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June 15, 2016

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

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

Dear Ms. Blundon:

Re: Rate Design Review for Newfoundland Power and Island Industrial Customers

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

Should you have any questions, please contact the undersigned.

NEWFOUNDLAND AND LABRADOR HYDRO

Tracey Pennell

Tracey L. Pennell
Senior Counsel, Regulatory

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Encl.
cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey Stirling Scales
Sheryl Nisenbaum – Praxair Canada Inc.
Thomas Johnson – Consumer Advocate
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Larry Bartlett – Teck Resources Limited

Rate Design Review

for

Newfoundland and Labrador Hydro

by

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June 15, 2016

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EXECUTIVE SUMMARY

Context

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

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

Design Objectives and Current Designs

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

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

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

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

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

Design Alternatives

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

<u>Blocked Designs</u>

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

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

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

Two-Part Pricing

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

Additional Design Features

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

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

Design Recommendations

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

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

Rate Design Review

for
Newfoundland and Labrador Hydro

by
CHRISTENSEN ASSOCIATES ENERGY CONSULTING, LLC

June 15, 2016

1. INTRODUCTION

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

3. NLH'S CURRENT RATES AND RIDERS

3.1 Rate and Rider Descriptions

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

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

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

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

3.1.1 Utility Tariff

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

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

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

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

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

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

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

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

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

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

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

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

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

3.1.2 Industrial Tariff

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

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

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

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

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

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

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

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

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

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

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

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

3.1.3 Rate Stabilization Plan

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

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

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

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

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

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

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

3.2 Rate Design Issues

3.2.1 Main Design Considerations

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

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

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

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

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

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

3.2.2 The Role of Marginal Costs

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

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

3.2.3 Customer Site Generation Resources

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

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

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

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

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

4. ALTERNATIVE DESIGN CANDIDATES

4.1 NLH's Rate Design Objectives

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

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

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

- Be simple, understandable, and acceptable
- Minimize controversy

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

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

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

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

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

4.2 Alternative I. Modified Current Rate Structures

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

4.2.1 Utility Rate

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

4.2.2 Tail Block Pricing Issues

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

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

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[19] The chosen boundary would need to be set to avoid weather-related reductions.

NLH will need to update its deferral account recovery mechanism value annually, which would also be an advantageous time to update the coming year's tail block price. However, since wholesale market conditions can change rapidly and significantly, it appears that more frequent opportunities to change the price would be beneficial to both NLH and Newfoundland Power. Perhaps a seasonal price, delivered 60 days before the start of a season, would provide sufficient accuracy and advance notice for pricing by Newfoundland Power. Shorter notice than that of the tariff sheet (which normally changes only with a rate case) can benefit both parties. NLH minimizes discrepancies between price and marginal cost and Newfoundland Power gets pricing that is as close to actual market prices as possible. The risk of price increase is balanced by the opportunity to benefit from price reductions soon after they occur in wholesale markets.

Regarding the selection of alternatives to a flat annual tail block price, there is no best time configuration for the second block price. Simplicity suggests that NLH offer Newfoundland Power a single price for all hours, while pricing precision suggests the use of RTP with hourly prices based on hourly marginal costs or wholesale prices. In offering prices with less frequent variation and greater advance notice, NLH provides Newfoundland Power and its customers with rate simplification and risk management services. Nonetheless, hourly pricing can be mutually beneficial to NLH, Newfoundland Power, and its customers in certain situations, such as when interruptible customers need to be called; but prices announced in advance via tariff sheets or regular postings with regulatory approval should suffice for most circumstances. It would be advisable to consider the range of price alternatives between a flat annual price and hourly pricing.

We reviewed the pattern of expected marginal costs via software that CA Energy Consulting has used to design time-of-use (TOU) pricing for many years. We investigated alternative seasons and two- and three-period TOU configurations. Based on our investigation, we concluded that marginal costs, and thus tail block pricing, should be seasonal but need not include a TOU component.[20]

It appears that a four-month winter season (December through March), a two-month summer season (July and August), and a spring/fall season containing the remaining six months provide the greatest degree of marginal cost similarity within seasons and thus offer meaningful differentiation between seasons. Table 1, below, provides the marginal cost results of this investigation. The appendix, Expected Marginal Cost Variability at NLH, reports fully on this investigation.

Table 1
Forecasted Marginal Cost Patterns at NLH – 2019

Season	Months	Average Marginal Cost ($/MWh)			MC Ratio	Peak Seasonal MC Ratio	
		Peak	Off-Peak	All Hours	P/O	vs. Spr/Fall	vs. Winter
Winter	12, 1, 2, 3	$ 59.41	$ 44.03	$ 50.56	1.35	1.27	1.00
Summer	7, 8	$ 78.50	$ 47.48	$ 59.70	1.65	**1.68**	**1.32**
Spr/Fall	4, 5, 6, 9, 10, 11	$ 46.85	$ 35.68	$ 40.87	1.31	1.00	0.79

This recommendation regarding time variation in pricing is tempered by awareness that NLH or Newfoundland Power may prefer simpler (all-year pricing) or more accurate (TOU or real-time) pricing. As mentioned above, we propose that these seasonal second block prices be updated at least annually, according to a mutually agreed schedule, and based on a formula that converts NLH's marginal cost forecast into a seasonal price.[21]

4.2.3 Industrial Rate

Option A. Current Structure, Modified Prices. NLH could retain the current structure, in which demand and the firm energy charge strive to recover required revenues. Customers who exceed their Power on Order may acquire power, if available, via non-firm pricing based on

[20] To deal with sudden shortage conditions, however, it would be helpful if the Utility rate included occasional real-time pricing or critical-peak pricing as described below.

