

It is worth mentioning that the means of calculating billing demand may merit review given the establishment of interconnection with other service territories. The current method recognizes that the peak period of the year is December to March and signals the customer by means of a ratchet based on this peak period. This may still be appropriate, since the Island transmission system will still peak in winter. Note that there would be minimal billing implications, since the revenue requirements would be divided by a different quantity but total recovery would not be affected.

A second influence is the possible removal of the generation and curtailable credits, to reflect changing capacity value of these assets. If NLH replaces the demand discounts with market-based pricing for timely generation and load relief these credits can be removed and payments will better match cost reductions at NLH when these services are provided.

Option B has the advantage of simplifying the rate structure and clarifying tail block energy pricing as being directly linked to marginal cost. The structure's disadvantage is that demand-related cost recovery is now fixed until the next rate case, unless NLH, Newfoundland Power and the PUB can agree on forecasted annual computation of revenue requirements and forecasted usage and peak demand.

Option C. Modification to Option A: Move More Load into the First Block. The current block boundary, as described above, results in large amounts of energy in the tail block in most months. Since required revenues are collected in the first block, the resulting price on the first block could be quite high relative to the tail-block price. First-block revenue is essentially a lump sum if the customer never reduces load below the block boundary. However, if this is a possibility, NLH could create monthly block boundaries at, say, 80% or 90% of forecasted load.[19] Newfoundland Power would face a tail-block price for all (or almost all) load changes. This approach might enhance the probability of revenue recovery in low-consumption months and would create a lower first-block price, reducing revenue attrition in the event that consumption declines significantly.

This option complicates the rate design somewhat, since NLH would have to set monthly block boundaries, revise them with each rate case, and introduce those boundaries into the billing system. In return, the likelihood of full revenue recovery might be enhanced and the revenue attrition from a large reduction in consumption could be reduced.

4.2.2 Tail Block Pricing Issues

If the tail block is to be priced according to marginal cost, NLH will face two challenges, mentioned above, that face NLH. First, for pricing accuracy, the price should respond to changes in the average level of marginal cost that may take place over time. Second, there may be need to set prices on a basis other than a flat annual value per kWh.

Making provision for regular updates to the tail block price to reflect changes in marginal cost could be managed in two ways. One approach would be to use the deferral account recovery mechanism. Another would be to make regular, PUB-approved tariff price changes. Since the deferral account recovery mechanism’s focus will be on revenue recovery and deferred cost balances, it appears to be preferable to rely on regularly scheduled tariff price updates for this purpose, if they can be approved expeditiously. Regular updates to tariff prices are to some degree novel, but are becoming more common with increased reliance on market prices. NLH would need to use marginal costs as the basis for such a price, with a rate setting formula being approved by the PUB at some point. The intent of the formula approach would be to set tail block prices with minimal controversy.

[19] The chosen boundary would need to be set to avoid weather-related reductions.

NLH will need to update its deferral account recovery mechanism value annually, which would also be an advantageous time to update the coming year's tail block price. However, since wholesale market conditions can change rapidly and significantly, it appears that more frequent opportunities to change the price would be beneficial to both NLH and Newfoundland Power. Perhaps a seasonal price, delivered 60 days before the start of a season, would provide sufficient accuracy and advance notice for pricing by Newfoundland Power. Shorter notice than that of the tariff sheet (which normally changes only with a rate case) can benefit both parties. NLH minimizes discrepancies between price and marginal cost and Newfoundland Power gets pricing that is as close to actual market prices as possible. The risk of price increase is balanced by the opportunity to benefit from price reductions soon after they occur in wholesale markets.

Regarding the selection of alternatives to a flat annual tail block price, there is no best time configuration for the second block price. Simplicity suggests that NLH offer Newfoundland Power a single price for all hours, while pricing precision suggests the use of RTP with hourly prices based on hourly marginal costs or wholesale prices. In offering prices with less frequent variation and greater advance notice, NLH provides Newfoundland Power and its customers with rate simplification and risk management services. Nonetheless, hourly pricing can be mutually beneficial to NLH, Newfoundland Power, and its customers in certain situations, such as when interruptible customers need to be called; but prices announced in advance via tariff sheets or regular postings with regulatory approval should suffice for most circumstances. It would be advisable to consider the range of price alternatives between a flat annual price and hourly pricing.

We reviewed the pattern of expected marginal costs via software that CA Energy Consulting has used to design time-of-use (TOU) pricing for many years. We investigated alternative seasons and two- and three-period TOU configurations. Based on our investigation, we concluded that marginal costs, and thus tail block pricing, should be seasonal but need not include a TOU component.[20]

It appears that a four-month winter season (December through March), a two-month summer season (July and August), and a spring/fall season containing the remaining six months provide the greatest degree of marginal cost similarity within seasons and thus offer meaningful differentiation between seasons. Table 1, below, provides the marginal cost results of this investigation. The appendix, Expected Marginal Cost Variability at NLH, reports fully on this investigation.

Table 1
Forecasted Marginal Cost Patterns at NLH – 2019

Season	Months	Average Marginal Cost ($/MWh)			MC Ratio	Peak Seasonal MC Ratio	
		Peak	Off-Peak	All Hours	P/O	vs. Spr/Fall	vs. Winter
Winter	12, 1, 2, 3	$ 59.41	$ 44.03	$ 50.56	1.35	1.27	1.00
Summer	7, 8	$ 78.50	$ 47.48	$ 59.70	1.65	**1.68**	**1.32**
Spr/Fall	4, 5, 6, 9, 10, 11	$ 46.85	$ 35.68	$ 40.87	1.31	1.00	0.79

This recommendation regarding time variation in pricing is tempered by awareness that NLH or Newfoundland Power may prefer simpler (all-year pricing) or more accurate (TOU or real-time) pricing. As mentioned above, we propose that these seasonal second block prices be updated at least annually, according to a mutually agreed schedule, and based on a formula that converts NLH's marginal cost forecast into a seasonal price.[21]

4.2.3 Industrial Rate

Option A. Current Structure, Modified Prices. NLH could retain the current structure, in which demand and the firm energy charge strive to recover required revenues. Customers who exceed their Power on Order may acquire power, if available, via non-firm pricing based on

[20] To deal with sudden shortage conditions, however, it would be helpful if the Utility rate included occasional real-time pricing or critical-peak pricing as described below.

[21] Annual adjustment could be aligned with annual changes to the value of the deferral account recovery mechanism. NP would then have known prices for its own ratemaking becoming available at a predictable time.

marginal cost. In principle, changing the demand and energy prices would suffice to update the rate. The advantages of this approach are that expected embedded costs are recovered fully, demand-related costs are recovered in a demand charge, and the structure is familiar to the customer, NLH, and the PUB. A leading disadvantage is that the marginal price is not commonly based on marginal cost, since non-firm power is not always used. Additionally, revenue recovery of costs that will be increasingly fixed will nonetheless depend upon volumetric pricing to some significant degree. It appears that the current design could be improved, perhaps while enhancing its blocked pricing structure.

Option B. Modified Block Boundary. One way to reduce variability of revenue recovery is to move the block boundary, currently defined by Power on Order, so that all customers consume above that level in (almost) every month. For example, defining the boundary as, say, 80% of the class average load factor multiplied by Power on Order would ensure that most customers reach the second block in most months. The boundary would change with changes in the Power on Order amount. In brief, the block boundary would be customer-specific but the block 1 price would be uniform across customers.

The price for the first block—embedded costs divided by adjusted forecasted energy—ensures full revenue recovery of embedded costs, as determined in the COS study, provided that usage does not fall below the block boundary. Below that boundary, the marginal rate becomes the embedded cost rate, which would likely be above the marginal cost rate. Load reduction would cut into required revenues and leave NLH with a revenue shortfall. Such shortfalls (and offsetting over-collections when loads are above forecast) are a normal part of embedded cost-based pricing. In this case, with no or very low margins being earned by NLH on load increases, shortfalls become problematic.

The price for the second block will be based on marginal cost, as in the modified Utility rate. Again, the rate should be seasonal but need not be time-varying over the course of the day. The outcome of this design is to offer Industrial customers marginal cost-based pricing at almost all times.

This option improves upon Option A by enhancing the likelihood of full revenue recovery and improving the marginal price seen by the customer. The design may create an issue by converting energy sales above the block boundary to firm sales. This challenge may be met with either quantity rationing—a rule setting an upper limit on tail block energy without gaining prior approval, or perhaps adjusting the Power on Order quantity—or price rationing—the use of RTP in critical-peak hours to signal a need to constrain usage.[22]

Possible disadvantages of this option include the need to compute and communicate customer-specific block boundaries, along with the retention of the revenue recovery variability inherent in a demand charge. As mentioned in the utility rate section above, demand prices based on embedded costs can be awkward price signals.

Option C. Hours-of-Use Demand Pricing. A modification of the block pricing design that may simplify it operationally is to use an hours-of-use demand (HUD) tariff. This long-established design is just a customer-specific blocked tariff, with the block boundary being determined by the customer's load factor and Power on Order. For example, a customer with 1 MW of peak demand facing a rate with a block boundary of 365 hours of use (half of 730 hours, which is approximately an average month's total hours) would have half their load priced at the first-block price and the remainder at the tail block price. Typically, there is no demand charge in an HUD tariff, but it can be used if desired.

In the Industrial class's case, NLH could select a block boundary in terms of hours of use that virtually guarantees that all customers will have some block 2 usage in each month. If a 70% load factor achieves this objective, then the block boundary would be 511 hours of use (70% of a 730-hour month). Since the HUD tariff has no demand charge and customer-related costs are recovered by Specifically Assigned Charges, the first-block energy price would equal revenue requirements for the class divided by forecasted class first-block usage, which equals total Power on Order multiplied by 511.

[22] More on critical-peak pricing appears below.

This approach to design produces full revenue recovery, provided that the customer consumes enough to get to the block boundary and that the tail block has a marginal cost-based price. Essentially, the first-block charge becomes a lump-sum charge. Only in cases when usage declines substantially relative to normal levels does less than full revenue recovery occur. Customers would see a rate that charges a total bill on the basis of load factor: high load factor customers would have a large share of load in the tail block while lower load factor customers would have a smaller share. This is in line with standard ratemaking practice. Customer bills would be relatively stable given stable consumption patterns, and average price would not change drastically with moderate changes in consumption.

Practitioners sometimes criticize the HUD design for apparent lack of clarity of price where usage approaches peak demand. Especially if the billed demand amount is ratcheted, the cost of exceeding this level can be high and long-lasting. Barring this criticism, the marginal price is clear.

In NLH's case, this criticism does not appear to apply with as much force, as customers are accustomed to respecting the Power on Order level, unless attempting to use non-firm or secondary power. NLH could make this design simpler still, by making peak demand equal to Power on Order and not charging for levels of demand above it. Retaining the link to actual billed demand, perhaps with a ratchet structure, would achieve the effect of limiting increases in peak demand if NLH feels that customers need a signal to limit flows on their customer-specific transmission line segments. However, this would lead to over- or under-collection of required revenues and complicate the marginal price in the tail block in the same manner as would a demand charge.

4.3 Alternative II: "Two-Part Pricing"[23]

The block pricing concept can be modified to produce a more formal segmentation between recovery of embedded costs and marginal cost pricing. Two-part pricing achieves this objective

[23] The "two-part pricing" label is potentially confusion to some readers. Traditional ratemaking sometimes refers to a tariff with a customer and an energy charge as two-part pricing. The version used here is in harmony with that

by establishing a bill that consists of a lump-sum Base Bill and an Incremental Energy Charge. The Base Bill is simply the cost allocated to the customer by the COS study divided by a forecasted or contract quantity, with the annual dollar assessment being divided into monthly amounts in some sensible fashion (*e.g.* equal per-hour amounts or equal per-month amounts). The Base Bill does not vary with current usage or peak demand.

Underlying the Base Bill is a contract quantity of usage for the billing period. Departures from the contract quantity, up or down, produce charges or credits based on a marginal cost-based price. Because the marginal price of the Incremental Energy Charge operates in both directions (increased and decreased usage) for any amount of usage, it is not necessary to scale back usage to create a block boundary that makes it unlikely that a customer will fall short of the boundary, as is the case in block pricing. Under this arrangement, actual usage may exceed or fall short of the forecast value and the Incremental Energy Charge can be positive or negative.

The two-part pricing structure creates a billing environment that is quite similar to the blocked tariff described in the preceding section. Customers pay their embedded cost obligation in one (dominant) lump sum and then pay for increases in usage, or obtain bill reductions from decreases in usage, at a marginal price that matches the forecasted marginal cost to serve additional load.

As with tail-block pricing for the blocked tariff designs, seasonal pricing and regular revision of prices to reflect market conditions are desirable properties for encouraging price efficiency.

Two-part pricing can be utilized with varying duration of pricing periods. In its simplest form, the contractual usage, or "customer baseline load" (CBL) can be a total usage amount for each billing period. The Base Bill is just revenue requirements for the billing period divided by the CBL amount. Departures from that amount are priced at the (seasonal average) marginal prices described immediately above. This simple version of two-part pricing, which is close in spirit to

definition, in that the bill has two lines; they just differ from the lines of the original definition in that that base bill is a customer-specific customer charge.

the block design described above, will serve for the discussion of a basic two-part pricing product immediately below. Variants of the concept, RTP and occasional RTP appear below, with suggestions for their use.

4.3.1 Utility Rate

A simple two-part design develops a monthly CBL for Newfoundland Power by applying its forecasted annual usage total to each billing period by means of Newfoundland Power's historical pattern of monthly usage. (Weather normalization or averaging of recent years' monthly totals can be applied to development of reasonable monthly usage shares of the annual total.) Annual revenue requirements could be divided into monthly amounts in two ways. A simple approach would place one-twelfth of the annual amount in each month, a plan that conforms well with NLH's pattern of fixed costs. An alternative approach would involve dividing the annual total into monthly values based on monthly CBL usage share, yielding an even per-kWh cost across months. This approach is more complicated for both parties, but would benefit the customer, possibly, by creating a bill obligation that conforms approximately to its revenue pattern. The first approach seems preferable, as it better reflects NLH's pattern of costs. The price for the Incremental Energy Charge is a seasonal average marginal cost, as with the blocked tariff.

