Connecting to the North American Grid: Time for Newfoundland to Discontinue Inefficient Price Regulation

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L'île de Terre-Neuve possède un réseau électrique isolé du continent, et, au cours des dernières années, le prix de l'électricité, qui y est réglementé, s'est éloigné de façon substantielle de son coût marginal. Cela a entraîné de l'inefficacité économique : coûts sociaux importants, accroissement de la consommation d'électricité et dépendance excessive à une centrale thermique. Dans les quelques années à venir, la capacité hydro-électrique augmentera considérablement, ce qui permettra de réduire la dépendance à la centrale thermique, mais le coût de la construction d'une nouvelle centrale est important ; des installations de transport sous-marin seront mises également mises en place, ce qui mettra fin à l'isolement de l'île par rapport au réseau nord-américain. Toutefois, sans un changement de la législation et du cadre réglementaire, l'efficacité économique restera un objectif impossible à atteindre ; des réformes politiques dans le but de soutenir une tarification efficace et d'adapter la réglementation à la nouvelle situation seront donc nécessaires.

Mots clés : électricité, efficacité, réglementation, fixation des prix, Muskrat Falls

The island of Newfoundland has an isolated electrical grid. In recent years, its regulated price of electricity has deviated substantially from marginal cost. This has led to economic inefficiency, causing significant welfare costs, higher electricity consumption, and excess reliance on thermal generation. In the next few years, substantial but costly hydroelectric capacity will be constructed, largely displacing reliance on thermal generation. In tandem with that new generation, subsea transmission facilities ending Newfoundland's isolation from the North American grid will be put in place. However, without a change in the governing legislation and the regulatory framework, economic efficiency will remain unattainable. Policy reforms that support efficient pricing and adapt the regulatory regime to the new circumstances are called for.

Keywords: electricity, efficiency, regulation, pricing, Muskrat Falls

Introduction

The electricity grid on the island of Newfoundland is entirely isolated from the North American grid, and the electricity load on its interconnected system is met by a mix of hydro and thermal generation. That is going to change. A new hydroelectric project at Muskrat Falls in the Labrador part of the province will add substantially to generating capacity. More significantly, associated transmission investments will connect Muskrat Falls to the island and will also connect the island to the North American grid.

As with other proposed and ongoing megaprojects by other provincial hydro corporations in northern Canada—for example, Site C in British Columbia; the Romaine River in Quebec; and Bipole III, Conawapa, and Keeyask in Manitoba—the Muskrat Falls project has been controversial. Criticisms of such large hydro projects typically involve community concerns, Aboriginal rights, environmental impacts, alternatives, cost, and risk. With respect to cost, the Muskrat Falls project has been plagued with overruns and delays. The final cost of Muskrat Falls will be substantially more than initially claimed, a phenomenon that Ansar et al. (2014) show to be common for dam projects in many countries. However, what sets the Muskrat Falls project apart from other major Canadian hydro projects is its transmission component that will connect the island's grid to transmission systems in other jurisdictions for the first time.

This article demonstrates that past regulatory practice imposed costs on the province by not supporting economic efficiency. It then argues that, after Muskrat Falls interconnection, planned continuation of that regulatory regime, combined with provincially legislated barriers to market entry, will further hurt ratepayers and the economy. An alternate regime is needed, one that maximizes economic efficiency of the province's electricity resources and also addresses the challenging problem of paying for the megaproject. To set the stage for that policy discussion, the next section provides the pertinent context.

Background

At present, the island's electricity load is met by hydroelectric generating units that serve base load. They are supplemented by the Holyrood oil-fired thermal generation plant, which is located near St. John's on the Avalon Peninsula, where most of the load is concentrated. That plant has a capacity of 490 megawatts and is essential to meet the higher loads that occur during the colder months of the year, typically November to May. These resources feed into an interconnected grid that serves almost all consumers other than those in some isolated rural areas, which have to be supplied by dedicated diesel generators. Residential and small non-residential customers pay a basic consumer charge and then a flat rate per kilowatt hour. Larger non-residential and industrial customers pay a flat rate but also are subject to demand charges. The flat rates vary by customer class.

In terms of industrial structure, the dominant player is Newfoundland and Labrador Hydro (NL Hydro), which is a vertically integrated public utility owned by the provincial government. NL Hydro owns, controls, or operates most of the generating capacity on the island as well as the transmission system and acts as a distributor in some interconnected rural areas. Its customers are the retail customers in those interconnected rural areas as well as the isolated rural customers, a few large industrial customers, and Newfoundland Power Ltd. (NP), a wholesale buyer. NP is the only other public electric utility in the province. It is primarily a distributor–retailer, and its service area covers most of the island, encompassing all areas not serviced by NL Hydro. It has no presence in Labrador. It has a small amount of own-generation capacity but must acquire more than 90 percent of its energy from NL Hydro. Both utilities are subject to cost-of-service regulation, which is also known as average-cost pricing or rate-of-return regulation. The regulatory authority is the province's Public Utilities Board, (PUB). Additional capacity is owned by a few small power producers who are under contract to NL Hydro and by the Corner Brook Pulp and Paper newsprint mill.

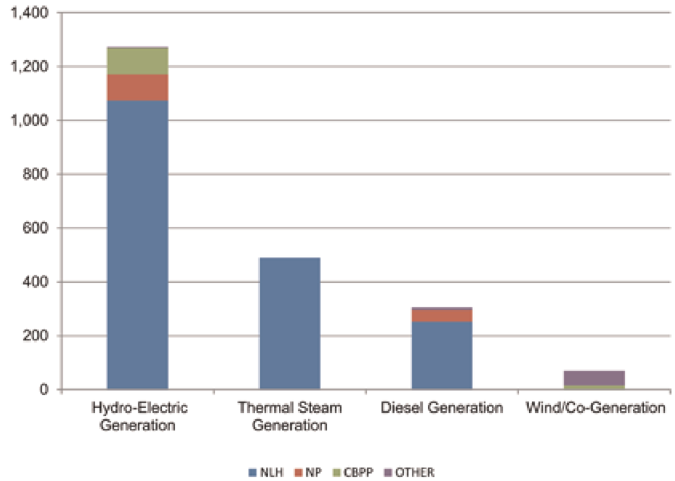

Figure 1: Island Interconnected Generating Capacity (in MW) by Type and Ownership, 2015.
Source: Power Advisory, LLC (2015, 25–26, Table 1).

Figure 1 illustrates the current mix of energy sources and their ownership. Two characteristics stand out. First, hydroelectricity dominates generating capacity. Second, NL Hydro owns and controls most of the capacity. The Muskrat Falls project will reinforce those two characteristics. It will add 824 megawatts to hydroelectric capacity. Even though that new capacity will be in Labrador, it will effectively be an addition to island capacity because it will be linked to it by a high-voltage direct-current connection. It will also enhance NL Hydro's dominance because the generating plant will be owned by a sister company.

