Q. What is Newfoundland Hydro's estimate of forecast system marginal energy costs, from 2020 through 2030 and how do those costs change by year, month, season, or hour of day?

A. Hydro forecast marginal costs by time period (both marginal energy costs and marginal capacity costs) are provided in the report entitled "Marginal Cost Study Update – 2018" filed with the Board on November 18, 2018 and provided as PUB-Nalcor-121, Attachment 1.

newfoundland labrador
hydro
a nalcor energy company

Hydro Place. 500 Columbus Drive.
P.O. Box 12400. St. John's. NL
Canada A1B 4K7
t. 709.737.1400 f. 709.737.1800
www.nlh.nl.ca

November 15, 2018

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

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

Dear Ms. Blundon:

Re: Marginal Cost Study and Rate Structure Review

Enclosed with this letter please find one (1) original plus thirteen (13) copies of a report entitled "Marginal Cost Study Update - 2018".

In accordance with the 2013 General Rate Application ("GRA") Settlement Agreement and Hydro's 2013 GRA Final Submission, Newfoundland and Labrador Hydro ("Hydro") previously filed reports on island interconnected system ("IIS") marginal costs in late 2015 and early 2016; and a review of wholesale and island industrial rates, filed in June 2016. The purpose of the reports was to provide marginal cost estimates for use in considering rate structure changes that may be required for the implementation of customer rates upon full commissioning of the Muskrat Falls Project. Marginal cost estimates are also useful in evaluation of retail rate designs and conservation and demand management evaluation, among other uses.

The Muskrat Falls Project commissioning was delayed. It is now forecast to be fully commissioned in September, 2020. The marginal cost information provided in the 2016 report required an update to reflect the forecast changes in load forecast and forecast capacity availability on the IIS upon the full commissioning of the Muskrat Falls Project. The attached marginal cost study report provides an update of the projected marginal costs for the period 2021-2029 and reflects the IIS outlook provided in the "Reliability and Resource Adequacy Report" to be filed with the Board.

In June 2016, Hydro filed a report prepared by Christensen Associates Energy Consulting entitled "Rate Design Review for Newfoundland Power and Island Industrial Customers". The report provided options to consider in modifying the rate designs of Newfoundland Power and Island industrial customers in response to interconnection with the North American grid and supply from the Muskrat Falls Project. Hydro believes the rate design alternatives provided in the 2016 report continue to be appropriate for consideration. Hydro plans to start an engagement process early in 2019 with Newfoundland Power and Island Industrial Customers to develop rate design proposals for submission to the Board. Hydro plans to file a report with the Board providing a status update on rate design proposals in the third quarter 2019.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

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

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey
Dennis Browne, Q.C. – Browne Fitzgerald Morgan & Avis

ecc: Dean Porter – Poole Althouse
Van Alexopoulos – Iron Ore Company of Canada
Senwung Luk – Olthuis Kleer Townshend LLP
Denis Fleming – Cox and Palmer
Benoît Pepin – Rio Tinto

MARGINAL COST STUDY UPDATE – 2018

Summary Report

November 15, 2018

A Report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro
a nalcor energy company

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1.0 Background

In late 2015 and early 2016, during the course of the 2013 General Rate Application proceeding, Newfoundland and Labrador Hydro ("Hydro") submitted a Marginal Cost Study for the Island Interconnected System to the Board ("2015-16 Marginal Cost Study").[1] The reports were authored by Christensen Associates Energy Consulting, LLC ("CA Energy Consulting Consulting") on Hydro's behalf and were filed in two parts. The first part of the 2015-16 Marginal Cost Study focused on methodology. The discussion provided a review of methodology options and identified the methods that would be adopted by Hydro for the purposes of estimating marginal costs in 2019. The second part further discussed methodology and its application, and presented estimates of marginal costs for the Island Interconnected System for 2019.[2]

In conjunction with the Cost of Service Methodology and Rate Design Review, Hydro is filing an updated marginal cost study ("Marginal Cost Study Update"), which is included as Appendix A to this summary report. The update to the results was required as a number of underlying assumptions in the original study have changed. Notable changes include revised load forecasts, revisions to Hydro's planning criteria,[3] the timing of generation additions to and retirements from Hydro's Island Interconnected System (including in-service of the Labrador-Island Link and the Muskrat Falls generating assets), and forecast market prices.[4]

This Marginal Cost Study Update explains the role of marginal cost in efficient pricing and the methods used to estimate Hydro's generation and transmission marginal costs. It also provides the estimated generation and transmission marginal costs for the period 2021 - 2029. This information is provided to assist the Board and parties in further understanding the contributing factors to the marginal cost estimates and their potential use in electricity pricing and conservation and demand management.

---

[1] Part I of the marginal cost study was filed on December 29, 2015 and Part II of the marginal cost study report was filed on February 26, 2016.
[2] 2019 was assumed to be the first full year of service from the Muskrat Falls Project.
[3] Hydro's planning criteria is outlined in its Reliability and Resource Adequacy Study, to be filed with the Board in mid-November.
[4] Forecast external market prices are used to determine opportunity costs.

2.0 Key Assumptions

The 2015-16 Marginal Cost Study was based on a number of underlying assumptions about Hydro's system configuration and planning criteria. Throughout the past number of years, several of these fundamental assumptions have changed and have had implications on the resulting marginal costs. Consequently, Hydro's projected marginal costs have changed materially from those presented in the 2015-16 Marginal Cost Study. This section summarizes the key assumptions for the Marginal Cost Study Update.

2.1 Load Forecast

The underlying load forecast in this Marginal Cost Study Update shows minimal change in Island Interconnected load throughout the next decade, with demand projected to grow by 16 MW (cumulative growth of less than 1%) and energy requirements expected to grow by 20 GWh (cumulative growth of less than 0.3%).

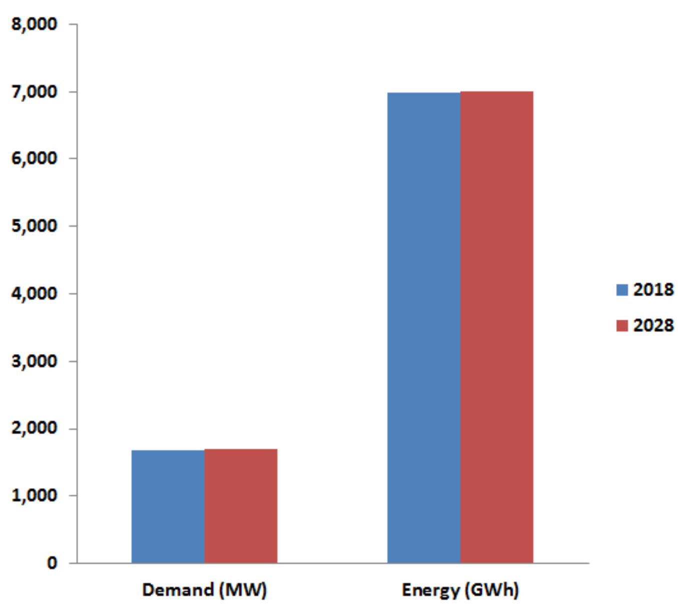

Chart 1: Projected Island Interconnected Load 2018 vs. 2028

The lack of load growth is largely a reflection of customer price sensitivity to the anticipated rate increases associated with the commissioning of the Muskrat Falls Project.[5] In the absence of a rate mitigation strategy, Hydro's load forecast assumes an increase in rates for residential customers from the current average unit cost of approximately 12.4 ¢/kWh to 17 ¢/kWh in 2021 (escalated yearly by annual inflation thereafter).[6]

2.2 Hydro's Planning Criteria

Hydro's planning criteria is outlined in its Reliability and Resource Adequacy Study which will be filed with the Board in mid-November 2018. This report proposes several changes to the planning criteria and assumptions including the adoption of a new interconnected system model, the transition from 0.2 LOLE to 0.1 LOLE as a planning criterion, and the return to the use of the P50 weather forecast as the base planning forecast. As such, the Marginal Cost Study Update reflects the proposed changes to the planning criteria.

2.3 System Expansion

Throughout the next several years, Hydro's Island Interconnected System will experience significant change. Hydro anticipates the retirement of the Holyrood Thermal Generating Station as well at the gas turbines at Hardwoods and Stephenville following the in-service of the Muskrat Falls Generating Station. The net impact of the additional capacity to the Island Interconnected System as a result of planned additions and retirements is shown in Table 1.

[5] OC2013-343 requires that costs associated with the Muskrat Falls Project (the Labrador-Island Link, Labrador Transmission Assets, and the Muskrat Falls Generating Station) must be paid by Hydro's Island Interconnected customers upon commissioning or near commissioning of the project. Based on Hydro's 2018 Cost of Service Methodology Review Report, the estimated residential rate is projected to be approximately 21¢ per kWh without additional rate mitigation beyond Hydro's forecast export revenues.

[6] The 17 ¢/kWh price is consistent with Government statements in 2017 and 2018.
Telegram News Article, July 28, 2017: https://www.thetelegram.com/news/local/electricity-rates-cant-go-much-above-17-cents-per-kwh-ball-says-130283/
CBC News Article, April 20, 2018: https://www.cbc.ca/news/canada/newfoundland-labrador/rates-doublingnalcor-scrum-coady-1.4627022

Table 1: Capacity Additions and Retirements 2018 – 2021

Capacity Addition/Retirement	Capacity Impact (MW)
Labrador-Island Link[7]	900
Less: Forecast Losses	(80)
Less: Emera's entitlement	(158)[8]
Subtotal Labrador-Island Link	662
Holyrood Thermal Generating Station Retirement	(490)
Hardwoods Retirement	(50)
Stephenville Retirement	(50)
Net Capacity Addition	72

Table 1 shows the net impact of 72 MW as a result of the capacity additions, offset by capacity retirements. The limited excess capacity forecast to be available to the Island Interconnected System demonstrates the limited capacity available to supply load growth. This limited generation capacity impacts marginal costs.

3.0 Marginal Cost Methodologies

Marginal costs reflect incremental generation and transmission costs incurred by Hydro to serve an increase in load.[9] Hydro's marginal costs can be broken into two components – generation and transmission.[10] Each of these two components can be further dissected into two sub-categories – energy and reliability. Reliability is measured as capacity for the purposes of Hydro's marginal costs. The Marginal Cost Study Update (Appendix A) provides a robust discussion regarding the methodologies used as the basis for estimating each component of marginal costs.

Chart 2 summarizes the components of overall marginal costs addressed in the Marginal Cost Study Update.

[7] Combination of recapture energy from Churchill Falls and Muskrat Falls generation.
[8] Firm capacity of the Emera Block as measured at Bottom Brook Terminal Station.
[9] The 2015-16 Marginal Cost Study and the Marginal Cost Study Update exclude the marginal cost of distribution.
[10] The current study does not provide marginal distribution costs as Newfoundland Power is the primary distribution service provide on the Island Interconnected System. Marginal distribution costs would be reflected in Newfoundland Power's marginal cost study.

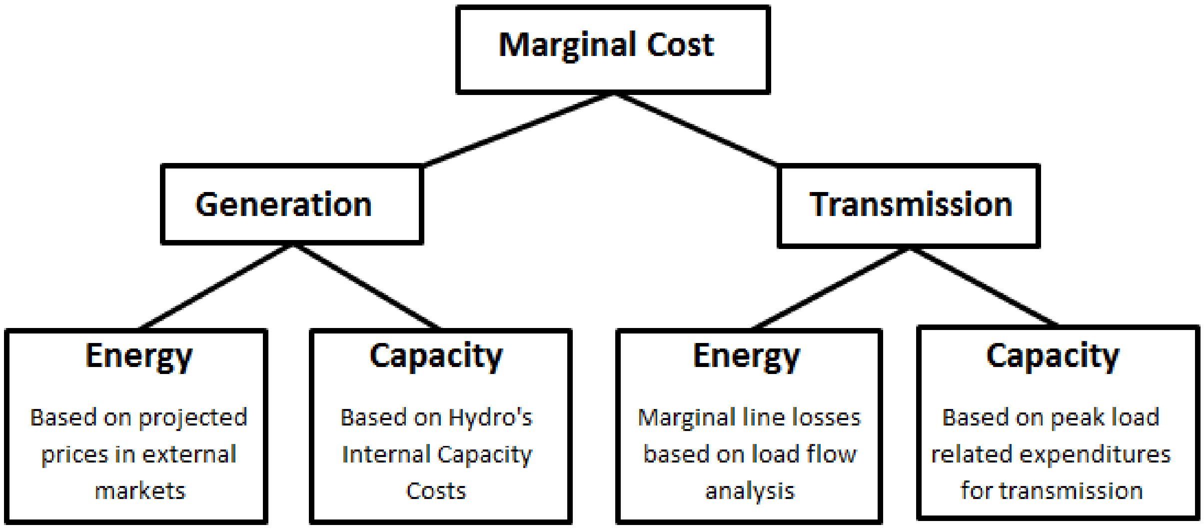

Chart 2: Components of Hydro's Marginal Cost of Generation and Transmission

3.1 Marginal Generation Costs

Hydro's marginal generation energy costs have historically been measured by internal production costs. That is, the variable costs associated with operating the Holyrood Thermal Generating Station to provide energy. However, Newfoundland and Labrador is transitioning to becoming interconnected to the North American grid, which gives Hydro the ability to import energy from, and sell energy to, other jurisdictions. Therefore, opportunity costs are the best measurement of Hydro's marginal energy costs going forward.