[21] Annual adjustment could be aligned with annual changes to the value of the deferral account recovery mechanism. NP would then have known prices for its own ratemaking becoming available at a predictable time.

marginal cost. In principle, changing the demand and energy prices would suffice to update the rate. The advantages of this approach are that expected embedded costs are recovered fully, demand-related costs are recovered in a demand charge, and the structure is familiar to the customer, NLH, and the PUB. A leading disadvantage is that the marginal price is not commonly based on marginal cost, since non-firm power is not always used. Additionally, revenue recovery of costs that will be increasingly fixed will nonetheless depend upon volumetric pricing to some significant degree. It appears that the current design could be improved, perhaps while enhancing its blocked pricing structure.

Option B. Modified Block Boundary. One way to reduce variability of revenue recovery is to move the block boundary, currently defined by Power on Order, so that all customers consume above that level in (almost) every month. For example, defining the boundary as, say, 80% of the class average load factor multiplied by Power on Order would ensure that most customers reach the second block in most months. The boundary would change with changes in the Power on Order amount. In brief, the block boundary would be customer-specific but the block 1 price would be uniform across customers.

The price for the first block—embedded costs divided by adjusted forecasted energy—ensures full revenue recovery of embedded costs, as determined in the COS study, provided that usage does not fall below the block boundary. Below that boundary, the marginal rate becomes the embedded cost rate, which would likely be above the marginal cost rate. Load reduction would cut into required revenues and leave NLH with a revenue shortfall. Such shortfalls (and offsetting over-collections when loads are above forecast) are a normal part of embedded cost-based pricing. In this case, with no or very low margins being earned by NLH on load increases, shortfalls become problematic.

The price for the second block will be based on marginal cost, as in the modified Utility rate. Again, the rate should be seasonal but need not be time-varying over the course of the day. The outcome of this design is to offer Industrial customers marginal cost-based pricing at almost all times.

This option improves upon Option A by enhancing the likelihood of full revenue recovery and improving the marginal price seen by the customer. The design may create an issue by converting energy sales above the block boundary to firm sales. This challenge may be met with either quantity rationing—a rule setting an upper limit on tail block energy without gaining prior approval, or perhaps adjusting the Power on Order quantity—or price rationing—the use of RTP in critical-peak hours to signal a need to constrain usage.[22]

Possible disadvantages of this option include the need to compute and communicate customer-specific block boundaries, along with the retention of the revenue recovery variability inherent in a demand charge. As mentioned in the utility rate section above, demand prices based on embedded costs can be awkward price signals.

Option C. Hours-of-Use Demand Pricing. A modification of the block pricing design that may simplify it operationally is to use an hours-of-use demand (HUD) tariff. This long-established design is just a customer-specific blocked tariff, with the block boundary being determined by the customer's load factor and Power on Order. For example, a customer with 1 MW of peak demand facing a rate with a block boundary of 365 hours of use (half of 730 hours, which is approximately an average month's total hours) would have half their load priced at the first-block price and the remainder at the tail block price. Typically, there is no demand charge in an HUD tariff, but it can be used if desired.

In the Industrial class's case, NLH could select a block boundary in terms of hours of use that virtually guarantees that all customers will have some block 2 usage in each month. If a 70% load factor achieves this objective, then the block boundary would be 511 hours of use (70% of a 730-hour month). Since the HUD tariff has no demand charge and customer-related costs are recovered by Specifically Assigned Charges, the first-block energy price would equal revenue requirements for the class divided by forecasted class first-block usage, which equals total Power on Order multiplied by 511.

[22] More on critical-peak pricing appears below.

This approach to design produces full revenue recovery, provided that the customer consumes enough to get to the block boundary and that the tail block has a marginal cost-based price. Essentially, the first-block charge becomes a lump-sum charge. Only in cases when usage declines substantially relative to normal levels does less than full revenue recovery occur. Customers would see a rate that charges a total bill on the basis of load factor: high load factor customers would have a large share of load in the tail block while lower load factor customers would have a smaller share. This is in line with standard ratemaking practice. Customer bills would be relatively stable given stable consumption patterns, and average price would not change drastically with moderate changes in consumption.

Practitioners sometimes criticize the HUD design for apparent lack of clarity of price where usage approaches peak demand. Especially if the billed demand amount is ratcheted, the cost of exceeding this level can be high and long-lasting. Barring this criticism, the marginal price is clear.

In NLH's case, this criticism does not appear to apply with as much force, as customers are accustomed to respecting the Power on Order level, unless attempting to use non-firm or secondary power. NLH could make this design simpler still, by making peak demand equal to Power on Order and not charging for levels of demand above it. Retaining the link to actual billed demand, perhaps with a ratchet structure, would achieve the effect of limiting increases in peak demand if NLH feels that customers need a signal to limit flows on their customer-specific transmission line segments. However, this would lead to over- or under-collection of required revenues and complicate the marginal price in the tail block in the same manner as would a demand charge.

4.3 Alternative II: "Two-Part Pricing"[23]

The block pricing concept can be modified to produce a more formal segmentation between recovery of embedded costs and marginal cost pricing. Two-part pricing achieves this objective

[23] The "two-part pricing" label is potentially confusion to some readers. Traditional ratemaking sometimes refers to a tariff with a customer and an energy charge as two-part pricing. The version used here is in harmony with that

by establishing a bill that consists of a lump-sum Base Bill and an Incremental Energy Charge. The Base Bill is simply the cost allocated to the customer by the COS study divided by a forecasted or contract quantity, with the annual dollar assessment being divided into monthly amounts in some sensible fashion (*e.g.* equal per-hour amounts or equal per-month amounts). The Base Bill does not vary with current usage or peak demand.