The advantages of this structure are that embedded costs are recovered fully, with exactitude, as they are independent of customer behavior; all changes in load of any size are priced at marginal cost; and the bill structure is simple, lacking a demand charge. The disadvantages of two-part pricing are that the absence of a demand charge eliminates a source of revenue growth as customers grow for whatever reason; and the rate design is potentially novel to the customer and to other parties, including NLH.

As with the blocked tariff, the challenge in determining revenue requirements under two-part pricing is to establish forecasted usage as the basis for cost to serve. With embedded cost predicted to be substantially above marginal cost, Newfoundland Power has an incentive to under-forecast usage, but perhaps to no greater extent than it has in the past.

NLH faces the challenge of establishing a CBL sufficient to recover costs not merely in the test year, but in subsequent years. Between rate cases NLH's obligation to pay for the MF project rises steadily according to a predetermined schedule. As at other utilities, other costs move upward over time as well. The assumption that supports rate stability at most utilities is that load growth provides the extra revenue necessary to cover gradually increasing fixed and variable costs. At NLH, for a base bill to achieve this effect, the CBL must adjust with time, either according to a multi-year forecast determined at the time of a rate case or a single-year forecast, updated annually. Unit costs established in the COS study associated with each rate case will then produce cost recovery associated with changes in Newfoundland Power's market size.

4.3.2 Industrial Rate

In a simple two-part design for Industrial customers, the CBL would be based on the same approach as the block boundary of the blocked tariff: adjusting the customer's Power on Order for load factor. In this case, the boundary does not need to be adjusted below this forecasted level since the marginal price applies on both sides of the CBL.

As with the Utility two-part rate, the advantages of this structure are that embedded costs are recovered fully, with exactitude, as they are independent of customer behavior; all changes in load of any size are priced at marginal cost; and the bill structure is simple, lacking a demand charge. The disadvantages of two-part pricing are that the absence of a demand charge eliminates a source of revenue growth as customers grow for whatever reason; and the product is potentially novel to the customer and to others, including NLH.

One criticism of the simple design, shared with the blocked tariff lacking a demand charge, is the absence of a signal to control peak demand. Price and quantity rationing can be applied here as well, along the lines mentioned: setting a quantity limit or adopting a short-notice price signal indicating supply constraints. However, at NLH, the customers of the Industrial class manage their own load requirements via the Power on Order approach, with adjustments influencing future revenue requirements even in the absence of a demand charge. This is in contrast to utilities where large customers are each responsible for a smaller share of utility sales than is the case here, and demand charges are a vehicle for signaling load requirements individually and for the class.

Industrial customers do not face the same issue of load growth that the Utility rate faces. NLH's Industrial customers may have variable loads but are not generally characterized by steady increases in consumption. A contractual CBL derived from Power on Order likely would suffice for cost recovery related to quantity.

4.3.3 Two-Part Real-Time Pricing

Two-part pricing is used predominantly in regulated service territories to support RTP as a voluntary service option for large customers. Two-part RTP consists of a base bill developed by applying a customer's current standard tariff to the historical usage and peak demand quantities that make up the CBL, with usage being defined as an hourly load profile. The Incremental Energy Charge is based on the sum over a billing period of hourly marginal cost-based prices (revealed on the preceding business day) multiplied by the hourly differences between actual usage and the CBL. RTP prices are generally delivered by utilities to their customers on the preceding business day. This short-notice structure provides accurate price representations of system conditions.

Two-part RTP creates a direct link for retail customers to market price/marginal cost while collecting embedded costs via the base bill. In principle, such a rate could be offered to both Newfoundland Power and NLH's Industrial customers. Those NLH Industrial and Newfoundland Power large general service customers with strong energy management capabilities might find RTP to be a useful option since load management actions might help to reduce incremental costs.

RTP has advantages that derive from improved price efficiency and the creation of opportunities for demand response. The product's disadvantages are administrative for both the utility and the customer: data management, billing, and customer support capabilities must all be enhanced, as must customer energy management capabilities if price response is to be secured.

Illustration: Service to Corner Brook Pulp and Paper

CBPP represents possibly NLH's most complex customer service challenge due to the unusual nature of its circumstances. The customer operates a mill that is served in part by its own hydraulic generation, with NLH providing remaining needs. (A cogeneration unit on site provides energy fed to NLH.) Complicating service further is the presence of 50-Hz generation and consumption on site, linked to 60-Hz lines by a frequency converter owned by NLH. NLH currently supplies 8 MW of firm power under the Power on Order arrangements of the Industrial rate. Excess 50-Hz power at the site is "trapped" lost through spill, or used in the customer's electric steam boiler.

At present, NLH can provide several different types of energy to CBPP: firm power, interruptible, generation outage (to support CBPP in the event of generator failure at their site) oil-fired boiler replacement (for the same purpose), secondary, and frequency converter replacement. NLH can also make capacity assistance requests of CBPP (through load interruption at the mill), as noted, and can obtain supplemental capacity assistance, through separate arrangements. Each of these types of supply operates under its own contractual limitations. As well, non-firm energy pricing depends on the supply source available to serve the load, if the load can actually be served.

CBPP's generation no longer needs to follow its load with the purpose of minimizing demand billed by NLH. A pilot generation credit agreement dating from 2009 enables this improvement in pricing efficiency.[24] For the present, this agreement appears to be a useful pricing incentive that is beneficial to CBPP, inducing efficiencies in the operation of their facilities.

In the future, it appears that a two-part pricing structure with hourly real-time prices might be able to simplify the contractual relationship, including the generation credit provision. The

[24] PUB Order No. P.U. 4(2012).

two-part structure could involve occasional RTP service in critical-peak hours only, a design set out in the next section below, or all-hours RTP, as described above. Since CBPP operates its own customer site generation, it provides a useful example of a situation in which all-hours RTP might be beneficial to the customer and to NLH.

CBPP could have a CBL based on its current Power on Order, multiplied by historical load factor (but backing out capacity assistance and interruptible load relief from the load profile) and, when priced at embedded cost, covers revenue requirements. (The CBL would continue to treat peak demand in the same manner as the pilot agreement, namely eliminating the need for CBPP to use generation to follow load.) All departures from the hourly CBL would be priced at day-ahead hourly RTP price. Variations in this price would indicate changes in all NLH system circumstances. CBPP could evaluate the RTP price pattern to evaluate how to operate its generation and mill to maximize value. Should a generator outage or other supply emergency occur, pricing would be available to evaluate how to respond. A low price would indicate that it would be cost effective to purchase more energy from NLH. A high price might cause CBPP to consider increasing its own supply or to cut production.

High prices in hours of very low system reserves likely will suffice to limit usage, but NLH may still need to impose availability limitations of the sort in place at the moment. However, it is possible that the contractual circumstances could be simplified.

Current contracting produces an arrangement that might appear to be unusual: the generation credit approach allows CBPP to exceed its firm demand level without having to pay for interruptible power. In return, CBPP is able to manage its hydraulic resources more efficiently. In addition, NLH can call on CBPP to maximize its generation to provide additional capacity to the grid (to the extent that it is available at the time of the request) under these arrangements. One way to view the two-part RTP concept is see it as gathering up all types of energy and pricing, and all operational commitments, and converting them into a price guideline that the customer then uses for its own planning purposes.

From the customer's point of view, this structure would transfer into their control decisions about mill consumption patterns and levels and hydraulic facility operation. RTP prices would show day-ahead (or hour-ahead if desired) system conditions and assist CBPP to get the most value possible from both facilities. Day-ahead notice is used elsewhere to assist energy-intensive facilities to plan site production and associated energy consumption levels and to control costs.

The RTP price provides an automatic signal for requesting load relief, as well, and the marginal cost-based price provides a market-based means of remunerating customers. Instead of paying customers the up-front credit and a fixed price during capacity requests, NLH would reimburse the customer using prices closer to market values. Payment could be entirely related to actual energy delivery relative to the CBL or there could be a small payment for participation (per kW). While high RTP prices might still come during the winter season predominantly, reflecting NLH system conditions, high prices at any time of year might afford an opportunity to CBPP to reduce energy costs by temporarily reducing load or increasing supply.

Additionally, this structure could include the sale of secondary energy, hitherto to Newfoundland Power, but perhaps transferred to NLH, with marginal cost-based settlement provisions with Newfoundland Power, if needed.

This arrangement would require review and approval by several parties: the customer, NLH, the PUB, and Newfoundland Power.

4.4 Peak-Hour Pricing Riders

Both blocked and the simple version of two-part pricing may be enhanced by inclusion of a peak-hour pricing rider. This could be in the form of occasional real-time pricing (ORTP) or "critical-peak" pricing (CPP). Under either ORTP or CPP, the second block price for hours with acute shortage conditions would be replaced by high prices based upon the power system's day-ahead or real-time marginal costs (for ORTP) or upon a longer-term forecast of critical-peak hour marginal costs (for CPP). Under block pricing, customers would pay this high price for all consumption above the block boundary. Under two-part pricing, customers would pay this high price for all consumption above the CBL and would receive this price for all power “sold back” to NLH by consuming energy below the CBL. ORTP and CPP tariffs have a history of reliably inducing demand response in the North American jurisdictions that have adopted them.

Newfoundland Power could use an ORTP arrangement to support its interruptible rate offerings in a manner that updates pricing from traditional methods. Instead of paying customers in advance for availability via a demand charge discount but not providing reimbursement for actual load relief, the utility could offer a reduced or zero credit for availability and a marginal cost-based price for load relief. The reduction in the customer’s bill due to price response during critical periods would match the reduction in Newfoundland Power’s costs.

4.5 Revenue Recovery between Rate Cases

Utilities under traditional rate regulation share a common challenge of a growing mismatch between revenues and costs as the most recent general rate case fades into history. Cost to serve increases as input prices and output quantities change, and falls as utilities find new cos-cutting efficiencies. Normally volumetric rates priced at embedded cost provide some coverage as load grows between rate cases. However, rates that recover revenues in a non-volumetric fashion, or based on volumes that don’t change over time, cannot take advantage of load growth for recovery of growing costs.

A high proportion of NLH’s costs will be fixed after the MF project is on-line. However, certain contractual payments are scheduled to grow over time. If regulation is applied in the traditional fashion, even though a forward test year is used, revenue recovery under both the blocked and two-part tariffs will not increase.

Some cost increases will be recovered through the deferral account recovery mechanism. These costs will consist of departures from forecasted values of operation and maintenance expense and other charges, along with cost variations related to hydrology and purchased power. However, scheduled increases in MF project payments may not be fully incorporated in cost recovery and the proposed designs, based on sound rate design principles, provide some cost exposure. Systematic under-collection of required revenues is likelier than at most utilities.

Below are some candidate solutions, or partial solutions.

- Block boundaries or CBLs could be adjusted annually in response to customer forecasts (Newfoundland Power) or Power on Order nominations (Industrial customers) and the associated revenues scaled up/down proportionally. This might happen as a matter of course for the Industrial customers but not for Newfoundland Power.
  - This plan operates under a possibly flawed assumption, that cost to serve would expand proportionately with load. However, with reasonably timely rate cases, this error is not likely to be large.
- The PUB could order that rate cases consist of multi-year COS studies which would result in multi-year pricing.
  - This plan would potentially be administratively burdensome.
- NLH could investigate formulary rate plans that set boundaries on rate of return and provide automatic price adjustments when returns are outside a range of return rates.
  - This approach permits greater time between rate cases as well as providing risk management for the utility in a structured fashion.

4.6 Review of Additional Tariff Components

4.6.1 Utility Rate

The Utility rate includes credits for Newfoundland Power's ability to meet peak demand with its own hydraulic and thermal generation, and a credit for Newfoundland Power customers' ability to provide interruptible load upon demand. The rate also makes provision for sale of secondary energy by CBPP to Newfoundland Power.

As mentioned in the recent COS Methodology report, the change in the supply situation following completion of the MF project has caused NLH to review the value of Newfoundland Power's generation in meeting peak demand. A possible means of addressing this issue is to price energy sold by Newfoundland Power to NLH in accordance with marginal cost, after adjusting for losses. The marginal cost-based price would need to be hourly, preferably hour-ahead or day-ahead to reflect system conditions as accurately as possible. Since NLH would call for power in conditions of low system reserves (conceivably due to a loss of transmission capability or extreme conditions in the Eastern Interconnection) the marginal cost-based offer likely would be quite high, at a level that calls forth demand response in North American RTOs. This price signal is efficient in terms of inducing Newfoundland Power to provide energy to the grid when it is most valuable (subject to any technical constraints). NLH would thus offers pricing to Newfoundland Power on the basis of pricing that it would offer to an independent power producer. This method of reimbursement would replace a payment for capacity (and remove or reduce the need for Newfoundland Power to demonstrate ability to provide such capacity) and would also offer a marginal cost-based price for energy to replace the zero payment for hydraulic energy and the fuel price based on Newfoundland Power's fuel costs for thermal energy.

Similarly, the secondary energy payment by Newfoundland Power to CBPP could be placed on a market value basis by replacing the firming up charge with marginal cost-based remuneration. This approach would permit separation of the two transactions of energy sale to CBPP and energy purchase from CBPP. For energy sales, NLH would establish annual revenue requirements and a CBL reflecting CBPP's historical usage in the absence of secondary energy provision. CBPP could select an ORTP or RTP design to support its ability to provide interruptible energy and then could provide secondary energy under similar pricing as a separate line item. NLH could purchase this energy at a marginal cost-based price, simplifying the current transaction structure that includes Newfoundland Power, provided that all parties approve of the move to a revised arrangement.