Hydro's Reliability and Resource Adequacy Study determined that if capacity additions are required to meet load growth, the capacity additions should be located on the island. Gas turbines have been chosen as the basis for the marginal generation capacity costs reflected in the marginal cost study for the Island Interconnected System. Gas turbines are generally accepted as the least-cost generation option to supply capacity-only requirements. The Reliability and Resource Adequacy Study indicates that Hydro has adequate energy supply for the forecast period reflected in the study.

3.2 Marginal Transmission Costs

Marginal transmission energy costs include line losses and congestion. These costs can be estimated based on load flow studies which reflect expected loads and the configuration of Hydro's transmission system. The Marginal Cost Study Update bases marginal transmission energy costs on load flow simulations which were conducted for 2019.

Transmission capacity costs include the cost of network expansion required to meet incremental load. Similar to the marginal generation capacity costs, Hydro's internal cost of making additional transmission capacity available to serve load is considered the basis for the marginal cost estimates. The marginal transmission capacity costs are estimated from Hydro's historical transmission investments and planned transmission expenditures to supply increased peak demand requirements.

4.0 Estimated Marginal Costs

For the years 2021-2029, all-in marginal costs[11] are expected to remain relatively stable, rising only slightly more than inflation each year. However, marginal costs are materially higher in the winter than during the non-winter months, and also vary materially by time of day.

4.1 Seasonal Marginal Cost Patterns

Hydro's marginal costs of generation and transmission services are significantly higher in winter (December-March) than non-winter (April-November) seasons. This is because the Island Interconnected System's marginal generation and transmission costs are primarily driven by peak loads. For example, the forecast 2021 winter peak load is estimated to be 1,486 MW while the forecast non-winter peak load is estimated to be 729 MW approximately half (729 MW).

Table 2 shows Hydro's 2021 estimated marginal cost by component for the Island Interconnected System for the winter and non-winter periods.

[11] All-in marginal costs include energy, operating reserves, and generation and transmission capacity.

Table 2: Hydro's 2021 Island Interconnected System Marginal Costs by Season (¢/kWh)

	Generation Energy	Generation Capacity	Transmission Generation and Capacity	All-in Marginal Costs
Winter	6.0	11.6	1.2	18.8
Non-Winter	2.5	0.2	0.0	2.7

As shown in Table 2, the average winter marginal cost is estimated to be 18.8 ¢/kWh. The average marginal cost for the non-winter period is estimated to be 2.7 ¢/kWh, approximately 1/7th of the winter marginal cost. The difference in winter and non-winter marginal costs is disproportionately larger than the difference in winter and non-winter peak loads.

The disparity in marginal capacity costs between winter and non-winter seasons is largely related to generation capacity costs, which occur primarily in the winter months. This is because Hydro's system is designed to accommodate its peak load, which occurs in the winter, with limited capacity available to serve additional loads during that period. As such, additional investment to supply increases in customer peak demand requirements would only be required during the winter period. During non-winter periods, Hydro has adequate capacity to serve incremental demand. Therefore, the marginal cost associated with a change in load during non-winter periods is negligible.

4.2 Daily Marginal Cost Patterns

Hydro's overall marginal generation and transmission costs also vary materially throughout the day. CA Energy Consulting assessed Hydro's marginal costs for 2021 based on both 2-period (peak and off-peak) and 3-period (peak, shoulder, and off-peak) models.

Chart 3 shows the marginal costs (in ¢/kWh) for winter based on the 2-period model, with off-peak being during the late night/early morning hours and on-peak being primarily during daytime hours.

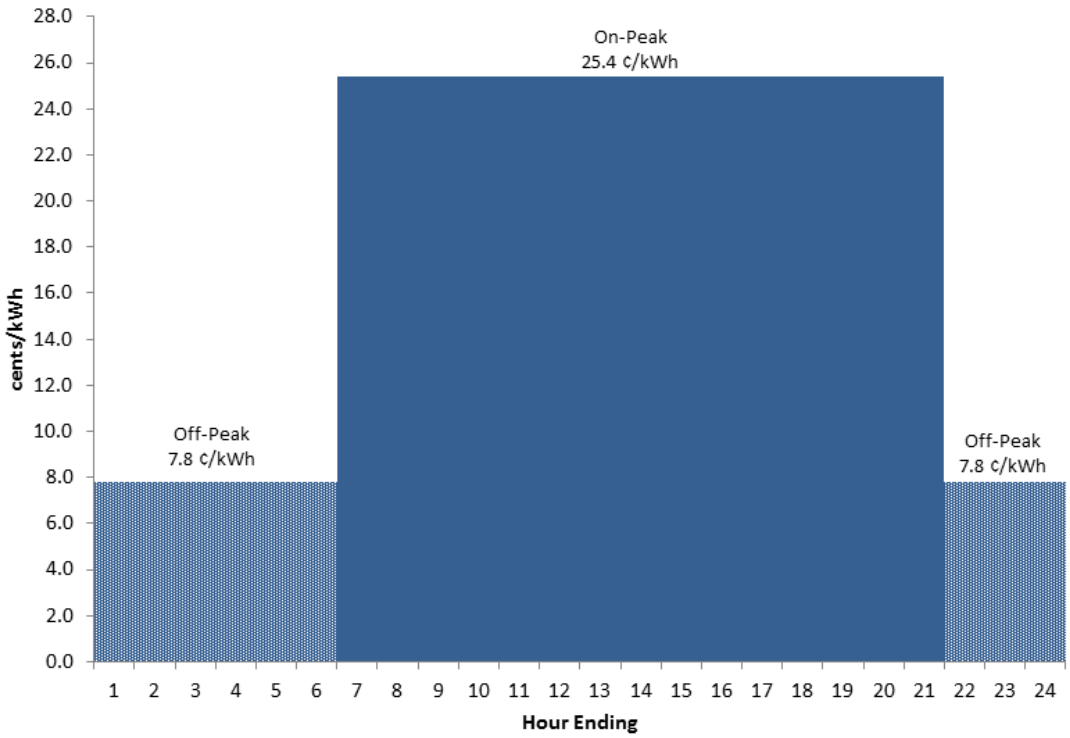

Chart 3 – Marginal Cost by Hour Based on 2-Period Model (Winter)

As shown in Chart 3, the 2-period model has high marginal costs during on-peak hours (6:01 am to 9:00 pm, or hours ending 7-21) and materially lower marginal costs during off-peak hours (9:01 pm to 6:00 am, or hours ending 22-6). The on-peak marginal cost is approximately three times that of the off-peak marginal cost (3-to-1 ratio). As stated earlier, non-winter marginal costs are substantially lower than those of winter period (average of less than 3 ¢/kWh) with minimal variability throughout the day.

Chart 4 shows the marginal costs (in ¢/kWh) for winter based on the 3-period model, with off-peak being during the late night/early morning hours, on-peak being primarily during the breakfast/supper hours, and the shoulder period being late morning/mid-afternoon hours.

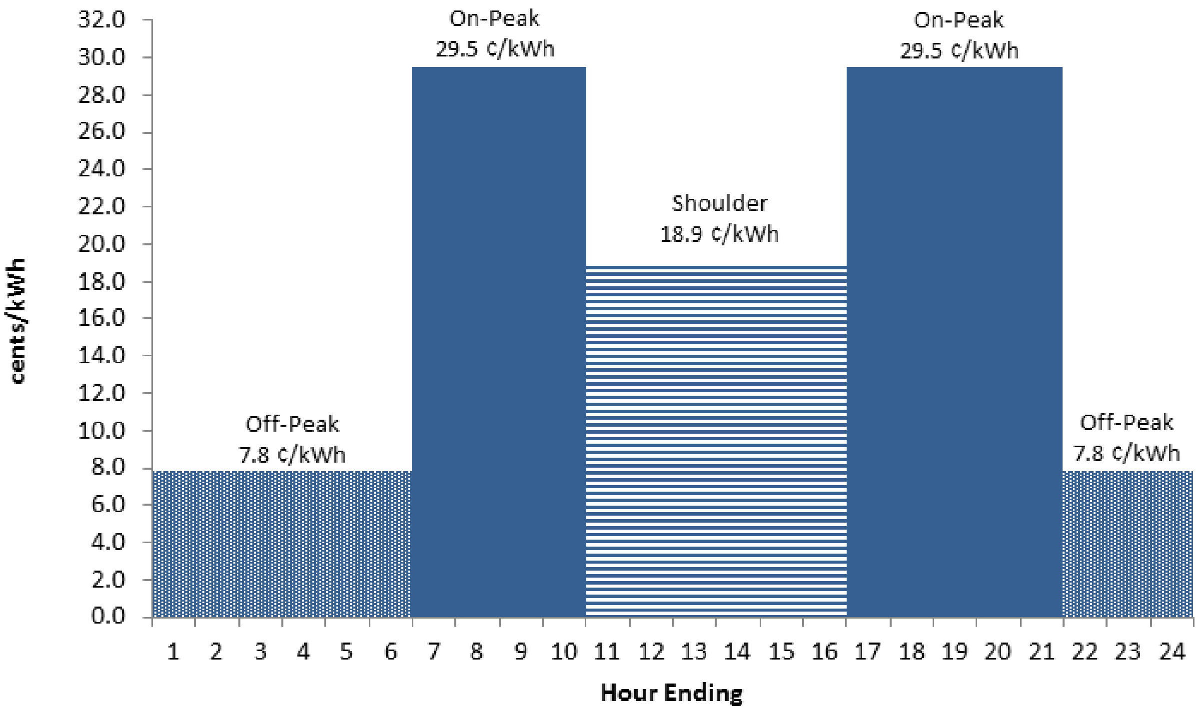

Chart 4 – Marginal Cost by Hour Based on 3-Period Model (Winter)

As shown in Chart 4, the 3-period model has high marginal costs during on-peak hours (from 6:01 am to 10:00 am and from 4:01 pm to 9:00 pm, or hours ending 7-10 and 17-21) and significantly lower during off-peak hours (from 9:01 pm to 6:00 am, or hours ending 22-6), with a shoulder period (from 10:01 am to 4:00 pm, or hours ending 11-16) that has moderate marginal costs relative to the peak and off-peak periods.

From a pricing perspective, the 3-period model would provide the highest price during the morning and evening peak periods, signalling to customers to reduce consumption during the highest-cost periods. The 3-period model would also provide more flexibility, enabling customers to shift their consumption from on-peak periods to shoulder or off-peak periods.

5.0 Application of Marginal Cost Information

The change in the Island Interconnected System's marginal costs has implications for Hydro's rate design for Newfoundland Power and Hydro's Island Industrial Customers. Hydro filed a report prepared by CA Energy Consulting on June 15, 2016 which addressed rate design for Newfoundland Power and Island Industrial Customers. The report provided options to consider in modifying the rate designs of Newfoundland Power and Island Industrial Customers in response to interconnection with the North American grid and supply from the Muskrat Falls Project. Hydro believes the rate design alternatives provided in the 2016 report continue to be appropriate for the Board's consideration. Hydro plans to start an engagement process early in 2019 with Newfoundland Power and Island Industrial Customers to develop rate design proposals for submission to the Board. Hydro plans to file a report with the Board in the third quarter 2019 which will provide a status update on rate design proposals.

Further to rate design, marginal cost estimates also enables Hydro to make business decisions which are in its customers' best interests. For example, having accurate estimates of marginal costs can assist Hydro in determining whether it should invest in customer demand management programs, smart metering and rate design options, or new generation/transmission infrastructure.

6.0 Conclusion

For the period of 2021-2029, Hydro has limited capacity available on the Island Interconnected System to serve additional customer load requirements during the winter period. Hydro's Reliability and Resource Adequacy Study has determined that if capacity additions are required to meet load growth, the capacity additions should be located on the island. Gas turbines have been chosen as the basis for the marginal generation capacity costs reflected in the marginal cost study for the Island Interconnected System.

As highlighted in the Marginal Cost Study Update, Hydro's marginal costs are materially higher in the winter than in non-winter months, and also vary between peak and off-peak periods throughout the day.

The updated marginal cost information provided in the Marginal Cost Study Update will assist Hydro in determining whether it should invest in customer demand management programs, smart metering and rate design options, or new generation/transmission infrastructure.

The Marginal Cost Study Update provided in Appendix A provides a detailed explanation of marginal cost methodologies and results for Hydro's Island Interconnected System.