Underlying the Base Bill is a contract quantity of usage for the billing period. Departures from the contract quantity, up or down, produce charges or credits based on a marginal cost-based price. Because the marginal price of the Incremental Energy Charge operates in both directions (increased and decreased usage) for any amount of usage, it is not necessary to scale back usage to create a block boundary that makes it unlikely that a customer will fall short of the boundary, as is the case in block pricing. Under this arrangement, actual usage may exceed or fall short of the forecast value and the Incremental Energy Charge can be positive or negative.

The two-part pricing structure creates a billing environment that is quite similar to the blocked tariff described in the preceding section. Customers pay their embedded cost obligation in one (dominant) lump sum and then pay for increases in usage, or obtain bill reductions from decreases in usage, at a marginal price that matches the forecasted marginal cost to serve additional load.

As with tail-block pricing for the blocked tariff designs, seasonal pricing and regular revision of prices to reflect market conditions are desirable properties for encouraging price efficiency.

Two-part pricing can be utilized with varying duration of pricing periods. In its simplest form, the contractual usage, or “customer baseline load” (CBL) can be a total usage amount for each billing period. The Base Bill is just revenue requirements for the billing period divided by the CBL amount. Departures from that amount are priced at the (seasonal average) marginal prices described immediately above. This simple version of two-part pricing, which is close in spirit to

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definition, in that the bill has two lines; they just differ from the lines of the original definition in that that base bill is a customer-specific customer charge.

the block design described above, will serve for the discussion of a basic two-part pricing product immediately below. Variants of the concept, RTP and occasional RTP appear below, with suggestions for their use.

4.3.1 Utility Rate

A simple two-part design develops a monthly CBL for Newfoundland Power by applying its forecasted annual usage total to each billing period by means of Newfoundland Power's historical pattern of monthly usage. (Weather normalization or averaging of recent years' monthly totals can be applied to development of reasonable monthly usage shares of the annual total.) Annual revenue requirements could be divided into monthly amounts in two ways. A simple approach would place one-twelfth of the annual amount in each month, a plan that conforms well with NLH's pattern of fixed costs. An alternative approach would involve dividing the annual total into monthly values based on monthly CBL usage share, yielding an even per-kWh cost across months. This approach is more complicated for both parties, but would benefit the customer, possibly, by creating a bill obligation that conforms approximately to its revenue pattern. The first approach seems preferable, as it better reflects NLH's pattern of costs. The price for the Incremental Energy Charge is a seasonal average marginal cost, as with the blocked tariff.

The advantages of this structure are that embedded costs are recovered fully, with exactitude, as they are independent of customer behavior; all changes in load of any size are priced at marginal cost; and the bill structure is simple, lacking a demand charge. The disadvantages of two-part pricing are that the absence of a demand charge eliminates a source of revenue growth as customers grow for whatever reason; and the rate design is potentially novel to the customer and to other parties, including NLH.

As with the blocked tariff, the challenge in determining revenue requirements under two-part pricing is to establish forecasted usage as the basis for cost to serve. With embedded cost predicted to be substantially above marginal cost, Newfoundland Power has an incentive to under-forecast usage, but perhaps to no greater extent than it has in the past.

NLH faces the challenge of establishing a CBL sufficient to recover costs not merely in the test year, but in subsequent years. Between rate cases NLH's obligation to pay for the MF project rises steadily according to a predetermined schedule. As at other utilities, other costs move upward over time as well. The assumption that supports rate stability at most utilities is that load growth provides the extra revenue necessary to cover gradually increasing fixed and variable costs. At NLH, for a base bill to achieve this effect, the CBL must adjust with time, either according to a multi-year forecast determined at the time of a rate case or a single-year forecast, updated annually. Unit costs established in the COS study associated with each rate case will then produce cost recovery associated with changes in Newfoundland Power's market size.

4.3.2 Industrial Rate

In a simple two-part design for Industrial customers, the CBL would be based on the same approach as the block boundary of the blocked tariff: adjusting the customer's Power on Order for load factor. In this case, the boundary does not need to be adjusted below this forecasted level since the marginal price applies on both sides of the CBL.

As with the Utility two-part rate, the advantages of this structure are that embedded costs are recovered fully, with exactitude, as they are independent of customer behavior; all changes in load of any size are priced at marginal cost; and the bill structure is simple, lacking a demand charge. The disadvantages of two-part pricing are that the absence of a demand charge eliminates a source of revenue growth as customers grow for whatever reason; and the product is potentially novel to the customer and to others, including NLH.

One criticism of the simple design, shared with the blocked tariff lacking a demand charge, is the absence of a signal to control peak demand. Price and quantity rationing can be applied here as well, along the lines mentioned: setting a quantity limit or adopting a short-notice price signal indicating supply constraints. However, at NLH, the customers of the Industrial class manage their own load requirements via the Power on Order approach, with adjustments influencing future revenue requirements even in the absence of a demand charge. This is in contrast to utilities where large customers are each responsible for a smaller share of utility sales than is the case here, and demand charges are a vehicle for signaling load requirements individually and for the class.

Industrial customers do not face the same issue of load growth that the Utility rate faces. NLH's Industrial customers may have variable loads but are not generally characterized by steady increases in consumption. A contractual CBL derived from Power on Order likely would suffice for cost recovery related to quantity.

4.3.3 Two-Part Real-Time Pricing

Two-part pricing is used predominantly in regulated service territories to support RTP as a voluntary service option for large customers. Two-part RTP consists of a base bill developed by applying a customer's current standard tariff to the historical usage and peak demand quantities that make up the CBL, with usage being defined as an hourly load profile. The Incremental Energy Charge is based on the sum over a billing period of hourly marginal cost-based prices (revealed on the preceding business day) multiplied by the hourly differences between actual usage and the CBL. RTP prices are generally delivered by utilities to their customers on the preceding business day. This short-notice structure provides accurate price representations of system conditions.

