CHRISTENSEN ASSOCIATES ENERGY CONSULTING

REVIEW OF NB POWER'S RATE DESIGN

prepared for
NB Power

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EXECUTIVE SUMMARY

NB Power wishes to review the extent to which its rates continue to meet its ratemaking goals, are consistent with current industry practice, and are suitable to a world with increasing competition from distributed energy resources. The utility is particularly concerned about its approach to the classification of customers and about several rate design issues raised by stakeholders. This report addresses these issues and makes recommendations concerning directions for future rate reform.

Rate Design Objectives

In general, rates should be designed to promote: a) utility financial stability necessary for reliable service; b) efficiencies characteristic of competition; and c) stakeholder support. Consistent with these general goals, NB Power presently has particular concerns about three sorts of equity issues related to its present tariffs:

- NB Power's present customer classification scheme sometimes results in similar customers paying very different average prices per kWh.
- NB Power wants to improve inter-class price equity by bringing all rate classes' revenue-to-cost ratios within a range of reasonableness of 0.95 to 1.05 by fiscal year 2027/28.
- NB Power wants to improve intra-class price equity so that, within each class, customers who are relatively inexpensive to serve pay relatively low average prices per kWh while relatively high-cost customers pay relatively high average prices.

Overview of NB Power's Present Tariffs

NB Power has four major rate classes: Residential; Industrial; General Service; and Wholesale. It also has five sets of other rate schedules: unmetered; miscellaneous; short-term unmetered; rental facility; and customer facility. In addition, NB Power offers interruptible service to large industrial customers.

NB Power's tariffs are conventional in that they are mostly straightforward two- or three-part tariffs and they do not separately recover generation costs and wires costs. They are unusual in that: a) there are no time-varying prices except for a relatively small quantity of interruptible and surplus power sold to Large Industrial customers; b) the Small Industrial tariff is a Wright tariff; and c) there is a plethora of rate schedules for miscellaneous uses of electricity.

NB Power's prices compare favorably to those of its regional peer utilities. Its average prices per kWh are between 11% and 26% below the average of its peers for all the major retail classes.

NB Power's Billing, Metering, and Data Management Capabilities

Currently, NB Power's pricing and rate designs are relatively simple, partly due to technical limitations in metering, data management, and billing capabilities. NB Power is modernizing its grid, and has proposed to upgrade its metering capabilities to an advanced metering infrastructure (AMI) over the next several years. With AMI data, NB Power will have enhanced ratemaking capabilities due to more detailed measurement of customer loads and better ability to communicate prices to customers.

Customer Classification

Customer classification should depend upon two main factors: the *costs* of serving different types of customers and the *competitive alternatives* available to different types of customers. Thus, to the extent feasible, customer classification should group together those customers who are as similar as possible in the costs that they impose on the utility and in their competitive alternatives to the utility's electricity, and should separate customers who are different with respect to these characteristics.

NB Power currently classifies retail customers as Residential, Industrial, or General Service. It divides Residential customers into the Urban, Rural or Seasonal subclasses. It separates Industrial and General Service customers according to their standard industrial classification codes, and then divides Industrial customers into subclasses by peak demand.

In contrast to NB Power's approach, the power industry generally uses classification schemes based on customer size (usually defined by peak demand) and voltage level. The size-based approach has the merit of better reflecting cost to serve, which facilitates cost recovery when demand and energy charges closely conform to demand- and energy-related cost to serve. On the other hand, an effort by NB Power to move to a size-based approach would create winners and losers, might entail a time-consuming effort, would change but not eliminate boundary issues, and might fail to recognize the dependence of competitive alternatives upon end uses.

Heating versus Non-Heating Residential Customers

About 63% of NB Power's Residential customers have winter space heating loads. Such heating customers are more expensive to serve than non-heating customers because they consume relatively more power during the winter on-peak hours when electricity is most expensive in New Brunswick. Charging the same price to customers with significant space heating consumption as is charged to other customers makes it likely that intra-class cross-subsidy is occurring.

Many utilities make no special provision for pricing electric space heating customers differently than other Residential customers. Utilities that *do* give special consideration to space heating customers usually offer either: a) separate rates for customers with space heating; b) block pricing that assumes that it will be primarily heating or cooling customers who reach the tail block; or c) time-of-use (TOU) pricing that recognizes the time-varying costs associated with heating load. Block pricing has been more common due its simple metering requirements; but the substantial decline in metering costs is making TOU more attractive. It has also been suggested that demand charges could be used as a tool to differentiate the revenues from heating versus non-heating customers.

Charitable Organizations

NB Power serves some charitable organizations, grandfathered by their status on August 29, 1979, under the Residential tariff. The remaining organizations are served under the General Service tariff. The treatment of charitable organizations as residential customers is unusual. Instead, the electric utility industry generally places such organizations in customer classes consistent with their premises.

Costs are central to a decision to reclassify the grandfathered organizations. A charitable organization operating out of commercial property (as opposed to a business office in a home) and having normal business hours is likely to have a load profile similar to a small General Service customer and arguably should be treated as such. There does not appear to be any cost or competitive basis for separate classification of charitable organizations, or for separate subclassification within General Service.

Farms

NB Power serves farms under the Residential Rate. This is problematic because farms have load patterns that are often very different than those of residences and because serving farms involves relatively high fixed distribution costs due to the relatively low density of the areas in which farms are located. Industry practice with respect to farms is mixed, with some utilities including farms in their Residential class, some including farms in their Small Industrial class, others offering special farm rates, and yet others making no explicit mention of farms in their tariffs.

Time-Varying Electricity Rates

Electricity prices with time variation can be classified as being *static* or *dynamic*. Static prices are enumerated in tariff sheets, and so are set well in advance of the time periods to which they apply and change only upon approval by regulators. In contrast, dynamic prices are determined through *processes* described by tariffs and approved by regulators, with the actual numbers being set and delivered to retail customers at short notice, such as a day or an hour before the time periods to which they apply.

Time-varying electricity rates can provide benefits if the marginal costs of electricity vary significantly over time and if customers respond to price by increasing consumption when prices are low and reducing consumption when prices are high. Thus, in principle, electricity prices should vary hourly with power system conditions as measured by marginal costs, which change over time with changes in power system conditions.

NB Power's marginal costs depend upon the costs of the generation resources available to its system operator, where such resources include both its own generators and power procured under power purchase agreements from resources both within and outside the province. NB Power's marginal cost estimates have time patterns that are consistent with the utility's designation of on-peak and off-peak hours in its interruptible and surplus power rates for Large Industrial customers, being higher on weekdays than on weekends and higher from 8 am to midnight than in other hours. Furthermore, NB Power's marginal costs are higher in the months of December through April than in other months. The marginal cost numbers show a moderate amount of time variation, with a ratio of about 2.3 between the highest- and lowest-cost periods.

Distributed Energy Resources

Distributed energy resources are sources of electrical energy located at or near loads rather than at central generating stations. Such resources currently consist predominantly of self-generation facilities such as solar panels, combined heat and power units, and wind turbines owned by retail customers; but they can also include battery storage.

In principle, distributed energy resources should be compensated for the services that they provide *to* the power system, and should pay for the services that they receive *from* the power system. All distributed energy resources provide electrical energy. Depending upon the dispatchability of a particular resource's technology, a resource might also provide automatic generation control, load following, operating reserves, capacity, voltage control services and/or environmental benefits. Distributed energy resources can impose three types of costs on the power system: those of ancillary services, particularly operating reserves and load following; those of transmission and distribution upgrades; and those of implementation.

In practice, the dominant vehicle for pricing these services is net metering which, as implemented by NB Power and nearly every other utility in North America, fails to compensate distributed energy resources according to the net values that they provide to the power system, but instead pays compensation that far exceeds these values. The result of this mispricing is generally a flow of cross-subsidies from customers *without* self-generation to customers *with* self-generation. As long as distributed energy resources have a trivial market share, these cross-subsidies are trivial; but as this market share rises, the cross-subsidies also rise.

The compensation enjoyed by owners of distributed energy resources has a large effect on investment in, and operation of, those resources. Higher compensation leads to more investment. For dispatchable resources, higher compensation also leads to greater use of resources; and time-varying prices can induce resources to produce more power when it is needed most, and less power when it is needed least. For all resources, time-varying prices can induce maintenance to be scheduled at those times when power is needed least.

Standby Pricing

Standby tariffs typically apply to self-generating customers that are ineligible for net metering. The purpose of these tariffs is to assure cost recovery from customers with their own generation in the usual situation that the utility's standard tariffs do not accurately reflect cost causation. Standby tariffs then serve as a means of recovering, from self-generation customers, the costs of the ancillary services and transmission and distribution services upon which these customers rely. On the other hand, if standard tariffs accurately reflected cost causation, then self-generation customers could simply purchase power under the standard tariffs, which would be sufficient to recover costs caused by these customers.

Over the long term, standard tariffs should be reformed or unbundled so that they better reflect cost causation and so that standby tariffs are unnecessary. In the short term, however, and particularly as long as significant shares of customer- and demand-related costs are recovered through energy charges, standby tariffs are needed to assure that standby customers pay their fair shares of costs.

Interruptible Customer Cost Responsibilities

NB Power must meet a renewable energy requirement embodied in the province's Renewable Portfolio Standard, requiring that 40% of in-province sales be sourced from renewable generation by 2020. NB Power may also be obligated to pay a carbon tax, if such becomes law.

The Renewable Portfolio Standard and an actual carbon tax would not necessarily change the basis for the price of the Large Industrial interruptible rate – it could still be incremental cost plus a small adder – but the calculation of incremental cost would be modified to include the incremental costs of these two environmental measures. Indeed, the incremental cost applicable to firm power would also need to be modified to include the incremental costs of these two measures.

Recommendations

Our recommendations regarding general issues include the following:

- *Time-Varying Prices*. We recommend that, when technology permits, NB Power offer time-varying rates to large customers on a mandatory basis and to mass-market customers on a voluntary conversion with opt-out basis.
- *Revenue-to-Cost Ratios*. We recommend that NB Power attempt to move Residential and General Service revenue-to-cost ratios closer together.
- *Standby Pricing*. We recommend that NB Power's standby service pricing reflect the costs of the unbundled services – electrical energy, ancillary services, transmission, and distribution – that together comprise standby service. Customers should also pay for any special costs of resolving problems, like voltage fluctuations, that customers' generation would otherwise cause. Since NB Power's rates (like those of other utilities) do not fully reflect cost causation, introducing a standby tariff in the upcoming filing would be both desirable and timely.
- *Allocation of Grid Modernization Costs*. We recommend that NB Power directly assign to participating customers the full cost of site-related upgrades related to customer initiatives such as distributed energy resources or electric vehicle (EV) charging. Otherwise, the utility should apply standard cost allocation techniques to the bulk of grid modernization costs.

- *Interruptible Service Pricing*. We recommend that interruptible customers continue to pay prices based upon incremental costs, which should include those of environmental policies.
- *Green Pricing*. We recommend that green pricing rates be based upon the same combination of incremental costs and embedded costs as applies to interruptible service.

Our recommendations regarding residential customer issues include the following:

- *Residential Time-Varying Prices*. We recommend that the Residential tariff include a seasonal element with two seasons. Upon completion of interval data recorder installation, NB Power can consider a seasonal TOU design with pricing periods and price ratios based on NB Power's marginal cost patterns, with two pricing periods in each season.
- *Heating versus Non-Heating Residential Customers*. We recommend that seasonal time-varying prices be used to recognize the cost differences between heating and non-heating residential customers. Such seasonal variation may be accompanied by two pricing periods in each season upon installation of interval data recorders.
- *Charitable Organizations*. We recommend that NB Power phase out the grandfathered charitable organization service under the Residential tariff.
- *Farms*. We recommend that NB Power consider a maximum size limitation on the farms that are allowed on the Residential rate.
- *AMI*. We recommend that NB Power allow Residential customers to opt out of AMI service subject to the caveat that opt-out customers pay the incremental costs of their decision.
- *Residential Customer Cost Recovery*. We recommend that NB Power consider increasing the recovery of fixed Residential customer-related costs through its Residential customer charges and/or through a demand charge. Such increases may be introduced on a phased-in basis.

Our recommendations regarding business customer issues include the following:

- *Business Customer Classifications*. We recommend that NB Power remove the distinction in rates between commercial and industrial customers, creating a size-based classification, splitting business customers into three or four subclasses, perhaps differentiated by peak loads and voltage levels. The timeframe for the transition might depend upon the sizes of the impacts, with larger impacts implying a longer transition period; though it may be advisable to aim for the fiscal year 2027/28 target that NB Power has already set for moving all rate classes' revenue-to-cost ratios to within the range of reasonableness. A scheme of transitional discounts and premia specific to the type of transition could provide a relatively simple price transition mechanism.
- *Business Time-Varying Prices*. We recommend that NB Power put small business customers on a standard seasonal tariff or seasonal TOU tariff (with an opt-out), and that it put medium and large business customers on a seasonal TOU rate. All business

customers should be offered optional dynamic pricing programs (like critical-peak pricing (CPP) and real-time pricing (RTP)) and an optional interruptible rate. To facilitate implementation, the optional programs could be offered on a phased-in basis starting with the largest customers.

- *Customer Charges*. We recommend that NB Power consider charging all classes for customer-related costs via a customer charge.
- *Demand Charges*. We recommend that mandatory demand charges be extended to apply to all business customers with at least 5 kW of demand.
- *Wright Tariff*. We recommend that the Wright tariff be phased out over a period of a few years.
- *Economic Development*. NB Power could continue offering a declining discount demand price for large industrial customers who add load in excess of a 5,000 kW threshold, based upon an updated rate portfolio with a base seasonal TOU tariff. On the other hand, if NB Power seeks increased ability to use discounting to attract new load, it could reduce this threshold. If this change is not desirable for some reason, but expanded eligibility is desired, NB Power could permit customers to meet this threshold through load expansions at multiple facilities or in prespecified phases. Alternatively, NB Power could offer an economic development rate (EDR) product based on RTP, under which energy above current consumption levels is sold to the customer at market-based prices and fixed charges are recovered through a demand charge that rises to the normal tariff level after (say) five years.
- *Load Retention*. For customers on current rates, who might take service in the future under seasonal, or seasonal TOU rates, we recommend that discounts be in the form of energy prices that move closer to marginal cost over the agreed life of the discount.
- To limit the subsidization of participating customers, we recommend that participation in EDRs and load retention rates programs be limited to those customers whose businesses offer substantial benefits to the Provincial economy and who can demonstrate such benefits.
- *Export Subsidies*. We do not recommend offering subsidies to exporters.

Our recommendations regarding distributed energy resource pricing issues include the following:

- We recommend that, at its earliest opportunity, NB Power replace its net metering tariff with an alternative design that avoids or minimizes cross-subsidy. This design could include a non-coincident demand charge that recovers demand-related costs, and a customer charge that fully recovers customer-related costs, and, as a result, an energy charge that covers volumetric costs only. TOU pricing would further improve price accuracy. This tariff could be designed to be bill neutral to the standard tariff that would otherwise serve the customer.
- In the long run, NB Power should have the goal of redesigning its standard tariffs to recover energy costs through energy charges, customer costs through customer charges,

and demand costs through demand charges. A companion long-term goal would be to credit or pay customers for excess energy according to marginal energy costs, market conditions, or accounting energy costs only.

REVIEW OF NB POWER'S RATE DESIGN

1. INTRODUCTION

NB Power wishes to review the extent to which its rates continue to meet its ratemaking goals and are consistent with current industry practice. In addition, the utility is concerned about whether its approach to the classification of customers should be continued, or whether possible alternatives might facilitate improved ratemaking.

Furthermore, like a large majority of electric utilities, NB Power designed its tariffs in a world in which customers had limited alternatives to power provided by their utilities. The costs of such alternatives, including customer-owned generation and other distributed energy resources, have fallen substantially in recent years and threaten to undermine the viability of traditional utility tariffs. NB Power wishes to consider whether its tariffs need to be adapted to this newly competitive business environment.

The purpose of this report is to review NB Power's retail rate portfolio in light of the above concerns. Christensen Associates Energy Consulting is undertaking this review at NB Power's request in response to the desire of the New Brunswick Energy and Utilities Board (Board) for a separate rate design proceeding.[1] In the course of this review, we examine several rate design issues that are of specific concern to NB Power, its stakeholders, and the Board; and we make recommendations concerning directions for future rate reform.