Appendix A

Marginal Cost Study Update -2018
prepared by Christensen Associates Energy Consulting

CHRISTENSEN
ASSOCIATES
ENERGY CONSULTING

MARGINAL COST STUDY UPDATE – 2018

COST ESTIMATES AND METHODOLOGY

FOR

GENERATION AND TRANSMISSION SERVICES, 2021-2029

prepared for:

NEWFOUNDLAND AND LABRADOR HYDRO

developed by:

CHRISTENSEN ASSOCIATES ENERGY CONSULTING
800 University Bay Drive, Suite 400
Madison, Wisconsin 53705

November 15, 2018

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EXECUTIVE SUMMARY

BACKGROUND

This report presents estimates of marginal costs of the generation and transmission services provided by Newfoundland and Labrador Hydro's (Hydro) Island Interconnected System for the years 2021-2029. The report does not provide estimates of distribution marginal costs. It also does not provide marginal cost estimates for the Labrador Interconnected System.

Marginal cost is the change in total costs resulting from a change in the load served, and thus the level of generation and transmission services provided to Hydro's customers. Marginal generation costs are measured as $/MWh of electricity consumed, and marginal transmission cost is measured as $/MW of peak demand. Both generation and transmission marginal costs include energy and capacity components, estimated for hourly timeframes within days including peak, shoulder, and off-peak periods for the years 2021 through 2029.

Marginal costs reflect the value of resources to markets. For infrastructure industries such as the electricity industry, it is broadly recognized as the appropriate cost basis on which to price incremental services (additional loads served). Marginal cost estimation is a core business capability. For electricity services, marginal cost estimates assume strategic importance, as they are the cost basis for:

- the design of tariffs and setting efficient prices;
- determination of wholesale transactions;
- cost of service allocation[1]; and,
- for short- and long-term resource decisions.

Marginal costs are particularly important for pricing. Marginal costs provide the cost basis to integrate electricity demand with Hydro's supply costs by communicating price signals to the market, thus encouraging efficient use of resources and providing cost savings as a result of reduced loads during high cost periods.

The marginal cost estimates presented herein are based on the methods detailed in Hydro's 2015/16 marginal cost study (Parts I and II).[2] This Marginal Cost Study Update – 2018 reviews methodology and presents updated estimates for the years 2021-2029. The report concludes with a summary of major findings and recommendations, focusing on time-of use tariff options including critical peak pricing.

[1] Hydro does not currently utilize the pattern of marginal costs as the basis for cost allocation.
[2] Part I of the Marginal Cost Study, which focused on methodology, was filed with the Board on December 29, 2015. Part II was filed on February 26, 2016, and focused on methodology and application and presented 2019 marginal cost estimates for Hydro's Island Interconnected System.

TIMING OF MARGINAL COST UPDATE

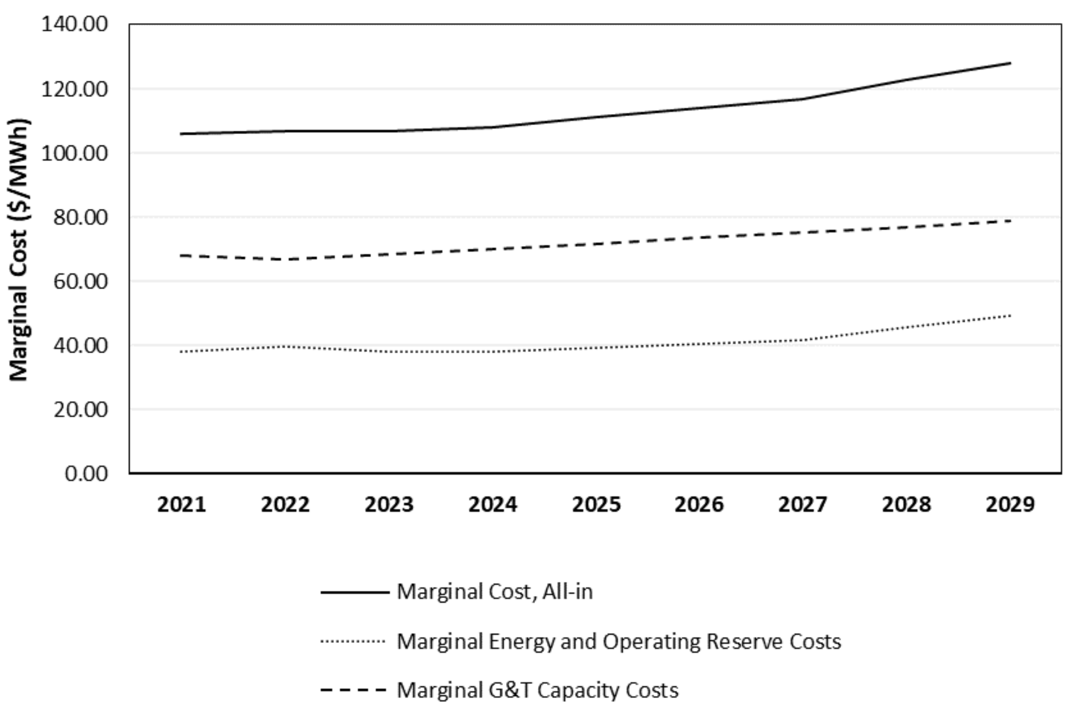
Marginal costs are driven by key factors including Hydro's generation and transmission resource pool and the level of loads served. Accordingly, Hydro's marginal cost study needs to be updated from time to time in response to ongoing changes in the near- and long-term outlook. This is the case for this Marginal Cost Study Update – 2018. Resources that constitute and serve Hydro's Island Interconnected System are undergoing major transformation including the addition of the Muskrat Falls Generating Station, the Labrador-Island Link, the retirement of combustion turbine generating units, and, more recently, the addition of planned new combustion turbine generating units. Coupled with Hydro's current load forecast and cost projections, material impacts are expected at all levels:

- total system costs will increase;
- projections of energy consumption are reduced; and
- power flows within the Island Interconnected System's transmission network have changed.

Further, wholesale sales to U.S. northeast markets will likely decline, partly as a result of lower than previously expected wholesale market prices. In brief, the pattern and level of marginal costs have changed in important ways.

MARGINAL COST ESTIMATES FOR THE YEARS 2021-2029

FIGURE 1: MARGINAL COSTS OF GENERATION AND TRANSMISSION SERVICES HYDRO'S ISLAND INTERCONNECTED SYSTEM, PEAK HOURS DURING 2021-2029 ($/MWh)



For years 2021-2029, all-in marginal costs[3] are expected to rise approximately 2.3% annually. Projected marginal costs are presented in Figure 1. The all-in marginal costs trend slighting downward through 2023, before assuming upward escalation for the years 2023-2029. This is driven by an expected decline in the marginal cost of energy and reserves. All-in marginal costs for 2021-2029 are projected to increase by 18.7%, which is somewhat faster than expected inflation. This overall trend holds for the components of marginal cost, where the energy and operating reserves rise by 25.8% (3.2% annually), while generation and transmission capacity costs rise by 14.6% (1.8% annually).

SEASONAL AND TIME-VARYING MARGINAL COST PATTERNS

Hydro's marginal costs of generation and transmission services are strongly differentiated between winter (December-March) and non-winter (April-November) seasons. The Island Interconnected System's marginal generation and transmission capacity costs are driven by peak loads. With limited capacity availability, the pattern of marginal costs closely adheres to the pattern of loads, though with greater variation. Presented for 2-period (peak, off-peak) and 3-period (peak, shoulder, and off-peak) models, below are estimates of 2021 marginal generation and transmission costs.

FIGURE 2: MARGINAL COSTS FOR HYDRO'S ISLAND INTERCONNECTED SYSTEM, 2021 ($/MWh)

WINTER (Jan-Mar, Dec)		Energy and Operating Reserves	Generation Capacity	Transmission Capacity	All-In Marginal Costs
(2 Period Model)	*Hours Ending*				
All Hours		59.87	116.48	11.80	188.15
Peak Hours	HR 7-21	61.81	174.47	17.92	254.21
Off-Peak Hours	HR 1-6, HR 22-24	56.63	19.83	1.58	78.04
(3 Period Model)	*Hours Ending*				
All Hours		59.87	116.48	11.80	188.15
Peak Hours	HR 7-10, HR 17-21	56.05	216.30	23.00	295.35
Shoulder Hours	HR 11-16	69.49	109.58	10.21	189.27
Off-Peak Hours	HR 1-6, HR 22-24	56.41	19.77	1.59	77.76
NON WINTER (Apr-Nov)		Energy and Operating Reserves	Generation Capacity	Transmission Capacity	All-In Marginal Costs
(2-Period - Broad Peak Model)	*Hours Ending*				
All Hours		24.93	1.88	0.09	26.89
Peak Hours	HR 9-22	25.51	2.49	0.13	28.13
Off-Peak Hours	HR 1-8, HR 23-24	24.12	1.01	0.03	25.16
(2-Period - Narrow Peak Model)	*Hours Ending*				
All Hours		24.93	1.88	0.09	26.89
Peak Hours	HR 14-20	29.14	3.44	0.19	32.76
Off-Peak Hours	HR 1-13, HR 21-24	23.21	1.19	0.05	24.44

For 2021, the estimated 1,466 MW January peak load is more than twice that of non-winter, which is estimated to be 729 MW. However, the average of marginal costs for winter, $188.15/MWh, are

[3] All-in marginal costs include energy, operating reserves, and generation and transmission capacity.

approximately sevenfold above cost estimates for non-winter, $26.89/MWh. While the marginal energy costs are consistent with the demand ratio (with winter being approximately twice that of the non-winter cost), the generation and transmission capacity costs are virtually non-existent during non-winter. This is because Hydro's capacity costs are largely fixed costs, and additional investment would only be required during winter peak periods. During non-winter periods, incremental demand can be supplied with existing capacity resources; therefore, the marginal cost associated with a change in load during this period consists of energy and line losses.

RECOMMENDATION

Electricity demands on Hydro's Island Interconnected System are characterized by substantial seasonal differences, with approximately 2-to-1 differences between winter and non-winter levels of energy consumption and peak demands. Hydro's marginal costs to serve those loads show yet further variation, well beyond 7-to-1. These system conditions afford substantial opportunities for cost savings. To this end, Hydro is strongly encouraged to explore time-of-use (TOU) tariff options.

TOU pricing includes static approaches such as seasonal and time-of-day tariffs, as well as more dynamic variants including critical peak pricing and real-time pricing options. Both static and dynamic approaches set prices by time of day, where the pattern of prices are set according to the pattern of marginal costs. Industry experience clearly demonstrates that participating consumers are often highly responsive to price variation. Consumers shift electricity consumption from high cost periods to low cost periods when faced high prices during timeframes when Hydro's power system is approaching capacity limits.

Time-of-use tariff options are being implemented across North American electricity markets. The end result has been substantial net gains in the form of bill reductions for participating customers and reduced capacity requirements. Indeed, empirical evidence suggests that modest changes in consumer demands during peak load periods can result in large cost savings. Generally speaking, wide-scale application of time-of-use tariff options can obtain net capacity reductions of 3-7%.[4] As a consequence, measurable cost savings in the form of reduced capacity needs are obtained.

In summary, characteristics of Hydro's Island Interconnected System, which has limited capacity available from 2021 forward, coupled with large seasonal and day-by-day variation in loads very clearly implies that the ISLAND INTERCONNECTED SYSTEM is well suited to the integration of demand and supply, obtained through marginal cost-based pricing of electricity services.

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[4] The level of capacity savings resulting from participation by customers in static and dynamic pricing options is driven by program participation by customers. Customer participation in TOU pricing options is driven by the expected realization of net benefits. Realization of benefits are largely a result of the capability of customers to respond to efficient price signals and the differences in the prices. For static TOU options, the relevant price differences are between peak and off-peak prices; for dynamic TOU options, the relevant price differences are between the *marginal prices* of the status quo tariff and marginal costs.

MARGINAL COST STUDY UPDATE – 2018[5]

METHODOLOGY AND COST ESTIMATES
FOR
GENERATION AND TRANSMISSION SERVICES, 2021-2029

prepared for:
NEWFOUNDLAND AND LABRADOR HYDRO

developed by:
CHRISTENSEN ASSOCIATES ENERGY CONSULTING

November 15, 2018

[5] Marginal Cost Study Update – 2018 prepared by David Armstrong, Robert Camfield (principal investigator) and Nicholas Crowley.

1.0 INTRODUCTION

Presented herein are 2018 estimates of marginal costs of the generation and transmission services provided by Newfoundland and Labrador Hydro (Hydro) covering years 2021-2029. Marginal cost refers to the change in total costs associated with a change in the level of services provided. Marginal generation and transmission costs include energy and reliability cost elements, with reliability measured as capacity costs. Marginal cost is estimated in hourly frequency for 2021 and for peak-, shoulder, and off-peak periods for 2022 through 2029.

Marginal cost reflects the value of resources. For infrastructure industries, marginal cost is broadly recognized as the appropriate basis to value the incremental resources used in the provision of services. The process and methods underlying marginal cost estimation is a core business capability. For electricity services, marginal cost estimates assume strategic importance, serving as a cost basis for the design of tariffs and setting efficient prices, for determination of wholesale transactions, for cost of service allocation, and for short- and long-term resource decisions.

Marginal costs reflect incremental costs incurred by Hydro to produce and transport electricity to the numerous delivery points across Hydro's transmission system, where Newfoundland Power and Hydro's small and large retail customers receive service. The marginal cost estimates presented herein are based on the methods detailed in Hydro's 2015/16 marginal cost study (Parts I and II). This immediate report reviews methodology, in addition to presenting updated cost estimates for 2021/29. The report concludes with a summary of observations and findings.