4.6.2 Industrial Rate

The terms of each Industrial customer's Power Service Agreement usually include the opportunity to purchase power, when available, in excess of the level of their Power on Order. This energy has two types: non-firm (interruptible) and secondary. The former refers to the type of power commonly available beyond NLH's firm commitment to deliver, while the latter refers to power available only in circumstances in which spilling water is very likely. NLH can allow for sales of both types of power within the context of any of the three main alternatives for core sales of energy by making use of marginal cost-based pricing available at short notice (e.g. day-ahead or even hour-ahead).

Under an ORTP pricing arrangement, in most hours, NLH would sell energy at the marginal cost-based seasonal rate. In cases of extremely low reserves (and associated high marginal costs) an ORTP structure would offer customers a chance to reduce usage in return for a billing credit at the high marginal cost-based price for critical-peak hours. In such hours, purchases above the CBL (as defined by Power on Order and historical load factor) would be made at the high price, while reductions in usage to any level would produce bill reductions at the same high price. In effect, the ORTP structure replaces a blocked tariff with a two-part tariff during extreme hours, or it replaces average seasonal marginal cost-based pricing of the two-part tariff with RTP.

This same approach could be used in water spill conditions, only this time the marginal cost-based price would be extremely low. Customers could increase their usage in the short term at the very low marginal cost-based price.

The ORTP concept can also be used to replace the current capacity assistance agreements, which offer load relief to NLH at the cost of substantial capacity payments. The payments could be reduced or eliminated, and short-notice energy payments for load reduction below a contractually agreed CBL (likely the Power on Offer level multiplied by historical load factor). Marginal cost-based prices would then determine the value of payment for load relief.

This alternative is applicable not only for cases of load reduction, but also for customer-site generation services. The pricing arrangements would be improved by the removal of large capacity payments for availability and by conversion of all payments for load relief, of whatever form, to a marginal cost-based hourly price determined either on a day-ahead or hour-ahead basis.

This structure may offer pricing benefits for NLH with its Nalcor affiliates, where contracting for certain loads is priced at an annual average of market prices. Since the degree of utilization of critical-peak pricing can vary widely from year to year, depending on weather, grid conditions, and conditions in other jurisdictions, it may be stabilizing to exclude departures from CBL and the cash flows between NLH and its customers from the transaction balances used to calculate annual average prices. The ORTP approach naturally generates the accounting quantities, prices and transaction values, which can then be netted against other trade values between NLH and the Nalcor affiliates. By removing transactions in the tail of the price distribution, this will help to stabilize the average covering the vast bulk of such transactions.

5. DESIGN RECOMMENDATIONS

The impetus for rate design modification at NLH is the increased share of costs that are fixed following completion of the MF project and interconnection with the grid of eastern North America. This review has presented rate design alternatives that appear best suited to meeting NLH's rate design objectives. Prominent among these objectives are overall revenue recovery and efficient pricing. In the past, NLH has striven to achieve these objectives by means of variants of blocked pricing, in which the first block recovers the bulk of forecasted revenue requirements and the tail block covers marginal cost.

In pursuit of other rate design objectives (rate stability, simplicity, minimal controversy, etc.) this report first explored designs close to block pricing. We then reviewed two-part pricing, which offers a structure similar to block pricing but with a marginal price that applies to all departures in usage from forecasted (CBL) usage, as opposed to load changes down to the block boundary in blocked pricing designs.

5.1 Utility Rate

The two-part design appears to allow NLH to avoid the weaknesses of the blocked design, and we recommend that NLH explore this design in detail. Both designs are similar in structure, so both parties and other stakeholders should not find two-part pricing excessively novel. Both designs recover revenue in a lump sum (two-part pricing) or in charges that are very close to a lump sum (the block 1 energy charge and demand charge of block pricing). In particular, the two-part design can be used to eliminate the complicating effect of the demand charge, a feature that may be appealing to both parties.

It would be feasible, but problematic to continue the current tariff structure, even with modified pricing. The structure itself appears capable of meeting both NLH's and Newfoundland

Power's needs following completion of the MF project. However, since we recommend that NLH request the ability to update its tail block structure regularly, and since such changes will modestly affect the first-block price, the design appears to be potentially administratively cumbersome for NLH, and possibly troublesome for Newfoundland Power.

If the blocked design is retained, it appears that simplifying the tariff by making the demand charge a function of forecasted rather than actual billing quantities would reduce variability in revenue recovery and simplify the price signal. Complicating the tariff by introducing monthly block boundaries might be worthwhile if the likelihood of NLH experiencing load reductions beyond the block boundary is materially reduced. Additionally, if the block design is preferred, the determination of billing demand can largely be retained, if desired, with adjustment for the elimination of generation credit and curtailable credit, if NLH gains approval for this change as part of its repricing of site generation and curtailable service support.

NLH should offer support for site generation at Newfoundland Power by means of day-ahead or hour-ahead real-time pricing based on its marginal cost, adjusting for losses. NLH will need to state its components of marginal cost and have a defined approach to their calculation. Current methods of dispatching Newfoundland Power's generation appear compatible with this pricing arrangement, and the pricing offers the downstream utility a market price for any sales.

NLH should offer support for Newfoundland Power's curtailable load program by means of an occasional RTP structure. This structure will pay an hourly market price to Newfoundland Power for load reductions by its customers. Newfoundland Power should be able to document the load changes based on its preferred tariff design.

5.2 Industrial Rate

The Industrial customers' current rate structure does not provide the opportunity for tail block consumption of firm energy to be priced to reflect marginal costs. Customers currently see the marginal cost signal if they increase their demand requirements above their Power on Order. A two-part rate design appears to be a relatively simple design in this case, despite its apparent novelty.

A central issue with two-part pricing for Industrial customers is the determination of customer-specific revenue requirement. Class revenue requirement is available in the COS study. Each customer's forecast of Power on Order and historical load factor leads to a forecasted total of usage for each customer and the class as a whole. Combined with unit costs from the COS study, individual customer revenue requirements may be developed, reconciling to total revenue requirement as a last step.

Each customer can have a customer-specific lump sum developed for each year or a Base Bill can be created from unit cost-based demand and energy prices applied to CBL values of demand and energy. The outcome is a customer-specific lump-sum charge in each month. High load factor customers would have a Base Bill with a lower implicit average price for the CBL than that of a customer with a lower load factor.

An Incremental Energy Charge with seasonal pricing should suffice. NLH should offer as an option either RTP or ORTP to encourage load relief from those capable of price response. These options require hourly definition of a CBL (which could just be a single value for all hours, if this reflects the customer's load profile). The extra administrative cost would be balanced by reduced cost to serve in critical-peak hours.

This hourly pricing option also permits continuation of the non-firm and secondary energy structures on a simpler basis, namely hourly marginal cost-based pricing. (Secondary energy would be reflected in very low hourly pricing.)

NLH can treat customer site generation in the same manner as it treats Newfoundland Power's owned generation: hourly pricing would support current practices for calling upon this generation and would provide market-based compensation. The illustration of a two-part RTP application for CBPP demonstrated the potential for simplification of a variety of special service conditions that can be achieved with an ongoing hourly pricing scheme.

If customers are wary of the two-part design, NLH could offer an HUD design, as its incentive properties are similar to those of two-part pricing. However, the HUD design may appear more complex than the two-part design to customers. The design also appears to be slightly more complex to administer from NLH's perspective, although selecting an initial hours-of-use boundary will require some work.

These design ideas likely will require review by interested parties, whose expression of preferences may suggest alterations in structure and pricing. For example, customers may prefer non-seasonal pricing of the tail block. NLH can offer this extra level of risk management, but should charge the premium necessary to cover the extra costs of less efficient pricing.

APPENDIX: EXPECTED MARGINAL COST VARIABILITY AT NLH

A pricing issue that arises as a result of the completion of the MF project is whether Newfoundland and Labrador Hydro (NLH) should introduce time variation in its rates. We have used our PRIOPT (Price Optimization) model to evaluate possible seasonal and time-of-use (TOU) pricing patterns that might be adopted, based on the pattern of forecasted marginal costs for the year 2019, which is anticipated to be the first full year of service following the completion of the MF project.

NLH's current rates for its utility customer, Newfoundland Power, and its industrial customers (IC) do not have seasonal or TOU price patterns. They feature a block pattern that includes marginal cost pricing in the tail block, with marginal cost being defined by Holyrood TGS. Since NLH will be linking to the Eastern Interconnection and ceasing to use Holyrood TGS for more than power quality, marginal cost will now become more variable and based on wholesale market conditions (in the absence of transmission constraints). The issue is whether the variability of marginal costs should result in time-varying pricing, especially where price is based on marginal cost.

APPROACH

CA Energy Consulting has developed a model, PRIOPT, that allows the analyst to evaluate a broad range of alternative time period configurations and discover the TOU pattern that meets the criterion of minimizing within-period variance. That is, this criterion searches across all possible price periods that have been designated feasible by the analyst and seeks to discover the configuration in which hourly marginal costs within each pricing period are as similar as possible and average marginal costs between pricing periods are as different as possible.

The analyst identifies each day by day type (weekday or weekend/holiday, by season) picks the seasonal pattern, selects whether a two-period (peak/off-peak) or three-period (peak/shoulder/off-peak) model will be run, optionally selects hours that should be defined in advance as peak or off-peak (to cut down search time), and runs the model. The model outputs are: 1) the time pattern in each season that minimizes the sum of within-period variances; and 2) the load-weighted marginal cost in each time period.

The data that the PRIOPT model uses consist of a year of hourly interval data for the class whose load is to be priced and an hourly vector of forecasted system marginal costs. In this case, the model was run for the Newfoundland Power and IC classes for calendar 2019. The marginal costs used here were generated jointly by NLH and CA Energy Consulting as part of the marginal costing analysis, and represent the scenario thought to be most likely, namely regular access to the New York and New England wholesale energy, reserves, and capacity markets in 2019.

SCENARIOS

We explored both two- and three-period models, and evaluated a range of seasonal scenarios, but always included three seasons: winter, summer, and “spring/fall.” We considered first a three-month winter (December–February) and three-month summer (June–August) based on visual inspection of monthly marginal cost patterns. By similar inspection, we also restricted hours 1–4 and 23–24 to be off-peak, but allowed all other hours to be selected by the model. We assumed that all weekends and holidays are off-peak. (This is a conventional assumption.) Holidays were selected with reference to the NL shop closure calendar.

MODEL RESULTS

We considered first the three-month summer and winter two-pricing-period scenario, which produced results that involved a long peak period in all three seasons, although of varying length. (Note that this does not require NLH to have TOU pricing in all three seasons, or to have peak periods that conform to the optimum. Actual rates need not even be TOU if marginal costs are not strongly different across the periods or across seasons.) Table A-1 presents the results for Newfoundland Power. Results for Industrial Customers are very similar.

Table A-1
Three-Season Configuration: Three Summer and Winter Months
Two Pricing Periods

Season	Months	Average Marginal Cost ($/MWh)				MC Ratio	Peak Seasonal MC Ratio		Within-Period
		Peak	Shoulder	Off-Peak	All Hours	P/O	vs. Spr/Fall	vs. Winter	Variance
Winter	12, 1, 2	$ 64.26	$ -	$ 48.11	$ 55.06	1.34	1.42	1.00	$ 58,924,132
Summer	6, 7, 8	$ 71.64	$ -	$ 45.03	$ 55.21	1.59	**1.58**	**1.11**	$ 51,838,938
Spr/Fall	3, 4, 5, 9, 10, 11	$ 45.28	$ -	$ 34.32	$ 39.37	1.32	1.00	0.70	$ 19,569,941
Total									$ 130,333,010

The model selects the peak hours as 7–20 inclusive in winter, 8–19 in summer, and 7–21 in winter. These long peak periods reflect the pattern of marginal costs in the Eastern Interconnection. The table reports resulting average marginal costs for the two pricing periods as well as for all hours in the season. This scenario yields peak/off-peak (P/O in the table) ratios of 1.59 in summer, 1.34 in winter, and 1.32 in the spring/fall months. The all-hours MC values show that winter and summer marginal costs are about 1.5¢/kWh ($15/MWh) above the spring/fall period value of $39.37/MWh. Additional columns report the ratio of summer average marginal cost vs. the spring/fall and winter periods, and the variance in marginal costs within periods and the total for all periods. (The variance values are not significant except as bases for comparison with other scenarios.)

We explored alternative definitions of seasons and discovered that the variance-minimizing seasonal configuration is a four-month winter season (adding March to the previous scenario) and a two-month summer season (subtracting June). Table A-2 presents the results of this scenario for Newfoundland Power.

Table A-2
Three-Season Configuration: Four Winter, Two Summer Months
Two Pricing Periods

Season	Months	Average Marginal Cost ($/MWh)				MC Ratio	Peak Seasonal MC Ratio		Within-Period
		Peak	Shoulder	Off-Peak	All Hours	P/O	vs. Spr/Fall	vs. Winter	Variance
Winter	12, 1, 2, 3	$ 59.41	$ -	$ 44.03	$ 50.56	1.35	1.27	1.00	$ 55,501,397
Summer	7, 8	$ 78.50	$ -	$ 47.48	$ 59.70	1.65	**1.68**	**1.32**	$ 44,393,277
Spr/Fall	4, 5, 6, 9, 10, 11	$ 46.85	$ -	$ 35.68	$ 40.87	1.31	1.00	0.79	$ 23,960,154
Total									$ 123,854,827

The model selects identical peak hours to those of the first scenario. This scenario features slightly larger peak/off-peak marginal cost ratios and modified ratios of summer peak prices to peak prices in other seasons. With three summer months, summer peak marginal costs average 58 percent more than the average for spring/fall months, while with just two summer months, that average increases to 68 percent.

Additionally, the second scenario produces a significant difference between all-hours marginal costs in summer and winter, while they were virtually equal in the first scenario. Were prices for the tail block to look like these marginal costs, they would be surprising in Newfoundland, as the cost of adding load would be higher in the summer than in the winter, a significant change from past circumstances.