Two-part RTP creates a direct link for retail customers to market price/marginal cost while collecting embedded costs via the base bill. In principle, such a rate could be offered to both Newfoundland Power and NLH's Industrial customers. Those NLH Industrial and Newfoundland Power large general service customers with strong energy management capabilities might find RTP to be a useful option since load management actions might help to reduce incremental costs.

RTP has advantages that derive from improved price efficiency and the creation of opportunities for demand response. The product's disadvantages are administrative for both the utility and the customer: data management, billing, and customer support capabilities must all be enhanced, as must customer energy management capabilities if price response is to be secured.

Illustration: Service to Corner Brook Pulp and Paper

CBPP represents possibly NLH's most complex customer service challenge due to the unusual nature of its circumstances. The customer operates a mill that is served in part by its own hydraulic generation, with NLH providing remaining needs. (A cogeneration unit on site provides energy fed to NLH.) Complicating service further is the presence of 50-Hz generation and consumption on site, linked to 60-Hz lines by a frequency converter owned by NLH. NLH currently supplies 8 MW of firm power under the Power on Order arrangements of the Industrial rate. Excess 50-Hz power at the site is "trapped" lost through spill, or used in the customer's electric steam boiler.

At present, NLH can provide several different types of energy to CBPP: firm power, interruptible, generation outage (to support CBPP in the event of generator failure at their site) oil-fired boiler replacement (for the same purpose), secondary, and frequency converter replacement. NLH can also make capacity assistance requests of CBPP (through load interruption at the mill), as noted, and can obtain supplemental capacity assistance, through separate arrangements. Each of these types of supply operates under its own contractual limitations. As well, non-firm energy pricing depends on the supply source available to serve the load, if the load can actually be served.

CBPP's generation no longer needs to follow its load with the purpose of minimizing demand billed by NLH. A pilot generation credit agreement dating from 2009 enables this improvement in pricing efficiency.[24] For the present, this agreement appears to be a useful pricing incentive that is beneficial to CBPP, inducing efficiencies in the operation of their facilities.

In the future, it appears that a two-part pricing structure with hourly real-time prices might be able to simplify the contractual relationship, including the generation credit provision. The

[24] PUB Order No. P.U. 4(2012).

two-part structure could involve occasional RTP service in critical-peak hours only, a design set out in the next section below, or all-hours RTP, as described above. Since CBPP operates its own customer site generation, it provides a useful example of a situation in which all-hours RTP might be beneficial to the customer and to NLH.

CBPP could have a CBL based on its current Power on Order, multiplied by historical load factor (but backing out capacity assistance and interruptible load relief from the load profile) and, when priced at embedded cost, covers revenue requirements. (The CBL would continue to treat peak demand in the same manner as the pilot agreement, namely eliminating the need for CBPP to use generation to follow load.) All departures from the hourly CBL would be priced at day-ahead hourly RTP price. Variations in this price would indicate changes in all NLH system circumstances. CBPP could evaluate the RTP price pattern to evaluate how to operate its generation and mill to maximize value. Should a generator outage or other supply emergency occur, pricing would be available to evaluate how to respond. A low price would indicate that it would be cost effective to purchase more energy from NLH. A high price might cause CBPP to consider increasing its own supply or to cut production.

High prices in hours of very low system reserves likely will suffice to limit usage, but NLH may still need to impose availability limitations of the sort in place at the moment. However, it is possible that the contractual circumstances could be simplified.

Current contracting produces an arrangement that might appear to be unusual: the generation credit approach allows CBPP to exceed its firm demand level without having to pay for interruptible power. In return, CBPP is able to manage its hydraulic resources more efficiently. In addition, NLH can call on CBPP to maximize its generation to provide additional capacity to the grid (to the extent that it is available at the time of the request) under these arrangements. One way to view the two-part RTP concept is see it as gathering up all types of energy and pricing, and all operational commitments, and converting them into a price guideline that the customer then uses for its own planning purposes.

From the customer's point of view, this structure would transfer into their control decisions about mill consumption patterns and levels and hydraulic facility operation. RTP prices would show day-ahead (or hour-ahead if desired) system conditions and assist CBPP to get the most value possible from both facilities. Day-ahead notice is used elsewhere to assist energy-intensive facilities to plan site production and associated energy consumption levels and to control costs.

The RTP price provides an automatic signal for requesting load relief, as well, and the marginal cost-based price provides a market-based means of remunerating customers. Instead of paying customers the up-front credit and a fixed price during capacity requests, NLH would reimburse the customer using prices closer to market values. Payment could be entirely related to actual energy delivery relative to the CBL or there could be a small payment for participation (per kW). While high RTP prices might still come during the winter season predominantly, reflecting NLH system conditions, high prices at any time of year might afford an opportunity to CBPP to reduce energy costs by temporarily reducing load or increasing supply.

Additionally, this structure could include the sale of secondary energy, hitherto to Newfoundland Power, but perhaps transferred to NLH, with marginal cost-based settlement provisions with Newfoundland Power, if needed.

This arrangement would require review and approval by several parties: the customer, NLH, the PUB, and Newfoundland Power.

4.4 Peak-Hour Pricing Riders

Both blocked and the simple version of two-part pricing may be enhanced by inclusion of a peak-hour pricing rider. This could be in the form of occasional real-time pricing (ORTP) or "critical-peak" pricing (CPP). Under either ORTP or CPP, the second block price for hours with acute shortage conditions would be replaced by high prices based upon the power system's day-ahead or real-time marginal costs (for ORTP) or upon a longer-term forecast of critical-peak hour marginal costs (for CPP). Under block pricing, customers would pay this high price for all consumption above the block boundary. Under two-part pricing, customers would pay this high price for all consumption above the CBL and would receive this price for all power “sold back” to NLH by consuming energy below the CBL. ORTP and CPP tariffs have a history of reliably inducing demand response in the North American jurisdictions that have adopted them.