In November 2010, the Muskrat Falls project concept was announced as a joint project of Nalcor Energy and Emera Inc. Nalcor is a corporation owned by the government of Newfoundland and Labrador; Nalcor in turn owns NL Hydro as well as the Muskrat Falls Corporation (MFCo), which will own and operate the Muskrat Falls plant. Emera is a publicly traded private corporation based in Nova Scotia and the owner of Nova Scotia Power Inc. (NSP), that province's public utility. The project was endorsed by the provincial governments of Nova Scotia and Newfoundland and Labrador, whose respective premiers were present at the public announcement. In fact, the event was largely dominated by the latter provincial government. The political desire of that government to develop hydro resources in Labrador and the growing consumption of electricity on the island were the impetuses for the project.

Here, the political motivation may have been dominant. Animosity toward Quebec over the 1969 Churchill Falls contract has frustrated many provincial governments in Newfoundland since the 1970s. Under that long-term contract, the bulk of the energy from the huge (5,428 MW) Churchill Falls plant, which is jointly owned by NL Hydro and Hydro-Quebec, is currently sold to Hydro-Quebec at $2.00 per megawatt hour, an extraordinarily low price. Also, recent attempts by Nalcor to develop the large site at Gull Island on the Lower Churchill River have also run into difficulties in gaining access through Quebec to external markets (Feehan 2014). By 2010, it was clear that access to markets through the Quebec system could not be had on acceptable terms, so Gull Island could not happen. As a result, Nalcor opted for the smaller Muskrat Falls project, which is located downstream from the Churchill Falls plant and is not dependent on access to the Quebec grid. During the Muskrat Falls announcement, the then-premier of Newfoundland, Danny Williams, remarked on how this project would be "free of the geographic stranglehold of Quebec" (Government of Newfoundland and Labrador, Government of Nova Scotia, Nalcor Energy, and Emera Inc. 2010, 1). Such a statement resonated favourably among the Newfoundland populace, especially coming from a premier who was extraordinarily popular at the time and considering the friction with Quebec.

From its inception, the economics of the project plan has been questionable. A joint federal–provincial Environmental Assessment Review Panel stated that it was not convinced that the project was in the province's long-term financial interest (see Joint Review Panel 2011, 25). A subsequent review by the PUB was not supportive. Its report concluded that there was not sufficient information for it to determine whether Muskrat Falls would be the less costly approach to meeting future island needs (PUB 2012, iv). Feehan (2012, 5) argued that proceeding with it would be premature and imprudent. Various individuals, journalists, and groups also voiced concerns—economic and otherwise—but the government remained popular, and there was no substantial protest against the project. These early objections to the project came when the estimated capital cost for Nalcor was $5 billion.

Throughout, Nalcor, in unison with the provincial government of the day, was a strong proponent. In December 2012, the Progressive Conservative government, having been reelected in October 2011 with a large but reduced majority, officially sanctioned the project, giving Nalcor the formal authority to proceed. By that time, the estimated capital cost of the project for Nalcor had been revised upward to $6.2 billion. Also, on 30 November 2012, the federal government committed to provide a loan guarantee to Nalcor of as much as $5 billion for the project. That was a positive development for the proponents because a Government of Canada loan guarantee would ensure lower interest rates on financing and significantly reduce that substantial component of the project's cost. The federal government also provided a loan guarantee of up to $1.3 billion for Emera's part of the project. Thus, by January 2013 the project was officially underway, contracts were finalized, and construction activity ramped up as soon as weather permitted.

The project itself consists of the following components:

- *The plant:* The plant will be a located at Muskrat Falls on the lower section of the Churchill River in east-central Labrador. It will have a capacity of 824 megawatts and produce an estimated average of 4.9 million megawatt hours annually.
- *The Labrador Transmission Assets:* The Labrador Transmission Assets will link the Muskrat Falls plant with the existing Churchill Falls plant to the west. This will be done by a 250-kilometre alternating-current transmission connection, the primary purpose of which is to permit optimization of the two plants, which both draw on the Churchill River.[1]
- *The Labrador–Island Transmission Link:* This link is a 900-megawatt direct-current connection consisting of 400 kilometres of transmission lines from the plant to the south Labrador coast, a 35-kilometre undersea crossing to the island of Newfoundland, and then 700 kilometres of transmission lines to a location near Holyrood. At that end point, a switchyard will convert the direct-current power to alternating-current power for distribution on the island grid.
- *The Maritime Link:* The core of this project is a 170-kilometre undersea 500-megawatt direct-current cable connection between the southwest corner of Newfoundland and Cape Breton in Nova Scotia. In addition, overhead direct-current transmission lines will extend from the cable's coastal end points to connect to the alternating-current grids in the two provinces.

The Maritime Link is being undertaken and paid for by Nova Scotia Power Maritime Link Inc., an affiliate of Emera. That infrastructure falls under the jurisdiction of Nova Scotia's Utility and Review Board (UARB). That agency gave its formal approval of the Link in November 2013 after several critical concerns were addressed (see UARB 2013). Associated with that approval are two agreements, both between Emera and Nalcor: the Energy and Capacity Agreement (ECA) and the Energy Access Agreement (EAA). They have significant implications for both provinces.[2]

The ECA provides that Emera or an Emera affiliate develop the Maritime Link and that, in exchange, Nalcor will compensate it in kind through the Nova Scotia Block, namely, 20 percent of the Muskrat Falls plant's

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annual output, approximately 1 million megawatt hours, for 35 years, with corresponding firm capacity. Ownership of the Maritime Link will be transferred to Nalcor after those 35 years. Also, associated agreements provide Nalcor with free access to the link and, subject to a pay-as-you-go tariff, access to Emera transmission rights across Nova Scotia and New Brunswick into Maine. Thus, Nalcor will be able to sell energy in the New England wholesale market.

Under the EAA , once the project is completed Nalcor must bid in annual competitive solicitations called for by NSP. Nalcor must offer at least an average of 1.2 million megawatt hours annually, and it can offer up to 1.8 million megawatt hours in any year. The EAA came about because the UARB required that Nova Scotia ratepayers be assured of access to competitively priced electricity beyond the amount forthcoming through the ECA. Under the EEA, the energy must be for consumption in Nova Scotia.

These two agreements are highly beneficial to Nova Scotia. Combined, they give ratepayers in that province access to a minimum of 45 percent of Muskrat Falls energy until 2041. That will allow a substantial reduction in fossil fuel generation in Nova Scotia and permit NSP to achieve the renewable energy standards set by the Nova Scotia provincial government. NSP and its ratepayers' cost exposure is limited to the Maritime Link, the capital cost of which is an estimated $1.56 billion. Also, the EEA is risk mitigating with regard to price. Under the EAA, NSP does not have to buy additional power from Nalcor. Moreover, if it chooses to accept a Nalcor bid, then, as discussed later, the price will be a competitive wholesale one. Although not of similar benefit to Newfoundland ratepayers, the two agreements will have far-reaching implications for setting the post-interconnection wholesale price of electricity in Newfoundland. That is the subject matter of the following section.