If we continue using four winter and two summer months as a seasonal definition, but allow three pricing periods (peak/shoulder/off-peak) the model yields increasing peak/off-peak ratios and an increase in peak period seasonal marginal cost differentiation. This might be expected, since increasing the number of price periods allows for greater concentration of marginal costs within like groups. Table A-3 presents results for Newfoundland Power. (Notice that the overall variance in marginal costs within groups drops significantly relative to the two-period model.)

Table A-3
Three-Season Configuration: Four Winter, Two Summer Months
Three Pricing Periods

Season	Months	Average Marginal Cost ($/MWh)				MC Ratio	Peak Seasonal MC Ratio		Within-Period
		Peak	Shoulder	Off-Peak	All Hours	P/O	vs. Spr/Fall	vs. Winter	Variance
Winter	12, 1, 2, 3	$ 60.78	$ 57.56	$ 44.03	$ 50.56	1.38	1.27	1.00	$ 52,417,704
Summer	7, 8	$ 85.70	$ 71.05	$ 47.48	$ 59.70	1.80	**1.79**	**1.41**	$ 30,422,566
Spr/Fall	4, 5, 6, 9, 10, 11	$ 47.89	$ 44.02	$ 35.68	$ 40.87	1.34	1.00	0.79	$ 20,335,370
Total									$ 103,175,641

The model selects peak hours as 7–9 and 18–20 in winter, 12–17 in summer, and 9–19 in the spring/fall months. Shoulder hours are 10–17 in winter, 8–11 and 18–19 in summer, and 7–8 and 20–21 in the spring/fall months. The winter heating season generates peak hours in the morning and the evening and shoulder hours in between, while other seasons feature a more familiar single peak in the middle of the day, flanked by shoulder hours.

IMPLICATIONS

The all-hours average marginal costs of all tables suggest that seasonal differences of $10 to $20/MWh (1 to 2¢/kWh at retail) are to be expected, and that pricing differentiation of marginal cost-based rates will bring marginal price noticeably closer to marginal cost for NLH. If NLH selects the seasonal pattern of four winter and two summer months (Tables 2 and 3) the resulting all-hours marginal costs are $50.56 in winter, $59.70 in summer and $40.87/MWh in the spring/fall season. Selecting the seasonal pattern of three summer and winter months (Table 1) produces very similar winter and summer marginal costs ($55.06 and $55.21/MWh, respectively) and $39.37/MWh in winter.

The variation in marginal costs across the day within each season is not high relative to what is observed in retail TOU rates. These rates often have peak/off-peak price ratios of 3:1, a ratio regarded in the industry as being required to induce detectable response to price. In the case of NLH, marginal cost ratios are all less than 2:1 (an index value of 2.0 in the table). These ratios do not suggest definitively that NLH should not use TOU pricing, but simply indicate that price differentials should likely be low.

The above information does not state that NLH ought to differentiate pricing by season or time of day. NLH still retains broad discretion in pricing and can tailor that pricing to its customers' preferences. The more sophisticated the customer, the more readily they can sustain product and price complexity, and accuracy of price with respect to marginal cost. It seems reasonable that both Newfoundland Power and the IC class could manage seasonal pricing at least. More generally, NLH faces the usual rate making tradeoff of pricing accuracy and rate complexity. Evaluating which pricing period structure to adopt may be assisted by comparison of variance values or review of marginal cost patterns, but will surely depend upon the utility's own preferences and its customers' tolerance of price complexity and risk.

The less time variation included in prices, the more risk that NLH absorbs, since their incremental costs are variable while those of the customer are not under fixed pricing. At one end of the risk spectrum, NLH could minimize its risk by designing rates for its customers using same-day hourly real-time prices. At the other end of the spectrum, it could offer a fixed all-hours, all-season price based on the customer class's load-weighted forecasted marginal cost. (This riskier product would include a modest premium for risk acceptance.) In practice, with the anticipated increase in variability of marginal cost, it seems sensible to introduce seasonal pricing. However, given the relatively small within-day marginal cost ratios, TOU pricing may not be very beneficial.

NLH has discretion in this regard, and the results above do not mandate a specific design. Nor does the design chosen foreclose the use of dynamic rate options in which price closely matches marginal cost. For example, NLH could offer its Industrial Class either a two-part RTP option for all hours or for critical-peak hours only, as a means of obtaining price response in hours of low system reserves. Similar plans, offered to Newfoundland Power, would enable pass-through of market-based pricing, especially in critical-peak hours, to its own customers.

newfoundland labrador hydro
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June 15, 2016

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: Supply Cost Recovery Mechanism Review

Further to the 2013 GRA Settlement Agreement and Hydro's Final Submission, please find enclosed the original and 12 copies of the above-noted report.

Should you have any questions, please contact the undersigned.

NEWFOUNDLAND AND LABRADOR HYDRO

Tracey Pennell

Tracey L. Pennell
Senior Counsel, Regulatory

TLP/bds
Encl.

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey Stirling Scales
Sheryl Nisenbaum – Praxair Canada Inc.
Thomas Johnson – Consumer Advocate
Thomas J. O'Reilly, Q.C. – Cox & Palmer
Larry Bartlett – Teck Resources Limited

NEWFOUNDLAND AND LABRADOR HYDRO

SUPPLY COST RECOVERY MECHANISM REVIEW

June 15, 2016

newfoundland labrador hydro
a nalcor energy company

Table of Contents

1.0 BACKGROUND

The commissioning of the Muskrat Falls (MF) Project and the subsequent interconnection of the Island Interconnected System with Labrador by way of the Labrador Island Link (LIL) and the North American grid by way of the Maritime Link (ML) will result in a major change in the source of supply of electricity to the Island of Newfoundland. For many years, load growth on the Island Interconnected System has been supplied by the Holyrood Thermal Generating Station (Holyrood TGS). Upon the commissioning of the MF Project, supply cost payments will commence under the Transmission Funding Agreement (TFA) and Muskrat Falls Power Purchase Agreement (MF PPA), and the Holyrood TGS will be phased-out.[1]

At present, fuel costs required to operate the Holyrood TGS comprise the largest single portion of the supply costs incurred by Newfoundland and Labrador Hydro (Hydro). As a result, Hydro has maintained a Rate Stabilization Plan (RSP) to stabilize customer rates from monthly variations in Holyrood TGS fuel costs due to price variances, volume variances, and load variations. The purpose of the RSP is to ensure that rates reasonably recover Holyrood No. 6 fuel costs and moderate customer bill variability between Test Years. The Labrador-Island Interconnection will result in the eventual discontinuance of the use of No. 6 fuel at the Holyrood TGS. The elimination of Holyrood fuel expense will mitigate the need for the RSP, as currently designed.

Hydro proposed in its Amended 2013 General Rate Application (GRA) to conduct a review of the requirements for regulatory mechanisms to deal with variability in supply costs prior to its next GRA. The Settlement Agreements to the 2013 GRA require Hydro to file its review of the regulatory mechanisms to provide supply cost recovery with the Board of Commissioners of Public Utilities (the Board) by June 15, 2016.

[1] Holyrood TGS 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 the Island. Thereafter, the Holyrood facility will be used as a synchronous condenser.

1.1 Introduction

This report provides a review of the requirement for a deferral mechanism to provide Hydro the opportunity to recover variations in supply costs from those reflected in customer rates subsequent to the commissioning of the MF Project. This report provides a review of the:

(i) legislative considerations;
(ii) cost implications of the contractual provisions of the MF Project agreements; and
(iii) requirements for a supply cost deferral mechanism.

The forecast annual revenue requirements required to recover the costs of the MF Project from Hydro customers will be updated to reflect the revised construction schedule and cost estimates. Hydro believes it is appropriate to have updated cost information for consideration in developing and illustrating the recovery mechanisms prior to finalizing its deferral account proposals. As a result, Hydro has not included the proposed deferral account definitions with this report. Hydro will file, prior to filing its next GRA planned for March 31, 2017, the proposed supply cost deferral accounts and recovery mechanisms that are required to permit Hydro to recover supply cost payments resulting from the commissioning of the MF Project assets.

2.0 LEGISLATION

Sub-section 80(2) of the Public Utilities Act permits a public utility to recover those operating expenses that the Board may allow as prudently incurred in providing electrical service. Supply costs such as power purchases and fuel costs are generally considered prudent and included in setting customer rates. Actual supply costs often vary from forecasted costs for reasons beyond the control of the utility. Permitting recovery of supply cost variances from the approved supply costs reflected in customer rates through deferral mechanisms is common practice in regulatory jurisdictions across Canada.[2]

For the MF Project, the Government of Newfoundland and Labrador (Government) provided specific direction on supply cost recovery. In OC2013-343, the Government set forth the

[2] See Response to Request for information PUB-NLH-388 in the 2013 Hydro GRA.

requirement for the cost of supply from the MF Project (including the Muskrat Falls generation, Labrador Island Link and the Labrador Transmission Assets (LTA)) to be recovered in full through Island Interconnected rates charged to the appropriate classes of ratepayers.[3]

OC2013-343 also requires that any expenditures, payments or compensation paid directly or indirectly by Hydro under an agreement or arrangement to which the Muskrat Falls Exemption Order applies, shall be included as costs in Hydro's cost of service, without disallowance, to be recovered through Island Interconnected System customer rates.[4] In order for Hydro to fully recover annual costs resulting from charges related to the MF Project, Hydro will be required to establish a supply cost recovery mechanism to replace the RSP and provide for recovery of supply cost variances relative to these included in approved Test Year rates.

Appendix 1 to this report provides the Muskrat Falls Exemption Order and Orders in Council related to the Muskrat Falls Exemption Order.

3.0 SUPPLY COSTS FROM THE MUSKRAT FALLS PROJECT

3.1 General

Two main contracts provide for the recovery of the MF Project costs from Hydro: (i) the MF PPA between Hydro and the Muskrat Falls Corporation (MF Corporation); and (ii) the TFA between Hydro, the LIL Limited Partnership and Labrador-Island Link Operating Corporation (LIL-Opco).

3.2 Muskrat Falls Power Purchase Agreement

3.2.1 Overview

The initial MF generation and LTA project capital costs are collected by way of a Base Block Capital Costs Recovery payment through the MF PPA. The LTA are the transmission facilities of the MF Project that are being constructed by Labrador Transmission Corporation (Labrador

[3] Section 5.1(2) of the *EPCA also* sets forth the authority of the Government to direct the Board to implement policies, procedures and directives with respect to the MF Project.
[4] OC2013-343 sections 1(a)(iii) and 2.

Transco) to interconnect the MF generation assets with the grid. The Base Block Capital Costs Recovery payments for MF generation and LTA assets reflect an internal rate of return approach to derive a payment schedule which escalates annually at a rate of 2%. The required payment amounts by year are provided in Schedule 1 of the MF PPA and provide for the recovery of the original cost of the MF generation and LTA assets. These payment amounts do not provide for the recovery of Operating and Maintenance (O&M) costs or the investment required for sustaining capital for the assets over the 50-year supply period reflected in the contract.[5]

In addition to the original capital cost recovery described above, MF Corporation will estimate and bill a separate charge monthly to Hydro, with quarterly true-ups, to recover the actual O&M Costs, including the cost of sustaining capital, for MF generation and the LTA. These costs will be recovered through a charge to Hydro for “O&M Costs”.[6] Charges to Hydro for O&M Costs also include other costs incurred by MF Corporation such as: payments to aboriginal peoples pursuant to impact and benefit agreements; payments pursuant to the water lease; payments pursuant to the Water Management Agreement; and administrative costs and taxes.[7]

The LTA payments made by MF Corporation to Labrador Transco are included in the O&M Costs charged to Hydro in the MF PPA. The LTA payments include amounts to provide for the recovery of both the initial capital cost recovery of the LTA, the LTA sustaining capital as incurred, and the O&M Costs for the LTA.[8]

[5] Schedule 1 of the MF PPA will be updated to reflect the costs as of the in-service date of the MF Project. The Generation Interconnection Agreement (GIA) also includes a Schedule 1 providing the original capital cost recovery schedule for charges from LTA to MF Corporation for the LTA. The GIA Schedule 1 will also be updated to reflect new cost information.
[6] The complete description of O&M Costs is provided on page 15 of 76 of the MF PPA.
[7] Ibid.
[8] See Section 8.1(b) of the GIA between Hydro (in its capacity as the system operator) and MF Corporation and Labrador Transco.

The MF PPA requires Hydro to fund the sustaining capital costs for the MF generation and the LTA assets as these costs are not reflected in the Base Block Capital Costs Recovery amounts.[9] The sustaining capital funding by Hydro will require one of two recovery methods: either a regulatory deferral account to recover capital costs from Hydro's customers over the period for which these assets are expected to provide service, or full cost recovery from Hydro's customers in the period in which the sustaining capital charges are billed to Hydro. The second approach which would charge full cost to customers in the period in which Hydro pays the costs could result in material rate volatility to customers. Further, this approach would not provide a reasonable matching of cost recovery from customers with the period for which the assets are in service. Therefore, Hydro recommends adoption of the regulatory deferral account approach, which will allow Hydro to amortize these costs for recovery from its customers in the same manner as if Hydro owned the assets.[10]

3.2.2 Relationship of Load Requirements to Supply Costs

Schedule 2 to the MF PPA provides the forecast of customer load requirements on the Island (NL Native Load)[11] and the forecast load requirements from MF generation for each operating year of the contract to serve the NL Native load (the Base Block Energy). If Hydro's customer load requirements in an operating year require Hydro's purchases from MF Corporation to exceed the Base Block Energy and MF Corporation has the additional amount of energy available (i.e., available Supplemental Block Energy[12]), Hydro is not required to pay additional charges for the increased purchases to supply customer load.[13] Similarly, if reduced customer load requirements result in Hydro's purchases being lower than the Base Block Energy in the operating year, Hydro's required payment amounts under the MF PPA are not reduced for the operating year.

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[9] Ibid, 6.

[10] Section 78(f) of the Public Utilities Act permits assets funded but not owned by Hydro to be included in rate base.

[11] A definition of NL Native Load is provided on page 14 and Schedule 2 of the MF PPA.