Newfoundland Power could use an ORTP arrangement to support its interruptible rate offerings in a manner that updates pricing from traditional methods. Instead of paying customers in advance for availability via a demand charge discount but not providing reimbursement for actual load relief, the utility could offer a reduced or zero credit for availability and a marginal cost-based price for load relief. The reduction in the customer’s bill due to price response during critical periods would match the reduction in Newfoundland Power’s costs.

4.5 Revenue Recovery between Rate Cases

Utilities under traditional rate regulation share a common challenge of a growing mismatch between revenues and costs as the most recent general rate case fades into history. Cost to serve increases as input prices and output quantities change, and falls as utilities find new cos-cutting efficiencies. Normally volumetric rates priced at embedded cost provide some coverage as load grows between rate cases. However, rates that recover revenues in a non-volumetric fashion, or based on volumes that don’t change over time, cannot take advantage of load growth for recovery of growing costs.

A high proportion of NLH’s costs will be fixed after the MF project is on-line. However, certain contractual payments are scheduled to grow over time. If regulation is applied in the traditional fashion, even though a forward test year is used, revenue recovery under both the blocked and two-part tariffs will not increase.

Some cost increases will be recovered through the deferral account recovery mechanism. These costs will consist of departures from forecasted values of operation and maintenance expense and other charges, along with cost variations related to hydrology and purchased power. However, scheduled increases in MF project payments may not be fully incorporated in cost recovery and the proposed designs, based on sound rate design principles, provide some cost exposure. Systematic under-collection of required revenues is likelier than at most utilities.

Below are some candidate solutions, or partial solutions.

- Block boundaries or CBLs could be adjusted annually in response to customer forecasts (Newfoundland Power) or Power on Order nominations (Industrial customers) and the associated revenues scaled up/down proportionally. This might happen as a matter of course for the Industrial customers but not for Newfoundland Power.
  - This plan operates under a possibly flawed assumption, that cost to serve would expand proportionately with load. However, with reasonably timely rate cases, this error is not likely to be large.
- The PUB could order that rate cases consist of multi-year COS studies which would result in multi-year pricing.
  - This plan would potentially be administratively burdensome.
- NLH could investigate formulary rate plans that set boundaries on rate of return and provide automatic price adjustments when returns are outside a range of return rates.
  - This approach permits greater time between rate cases as well as providing risk management for the utility in a structured fashion.

4.6 Review of Additional Tariff Components

4.6.1 Utility Rate

The Utility rate includes credits for Newfoundland Power's ability to meet peak demand with its own hydraulic and thermal generation, and a credit for Newfoundland Power customers' ability to provide interruptible load upon demand. The rate also makes provision for sale of secondary energy by CBPP to Newfoundland Power.

As mentioned in the recent COS Methodology report, the change in the supply situation following completion of the MF project has caused NLH to review the value of Newfoundland Power's generation in meeting peak demand. A possible means of addressing this issue is to price energy sold by Newfoundland Power to NLH in accordance with marginal cost, after adjusting for losses. The marginal cost-based price would need to be hourly, preferably hour-ahead or day-ahead to reflect system conditions as accurately as possible. Since NLH would call for power in conditions of low system reserves (conceivably due to a loss of transmission capability or extreme conditions in the Eastern Interconnection) the marginal cost-based offer likely would be quite high, at a level that calls forth demand response in North American RTOs. This price signal is efficient in terms of inducing Newfoundland Power to provide energy to the grid when it is most valuable (subject to any technical constraints). NLH would thus offers pricing to Newfoundland Power on the basis of pricing that it would offer to an independent power producer. This method of reimbursement would replace a payment for capacity (and remove or reduce the need for Newfoundland Power to demonstrate ability to provide such capacity) and would also offer a marginal cost-based price for energy to replace the zero payment for hydraulic energy and the fuel price based on Newfoundland Power's fuel costs for thermal energy.

Similarly, the secondary energy payment by Newfoundland Power to CBPP could be placed on a market value basis by replacing the firming up charge with marginal cost-based remuneration. This approach would permit separation of the two transactions of energy sale to CBPP and energy purchase from CBPP. For energy sales, NLH would establish annual revenue requirements and a CBL reflecting CBPP's historical usage in the absence of secondary energy provision. CBPP could select an ORTP or RTP design to support its ability to provide interruptible energy and then could provide secondary energy under similar pricing as a separate line item. NLH could purchase this energy at a marginal cost-based price, simplifying the current transaction structure that includes Newfoundland Power, provided that all parties approve of the move to a revised arrangement.

4.6.2 Industrial Rate

The terms of each Industrial customer's Power Service Agreement usually include the opportunity to purchase power, when available, in excess of the level of their Power on Order. This energy has two types: non-firm (interruptible) and secondary. The former refers to the type of power commonly available beyond NLH's firm commitment to deliver, while the latter refers to power available only in circumstances in which spilling water is very likely. NLH can allow for sales of both types of power within the context of any of the three main alternatives for core sales of energy by making use of marginal cost-based pricing available at short notice (e.g. day-ahead or even hour-ahead).

Under an ORTP pricing arrangement, in most hours, NLH would sell energy at the marginal cost-based seasonal rate. In cases of extremely low reserves (and associated high marginal costs) an ORTP structure would offer customers a chance to reduce usage in return for a billing credit at the high marginal cost-based price for critical-peak hours. In such hours, purchases above the CBL (as defined by Power on Order and historical load factor) would be made at the high price, while reductions in usage to any level would produce bill reductions at the same high price. In effect, the ORTP structure replaces a blocked tariff with a two-part tariff during extreme hours, or it replaces average seasonal marginal cost-based pricing of the two-part tariff with RTP.

This same approach could be used in water spill conditions, only this time the marginal cost-based price would be extremely low. Customers could increase their usage in the short term at the very low marginal cost-based price.