Getting the Price Right

Economically efficient production and consumption of any commodity requires that its price correspond to the marginal cost of producing it, including environmental and other social costs. However, throughout most of the twentieth century, electricity has been regulated, with the price usually set according to average cost. Economists have long recognized that such a practice is inconsistent with maximizing economic efficiency, but early thinking was that marginal cost pricing was not practical for electricity generation. However, Harberger (1972), citing practices in post–World War II France, was among the pioneering economists who demonstrated the feasibility of marginal cost pricing of electricity. He shows that optimal investment in generation capacity and marginal cost pricing go hand in hand, each depending on the success of the other, as in a virtuous circle.

There is evidence that achieving economic efficiency in the electricity sector in Canada could lead to large gains. Bernard and Chatel (1985) estimate that application of marginal cost pricing in Quebec, which would entail higher prices, would generate net welfare gains of hundreds of millions of dollars annually. Pineau (2008) demonstrates that efficient pricing in British Columbia would also lead to annual net benefits of hundreds of millions of dollars. He also says that residential electricity consumption would fall by 25 percent. That would reduce the need to build additional capacity, thereby avoiding the environmental and community concerns that often arise with such projects. Interestingly, Pineau also finds that, despite the 50 percent increase in price needed to achieve efficiency, the adverse impact on low-income consumers in British Columbia would be relatively mild and suggests that the income tax system could be used to compensate them.

Despite the overwhelming economic case for marginal cost pricing, little progress has been made in Canada. Dewees (2010) argues that Ontario has failed in that regard, and most provinces with dominant, and usually Crown-owned, vertically integrated electric utilities continue to use average-cost pricing regulation. Cairns and Heyes (1993) find that there is no complete political–economic theory of why this wasteful practice of deviating from efficient pricing principles persists. It may simply be the case that ratepayers, as voters, do not believe offers of compensation for the higher prices that are generally required in those provinces. With electricity pricing being set by regulatory agencies that have been in place for many decades, perhaps institutional inertia as well as ratepayers' votes pose barriers to reform.

Newfoundland and Labrador remains in the traditional regulatory camp. In that regard, the following subsection examines the pre-Muskrat situation, both to provide context and to set the stage for the discussion in the subsequent subsection, which deals with efficient pricing once the island is connected to the external grids.

Preinterconnection

The regulatory norm of average-cost pricing led to substantial deviation from the efficient price at times when the cost of fuel for thermal electricity was particularly high; the regulated price was much less than marginal cost. For instance, in 2014 the marginal cost for thermal generation at NL Hydro's Holyrood plant was approximately $170 per megawatt hour, and consumption was such that the plant had to operate almost every week of the year, making its marginal cost the relevant value for efficient pricing.[3] In stark contrast, the regulated wholesale price at which NL Hydro sold energy to NP was

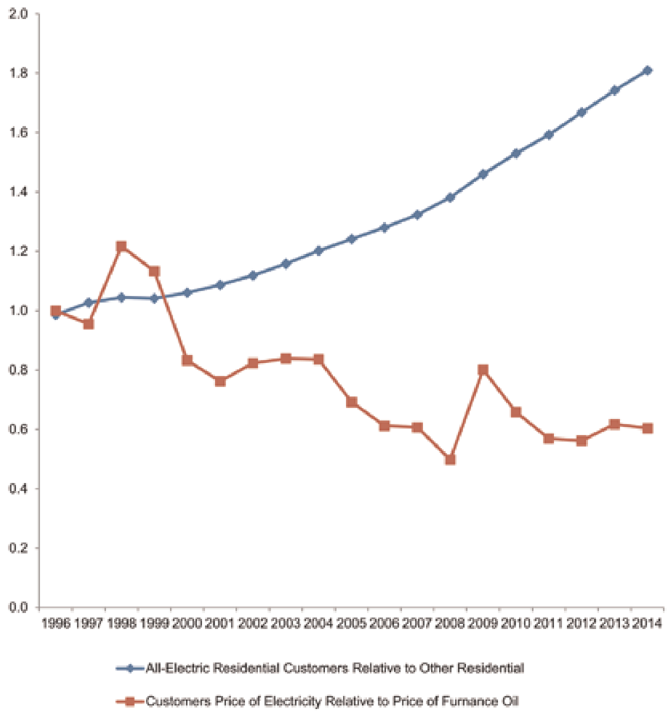

Figure 2: Sources of Heat for Residential Customers and Relative Fuel Prices, Newfoundland Island Grid
Sources: Number of customers and consumption data were provided by NL Hydro at author's request. Price data were provided by Newfoundland Power on request. Calculations performed by author.

approximately $100 per megawatt hour, and the energy charge was even lower for its industrial customers.[4]

Had the price reflected marginal cost, then electricity consumption would have been lower. The immediate impact of a higher price would likely have been modest because the demand for electricity tends to be price-inelastic in the short term. Over the long term, however, consumption can be much more responsive to a change in price because consumers have more time to adjust and find alternatives. This is particularly so with respect to space heating, the infrastructure for which takes time and some expenditure to install or replace. Since the 1970s, the options for space heating in Newfoundland have been limited. The two main sources are electric baseboard heat and oil furnace heat; there is no natural gas, and propane gas and wood are largely limited to providing supplemental heat. Over the years, there has been a trend away from furnace heat. That trend has been especially pronounced in recent years and was, in part, driven by relatively cheap electricity. For 1996–2014, Figure 2 shows the ratio of the price of electricity to the price of furnace oil, normalized to one for 1996. It also shows, for the island's interconnected system, the ratio of the number of residential customers who are all electric—that is, those who have electric space heating—to other residential customers. In 1996, that customer ratio was 1, indicating that the numbers in each group were equal. As for the price ratio, the index for the relative price of electricity declined quite substantially from 1998 to 2014. The figure shows that over the same period, reliance on electric heat increased. By 2014, the ratio of the number of all-electric consumers to the others was 1.8, an 80 percent increase since 1996.

The consequence of shifting to electric heat is to add to the demand for electricity quite significantly. For instance, in 2014 the average domestic customer without electric heat consumed 10.95 megawatt hours, and domestic all-electric customers consumed 18.94 megawatt hours.[5] Most of the increase in electricity demand from switching is concentrated in the cold months of the year, which leads to higher seasonal demand and greater pressure on existing generation capacity.