The review is predominantly qualitative in nature, commensurate with the broad overview of NB Power's rate portfolio and customer classification methods. While we offer illustrative computations with respect to certain costs, prices, and bills, more precise computation will be undertaken after policy decisions are made to pursue specific rate reform. At this point, prior to such policy decisions, it is sufficient and cost-effective to focus the analysis on qualitative assessment of alternatives approaches.

2. BACKGROUND

This section provides overviews of rate design objectives, NB Power's present tariffs, and the company's billing, metering, and data management capabilities.

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[1] At ¶95 of its May 13, 2016 decision in Matter 271, the Board states "NB Power is directed to prepare a proposed strategy for the timely introduction of seasonal allocation of energy and demand production costs together with a corresponding rate design strategy." At ¶93 of that same decision, the Board refers to the need for "a hearing in which rate design and rates are under consideration." In a letter to NB Power dated August 2, 2016, the Board says that it "has determined that a separate proceeding should be held to address rate design."

2.1. Criteria for Successful Rate Design

James Bonbright authored what have become the generally accepted criteria for electricity rate design.[2] Although these criteria were developed during the era of fully regulated vertically integrated utilities, they reflect considerations that are relevant to today's increasingly competitive markets. Specifically, the criteria simultaneously promote the financial stability necessary to maintaining the physical power generation and delivery facilities that are critically important to modern economies, the efficiencies that ideally arise from competition in generation services, and the stakeholder support that is essential to the power system's institutional stability. Along these lines, the Bonbright criteria can be listed as follows:

Promote Financial Stability Necessary for Reliable Service:

1. Provide revenue stability and predictability.
2. Recover total revenue requirements.

Promote Efficiencies Characteristic of Competition:

3. Encourage efficient use of electricity.
4. Reflect present and future private and social costs and benefits of electricity service.
5. Encourage technical innovation and economic response in the production and use of energy.

Promote Stakeholder Support:

6. Promote rate stability for customers.
7. Strive for fairness in apportioning costs.
8. Avoid undue discrimination.
9. Be simple, understandable, and acceptable to stakeholders.
10. Be free from controversy as to interpretation.

These criteria are applicable to both investor-owned utilities and to publicly owned utilities such as Canadian Crown corporations, as both types of utilities inevitably serve the public's interest in providing the reliable and reasonably priced service that is central to modern society's functioning. As a practical matter, electricity is such a critical commodity that even privately owned firms must be held accountable to meet minimum criteria for its provision and pricing. The Bonbright criteria thus continue to be relevant to the core regulatory objectives of assuring reliable electricity supply through the financial stability of the industry, emulating competitive markets, and achieving public acceptability.

[2] J.C. Bonbright, A.L. Danielson, and D.R. Kamerschen, *Principles of Public Utility Rates*, Public Utility Reports, Inc., 1988, pp. 382-384.

2.2. Rate Objectives of NB Power

Consistent with the Bonbright criteria, NB Power shares rate objectives common to other utilities, namely revenue sufficiency, pricing efficiency, and cost causality. Consequently, the company is particularly concerned about three sorts of apparent inequities in its present tariffs.

First, its customer classification scheme sometimes results in customers of similar size and similar load patterns being placed in different rate classes, with the consequence that similar customers can have quite different bills as expressed in average prices per kWh. Although such circumstances also occur at other electric utilities, they nonetheless highlight a need for the company to review its methodology for classifying customers. NB Power uses a traditional residential/commercial/industrial segmentation, with subdivision of the business class on the basis of size. The utility would like to review alternatives and determine whether it would be beneficial to switch to a segmentation approach based more on customer size and load characteristics than on customer type as defined by end use of electricity.

Second, the company has an objective of improving inter-class price equity, by which pricing would more closely reflect cost causation than it does now. The degree of equity can be measured by the extent to which each rate class' revenue-to-cost (RC) ratio approaches 1.00. Like some other utilities, NB Power operates in a jurisdiction with a "range of reasonableness" for RC ratios, which the Board has set as 0.95 to 1.05 for all rate classes.[3,4] Like other regulators, the Board does not require an exact value of 1.00, since such a requirement would result in sudden drastic rate changes; but it instead encourages NB Power to move its tariffs in the direction of rate parity, with all RC ratios moving toward the range of reasonableness over a series of rate applications over a period of several years. NB Power's goal is to have all rate classes within the range of reasonableness by fiscal year 2027/28, while recognizing that external factors can affect its success in achieving this objective.

Third, the company has an objective of improving intra-class price equity. Unlike *inter*-class equity, *intra*-class equity is concerned with moving all customers within each class to a range of reasonableness for RC ratios: customers who are relatively inexpensive to serve should pay relatively low average prices per kWh, while relatively high-cost customers should pay relatively high average prices. As a practical matter, utilities do not typically seek to achieve uniform RC ratios on a customer-specific basis but instead pursue intra-class equity by setting average customer, demand, and energy prices close to their respective customer, demand, and energy unit costs.

[3] New Brunswick Energy and Utilities Board, in its June 14, 2017 decision in Matter No. 336, states, at p. 8, "In its decision of May 13, 2016 (Matter 271), the Board reaffirmed that a RCR [revenue-to-cost ratio] within a range of 0.95 to 1.05 is reasonable."

[4] For examples of utilities with ranges of reasonableness, see Leidos, Inc., *Cost of Service Methodology Review*, prepared for British Columbia Hydro and Power Authority, Dec. 20, 2013, Table C-13. Some utility targets are 100%; but the small sample also revealed target ranges of reasonableness of ±5% and ±10%.

2.3. Overview of NB Power's Present Tariffs

This section describes NB Power's present customer classes, tariff structures, and price levels.

2.3.1. Class Definitions

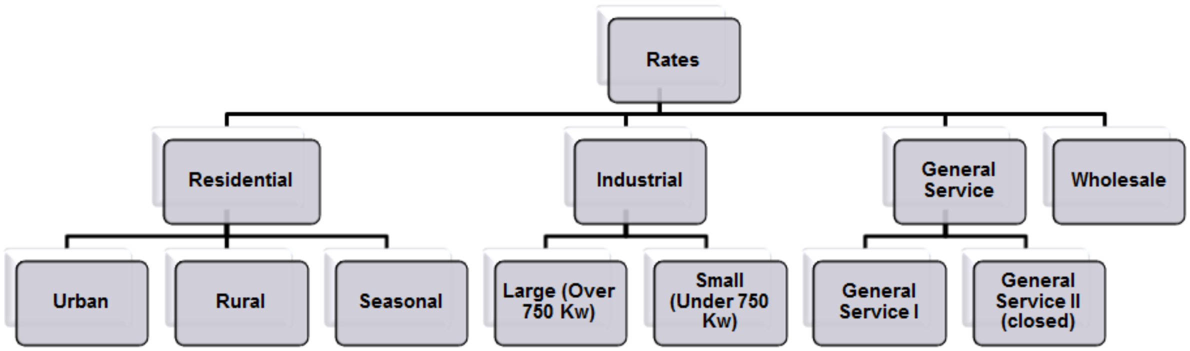
NB Power has four major rate classes, which are defined as follows:

- *Residential Customers* are retail customers who use electricity for their homes, churches, and farms.
- *Industrial Customers* are retail customers who use electricity mainly for manufacturing, assembly or processing of goods, or the extraction of raw materials.
- *General Service Customers* are retail customers who do not fall into the Residential, Industrial, street lighting, or unmetered customer classes.
- *Wholesale Customers* are two municipal distribution electric utilities, Saint John Energy and City of Edmundston.

Figure 1 shows the structure of these four major classes and their subclasses. The Residential Customer subclasses are distinguished by the sizes of the municipalities in which customers live (municipalities with populations over 2,000 are deemed "urban") and by whether service is for a primary residence or a second home used seasonally. Industrial Customer subclasses are distinguished by the sizes of customers' non-coincident peak loads, with 750 kW being the cutoff between "small" and "large" customers. General Service customers are served primarily under the General Service I (GS I) tariff, but some continue to be served under the now-closed General Service II (GS II) tariff.[5]

[5] The GS II tariff gives favorable treatment, in the form of a low demand charge, to those customers who are lucky enough to be grandfathered onto this rate. Because GS II apparently discriminates in favor of some customers (on GS II) over similar customers (on GS I), "NB Power continues to support any and all efforts that will lead to the eventual elimination of the GS II customer class." In the meantime, NB Power intends to gradually close the gap between the GS I and GS II demand charges. See New Brunswick Power Corporation, *2017 Rate Design*, filing with New Brunswick Energy and Utilities Board, May 1, 2017, pp. 22-23.

Figure 1
NB Power's Present Major Customer Classifications[6]



In addition to the major classes depicted in Figure 1, NB Power has five sets of other rate schedules:

- *Unmetered Rate Schedules* base the customer's bill upon estimated consumption. These schedules apply to electricity uses for which consumption is uniform and easily estimated, such as traffic control lights, radio transmitters, airport runway lights, and highway traffic counters.
- *Miscellaneous Rate Schedules* apply to railway flashing signals, railway safety gates, air raid and fire sirens, and outdoor Christmas lighting.
- *Short-Term Unmetered Rate Schedule* applies to electricity uses connected for no longer than one month.
- *Rental Facility Rate Schedules* apply to water heaters, area lighting, street lighting, and poles.
- *Customer Facility Rate Schedule* applies to customer-owned street lighting, area lighting, and outdoor recreational lighting.

In addition, NB Power offers interruptible service to large industrial customers.

2.3.2. Tariff Structures

NB Power's Residential tariffs are conventional two-part tariffs, with a 10.81 cent per kWh energy charge and monthly customer charges of $21.60 for urban customers and $23.69 for all other customers.[7]

NB Power's Small Industrial tariff is an "hours-of-use" or "Wright" tariff. It has a conventional demand charge, of $6.90 per kW-month, subject to a 5 kW minimum; but its energy charge has two blocks that apply to quantities of power related to the customer's peak demand. The first block has a price of 13.39 cents per kWh, and applies to a quantity of power equal to 100 times

[6] *Id.*, p. 14.

[7] Throughout this document, all dollar figures are in Canadian currency unless otherwise noted.

the customer's peak demand for the month. For example, a customer with peak demand of 500 kW in a particular month would pay 13.39 cents per kWh on the first 50,000 kWh of energy consumption in that month. All additional consumption falls into the second block, which has a price of 6.32 cents per kWh. The purpose and effect of this Wright tariff is to give customers with load factors below 14%[8] – like sawmills with short demand spikes – a lower average cost per kWh than they would have with an equivalent two-part demand and energy tariff.[9]

NB Power's Large Industrial tariff is a conventional two-part tariff with a $14.07 per kW-month demand charge and a 5.20 cents per kWh energy charge. For interruptible and surplus energy in excess of reserved demand, there is no demand charge, and the energy charge is set as follows:

- For the on-peak period of 8 am to midnight on non-holiday weekdays, the energy charge is the on-peak period incremental cost plus 0.90 cents per kWh.
- For the off-peak period consisting of all other hours, the energy charge is the off-peak period incremental cost plus 0.30 cents per kWh.

NB Power defines incremental cost as the utility's additional cost of generation or purchased power after supplying its firm loads, as forecast a day ahead of the periods to which the incremental cost-based prices apply. It is calculated by a short-term dispatch optimization model, and interruptible energy prices are communicated to customers by NB Energy Marketing for the following week each Wednesday.

NB Power's General Service I tariff has, in each billing period (i.e., month), a customer charge of $22.70, a demand charge of $10.45 per kW for demand in excess of 20 kW, and an energy charge that is 13.07 cents per kWh on the first 5,000 kWh of consumption and 9.27 cents per kWh on all addition consumption.[10]

NB Power's Wholesale tariff is a conventional two-part tariff with a $14.15 per kW-month demand charge and a 6.63 cents per kWh energy charge.

In summary, NB Power's tariffs are conventional in the following ways:

- They are mostly conventional two- or three-part tariffs.
- They do not separately recover generation costs and wires costs.

NB Power's tariffs are unusual in the following ways:

- With the exception of the relatively small quantity of interruptible and surplus power sold to Large Industrial customers, there are no time-varying prices.
- The Small Industrial tariff is a Wright tariff, which is unusual but not extraordinary.

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[8] The 14% figure equals the 100 hours factor that is multiplied by the customer's peak demand, divided by the number of hours in the month. For example, in a 30-day month with 720 hours, the threshold load factor would be 100/720 = 13.9%.

[9] The equivalent tariff would have a 6.32 cents per kWh energy charge and a $13.97 per kW-month demand charge. $13.97/kW-mo = $6.90/kW-mo + ($0.1339/kWh – $0.0632/kWh)*(100 hours/month).

[10] The text ignores General Service II, which has similar prices but is closed.

- There is a plethora of rate schedules for miscellaneous uses of electricity.

2.3.3. Price Levels

NB Power's prices compare favorably to those of its regional peer utilities. As shown in Table 1, NB Power's average prices per kWh are between 11% and 26% below the average of its peers for all the major retail classes; and, for all these classes, NB Power has the third lowest prices of the eight utilities. In other words, NB Power has prices that are toward the lower end of the spectrum.

Elenchus Research Associates, in a recent cost allocation review prepared for NB Power, examines the relationship of revenues to costs of service for each customer class. Their report implicitly finds that, at present price levels, Residential and Wholesale customers are being subsidized by customers served under the General Service, Large Industrial, Street Lights & Unmetered, and Water Heater tariffs.[11]

Table 1
Average Prices, by Retail Class, as of 1 April 2017
(cents per kWh, excluding taxes)[12]

Utility	Residential	General		Small Industrial	Large Industrial
	1,350 kWh	40 kW 10,000 kWh	500 kW 200,000 kWh	150 kW 60,000 kWh	50 MW 31,025 MWh
Central Maine Power	18.79	17.17	12.40	14.25	8.99
Hydro One (Ontario)	14.30	15.30	16.30	16.53	12.83
Hydro-Quebec	7.60	9.83	8.30	8.17	5.03
Maritime Electric (PEI)	15.78	17.11	14.50	12.40	9.28
Newfoundland Power	10.74	11.56	7.90	8.57	4.88
Nova Scotia Power	15.87	15.33	12.80	11.70	10.11
Public Service New Hampshire	25.54	24.00	21.10	21.41	19.23
Average Peer	15.52	15.76	13.33	13.29	10.05
New Brunswick Power					
Price	12.41	13.49	11.80	9.81	7.47
Discount Relative to Peers	20%	14%	11%	26%	26%
Rank	3	3	3	3	3

[11] Elenchus Research Associates Inc., *New Brunswick Power Seasonal Customer Cost Allocation Study*, 31 May 2017, p. i. The subsidization is implicit in the revenue-to-cost ratios, with low ratios indicating recipients of subsidies and high ratios indicating payers of subsidies.

[12] NB Power, *Utility Comparison Summary*, 1 April 2017.

2.4. NB Power's Billing, Metering, and Data Management Capabilities

NB Power's pricing and rate designs are relatively simple, partly due to past technical limitations in metering, data management, and billing capabilities. For mass market customers, rate design and costing has been supported by simple metering that records monthly total energy usage only; meter readers have manually collected data according to a defined reading schedule; and bills have been based primarily on monthly total energy usage records and peak demand readings. Only wholesale customers and the largest industrial customers have had bills based upon interval data.

NB Power is modernizing its grid, and has proposed to upgrade its metering capabilities to an advanced metering infrastructure (AMI) over the next several years. With AMI, new meters for essentially every customer will collect customer usage data as frequently as every five minutes and will enable two-way communication between customer meters and NB Power.

NB Power and its customers can benefit from advanced billing, metering, and data management capabilities. These benefits may include more efficient use of electricity, reduced meter-reading costs, reduced service connection and disconnection costs, reduced distribution system energy losses, improved reliability through better system control, better integration of distributed resources with conventional power system resources, and quicker response to power outages. In addition, there are at least two ways in which these advanced capabilities can enhance rate design.

First, these capabilities can facilitate better allocations of costs among customers. The broad availability of interval data will help the company to better understand the cost to serve various rate classes for whom estimates of load profiles have been incompletely available in the past. Within classes, the utility will be able to understand better the variation across customers in costs to serve. For example, the effect of heating systems and of the influence of weather on heating consumption will be much more clearly discernible than in the past.

Second, advanced capabilities allow more complex rate designs than NB Power presently has. In particular, NB Power will be able to offer its customers an increased range of time-varying products, which will allow the company to better match the time pattern of prices with that of costs. Additionally, NB Power will be able to explore more fully the use of marginal cost-based pricing products, especially those that are capable of eliciting demand response. By better communicating marginal costs to customers through time-varying prices, and with the aid of communications systems that link directly to programmable appliances, NB Power will be able to induce customers to reduce load (or perhaps increase self-generation) during periods of low reserves. Pricing alternatives that can take advantage of this communication structure include:

- Direct load control programs that disconnect customers' designated processes at times of low reserves.
- Interruptible pricing that is triggered by power system conditions and pays customers for load reductions at market-based prices announced at short notice.