[12] The Supplemental Block Energy represents the amount by which the actual NL native load in any operating year exceeds the Initial Load Forecast as defined in the MF PPA.

[13] This assumes no change in Hydro's energy supply from the forecast reflected in Schedule 2 to the MF PPA.

Changes in customer load requirements impact the amount of MF generation available for export sales.[14] In the scenario in which Hydro is required to access the Supplemental Block Energy to meet customer load requirements, there is reduced MF generation available for export sales. In the scenario in which Hydro purchases less than the Base Block Energy as a result of lower customer load requirements, there is increased MF generation available for export sales. In this scenario, Hydro has the opportunity to either monetize the unused portion of the Base Block Energy based on the value that can be obtained through the export market or defer such energy for future use (NLH Deferred Energy).[15] Transactions between Hydro and MF Corporation will use the Average Annual Sales Price in computing charges for transactions to external markets.[16]

On average, the embedded cost of service on a unit cost basis to be recovered from customers upon commissioning of the MF Project is forecast to be materially higher than the marginal cost of serving customers (i.e., the external market value). Based on the results of the Cost of Service Methodology Review and the Marginal Cost Study, the average embedded cost of providing service (i.e., generation and transmission) is forecast to be more than 11¢ per kWh, which is more than 6¢ per kWh higher than the forecast 2019 average marginal cost of approximately 5¢ per kWh.[17] The material difference between the forecast average embedded cost of service and the marginal cost on a unit cost basis is an important factor when considering rate design alternatives.

[14] There is no explicit provision in legislation requiring the value of export sales related to MF generation to be credited back to ratepayers to offset the cost of supply from Muskrat Falls. However, the current Government has indicated that export sales will be used to mitigate potential increases in electricity rates. See letter from the Premier to the Minister of Natural Resources dated December 14, 2015.

[15] See Article 3.1(c) on page 25 of 76 of the MF PPA.

[16] See Article 4.5(d), page 34 of 67 of the MF PPA.

[17] Based on a comparison of average unit costs derived from Attachment 1 (Row, 4) of the Cost of Service Methodology Review Report filed March 31, 2016 and the Marginal Cost Report, Part II, Table 1 on page 4. The average embedded cost will change when the MF Project costs are updated.

Aside from decisions about rate structure and pricing, the issue arises as to whether there should be a requirement for the financial impact of customer load variations to be dealt with in a supply cost recovery mechanism.[18]

3.2.3 Relationship of Island Interconnected Generation to Supply Costs

As indicated in the previous section, if customer load requirements increase beyond the Base Block Energy for an operating year, Hydro does not incur additional purchases costs in the MF PPA if MF generation is available for export. The additional customer requirements are provided through the Supplemental Block Energy and exports are reduced.[19] However, Hydro does incur additional purchased power costs if Hydro requires additional MF generation due to reduced energy generation being available to Hydro from other sources (i.e., total of self-generation, power purchases, and customer owned-generation).[20] The Base Block Energy was determined based on Hydro's current Island Interconnected energy supply carried forward for the term of the MF PPA with increases to the Base Block Energy made in 2022 and 2028 to reflect the forecast retirement of the Corner Brook Pulp and Paper Co-gen in 2022 and the 2028 retirements of the wind farms in St. Lawrence and Fermeuse.[21]

As stated earlier, the MF PPA makes the option available for Hydro to defer unused Base Block Energy as a result of lower customer load requirements resulting in Hydro not requiring the full amount of the available Base Block Energy in an operating year. This option is also available in years when Hydro requires less than the Base Block Energy as a result of higher than normal total hydraulic energy supply (e.g., a year of high precipitation) or above average energy

[18] This is evident in the pricing structures currently in place for Newfoundland Power and Island Industrial Customers. The load variation component of the RSP is currently required to deal with the earnings impacts of load variations of Island Industrial Customers because the energy price is derived based on the average embedded cost which is materially lower than the marginal cost (i.e., No. 6 fuel at Holyrood). However, no load variation component is required to deal with load variations from Newfoundland Power because the end block is priced at the Test Year Holyrood fuel price.

[19] If the full MF generation is being utilized and no Supplemental Block Energy is available, additional customer load requirements would require additional purchase costs to be incurred by Hydro based on market rates which would be included in the SCRUM.

[20] Assumed annual generation at Corner Brook Pulp and Paper is 880.1 GWh and Newfoundland Power is 437 GWh. These amounts are included in the NL Native Load Forecast in Schedule 2 of the MF PPA.

[21] See footnotes on page 2 of 2, Schedule 2 to MF PPA.

purchases being available to Hydro on the Island. The NLH Deferred Energy option permits Hydro to carry an energy reserve to avoid increased purchased power costs from MF Corporation in years when lower energy supply requires Hydro to purchase more than the designated Base Block Energy.

Hydro is also provided the opportunity to manage hydraulic production variability in years when water levels are low due to dry conditions on the Island by effectively borrowing Base Block Energy from a future year to a current year.[22] The MF PPA does not permit the NLH Deferred Energy balance to be negative. If no NLH Deferred Energy is available, Hydro has reduced energy supply available from other sources, and Hydro does not transfer Base Block Energy from a future year, then Hydro will incur purchased power cost at the external market Average Annual Sales Price for the additional purchases required from MF generation. Hydro would propose to recover these additional purchased power costs that would not have been reflected in Test Year rates from its customers through a supply cost recovery mechanism. The availability to Hydro of NLH Deferred Energy within the MF PPA limits the potential for supply cost variations as a result of year-over-year variations in Hydro's energy supply.[23] This option for supply cost deferral within the MF PPA influences whether Hydro requires a deferral account to deal with energy supply variances related to variability in hydrology.

3.2.4 MF Cost Reporting and True-ups

The terms of the MF PPA require Hydro to pay the Base Block Payments and the estimated O&M Costs on the first day of each operating month for service provided during that operating month. The MF PPA provides for a true-up to actual O&M Costs on a quarterly basis.

[22] See Article 3.1(f) in the MF PPA.
[23] This does not include the potential for cost variations from the required operation of Hydro's thermal generation facilities.

Further, MF Corporation must provide an Annual Energy Report[24] to Hydro on External Market Energy Sales within 30 days of each operating year-end. This report will provide details from the previous operating year on the following:

(i) Delivered energy;
(ii) Delivered capacity;
(iii) NLH Deferred Energy;
(iv) Contracted Commitments;
(v) Amount of delivered energy to Hydro for which Hydro is required to pay when it uses in excess of the Base Block Energy giving consideration to available Supplemental Block Energy and accumulated NLH Deferred Energy;
(vi) Energy that was scheduled by Hydro for delivery but was not delivered, with reasons for such non-deliveries;
(vii) Amount of Residual Block Energy[25] and Capacity sold into External Markets ("Residual Block Sales");
(viii) Average Annual Sales Price, including the calculation; and
(ix) Water spilled.

Hydro must decide within five business days of receipt of the Annual Energy Report how much of the NLH Deferred Energy shall be deemed to be sold on Hydro's behalf. Hydro will receive payment from MF Corporation within 45 days after the operating year-end based on the Average Annual Sales Price for the operating year.

Correspondingly, Hydro must pay MF Corporation within 45 days after the operating year-end for any amount by which delivered energy exceeds the total of the Base Block Energy, the Supplemental Block Energy and the NLH Deferred Energy. The price paid will be based on the Average Annual Sales Price for the operating year.

[24] See Article 4.5 on pages 33 and 34 of the MF PPA.
[25] Residual Block Energy refers to energy in an operating period that is forecast to be not required to serve NL Native Load or the Nova Scotia Block and is available for making non-firm sales and Contracted Commitments. See Article 3.1(e) on page 26 of 76 of the MF PPA.

Because each fiscal operating year is concluded prior to the finalization of the MF PPA transactions for that year, Hydro will be required to estimate an accrual of its purchased power expense from MF Corporation for financial reporting.

3.3 Transmission Funding Agreement

The TFA recovers costs associated with the LIL facilities through payments by Hydro to LIL Opco, the operating entity. The payments to LIL Opco are based on a cost of service approach in which the annual cost recovery amount is based on return on equity plus operating costs, depreciation and taxes.

Under the cost of service approach, cost recovery in the TFA is higher in the early years of the service period, reflecting high early levels of return due to the higher net book value of the plant. As the assets age and the net book value declines, the annual cost recovery declines. The return on equity in the TFA will reflect the approved return on equity for Newfoundland Power Inc. (Newfoundland Power). As a result, changes in the allowed return on equity for Newfoundland Power will require a change in the annual cost recovery amount in the TFA.

Like the MF PPA, the initial forecast for cost recovery under the TFA does not provide for the recovery of investment required for sustaining capital over the term of the contract. There is a provision for a separate charge to be estimated and billed monthly to Hydro covering the cost of sustaining capital for LIL assets in addition to true-up adjustments to recover the difference between the actual and forecast O&M Costs reflected in the charge for the annual cost recovery. These costs will be recovered through the charge from LIL Opco to Hydro for O&M Activities. Unlike MF Corporation, the LIL Limited Partnership will internally finance sustaining capital. LIL Opco will amortize the associated costs and bill Hydro for the capital cost recovery on a monthly basis.

3.4 Power Availability in Advance of Full Commissioning

It is expected that the LIL and the ML will be completed in advance of generation being available from the MF Project. The availability of the LIL will provide the opportunity to purchase energy to reduce Holyrood TGS production.[26]

Also, during the construction of the MF facilities, power and energy will be produced between the period when the first generating unit is available to reliably generate power until the full commissioning of the MF plant. Contractually, this energy is termed as the Commissioning Period Block.[27] MF Corporation will make such power and energy available to Hydro during this commissioning period at no cost. However, Hydro has the option to pay for the Commissioning Period Block based on its own terms and these payments will be applied as a contribution to reduce the development capital costs and reduce the charge to be reflected in the Base Block Capital Costs Recovery.[28]

Hydro also has the option to either take delivery of such energy immediately to meet NL Native Load or choose to defer delivery until some later date. Due to construction delays, Hydro is uncertain of the timing and the amount of the available energy; this will be determined when the construction schedule for the MF Project assets is updated.

Hydro anticipates it will achieve savings relative to the Holyrood TGS fuel costs reflected in current customer rates as a result of the ability to access other supply sources prior to full commissioning of the MF Project. The manner in which these savings will be used to benefit customers is an element in an ongoing review with respect to developing a rate implementation plan for recovery of the costs of the MF Project assets.

[26] The contract terms with respect to payments being required from Hydro for using LIL in advance of any generation being available from MF are currently under review.
[27] See page 4 of 76 of the MF PPA.
[28] See Article 4.1, pages 31 to 32 of the MF PPA.

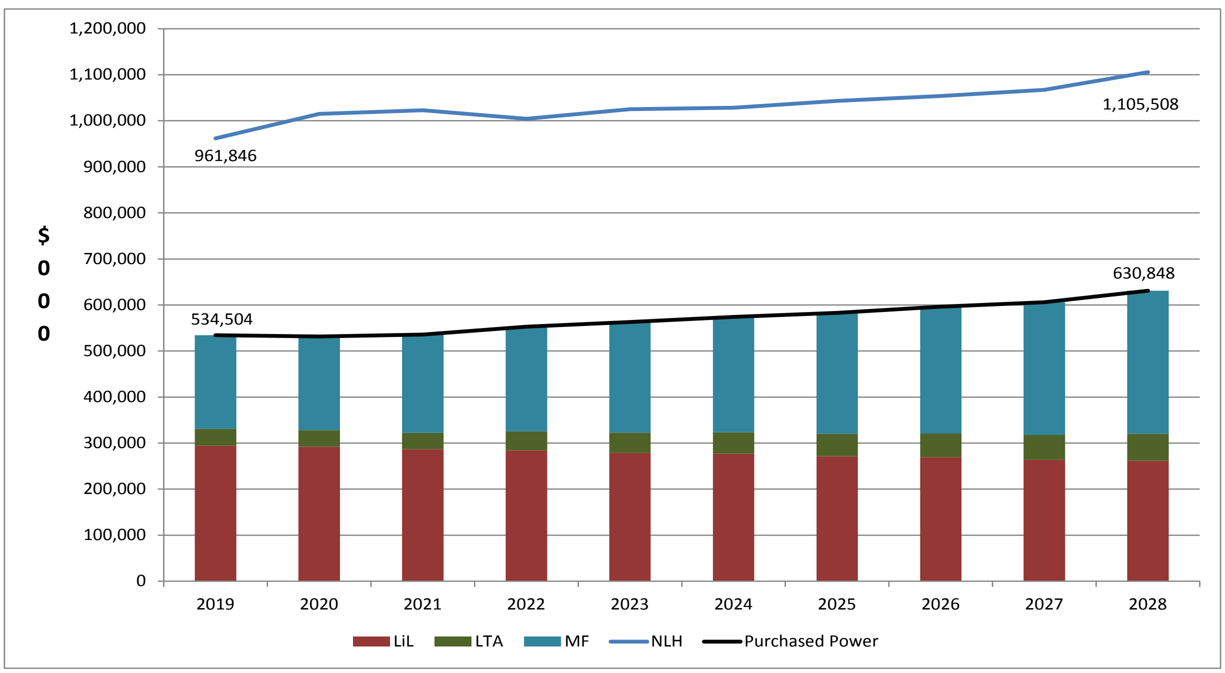
3.5 Variability in Supply Costs from the MF Project

Chart 1 provides an illustration of the change in revenue requirement for the period 2019 to 2028 for the MF Project assuming full commissioning has been achieved prior to 2019. This chart assumes a total MF project construction cost of $7.652 billion plus interest and other carrying charges. The annual revenue requirements required to recover the MF Project costs will change based on updated construction schedule and updated costs of the MF Project.