Although other factors were at play, the dramatic decline in the relative price of electricity as illustrated in Figure 2 played a role in the shift of customers from furnace to electric heat. Had the price of electricity been set according to marginal cost, then the price ratio, rather than declining to 0.6 in 2014 as shown, would have remained approximately at 1 because the price of furnace oil and the cost of the heavy fuel (known as bunker-C) burned at the Holyrood thermal plant are highly correlated. Marginal cost pricing would have acted to induce some reduction in consumption by all customer types and mitigate the trend toward electric heat. Also, marginal cost pricing would have been environmentally friendly because home furnaces typically operate at more than 80 percent effectiveness in converting fuel into heat, whereas steam thermal plants such as the one at Holyrood achieve only about 33 percent. In addition, home furnaces use diesel fuel; the thermal plant's bunker-C fuel produces much dirtier emissions.

At this stage, it is helpful to illustrate the basic analytics of the pre-Muskrat circumstances in a supply-and-demand–type diagram. That is done in Figure 3, which shows that short-run marginal cost follows a stepwise pattern; it is short run because the illustration is based on in-place generating capacity. Initially, the marginal cost of generating electricity is very low, which reflects the near-zero marginal cost of producing electricity from existing on-island hydroelectric plants. MC_1 represents the marginal cost of hydrogeneration, and Q_1 denotes the amount of on-island hydrogeneration.[6] The second tier is much higher at MC_2. It represents the marginal cost of operating Holyrood's thermal generating units and should include environmental cost, which has a production range represented by the distance from Q_1 to Q_2. Beyond that, production would have to come from diesel-fired combustion turbines, which are more

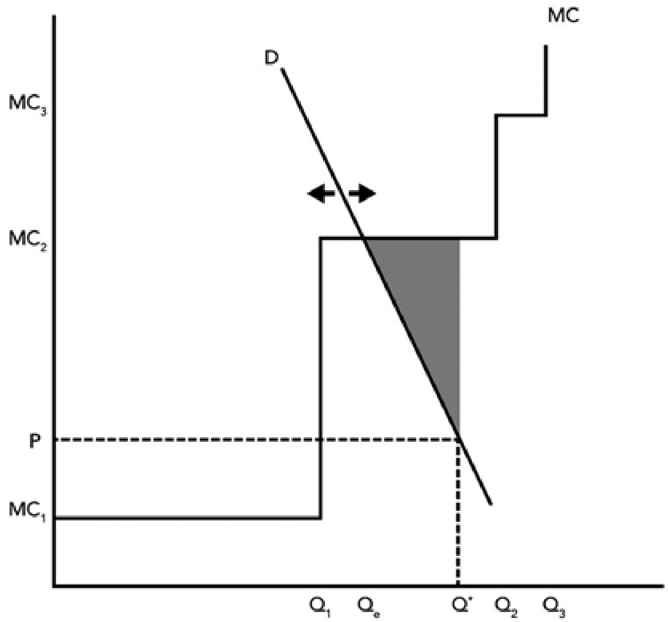

Figure 3: Marginal Cost Structure for Electricity for In-Province Generation Available to the Island of Newfoundland: Pre–Muskrat Falls

costly to operate (MC_3). Q_3 represents the physical limits of diesel capacity; diesel turbines are for backup, to be used only when the Holyrood plant has technical difficulties. On the consumption side, the demand curve is represented by the downward sloping curve labelled *D*. The arrows by that curve indicate that it shifts depending on the seasonal weather connections. Efficiency requires that the price be determined by the intersection of the demand and the marginal cost curves. As presented in Figure 3, that means the price should equal MC_2. However, average-cost regulation would set the price lower. Suppose that regulated price is at *P*, in the diagram, with corresponding consumption at Q^*. The economic loss that results is represented by the shaded triangular area, which corresponds to the gap between the marginal cost and the demand curve over the range of excess consumption relative to the efficient amount, Q_e.

A rough estimate of that cost is of interest. In 2014, actual electricity consumption on the island grid was 6.7 million megawatt hours.[7] The previously mentioned difference between the wholesale price and the marginal cost of generation in 2014 suggests an approximate 70 percent increase ($70 per MWh) in price would have been needed to achieve efficiency. To estimate the impact of marginal cost pricing requires a value for the price elasticity of demand. A reasonable assumption for short-run elasticity is 0.3. This elasticity assumption is consistent with Pineau (2008), who uses 0.5 as a base value but included 0.3 within a sensitivity analysis.[8] As a consequence of raising the price to match the marginal cost, a 0.3 elasticity implies that consumption would have fallen by approximately 1.4 million megawatt hours and led to a gain of approximately $50 million for that year.[9] Not doing so means a $50 million loss.[10]

Three observations from the preceding analysis are in order. First, although efficiency would have required a substantial price increase, it is worth emphasizing that the outcome would have been a net gain. Any concern about the distributional implications or the greater burden on ratepayers could have been addressed by compensation. Still, as suggested earlier, the politics of raising a price that is subject to regulation is problematic. A second observation is that the reduction in consumption arising from marginal cost pricing in Newfoundland would have substantially decreased reliance on, and emissions from, the Holyrood plant, the marginal supplier. Bearing in mind that reliance on thermal generation varies by the season, application of efficiency pricing might have called for seasonal pricing.[11] With reference to Figure 3, the demand curve moves to the left during the summer months, and its intersection with the vertical section of the *MC* curve above Q_1 would determine the lower seasonal rate. The third observation is that marginal cost pricing would have substantially reduced consumption growth, resulting in either an elimination of or a substantial delay in the need to add generation capacity.

On the contrary, Nalcor and the Newfoundland government advocated for a massive increase in capacity. They argued that electricity consumption would substantially increase in the future; that oil prices would remain high and increase, causing thermal costs to rise ever more; and that closure of the aging Holyrood plant would be environmentally beneficial. Marginal cost pricing would have addressed those matters, but it simply was not part of those proponents' lexicon. Moreover, current plans are to continue the practice of cost-plus price setting. Although it is too late to rectify the pre-Muskrat situation or to stop the Muskrat Falls project, regulatory policy can be reformed so as to avoid the additional costs associated with mispricing. That is the subject matter of the following subsection.

Postinterconnection

In 2007, the provincial government released its Energy Plan (Government of Newfoundland and Labrador 2007). That plan called for the development of hydroelectric projects in Labrador on the Churchill River, including Muskrat Falls. It also endorsed maintaining the existing regulatory regime for electricity pricing. Yet, the MFCo will not be regulated. Rather, it will be treated as an independent power producer, albeit one with a cost-plus contract to sell electricity to Nalcor's regulated utility, NL Hydro. That cost, no matter how

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high, will be added to all NL Hydro's other allowable costs as determined by the PUB. Then the price of electricity for NL Hydro's island customers will be set.[12] As a result, there will be a two-price regime: a domestic wholesale price and an export price. Nalcor will sell surplus power on external markets according to market opportunities. There is no intent that the external price and the domestic island price be equal. In fact, provincial legislation enacted in 2012 specifically to support Muskrat Falls prevents any arbitrage that would cause price convergence. Specifically, all industrial customers and retailers on the island must purchase from Nalcor's NL Hydro; any island electricity producer must sell to NL Hydro, which does not have to buy; and industrial customers and NP are not permitted to add any self-generating capacity.[13] This iron-grip monopolization of the island market ensures that Nalcor, through NL Hydro, will be able to obtain whatever domestic price is needed to pay for Muskrat Falls. It also ensures that electricity exported at a lower market price does not return to Newfoundland for sale at a price that undermines the higher island price.