- Critical-peak pricing (CPP) programs that signal periods of low reserves and induce customers to reduce consumption, either by taking action themselves or according to preprogrammed responses.

Past evidence at other utilities indicates that customers who volunteer for such programs can achieve load reductions that significantly increase system reserves in the short run, and that can postpone investment in new generation in the long run. Thus, innovative pricing can help customers to control electricity expense while benefiting other customers on the system by improving reliability.

Table 2 provides a list of some of the rate designs that may be supported by AMI. The leftmost column lists rate designs of increasing sophistication, starting with a basic flat energy charge and no price variation over the year. This rate is typically offered to residential customers and perhaps small business customers; its pricing is "static" in that prices are enumerated in tariff sheets; a traditional meter records usage; billing is traditional in format; and communication is one-way in the sense that data (on electricity consumption) flows only from the customer to the utility.

Table 2
A Taxonomy of Rate Designs and Technical Underpinnings

Rate Design	Target Customers	Pricing	Technical Characteristics		
			Metering	Billing	Communication
Flat	residential	static	watthour meter	traditional	one-way
Seasonal	residential, business	static	watthour meter	traditional	one-way
Blocked	residential, business	static	watthour meter	traditional	one-way
+ Demand	business	static	demand meter	traditional	one-way
Time of Use	residential, business	static	two-channel meter	traditional	one-way
Interruptible	business	static	interval data recorder	traditional	two-way
Real-Time Pricing	business	dynamic	interval data recorder	upgraded	two-way
Critical-Peak Pricing	residential, business	dynamic	interval data recorder	upgraded	two-way

The remainder of the table presents rate designs of increasing time variation. Seasonal rates vary by season. Blocked rates vary by the amount of energy consumed within each billing period (e.g., month). Demand charges require the ability to measure peak power flows as well as total power flows. Time-of-use (TOU) rates require a two-channel meter or an interval data recorder. Interruptible and curtailable pricing has static design in the sense that prices are enumerated in advance via tariff sheets, although notice to interrupt comes at short notice; but they require that the utility know the usage/demand in the period of interruption, which may be facilitated by an interval data recorder; and communication must be two-way so that the utility can provide notice of interruption.

The benefits of interval data recording and AMI features are most pronounced for dynamic pricing regimes like CPP and real-time pricing (RTP), under which prices may change hourly. These designs rely on the customer being able to receive prices for upcoming time periods at short notice, and require hourly interval data being recorded and used in billing. Communication is two-way and likely more demanding than an interruption call, since both prices and time intervals to which they apply must be provided. Additionally, if the customer and utility agree on automated data management, the price signal (or some other signal) can be used to trigger changes in the levels of consumption of various end uses.

The table implies that the key elements for broadening the range of retail pricing designs are the arrival of interval data recording, the ability to make use of interval data, and the ability to communicate to the customer at short notice.

Aside from the characteristics portrayed in the table, it is worth noting that the utility benefits if, in making use of interval data recorders, it can use its store of load research data to improve the pricing of its contracts with customers. Aside from being able to estimate cost to serve with greater accuracy than is possible from billing data only, some rate designs rely on contractual levels of usage. Having a customer's usage pattern in hourly detail throughout the year can facilitate arriving at a mutually beneficial pricing arrangement. Examples include real-time pricing, special contracts, economic development rates, and interruptible/curtailable pricing.

3. CUSTOMER CLASSIFICATION

NB Power is concerned that its customer classification system may be in need of significant reform. One issue is whether business customers should be classified according to: a) their business type (i.e., standard industry classification); or b) their load characteristics (predominantly peak demand) and voltage level. Another issue is whether residential customers should be divided into separate subclasses depending upon whether or not they have electric space heating. A third issue concerns whether charitable organizations should continue to be separated from the General Service customer class for reasons unrelated to cost or competitive alternatives.

To address these and other issues, this section first provides some principles for customer classification. For each of these issues, it then summarizes NB Power's current approach, reviews general industry practice, and makes recommendations.

3.1. Principles for Customer Classification

Customer classification should depend upon two main factors: the costs of serving different types of customers and the competitive alternatives available to different types of customers. Thus, to the extent feasible, customer classification should group together those customers who are as similar as possible in the costs that they impose on the utility and in their competitive alternatives to the utility's electricity, and should separate customers who are different with respect to these characteristics.

With respect to costs, customers are distinguishable by their sizes, load patterns, and locations. In general, average costs are lower:

- for larger customers than for smaller customers (because fixed costs, such as for metering and billing, do not rise as rapidly as customer size rises)[13];
- for customers with relatively large off-peak loads than for customers with relatively large on-peak loads;
- for customers with high load factors than for customers with low load factors;
- for customers located near generation resources than for customers located far from generation resources;
- for customers obtaining service at higher voltage levels than for those obtaining service at lower voltage levels; and
- for customers located in densely populated areas than for customers located in sparsely populated areas.

With respect to competitive alternatives, large commercial and industrial customers often have competitive alternatives for where they locate new or existing business. The cost of electricity service can influence such locational decisions. These customers sometimes use their locational flexibility as a tool for extracting discounts from their electricity service providers.

Additionally, many customers – residential, commercial, and industrial – have long had alternative sources of energy for certain uses of electricity, such as heating. Distributed energy resources now offer the possibility of providing another competitive alternative to utility-supplied electricity for many customers of all types. In brief, competitive alternatives for customers have long existed and have recently been increasing, and thus are likely to figure more prominently in the future than they have in the past in determining customer classes and subclasses. Like every other business, electric utilities need to consider how the demand for their product is affected by the price (and other terms of sale) of the product; and competition can have important impacts on demand.

Utilities (and their regulators) have often faced challenges from customers and customer groups who request that they be separated from other customers, sometimes on the basis of cost, sometimes on the basis of competitive alternatives, and sometimes merely as a matter of special privilege. One result of these challenges has been the development of special contracts for very large customers and of economic development rates and load retention rates for other business customers. These contracts and rates, along with nominally "interruptible service" programs that rarely or never interrupt customers, serve as means for giving price discounts to customers with plausible competitive alternatives. Another result of these challenges is that almost all utilities carry in their tariff books a variety of distinctions for such groups as churches, schools, farms or irrigation accounts, government installations, and other entities that have persuaded the utility and its regulators that they are meaningfully different from other customers in the class to which

[13] Larger customers tend to need more individualized customer care than do smaller customers, but it does not follow that the average cost of customer service per kWh rises with customer size.

they previously belonged. The cost and competitive rationales for such special contracts and distinctions merit periodic reconsideration.

These examples of utility practice illustrate how utilities have managed customer classification challenges in the past. Cost-related considerations – like size, load pattern, and location – have served to identify the main customer classes. Both cost- and demand-related considerations have created subclasses served under individual rates. For example, residential customers who can heat their homes with either natural gas or electricity have very different load profiles and levels of consumption; but they also can, at some cost, change their heating systems. Developers who construct new homes or renovate existing homes will respond to customers' awareness of heating costs in choosing the heating systems that they install.

For NB Power, the classification debate focuses first on whether the current classification among Residential, Industrial, General Service, and other customers should be retained or whether an alternative classification should be introduced. There are also secondary issues pertaining to the treatment of certain subclasses, specifically charitable organizations, and heating versus non-heating residential customers.

The central challenge is to select classification methods that consider the key characteristics of cost and competition. Meeting this challenge requires data revealing customer characteristics and viable alternatives in classification approach.

3.2. Basis for Classification

NB Power is concerned that its present classification approach sometimes results in two customers in different classes paying very different average bills in spite of being served by essentially identical equipment at the same voltage level. The utility therefore wonders if a different classification scheme might result in a better match between revenues and costs, though it is also concerned about how a change in classification scheme might impact bills.

3.2.1. NB Power's Current Classification Approach

NB Power currently classifies customers based on rules found in its *Rate Schedules and Policies* manual. NB Power places new customers into a customer class by first determining whether the customer is Residential, Industrial, or General Service, with division between the latter two categories depending upon standard industrial classification (SIC) code. Residential customers are domestic residences, churches, and farms. Industrial customers are those "who use electricity chiefly for manufacturing, assembly or processing of goods, or the extraction of raw materials," while General Service customers are those "who use electricity for all purposes other than those specifically covered under the Residential, Industrial, street lighting or unmetered service categories."[14] NB Power then divides Residential customers into the Urban, Rural or Seasonal subclasses, and divides Industrial customers into subclasses by peak demand.

[14] NB Power, *Rate Schedules and Policies*, Effective April 1, 2017, RSP page B-2. SIC definitions for Industrial customers appear in RSP page N-8.

This approach differentiates customers on the basis of inferred load profiles. For example, a manufacturer might be likely to have multiple shifts and fairly constant levels of electricity usage throughout the day, while a General Service customer might be likely to consume energy primarily during the weekday daylight hours. The chief difficulty with this approach, however, is that manufacturers and General Service customers each have a wide variety of operating practices and, consequently, a wide variety of load profiles and costs to serve. Another difficulty is that enterprises generally evolve over time; so accurate assumptions about the cost of serving a customer at a given time may not be true at a later time.

3.2.2. Overview of the Power Industry's Approaches

The power industry generally uses classification schemes based on customer size (usually defined by peak demand) and voltage level. The attraction of such schemes is that they base billing on the observable customer characteristics of usage, peak demand, and voltage level rather than upon potentially controversial information requirements (such as identification of SIC code for enterprises with multiple lines of business).

Table 3, which presents customer classifications for major Canadian utilities and for a sample of large U.S. utilities, shows that industry practice in Canada and the U.S. leans toward the size-based approach. The table lists the main rate class labels of each utility. Utilities using the business type approach are designated as "Res, Com, Ind" or "Res, Gen, Ind," which means that business customers are divided into commercial and industrial classes according their business type. The remaining utilities use labels that are variants of "Res, Gen" or "Res, Bus", indicating that non-residential customers are included in a single group and are differentiated by the sizes of their loads.[15]

[15] The abbreviations denote <u>res</u>idential, <u>com</u>mercial, <u>ind</u>ustrial, <u>gen</u>eral, and <u>bus</u>iness customers. Two utilities use the label "Domestic" in place of "Residential". Hydro-Quebec uses the label "Power" in place of "Business".

Table 3
Classification Methods in Current Use for a Sample of North American Utilities

Utility	Customer Classification
Canada	
BC Hydro	Res, Bus
Enmax[16]	Res, Bus
Epcor	Res, Com, Ind
Hydro Ottawa	Res, Bus
Hydro-Quebec	Domestic, Power
Manitoba Hydro	Res, Gen
NB Power	Res, Gen, Ind
Newfoundland Power	Domestic, General
Nova Scotia Power	Res, Com, Ind
SaskPower	Res, Bus
Toronto Hydro	Res, Bus
United States	
Alabama Power Co	Res, Bus
Arizona Public Service Co	Res, Bus
Central Maine Power	Res, Gen
DTE Electric Company	Res, Gen
Duke Energy Florida	Res, Com
Georgia Power Co	Res, Gen
Niagara Mohawk Power	Res, Gen
Public Service Co of Colorado	Res, Gen
Public Service of New Hampshire	Res, Bus
Union Electric Co	Res, Gen
Salt River Project	Res, Gen
Wisconsin Electric Power	Res, Gen

Among eleven Canadian utilities, three adopt the business type approach (including NB Power) while the remaining eight use the size-based approach. In the sample of twelve large U.S. utilities, none utilize the business type approach.[17] The only partial exceptions are Alabama Power, which offers its transmission-level industrial customers optional special "restricted" service, and DTE Energy, which has a Special Manufacturing Supply rate for certain customers who signed a contract in 2004. Nonetheless, both of these utilities classify customers primarily

[16] Enmax Power Corporation, Enmax's wires company, offers regulated service to Residential and Commercial classes. Enmax Energy Corporation provides competitive energy services to Residential and Business classes. Both are subsidiaries of Enmax Corp.

[17] In spite of the findings of our sample, there are still some U.S. utilities, like Alliant Energy, that use the business type approach.

on the basis of size, not business type. Thus, NB Power will find itself somewhat at variance with industry practice if it retains its current method and will join the majority by converting.

3.2.3. Review of Alternatives

Moving from a business type approach to a customer size approach has merits and shortcomings. On the positive side, such a change in classification methodology would permit rates to better reflect cost to serve than is the case when industry designation serves as a poor proxy for observable customer behavior. Cost recovery can closely match cost to serve when size-based classification is accompanied by demand and energy charges that closely conform to demand- and energy-related cost to serve.

On the negative side, a customer size approach might arguably raise the following challenges:

- *A change in the customer classification scheme will create winners and losers*. Customers whose bills increase substantially would naturally oppose the reform, especially if rates were to change abruptly. For NB Power, a rough initial analysis (in the following discussion surrounding Table 5) indicates that current Commercial class customers will experience lower bills upon amalgamation, while current Industrial customers will, on average, experience higher bills.

- *Rate redesign may be a non-trivial and perhaps time-consuming challenge*. Conversion to the customer size approach entails redesign of rates or broadening of the application of some current rates. It will require review of special provisions or riders associated with the current rates, including matters related to non-firm interruptible energy, definitions of contract reservations for large customers, and the declining (demand) discount incentive for economic development. There may be issues of eligibility and pricing that also need review. On the other hand, the imminent arrival of interval data capabilities may provide a timely opportunity for systematic rate revision in any event.

- *Boundary issues will persist*. Changing the customer classification scheme will change the gray areas that distinguish one customer group from another, but will not eliminate those gray areas. For example, if NB Power were to introduce General Service tariffs in three sizes, with the smallest size excluding a demand charge, one might expect customers at the size boundary to experience a bill advantage on one side of that boundary. Thus, customers close in size might have quite different bills if they fall on opposite sides of a boundary. This is a common feature of utility tariff design, and one that can be difficult or impossible to avoid. These challenges notwithstanding, NB Power will need to determine the number of size groups and the group boundaries, which may be defined by energy use, peak demand, and/or voltage level.

- *Competitive alternatives may depend upon end uses, not upon customer sizes*. If the availability of competitive alternatives differs among customer *types* to a greater degree than among customer *sizes*, NB Power's current classification system may allow rate designers to better respond to competition. On the other hand, utility discounting strategies must surely give significant consideration to a customer's gross business revenues, employment impacts, and multiplier effects on the local economy. Indeed, utilities' rules for eligibility for economic development and load retention rates are generally open to all business customers above a given size, not only to certain types of business customers. This indicates that a utility will not likely be handicapped in its ability to discount by converting to size-based classification.

Of the foregoing problems, the most serious obstacle is that of potentially large billing impacts. Those experiencing bill reductions will be pleased, but those experiencing sudden significant bill increases will oppose the change in classification methodology.

To assess these impacts, we offer the following illustration in which there are three levels of business customer pricing (Small, Medium, and Large) that recover the same quantity of total revenues as is recovered under NB Power's current customer classification system.[18] This illustration is based upon the characteristics of the current customer classes and subclasses for the period April 2016 to March 2017, which are summarized in Table 4. The left side of the table presents aggregate values while the right side provides per-customer, per bill information.[19] The table shows that the GS-I (> 20 kW), GS-II, and Small Industrial (SI) groups are similar in average peak demand and monthly usage. There are two subsets of the SI group with small numbers of customers for whom separate data are available. The SI Distribution (SID) and Transmission (SIT) groups, which are not included within the SI group shown in the table, have customers who are substantially larger in size than the other SI customers, but are still billed on the SI tariff. The Large Industrial (LI) tariff group is split into two subgroups, LID customers served by the distribution system and LIT customers served by the transmission system. These groups consist of customers who are much larger than the other customers.

[18] This approach does not attempt to establish underlying total costs, but instead uses revenues under existing rates as a proxy for total costs.

[19] Revenues are not historical but are instead based on current tariff sheet prices rather than upon the prices that applied at the time that loads were recorded. Customer numbers are bills divided by 12.