2.0 MARGINAL COST DEFINITIONS AND METHODS

Marginal cost is the change in total cost with respect to a change in the level of production and transport of goods and services. Marginal costs are highly specific to industry and the underlying technology, as well as the goods that are produced or the services provided.

The provision of electricity is provided as a continuous flow of services, the marginal cost of which includes:

- *generation services*, which is the production of electric power and the provision of operating reserves;
- *transmission services*, which is the long-distance transport of power (energy and reserves) between production locations (generator sites), and delivery locations, including power distribution systems[6] and large industrial consumer sites. Transmission services are provided by:
    - *high voltage electrical networks* configured as either meshed[7] or radial circuits; and,

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

[7] "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 of North America.

- *interconnection services* which involve the electrical interconnection of generator sites, power distribution systems, and large consumers, with the transmission network. Interconnection also includes voltage transformation functionality, carried out at the various points of delivery. For Hydro, interconnection includes substation facilities and large-scale pad mount transformers and associated control equipment.[8]

For the immediate purposes, the analysis underlying marginal cost estimates draws upon s*hort*- and *long-run* concepts.[9] The most relevant definition for costing and pricing electricity services is short-run marginal cost, as estimated for either near real-time or longer-term forward periods. As a practical matter, however, short-run marginal costs for transmission services including interconnection is readily observable, typically.[10] Thus, for these services, estimates of long-run marginal costs can often serve as viable proxies for forward-looking short-run marginal costs.

2.1 GENERATION SERVICES

Marginal generation costs consist of marginal energy and marginal reliability cost elements. Each is discussed below.

Marginal Energy Cost refers to the variable operating cost associated with a change in load level. Marginal energy costs can be defined in two ways:

- Internal production costs associated with change in amount of electricity produced including fuel costs and variable operating and maintenance costs; and,
- Opportunity costs measured as the market price associated with the sale or purchase of electric energy within regional wholesale energy markets.

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[8] 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).

[9] 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 long-run marginal cost all costs including capital charges and fixed operating and maintenance costs 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 perhaps as long as a decade. Furthermore, 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.

[10] 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 losses) among relevant locations. A change in load at a specific location gives rise to changes in costs at multiple locations.

Hydro's estimates of marginal energy and operating reserves reflect opportunity costs.

Marginal reliability cost refers to the costs incurred by consumers as a consequence to unexpected power interruptions—i.e., the likelihood and magnitude of electricity demand not served because of power outages. Generation reliability costs can be measured in two ways:

- Outage costs incurred by electricity consumers as a consequence of unexpected power failures. Consumer Outage Costs are the foregone value as a result of power not served; and,
- Capacity costs, measured as the costs of making available additional generating capacity.[11]

For generation, Hydro's marginal reliability costs are set according to incremental capacity costs, internal to Hydro's Island Interconnected System.

2.1.1 Marginal Energy Cost

As identified above, marginal energy costs can be estimated as internal production costs, and market-based opportunity costs.

Internal production costs: 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.[12] Least cost dispatch procedures are simulated, thus obtaining internal production costs over future timeframes.[13] 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.

Opportunity costs: The alternative approach, opportunity cost, sets marginal energy cost according to the expected electricity prices resulting from wholesale electricity market processes over forward periods. Generally speaking, electricity prices so determined are the result of competitive auction procedures, reflecting the highest-valued use of the participating generator units, for the market as a whole. Properly designed, auctions simultaneously obtain least-cost short-run supply and prices approximating marginal supply cost.

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[11] Under the condition of least-cost (optimal) supply-demand balance, the incremental costs of generating capacity, measured as $/kW-year installed approximates marginal reliability costs measured as the product of the likelihood of power outage and consumer outage costs, stated on an annual basis. The likelihood of power outages often serves as criteria underlying generation expansion plans and is typically expressed as a one-in-ten-year criterion. Surveys of consumers typically obtain outage cost estimates ranging from $4.00 to $10.00 per kWh, or higher.

[12] 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.

[13] For a simulation, the marginal energy cost in some hour of, say 2021, is the marginal running cost of the highest cost unit dispatched in order to satisfy the total system load in the hour.

Under least-cost dispatch, internal production costs rise with increased demand. Competitive wholesale power markets across regions present cost-minimizing opportunities not otherwise available. That is, participating generation service providers including utilities 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 under two conditions:

1) the opportunity for the sale of power by Hydro under the condition when Hydro's internal production costs are less than market energy prices; and
2) the purchase of power from markets by Hydro when Hydro's internal costs are above market prices.

Under the first condition, it is appropriate to sell power up to the point where the internal marginal production cost approximates market prices. Under the second condition, it is appropriate to purchase power up to the point where the internal production cost savings approximates prices in markets.

In brief, in the presence of competitive wholesale markets, the prices obtained reflect opportunity costs, in other words, 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, providing that service providers are actively engaged in competitive markets. When applied over forward periods, the opportunity cost methodology involves dispatch simulation,[14] applied to hourly loads and generation in the regional market. In this way, projections of market prices serve as expectations of forward marginal costs—hence, the notion of opportunity costs.

Like Hydro's 2016 Marginal Cost Study, marginal costs of energy and operating reserves for the 2018 study are based on opportunity costs. Marginal energy cost estimates over 2021-2029 are reflected in hourly frequency for 2021 and for peak-, shoulder, and off-peak winter months December-March, and for peak and off-peak timeframes for non-winter months, April-November.

The starting point underlying the analysis involves observed hourly day-ahead wholesale energy prices for the Salisbury hub (345kV) for years 2016 and 2017. Salisbury hourly prices are assessed according to daily price shapes, by month. A generic hourly price shape is constructed by randomly drawing from

[14] 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 variable operating and maintenance costs). 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.

groups of price shapes specific to each month, taking account of the frequency for each group.[15] The result of these procedures is a time series of hourly prices, ordered according to a week day/weekend day sequence.

Regional wholesale energy prices for the years 2021-2029 are projected using dispatch simulation tools, applied to the relevant regional markets including the New York (New York Independent System Operator; NYISO) and New England (ISO New England; NEISO). These forward energy price projections are determined for the commercial peak (5 weekdays x 16 hours) and off-peak (5 weekdays x 8 hours and 2 weekend days x 24 hours) timeframes, common to regional wholesale electricity markets of North America. The simulation of regional dispatch results in projections of peak and off-peak wholesale prices by month (24 values) over forward years 2021-2029.

The hourly price shape of each month, determined from observed hourly prices at the Salisbury hub is fit under the peak and off-peak projections of wholesale prices for the NEISO: peak period hourly prices of the month are fitted to equal the projected peak period energy price (commercial period) for the month. This procedure is carried out for all months for 2021, 2025, and 2029.

The marginal operating reserve costs are based on the historical relationship between marginal energy operating reserve prices, observed for the NEISO in hourly frequency for years 2012-2015. In brief, operating reserve costs, on the margin, are a constant ratio of the regional energy prices, 2021-2029.[16]

2.1.2 Marginal Generation Capacity Cost (Reliability)

For generation, 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 level. 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 two ways: consumer outage costs, incremental capacity cost. In turn, incremental capacity costs can be set according to the internal capacity costs of service providers or, in the presence of competitive wholesale markets, capacity auction prices.

Consumer Outage Costs: Outage cost refers to the value or economic worth foregone by consumers as a consequence of not having electricity service available on demand.[17] Outage cost is measured as $/kWh

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[15] Carried out separately for week days and weekend days, the daily price shapes of each month are grouped into day types based on hierarchical clustering, applied to the reference mean of each day. For each, month, daily price shapes are grouped into five day types plus the max price day, for the weekend days and two day types for weekend days.

[16] It is important to note that the relevant marginal cost of energy is Hydro's internal production costs under some conditions of flow constraints along the transmissions paths to Northeast markets.

[17] 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);

not served. Annual outage cost can be measured as the product of two metrics: expected unserved energy or loss of load hours,[18] 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 (or loss of load expectation and VOLL. Generally speaking, expected unserved energy is arguably the preferred outage cost metric for purposes of cost estimation, as it takes account of the frequency, duration, and depth of power outages (MWs). Like many large power systems including U.S. Regional Transmission Organizations and Independent System Operators (RTO/ISOs), Hydro's criteria for potential power outages as a consequence of a shortfall in supply is set at one day in ten years. This standard provides the means to determine the least cost basis of marginal capacity, as reflected in planning reserves.

Internal Capacity Costs: Marginal capacity cost refers to the costs associated with incremental changes in expected peak demands. Capacity cost is essentially the shadow price of consumer outage costs, providing that generation supply reasonably approximates least total cost, and is measured as $/kW-year. Marginal capacity cost refers to the annual charges, including capital- and operating-related costs of attending capacity, newly installed. Charges associated with marginal generating capacity are distributed to those hours in an annual period where reliability standards are not likely to be fully satisfied on an expected value basis.

Power systems consist of large, highly integrated facilities and equipment, implemented on 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 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. Resource commitments are made in advance, taking account of considerable risk with respect to

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- 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.

[18] LOLH and related reliability metrics—*Loss of Load Probably* (LOLP), *Loss of Load Expectation* (LOLE), *Loss of Load Frequency* (LOLF), and *Expected Unserved Energy* (EUE)—are longstanding measures of reliability for power systems. These metrics measure the likelihood that electricity demands, in total, will not be satisfied because of inadequate supply. LOLP reflects a stochastic view of reliability and is conceptually straightforward, at least s applied to generation in isolation of transmission networks. Analysis can proceed accordingly. Not accounting for maintenance services, individual facilities (generator units, lines) are in one of two states: facilities are either available, referred to as an *up state*, or unavailable, referred to as a *down state*.

electricity demand and, to a lesser extent, capacity costs. As with all decisions regarding costs and benefits in the future, resource decisions made 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 in expansion plans—for both the current period and near-term years following the installation (or acquisition) of new capacity.[19]

Capacity Auction Prices: This third approach to reliability costs draws upon capacity auction prices as the basis for marginal capacity costs, where available. For Hydro, the use of capacity prices obtained from competitive auction processes is conceptually plausible for determining the worth of capacity insofar as both the New York ISO and ISO New England have organized capacity auctions. The use of auction prices as the basis for generation capacity costs involves accounting for line losses and, second, ensuring that transmission capacity is available to import reserve power along the two relevant transmission paths through Quebec and Nova Scotia-New Brunswick for markets operated by the NYISO and NE-ISO, respectively. As a practical matter, the issue of long distances and limited proximity translate into concerns regarding path availability: would Hydro have access to capacity during critical times when necessary?

Following the 2016 Marginal Cost Study, marginal reliability costs for this 2018 Marginal Cost Study update employs an internal cost approach, where generation capacity costs are set according to the internal costs incurred by Hydro to provide incremental capacity to the Island Interconnected System.

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: to inform the determination of tariff rates and rate options, resource evaluation such as the assessment of conservation and demand manage programs, and the process of cost allocation process and tariff design over the near-term years, 2021-2029.[20]

[19] Recent history chronicles several timeframes with supply-demand imbalance: the comparative capacity-short position of the Eastern Interconnection and California systems during 1998-2000; the severe power outages in California during 2001; the intermittent power outages of 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.

[20] 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.

Marginal generation capacity costs are exclusively load-related costs. Stated on an expected value basis, capacity costs are often vanishingly small during off-peak timeframes, where a modest change in load level has no 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 condition—*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 are peak or off-peak. But for expected conditions regarding load level and available supply, reliability costs with respect to loads are concentrated during peak loads. For Hydro, these are the peak load hours during winter months, December-March.

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. The process of sizing facilities often favors 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, consequently, estimates of marginal costs.[21]

As mentioned previously, in lieu of internal capacity costs, estimates of capacity auction prices could seemingly be utilized as the measure of reliability costs, were it not for practical considerations in the form of delivery constraints: Hydro's system is not contiguous to the footprint of regional wholesale markets with organized capacity auctions. As a consequence of proximity and institutional constraints, this Marginal Cost Study Update – 2018 employs an internal capacity cost approach.

[21] 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: 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 model results obtained from well-grounded analytical methods coupled with well-grounded perspective based on 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.

2.2 TRANSMISSION SERVICES

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).[22] Marginal costs of transmission is the change in the cost of transmission capacity (and capability), in response to changes in expected peak loads.

Transmission networks can assume both radial and parallel path configurations; parallel paths can be in the form of either loop or meshed networks. Network expansion can also involve—i.e., can be driven by—the expansion of generation including, as in the case of Hydro, a major reconfiguration of power supply. However, transmission investment costs complementary to new generation are not necessarily on the margin with respect to *changes expected peak loads*.

2.2.1 Transmission Marginal Cost Methods

The marginal cost of transmission services, like generation, include energy and reliability cost elements, where energy costs include line losses and congestion. Transmission capacity can be viewed in terms of the shadow price paradigm: the capability of the network can be expanded up to the point that the decrease in transmission cost counterparts (losses, congestion, and power shortfalls) approximate the incremental capacity costs of expanding the network.[23] Essentially, transmission expansion obtains cost savings: should Hydro not expand its network, losses, congestion, and reliability measured as the likelihood of power outages wound by higher on an expected value basis.