Such anticompetitive and protectionist measures are damaging to the economy and are strongly contrary to policy trends. Many jurisdictions in North America and elsewhere have established open access transmission tariffs, and there is a movement toward more integration of regional grids and greater regional trade in electricity, all of which are supported by many Canadian electricity policy experts (see, e.g., Pierce, Trebilcock, and Thomas 2006 and Pineau 2009). Yet, Nalcor's electricity subsidiaries would be protected from outside competition. This will not be a zero-sum outcome. The gain to Nalcor and the loss to island consumers will not be exactly offsetting. There will be a loss arising from the deviation of the domestic price from the external price. That loss will occur because the higher price would hurt local consumers and induce them to reduce consumption, but the export of that freed-up electricity would earn a lower price. This loss can be avoided by switching to a regime of efficient pricing.

When the Muskrat Falls generation and transmission project is completed, the fossil fuel–generating capacity of the island will become redundant. In terms of Figure 3, the lowest *MC* segment will be extended substantially to the right, effectively pushing thermal and diesel generation out of the picture. In an isolated system, that very low marginal cost would be the efficient price. However, the system will no longer be isolated. The connection of the island to external markets will be a game changer. On the margin, the opportunity cost of electricity will become the external price. To the extent that price is different from the marginal cost of production, the gap will give rise to the gains from trade. Efficiency requires that the wholesale price in Newfoundland inclusive of transmission cost should be equal to the price obtained in external wholesale markets.[14] The key questions are these: Where are those markets, and what are the relevant prices?

For Newfoundland, identification of the relevant markets is straightforward. The EAA provides the starting point. Recall that under that agreement, an average of at least 1.2 million megawatt hours of electricity a year must be offered to NSP for sale. The sale price regime for this electricity, inclusive of transmission costs to Cape Breton, will vary by year. For each year, Nalcor is to bid quantities for peak and off-peak periods in each month, indicating the corresponding price per megawatt hour. Section 2.4 of the EAA limits those bid prices; they cannot exceed the larger of the following:

- the hourly Day Ahead Price at the ISO-NE Mass Hub node for the delivery hour, where that price means the energy price, without adjustments for transmission losses, tariff fees, or other fees (the ISO–NE is responsible for the operation of the competitive wholesale electricity market in the six New England states[15]), where the day-ahead price is a competitive wholesale price based on bids and offers made 24 hours in advance with the ISO–NE acting to determine the price at which the quantity offered is equal to the quantity being sought.
- the price associated with any alternative market opportunities identifiable by Nalcor at the time of the Nalcor bid that are available to Nalcor within 1 year after the Nalcor bid into the NSPI solicitation to the extent that Nalcor can provide sufficient proof to demonstrate that such opportunities are realizable.

The first of the two reference prices suggests the New England wholesale market is the relevant one, despite the fact the energy would be sold in Nova Scotia if the bid were accepted. The second reference price for the upper bound of the bid appears broader. However, Nalcor would have limited scope to access other feasible market opportunities. It could reach the New York wholesale market by using its existing 265-megawatt transmission rights through Quebec to the New York border (Power Advisory, LLC 2015, 46). That would involve sending Muskrat Falls energy west to the Quebec border and then through that province, but this would entail transmission tariffs and line losses, and there is little reason to expect that the New York wholesale market, being adjacent to and connected with the New England market, would offer better prices. Other alternate markets are also closely related to the New England wholesale one. For instance, Nalcor could possibly find a New England customer who is willing to pay more

Table 1: Comparison of Electricity Prices (in C$ per MWh)

Reference Price	2013	2014
Average day-ahead price in New England at the hub[a]	58.11	71.31
Hydro-Quebec average export price[b]	44.00	60.00
Nalcor average export price[c]	39.96	42.85
Estimated Nalcor average profit per MWh exported[d]	19.51	21.54

[a] The US dollar values were $56.42 and $64.57 for 2013 and 2014, respectively; see ISO–New England (2015, 57). Average annual exchange rates, $1.0299 for 2013 and $1.1045 for 2014, are from the Bank of Canada (n.d.).
[b] Hydro-Quebec (2015, 54).
[c] Nalcor (2015, 35) gives the US dollar prices as $37.68 and $38.80 for 2013 and 2014, respectively. Their Canadian dollar equivalents are reported here.
[d] These estimates were obtained by taking the ratio of revenue to cost for Nalcor's marketing subsidiary, which handles exports and for which exports make up approximately 90 percent of its revenues. For each year, the Nalcor average price was multiplied by the corresponding ratio.

than the day-ahead price via a bilateral contract to obtain an assured supply. In such a case, Nalcor could deliver to the New England market using the transmission access provided by Emera as part of the Maritime Link agreements. However, transmission fees would apply when those facilities are used, there would be transmission line losses, and there would be further costs associated with transmission fees within New England.[16] Sales opportunities in New Brunswick might be possible, but New Brunswick borders New England, with which it trades. Moving to markets further away, such as Ontario or the US Mid-Atlantic states, would entail more transmission costs and greater complexity in finding feasible transmission routes. In short, the upper bound of a bid into an NSP solicitation will be close to the prices prevailing in the northeastern US wholesale markets, particularly the New England one.

Nalcor's actual bid will be less than that upper bound because the NSP solicitations will be open to competition. One potential bidder is Hydro-Quebec, but others, such as an Emera affiliate or New Brunswick Power, might also be interested and capable of meeting the requirements. This would pressure Nalcor to bid less than the New England price. A similar outcome would arise even if NSP decides not to call for a solicitation or not to accept a Nalcor bid. Nalcor's alternative markets would still be New England or areas in which New England prices hold sway, but transmission costs, line losses, and other transactions costs would cut into the sale price. The result would be a price that is related to but likely less than the New England price. This prediction is consistent with recent experience, as illustrated in Table 1.