Table 4
Average Business Customer Characteristics by Present Rate Classifications
(April 2016 to March 2017)

Present Rate Class	Aggregate			Load Factor	Per-Customer, Per-Bill	
	Customers	MW	MWh		kW	kWh
GS-I						
<20 kW	18,248		304,823			1,392
>20 kW	4,300	321	1,302,259	46.3%	74.6	25,239
GS-II	3,451	230	859,089	42.6%	66.7	20,745
SI	1,645	136	402,406	33.9%	82.5	20,385
SID	7	4	13,110	38.8%	593.4	168,075
SIT	11	7	17,023	29.2%	614.6	130,949
LID	32	59	302,909	58.1%	1,844.0	782,710
LIT	30	475	2,757,706	66.2%	15,978.3	7,724,668
Total	27,723		5,959,325			

Table 5 reclassifies customers as shown in the two leftmost columns, separating the customers on the current tariffs into Small, Medium, and Large Business groups (S, M, and L, respectively), with the "T" rows presenting totals. The Average Price columns present the average bill impact outcomes from this exercise.[20]

To ensure that overall revenue impacts are zero, the illustrative rates that underlie this computation are designed to be identical in structure to current rate designs, with prices that are uniformly scaled up or down relative to existing prices. The designs are summarized as follows:

- The Small Business rate has service and energy charges but no demand charge. The energy charge has a declining block structure, with a boundary equal to that of GS-I's current boundary of 5,000 kWh.
- The Medium Business rate has demand and energy charges, with energy charges being hours-of-use in structure. There is a single block boundary at 100 times the customer's peak demand for the month.
- The Large Business rate has demand and energy charges with a flat energy charge.

[20] Customer size does not affect bill impacts for flat rates, but can have an impact for blocked tariffs.

Table 5
Illustrative Bill Impacts from a Revised Classification System

Rate		GWh	Bills ($000)		Average Price		
Current	**New**		**Current**	**New**	**Current**	**New**	**% Diff**
GS-I	**S**	305	44,825	44,595	0.1470	0.1462	-0.5%
(<20 kW)	**M**						
	L						
	T	305	44,825	44,595	0.1470	0.1462	-0.5%
GS-I	**S**						
(>20 kW)	**M**	1,130	139,886	133,780	0.1238	0.1184	-4.4%
	L	174	21,559	16,898	0.1236	0.0969	-21.6%
	T	1,304	161,445	150,678	0.1238	0.1155	-6.7%
GS-II	**S**	22	3,218	3,174	0.1470	0.1450	-1.4%
	M	721	88,996	88,308	0.1234	0.1224	-0.8%
	L	116	14,105	11,664	0.1217	0.1006	-17.3%
	T	859	106,318	103,146	0.1238	0.1201	-3.0%
SI	**S**	9	1,003	1,276	0.1141	0.1453	27.3%
	M	394	44,977	50,936	0.1141	0.1292	13.2%
	L						
	T	403	45,979	52,212	0.1141	0.1296	13.6%
SID	**S**	0	1	2	0.1129	0.1433	27.0%
	M	13	1,479	1,675	0.1129	0.1278	13.2%
	L						
	T	13	1,480	1,676	0.1129	0.1278	13.3%
SIT	**S**						
	M	17	2,031	2,300	0.1195	0.1353	13.2%
	L						
	T	17	2,031	2,300	0.1195	0.1353	13.2%
LID	**S**						
	M	4	341	433	0.0899	0.1142	27.1%
	L	299	26,890	26,656	0.0899	0.0891	-0.9%
	T	303	27,231	27,089	0.0899	0.0894	-0.5%
LIT	**S**						
	M	11	971	1,242	0.0846	0.1082	27.9%
	L	2,752	210,156	217,492	0.0764	0.0790	3.5%
	T	2,763	211,127	218,734	0.0764	0.0792	3.6%
Total	**S**	336	49,046	49,046	0.1461	0.1461	0.0%
	M	2,291	278,680	278,674	0.1217	0.1217	0.0%
	L	3,341	272,710	272,710	0.0816	0.0816	0.0%
	T	5,968	600,437	600,431	0.1006	0.1006	0.0%

Note that this illustration has basic rate designs that approximate current rate structures, thus isolating the bill impacts of customer reclassification from any rate design initiatives by NB Power. In practice, the utility would likely revise its designs both to ameliorate the short-term bill impacts of customer reclassification and to adopt new rate design approaches as influenced by utility, stakeholder, and regulatory views. Additionally, this analysis does not attempt to adjust for changes in cost to serve: reclassification will surely result in different revenue requirements by class than those inferred here. Furthermore, NB Power likely would recommend changes in revenue-to-cost ratios for each class that would mitigate aggregated bill impacts. Consequently, the table depicts possible bill impacts in the absence of any compensatory pricing changes by NB Power or by any improvements in rates that might be introduced in future rate cases.

With all the foregoing caveats, this bill impact exercise indicates that customers in the current GS classes would tend to experience modest bill reductions, as shown in the *Average Price %Diff* column. GS-I customers with less than 20 kW peak demand would have reductions of about 0.5%. The reduction for those above 20 kW would be about 6.7%. GS-II's average reduction would be about 3.0%. By contrast, the Industrial classes would tend to experience bill increases, which would average 13.6% for Small Industrial customers and 3.6% for Large Industrial customers served at the transmission level. Large Industrial customers served at the distribution level would experience an average decrease of about 0.5%.

The table also reveals differences in impact by size of customer due to their reclassification into the three Business groups. For example, LI customers reclassified as Medium Business customers would experience substantial bill increases in this rate design scenario.

Individual bill impacts will differ within each class, depending on customer load factor and customer size. In other words, variations among customers in bill impacts, both between and within classes, will accompany a revision in classification approach. However, if the reclassification improves the match between price and cost to serve, then it is reasonable to infer that customers experiencing the largest bill increases are likely to be those who had enjoyed the largest inter-class or intra-class subsidies hitherto.

If the range of bill impacts ultimately turns out to be about the sizes of the illustrative impacts depicted in Table 5, then NB Power will want to consider a plan that phases in rate changes. A relatively simple approach to this problem might involve a simultaneous movement of all customers to the new rate designs, accompanied by transition discounts (for customers facing bill increases) and premia (for customers enjoying bill reductions) that taper to zero over a predetermined period (like five or ten years) depending on the size of bill impacts. The transition period might be matched to the rate parity schedule, with completion in 2027/28.

Average results like those of Table 5 could be used to set the initial discount, with a bill discount or premium percentage for each type of rate transition. For example, a customer converting from GS-I to the Medium Business tariff would see an immediate 4.4% premium on their new bill, but the premium would result in no immediate bill change because conversion to the new rate would have reduced their bill by 4.4%. The GS customer's bill would then decline over time as the premium tapers to zero over (say) five years. In contrast, a Small Industrial customer converting to the Medium Business tariff would see an immediate 13.2% discount on their new bill, but the discount would result in no immediate bill change because conversion to the new rate would have increased their bill by 13.2%. The SI customer's bill would then increase over time as the discount is phased out over (say) five years. By this means, the average price to serve customers with similar load characteristics would move toward equality over that transition period. New customers could be placed on the appropriate rate without the transition discount or premium or they could be included in the transition scheme for purposes of administrative simplicity and fairness to customers.

3.2.4. Recommendations

Because the customer size approach is better than the business type approach at matching revenues with costs, we recommend that NB Power move toward a size-based classification method. Determining rate class boundaries would be facilitated by a cost-of-service (COS) study based on the candidate rate classifications, as this would provide an accurate understanding of average cost to serve within the new classes. The next step would involve review of alternative base rate designs tailored to NB Power's updated pricing objectives. Such designs might further improve the match between price and cost, not only between classes but within. Once the utility has a good understanding of the price-cost relationship for its customers, it can then determine the timing and path of rate level revision.

The timeframe for the transition might depend upon the sizes of the impacts, with larger impacts implying a longer transition period. Because NB Power already has the goal of moving all rate classes' revenue-to-cost ratios to within the range of reasonableness by fiscal year 2027/28, it may be advisable to have both transitions occur simultaneously, depending upon the sizes of bill impacts affecting significant numbers of customers.

3.3. Heating versus Non-Heating Residential Customers

About 63% of NB Power's Residential customers have winter space heating loads.

NB Power shares with many other winter-peaking utilities the dilemma of how to price heating usage, which is a significant share of total annual residential consumption and is concentrated at times when generation costs are high relative to the annual average. If the residential electricity price is flat – that is, if it does not vary over time – then charging the same price to customers with significant space heating consumption as is charged to other customers makes it likely that intra-class cross-subsidy is occurring. The stakeholder process of the past year raised this issue and offered a range of design alternatives for mitigating or eliminating the cross-subsidy between NB Power's heating and non-heating customers. These alternatives include time-varying pricing, block pricing, and residential demand charges.

3.3.1. Overview of the Power Industry's Approaches

Many utilities make no special provision for pricing electric space heating customers differently than other Residential customers. Utilities that do give special consideration to space heating customers have two general approaches for doing so. Some of these utilities offer separate rates for customers with space heating.[21] Other utilities use pricing structures designed to charge different prices for heating (and cooling) than for other electricity uses. Common approaches for charging such differing prices include: a) block pricing that assumes that it will be primarily heating or cooling customers who reach the tail block; and b) time-of-use (TOU) pricing that recognizes the time-varying costs associated with heating load.[22] Block pricing has been more common due its simple metering requirements; but the substantial decline in metering costs is making TOU more attractive.

Canadian utilities do not appear to make use of separate space heating rates, but some residential rates have features that implicitly recognize cost differences between heating and non-heating customers. For example, Hydro-Quebec and BC Hydro have inclining block rates that put a relatively high price on usage levels in excess of normal "year-round" usage. Manitoba Hydro offers seasonal pricing with an elevated winter energy price. In Ontario, utilities offer seasonal three-period TOU pricing that recognizes differences in costs that arise due to differences in the time pattern of usage.

On the other hand, utilities in Alberta, Saskatchewan, Nova Scotia, and Newfoundland and Labrador all lack price variability in residential customer pricing and do not recognize differences between space heating and other customers. Nova Scotia Power and Newfoundland Power both have rates for seasonal dwellings directed at customers' summer homes where the building isn't occupied much of the year.

U.S. utilities make widespread use of seasonal and block pricing for cooling consumption in summer, but some also make use of separate space heating rates. The pricing approach at summer peaking utilities, in regions where winter night-time generation costs have been traditionally low, has been to use *declining* block pricing to encourage electric heating during their periods of relatively low marginal costs. Examples include Georgia Power, DTE Energy in Michigan, Xcel Energy in Minnesota, and Emera Maine. These utilities' tariffs provide service options for space heating with either block or seasonal pricing:

- Georgia Power's Residential Service schedule offers seasonal pricing with an inclining block in the summer and a declining block in the non-summer period. The block sizes and the price of the first block are identical in both seasons, so variations in the prices of the second and third blocks cause the inclines and declines. For the second and third blocks, summer prices are about double winter prices.[23]
- DTE Energy offers a Residential Space Heating tariff that provides seasonal pricing with an inclining block in summer and a declining block in winter. Summer prices are 22% to 82% higher than winter prices, while the inclines and declines within each season are only about 20%.[24]

[21] Separate rates for customers with cooling are not in general use.

[22] See Section 4 for a discussion of time-varying pricing, including TOU pricing.

[23] Georgia Power, Residential Service Schedule R-22, effective January 2016.

[24] These rates are in effect as of February 7, 2017.

- Xcel Energy (Northern States Power) offers a Residential Service rate that differentiates between Standard and Electric Space Heating. The latter features seasonal energy prices that are constant (flat) in each season, that are higher in summer than in the non-summer season, that are the same for all customers in summer, and that is 28% lower for space heating customers than for standard customers in the non-summer season.[25]
- Emera Maine offers Residential Space Heating Service that is essentially identical to its standard Residential Service except that the former has a declining block structure with a 31% price discount on all consumption over 600 kWh per month in the winter heating season.[26] The utility also requires residential customers with usage in excess of 2,000 kWh in any winter month to be served under TOU pricing, thereby catching customers who do not sign up for heating service.[27]

3.3.2. Pricing Alternatives

Differences in the costs of serving heating and non-heating customers arise solely from difference in their load profiles over the course of the year – that is, their different time patterns of consumption. Figure 2 shows these hourly patterns for non-heating customers (blue lines) and heating customers (red lines). For the summer season (dashed lines), these patterns are very similar; while for the winter season (solid lines), these patterns are radically different, with heating customers having far higher loads in all hours than do non-heating customers. Also note that, while heating customers clearly have higher winter load than summer load due to their heating needs, non-heating customers also have higher winter consumption, perhaps due to greater need for lighting in winter.

The current rate design prices both subclasses of the Residential class identically despite the differences in seasonal share of usage. This is problematic because, as shown in Table 7 below, NB Power's marginal costs are highest during winter on-peak hours and lowest during summer off-peak hours. Consequently, the costs of serving heating customers are higher than those of serving non-heating customers due to the former's relatively high winter loads.

There are at least four approaches to designing rates so that they better reflect the relative costs of serving heating versus non-heating customer. Given current and imminently available metering and communication technologies, time-varying prices would be our preferred approach; so we mention the others for the sake of completeness rather than for the purpose of suggesting that they be adopted.

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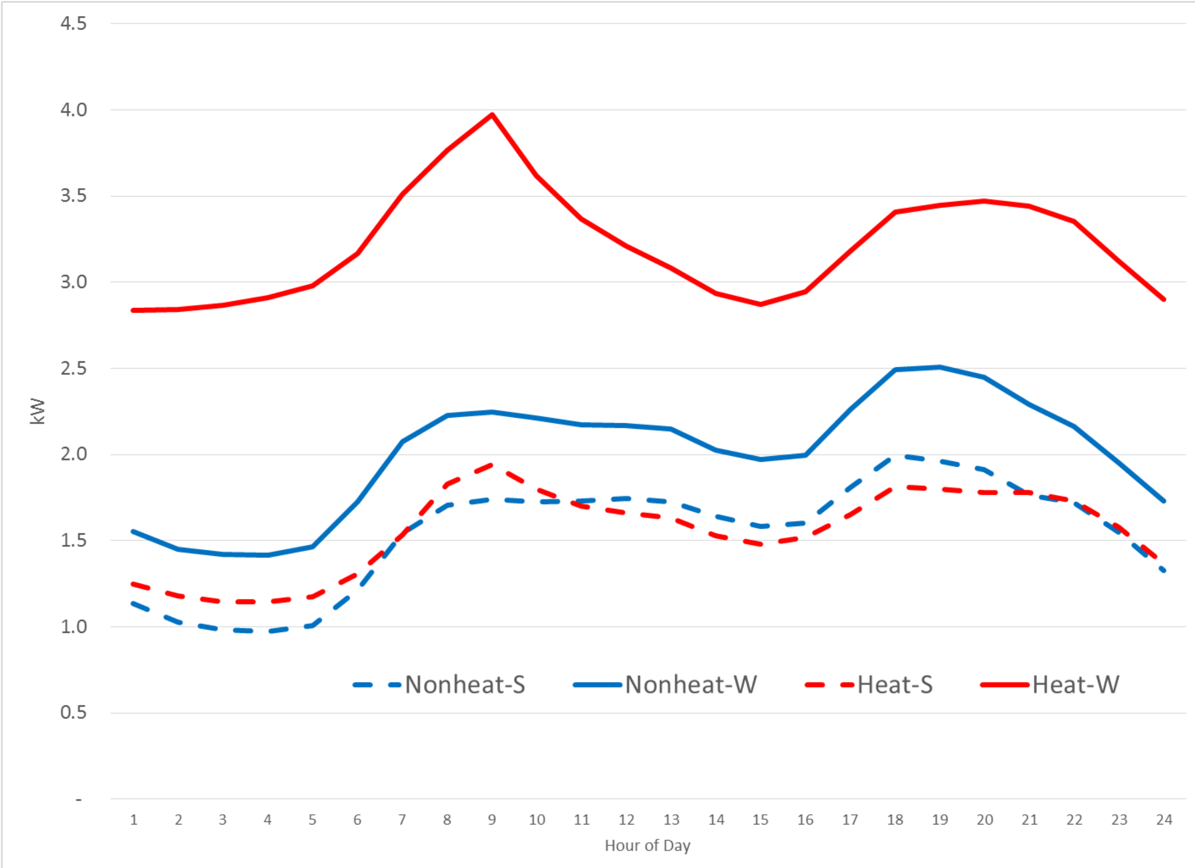
[25] Northern States Power Company, *Minnesota Electric Rate Book – MPUC No. 2*, Residential Service Rate Code A00, A01, A03, effective January 1, 2016.

[26] Emera Maine, *Residential Service Rate* (Rate A) and *Residential Space Heating Service Price* (Rate A-20), effective July 1, 2017.

[27] Emera Maine, *Residential Service Rate: Time-Of-Use* (Rate A -4), effective July 1, 2017.