The ORTP concept can also be used to replace the current capacity assistance agreements, which offer load relief to NLH at the cost of substantial capacity payments. The payments could be reduced or eliminated, and short-notice energy payments for load reduction below a contractually agreed CBL (likely the Power on Offer level multiplied by historical load factor). Marginal cost-based prices would then determine the value of payment for load relief.

This alternative is applicable not only for cases of load reduction, but also for customer-site generation services. The pricing arrangements would be improved by the removal of large capacity payments for availability and by conversion of all payments for load relief, of whatever form, to a marginal cost-based hourly price determined either on a day-ahead or hour-ahead basis.

This structure may offer pricing benefits for NLH with its Nalcor affiliates, where contracting for certain loads is priced at an annual average of market prices. Since the degree of utilization of critical-peak pricing can vary widely from year to year, depending on weather, grid conditions, and conditions in other jurisdictions, it may be stabilizing to exclude departures from CBL and the cash flows between NLH and its customers from the transaction balances used to calculate annual average prices. The ORTP approach naturally generates the accounting quantities, prices and transaction values, which can then be netted against other trade values between NLH and the Nalcor affiliates. By removing transactions in the tail of the price distribution, this will help to stabilize the average covering the vast bulk of such transactions.

5. DESIGN RECOMMENDATIONS

The impetus for rate design modification at NLH is the increased share of costs that are fixed following completion of the MF project and interconnection with the grid of eastern North America. This review has presented rate design alternatives that appear best suited to meeting NLH's rate design objectives. Prominent among these objectives are overall revenue recovery and efficient pricing. In the past, NLH has striven to achieve these objectives by means of variants of blocked pricing, in which the first block recovers the bulk of forecasted revenue requirements and the tail block covers marginal cost.

In pursuit of other rate design objectives (rate stability, simplicity, minimal controversy, etc.) this report first explored designs close to block pricing. We then reviewed two-part pricing, which offers a structure similar to block pricing but with a marginal price that applies to all departures in usage from forecasted (CBL) usage, as opposed to load changes down to the block boundary in blocked pricing designs.

5.1 Utility Rate

The two-part design appears to allow NLH to avoid the weaknesses of the blocked design, and we recommend that NLH explore this design in detail. Both designs are similar in structure, so both parties and other stakeholders should not find two-part pricing excessively novel. Both designs recover revenue in a lump sum (two-part pricing) or in charges that are very close to a lump sum (the block 1 energy charge and demand charge of block pricing). In particular, the two-part design can be used to eliminate the complicating effect of the demand charge, a feature that may be appealing to both parties.

It would be feasible, but problematic to continue the current tariff structure, even with modified pricing. The structure itself appears capable of meeting both NLH's and Newfoundland

Power's needs following completion of the MF project. However, since we recommend that NLH request the ability to update its tail block structure regularly, and since such changes will modestly affect the first-block price, the design appears to be potentially administratively cumbersome for NLH, and possibly troublesome for Newfoundland Power.

If the blocked design is retained, it appears that simplifying the tariff by making the demand charge a function of forecasted rather than actual billing quantities would reduce variability in revenue recovery and simplify the price signal. Complicating the tariff by introducing monthly block boundaries might be worthwhile if the likelihood of NLH experiencing load reductions beyond the block boundary is materially reduced. Additionally, if the block design is preferred, the determination of billing demand can largely be retained, if desired, with adjustment for the elimination of generation credit and curtailable credit, if NLH gains approval for this change as part of its repricing of site generation and curtailable service support.

NLH should offer support for site generation at Newfoundland Power by means of day-ahead or hour-ahead real-time pricing based on its marginal cost, adjusting for losses. NLH will need to state its components of marginal cost and have a defined approach to their calculation. Current methods of dispatching Newfoundland Power's generation appear compatible with this pricing arrangement, and the pricing offers the downstream utility a market price for any sales.

NLH should offer support for Newfoundland Power's curtailable load program by means of an occasional RTP structure. This structure will pay an hourly market price to Newfoundland Power for load reductions by its customers. Newfoundland Power should be able to document the load changes based on its preferred tariff design.

5.2 Industrial Rate

The Industrial customers' current rate structure does not provide the opportunity for tail block consumption of firm energy to be priced to reflect marginal costs. Customers currently see the marginal cost signal if they increase their demand requirements above their Power on Order. A two-part rate design appears to be a relatively simple design in this case, despite its apparent novelty.

A central issue with two-part pricing for Industrial customers is the determination of customer-specific revenue requirement. Class revenue requirement is available in the COS study. Each customer's forecast of Power on Order and historical load factor leads to a forecasted total of usage for each customer and the class as a whole. Combined with unit costs from the COS study, individual customer revenue requirements may be developed, reconciling to total revenue requirement as a last step.

Each customer can have a customer-specific lump sum developed for each year or a Base Bill can be created from unit cost-based demand and energy prices applied to CBL values of demand and energy. The outcome is a customer-specific lump-sum charge in each month. High load factor customers would have a Base Bill with a lower implicit average price for the CBL than that of a customer with a lower load factor.

An Incremental Energy Charge with seasonal pricing should suffice. NLH should offer as an option either RTP or ORTP to encourage load relief from those capable of price response. These options require hourly definition of a CBL (which could just be a single value for all hours, if this reflects the customer's load profile). The extra administrative cost would be balanced by reduced cost to serve in critical-peak hours.

This hourly pricing option also permits continuation of the non-firm and secondary energy structures on a simpler basis, namely hourly marginal cost-based pricing. (Secondary energy would be reflected in very low hourly pricing.)

NLH can treat customer site generation in the same manner as it treats Newfoundland Power's owned generation: hourly pricing would support current practices for calling upon this generation and would provide market-based compensation. The illustration of a two-part RTP application for CBPP demonstrated the potential for simplification of a variety of special service conditions that can be achieved with an ongoing hourly pricing scheme.