The first row of the table shows the simple average annual day-ahead price at the mass hub node in 2013 and 2014. The second row shows the average export price that Hydro-Quebec was able to obtain in those years; its out-of-province exports were largely to the New England and New York markets. The third row shows the average price that Nalcor received for its exports. Those exports were limited to sales of surplus energy from its entitlement from the Churchill Falls plant and largely sold in the New York market using Nalcor's transmission rights through Quebec. Neither Hydro-Quebec nor Nalcor received an average price as high as the New England hub average. Nalcor realized lower prices than Hydro-Quebec.[17] That difference may reflect the latter's proximity to wider market opportunities and its ability to strategically use its extensive reservoir system to hold water for times when export prices are more attractive. In addition, as shown in the last row of Table 1, the net gains from Labrador exports were quite small; this reflects the high costs of delivering energy across the vastness of Quebec to distant markets.[18]

The key prices in Table 1 are the New England and Hydro-Quebec ones. The Nalcor prices are less relevant because they reflect a restricted export capacity. Once the Maritime Link is in place, Nalcor will have a new route for exports, one that will give it scope to sell in more markets and, at least for sales in Nova Scotia, will entail less marketing and no external transmission costs. The New England price is important because it represents, given the EAA, the likely upper bound for Nalcor's bid price. The Hydro-Quebec export prices are suggestive of the lower bound. Hydro-Quebec would have no incentive to offer less in a bid to NSP, and selling into Nova Scotia might involve additional transmission and transaction costs. Therefore, it appears that if the Muskrat Falls generation and transmission project had been completed at the time, a successful Nalcor bid in 2013 would likely have received between $44 and $58 per megawatt hour and in 2014, between $60 and $71 per megawatt hour.

The fundamental proposition herein is that after connection to the North American grid, the wholesale price of electricity in Newfoundland should be determined by the external price. The best candidate for that price will be Nalcor's bid in the NSP solicitations. In 2015, NL Hydro's PUB-approved wholesale price to NP was $95.09 per megawatt hour as well as a demand charge (see NL Hydro 2015). Adopting the assumption that the existing pricing regime will be maintained and that the cost of Muskrat Falls will be fully passed through electricity rates, Nalcor has indicated that there will be a much higher price after NL Hydro begins purchasing Muskrat Falls power.

In June 2016, Nalcor updated its project's costs (Nalcor 2016). It announced that the project competition was two years behind schedule and that its estimated capital cost had risen to $9.1 billion and that financing costs during construction would be $2.3 billion, for a total of $11.4 billion. On the basis of those costs, and assuming the current system for price setting, it reported that once Muskrat Falls energy is integrated into the island grid in 2020, the resulting retail electricity rate for NP residential customers would more than double the 2016 rate. Specifically, Nalcor's update document forecast a future price of 21.4 cents per kilowatt hour compared with approximately 10 cents per kilowatt hour in 2016. Allowing 4.6 cents for NP's costs, the implied wholesale price is 16.8 cents, that is, $168 per megawatt hour. That price, which is a blended one that reflects the average of the cost of Muskrat Falls energy and energy generated by existing low-cost hydro facilities, is much higher than the New England prices shown in Table 1. If wholesale prices in New England remain relatively low, then maintaining the current regulated price regime in Newfoundland would set the price of electricity well in excess of its opportunity cost. Passing that price distortion on to retail customers will impose an additional economic burden on the provincial economy. Customers will incur costs in efforts to substitute away from high-priced electricity, but doing so will be fruitless because the cost of the project cannot be avoided. However, the burden can be avoided. A new policy regime is required to do it.

Policy and Implementation

When the island grid is connected to North America, economic efficiency requires that the wholesale price reflect the opportunity cost of the energy. That opportunity cost is the price of energy sold to NSP under the EEA. Because that sale price includes transmission to the Maritime Link, it follows that the wholesale price in Newfoundland should be inclusive of transmission costs to the wholesale buyers, namely NP and NL Hydro's distribution arm. This efficiency approach is a reversal of current practice. Instead of an approved rate of return plus costs determining the price, the price would be set first and, given the costs, the rate of return would be the outcome. Associated with the implementation of this pricing strategy are three policy questions: How should prices to the island end users be determined, how should the cost of Muskrat Falls be covered, and should anticompetitive measures remain in place?

Pricing for Domestic End Users

As a market-based price, the Nalcor bid in NSP solicitations should serve as the basis for regulatory rate setting in Newfoundland. That price is a wholesale price for energy, and it will vary with market conditions in New England. It is a starting point for determining what end users would pay.

Consider first the path from wholesale prices to end-user bills. As discussed, in Newfoundland there is a single wholesale purchaser, NP. A regime of efficient pricing requires that NP be given comparable wholesale price terms as offered to NSP.[19] That bid price to NSP is to be on a per-megawatt-hour basis and includes transmission delivery to the NSP; thus, an NL Hydro transmission tariff is already implicit in the price. That price, without any demand charge, would be the appropriate base on which to set the regulated wholesale price to NP.[20] In turn, NP's retail customers would pay for the electricity as well as for the distribution and other customer services it provides. Because in its service area NP would remain a natural monopoly in its distribution business, it is appropriate to maintain cost-of-service regulation of it. However, in this new environment the energy price, whether purchased from NL Hydro or obtained from NP's modest self-generation, should be the wholesale price. NP would then recover its costs and earn its approved rate of return through basic customer charges, demand charges for larger commercial customers, and distribution fees, which could all be identified, along with the energy charge, as entries on bills to its end-use residential and commercial customers. The details of these unbundled charges, as with allowable costs and rate of return, would remain a matter for the PUB to determine.[21]

The remaining end users of electricity on the island grid are direct customers of NL Hydro. They are residential and general services customers in certain rural areas as well as the few industrial customers. Billing of industrial customers should also change to primarily energy only and be the same as charged to NP; whether other specific charges are needed that reflect NL Hydro's services dedicated to an industrial customer as well as demand charges could be assessed on their merits by the PUB. In the rural areas in which NL Hydro also acts as a distributor–retailer, the pricing would be the same as that proposed with respect to NP customers.[22] The key aim here is that all end users on the island grid face the same market-determined energy prices. Consumption decisions can then be made on the basis of the true opportunity cost of electricity.

One complication is that this opportunity cost, that is, the export price obtainable in external wholesale markets, is not constant. If the power is sold in the northeastern US wholesale markets, then the price varies throughout the day as determined by competitive supply-and-demand conditions. In the more likely case in which the bulk of exports are sold via a successful bid in an NSP solicitation, under the EAA that bid must be in the form of a price per megawatt hour for different times of the day, namely peak and off-peak times in Nova Scotia, as well as throughout the contract year.

Either way, the price will vary considerably, and end users would not be able to adapt to potentially large price swings on a very short-term basis.

This raises the question of what price to use as a reference for the Newfoundland market. Fortunately, there are many feasible options. With a successful bid, the price regime will be known for the associated contract year. In addition, other markets provide information; there are futures markets and bilateral markets for US northeastern electricity that yield a profile of future prices. On the basis of such information, a simple annual average price can be deduced that could serve as the annual energy price for the end users on the island grid. There are, however, other potentially better options. The island price could incorporate some variability to track seasonal movements in the external price or peak and off-peak prices that again reflect market circumstances; in light of the variation in wholesale prices in New England, setting the price on a quarterly basis seems most appropriate and would enhance efficiency when the quarter-over-quarter prices are very different. The degree of seasonality in pricing would be a decision for the PUB and depend on market characteristics after the island is connected. However, the overarching goal of economic efficiency requires that the island wholesale energy price reflect the export price and not deviate from it on the average over a reasonable amount of time.