Transmission networks have strong network externalities, a consequence of the physical properties of power systems. This means that load changes in one location can have substantial impact on the costs at other locations. As a result, marginal cost of transmission is unique to each location. Furthermore, locational cost differences are specific to timeframe (hour, day, or year). However, locational differences are not necessarily large and can be assumed within system-wide cost estimates, though it may be appropriate to recognize cost differences across specific areas of power systems.

Marginal transmission costs can be estimated using advanced simulation tools, such as security constrained optimal power flow models, which can provide estimates of losses, congestion, and

[22] Generator locations can be referred to as points of injection of electricity into the transmission network, while load centers and delivery points can be described as points of withdrawal of electricity from the network.

[23] Similar to generation, transmission service providers operate transmission networks in a manner that satisfies established reliability criteria—defined by the North American Electric Reliability Corporation (NERC) and adopted by regional regulatory authorities. Reliability standards are expressed in terms of maintaining service continuity under contingency events, such as loss of a major transmission path or generating stations. Reliability standards are expressed as physical limits. Transmission reliability is gauged through technical studies (e.g., transient stability) of the response of power systems under contingency events. 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 the transmission network increases the capability of the network at least cost, given that reliability standards are satisfied.

reliability cost changes. Simulation results are sensitive to the accuracy with which input data capture future changes to the network, including transmission upgrades and generation over long-term future periods. However, the application of advanced methods give rise to unusual challenges, largely because of the limitations associated with the development of input data over extended future years. It is a difficult forecast problem: technology changes, the location of new generation, and load growth for the various locales served by power systems over future years are not easy to discern.

An alternative approach is to draw on the results of piecemeal transmission studies. That is, rely on load flow simulation studies to estimate line losses and transmission expansion studies and plans to estimate transmission capacity costs (proxy for reliability). Load flow studies provide detailed estimates of energy losses including conductor and transformer losses for major segments of networks: Losses are estimated for a set of conditions (load levels, seasons), given the expected configuration of the network over near-term years. Results are highly accurate for the system conditions inherent to the study.

In the case of capacity costs for reliability, expansion plans are fairly definitive with respect to expected transmission facility changes and costs, where costs are reflected in planned capital budget expenditures over forward years (e.g., ten years).[24] For purposes of marginal transmission capacity cost estimation, the planned changes in facilities and estimated cost impacts are of interest. Marginal transmission costs are measured in $/kW-year metrics.

Hydro's Marginal Transmission Cost Approach: The immediate study assumes a capacity cost approach, for determination of peak-load related marginal transmission costs of Hydro's power system. For the prospective years 2019-2029, marginal transmission capacity costs stated on $/kW-year basis are estimated from Hydro's transmission expansion plans and expected peak loads. In brief, for the years 2019-29, marginal transmission capacity cost is equal to the incremental investment costs associated with the changes peak loads over the prospective period. Marginal transmission energy costs (line losses) are drawn from set of load flow simulations, conducted for 2019.

2.3 SUMMARY OF METHODS, MARGINAL COST STUDY UPDATE - 2018

To summarize, Hydro's 2018 marginal cost study is based on the following methodology:

2.3.1 Marginal Costs of Generation Services

<u>*Energy Cost based on Opportunity Costs*</u>*:* Energy costs set according to projections of marginal energy prices and operating reserves of the NYISO and NEISO regional markets.

[24] Generally speaking, it is useful to benchmark forward-looking transmission capacity costs, estimated from expansion plans, against historical expenditures. Historical benchmarks can be misleading, however. Beginning in 2003 approximately, industry-wide capital expenditures for transmission facilities have far exceeded historical expenditure levels. This higher expenditure level is largely a consequence of changes in regional flow patterns, higher reliability standards, and replacement facilities rather than a result of changes peak loads.

Hydro's Internal Capacity Costs: Internal capacity costs, set according to the annual charges associated with Hydro's incremental capacity, oil-fired combustion turbine generators situated on existing sites near Hydro's load centers of the Island Interconnected System.

2.3.2 Marginal Costs of Transmission Services

Energy Costs (Losses) Drawn from Load Flow Simulation Studies: Marginal line losses for transmission services are based on estimates obtained from load flow analysis, as mentioned. Study results reflect expected loads and the configuration of Hydro's transmission system during 2019.

Capacity Cost Proxy for the Benefits of Expanded Transmission Capability on the Margin: Estimates of marginal reliability costs of transmission are based on the Company's peak-load related expenditures (capacity) for transmission, as planned for forward years through 2024.

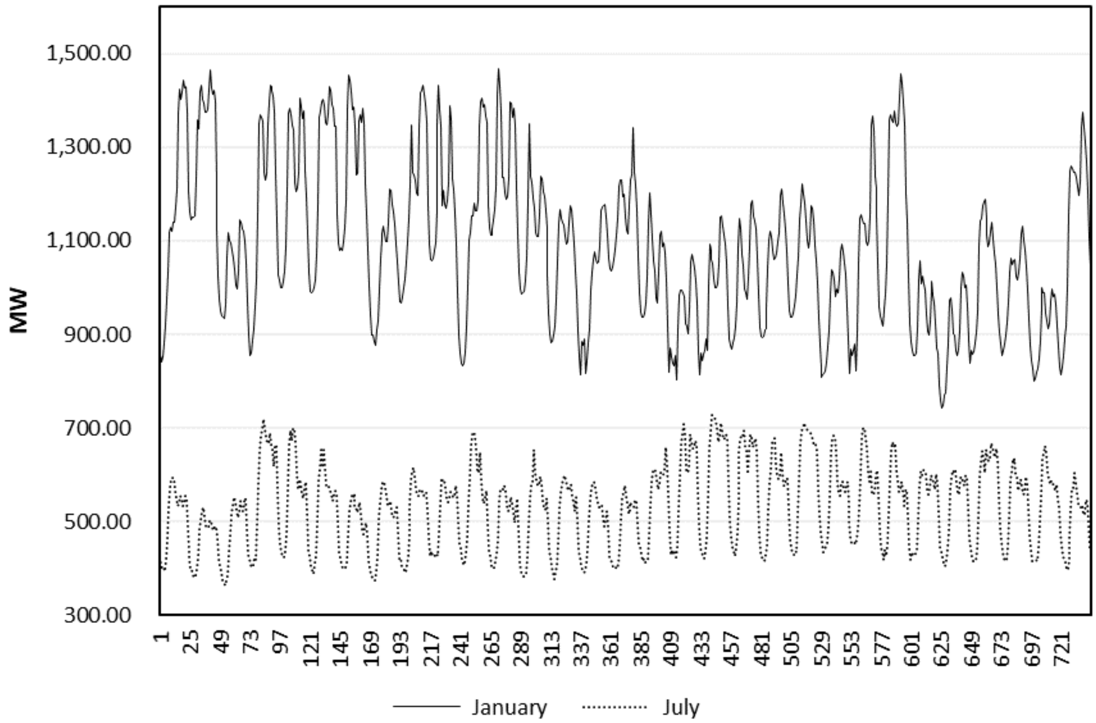
3.0 MARGINAL COST ESTIMATES, 2021-2029

3.1 ELECTRICITY DEMANDS, THE STARTING POINT FOR MARGINAL COST ESTIMATION

Marginal costs are a function of the conditions and characteristics of supply, and electricity demand, measured in loads. Both are necessary to estimate marginal cost. For the Marginal Cost Study Update – 2018, electricity demands are based on historical loads of the Island Interconnected System, observed in hourly frequency. This vector of 8760 hourly loads is adjusted, resulting in an hourly load profile for estimation years 2019-2021.

As mentioned, load levels for January are markedly above loads for July, as presented below.

Figure 3: JANUARY AND JULY HOURLY LOADS



The hourly average loads displayed above reveal substantially different magnitude (MW) between the peak winter month of January and mid-summer, July. Variation of loads served by Hydro during winter and non-winter months is shown below.

Figure 4: MINIMUM AND MAXIMUM HOURLY LOADS (MW) SERVED BY HYDRO'S ISLAND INTERCONNECTED SYSTEM

Month	Minimum Houly Load	Maximum Hourly Load
January	742.34	1466.57
February	778.11	1428.90
March	705.30	1376.00
April	640.72	1201.00
May	420.24	1010.27
June	384.45	860.60
July	365.02	728.50
August	347.45	698.20
September	375.51	818.60
October	384.30	1006.30
November	553.49	1308.44
December	647.55	1485.60

Differences viewed in percentage terms have July with larger variation,69% compared to 41% for January. In terms of marginal costs, however, it is the differences measured in MW that matter, particularly where the maximum peak loads are at or near the maximum load levels, as it is the very high loads where much capacity cost resides.

3.2 STRUCTURE OF MARGINAL COST

Estimates of marginal generation costs over 2021-2029 are presented below. Hourly cost estimates for energy (including operating reserves), and reliability (capacity cost proxy) are developed for years 2021, and for peak and off-peak timeframes for the 2021-2029.

The general construct[25] underlying Hydro's marginal costs is as follows:

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

where,

$$MEC = marginal\ energy\ cost\ and\ operating\ reserves$$

$$GenCap^{Internal\ Cost} = Hydro\ generation\ capacity\ costs$$

$$TransCap = transmission\ capacity\ costs$$

$$LL^{Network} = marginal\ loss\ factors\ for\ Hydro's\ network\ and\ transmission\ paths\ to\ wholesale\ markets$$

$$LL^{Peak} = marginal\ losses\ associated\ with\ peak\ loads$$

[25] The proposed is conventional insofar as energy and capacity costs are additive. However, where reliability costs are explicitly modeled, all-in marginal costs can be formulated as:

$$marginal\ energy\ cost = \lambda * (1 - \partial\ \rho/\partial L) + (\partial\ \rho/\partial L) * VOLL$$

where,

$\lambda = marginal\ energy\ costs; \rho = probability\ of\ power\ outage; L = Load; VOLL$ = *value of lost load*

Hourly generation and transmission costs are stated as $/kW-year and, as discussed, can be assigned to hours in several ways including the distribution of *loss of load hours* (LOLH) or *expected unserved energy* (EUE) among hours, and the distribution of peak loads.

3.3 COST ESTIMATES FOR GENERATION SERVICES, 2021-2029

As defined above, marginal energy and operating costs are set equal to estimates of market prices (opportunity cost), as determined by regional wholesale electric markets. Marginal reliability costs are based on Hydro's estimates of marginal capacity costs (capacity cost proxy). Marginal generation cost estimates are presented below.

3.3.1 Marginal Energy Costs

As mentioned above, estimates of marginal energy and operating reserve costs ($/MWh) are based on projections of electricity prices for the NEISO[26] and NYISO regional markets. 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 the electricity supply function for the region (i.e., generation dispatch curve), as simulated. Forecasts of prices over forward years incorporate projections of new generator additions and primary fuel prices, and various generator unit parameters including heat rates and unit availability (expected forced outage rate). 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, cost estimation algorithms can then commit 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 available generators is then ordered into a supply function according to running costs (fuel and variable operations and maintenance expenses).

In summary, estimates of the marginal energy prices including reserved are determined at the intersection of demand (loads) and short-run electricity supply.[27] For the Marginal Cost Study Update – 2018, marginal reserve prices (regulation, spin, and non-spin reserves) are drawn from observed hourly

[26] Estimates of the marginal costs shown in the Marginal Cost Study Update – 2018 reflect NEISO opportunity costs of energy and reserves.