Chart 1 is provided to demonstrate that Hydro's MF supply costs will increase annually after the initial rate change which is required to include MF Project costs in customer rates. These annual cost changes beyond the MF Project commissioning reflect the structure of the contractual agreements that provide for the increased annual payments by Hydro to recover the capital and operating costs of the MF Project.[29]

Chart 1: Island Interconnected System

Illustrative Cost of Service



[29] The forecast annual revenue requirement for MF Project Costs excludes the required investment for sustaining capital. However, the sustaining capital investment is expected to be minimal over the time period presented in Chart 1.

Chart 1 shows Hydro's increased annual costs of approximately $14 million per year (approximately 1.5% per year) of which approximately $10 million additional costs per year are required to recover changes in the capital and operating costs of the MF Project assets. The increases in charges to Hydro through the MF Project contracts are related to the project's capital and operating costs and do not vary with customer load requirements.

Hydro is forecasting approximately 3.0% cumulative load growth for the period 2019 to 2028 (i.e., approximately 0.33% per year).[30] The annual rate of increase in the cost to serve per year illustrated in Chart 1 exceeds the forecast annual rate of customer growth. Most of the cost increase per year is a result of the change in the cost of supply from the MF Project. The increase in year-over-year costs combined with minimal load growth will contribute to a revenue deficiency between Test Years unless a deferral account is implemented to provide recovery of the costs of the MF Project.

As stated earlier, recovery of supply cost variances from those reflected in customer rates through deferral mechanisms is common in regulatory jurisdictions across Canada and, for the MF Project, Government has provided direction that the charges to Hydro for the cost of supply from the MF Project be recovered in full through Island Interconnected rates. Hydro would expect a GRA filing every three years. However, Hydro's cost increases between Test Years are forecast to exceed additional revenues from rates that result from load growth between Test Years. The implementation of a deferral account to permit Hydro to recover cost increases resulting from changes in capital and operating costs related to the MF Project is consistent with OC 2013-343.

4.0 MF SUPPLY COST DEFERRAL ACCOUNT

4.1 MF Project Supply Cost Deferrals

Based on the discussion of the MF PPA and the TFA in the previous sections, Hydro will require a supply cost variance account and recovery mechanism to permit recovery of annual variances

[30] Hydro long-term load forecast dated June 1, 2016.

in MF Project costs from those reflected in Test Year rates. This deferral account and recovery mechanism will replace the RSP upon commissioning of the MF Project.

4.1.1 MF PPA Cost Variances

Capital Cost Recovery

Hydro will incur annual cost increases each year as a result of the requirement for annual changes in the Base Block Capital Costs Recovery amounts stated in Appendix A to Schedule 1 of the MF PPA.[31] The Muskrat Falls supply cost deferral account (MFSCDA) would permit Hydro to defer the increases in the Base Block Capital Costs Recovery amounts from those reflected in the Test Year rates for future disposition through a recovery mechanism.

MF Corporation is permitted to apply an additional charge to the Base Block Capital Costs Recovery amount if the amounts charged to Hydro for capital cost recovery in any month are insufficient to enable MF Corporation to meet all its financing obligations.[32] MF Corporation is required to reimburse Hydro for additional capital cost recovery payments, including interest, at a rate equal to Hydro's regulated cost of capital. Hydro considers these additional capital cost recovery payments to MF Corporation to be affiliate loans and is proposing not to recover the additional payment obligation from customers.

Operating and Maintenance Costs

The MF PPA also provides for charges to Hydro from MF Corporation for the actual cost of the operating activities each quarter. The MFSCDA would permit Hydro to defer changes in O&M Costs from the level reflected in the Test Year rates for future disposition.[33] The differences in O&M charges to Hydro relative to the O&M Costs reflected in customer rates will result from an

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[31] These annual increases also reflect changes in Schedule 1 of the GIA for the capital cost recovery of the LTA assets.

[32] See Section 4, page 3 of 6 of Schedule 1 entitled "Base Block Capital Costs Recovery Adjustment".

[33] Operating and maintenance costs would include all charges referred to as "O&M Costs" in the MF PPA with the exception of charges for sustaining capital for MF generation and LTA. Hydro will determine what charges are related to sustaining capital based on the regulatory accounting standards which apply to Hydro in defining a capital expenditure.

annual revision to the forecast O&M Cost to be charged to Hydro as well as the true-up to actual costs.

Sustaining Capital

Under the MF PPA, Hydro is required to fund the investment for sustaining capital for MF generation and the LTA through O&M Cost payments. Hydro proposes to establish a regulatory asset to record these sustaining capital investments. Hydro would then determine the annual cost recovery for the sustaining capital asset charges in the MF PPA based on the annual cost that would be charged to customers in the most recent Test Year if the sustaining capital was owned by Hydro. This would include reflecting the MF generation and LTA sustaining capital regulatory asset in Hydro's rate base.[34]

Hydro would reflect a forecast of sustaining capital investments for the MF generation assets and LTA in setting its Test Year revenue requirement. Differences from the actual sustaining capital investment by Hydro and that forecast in the approved Test Year would result in sustaining capital cost recovery differences relative to the approved Test Year.[35] The MFSCDA would defer for future disposition the difference between the actual annual cost of sustaining capital and the annual cost of sustaining capital reflected in customer rates.

In Hydro's subsequent GRA proceedings, Hydro would update its sustaining capital regulatory asset to include the cumulative change from the previous Test Year and the forecast sustaining capital investment for the new Test Year. The forecast sustaining capital regulatory asset would be included in Hydro's rate base for use in determining the Test Year revenue requirement.

[34] Hydro would base its annual costs on its approved depreciation rates and its approved rate of return and include the unamortized portion of sustaining capital investment in rate base in accordance with Section 78(e) of the Public Utilities Act.
[35] The impact of sustaining capital investments on costs between Test Years will depend on the annualized cost of the variance from the Test Year amount of sustaining capital investment reflected in the approved Test Year. The Base Block Capital Costs Recovery amounts in Schedule 1 of the MF PPA and GIA reflect recovery of the original costs of the assets.

4.1.2 TFA Cost Variances

TFA Annual Cost Recovery

Hydro will incur a cost variance each year reflecting increased accumulated depreciation and declining net book value of the transmission assets. The annual cost recovery amount can also change as a result of possible changes in allowed return on equity, depreciation rates and tax rates.

Hydro will incur variances in O&M charges relative to the O&M Costs reflected in customer rates for the TFA as a result of (i) an annual revision to the forecast O&M Cost to be charged to Hydro and (ii) the true-up to actual O&M costs each quarter. The MFSCDA would permit Hydro to defer changes in TFA O&M Costs from the level reflected in the Test Year rates for future disposition.[36]

Sustaining Capital

Hydro would reflect a forecast of the recovery for the LIL sustaining capital investments in setting Hydro's Test Year revenue requirement. Differences from the actual capital recovery costs incurred by the LIL Limited Partnership and that forecast in Hydro's most recent Test Year would result in cost recovery differences relative to the approved Test Year. Variances from forecast can result from changes from the Test Year for such items as the amount of sustaining capital investment, return on equity, depreciation and taxes.

Under the TFA, Hydro will pay a true-up adjustment quarterly to reflect the actual capital recovery cost resulting from sustaining capital investments in the LIL. The MFSCDA would defer for future disposition the difference between the annual charges for sustaining capital and the annual cost of sustaining capital reflected in customer rates.

[36] Operating and maintenance costs would include all charges referred to as "O&M Costs" in the TFA with the exception of charges for sustaining capital.

4.2 Energy Supply Variances

Hydro's purchased power costs under the MF PPA are also impacted by variances in Hydro's other energy sources; the largest variance would be related to hydraulic production on the Island.

The MF PPA has effectively created a deferral mechanism to limit the impacts of hydraulic production variability by permitting Hydro to defer energy accumulated in years with above normal hydraulic production to offset the additional energy requirements in years when hydraulic production on the Island is below normal. Hydro can also borrow Base Block Energy from future years to deal with low hydrology periods.

Therefore, Hydro is not proposing a regulatory deferral account to deal with cost variances resulting from hydraulic production variations. However, as export sales opportunities diminish over time with customer load growth, Hydro may need to re-evaluate the requirement for a deferral account mechanism to deal with hydraulic production variations.

It is anticipated that Hydro will experience some purchased power cost variability as a result of energy supply variability for an operating year. Any cost variances that result from reduced availability of energy supply from that approved in the Test Year would be recorded in the MFSCDA for future disposition.

4.3 Customer Load Variances

As long as MF generation output is available for exports, Hydro's purchased power costs under the MF PPA do not vary as a result of customer load requirements being above forecast. Hydro plans to implement a rate design for Newfoundland Power and Island Industrial Customers so that changes in customer load requirements in a month are priced based on an estimate of the market value of exports. In years when customer load requirements are lower than forecast, Hydro can recover its revenue shortfall through the sale of the load variation to export markets.

The use of the forecast market value to deal with load variations in rate design would avoid the requirement for a deferral account to provide recovery of the financial impacts on Hydro of customer load variations. This is because changes in customer load requirements would impact Hydro's revenues by a similar amount as the resulting variance in export revenues. However, as market costs can change materially from forecast throughout the year, Hydro believes a mechanism is needed to permit a change in the market rate to be reflected in the wholesale and Industrial Customer rate designs.

4.4 Export Sales Credits

Currently there is no explicit provision requiring the value of export sales generated from MF generation to be credited back to ratepayers to offset the cost of the MF Project. The current Government has, however, indicated that export sales will be used to mitigate potential increases in electricity rates.[37] Due to the uncertainty with respect to the amount of an export sales credit that may be available annually, Hydro recommended in its Cost of Service Methodology Review Report that disposition of any export sales credit should be handled through a deferral mechanism outside the Cost of Service Study.[38]

To implement this approach, the MFSCDA would require a provision to allocate an export sales credit to customers. Hydro recommends that the export sales credit be a separate rate component in the wholesale rate to Newfoundland Power and the rates to Island Industrial Customers. For the initial year of implementation, the export sales credit would be based on a forecast. The export sales credit would be updated annually based on the actual export value achieved in the previous operating year and an adjustment to reflect the forecast exports for the subsequent operating year.[39] Hydro recommends the export sales credit be allocated

[37] See letter from the Premier to the Minister of Natural Resources dated December 14, 2015.
[38] The Cost of Service Methodology Review Report was filed March 31, 2016.
[39] The forecast export sales credit for the subsequent operating year would need to be updated to reflect an updated market forecast to be reflected in Average Annual Sales Price which forms the basis for the marginal rate to be charged to Newfoundland Power and the Island Industrial Customers.

among customer classes based on the most recently approved Test Year allocation percentages of supply costs from the MF Project.[40]

4.5 Deferral Account Disposition

The Annual Report from MF Corporation is provided to Hydro within 30 days following the end of an operating year. The report covers items including NLH Deferred Energy, Average Annual Sales Price, payments to Hydro for External Market Sales and payments by Hydro for energy requirements in excess of the aggregate of Base Block Energy, Supplemental Block Energy and accumulated NLH Deferred Energy. This information, along with the balances in the deferral accounts discussed in the previous section would form the basis for determining the annual MF Project purchase cost variance relative to the Test Year revenue requirement.

Hydro believes it is appropriate that variances from Test Year costs be recovered annually with the implementation of rate adjustments to occur on the same effective date for Newfoundland Power and Island Industrial Customers.[41]

As previously noted, Hydro will provide deferral account definitions and propose a recovery mechanism to permit recovery of supply costs related to the MF Project prior to filing its next GRA. This will provide Hydro the opportunity to have available updated MF Project forecast costs for consideration in developing and illustrating the recovery mechanisms.

[40] The allocation of the export sales to Newfoundland Power and Hydro's Island Interconnected Rural Customers would be combined as the rate adjustment would flow through to Hydro's Rural Customers through Newfoundland Power rate changes.

[41] Hydro rates are currently required to be updated for RSP adjustments on each July 1 for Newfoundland Power and each January 1 for Island Industrial Customers. It may also be practical from an administrative perspective to implement the annual recovery adjustment earlier in the year (i.e., either May 1 or June 1) than is currently the case for the RSP (i.e., July 1).

5.0 OTHER SUPPLY COST VARIANCE DEFERRAL ACCOUNTS

5.1 Island Interconnected Supply Costs

Hydro will continue to operate the Holyrood TGS for generation for a period of time beyond the initial availability of MF generation. All generating units at the MF generation facility will not be available to provide power on the same date. The timing of the availability of MF generation and the availability of supply from other sources through the LIL and ML prior to full availability of MF generation creates uncertainty in the amount of generation required from the Holyrood TGS. Hydro will also continue to ensure that its gas turbines and diesel generation on the Island Interconnected System are available to serve customers, as required.

Hydro will propose to implement a deferral account to permit recovery of Island Interconnected fuel cost variances between Test Years (i.e., Island Interconnected Supply Cost Deferral Account). The deferral account will provide for the recovery of the cost variance on the Island Interconnected System between the Test Year fuel cost and the actual fuel cost. The deferral account should also provide Hydro the opportunity to recover the additional supply costs resulting from use of customer resources to minimize the cost of providing service (e.g., capacity assistance agreements).

5.2 Isolated System Supply Costs

5.2.1 Background

In Hydro's 2013 GRA, Hydro proposed an Isolated Systems Energy Supply Cost Variance Deferral Account. The Board has not yet ruled on Hydro's 2013 GRA. Hydro continues to believe a deferral account is required to permit Hydro to recover supply cost variances on its Isolated Systems. The following section updates the evidence provided in the 2013 GRA.

Hydro will propose a modification from the deferral account proposed in the 2013 GRA to reflect in this account the impact of the changes in Hydro's Rural revenues that result from Newfoundland Power GRA rate changes. This is currently dealt with in the Rural Rate Alteration of the RSP which Hydro proposes to discontinue on full commissioning of the MF Project assets.

Hydro considers it appropriate to apply the revenue impacts of rate changes that result from Newfoundland Power GRA rate changes against the isolated systems supply cost variance prior to determining the amount for disposition. In general, this approach looks at both the revenue change as well as the cost change in determining the cost variance to be considered for disposition to Newfoundland Power.