Paying for Muskrat Falls

By itself, requiring NL Hydro to base its wholesale price on the export price would create a financial challenge for that public utility. Under current arrangements as structured by Nalcor, NL Hydro is compelled to buy its energy from MFCo, and it must pay whatever price is necessary to cover the full cost of building the facility and provide an 8.4-percent return on Nalcor's government-provided equity investment in it.[23] NL Hydro will be financially squeezed between selling at a competitive price and having to buy a large portion of its energy from a hugely expensive facility on a cost-plus basis.

To ensure that there is sufficient revenue, several steps can be taken. First, export revenue, net of transactions costs, should be transferred to NL Hydro from Nalcor to contribute to the utility's revenue requirement. Second, to the extent that export revenue is not sufficient, the earnings of MFCo should be transferred to NL Hydro. A third but uncertain revenue source is greenhouse gas credits or other related renewable energy credits. Under the ECA, Emera will own the greenhouse gas credits associated with the Nova Scotia block, but Nalcor retains the credits for the remainder of the energy. To the extent that Nalcor-owned greenhouse gas and related credits can be monetized in the future, those funds should also go to NL Hydro.

The best way to ensure that those sources of revenue accrue to NL Hydro is to amalgamate the Muskrat Falls facilities with it. However, far more complex arrangements were put in place. Nalcor subsidiaries were created for the Labrador–Island Link and its wholly owned MFCo will own and operate the dam and generating plant. One underlying rationale for separating Muskrat Falls out as a stand-alone corporation was to avoid so-called rate shock. Had NL Hydro undertaken such a massive investment, its rate base—that is, its undepreciated capital stock—would have increased accordingly. Under the current system, however, its revenue requirement would then have increased by the regulated rate of return as applied to the new higher rate base. That would have resulted in even higher prices than Nalcor anticipates under its plans. To avoid this scenario, MFCo was created and, crucially, legislatively exempted from PUB authority. That allowed Nalcor to put in place a power purchase agreement between its two wholly owned subsidiaries, NL Hydro and MFCo, that would spread the cost of the Muskrat Falls energy over time. In short, there was a recognition that existing cost-of-service regulation would be problematic for the project, but, astonishingly, the solution was to avoid it rather than reassess its design in light of both the magnitude of the investment and the connection to the North American grid.[24] Under a reformed system of price-based regulation, such rate-shock considerations would be largely eliminated because the price would not be a cost-plus one. That would make merging MFCo and other Nalcor wholly owned electricity subsidiaries into NL Hydro straightforward and place them all under PUB jurisdiction.[25]

Whether the revenues identified here are transferred to NL Hydro or accrue to an enlarged version of it, it may still face a revenue challenge. If revenues are insufficient to meet NL Hydro's financial soundness under a price-based policy regime, then other mechanisms must be put in place. The ultimate owner of NL Hydro, the provincial government, may have to forego dividends and even make financial contributions. The latter would involve increasing taxation, reducing program expenditures, or incurring more public debt. Each has its drawbacks and costs. A better alternative is to solve the revenue problem within the new regulatory framework. To avoid a price difference from the external price, the PUB could impose a fixed charge on all end users of electricity, possibly differentiated by customer classes and payable to NL Hydro. It would be set at levels such that, when it is added to other revenues, NL Hydro would have revenues sufficient for the sound financial position expected of a public utility. Also, the PUB could determine the magnitude of the charge and its allocation across customer classes.

In fact, there is a precedent for imposing a charge related to past expenses. In Ontario, ratepayers' bills include a debt-expense item. Started in 1996, it is called the "debt retirement charge" and is earmarked for the payment of outstanding debt left from the now-defunct Ontario Hydro. It has been collected from ratepayers by their respective electricity providers and turned over to the Ontario Electricity Financial Corporation, the agency responsible for paying off the debt. In a similar fashion, the two Newfoundland public utilities could be required to add a Muskrat Falls debt-retirement charge to their island ratepayers' itemized bills. As in the Ontario case, the debt charge would be eliminated when the debt is fully paid off. (One drawback to the Ontario debt-retirement charge is that it was imposed according to consumption. A fixed charge would be more efficient because it would not change the price of electricity on the margin.)

Anticompetitive Policies

Another policy question is whether anticompetitive policies within the province should be maintained. The current legislation makes NL Hydro the only legal buyer in the province for independent power producers and provides such entities with no mechanism to export. That should change. There should be a nondiscriminatory transmission tariff so independent power producers could use the island transmission system, which is practically all Nalcor owned or controlled, to sell within the province, not just to NL Hydro but also to NP, and also to export. This would create an incentive for entrepreneurs to establish independent power producers and would spur innovation because their commercial success would depend on their ability to produce electricity at a lower cost than the prevailing market-based price as set by the PUB but based on the external price. A non-discriminatory tariff would also allow imports to enter the province and potentially be sold to NP and industrial customers with Nalcor simply being the transmission provider rather than a middleman. In practice, imports would be highly unlikely if the price is set at the external price, but they would be huge if Nalcor set a high monopoly price in the absence of trade barriers. A further spur to innovation would be to again make it legal for NP and NL Hydro's industrial customers to invest in new self-generation.

Conclusion

This article has argued that in the years leading up to the sanctioning of the Muskrat Falls project, the price of electricity in Newfoundland deviated substantially from the benchmark required for efficiency. That benchmark was the marginal cost of oil-fired thermal generation, which was especially high from 2008 through 2015 when oil prices surged. The regulated domestic price was much less than that. Had the price been set according to marginal cost principles, the price of electricity would have been higher. Ratepayers would not have been sympathetic, but there would have been significant net benefits, including greatly reduced reliance on fossil fuel generation and less need to make capacity additions. However, moving to marginal cost pricing was not considered as a policy option. Instead, to meet future demand and in frustration over obtaining access through Quebec for new hydroelectric development in Labrador, the Muskrat Falls project was put in place.

That development does offer some benefits. Nova Scotia will gain access to at least 45 percent of the energy, which means reduced reliance on fossil fuel generation in that province. In addition, Nova Scotia ratepayers will have access to that electricity at attractive rates because NSP will pay less than the competitive wholesale rates in New England and bear little risk. However, Newfoundland ratepayers and taxpayers will bear the cost of the project, including all the cost overruns. There would be some environmental benefits to Newfoundland as a result of the elimination of fossil fuel generation on the island, but efficient pricing without the project would have gone a long way in that direction anyway. Also, by providing incentives for reduced electricity consumption, such pricing would have undermined any rationale for massive increases in capacity. In addition, the intended policy of raising the electricity price to pay for Muskrat Falls will impose additional costs on ratepayers as they seek substitutes for electricity based on a price that exceeds its opportunity cost.