[27] Note that simulations of wholesale market prices over forward periods are similar, as a matter of analysis procedure, to the simulation of internal generation production costs.

prices over several years, and then scaled to the marginal energy cost estimates for the NEISO, for the years 2021-2029.[28]

As mentioned, marginal energy and operating reserve costs for Hydro's Island Interconnected System is based on projections of NEISO energy and operating reserve prices, after accounting for path charges and Hydro's network losses.[29] For the Island Interconnected System, energy and operating reserve costs—essentially, NEISO energy and reserve prices—vary with respect to season by approximately two-to-one with higher costs experienced during winter months, as shown below:

Figure 5: HYDRO'S MARGINAL COSTS OF ENERGY AND OPERATING RESERVES, SEASONAL AVERAGES INCLUDING PEAK AND OFF-PEAK PERIODS ($/MWh)

JANUARY		Energy and Operating Reserves
(2 Period Model)	*Hours*	
All Hours		74.43
Peak Hours	HR 7-21	77.55
Off-Peak Hours	HR 1-6, HR 22-24	69.22
MARCH		
(2 Period Model)	*Hours*	
All Hours		44.55
Peak Hours	HR 7-21	48.61
Off-Peak Hours	HR 1-6, HR 22-24	37.80
JULY		
(2-Period - Broad Peak Model)	*Hours*	
All Hours		26.16
Peak Hours	HR 9-22	26.58
Off-Peak Hours	HR 1-8, HR 23-24	25.57

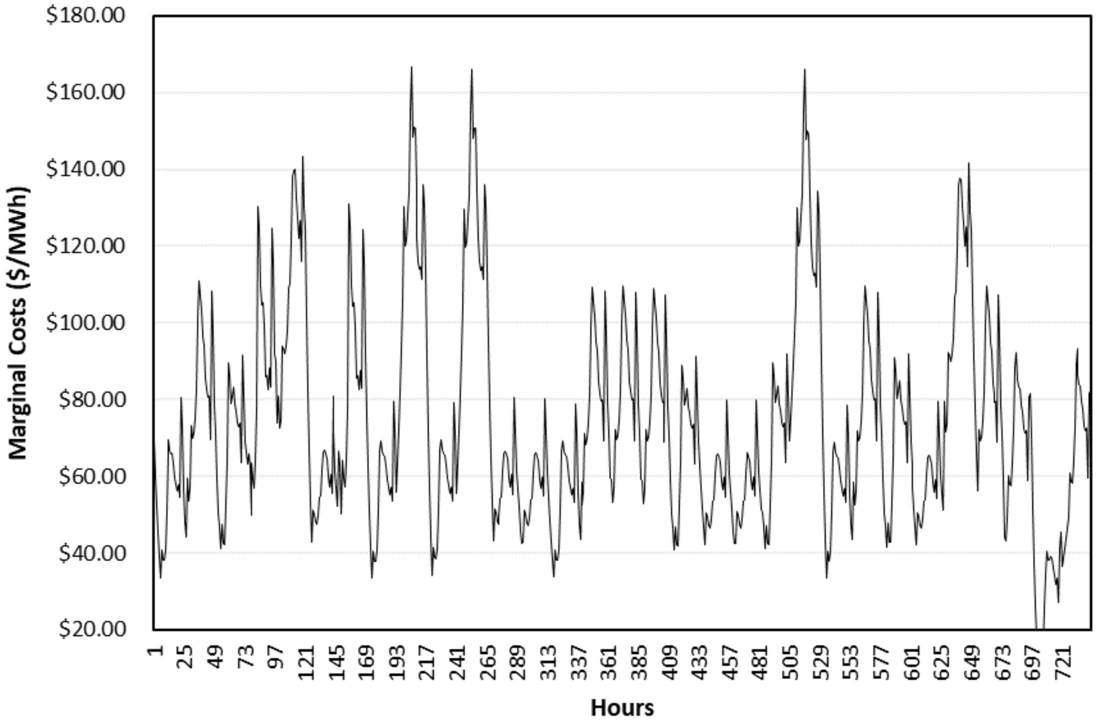
Energy and operating reserve costs are highly similar for peak and off-peak periods during non-winter months, July serving as a representative sample. Winter months have somewhat larger cost differences across the peak and off-peak periods.

Day-to-day variation of estimated hourly marginal energy and operating reserve costs are shown below.

[28] 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.

[29] The analysis implicitly presumes that Hydro has sufficient capacity to sell power into the NEISO. However, there are occasional timeframes where such assumption may not hold owing to generation or capacity constraints. In addition, it is likely that, on occasion, Hydro will face NEISO energy prices sufficiently low that the sale of power into wholesale markets is not warranted, as path charges would negate all benefits arising from the sale.

Figure 6: ESTIMATES OF HOURLY MARGINAL ENERGY AND OPERATING RESERVE COSTS, JANUARY 2021 ($/MWH)



Substantial variation in hourly costs are revealed in projected costs, in parallel with observed historical experience. The above charts are descriptive, arguably. However, the analysis procedures underlying marginal energy/operating reserve costs cannot determine high cost days, and comparatively low cost days. Marginal costs follow loads to a substantial extent (particularly for generation and transmission capacity). Loads drive costs but random variation contributes to cost levels. As an example, for January 2021, the projected maximum hourly load is 1,466MW, while marginal energy and reserve costs is $166.75/MWh. In contrast, the maximum load and marginal energy/operating reserve costs for July is 729MW and $94.70/MWh, respectively. Reflecting frequent high load levels, marginal energy and operating reserve costs for January are corresponding frequent, whereas July high cost experience is an occasional anomaly.

In brief, there is substantial variation in daily energy/operating reserve costs which, in the case of high load experience, is complemented by high capacity costs, discussed below.

3.3.2 Marginal Capacity Costs

For the Marginal Cost Study Update – 2018, the approach for determining capacity is similar to the methodology clarified in the 2016 Marginal Cost Study. Estimation of marginal generation capacity cost involves three fundamental processes: estimation of investment costs, stated according to all-in annual costs on a $/kW-year basis; attribution/assignment of capacity costs according to timeframe (peak, off-peak) and load level, and determination of cost escalation, 2021-2029.

INVESTMENT COSTS: As discussed, the capacity cost proxy for reliability cost is based on the annual costs of the combustion turbine technology. Combustion turbines are well recognized as the least-cost basis by which electricity service providers satisfy generation reliability. Estimates of combustion turbine capacity costs, sometimes referred to as the cost of new entry, are commonly used as the basis to determine marginal reliability costs of generation services. This more-or-less standard approach is not without reason: combustion turbines have high flexibility, are capable of high ramp rates, can be put in place with short construction times, and assume only a modest-sized footprint. In addition, combustion turbine generating units are capital divisible—available in a wide range of capacity sizes. Driven by increased availability and a lower path of petroleum and natural gas fuel prices, combustion turbines along with combined cycle units have represented much of the total capacity additions in North American over recent years.

Hydro's planned capacity additions for years 2019-2029 include two 58.5MW single cycle combustion turbines. The expected investment expenditures for these two units are the basis for the all-in annual cost estimates of generation capacity costs, on the margin. The estimated investment costs, stated in 2018 Canadian dollars, are incurred by Hydro during a two-year construction cycle, with 35% of expenditures expected to be incurred during year 1 and 65% incurred during year 2. Interest is capitalized during construction at 5.90%, Hydro's marginal weighted average cost of capital. Cost escalation is based upon projected escalation in investment costs of the combustion technology, normalized with respect to expected inflation. The escalation in investment cost, net of inflation, is based on the observed historical experience in cost escalation for combustion turbine technologies and overall inflation over the long-term.

Stated on a \$/kW-year basis, combustion turbine capacity costs vary considerably, owing largely to differences in the specifications of units, site-specific factors, and scale economies favoring larger units. For this study, estimates of capacity cost are drawn from Hydro's planned additions of combustion turbine capacity. Hydro's expected investment expenditure for a 58.5MW combustion turbine, as installed, serves as the foundation for Hydro's marginal generation capacity cost. The overall cost estimate (\$/kW-year), referred to *all-in capacity cost estimate*, incorporates several cost elements 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,

$Capacity\ Cost_{CT} = total\ annual\ direct\ and\ indirect\ cost\ of\ combustion\ turbine\ technology$

$I_{CT} = direct\ CT\ investment\ expenditure\ including\ interest\ during\ construction$

$I_{GP} = investment\ expenditure\ in\ indirect\ plant\ and\ equipment$

$I_{M\&S} = investment\ expenditure\ for\ materials\ and\ supplies\ inventory$

$I_{F_{Inv}} = investment\ expenditure\ in\ fuel\ inventory$

$WK = working\ capital\ associated\ with\ fixed\ O\&M\ and\ fuel\ inventory$

$$ECC = economic\ carrying\ charge\ rate, generation$$
$$ECC = economic\ carrying\ charge\ rate, general\ plant$$
$$OM_{CT} = annual\ expenditure\ for\ operations\ and\ maintenance$$
$$A\&G_{wrt\ OM} = annual\ expenditure\ for\ administrative\ and\ general\ expenses$$
$$Ins_{K,Ops} = annual\ expenditure\ for\ insurance, plant\ and\ operations$$

As presented above, generation capacity costs, in total, include the carrying charges on capital and operating costs, stated annually. Capital-related cost is the sum of the direct investment expenditures, general plant, fuel inventory, materials and supplies, and working capital, multiplied by the carrying charge rates. The carrying charge rates are based on the economic carrying charge approach,[30] sometimes referred to as trended real capital costs.[31] Economic carrying charge-based charges rise with respect to shorter capital life; as presented below, the economic carrying charge rate for general plant is substantially higher than counterpart rates for generation (and transmission) capacity.

Capital investment associated with the direct investment in the combustion turbines, including general plant, materials and supplies, fuel inventory, and working capital are drawn from Hydro's 2019 cost of service study. Fuel inventory is set at a sufficient level to cover continuous or near-continuous running hours for the planned combustion turbines over one week (168 hours), an expected average heat rate of 9,637 BTU/kWh, and energy content of 5.8 MMBTU per barrel. The combustion turbines will utilize No. 2 fuel oil. Prices for No. 2 oil are based on Hydro's planning assumptions, including the costs of transportation.

Operating costs comprise direct operating expenses including both fixed operating and maintenance costs, indirect administrative and general expenses, and insurance charges. Fixed operating and maintenance costs are based on Hydro's estimates, adjusted for new units, and is equal to $17.82/kW-year for an installed unit. The average level of administrative and generation expenses is equal to 15.01% of direct operations and maintenance costs for Hydro combustion turbines, as presented with

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[30] 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*.

[31] 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 economic carrying charge 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 economic carrying charge approach is equivalent to levelized fixed charges over the life of capital.

the 2019 test year cost of service study.[32] Insurance costs are also set equal to the implied insurance rates reflected in Hydro's test year 2019 cost of service study.

Marginal generation capacity costs are shown below.

Figure 7: MARGINAL GENERATION CAPACITY COST HYDRO'S ISLAND INTERCONNECTED SYSTEM ($/kW-year)

Investment Cost ($/kW)	Parameters	Investment Costs per kW	Charges on Capital ($/kW-year)
Direct Facility Investment		3,114.6	169.86
General/Common	8.98%	279.64	18.34
Materials and Supplies	1.16%	36.17	1.97
Fuel Inventory		24.04	1.31
Working Capital (%/FOM)	1.76%	0.72	0.04
Charge Rates (%)	Parameters		Cost Elements ($/kW-year)
Carrying Charges, Direct	5.45%		173.19
Carrying Charges, Gen/Com	6.56%		18.34
Insurance Costs	0.11%		3.74
FOM Rate ($/kW-year)	$35.63		35.63
A&G Cost Rate (% OM)	15.01%		5.35
	All-In Cost/kW-year:		236.26
Costs of Reserves (% of Supply)		14.00%	33.08
Cost Effect of E(Forced Outage)		5.03%	14.26
Adjusted All-Inj total Cost/kW-year:			283.60

Stated on a $/kW-year basis, the capital-related charges total to $191.53[33] and operating expenditures totaling $44.72, obtaining a total cost of $236.26/kW-year. The recognition of a reserve margin of 14% adds further to capacity costs in the amount of $33.08/kW-year; similarly, expected forced outage rates of 7% amounts to $14.26/kW-year. Altogether, the estimate of marginal generation capacity cost for Hydro during 2019 is $283.60/kW-year.

This marginal capacity cost estimate reflects an installed all-in cost result and may not, for several reasons, initially 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

[32] Marginal administrative and general expenses may be substantially less than average administrative and general costs because of economies of scale across many of the various support functions and activities which constitute administrative and general activities and functions.

[33] This includes charges on 1) direct investment, materials and supplies, fuel inventory, and working capital of $173.16, and 2) associated investment in general plant balances of $18.34.

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 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. While this condition was expected to hold at the time of the 2016, Hydro's Island Interconnected System is not expected to be capacity long currently. Indeed, as demonstrated in Hydro's *Reliability and Resource Adequacy Study*, the Island Interconnected System is expected to be just capacity sufficient (14% reserves) in generation for years 2021-2029, in accordance with planning criteria presented in Volume I of Hydro's Reliability and Resource Adequacy Study.

This change in capacity status is largely result of additional capacity retirements, not anticipated at the time of the 2016 Marginal Cost Study. As a consequence, the 2018 Marginal Cost Study Update – 2018 does not attenuate generation capacity costs during early years. Indeed, attenuation effects are not present in any year, 2021 forward. For the 2021-2029 timeframe, marginal generation capacity costs are accounted for in full during each year.

3.4 COST ESTIMATES FOR TRANSMISSION SERVICES, 2021-2029

3.4.1 Introduction

Marginal transmission costs include energy and capacity cost elements, where transmission energy costs are determined by the energy costs of generation and physical losses and congestion[34] within transmission networks. Marginal energy and capacity costs for transmission are discussed below.

3.4.2 Losses: Transmission Energy Costs

For transmission, marginal energy costs are determined by the marginal energy costs of generation and the physical energy losses within transmission networks. Transmission energy costs rise linearly with respect to marginal energy costs. However, physical losses are non-linear with respect to load level. Physical losses include charging losses and thermal losses, often referred to as I^2 losses, where *I* refers to electrical current flows within circuits. Charging losses are associated with conductors and transformers. Charging losses do not change with respect to load levels and are comparatively small. Key factors that determine transmission losses, which occur predominantly in the conductors that constitute transmission lines, are as follows:

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

[34] Transmission congestion costs, a form of energy costs, is manifest as generation redispatch costs.