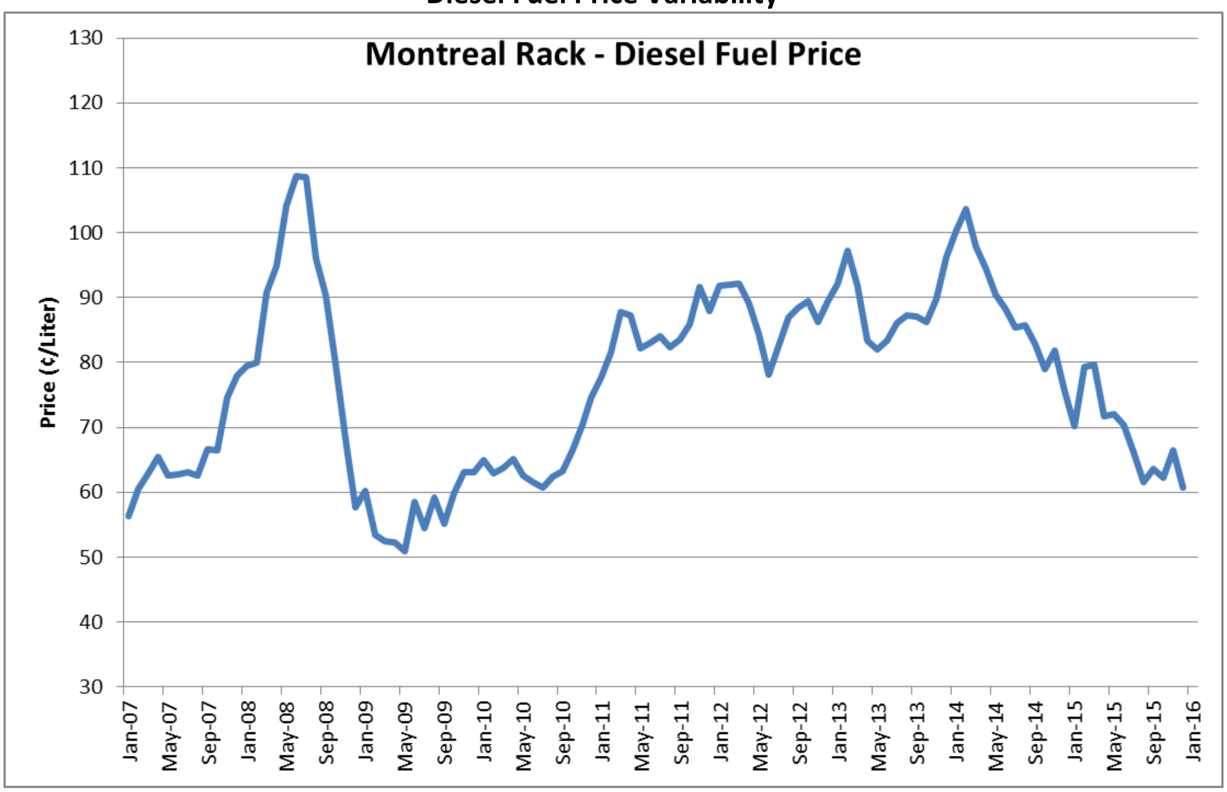
5.2.2 Isolated Systems Supply Cost Variance

Over the past several years, diesel fuel and certain power purchase prices have been subject to the same variability as Holyrood fuel costs.

Chart 2 illustrates the National Resources Canada (NRCan) reported Montreal rack prices for diesel fuel from 2007-2015.

Chart 2

Diesel Fuel Price Variability[42]



[42] Data obtained from NRCan – Montreal Rack Prices January 2007 - December 2015.

As shown in Chart 2, the year-over-year average price has varied by more than 50%.[43] Variances of this magnitude relative to the price reflected in customer rates exposes Hydro to material risk in recovery of Isolated System supply costs. Hydro's Isolated System supply cost variances from 2007 to 2015 relative to the 2007 Test Year have ranged from $0.3 million to approximately $6.0 million. These cost variances are beyond Hydro's control. As a result, Hydro proposed an Isolated Systems Supply Cost Variation Deferral Account in its 2013 GRA to provide Hydro a reasonable opportunity to recover its supply costs on the Isolated Systems.

The current RSP provides for Hydro to credit back to the customers of Newfoundland Power additional revenue that accrues to Hydro as a result of Newfoundland Power rate changes. Hydro proposes that these annual revenue changes to Hydro as a result of Newfoundland Power GRA base rate changes be recorded in the Isolated System supply cost deferral account. As such, both changes in Hydro's Isolated Systems fuel costs and revenue changes, as a result of Newfoundland Power base rates changes, would be recorded in a single account to be recovered and/or refunded to customers of Newfoundland Power.

6.0 SUMMARY

Hydro anticipates it will achieve savings relative to the Holyrood TGS fuel costs reflected in current customer rates as a result of the ability to access other supply sources prior to full commissioning of the MF Project assets. The manner in which these savings will be used to benefit customers is an element in an ongoing review with respect to developing a rate implementation plan for recovery of the costs of the MF Project assets. Hydro will keep the Board informed as this process progresses.

Based on a review of anticipated annual supply cost changes reflecting the MF Project contractual agreements subsequent to the full commissioning of the MF Project assets, Hydro will require approval of a deferral account and recovery mechanism to provide Hydro the opportunity for full recovery of MF Project supply costs, consistent with Government direction.

[43] The 2008 annual average was 88.18 cents per litre and 2009 annual average was 56.89 cents per litre.

Hydro will also propose that the Board approve a regulatory asset for inclusion in Hydro's rate base that reflects the sustaining capital investments by Hydro as required under the MF PPA, less accumulated amortization.

Hydro recommends that a separate rate component to reflect a credit for export sales be implemented and updated annually in the wholesale rate to Newfoundland Power and the rates to Island Industrial Customers. Hydro supports the allocation of export sales credits among customer classes based on the most recently approved Test Year allocation percentages of supply costs from the MF Project.

After the full commissioning of the MF Project assets, Hydro will continue to require a deferral account recovery mechanism to provide Hydro a reasonable opportunity to recover fuel cost variances on the Island Interconnected System and supply cost variances on its Isolated Systems.

The forecast annual revenue requirements required to recover the costs of the MF Project from customers will be updated to reflect the revised construction schedule and cost estimates. Hydro believes it is appropriate to have updated cost information for consideration in developing and illustrating the recovery mechanisms prior to finalizing its deferral account proposals. As a result, Hydro has not included the proposed deferral account definitions with this report. Hydro will file, prior to filing its next GRA planned for March 31, 2017, the proposed supply cost deferral accounts and recovery mechanisms that are required to permit Hydro to recover supply cost payments resulting from the commissioning of the MF Project assets.

Appendix 1

Muskrat Falls Exemption Order
and Orders in Council

This is an official version.

Important Information

(Includes details about the availability of printed and electronic versions of the Statutes.)

Table of Regulations | Main Site | How current is this regulation?

NEWFOUNDLAND AND LABRADOR
REGULATION 120/13

Muskrat Falls Project Exemption Order
under the
Electrical Power Control Act, 1994
and the
Public Utilities Act
(O.C. 2013-342)

(Filed November 29, 2013)

Under the authority of section 5.2 of the *Electrical Power Control Act, 1994* and section 4.1 of the *Public Utilities Act,* the Lieutenant-Governor in Council makes the following Order.

Dated at St. John's , November 29, 2013.

Julia Mullaley
Clerk of the Executive Council

REGULATIONS

Analysis

Short title

1. This Order may be cited as the *Muskrat Falls Project Exemption Order* .

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Interpretation

2. (1) In this Order

(a) "LiL" means the transmission line and all related components of the Muskrat Falls Project described in section 2.1(1)(a)(ii) of the *Energy Corporation Act* , and for greater certainty "all related components" in that subparagraph includes converter stations, synchronous condensers, and terminal, telecommunications, and switchyard equipment;

(b) "LilParty" means Labrador-Island Link Holding Corporation, the Labrador-Island Link General Partner Corporation, the Labrador-Island Link Limited Partnership, or Labrador-Island Link Operating Corporation, or any combination of them as the context may require;

(c) "LTA" means the transmission facilities of the Muskrat Falls Project described in subparagraph 2.1(1)(a)(iii) of the *Energy Corporation Act* ;

(d) "LTACo" means the Labrador Transmission Corporation;

(e) "MFCo" means the Muskrat Falls Corporation;

(f) "Muskrat Falls " means the hydroelectric facilities of the Muskrat Falls Project as described in subparagraph 2.1(1)(a)(i) of the *Energy Corporation Act* .

(2) In this Order, references

(a) to a public utility or an activity being "exempt" means the public utility or the activity is exempt from the application of

(i) the P*ublic Utilities Act,* and

(ii) Part II of the *Electrical Power Control Act, 1994* ; and

(b) to a corporation or limited partnership, where the corporation or limited partnership does not exist as of the date of this Order coming into force, shall be valid upon the creation of the corporation or limited partnership under the *Energy Corporation Act* and the *Corporations Act* or the *Limited Partnership Act* .

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Public utilities

3. LilParty, LTACo and MFCo are acknowledged to be public utilities under the *Public Utilities Act* for the purpose of this Order.

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Exemption

4. (1) Newfoundland and Labrador Hydro is exempt in respect of

(a) any

(i) expenditures, payments, or compensation paid to MFCo by Newfoundland and Labrador Hydro relating to the purchase and storage of electrical power and energy, the purchase of interconnection facilities, ancillary services, and greenhouse gas credits,

(ii) obligations of Newfoundland and Labrador Hydro in addition to subparagraph (i) to ensure MFCo's and LTACo's ability to meet their respective obligations under financing arrangements related to the construction and operation of Muskrat Falls and the LTA, and

(iii) expenditures, payments, or compensation paid to MFCo and revenues, proceeds or income received by Newfoundland and Labrador Hydro relating to the sale of electrical power and energy acquired from MFCo to persons located outside of the province

whether under one or more power purchase agreements or otherwise;

(b) any activity relating to the receipt of delivery, use, storage or enjoyment by Newfoundland and Labrador Hydro of any electrical power and energy, interconnection facilities, ancillary services, and greenhouse gas credits under paragraph (a);

(c) any expenditures, payments, or compensation paid to LilParty and claimed as costs, expenses or allowances by Newfoundland and Labrador Hydro relating to the design, engineering, construction and commissioning of transmission assets and the purchase of transmission services and ancillary services, electrical power and energy, from LilParty or otherwise with respect to the LiL, under one or more transmission services agreements, transmission funding agreements, or otherwise; and

(d) any activity relating to the receipt of delivery, use, storage or enjoyment by Newfoundland and Labrador Hydro of any transmission services and ancillary services, electrical power and energy, with respect to the LiL under paragraph (c).

(2) MFCo is exempt in respect of any activity, and any expenditures, payments or compensation, or any revenues, proceeds or income, relating to the following:

(a) the design, engineering, planning, construction, commissioning, ownership, operation, maintenance, management and control of Muskrat Falls ;

(b) producing, generating, storing, transmitting, delivering or providing electric power and energy, capacity, ancillary services, and greenhouse gas credits, to or for Newfoundland and Labrador Hydro or any other person or corporation for compensation;

(c) any activity required or related to an agreement under section 5.4 or 5.5 of the *Electrical Power Control Act, 1994* ;

(d) negotiating, concluding, executing and performing any and all agreements for any activity referred to in paragraph (a), (b) or (c);

(e) raising and securing financing necessary to conduct any activity in paragraph (a), (b), (c) or (d), including without limitation the negotiation, conclusion, execution and performance of any and all agreements and security documentation with any lender providing that financing; and

(f) any agreements, contracts or instruments necessary or incidental to any activity described in this exemption, including agreements with LTACo.

(3) LilParty is exempt in respect of any activity, and any expenditures, payments or compensation, or any revenues, proceeds or income, relating to the following:

(a) the design, engineering, planning, construction, commissioning, ownership, operation, maintenance, management and control of the LiL;

(b) producing, generating, storing, transmitting, delivering or providing electric power and energy to or for Newfoundland and Labrador Hydro or any other person or corporation for compensation;

(c) negotiating, concluding, executing and performing any and all agreements for activities referred to in paragraph (a) or (b);

(d) raising and securing any financing necessary to conduct any activity in paragraph (a), (b) or (c), including without limitation the negotiation, conclusion, execution and performance of any and all agreements and security documentation with any lender providing that financing; and

(e) any agreements, contracts or instruments necessary or incidental to any activity described in this exemption, including agreements between one or more LilParty.

(4) LTACo is exempt in respect of any activity, and any expenditures, payments or compensation, or any revenues, proceeds or income, relating to the following:

(a) the design, engineering, planning, construction, commissioning, ownership, operation, maintenance, management and control of the LTA;

(b) producing, generating, storing, transmitting, delivering or providing electric power and energy to or for Newfoundland and Labrador Hydro or any other person or corporation for compensation;

(c) negotiating, concluding, executing and performing any and all agreements for activities referred to in paragraphs (a) and (b);

(d) raising and securing any financing necessary to construct the LTA, including without limitation the negotiation, conclusion, execution and performance of any and all agreements and security documentation with any lender providing that financing to the projects; and

(e) any agreements, contracts or instruments necessary or incidental to any activity described in this exemption, including agreements with MFCo.

Newfoundland Labrador

Government of Newfoundland and Labrador
Executive Council

November 29, 2013

I, Julia Mullaley, do hereby make oath and say as follows:

1. That I am the Clerk of the Executive Council of the Province of Newfoundland and Labrador.

2. That I have access to the signed original copies of all orders of the Lieutenant Governor in Council of the Province of Newfoundland and Labrador.

3. That I have examined the attached copies of Orders in Council 2013-341, 2013-342, 2013-343, 2013-344, 2013-345, 2013-346, 2013-347, 2013-348, 2013-349, 2013-350, 2013-351, 2013-354, 2013-355 and certify that they are true copies of the content of those Orders in Council approved by His Honour, the Lieutenant Governor on the 29th day of November, 2013.