With no reform of the regulatory pricing regime, the domestic price will be driven by the high cost of the Muskrat Falls project. Domestic residents will be in a strongly monopolized market and will have to pay whatever energy price is necessary to support Muskrat Falls and NL Hydro. They will have no opportunity to access market-priced electricity. Imposing monopoly pricing to pay for Muskrat Falls and thereby forcing consumers to incur the cost of reducing consumption, foregoing the gains from interregional trade, and stifling innovation in the electricity sector is poor public policy.

Once the island grid is connected to North America, the wholesale energy price should be set by the regulatory authorities with reference to the price at which energy is exported. Rather than imposing a cost-driven monopoly price, other, less damaging ways can be found to pay for the Muskrat Falls project. Also, reform should be extended to include a non-discriminatory transmission tariff and the removal of legislated restrictions on market entry by independent power producers. Although the particular technological characteristics of electricity generation, transmission, and distribution create complications, following the general thrust of these proposals would set the stage in the long run for a dynamic electricity sector based on appropriate price signals.

Movement to efficiency pricing often means higher prices. Economic principles demonstrate that there will still be net gains, regardless of the direction of the needed change in price. However, ratepayer resistance can be considerable and thus create a serious obstacle to reform. With the very high cost of the Muskrat Falls project and the relatively low export price, efficiency pricing in Newfoundland would likely mean a lower price for electricity and certainly less of an increase than under the current regime. With economic principles and political considerations reinforcing one another, this may be one instance in which reform will actually occur.

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Notes

1 In July 2013, Hydro-Quebec filed a motion in the Quebec Courts to obtain a declaratory judgement regarding its rights under that contract for the period 2016–2041. In August 2016, the Quebec Court ruled in favour of Hydro-Quebec. That judgement may affect Nalcor's plans for water optimization.

2 Both are available at Nalcor's website (Nalcor Energy and Emera Inc. 2012; Nalcor Energy, Emera Inc., and Nova Scotia Power Inc. 2015).

3 This $170 figure is based on the cost of fuel divided by the number of megawatt hours produced at Holyrood, which serves as a reasonable proxy for marginal fuel cost. In principle, the marginal cost should be higher because of other operating costs that may vary with output, plus there are considerations of externality costs because of emissions from the thermal plant.

4 On 1 July 2014, the PUB approved a wholesale rate to NP on purchases in excess of 250,000 megawatt hours at $88.05 per megawatt hour, to which was added a further adjustment of $9.75. The cost to NP was thus a little less than $100 per megawatt hour. NL Hydro also applied demand charges to those customers. See PUB (2014).

5 This information was provided by Market Analysis Section at NL Hydro in response to a request from the author.

6 The marginal cost for each hydro plant may be different but, because they do not require purchased fuel, those costs would all be quite low and similar. For simplicity of exposition, they are assumed to be identical. In the same vein, the marginal cost of operating the Holyrood thermal plant is assumed to be constant over its range of output, although in practice the relationship between marginal cost and output may have a saucer shape.

7 Consumption data were provided by NL Hydro.

8 The 0.3 elasticity is also used in Feehan (2012), and it is similar to unpublished estimates. The long-run value is likely greater because installing alternate heating sources and more efficient electricity-consuming appliances requires significant capital investment and an expectation that the change in price will be long lasting. On the basis of an extensive survey of the literature, Espey and Espey (2004) find that estimates of the long-run elasticity have a mean of 0.85 and that a number of estimates exceed 1.0. It is interesting that Bernard et al. (2011) estimate Quebec residential price elasticities at 0.51 and 1.32 for the short run and long run, respectively.

9 A 70-percent increase at a price elasticity of 0.3 gives a 21-percent reduction in consumption. On the basis of the associated 1.4 million megawatt hour change in consumption and the $70 change in price, the estimated area of the triangle is approximately $50 million.

10 This estimate, which is merely indicative, would fluctuate substantially over time, because thermal generation marginal cost rises and falls in proportion to changes in oil prices. In Figure 3, that would be represented by parallel up-and-down shifts of the MC_2 segment. In contrast, the MC_1 segment would remain stable because hydroelectric generation facilities, once built, have low and stable operating costs.

11 In some jurisdictions, time-of-use rates can be very effective, but seasonal rates would be sufficient in Newfoundland because the Holyrood plant, barring equipment failure, has enough capacity to meet peak demand. Seasonal variation in consumption is the more pressing challenge.

12 Similar arrangements are in place for the project's Labrador–Island Link transmission assets.

13 That legislation was enacted as amendments to the Electrical Power Control Act (Government of Newfoundland and Labrador 1994) at the same time that the provincial government sanctioned the Muskrat Falls project.

14 Distribution and customer costs would be additional components of the price to end users and could be set by the PUB in the traditional manner.

15 The competitive nature of that wholesale market makes the prices across nodes almost identical with significant deviations short lived, so the mass hub node day-ahead price is almost identical to the overall average of day-ahead prices for the same time period.

16 A further complication of any direct sales to US markets is the possibility that Nalcor might have to adhere to US Federal Energy Regulatory Commission requirements, which could involve allowing outside competitors to sell into Newfoundland and require that there be an open-access transmission tariff in the province (see Power Advisory, LLC 2015, 162).

17 The greater difference for 2014 may have been due to a disruption in the Hydro-Quebec system that impeded Nalcor's access to the New York market (Nalcor 2015, 35).

18 Nalcor actually earned much less than the price because of high operating costs. Those costs consumed almost 40 percent of export revenues in 2013 and 2014 and largely reflect transmission tariffs for use of the Quebec grid.

19 The complexity of electricity systems may require some deviations, and the price to NP would be based on firm delivery, whereas a solicitation sale to NSP allows Nalcor some flexibility to change delivery scheduling.

20 Even in the existing isolated system, the effectiveness of a demand charge for a wholesale buyer is questionable. Presumably, it is intended to encourage lower peak demands, but its effectiveness may be very limited because most end users do not face demand charges, and there is no seasonal or peak-load pricing for end users. Moreover, once the Muskrat Falls plant is completed and integrated with the island system, there will be a substantial addition to capacity. That makes any argument for demand charges weaker.

21 It is interesting that the use of fixed charges as the sole means of paying for distribution services is under consideration in Ontario (see Ontario Energy Board 2014).

22 In those rural areas, distribution and related costs tend to be somewhat higher. Under current government policy, rates in those areas are kept identical to those in NP's service areas for corresponding customer classes. Whether that policy should be continued is a separate question and not the subject of this analysis.

23 Under the terms of the federal loan guarantee, equity investment in Muskrat Falls must be at least 35 percent, that is, debt financing cannot exceed a debt–equity mix of 65/35 (see NRCan 2012).

24 The provincial government's energy plan indicated that the regulatory regime would remain in place. That was in 2007. The first announcement of the Muskrat Falls arrangement was not until late 2010, and the project was not sanctioned by the provincial government until two years later, but no reassessment of the regulatory framework took place.

25 This would leave Nalcor with its various oil and gas interests. Whether it should continue as a provincial government–owned entity is a significant but separate public policy question.

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