- Transmission losses which are predominantly thermal losses, resulting from line resistances. Larger conductors will generally have lower losses.
- Transmission losses which 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.[35]

Most important for marginal cost estimation, 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, providing that the configuration of flows on lines is largely unchanged. In support of the Marginal Cost Study Update – 2018, marginal losses are measured as a percent of load served. Estimates of marginal losses are based on estimates of hourly losses for 2019, as well as a set of differential load flow studies conducted by Hydro.

Average and marginal losses are shown below:

Figure 8: TRANSMISSION MARGINAL LOSSES: PERCENT OF LOAD
HYDRO'S ISLAND INTERCONNECTED SYSTEM, 2021

	Peak	Off-peak	All Hours
January	11.26%	10.45%	10.95%
February	11.29%	10.71%	11.05%
March	10.68%	10.31%	10.49%
April	10.09%	9.77%	9.96%
May	9.18%	8.75%	8.97%
June	8.82%	8.35%	8.53%
July	8.59%	8.20%	8.22%
August	8.45%	8.20%	8.05%
September	8.72%	8.58%	8.34%
October	9.43%	9.35%	9.11%
November	10.33%	10.34%	9.96%
December	11.08%	11.13%	10.77%

3.4.3 Marginal Transmission Capacity Costs

Marginal transmission capacity costs are, by definition, load-related costs. That is, the change in total (transmission) costs with respect to a change in load-carrying capability (MW). Key features of transmission facilities drive capacity costs: 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., an increase of 1.5 times), other factors held constant. Second, transmission capacity costs, measured in load capability (MWs), change more-or-less one-to-one with respect to transport distances.[36] Over years, ongoing investment in transmission

[35] Voltage adequacy is important. Declining voltages over long transmission lines can contribute to substantial energy losses along conductors.

[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

facilities is largely a function of reinvestment (replacement), expected increases in peak loads and, particularly in recent years, upgraded reliability.[37]

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 Hydro's expected budget expenditures attending transmission expansion plans and estimated growth in peak loads for years 2018-2024. Properly executed and appropriately attenuated, this *change in cost-change in load* approach for estimation obtains plausible transmission capacity cost estimates, on the margin.

Hydro's expected budget expenditures follow directly from transmission plans, including near-term capital plans for three categories of facility needs, including:

- Replacement of aging transmission facilities (replacement);
- 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 facility voltage; expressed as line ratings, conductor size, conductor material, voltage support over extended distances, and span lengths all contribute to the overall capability transmission circuits. 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 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—the *change in cost-change in load* paradigm—load-related transmission expenditures, expected by Hydro over 2018-24, serve as the *cost basis*. Similarly, Hydro's long-term path of peak loads for the Island Interconnected System serves as the load basis.

Stated as a $/kW-year cost metric, estimates of marginal 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:

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capacity banks placed along the circuits of long transmission lines in order to manage the inductive capacitance inherent to the facilities.

[37] While transmission capability is more stressed during very high load periods, power system outage events often take place during moderate load levels, industry history suggests.

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

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 similar to the methodology utilized to determine the 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, 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 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. As mentioned above, economic carrying charges rise with respect to shorter capital life and are thus substantially higher for general plant facilities associated with transmission, than for the direct expenditures in transmission facilities.[38]

Estimates of marginal operating costs associated with transmission, like generation, include the annual direct operating expenses, indirect administrative and general expenses, and insurance charges, each drawn from Hydro's 2019 Test Year Cost of Service Study. Estimates of the marginal cost of transmission capacity are presented below.

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

[38] Estimates of incremental investment in general plant are drawn from Hydro's 2019 cost of service study.

Figure 9: MARGINAL COST OF TRANSMISSION CAPACITY HYDRO'S ISLAND INTERCONNECTED SYSTEM, 2019 ($/kW-year)

Investment Cost ($/kW)	Parameters	Investment Costs per kW	Charges on Capital ($/kW-year)
Direct Facility Investment		520.11	22.19
General/Common	3.28%	17.07	1.12
Materials and Supplies	1.02%	5.32	0.23
Working Capital (% OM)	5.22%	0.50	0.03
Charge Rates (%)	Parameters		Cost Elements ($/kW-year)
Carrying Charges, Direct	4.27%		22.45
Carrying Charges, Gen/Com	6.56%		1.12
Insurance Costs	0.03%		0.18
FOM Rate ($/kW-year)	0.97%		5.05
A&G Cost Rate (% OM)	91.04%		4.60
	All-In Costs ($/kW-year)		33.40

As shown above, the underlying structure for transmission capacity costs/kW-year is similar to the approach for generation: capital-related expenditures include generation and common facilities, materials and supplies, and working capital. As for generation, each of supporting cost elements are estimated by Hydro and incorporated within its cost of service methodology, and then coupled with non-capital related capacity cost elements including insurance fixed operating and maintenance expenses and administrative and general expenses. The end result is $33.40/kW-year. Note that, transmission capacity cost estimates do not explicitly incorporate cost elements for reserve margins. However, planning and operating reserves are implicit within the marginal capacity costs for transmission services in the form of *transmission reliability* and *capacity benefit margin*s.

3.5 CAPACITY COSTS ACCORDING TO TIMEFRAMES

This Marginal Cost Study Update – 2018 assigns annual generation (and transmission) capacity costs ($/kW-year) according to hour loads. Marginal capacity costs are driven by the system-wide need to satisfy reliability expectations of consumers at least cost. As discussed above, reliability hinges on the value of reliability implicit in capacity planning standards (loss of load hours) which, in North American, is codified as one-in-ten years criterion. This well-accepted standard, related criteria, and the experience across the wholesale electricity markets guide how best to manage the issue of capacity costs within timeframes. Three methods are available, as follows:

Parameterized max function, which distributes annual capacity costs to the highest hourly loads, as selected by the function. Selection of peak loads can include linear and non-linear methods. Depending on the setting of model parameters, costs can be distributed fairly narrowly or broadly across peak loads.

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 hourly loads.

Scarcity rents algorithm, which provides a basis to simulate the demand for reliability.

While the approach options listed above are plausible, Hydro's Marginal Cost Study Update – 2018 applies the parameterized max function approach, described below:

$$Hourly\ Factor\ for\ Cap\ Cost_h = \max\left(0, \left(L_h - \alpha * L^{Peak}\right)^{\beta}\right) / \sum_{h=1}^{8760} \max\left(0, \left(L_h - \alpha * L^{Peak}\right)^{\beta}\right)$$

where,

$$\alpha = threshold\ distribution\ parameter;\ \alpha \leq 0.90$$
$$B = exponential\ distribution\ parameter$$
$$L_h, L^{Peak} = Loads\ for\ hour\ h, peak\ h$$

The parameterized max function proves to be highly flexible, allowing for testing with respect to exogenous studies and observed load and price data reported for wholesale electricity markets. Second, capacity additions provide reliability value broadly across high load hours. Implicitly, the *distribution of peak demands* often provides a fairly narrow interpretation of reliability: the application of reserve capacity is more broadly distributed than suggested by peak loads viewed in isolation; reserve calls are more strongly related to the conditions of supply-demand balance. Thus, in the interest of obtaining efficient resource allocation through cost allocation and pricing initiatives, it is best to not distribute capacity costs too narrowly. Third, it is common to find that the limits of the available supply of capacity is approached much more broadly across hours than suggested by planning models.

It is nonetheless useful to draw upon the analytics reached through generation planning tools to determine the appropriate parameters for application of the parameterized max function approach. Simulation of scarcity rents, estimated with variants of max functions and other methods, provide plausible surrogates for the implicit worth of reliability, particularly for inclusion within day-by-day cost simulation in support of tariff options for dynamic pricing.

Along this line, shown below are simulations of several levels of capacity cost concentration for the α distribution parameter (*ρ*) set between 0.60 and 0.90.

Figure 10: CONCENTRATION OF GENERATION CAPACITY COSTS:
COUNT OF HOURLY CAPACITY COSTS ABOVE $100/MWh

Month	ρ=0.60	ρ=0.70	ρ=0.80	ρ=0.90	ρ=0.77 (2018 Study)
January	399	327	175	175	221
February	449	353	158	158	229
March	228	153	45	45	74
April	53	33	0	0	8
May-November	109	91	19	19	35
December	354	284	119	37	177

As can be seen, high capacity costs (>$100/MWh) are present in more hours as the parameterization is set lower—ρ=0.60 compared to ρ=0.80, for example. The relationship between parameter setting and the frequency (and amount) of high capacity costs is non-linear. The concentration of high capacity costs rises sharply, with progressively fewer high cost hourly loads at ρ>0.75.

The distribution of transmission capacity costs across hours are shown below where, for transmission, the count is shown with reference to a above $100/MWh boundary.

Figure 11: CONCENTRATION OF GENERATION CAPACITY COSTS:
COUNT OF HOURLY CAPACITY COSTS ABOVE $40/MWh

Month	ρ=0.60	ρ=0.70	ρ=0.80	ρ=0.90	ρ=0.80 (2018 Study)
January	0	121	124	100	124
February	0	47	83	28	83
March	0	18	42	4	42
April	0	0	0	0	0
May-November	0	0	4	0	4
December	0	41	60	35	60

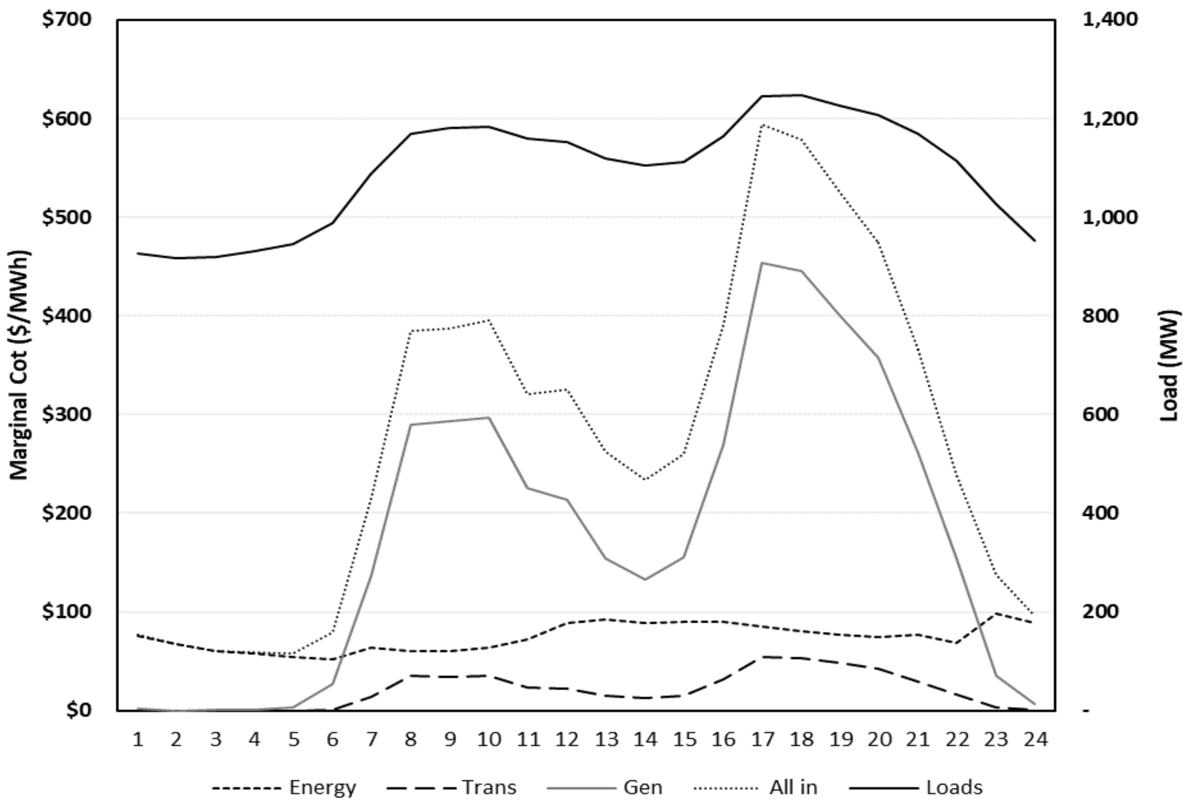
For transmission, the parameterized max function obtains remarkably different "hours count" within hours, mainly as a consequence of much lower costs per kW-year--$33.40/k-year compared to $236.26 for generation. However, the distributional pattern of capacity costs where small and trace amounts of capacity costs are similar, though transmission costs appear in somewhat fewer hours (ρ>0.77) than generation (ρ>0.80).

4.0 ALL-IN MARGINAL COSTS: HYDRO'S ISLAND INTERCONNECTED SYSTEM

As discussed, Hydro's Island Interconnected System has remarkably high concentrations of annual energy consumption during winter compared to non-winter months. January energy levels (813,880 MWh) exceeds that of July (396,823 MWh) by more than twofold. Similarly, for peak loads: The estimated 1,466 MW peak load for January is more than twice that of July (729 MW).