SWORN TO before me at
St. John's in the Province of
Newfoundland and Labrador

This 29th day

of November, 2013

Barrister - Newfoundland and Labrador

Julia Mullaley
Julia Mullaley
Clerk of the Executive Council

Executive Council

Newfoundland and Labrador

Certified to be a true copy of a Minute of a Meeting of the Committee of the Executive Council of Newfoundland and Labrador approved by His Honour the Lieutenant-Governor on

2013/11/29

OC2013-341

NR/DM
Asst. Sec/EPC
E. Martin/Nalcor
AG
Deputy Clerk
File

MC2013-0534. NR2013-021. EPC2013-060.

Under the authority of section 17 of An Act to Amend the Electrical Power Control Act, 1994, the Energy Corporation Act and the Hydro Corporation Act, 2007, Statutes of Newfoundland and Labrador 2012, Chapter 47, the Lieutenant Governor in Council is pleased to cause a proclamation to be issued for the signature of His Honour the Lieutenant Governor to bring An Act to Amend the Electrical Power Control Act, 1994, the Energy Corporation Act and the Hydro Corporation Act, 2007 into force upon publication of a proclamation in the Gazette.

Julia Mullaley

Clerk of the Executive Council

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2013/11/29

OC2013-342

NR/DM
Asst. Sec/EPC
E. Martin/Nalcor
A. Wells/PUB
AG
Deputy Clerk
File

MC2013-0534. NR2013-021. EPC2013-060.

Under the authority of section 5.2 of the Electrical Power Control Act, 1994 and section 4.1 of the Public Utilities Act, the Lieutenant Governor in Council is pleased to make the Muskrat Falls Project Exemption Order, a copy of which is on file with the Clerk of the Executive Council.

Julia Mullaley

Clerk of the Executive Council

Executive Council

Newfoundland and Labrador

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2013/11/29

OC2013-343

NR/DM
TB/Secretary
FIN/DM
E.Martin/Nalcor
A. Wells/PUB
AG
Deputy Clerk
File

MC2013-0534. NR2013-021. TBM2013-180.

Under the authority of section 5.1 of the Electrical Power Control Act, 1994, the Lieutenant Governor in Council is pleased to direct the Board of Commissioners of Public Utilities to adopt a policy, subject to section 3, that:

1) Any expenditures, payments or compensation paid directly or indirectly by Newfoundland and Labrador Hydro, under an agreement or arrangement to which the Muskrat Falls Project Exemption Order applies, to:

a) a LiLParty,

b) a system operator in respect of a tariff for transmission services or ancillary services in respect of the LiL, that otherwise would have been made to a LiLParty, or

c) Muskrat Falls Corporation, in respect of:

i) electrical power and energy forecasted by Muskrat Falls Corporation and Newfoundland and Labrador Hydro to be delivered to, consumed by, or stored by or on behalf of Newfoundland and Labrador Hydro for use within the province, whether or not such electrical power and energy is actually delivered, consumed, or stored within the province,

ii) greenhouse gas credits, transmission services and ancillary services, and

iii) obligations of Newfoundland and Labrador Hydro in addition to those in paragraphs (i) and (ii) to ensure the ability of Muskrat Falls

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Corporation and Labrador Transmission Corporation to meet their respective obligations under financing arrangements related to the construction and operation of Muskrat Falls and the LTA

shall be included as costs, expenses or allowances, without disallowance, reduction or alteration of those amounts, in Newfoundland and Labrador Hydro's cost of service calculation in any rate application and rate setting process, so that those costs, expenses or allowances shall be recovered in full by Newfoundland and Labrador Hydro in Island interconnected rates charged to the appropriate classes of ratepayers;

2) The costs, expenses or allowances of Newfoundland and Labrador Hydro described above, and the rates for Newfoundland and Labrador Hydro established by the Board of Commissioners pursuant to the direction under section 1, shall not be subject to subsequent review, and shall persist without disallowance, reduction or alteration of those costs, expenses or allowances or rates, throughout any processes for any public utility, including Newfoundland Power Inc., or any other process under the Electrical Power Control Act, 1994 or the Public Utilities Act;

3) Notwithstanding sections 1 and 2, no amounts paid by Newfoundland and Labrador Hydro described in those sections shall be included as costs, expenses or allowances in Newfoundland and Labrador Hydro's cost of service calculation or in any rate application or rate setting process, and no such costs, expenses or allowances shall be recovered by Newfoundland and Labrador Hydro in rates:

a) where such amounts are directly attributable to the marketing or sale of electrical power and energy by Newfoundland and Labrador Hydro to persons

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located outside of the province on behalf of and for the benefit of Muskrat Falls Corporation and not Newfoundland and Labrador Hydro; and

b) in any event, in respect of each of Muskrat Falls, the LTA or the LiL, until such time as the project is commissioned or nearing commissioning and Newfoundland and Labrador Hydro is receiving services from such project.

4) In this Order in Council, terms shall have the same meaning ascribed to them in the Muskrat Falls Project Exemption Order.

Julia Mullaley

Clerk of the Executive Council

Executive Council

Newfoundland and Labrador

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2013/11/29

OC2013-344

NR/DM
Asst. Sec/EPC
Hon. S. Kent
S. Dutton
FIN/DM
E. Martin/Nalcor
AG
Deputy Clerk
File

MC2013-0535. NR2013-022. EPC2013-064.

Under the authority of sections 10 and 11 of the Executive Council Act and section 7 of the Intergovernmental Affairs Act, the Lieutenant Governor in Council is pleased to authorize the Minister of Natural Resources, the Minister of Finance, and the Minister of Municipal and Intergovernmental Affairs to sign the Inter-Governmental Agreement Pursuant to the Federal Loan Guarantee, substantially as outlined in the draft on file with the Clerk of the Executive Council.

Julia Mullaley

Clerk of the Executive Council

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Newfoundland and Labrador

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OC2013-345

NR/ DM
FIN/DM
Asst. Sec/EPC
Hon. S. Kent
S. Dutton
E. Martin/Nalcor
AG
Deputy Clerk
File

MC2013-0536. NR2013-023. FIN2013-016. EPC2013-065. XX2013-098.

Under the authority of sections 10 and 11 of the Executive Council Act, section 7 of the Intergovernmental Affairs Act and sections 25 and 27 of the Energy Corporation Act, the Lieutenant Governor in Council is pleased to authorize the Minister of Finance, as designate for the Minister of Municipal and Intergovernmental Affairs, to sign separate Guarantees for the NL Equity Support Agreements for each of Muskrat Falls, Labrador Transmission Assets, and the Labrador Island Link and the Master Definition Agreements, substantially as outlined in the drafts on file with the Clerk of the Executive Council.

Julia Mullaley

Clerk of the Executive Council

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2013/11/29

OC2013-346

NR/DM
TW/DM
SNL/DM
ENVC/DM
Asst. Sec/EPC
E. Martin/Nalcor
AG
Deputy Clerk
File

MC2013-0537. NR2013-024. TW2013-033. SNL2013-028. ENVC2013-044. EPC2013-066.

Under the authority of sections 11, 47 and 58 of the Muskrat Falls Project Land Use and Expropriation Act, the Lieutenant Governor in Council is pleased to make the Muskrat Falls Project Land Use and Expropriation Regulations, a copy of which is on file with the Clerk of the Executive Council.

Julia Mullaley

Clerk of the Executive Council

Executive Council

Newfoundland and Labrador

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OC2013-347

NR/DM
TW/DM
SNL/DM
ENVC/DM
Asst. Sec/EPC
E. Martin/Nalcor
AG
Deputy Clerk
File

MC2013-0537. NR2013-024. TW2013-033. SNL2013-028. ENVC2013-044. EPC2013-066.

Under the authority of section 5 of the Executive Council Act and the Prerogative of the Crown, the Lieutenant Governor in Council hereby assigns ministerial responsibility for the Muskrat Falls Project Land Use and Expropriation Act, as follows:

a) Part I - Minister of Environment and Conservation;

b) Part II – Minister of Transportation and Works;

c) Part III – Minister of Natural Resources;

d) Part IV – Minister of Service NL; and

e) Part V - Minister of Environment and Conservation, Minister of Transportation and Works, and Minister of Service Newfoundland and Labrador as required by the context and in accordance with a), b) and c) above.

Julia Mullaley

Clerk of the Executive Council

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2013/11/29

OC2013-348

NR/DM
TW/DM
SNL/DM
ENVC/DM
Asst. Sec/EPC
E. Martin/Nalcor
AG
Deputy Clerk
File

MC2013-0537. NR2013-024. TW2013-033. SNL2013-028. ENVC2013-044. EPC2013-066.

Under the authority of section 5 of the Executive Council Act and the Prerogative of the Crown, the Lieutenant Governor in Council hereby assigns ministerial responsibility for the Muskrat Falls Project Land Use and Expropriation Regulations as follows:

a) Part I - Minister of Environment and Conservation;

b) Parts II, III and IV – Minister of Transportation and Works; and

c) Part V – Minister of Service NL.

Julia Mullaley

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2013/11/29

OC2013-349

NR/ DM
E. Martin/Nalcor
Asst. Sec/EPC
AG
Deputy Clerk
File

MC2013-0539. NR2013-026. EPC2013-067.

Under the authority of section 5.2 of the Electrical Power Control Act, 1994 and section 4.1 of the Public Utilities Act, the Lieutenant Governor in Council is pleased to make the Maritime Link Exemption Order, a copy of which is on file with the Clerk of the Executive Council.

Julia Mullaley

Clerk of the Executive Council

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Certified to be a true copy of a Minute of a Meeting of the Committee of the Executive Council of Newfoundland and Labrador approved by His Honour the Lieutenant-Governor on

2013/11/29

OC2013-350

NR/DM
E. Martin/Nalcor
Asst. Sec/EPC
AG
Deputy Clerk
File

MC2013-0539. NR2013-026. EPC2013-067.

Under the authority of section 5.1(2) of the Electrical Power Control Act, 1994, the Lieutenant Governor in Council is pleased to direct the Board of Commissioners of Public Utilities to adopt a policy that:

1) An order under section 8(2) of the Electrical Power Control Act, 1994 shall not be made with respect to energy and capacity designated for delivery pursuant to the Energy and Capacity Agreement dated July 31, 2012 ("the ECA");

2) This policy shall apply from the day that energy and capacity is first delivered pursuant to the ECA until a day 35 years later, unless the initial term of the ECA is extended due to a forgivable event, but shall not apply to extensions or subsequent terms to the ECA; and

3) For the purposes this Order in Council, terms shall have the meaning ascribed to them in the Maritime Link Exemption Order.

Julia Mullaley

Clerk of the Executive Council

Executive Council

Newfoundland and Labrador

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2013/11/29

OC2013-351

NR/DM
E. Martin/Nalcor
Asst. Sec/EPC
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File

MC2013-0540. NR2013-027. EPC2013-068.

Under the authority of sections 10 and 11 of the Executive Council Act, section 6 of the Energy Corporation of Newfoundland and Labrador Water Rights Act and the Prerogative of the Crown, the Lieutenant Governor in Council is pleased to authorize the Minister of Natural Resources, Nalcor Energy and Muskrat Falls Corporation to enter into an Assignment and Assumption Agreement, substantially along the lines of the draft on file with the Clerk of the Executive Council.

Julia Mullaley

Clerk of the Executive Council

Executive Council

Newfoundland and Labrador

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OC2013-354

NR/DM
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TB/ Secretary
E. Martin/Nalcor
JUS/DM
AG
Deputy Clerk
File

MC2013-0504. XX2013-087.

Under the authority of sections 18 and 14.1 of the Energy Corporation Act, the Lieutenant Governor in Council is pleased to authorize the Energy Corporation and its subsidiaries established in connection with the Labrador-Island Link, the Muskrat Falls Generation Facility/Labrador Transmission Assets projects to:

(a) raise debt financing of up to \$2.6 billion for the Muskrat Falls/Labrador Transmission Assets project through the issuance and sale of bonds by the Muskrat Falls/Labrador Transmission Funding Trust and up to \$2.4 billion for the Labrador-Island Link project through the issuance and sale of bonds by the Labrador-Island Link Funding Trust; and

(b) secure payment and performance of all obligations arising in connection with the financings referenced in paragraph (a) above through the issuance of bonds, debentures or other securities; execution and delivery of mortgages, assignments, conveyances, charges, pledges, security interests or other encumbrances of and over property of every nature and kind, both present and future; and the entry into, execution, delivery and performance of trust deeds, trust indentures, debentures, pledges, assignments and all other agreements with respect to the financings (including without limitation, project finance agreements, master definitions agreements, collateral agency agreements, equity support agreements, guarantees, guarantee assurance agreements, blocked account agreements, step in agreements and related financing documentation) with lenders, a trustee or

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collateral agent acting for the lenders, the holders of bonds and debentures or other person providing or extending credit or directly with any person providing or extending credit in connection with such financing, or providing a guarantee or assurance thereof;

subject to:

(c) except with respect to its equity support agreements with respect to each Project and its limited recourse pledge of its ownership interests in its subsidiaries, the debt financing structure having no ultimate liability accrue to the Energy Corporation; and

(d) the receipt of approval from the Minister of Finance as to the terms of such financing.

Julia Mullaley

Clerk of the Executive Council

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OC2013-355

NR/DM
TB/Secretary
FIN/DM
JUS/DM
E. Martin/Nalcor
AG
Deputy Clerk
File

MC2013-0504. XX2013-087.

Under the authority of section 18 of the Energy Corporation Act, the Lieutenant Governor in Council is pleased to delegate to the Minister of Finance, the authority to approve:

a) The terms of the binding financing commitment with such institution(s) as the Minister shall approve in order to raise debt financing up to $2,600,000,000 for the Muskrat Falls/Labrador Transmission Funding Trust and up to $2,400,000,000 for the Labrador Island Link Funding Trust; and

b) Any necessary documentation related to the financing commitment with such institution(s).

Julia Mullaley

Clerk of the Executive Council