Figure 2
Average Hourly Consumption of NB Power's Residential Heating and Non-Heating Customers, by Season, April 2015 – March 2016[28]



Time-Varying Prices

The simplest way to substantially reduce cross-subsidies between heating and non-heating customers would be to replace the current Residential rate with a seasonal rate that, given current seasonal differences in marginal cost, would have winter energy prices about 66% higher than summer prices. Such a seasonal rate can be implemented with NB Power's existing metering.

A somewhat more complex way to reduce the cross-subsidies even further would be to have Residential prices vary not only by season but also by on-peak and off-peak periods within each season. Such a rate would require advanced metering, and would be well within the capabilities of the AMI that NB Power has proposed.

[28] The figure is based upon data provided by NB Power.

We note that, as an approximation, efficient time-varying prices are proportional to time-varying marginal costs. As shown in Table 7 below, NB Power's marginal energy costs appear to be about 66% higher in Winter and in Summer, about 23% higher in on-peak Winter hours than in off-peak Winter hours, and 50% higher in on-peak Summer hours than in off-peak Summer hours. Given these differences, it is more important to have seasonal price differences than to have price variation within season: seasonal prices would capture most of the marginal energy cost variation without the complexity of TOU pricing. Nonetheless, additional benefits are available from prices variations within seasons.

Block Tariff

Another design would have a block tariff structure in the winter season, wherein the first block would have a kW size approximating the average customer's non-winter consumption level. Consequently, most customers' space heating consumption would fall in the tail block, which would have a higher price than the first block. Not all consumption in the tail block would necessarily be related to space heating, but most space heating customers would perceive that the incremental price of home heating is the tail block price. This is a common industry design, especially in the U.S., where space heating consumption occurs predominantly off-peak.

At NB Power, however, space heating consumption occurs predominantly in the peak pricing season rather than in an off-peak period. With NB Power's current Residential tariff having a 10.81 cent per kWh price and a prospective winter marginal energy cost of 6.83 cents per kWh, a two-block tariff would have a tail-block price of between 6.83 and 10.81 cents, and a first block price set above 10.81 cents in order to meet the revenue loss in the tail block. Accordingly, the effect of such a design would be to encourage more spacing heating and higher loads in the peak winter season. Such a design does not seem to be a desirable policy, particularly because the 6.83 cent marginal energy cost figure does not consider the potential capacity cost implications of load increases.

Fundamentally, a block tariff is an ineffective tool for the job of addressing the heating customer issue because the cost differences between heating and non-heating customers arise from the *timing* of the customer's consumption, not the *quantity* of the customer's consumption. It is, at best, a crude tool for recognizing these cost differences if metering and communications technologies are not adequate to implement time-varying prices. But given the present state of technology, it is unnecessary to use such a crude tool.

Demand Charge

The arrival of interval data recorders makes it feasible to use a demand charge as a tool for recovering fixed costs of delivering power to residential customers; but it might also tempt some to suggest introduction of a residential demand charge as a means of ensuring a fair and efficient allocation of costs between heating and other customers. On the contrary, a residential demand charge would not serve the purpose of distinguishing between the costs of serving heating and non-heating customers because the cost differences arise from the time pattern of the energy a customer consumes, not from the customer's peak load. Residential demand charges might well serve other purposes, such as fixed cost recovery; but it is an ineffective tool for dealing with a costing issue that arises from customers' time patterns of consumption.

Separate Heating Rate

Another possible approach to the space heating issue is to create an entirely separate rate, or separate designation within a rate as Xcel Energy does. This approach requires that the utility be able to differentiate between heat and non-heat customers or that customers self-select. Because most of the cost difference in serving heating and non-heating customers can be captured by a seasonal rate, however, two sets of Residential prices seem unnecessarily complicated. This complication will become even more unnecessary if NB Power installs advanced metering that allows price variation within each season. With or without advanced metering, a single set of time-varying Residential prices, under a single Residential rate, is quite capable of capturing the cost differences in serving different types of Residential customers, without any need to determine which customers fit into which type.

3.3.3. Recommendations

The block pricing approach may be appropriate for a world in which metering and communicating time-varying loads is costly, but does not make sense under present circumstances in which such metering and communication has become cheap. Block pricing and demand charges can address problems of recovering fixed costs; but they do a poor job, relative to time-varying prices, of distinguishing between the costs of serving heating and non-heating customers. A separate heating rate is simply unnecessary in a world in which technology is sufficient to cheaply implement time-varying prices.

Time-varying prices are the best solution to the problem of recognizing cost differences between heating and non-heating residential customers; and particularly with NB Power's prospective investment in AMI, it is the solution that NB Power should adopt. We therefore recommend that NB Power revise its Residential tariff to include at least a seasonal element with constant prices within each season. Once interval load data are available, NB Power can consider a seasonal TOU design of the sort found in Ontario, but with pricing period timing and price ratios based on NB Power's marginal cost patterns.[29]

Some education will be required to inform customers of the variation in prices by season and by time period, and to help them understand how they might reduce their bills by responding to those prices. It is therefore desirable to keep the pricing as simple as possible, such as by having

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[29] As noted in Section 4.2, the marginal cost data seem to support a Winter season of December through April, with all other months being Summer; and on-peak hours of 8 am to midnight on weekdays in both seasons, with all other hours being off-peak. This marginal cost pattern differs from NB Power's historical reliability winter season of November through March, which appears to be based upon average monthly load levels (in MWh) or operating reserve levels rather than upon marginal costs. See NB Power's responses to NBEUB IR-03, September 26, 2017, p. 3, and EGNB IR-03, September 26, 2017, p. 3, in Matter 357.

only two seasons and the same two pricing periods in both seasons. Such simplicity would only modestly reduce the efficiency and fairness benefits of time-varying pricing.

An operational concern with mass market TOU pricing is whether TOU should be mandatory or optional. We discuss this issue and make recommendations in Section 4.3.2 below.

3.4. Charitable Organizations

NB Power handles charitable organizations, including churches, in two different ways.

- Charitable organizations that began taking service since August 29, 1979, or that were not recognized as charitable organizations on that date, are served under the General Service tariff.
- Certain entities that were deemed charitable institutions by August 29, 1979 are served under the Residential tariff. If such an entity moves to new premises or upgrades their service in their current premises, however, they are taken off the Residential tariff and put on the General Service tariff.

This odd handling of charitable organizations is a legacy of Provincial government policy from the 1970s.[30] An effect of this discrimination is to impair cost recovery. At issue is whether this price discrimination, which lacks a cost basis, should persist or be terminated eventually.

The electric utility industry does not generally give charitable organizations their own tariffs but instead places them in customer classes consistent with their premises. We reviewed the tariff sheets of the same utilities reviewed regarding overall classification and found one mention in Canada (at Manitoba Hydro where community centers are part of its Small General service class but enjoy no pricing different from other customers in the class) and one in the U.S. (at Public Service of Colorado, where "eleemosynary organizations"[31] are part of the Residential class). In no case did we find a charitable organization being differentially priced from the residential or business class in which it was placed.

The cost issue is central to a decision for rate reform. A charitable organization operating out of commercial property (as opposed to a business office in a home) and having normal business hours is likely to have a load profile similar to a small General Service customer and arguably should be treated as such in COS studies. Any decision to confer a discount should be made according to present considerations, not according to a forty-year-old legacy. Small subclasses of customers should be created only when it can be demonstrated that they are recognizably different from other customers in the class.

Aside from the issue of cost, there does not appear to be any basis for separate classification of charitable organizations, or for separate subclassification within General Service. Nor are charitable organizations likely to have special competitive alternatives relative to other small

[30] See New Brunswick Power Corporation, *2017 Rate Design*, *Evidence of May 1, 2017, in accordance with a letter by the Board dated August 2, 2016, and Paragraph 95 of the Board decision dated May 13, 2016 regarding Matter 271*, p. 28. This evidence is associated with Matter 357. The policy date is implicit in the 1979 cutoff date.

[31] Per Merriam Webster, *eleemosynary* is defined as "related to, or supported by charity."

General Service customers that would justify separate treatment. The justification for special treatment likely lies in a general desire to subsidize charities at the expense of other customers. The justification for eventual incorporation of all charitable organizations within the General Service class is that such incorporation would likely better reflect costs.

Any rate shock associated with moving the grandfathered charitable organizations to the General Service class could be mitigated by steadily moving the Residential and General Service classes' revenue-to-cost ratios closer together over several rate cases. In addition, the grandfathered organizations could be switched from one rate class to the other through a phased process, such as by immediately moving these customers to the GS-I rate but with a five-year declining discount relative to the Residential rate. Such tapered discounting is found in economic development and load retention rates, including NB Power's; and this issue may be seen as a small-customer variant thereof.

We recommend that NB Power apply to the Board (and the Provincial government if necessary) to phase out the grandfathered charitable organization service under the Residential tariff and attempt to move Residential and General Service revenue-to-cost ratios closer together.[32]

3.5. Farms

NB Power serves farms under the Residential Rate. This is problematic for at least two reasons: farms have load patterns that are often very different than those of residences; and serving farms involves relatively high fixed distribution costs due to the relatively low density of the areas in which farms are located.

Industry practice with respect to farms is mixed. We reviewed the tariff sheets of the same utilities reviewed regarding overall classification practices and found two Canadian and three U.S. cases of special farm rates, plus three cases of irrigation/pumping service in the U.S. We found four Canadian and three U.S. utilities that explicitly include farms in their Residential class, while Nova Scotia Power places farms in their Small Industrial class. The residual, two Canadian and four U.S. utilities, make no explicit mention of farms.

We recommend that, to separate farms that are more residential in character from those that are less so, NB Power consider a maximum size limitation on the farms that are allowed on the Residential rate. Mimicking the size limitation on a combined dwelling and business operation, farms could be allowed on the Residential tariff only if their peak load is no more than 2 kW, excluding space heating or cooling. This limitation could be combined with a TOU pricing option

[32] The issue of charitable organization treatment was examined ten years ago in Concentric Energy Advisors, *Review of Rate Related Studies Identified in the 2005 Cost Allocation and Rate Design Ruling*, prepared for NB Power, June 22, 2007. The conclusion (at p. 1) was that "there is no compelling reason to remove churches from the residential class. Churches currently represent a very small proportion of the residential class and have generally load patterns and consumption factors similar to the rest of the residential class. Further, there would be adverse bill impacts for most churches if they were moved to the GS class." Nonetheless, Concentric Energy Advisors further says (at p. 2), "However, it is recommended that Disco consider the transfer of the nonresidential load of the larger farm and church accounts to GS."

for small GS customers that might reduce a bill increase for a farm that uses energy predominantly in off-peak periods.[33]

4. TIME-VARYING ELECTRICITY RATES

Electricity prices with time variation can be classified as being *static* or *dynamic*. Static prices are specified in tariff sheets, and so are set well in advance of the time periods to which they apply and change only upon approval by regulators. In contrast, dynamic prices are determined through *processes* described by tariffs and approved by regulators, with the actual numbers being set and delivered to retail customers at short notice, such as a day or an hour before the time periods to which they apply.

Static pricing variants include seasonal and time-of-use pricing:

- *Seasonal* pricing takes the form of pricing that varies by season only, with a single price or price structure for the season. For example, a tariff with block prices that are set for summer, winter, and shoulder seasons would be deemed seasonal.
- *Time-of-use* (TOU) pricing has prices that are fixed for periods of time that may be distinguished by day of week (like weekday versus weekend) and time of day. TOU prices often vary on a seasonal basis.

Dynamic pricing designs convey to retail customers information about current cost conditions in wholesale markets, allowing customers to share in the power system's cost savings by modifying the pattern and level of their usage in response to short-notice price signals about these cost conditions. In so doing, customers may reduce generation operating costs, increase real-time power system reserves, and reduce the power system's long-term need for capacity. Dynamic pricing can be offered at all times or at times of reserve shortage only.

- *Real-time pricing* has prices that change hourly according to power system conditions as forecast at short notice and provided to customers a day, or even an hour, in advance.
- *Critical-peak pricing* and *peak-time rebates* have prices that are usually about the same as those of the customer's standard tariff, but that rise to very high pre-specified levels in a small numbers of hours wherein operating reserves become very low.[34] These programs

[33] Concentric Energy Advisors, *op cit*., p. 2, finds that "farms, particularly rural farms, may be a better fit in the GS class as opposed to the residential class. However, farms are a small proportion of the residential class and there are customers of comparable size in the residential class. In addition there would be significant adverse bill impacts for the majority of the farm customers if moved to the GS rate structure. In light of this, CEA does not recommend a general move of farm customers out of the residential class. However, it is recommended that Disco consider the transfer of the nonresidential load of the larger farm and church accounts to GS."

[34] CPP features standard tariff prices that are reduced by just enough to offset the high prices in the expected number of critical-peak hours. If the expectation is correct and the customer does not respond to price, the customer's bill should match that of the standard tariff.

Peak-time rebate prices, in contrast, are identical to those of the standard tariff except at peak times, when customers who reduce load from their normal consumption level are paid at the critical-peak price. Failure to respond yields a bill identical to that of the standard tariff.

are usually activated an hour to a day in advance of the hours to which their high prices apply.

This section begins by discussing the ways in which time-varying rates may create benefits. It then looks at the available information on the marginal costs that should serve as the basis for designing NB Power's time-varying rates, and recommends directions for the future evolution of those rates.

4.1. The Rationale for Time-Varying Rates

Time-varying electricity rates provide benefits if the marginal costs of electricity vary significantly over time and if customers respond to price by increasing consumption when prices are low and reducing consumption when prices are high. Thus, the *gross* benefits of time-varying rates are greatest when marginal costs are highly variable and customers are highly responsive to price. The *net* benefits of time-varying rates equal these gross benefits minus the costs of implementing the time-varying rate program. Implementation costs have been falling dramatically over time with improving computer technologies, including advanced metering systems; and these falling costs are making time-varying rates more attractive.

Time-varying rates are *not* justified, however, by seasonal or daily variations in the utilization of generation assets, except to the extent that these variations in utilization lead to variations in marginal costs. Although high generating plant utilization is desirable for investment purposes and relevant to plant retirement decisions, shifts in customer loads from one time period to another are beneficial only if there are marginal cost differences between those time periods. Time-varying rates that follow marginal costs are likely to result in higher plant utilization; but the gross benefits of this outcome, which come in the form of cost savings, depend entirely upon the variation in marginal costs over time.

4.1.1. The Efficiency of Marginal Cost-Based Pricing[35]

The marginal cost of a service is defined as the change in the cost of producing and delivering that service that accompanies a small change in the quantity consumed of that service. Formally, this relationship can be expressed as follows:

$$Marginal\ Cost\ \equiv \frac{\Delta Cost}{\Delta Consumption} \quad (1)$$

Since the late 1800s, the economics profession has recognized that the price of a service is most efficient when price equals that service's marginal cost, and that competitive markets drive prices toward marginal cost. Therefore, when utility rate designers seek efficient pricing, they seek regulated retail pricing that, as nearly as possible, produces this outcome of a competitive market.

Marginal costs change over time with changes in power system conditions. These conditions include load levels, generator availability, and transmission and distribution facility availability.

[35] See Appendix B for more detail.

Marginal costs can vary by location because transmission and distribution constraints can divide electrical energy markets geographically. Just as the price of apples tends to be lower near apple orchards than it is near cities, so the marginal cost of electricity tends to be lower near large generators than it is near large loads.

The power industry has well-developed mathematics and computational tools for quantifying how marginal costs vary over time and space, down to individual nodes within power systems. Such mathematics and tools are used by Regional Transmission Organizations to calculate locational electrical energy prices that equal marginal energy costs.

4.1.2. The Applicability of Marginal Costs to Electric Utility Pricing

In principle, electricity prices should vary hourly with power system conditions as measured by marginal costs. This is most important for dispatchable generators and for customers who own dispatchable generators or readily adjustable loads, because such hourly pricing would induce them to produce or consume quantities of power that are related to the power system's time-varying need for power. It is also important, though less so, for non-dispatchable generators and customers without dispatchable generators, because these generators and customers are responsive to price in the long run (with their investment decisions) even though they are relatively unresponsive in the short run.

When prices are determined through a regulatory process, economic efficiency is promoted by regulatory policies that attempt to set price close to marginal cost. This is particularly important in situations wherein customers have access to competitive alternatives to utility service, like distributed energy resources.

4.2. The Time Pattern of NB Power's Marginal Costs

NB Power's marginal costs depend upon the costs of the generation resources available to its system operators. These resources include the company's own generators and its power purchases from other generation owners. Because NB Power's access to purchased power from outside the province depends upon its transmission interties with other jurisdictions, its marginal costs in any hour depend upon a combination of its own generators' costs, the terms of its power purchase agreements (PPAs) both within and outside the province, and the availability of transmission with other jurisdictions.