Marginal generation and transmission costs follow accordingly. For well-balanced but capacity constrained systems, the pattern of marginal costs closely adheres to the pattern of loads, though with greater variation. This is demonstrated most dramatically for January where annual peak loads, driven by cold temperatures, are typically experienced. Hydro's estimates of January 2021 marginal generation and transmission costs along with the typical hourly load pattern are shown below:

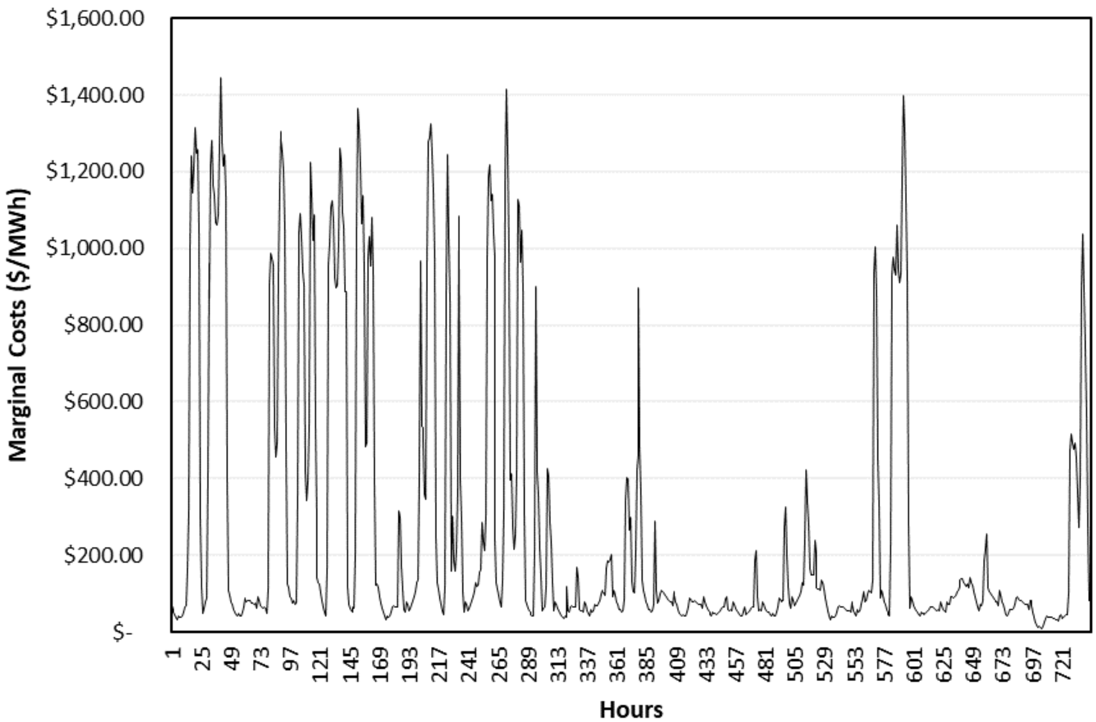
Figure 12: JANUARY 2021 AVERAGE HOURLY MARGINAL COSTS AND LOADS



For a typical January day during year 2021, estimates of the marginal costs for generation and transmission services of Hydro's Island Interconnected System reach a maximum value of approximately $600/MWh. Though with less variation, the load and marginal cost patterns for January are replicated for other winter months (December-March).

The economic costs of power systems are determined by critical properties of power systems. First, as a consequence of non-storability, the quantity of electricity production must balance with demand in real time. Second, the pattern of power flows within power networks are determined exactly according to physical laws. Thus, the economic costs can vary greatly over the course of short intervals, such as the course of weekday.

Figure 13: JANUARY 2021 HOURLY ALL-IN MARGINAL COST HYDRO'S ISLAND AND INTERCONNECTED SYSTEM



Shown for relevant timeframes for time varying tariff design—including static time-of-use and dynamic critical peak pricing—estimates of hourly marginal generation and transmission costs for Hydro's Island Interconnected System are presented below.

Figure 14: MARGINAL COST ESTIMATES, 2021 ($/MWH)
NEWFOUNDLAND AND LABRADOR HYDRO

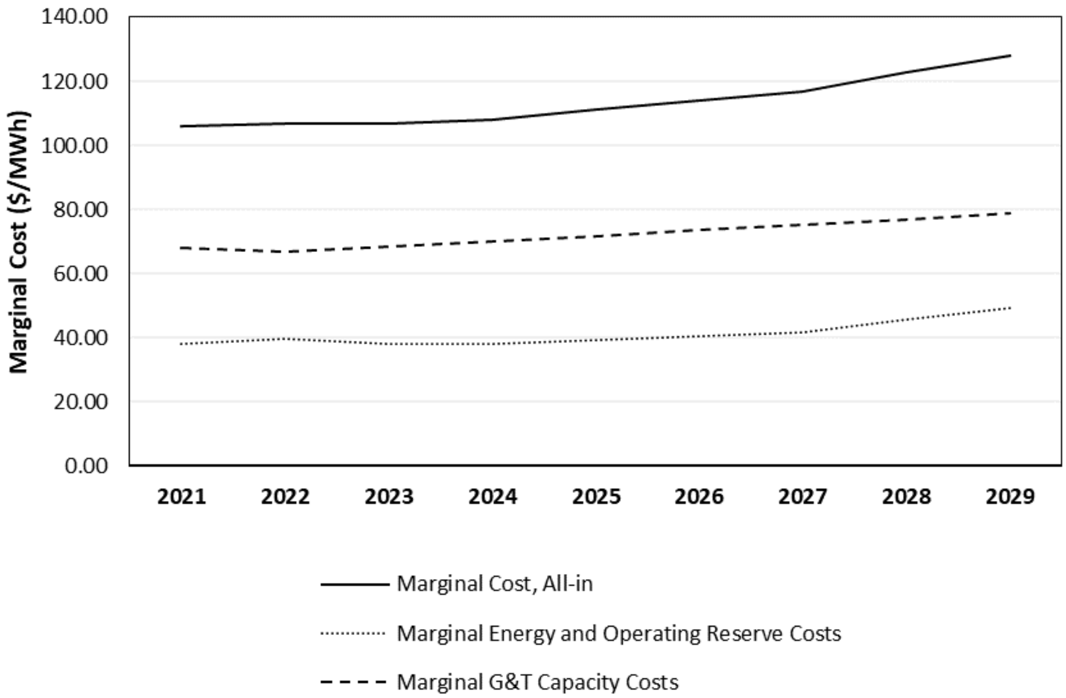
WINTER (Jan-Mar, Dec)		Energy and Operating Reserves	Generation Capacity	Transmission Capacity	All-In Marginal Costs
(2 Period Model)	*Hours Ending*				
All Hours		59.87	116.48	11.80	188.15
Peak Hours	HR 7-21	61.81	174.47	17.92	254.21
Off-Peak Hours	HR 1-6, HR 22-24	56.63	19.83	1.58	78.04
(3 Period Model)	*Hours Ending*				
All Hours		59.87	116.48	11.80	188.15
Peak Hours	HR 7-10, HR 17-21	56.05	216.30	23.00	295.35
Shoulder Hours	HR 11-16	69.49	109.58	10.21	189.27
Off-Peak Hours	HR 1-6, HR 22-24	56.41	19.77	1.59	77.76
NON WINTER (Apr-Nov)		Energy and Operating Reserves	Generation Capacity	Transmission Capacity	All-In Marginal Costs
(2-Period - Broad Peak Model)	*Hours Ending*				
All Hours		24.93	1.88	0.09	26.89
Peak Hours	HR 9-22	25.51	2.49	0.13	28.13
Off-Peak Hours	HR 1-8, HR 23-24	24.12	1.01	0.03	25.16
(2-Period - Narrow Peak Model)	*Hours Ending*				
All Hours		24.93	1.88	0.09	26.89
Peak Hours	HR 14-20	29.14	3.44	0.19	32.76
Off-Peak Hours	HR 1-13, HR 21-24	23.21	1.19	0.05	24.44

Marginal generation and transmission costs are estimated in hourly frequency and vary with respect to load level and system conditions. For well-balance power systems like the Island Interconnected System, marginal costs are highly specific to load level and timeframe, as demonstrated above. As shown, Hydro's all-in marginal costs for generation and transmission services during winter is $188.15/MWh, approximately seven times above the counterpart during spring-early winter, $26.89.

Driven by the differences in both the level and pattern of hourly loads, these large generation and transmission cost differences are a consequence of seasonal differences in each of the marginal cost components, including the short-run variable costs, energy and operating reserves, and the capacity costs of generation and transmission (generation and transmission capacity), where capacity serves as a proxy for reliability. However, much of the seasonal variable is attributable to capacity: estimates of generation and transmission capacity costs, $116.48/MWh and $11.80/MWh respectively, for winter are more than two orders of magnitude greater than the counterparts for non-winter months (<$2/MWh). Effectively, generation and transmission capacity costs of the Island Interconnected System are not present outside the winter season. Finally, it is useful to take note of the differences in all-in marginal costs within the winter season: approximately 3-to-1 cost differences are observed between peak hours ($254.21/MWh) and off-peak hours ($78.04/MWh). For the 3-period winter season, including peak, shoulder, and off-peak timeframes, peak–off peak marginal cost differences expand somewhat though, critically, the peak to off-peak cost ratio remains approximately the same.

All-in marginal costs—include energy, operating reserves, and generation and transmission capacity—over forward years 2021-2029 are expected to rise 2.3% annually. Projected marginal costs are presented below:

Figure 15: HYDRO'S MARGINAL COSTS OF GENERATION AND TRANSMISSION CAPACITY DURING PEAK HOURS, 2021-2029 ($/MWh)



Driven by an expected cost decline for energy and operating reserves, all-in marginal costs trend slighting downward through 2023, before assuming upward escalation from 2023-2029. All-in marginal costs for 2021-2029 are projected to increase by 18.7%, or somewhat faster than expected inflation. This overall trend holds for the several marginal cost components, where the costs of energy and reserves rise by 25.8% (3.2% annually), while generation and transmission capacity costs rise by 14.6% (1.8% annually). However, high rates of escalation are expected for 2023-2029, where the costs of energy and reserves, generation and transmission capacity, and all-in marginal costs are expected to rise annually by 4.2%, 2.3%, and 3.0%, respectively.

5.0 SUMMARY OF FINDINGS

Marginal costs are defined as the incremental change in total costs incurred by service providers, as a consequence of a change in load served. Estimates of marginal costs embody the cost-basis for resource decisions including conservation and demand management resources, tariff design and pricing, and cost allocation. Marginal costs are thus central to the efficient operation of power systems and markets.

Marginal costs, observed and estimated, are unusually sensitive to the level of load served and system conditions, and vary dramatically across short-term periods—hours, day-by-day. Hydro's 2018 study of marginal costs covers both generation and transmission services and is based on the methodology detailed in the 2016 Marginal Cost Study filed before the Public Utility Board. As discussed above, Hydro's marginal cost methodology assumes an internal cost approach for generation and transmission and transmission energy costs (line losses), and an opportunity cost approach for marginal energy and operating reserves. Combined, these several marginal cost elements are referred to as all-in marginal costs of generation and transmission services.

Over forward years 2021-2029, Hydro's all-in marginal costs are expected to escalate at an overall rate of 2.3%, somewhat above that of expected price inflation for the economy as a whole. Much like the 2016 Marginal Cost Study, Hydro's Marginal Cost Study Update – 2018 marginal cost estimates marginal costs in hourly frequency for selected years. This deeper look reveals substantial variation in the economic costs incurred by Hydro to provide electricity services, particularly during winter months. For January 2021, estimates of Hydro's average all-in marginal cost during winter peak hours of $254.21/MWh declines to an average of $78.04/MWh during off-peak hours—a variation of 3-to-1. The statistical variation in hourly marginal costs demonstrate similar seasonal differences: variation (standard deviation) in January hourly marginal is $374.50/MWh, while variation during May is a mere $12.69/MWh.

Newfoundland and Labrador Hydro is implementing a major transformation of its power supply system. Empirical evidence clearly indicates that Hydro's Island Interconnected System is expected to be well balanced, measured in terms of capacity supply compared to expected peak load levels. As shown above, electricity demands facing Hydro's Island Interconnected System are characterized by exceptionally high levels of season differences, with approximately 2-to-1 differences between January and mid-summer levels of energy consumption and peak demands. Indeed, short-term variation in Hydro's economic costs to serve show yet further variation, well beyond 7-to-1. These system conditions afford substantial opportunities for cost savings. To this end, Hydro is strongly encouraged to explore time-of-use tariff options.

Time-of-use tariff options, including both static and dynamic variants, set marginal prices based on marginal costs. Participating consumers are highly response to price variation. Facing high prices during timeframes when Hydro's power system is approaching capacity constraints, and low prices during timeframes of capacity sufficiency, consumers shift electricity consumption from high cost periods to low cost periods. Cost elasticities are unusually high during capacity-constrained periods—greater than five. As a consequence, measurable cost savings in the form of reduced capacity needs result therefrom. Indeed, empirical evidence suggests that modest changes in consumer demands during peak load periods can obtain large cost savings.

In summary, Hydro's Island Interconnected System's limited available capacity for 2021 forward coupled with large seasonal and day-by-day variation in loads makes for market conditions well suited to the integration of demand and supply, to be obtained through marginal cost-based pricing of electricity services.