If customers are wary of the two-part design, NLH could offer an HUD design, as its incentive properties are similar to those of two-part pricing. However, the HUD design may appear more complex than the two-part design to customers. The design also appears to be slightly more complex to administer from NLH's perspective, although selecting an initial hours-of-use boundary will require some work.

These design ideas likely will require review by interested parties, whose expression of preferences may suggest alterations in structure and pricing. For example, customers may prefer non-seasonal pricing of the tail block. NLH can offer this extra level of risk management, but should charge the premium necessary to cover the extra costs of less efficient pricing.

APPENDIX: EXPECTED MARGINAL COST VARIABILITY AT NLH

A pricing issue that arises as a result of the completion of the MF project is whether Newfoundland and Labrador Hydro (NLH) should introduce time variation in its rates. We have used our PRIOPT (Price Optimization) model to evaluate possible seasonal and time-of-use (TOU) pricing patterns that might be adopted, based on the pattern of forecasted marginal costs for the year 2019, which is anticipated to be the first full year of service following the completion of the MF project.

NLH's current rates for its utility customer, Newfoundland Power, and its industrial customers (IC) do not have seasonal or TOU price patterns. They feature a block pattern that includes marginal cost pricing in the tail block, with marginal cost being defined by Holyrood TGS. Since NLH will be linking to the Eastern Interconnection and ceasing to use Holyrood TGS for more than power quality, marginal cost will now become more variable and based on wholesale market conditions (in the absence of transmission constraints). The issue is whether the variability of marginal costs should result in time-varying pricing, especially where price is based on marginal cost.

APPROACH

CA Energy Consulting has developed a model, PRIOPT, that allows the analyst to evaluate a broad range of alternative time period configurations and discover the TOU pattern that meets the criterion of minimizing within-period variance. That is, this criterion searches across all possible price periods that have been designated feasible by the analyst and seeks to discover the configuration in which hourly marginal costs within each pricing period are as similar as possible and average marginal costs between pricing periods are as different as possible.

The analyst identifies each day by day type (weekday or weekend/holiday, by season) picks the seasonal pattern, selects whether a two-period (peak/off-peak) or three-period (peak/shoulder/off-peak) model will be run, optionally selects hours that should be defined in advance as peak or off-peak (to cut down search time), and runs the model. The model outputs are: 1) the time pattern in each season that minimizes the sum of within-period variances; and 2) the load-weighted marginal cost in each time period.

The data that the PRIOPT model uses consist of a year of hourly interval data for the class whose load is to be priced and an hourly vector of forecasted system marginal costs. In this case, the model was run for the Newfoundland Power and IC classes for calendar 2019. The marginal costs used here were generated jointly by NLH and CA Energy Consulting as part of the marginal costing analysis, and represent the scenario thought to be most likely, namely regular access to the New York and New England wholesale energy, reserves, and capacity markets in 2019.

SCENARIOS

We explored both two- and three-period models, and evaluated a range of seasonal scenarios, but always included three seasons: winter, summer, and “spring/fall.” We considered first a three-month winter (December–February) and three-month summer (June–August) based on visual inspection of monthly marginal cost patterns. By similar inspection, we also restricted hours 1–4 and 23–24 to be off-peak, but allowed all other hours to be selected by the model. We assumed that all weekends and holidays are off-peak. (This is a conventional assumption.) Holidays were selected with reference to the NL shop closure calendar.

MODEL RESULTS

We considered first the three-month summer and winter two-pricing-period scenario, which produced results that involved a long peak period in all three seasons, although of varying length. (Note that this does not require NLH to have TOU pricing in all three seasons, or to have peak periods that conform to the optimum. Actual rates need not even be TOU if marginal costs are not strongly different across the periods or across seasons.) Table A-1 presents the results for Newfoundland Power. Results for Industrial Customers are very similar.

Table A-1
Three-Season Configuration: Three Summer and Winter Months
Two Pricing Periods

Season	Months	Average Marginal Cost ($/MWh)				MC Ratio	Peak Seasonal MC Ratio		Within-Period
		Peak	Shoulder	Off-Peak	All Hours	P/O	vs. Spr/Fall	vs. Winter	Variance
Winter	12, 1, 2	$ 64.26	$ -	$ 48.11	$ 55.06	1.34	1.42	1.00	$ 58,924,132
Summer	6, 7, 8	$ 71.64	$ -	$ 45.03	$ 55.21	1.59	**1.58**	**1.11**	$ 51,838,938
Spr/Fall	3, 4, 5, 9, 10, 11	$ 45.28	$ -	$ 34.32	$ 39.37	1.32	1.00	0.70	$ 19,569,941
Total									$ 130,333,010

The model selects the peak hours as 7–20 inclusive in winter, 8–19 in summer, and 7–21 in winter. These long peak periods reflect the pattern of marginal costs in the Eastern Interconnection. The table reports resulting average marginal costs for the two pricing periods as well as for all hours in the season. This scenario yields peak/off-peak (P/O in the table) ratios of 1.59 in summer, 1.34 in winter, and 1.32 in the spring/fall months. The all-hours MC values show that winter and summer marginal costs are about 1.5¢/kWh ($15/MWh) above the spring/fall period value of $39.37/MWh. Additional columns report the ratio of summer average marginal cost vs. the spring/fall and winter periods, and the variance in marginal costs within periods and the total for all periods. (The variance values are not significant except as bases for comparison with other scenarios.)

We explored alternative definitions of seasons and discovered that the variance-minimizing seasonal configuration is a four-month winter season (adding March to the previous scenario) and a two-month summer season (subtracting June). Table A-2 presents the results of this scenario for Newfoundland Power.