If NB Power's resources included hydropower with significant reservoir capacity, NB Power's marginal costs in the present hour would also depend, in a complex way, upon current and future hydrological conditions. But although the company does have significant hydropower resources, these resources lack significant reservoir capacity and are therefore virtually run-of-river.[36] Consequently, NB Power's marginal costs depend upon the current availability of water for its hydro resources, but do not need to consider future hydrological conditions.

[36] As noted below, however, these resources do have enough reservoir capacity to offer regulation and load following services.

4.2.1. Overview of NB Power's System

NB Power's loads vary between roughly 750 MW and 3,100 MW, with the lowest loads tending to occur in June through September while the highest loads tend to occur in January and February. As implied by Table 6, NB Power depends upon its own resources to serve about 71% of its customers' electrical energy needs, while about 19% are served by in-province resources owned by other entities and about 10% are served by out-of-province resources. NB Power's hydroelectric resources are all run-of-river, with flows being greatest during the spring runoff period in April and May.[37]

Table 6
NB Power's Generation Resources[38]

Source	Capacity (MW)		Energy (GWh)	
NB Power-Owned:				
thermal[39]	1,439		3,153	
hydro	889		2,461	
nuclear	660		4,330	
combustion turbine	525		2	
subtotals		3,513		9,946
In-Province PPAs:				
biomass	39		199	
gas	375		1,596	
hydro	24		41	
wind	294		776	
other	6			
subtotals		738		2,612
Out-of-Province				1,440
Total		4,251		13,998

NB Power operates its own Balancing Authority Area (BAA), which means that it is responsible for assuring that the BAA has a continual balance between supply and demand during each five-minute dispatch interval. NB Power's BAA includes bits of Maine and all of Prince Edward Island (which is interconnected with New Brunswick through three underwater cables). To maintain

[37] "Appendix B - NB Power Electric Power Supply System (Matter 271)," p. 12.

[38] Capacity figures are from NB Power, *Annual Report 2015-2016*, p. 4. The figures shown in the table do not include 80 MW of biomass capacity (Irving Pulp and Paper, AV CELL, and AV Nackawic) that appears at "Appendix B - NB Power Electric Power Supply System (Matter 271)," p. 3. Energy figures are from "Appendix B-2 2014-15 LDC and Load Profile CONFIDENTIAL.xls."

[39] The thermal fuels are coal, oil, and natural gas.

power balance, the BAA has five ancillary services: automatic generation control (regulation), load following, 10-minute spinning reserves, 10-minute non-spinning reserves, and 30-minute reserves.[40] Hydroelectric resources are the primary providers of regulation and load following services.[41] NB Power has reserve sharing agreements with ISO New England and Nova Scotia Power.

NB Power's BAA has strong interties with adjacent BAAs. Transmission capabilities vary over time with power system conditions. For simplicity, Figure 3 shows NB Power's maximum transfer capabilities rather than these variations. These maximum import capabilities are about 550 MW with ISO New England, 770 MW with Hydro-Quebec, 350 MW with Nova Scotia, and 105 MW with Prince Edward Island.

Figure 3
NB Power's Transmission Maximum Import and Export Capabilities (MW)[42]

The foregoing transfer capabilities amount to about half of New Brunswick's peak load, which allows for large power imports. Indeed, as shown in Figure 4, imports during a recent twelve-

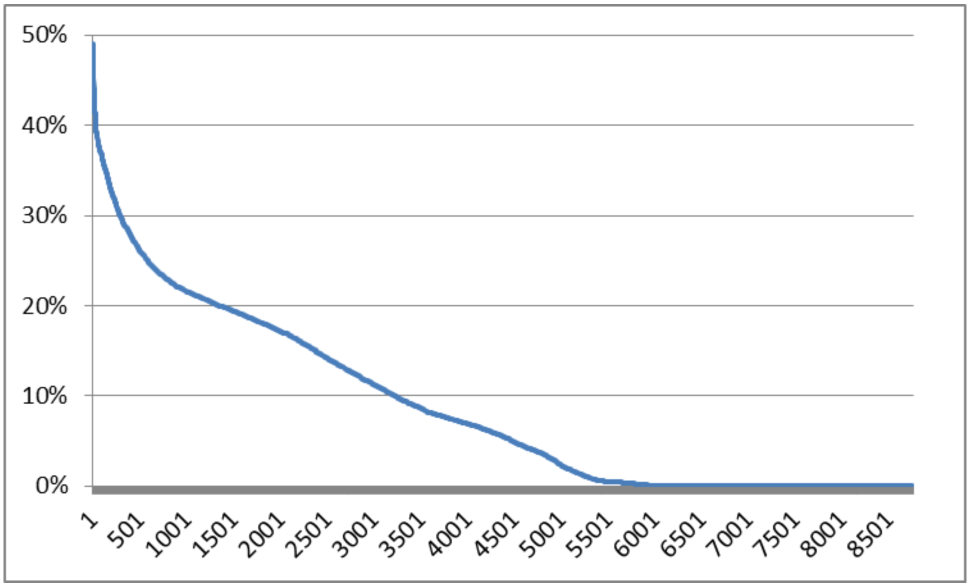
[40] In addition, New Brunswick recognizes two ancillary services not directly related to maintenance of power balance: reactive power or voltage support service; and black start capability service.

[41] "Appendix B - NB Power Electric Power Supply System (Matter 271)," p. 11.

[42] NB Power, *Integrated Resource Plan 2014*, p. 20.

month period served as much as 49% of NB Power's load in one hour, served over 30% of load in 290 hours, and served over 10% of load in 3,231 hours. More to the point, imports peaked at 911 MW during this period, indicating that transmission import capacity is rarely constrained. The fact that most of NB Power's contracts are tied to ISO New England's prices corroborates the near-absence of significant regional transmission constraints.[43]

Figure 4
Number of Hours in Which Imports Exceeded Percentages of Load,
April 2014 to March 2015[44]



4.2.2. New Brunswick Marginal Costs and New England Prices

Because transmission between New Brunswick and its neighbors is rarely constrained, arbitrage performed by NB Power's system operators should generally equalize the marginal cost of electricity in New Brunswick with the relevant day-ahead power prices in New England in the large majority of hours. In other words, NB Power can use its unconstrained transmission links with other BAAs to minimize its power production and procurement costs through trade with entities in the other BAAs. Such trades would affect marginal costs in the following specific ways:

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[43] New Brunswick's imports are often limited by operating conditions that require high-cost generation within the Province to operate at some times when cheaper power is available for import elsewhere. Such operating conditions include minimum generator run times and needs for local voltage support. These limitations notwithstanding, the fact remains that transmission is almost always available to allow arbitrage between New Brunswick and its neighbors, implying that New Brunswick's marginal costs are almost always the same as its neighbors' marginal costs, aside from relatively small differences due to energy losses in transmission.

[44] The figure is derived from data appearing in "CAEC Item 1 - CONF2 - Appendix B-2 2014-15 LDC and Load Profile CONFIDENTIAL.xls."

- *The marginal cost in New Brunswick should almost never exceed the import price from New England*. Suppose, for example, that the import price of electrical energy is $65 per MWh in a particular hour. If NB Power would otherwise need to run generators with incremental costs higher than $65 to serve its own load, NB Power could reduce its costs by buying power from New England at $65 and turning down its generators with incremental costs above $65. This means that, unless transmission is constrained, marginal costs in New Brunswick should never exceed the import price.[45]
- *The marginal cost in New Brunswick should almost never be less than the export price to New England*. Suppose, for example, that the export price is $40 in a particular hour and that NB Power could serve its load without running all of its generators with incremental costs below $40. In this case, NB Power could profit by turning up its low-cost generation and selling power to New England.[46] This means that, unless transmission is constrained, marginal costs in New Brunswick should never be less than the export price to New England.

In summary, NB Power minimizes its costs by equalizing the loss-adjusted marginal costs of its own generation fleet with the prices of the power markets in adjacent BAAs. More specifically, prices in New England should bound marginal costs in New Brunswick: unless transmission is constrained, marginal costs in New Brunswick should never exceed the import price from New England nor should it ever be less than the export price to New England. Mathematically:

$$Import\ Price\ from\ NE\ \geq\ MC\ in\ New\ Brunswick\ \geq\ Export\ Price\ to\ NE \qquad (2)$$

The import and export prices described by this equation are those at the Salisbury interface with ISO New England[47]; so the marginal costs described by this equation are also those at the Salisbury interface. The marginal costs applicable to New Brunswick customer loads would be several percent higher due to energy losses within the New Brunswick transmission and distribution system.[48]

It is important to note that the settlement prices of contractual obligations for fuel purchases, power purchases, or power sales are not relevant to the determination of marginal costs.

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[45] The fact that operating conditions sometimes require use of high-cost in-Province generation does not mitigate the text's conclusion that arbitrage allows loss-adjusted equalization of marginal costs between New Brunswick and its neighbors, as such use of high-cost generation is infra-marginal.

[46] The profit would be used to offset NB Power's costs, which would ultimately benefit customers by reducing the costs that are recovered through rates.

[47] ISO New England calls Salisbury the "New Brunswick Interface," with node name ".I.SALBRYNB345 1."

[48] Per file "CCAS 2017-18 Exhibit NBP5.11 Matter 336.xls," sheet "Sch 1.1 Ene and AvgDemand Alloc," row 44, average percentage losses are as follows: secondary, 0.998%; distribution transformer, 2.442%; primary, 1.184%; distribution substation, 0.545%; and transmission, 3.541%. Cumulative average percentage losses (which are the geometric sums rather than the arithmetic sums of the foregoing) are therefore 3.541% for customers served at the transmission voltage level, 5.337% for customers served at the primary distribution voltage level, and 8.986% for customers served at the secondary distribution voltage level. Note, however, that efficient prices would be based upon *marginal* losses rather than *average* losses, and that marginal losses are somewhat less than double average losses.

Suppose, for example, that NB Power is obligated to buy 100 MW from Hydro-Quebec at $80 per MWh in an hour when the import price of electrical energy from New England is $65 per MWh. Being a fixed obligation, the $80 purchase from Hydro-Quebec is infra-marginal. NB Power would satisfy a 1 MW load increase with either a 1 MW import from New England at $65 or with an increase in its own generation at an incremental cost of no more than $65. NB Power would not serve a load increase by purchasing more Hydro-Quebec power at $80. Because marginal cost is defined as the change in cost that accompanies a change in load, marginal cost will not exceed $65. In summary, the prices of fixed obligation contracts, whether for buying or selling, whether high or low, or whether for power or fuel, are not relevant to determining marginal costs.

4.2.3. NB Power's Methods for Determining Marginal Costs

NB Power calculates marginal costs in both forecast and historical (after-the-fact) modes.

For forecast mode, NB Power uses the PROMOD production costing model. This model identifies the combination of generation and power purchase resources that can serve in-province load at least cost in each time period (e.g., each hour), with consideration of fuel prices, power system operating constraints, resource availability, and ancillary service requirements.[49] The model assumes long-term median hydro flows and weather and, importantly, "Fuel and purchased power costs based on fuel forward prices and exchange rate forward prices."[50]

For historical mode, NB Power uses the Transaction Scheduling and Settlement (TSS) model to determine marginal costs. Like PROMOD, this model determines marginal costs with due consideration of operating constraints, resource availability, and ancillary service requirements; but the TSS model determines these marginal costs while also considering how resources were actually dispatched.

For both modes, the marginal cost in each time period reflects the incremental cost or the settlement (contract) cost of the resource(s) that would serve a small increase in load. These marginal resources may be NB Power's own generators or they may be power purchased from other entities. For both modes, NB Power calculates marginal costs with and without export sales.

4.2.4. NB Power's Marginal Cost Estimates

For the purpose of setting prices, the marginal costs that matter are those that consider all power imports and exports: these are the marginal costs that best reflect all of the factors that affect the cost changes that would accompany load changes. For the purpose of setting prices for forthcoming years, the marginal costs that matter are the future-year forecasts.

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[49] Power system operating constraints include generators' minimum and maximum output levels, generators' minimum run times, and transmission limits. Resource availability refers to generators' outages and sellers' rights to sometimes fail to provide power purchased under contract. Ancillary service requirements include the needs for regulating reserves, operating reserves, and voltage control.

[50] "Appendix B - NB Power Electric Power Supply System (Matter 271)," p. 13.

NB Power has forecast marginal costs for a typical 168-hour week for each of the twelve months April 2017 through March 2018. For this time period, NB Power has also assembled the day-ahead prices at which it is able to buy (import) and sell (export) power at the Salisbury interface with ISO New England. As is normal for virtually all markets, the import prices are higher than the export prices.

Although we have not reviewed NB Power's marginal cost calculations, we have noticed that the marginal cost figures do not fully satisfy equation 2:

- The forecast marginal costs exceed the import prices in 566 typical hours of the 2,016 typical hours in the forecast year, by an average of $6.94 per kWh.
- The forecast marginal costs are less than the export price in 305 typical hours, with the shortfall averaging $6.83 per kWh.

We believe that the inconsistency between the marginal cost estimates and New England's power prices arises from NB Power's use of contract prices (for fuel and/or power) in its marginal costing model, when a more accurate approach would use current or short-term forward market prices.[51] In addition, the forecast import prices are biased downward by NB Power's assumption that these prices are zero in those hours when there is no forecast need for imports.[52]

4.2.5. Adjusted Marginal Cost Estimates

We consider two sets of marginal costs. The first set is NB Power's estimate of marginal costs, including exports. The second set is NB Power's marginal costs, including exports, as adjusted for New England power prices according to the following equation:

$$MC2_h = max\{0, Export\ Price_h, min[Import\ Price_h, MC1_h]\} \tag{3}$$

where $MC1_h$ is NB Power's marginal cost estimate for hour h and $MC2_h$ is the revised marginal cost for hour h. This equation assures satisfaction of the condition of equation 2, which requires that marginal cost be no less than the export price, and no greater than the import price.

Table 7 presents the two sets of load-weighted marginal cost results, one for NB Power's marginal cost estimates (*MC1*) and the other as adjusted for New England power prices (*MC2*). The table shows that the adjustment hardly matters at all, which we believe occurs partly because of the reasonableness of the marginal cost forecast and partly because the typical-hour approach washes out much of the time-variation in marginal costs and consequently prevents the

[51] NB Power claims to use the forward market price approach in "Appendix B - NB Power Electric Power Supply System (Matter 271)," p. 13, as quoted above, but calculates marginal costs partly based upon settlement values. In other words, it appears that NB Power's system dispatch is based upon true marginal costs, which is good for minimizing power system costs; but that settlement values related to accounting costs rather than to marginal costs have entered the marginal cost calculation.

[52] This simplifying assumption is suitable for the purpose for which NB Power forecast the import prices, namely determining its import costs. It is not helpful, however, for our present purpose of assessing the accuracy of the marginal cost forecasts.

adjustment process from finding discrepancies between NB Power's marginal costs and New England power prices.

Table 7
Forecast Marginal Costs, April 2017 through March 2018 (dollars per MWh)[53]

	Per NB Power	Adjusted
maximum	103.74	126.24
minimum	10.16	17.56
standard deviation	19.71	20.16
Averages:		
all hours	55.77	55.04
winter all hours	69.67	68.30
summer all hours	41.13	41.09
winter on-peak	76.16	75.19
winter off-peak	63.03	61.24
summer on-peak	47.57	48.89
summer off-peak	34.09	32.56

The resulting marginal cost numbers have time patterns that are consistent with NB Power's designation of on-peak and off-peak hours in its interruptible and surplus power rates for Large Industrial customers. Specifically, marginal costs are higher on weekdays than on weekends; and they are higher from 8 am to midnight than in other hours. Furthermore, the marginal costs are higher in the months of December through April than in other months. With or without adjustment, these marginal costs show a moderate amount of time variation, with a ratio of about 2.3 between the highest- and lowest-cost periods.

4.3. Designing Time-Varying Rates at NB Power

Although the time-variation in NB Power's marginal costs is fairly modest, the Board, in its May 13, 2016 decision regarding Matter 271, stated:

> NB Power is directed to prepare a proposed strategy for the timely introduction of seasonal allocation of energy and demand production costs together with a corresponding rate design strategy. The proposed strategy is to be filed with the Board by June 1, 2017.

In response to this requirement, NB Power timely requested that the Board consider introducing time-varying rates after further study of seasonal rate design, development of satisfactory load research data from an AMI, development of a broad rate design strategy wherein time-of-use

[53] Winter is December through April, and Summer is all other months. On-peak hours are 8 am to midnight on weekdays, and off-peak hours are all other hours.

rates or other load shifting programs are considered, and due consideration of inter-class and intra-class equity issues.[54] This section addresses several issues relevant to this response.

4.3.1. The Relationship of NB Power's Present Rates to Marginal Costs

In general, NB Power's energy prices significantly exceed its marginal costs. Table 7 shows that average adjusted forecast marginal costs have average period values of between 3.3 and 7.5 cents per kWh, with a prospective maximum of 12.6 cents.[55] By contrast, Table 8 shows that, with the notable exceptions of the Large Industrial and Wholesale Rate classes, NB Power's energy prices are well above marginal costs.[56] This means that, aside from the exceptions, NB Power's profit margins rise when sales rise and fall when sales fall. For the exceptions, changes in sales have little impact on NB Power's profits.

Table 8
NB Power's Retail Energy Prices (cents per kWh)

Class	Low	High
Residential	10.81	
General Service	9.27	13.18
Small Industrial	6.32	13.39
Large Industrial	5.20	
Wholesale Rate	6.63	
Unmetered	13.62	

As already noted, NB Power's only time-varying prices are for interruptible and surplus power sold to Large Industrial customers. Because these prices are directly tied to NB Power's marginal costs, they reflect the time-variation in marginal costs.

4.3.2. Managing Time-of-Use Rates

If NB Power concludes that introducing time-varying pricing for some or all customer classes is worth exploring, it will confront questions of rate design and management. Given the broad range of time-varying designs available, numerous design questions arise. The central design question is whether increasing complexity offers benefits that exceed the cost to the customer and utility of that complexity. Subsidiary design questions are as follows:

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[54] New Brunswick Power Corporation, *Strategy for the timely introduction of Seasonal Allocation of Energy and Demand Production Costs*, before the New Brunswick Energy and Utilities Board, Matter 357, June 1, 2017

[55] These cents-per-kWh figures are equivalent to the $32.56, $75.19, and $126.24 per MWh figures shown in Table 7.

[56] This is a common outcome in utility pricing, since fixed costs tend to be recovered to some degree in volumetric charges, especially for mass market rates that lack a demand charge. This practice, though, means that a change in consumption level changes revenues by more than it changes costs.

Does the time variation in marginal costs justify or suggest a preferred time pattern?

Are customers able to respond to prices in that time pattern? The preferred design could be seasonal only, TOU only, or a combination thereof. We recommend that NB Power have time variation that is at least seasonal, with time variation within seasons being a less urgent need.

How many TOU pricing periods are desirable, and which hours belong in each time period?

Residential TOU rates commonly have two time periods, but a three-period approach may sometimes provide a better match for marginal costs. Statistical methods are available to evaluate this issue. For the sake of simplicity, we recommend that there be two periods within each season, and that the periods (but not the prices) be the same for each season.

How shall marginal cost-based prices be reconciled with revenue requirements?

Marginal cost patterns suggest price ratios between periods, but revenue requirements will not be satisfied without an adjustment. Various strategies are available, including having customer and demand charges fully recover customer- and demand-related costs, proportionally scaling prices to satisfy revenue requirements, and loading costs disproportionately into peak period prices.

What type of time-varying pricing shall be introduced?

Options include seasonal and TOU prices that each apply to large numbers of hours, prices that vary hourly, and high prices (as under critical-peak pricing) that apply to only a very few hours when the power system's reserves are low. NB Power's new data management capabilities offer the opportunity to experiment here.

Shall time-varying rates be optional or mandatory?

In principle, a utility should not be averse to offering customers a choice among rates. The requirements of successful rate design with optional rates are that the pricing of flat rate products relative to time-varying products should reflect: 1) the extra risk borne by the utility in offering flat pricing at retail when faced with hourly pricing at wholesale; and 2) the revenue attrition associated with allowing choice, because lower-cost customers will migrate to the time-varying products while higher-cost customers stay with the flat rate products.

In practice, it is generally a good idea to make time-varying rates mandatory for large customers, who can tolerate greater rate complexity than can small customers and who are likely to be more responsive to time-varying prices. Again, NB Power's introduction of new interval data recorders and data management offers a potentially significant broadening of the range of pricing products that can be offered to large customers.

As for mass market customers, the data will soon become available for implementing time-varying rates; but these customers may not have much appetite for rate complexity or for mandatory conversion to TOU. Conversion to a seasonal rate might be more acceptable. Other jurisdictions have gone further, with California being a leading example of converting small customers to mandatory TOU service.

There are three basic approaches to dealing with mass market participation with seasonal or TOU rates: *mandatory participation*, under which the customer has no choice; *voluntary conversion on an opt-out basis*, under which the customer will be switched over to the new rate unless they request to remain on their current tariff; and *voluntary conversion on an opt-in basis*, under which the customer switches over to the new rate only if they request the switch. The mandatory approach assures universal participation in the new rate, though some customers will be unhappy about being forced onto a new rate. The opt-out approach will result in a much larger participation rate than will the opt-in approach simply because of *status quo* bias: customers will generally not act, one way or the other, unless they are strongly motivated.[57] The opt-out approach is thus likely to get high participation without making customers unhappy: anyone who does not like the new rate can go back to the old rate within some limited period of time. The advantages of high participation are first, that customers are on a more fair and efficient rate; and second, that the marketing and data management costs associated with the new rate will be divided over many participants, making the initiative more cost-effective.

We recommend that, when appropriate metering, communication, and data management are available, NB Power offer time-varying rates to large customers on a mandatory basis and to mass-market customers on a voluntary conversion with opt-out basis.

4.3.3. Advanced Metering

NB Power's introduction of advanced metering has brought the company into contact with customers who are opposed to radio frequency meters. Common reasons for this opposition are fears about the possible health impacts of radio frequency emissions from the signal generated by the meter when communicating data to the data management system, and privacy concerns about the utility acquiring detailed information about the customer's usage profile and disseminating this information to third parties.

Regulators elsewhere have proven reluctant to force customers to accept new metering. If customers must be given an option, what options are available, and what are the cost impacts of these alternatives?

One obvious option is to continue accumulating only traditional billing information, either with an existing traditional meter, a reinstalled traditional meter, or a new meter that collects only traditional billing information. This option involves additional costs for a utility that has committed to AMI, since a non-standard meter must be found and installed, the meter must be manually read, and the data management system must deal with non-standard data. This can be

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[57] Strong *status quo* bias induces customers to almost always accept whatever status they are given. Consequently, if customers are kept on standard rates with the ability to opt in to TOU, they will almost always remain on the standard rate; while if customers are put on the TOU rate with the ability to opt out, they will almost always remain on the TOU rate. See the Environmental Defense Fund's *A Primer on Time-Variant Electricity Pricing*, 2005, with its discussion of opt-in versus opt-out designs, especially the experience of SMUD at p. 15.

particularly costly because traditional analog meters are no longer manufactured in North America, requiring a utility that offers this option to locate old equipment or purchase it in an after-market. Utilities have enumerated these costs and used them in developing premium pricing for customers who are unwilling to transfer to AMI.

A second option is to simply turn off the transmission of data and to read contemporary interval data manually. This approach avoids meter change-out costs and the retention of old technology, but still requires both an initial visit and regular meter-reading visits that would otherwise be unnecessary.

It appears that the industry trend is to allow customers to opt out of AMI, to allow them a single technically feasible option involving simple metering and perhaps manual meter reading, and to charge the customer for the cost of this service. This approach tends to result in a tiny share of opt-outs and substantial additional charges to the affected customers.[58]

We recommend that NB Power allow customers to opt out of AMI service. The utility should charge opt-out customers for the incremental costs of their decision, which will usually involve an installation charge for the restoration of old technology or the deactivation of communication capabilities of new technology, and a monthly charge for separate meter reading.

5. RATE REVISION OPTIONS AT NB POWER

NB Power's planned investment in grid modernization, especially interval data recording and related data management and billing capability, has opened up the possibility for revision of the utility's rates generally. This section reviews some of the available alternatives along with the strengths and weaknesses of converting from the current to a new rate portfolio. The discussion focuses on standard service in absence of distributed energy resources, leaving that latter topic for Section 6.

5.1. Residential Customers

5.1.1. Price Variation Over Time and Space

The current residential tariff has the virtue of simplicity, and it also provides slight cost differentiation related to geography (urban/rural/seasonal). Even in the absence of interval metering, there is a case to be made for seasonal pricing of energy, given the marginal cost figures shown in Table 7. A seasonal rate would match prices to costs better than would an annual rate, and would address the issue of heating versus non-heating customers.

Once NB Power's interval recorders are tested and functioning reliably, the base residential tariff could be augmented with a TOU structure with two pricing periods within each season, though the marginal cost variation *within* seasons appears to be smaller than *between* seasons. Two

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[58] For illustrative charges in several states, see J. Evans, "The Opt-Out Challenge," *Electric Light & Power*, March/April 2012, p. 4. See also West Monroe Partners, *AMI Opt-Out: Policies, Programs and Impacts on Business Cases*, 2015, http://www.westmonroepartners.com/en/Insights/White-Papers/AMI-Opt-Out.

periods are simpler for customers new to TOU service to understand than three periods, and in the absence of significant marginal cost differences over time, are likely adequate to represent marginal cost patterns. Industry practice leans toward two-period TOU designs.

A TOU product that has an opt-out feature would be more readily accepted than would a mandatory product. Such a TOU product likely would attract non-heating customers since they would have a lower share of on-peak usage than would space heating customers, and would be unattractive to heating customers. Opt-out customers would generally be "instant losers," which would be fair in the sense that such customers impose higher costs on the power system than do other customers. Before proposing such a TOU rate, however, NB Power should estimate the expected revenue attrition from the opt-out customers and develop a plan to eventually recover lost revenue from such customers.

Some years after a static time-varying design has been in place for the bulk of customers, NB Power can explore augmenting its residential portfolio with a dynamic pricing product such as CPP. This product offers the potential to deliver load relief when system reserves are low. There is no present urgency in offering such a product because NB Power does not anticipate reserve or capacity shortages for the next several years, because it will take a couple of years for customers to become accustomed to seasonal TOU pricing, and because introduction of dynamic pricing products presents significant challenges. To implement CPP, for example, NB Power would need to be able to do the following:

- Determine when a critical-peak period should be called. This requires an algorithm that estimates whether the current hour is likely to be more critical than future hours. Such algorithms exist in current CPP programs.
- Communicate to customers timely information indicating the timing and duration of a critical-peak period.
- Measure customer load response behavior during critical-peak periods and bill customers based on their responses.
- Develop CPP prices based on forecasted marginal costs, and develop adjustments to the base TOU prices to ensure the proper level of revenue recovery.

Importantly, for CPP to succeed, customers would need to be able to respond to advance notice of high prices. At U.S. summer-peaking utilities, this challenge is readily met by means of programmable thermostats on the largest end use, air conditioning. In New Brunswick's winter-peaking environment, there is some question as to whether programmable thermostats could control heating loads, which are predominantly of the baseboard variety. A New Brunswick CPP program might be limited to customers whose load control can be automated.

5.1.2. Fixed Charges

Because utilities recover a significant share of their fixed costs through variable energy charges, the growing market shares of distributed energy resources are undermining utilities' ability to recover their fixed costs. Consequently, utilities are looking for ways to shift fixed cost recovery from energy charges to fixed charges, which more or less means recovery of customer-related costs through customer charges and demand-related costs through demand charges. In general, such a shift in cost recovery will raise bills for lower-volume customers and lower bills for larger-volume customers. There is the concern that low-volume customers are low-income customers, though this is not necessarily true, and will become less true over time as large customers satisfy much of their consumption through self-generation.

For reasons of both efficiency and equity, it would be beneficial for NB Power to increase the recovery of fixed Residential customer-related costs through its Residential customer charges. Geographical diversity in the customer charge is unusual by industry standards but defensible, as the practice helps to reflect differences in cost to serve. Indeed, utilities serving rural jurisdictions exclusively tend to have relatively high customer charges when compared with urban-dominated service territories.[59]

A more ambitious approach to fixed cost recovery would be to introduce a demand charge to cover the fixed delivery costs of distribution and, perhaps, transmission. This approach has the advantages of improving fixed cost recovery, improving the efficiency of prices by moving energy prices in the direction of recovering predominantly energy-related costs, and resolving pricing issues related to distributed energy resources (which are discussed in Section 6). The disadvantages are increased rate complexity and a tendency to shift cost recovery from larger customers toward smaller customers: if low usage and low income are strongly correlated, this latter tendency raises concerns about impacts on low-income customers. Interval data recorders make residential demand charges feasible. Experience to date with residential demand charges is limited, but their use is spreading, spurred particularly by the increasing market penetration of distributed energy resources.

Significant changes in rate structure (such as the introduction of a residential demand charge) or in prices (such as doubling the customer charge while commensurately reducing energy price) can lead to "rate shock" for customers. Consequently, utilities often make structural changes that phase in price changes over time. For example, if the customer-related cost to serve a residential customer is far above the current customer charge, increases over multiple rate cases, matched by offsetting energy price reductions, may be approved by regulators. The time period for the transition depends on the scale of the change in price and associated bill impacts. The actual phase-in may occur at preset times or whenever rate applications are approved.

[59] For example, Power System Engineering, Inc., *Survey: Electric Cooperative Fixed Cost Recovery,* 2014, http://www.powersystem.org/docs/publications/nreca-fixedcost_1407_email.pdf, Appendix A surveyed electric cooperatives' rates for 2012-13. These cooperatives tend to serve rural areas. For a sample of 35 cooperatives, this survey found residential customer charges averaging U.S. $27.08 per month, an 18% increase over the previous average value of U.S. $22.91. The report notes (at page 3) that "the cooperatives in the survey recovered only about 60 percent of the customer cost in the Customer Charge on average."

5.1.3. Recommendations

In the near term, NB Power can improve the efficiency and fairness of its Residential pricing by taking the following steps:

- Introduce mandatory seasonal pricing on a phased-in basis, with a winter season and a summer season.
- Consider introducing TOU pricing within each season on a phased-in basis, using the same time periods (on-peak weekdays 8 am to midnight for the on-peak, and all other hours for the off-peak) that NB Power already applies to its Large Industrial interruptible and surplus energy services. Customers would be allowed to opt out.
- Increase customer charges on a phased-in basis, so that they eventually fully recover customer-related costs.

In the intermediate term, NB Power can take the following steps:

- Consider adding a demand charge to recover demand-related costs.
- Explore offering a CPP option if and when New Brunswick's reserve situation tightens.

5.2. Business Customers

This section addresses several of the issues that NB Power will face in the course of reforming its rates for business customers.

5.2.1. Customer Classification

It may be advantageous to convert to a business customer classification approach based upon size rather than upon business type. Business customers would then be split into three or four subclasses, perhaps differentiated by peak loads and voltage levels.

5.2.2. Time-Varying Pricing

Time-varying pricing is warranted by prospective competition and by its promotion of efficient use of electricity. A time-varying price is better than a fixed price at communicating to customers the cost of obtaining additional supply, inducing load management in the short term and conservation in the long term. Time-varying pricing is enabled by ongoing enhancements to and cost reductions in metering, data management, and billing capabilities.

As with Residential rate updating, a starting point would be to introduce seasonality for all rate classes' energy charges. Given the capabilities of business customers, there is a stronger case than for residential customers to introduce TOU service. Mandatory TOU service for medium-sized and large customers would be well within industry practice. TOU service could be offered to small business customers on an opt-out basis, where the switching of small customers would occur over a period of a year or more so that the utility would not have to deal with large numbers of customers switching simultaneously.

The arrival of interval data recording also offers NB Power and its customers the opportunity to explore dynamic pricing options such as RTP, under which customers pay market-based prices that may vary by hour. NB Power could also update its interruptible and economic development rate (EDR) and load retention rate (LRR) programs to ensure that they reflect revisions in underlying business rates and that discounted prices do not fall below marginal cost.

In theory, a utility could offer customers a variety of pricing options with varying degrees of price risk. At one end of the spectrum is hourly pricing that accurately reflects hourly wholesale market conditions, while at the other end is a single fixed non-seasonal all-hours price. In theory, customers would gravitate to the design that they prefer; and the utility, anticipating customer preferences, would price each product based on customers' expected cost to serve, including the utility's cost of risk.

In practice, a large number of pricing options can be bewildering to customers and costly to administer. Consequently, all customers should be put on a standard seasonal tariff or seasonal TOU tariff, and then be offered optional dynamic pricing (like CPP and RTP) and an optional interruptible rate.