Table A-2
Three-Season Configuration: Four Winter, Two Summer Months
Two Pricing Periods

Season	Months	Average Marginal Cost ($/MWh)				MC Ratio	Peak Seasonal MC Ratio		Within-Period
		Peak	Shoulder	Off-Peak	All Hours	P/O	vs. Spr/Fall	vs. Winter	Variance
Winter	12, 1, 2, 3	$ 59.41	$ -	$ 44.03	$ 50.56	1.35	1.27	1.00	$ 55,501,397
Summer	7, 8	$ 78.50	$ -	$ 47.48	$ 59.70	1.65	**1.68**	**1.32**	$ 44,393,277
Spr/Fall	4, 5, 6, 9, 10, 11	$ 46.85	$ -	$ 35.68	$ 40.87	1.31	1.00	0.79	$ 23,960,154
Total									$ 123,854,827

The model selects identical peak hours to those of the first scenario. This scenario features slightly larger peak/off-peak marginal cost ratios and modified ratios of summer peak prices to peak prices in other seasons. With three summer months, summer peak marginal costs average 58 percent more than the average for spring/fall months, while with just two summer months, that average increases to 68 percent.

Additionally, the second scenario produces a significant difference between all-hours marginal costs in summer and winter, while they were virtually equal in the first scenario. Were prices for the tail block to look like these marginal costs, they would be surprising in Newfoundland, as the cost of adding load would be higher in the summer than in the winter, a significant change from past circumstances.

If we continue using four winter and two summer months as a seasonal definition, but allow three pricing periods (peak/shoulder/off-peak) the model yields increasing peak/off-peak ratios and an increase in peak period seasonal marginal cost differentiation. This might be expected, since increasing the number of price periods allows for greater concentration of marginal costs within like groups. Table A-3 presents results for Newfoundland Power. (Notice that the overall variance in marginal costs within groups drops significantly relative to the two-period model.)

Table A-3
Three-Season Configuration: Four Winter, Two Summer Months
Three Pricing Periods

Season	Months	Average Marginal Cost ($/MWh)				MC Ratio	Peak Seasonal MC Ratio		Within-Period
		Peak	Shoulder	Off-Peak	All Hours	P/O	vs. Spr/Fall	vs. Winter	Variance
Winter	12, 1, 2, 3	$ 60.78	$ 57.56	$ 44.03	$ 50.56	1.38	1.27	1.00	$ 52,417,704
Summer	7, 8	$ 85.70	$ 71.05	$ 47.48	$ 59.70	1.80	**1.79**	**1.41**	$ 30,422,566
Spr/Fall	4, 5, 6, 9, 10, 11	$ 47.89	$ 44.02	$ 35.68	$ 40.87	1.34	1.00	0.79	$ 20,335,370
Total									$ 103,175,641

The model selects peak hours as 7–9 and 18–20 in winter, 12–17 in summer, and 9–19 in the spring/fall months. Shoulder hours are 10–17 in winter, 8–11 and 18–19 in summer, and 7–8 and 20–21 in the spring/fall months. The winter heating season generates peak hours in the morning and the evening and shoulder hours in between, while other seasons feature a more familiar single peak in the middle of the day, flanked by shoulder hours.

IMPLICATIONS

The all-hours average marginal costs of all tables suggest that seasonal differences of $10 to $20/MWh (1 to 2¢/kWh at retail) are to be expected, and that pricing differentiation of marginal cost-based rates will bring marginal price noticeably closer to marginal cost for NLH. If NLH selects the seasonal pattern of four winter and two summer months (Tables 2 and 3) the resulting all-hours marginal costs are $50.56 in winter, $59.70 in summer and $40.87/MWh in the spring/fall season. Selecting the seasonal pattern of three summer and winter months (Table 1) produces very similar winter and summer marginal costs ($55.06 and $55.21/MWh, respectively) and $39.37/MWh in winter.

The variation in marginal costs across the day within each season is not high relative to what is observed in retail TOU rates. These rates often have peak/off-peak price ratios of 3:1, a ratio regarded in the industry as being required to induce detectable response to price. In the case of NLH, marginal cost ratios are all less than 2:1 (an index value of 2.0 in the table). These ratios do not suggest definitively that NLH should not use TOU pricing, but simply indicate that price differentials should likely be low.

The above information does not state that NLH ought to differentiate pricing by season or time of day. NLH still retains broad discretion in pricing and can tailor that pricing to its customers' preferences. The more sophisticated the customer, the more readily they can sustain product and price complexity, and accuracy of price with respect to marginal cost. It seems reasonable that both Newfoundland Power and the IC class could manage seasonal pricing at least. More generally, NLH faces the usual rate making tradeoff of pricing accuracy and rate complexity. Evaluating which pricing period structure to adopt may be assisted by comparison of variance values or review of marginal cost patterns, but will surely depend upon the utility's own preferences and its customers' tolerance of price complexity and risk.

The less time variation included in prices, the more risk that NLH absorbs, since their incremental costs are variable while those of the customer are not under fixed pricing. At one end of the risk spectrum, NLH could minimize its risk by designing rates for its customers using same-day hourly real-time prices. At the other end of the spectrum, it could offer a fixed all-hours, all-season price based on the customer class's load-weighted forecasted marginal cost. (This riskier product would include a modest premium for risk acceptance.) In practice, with the anticipated increase in variability of marginal cost, it seems sensible to introduce seasonal pricing. However, given the relatively small within-day marginal cost ratios, TOU pricing may not be very beneficial.

NLH has discretion in this regard, and the results above do not mandate a specific design. Nor does the design chosen foreclose the use of dynamic rate options in which price closely matches marginal cost. For example, NLH could offer its Industrial Class either a two-part RTP option for all hours or for critical-peak hours only, as a means of obtaining price response in hours of low system reserves. Similar plans, offered to Newfoundland Power, would enable pass-through of market-based pricing, especially in critical-peak hours, to its own customers.