For small business customers, the standard rate would either be a seasonal rate or a seasonal TOU rate with opt-out. NB Power could offer an optional CPP program that parallels the design contemplated for Residential customers. The parallels would simplify design and administration.

For medium-sized and large business customers, the standard rate would be a seasonal TOU rate. NB Power could offer both CPP and RTP options. To facilitate implementation, both of the optional programs could be offered on a phased-in basis starting with the largest customers.

RTP can be implemented as a two-part tariff under which the first part is a price hedge on a contract quantity of load and the second part is an energy charge or credit by which differences from the contract quantity are bought or sold at market-based hourly prices established on the previous day. The contract quantity roughly represents a customer's usage in the absence of RTP, and is the basis for recovery of required revenue based on the standard (seasonal TOU) tariff. Customers who opt for this product would be likelier than most customers to engage in energy management activities.[60]

CPP and RTP are partial substitutes for interruptible service because they induce customers to curtail their loads in response to high prices during periods of supply shortage. Nonetheless, they may not curtail load sufficiently to relieve shortages under all conditions. NB Power may therefore wish to also offer an interruptible tariff under which the system operator has the authority to *mandate* load curtailments under shortage conditions.

In summary, business customers can be offered a retail rate portfolio with a range of time-varying options. Such options can help customers control their electricity costs and would help NB Power and its customers take maximum advantage of its grid modernization efforts.

[60] The current surplus energy offering would be supplanted by RTP, as the latter in effect offers surplus energy at marginal cost on an hourly basis.

5.2.3. Customer Charges

In principle, there might be a benefit from charging all classes for customer-related costs via a customer charge if these costs are truly related to the number of customers rather than to customers' peak demand. This would be a change only for present industrial customers, for whom customer-related costs are presently recovered through demand charges.

5.2.4. Demand Charges

In traditional electricity markets without significant competition, it has been a general goal to recover demand-related costs through demand charges, with little recovery of these costs through energy charges. Demand-related charges for business consumers have historically recovered both generation and delivery capacity costs; but in a world with competition in generation services, such as from distributed energy resources, demand charges might arguably be justified only for recovery of delivery capacity costs.

Utilities have a wide variety of demand charge structures. Some utilities impose a single bundled demand charge for generation, transmission, and distribution services. A minority impose two separate charges, a generation and transmission demand charge based upon a coincident peak period demand and a distribution charge demand charge based on the customer's non-coincident demand in all periods. Additionally, some utilities apply a ratchet to demand, basing the demand charge in each month on the peak demand of the past twelve months or on the peak demand in the most recent peak season. NB Power is familiar with this approach, since its demand charge for large industrial customers is based on a maximum of contract, ratcheted, and current peak demand.

Large customers at other utilities are frequently required to nominate a contract demand level for the coming year, after which they face constraints in adjusting that level. This design provision helps a utility to avoid unexpected large changes in generation and transmission requirements. Utilities like Hydro-Quebec, with large plants on the fringe of the North American grid, find this provision particularly valuable.

NB Power currently has size limitations on its tariffs as follows:

- GS I: Customer eligibility for the tariff is not limited by a size, but a demand charge applies only above 20 kW billed demand.
- SI: Customers are eligible for the tariff if they have at least 5 kW of contracted demand, all of which is subject to a demand charge.
- LI: customers are eligible for the tariff if they have at least 750 kW of contracted demand, all of which is subject to a demand charge.

Three considerations seem relevant to the question of whether demand charges might be extended to include all customers with 5 kW or more of peak load. One consideration is that a demand charge may improve the fairness and efficiency of cost recovery with respect to the fixed power delivery infrastructure used by smaller customers. Second, Small Industrial customers above 5 kW already pay a demand charge, so it would be desirable to avoid retreating to the 20 kW boundary applicable to GS I customers. Instead, it would be preferable to extend demand charges to former GS customers larger than 5 kW. Third, if demand charges are going to be considered for at least some Residential customers (particularly those with self-generation) and eventually perhaps all Residential customers, it would not be unrealistic to require a demand charge structure even for the smallest business class.

We therefore recommend that demand charges be extended to apply to all business customers with at least 5 kW of demand. Although NB Power might consider allowing small business customers to opt out of such a demand charge, such an opt-out would become increasingly problematic as distributed energy resources achieve higher penetration among small business customers. We therefore recommend that the demand charge for business customers with at least 5 kW of demand be mandatory.

5.2.5. The Small Industrial Customer Challenge

Converting the Small Industrial customers to a seasonal TOU product poses particular difficulties because there would be significant bill impacts relative to the present Wright tariff for customers with extremely low load factors. Customers on the present Small Industrial tariff might find their bills increasing with the combining of commercial and industrial customer classes, but would surely be hurt by bill increases if they have load factors below 14%. Because low load factor customers have a high cost to serve relative to customers with average load factors, a rate reform that reasonably reflected unit costs in its customer, energy, and demand charges would induce customers, including present Small Industrial customers, to pay their fair shares. Indeed, the present Small Industrial rate has a low revenue-to-cost ratio relative to that of the General Service rate, so merely achieving parity in ratios will result in an average bill reduction for the GS I customers and a bill increase for the SI customers. Aside from this impact, though, abandonment of the Wright tariff for a TOU rate will increase bills for low load factor former SI customers. Can such a rate change be justified? Can alternative designs be applied to reduce or limit the bill impacts?

Moving from a Wright tariff to a TOU tariff has the merit of rate simplicity. Customers have difficulty in understanding the Wright tariff, aside from its central concept of reducing bills by minimizing peak demand. TOU pricing is not only an improvement in pricing efficiency but is also easier to understand.

To mitigate the bill impacts on low load factor Small Industrial customers of converting to TOU service, there can be a transitional pricing plan, possibly including tapered discounts for former SI customers. These low load factor customers have been enjoying a cross subsidy. The question is whether this cross subsidy should continue in some form. Do their businesses create more jobs or economic activity than others'? If some of these customers support the provincial economy, then some form of extended subsidy may be easier to defend than it would otherwise be. Otherwise, the Wright tariff should be phased out over a period of a few years.

5.2.6. Economic Development Rates

NB Power currently offers a declining discount demand price for large industrial customers who add load in excess of 5,000 kW. This is a conventional EDR with a tapered demand charge.

NB Power can continue to offer this product under the updated rate portfolio, based on the base seasonal TOU tariff.

By industry standards, the threshold of 5,000 kW is relatively high. The only other Canadian utility that has an EDR provision with a minimum addition is Hydro-Quebec, whose minimum is 1,000 kW. U.S. utilities have limits in the range of 100 to 2,000 kW.[61] NB Power could reduce its minimum addition to 500 or 1,000 kW, which are values that comport with industry practice. If reducing the threshold is not desirable for some reason, but expanded eligibility is desired, NB Power could make its threshold of 5,000 kW more flexible. The threshold could be permitted to apply to load additions at multiple customer sites or to multiple phases of a single-site addition.

Alternatively, NB Power could offer an EDR product based on two-part RTP, under which energy above normal current consumption levels (contractual consumption) is sold to the customer at market-based prices, and fixed charges are recovered through a demand charge that rises to the normal tariff level after (say) five years. Such a customer would thus not immediately pay the full embedded cost on the contract quantity but would slowly reach that level over time.

NB Power could also consider an LRR product for large customers who are expecting to reduce their electricity consumption or perhaps even shut down their facilities. The form of the discounts that are given to such customers should depend upon whether the customers are on current, seasonal, seasonal TOU, or RTP rates. For customers on current, seasonal or seasonal TOU rates, discounts should be in the form of energy prices that are moved closer to marginal cost, which would reduce the customer's bill and give the customer incentives to continue consuming power. For customers on two-part RTP, discounts should be in the form of reductions in the charge on the contract quantity, as load variations relative to the contract quantity would already be priced close to marginal cost. (Discounting should also avoid pricing so low that negative margins are earned on sales in total.)

To limit the subsidization of participating customers, both EDR and LRR programs should have limited program participation. Such limitations may be imposed by allowing participation only by those customers whose businesses offer substantial benefits to the Provincial economy and who can demonstrate such benefits.

5.3. Industrial Class Exporters

At least one NB Power business customer has raised the possibility that their electricity-intensive business ought to be granted subsidies because of the potential to generate extra benefits for the Province through increases in their exports. Such subsidization of exports may be justified when the benefits created by the exports exceed the costs of the subsidies. The benefits generally include jobs created directly by export sales, either for the industrial exporter or for suppliers serving the exporter. There may also be indirect benefits when the local workers or businesses that profit from the exports spend their money on goods and services provided by

[61] Illustrative U.S. EDRs include Kansas City Power & Light (200 kW), Alabama Power (1,000 kVa), Duke Power North Carolina (1,000 kW), and Florida Power & Light (350 kW).

other local businesses. The direct costs of the subsidies are the subsidies themselves, a part of which ends up in the pockets of out-of-province consumers of the exported goods; but there are also indirect costs due to the fact that the subsidies are financed through higher electricity prices, which means that other electricity customers have less money to spend on services provided by local businesses, thus putting a drag on the local economy.

There are two serious economic problems with subsidizing exports. The first is that the benefits may be less than the costs. In fact, it is not unusual for such subsidies to have costs that are much greater, per job created, than the wages paid to each worker. A benefit-cost study, with all the usual challenges, can quantify these benefits and costs. The second problem is that subsidies tend to last forever, even if the circumstances that initially justified the subsidies have disappeared.

There may also be legal problems with subsidizing exports. One problem is that they may run afoul of the legally binding rules of the World Trade Organization, of which Canada has been a member for over two decades. Another problem is that subsidization of exports to other Canadian provinces may run afoul of Canadian law. Clearly, appropriate legal experts should be consulted before undertaking any export subsidization program.

For a utility, an export-oriented request for a bill discount threatens a snowball effect by which approval of a discount for one customer might lead to an avalanche of discount requests by other customers, particularly by customers who are competitors of the first customers who were granted discounts. Nonetheless, electric utilities have had extensive experience with EDRs and LRRs that are comparable to the export support request. Requests for EDRs and LRRs tend to be supported by documentation demonstrating that the customer has competitive alternatives for location of their new business activities (EDRs) or that failure to grant discounts will have negative economic consequences for the regional economy (LRRs). By contrast, export-driven customers tend to have weaker claims because their business is not materially different from a business of similar load characteristics that does not export. There is little justification for a discount unless they would qualify for an EDR or an LRR, in which case the EDR or LRR application process should be pursued.

6. DISTRIBUTED ENERGY RESOURCES

Distributed energy resources are sources of electrical energy located at or near loads rather than at central generating stations. Such resources currently consist predominantly of self-generation facilities such as solar panels, combined heat and power units, and wind turbines owned by retail customers; but they can also include battery storage.

In principle, distributed energy resources should be compensated for the services that they provide *to* the power system, and should pay for the services that they receive *from* the power system. In practice, however, the dominant vehicle for pricing their services is net metering which, as implemented by NB Power and nearly every other utility in North America, fails to compensate distributed energy resources according to the net values that they provide to the power system. The result of this failure is generally a flow of cross-subsidies from customers *without* self-generation to customers *with* self-generation. As long as distributed energy resources have a trivial market share, these cross-subsidies are trivial; but as this market share rises, the cross-subsidies also rise.

This section begins by reviewing the values and costs of the services provided by and used by distributed energy resources. It then looks at net metering, which is a major means of compensating these resources in New Brunswick and elsewhere. Finally, it looks at the pricing of standby service, which is a service inevitably needed by nearly all customers with distributed energy resources.

6.1. The Value of Services Provided by Distributed Energy Resources

All distributed energy resources provide electrical energy. Depending upon the dispatchability of a particular resource's technology, a resource might also provide automatic generation control, load following, operating reserves, capacity, voltage control services, and/or environmental benefits.

Energy Service. The energy value of a distributed energy resource depends upon the utility's avoided energy costs – that is, upon the reduction in the utility's costs of fuel or power purchases that result from displacement of utility generation by energy from the distributed energy resource. This energy value can be measured by the utility's hourly marginal energy costs or by relevant market hourly prices of electrical energy. The relevant cost or price benchmark is described above in Section 4.2.

Ancillary Services. Only dispatchable resources can provide automatic generation control, load following, and operating reserve services. For such resources, the values of these services can be measured by the respective marginal costs or market prices of these services. In principle, these values may be inferred from data on the capabilities of NB Power's resources, combined with a costing model such as PROMOD; and there may be hours in which the ISO New England market's prices provide relevant benchmarks for the values of these services in New Brunswick. In practice, NB Power implicitly values ancillary services according to the costs of their provision by a hypothetical new generating plant.[62]

Capacity. The capacity value of a distributed energy resource depends upon the extent that the resource supports power system reliability. This value can be quantified as the product of three factors: 1) the utility's annualized cost of capacity, which is often measured by the annualized capacity cost of a new pure peaking generator; times 2) an adjustment term, between 0.00 and 1.00, that reflects the utility's current need for capacity, which can be calculated from the outputs of an appropriate production simulation model[63]; times 3) the probability that the resource will

[62] Note that any compensation to a particular distributed energy resource should reflect the quality of the services provided by that resource, which depends upon the speed, accuracy, predictability, and reliability with which that resource changes output or load in response to the system operator's dispatch instructions. Compensation should also depend upon the extent to which the services provided by that resource are deliverable to the network in compliance with the rules of the North American Electric Reliability Corporation.

[63] In NB Power's present circumstance of not needing any new capacity for the next several years, the adjustment factor would be much closer to 0.00 than to 1.00.

actually be available during the peak load periods when resources are most needed to support reliability.[64]

Voltage Control Service. Distributed energy resources can sometimes act to control local voltages. This service may be valued according to either the customer's costs of providing such services or the costs that the utility saves from not needing to install and operate its own voltage control equipment in that locality. The cost and value will be particular to each situation.

Environmental Benefits. Distributed energy resources can provide environmental benefits to the extent that they are cleaner and less polluting than the resources that their power replaces.

The value of the services provided by distributed energy resources equals the quantities of these services times the values described above. This valuation method applies equally to all distributed energy resources. Distributed storage resources are not an exception, aside from the minor difference that they use electric power as their "fuel."[65]

6.2. The Costs of Services Used by Distributed Energy Resources

Distributed energy resources can impose three types of costs on the power system: those of ancillary services, particularly operating reserves and load following; those of transmission and distribution upgrades; and those of implementation.

Ancillary Services. Intermittent generation, such as by solar panels, has the characteristic of fluctuating with weather conditions. To keep a continuous balance between power supply and power demand, the utility must have dispatchable resources that are available to provide ancillary services that offset the fluctuations in intermittent generation. For each type of ancillary service, the marginal cost of backing up distributed energy resources equals the utility's marginal cost of the ancillary service (or the corresponding market price) times the quantity of the ancillary service that is needed to maintain reliability. Engineering analysis can quantify the ancillary services that are needed to maintain a level of reliability (as measured by expected unserved energy, for example) that is the same in scenarios with and without distributed energy resources. The costs of the ancillary services can be objectively allocated among resources according to the characteristics of their output fluctuations.

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[64] This probability might be 90% for a dispatchable resource like an oil-fired generator, but only 50% for an intermittent renewable resource like an array of solar panels (if the weather records indicate that the sun will be shining half of the times when power is most needed). For example, a 4 kW array of solar panels with a 50% on-peak availability factor would provide the power system with 2 kW of expected capacity.

[65] Distributed storage resources consume electrical energy in hours when energy is cheap and produce electrical energy in hours when energy is expensive. Consequently, the gross value of a distributed storage facility equals: a) the sum, over hours when the resource exports power to the grid, of the per-unit values of electrical energy times the quantities of energy exported; minus b) the sum, over hours when the resource imports power from the grid, of the per-unit values of electrical energy times the quantities of energy imported. The relationship between export and import quantities depends upon the physical efficiency of the storage unit, which is more or less measured by the ratio of the quantity of energy it exports divided by the quantity of energy that it imports. Therefore, the gross profit of a storage unit to its owner depends upon the prices that the unit pays and receives for power, and upon the unit's physical efficiency.

Transmission and Distribution Upgrades. Engineering analysis can determine the upgrades that are needed to maintain the same level of reliability with and without distributed energy resources. The costs of such upgrades are relatively easy to estimate. The hard part is allocating these costs among resources, as transmission and distribution upgrade needs are often discontinuous: there may be no need at all for upgrades over some large range of system conditions; but then a multi-million dollar need might arise when conditions fall slightly outside of that range.

Implementation Costs. The utility's costs of facilitating integration of distributed energy resources are those of the communication, control, and metering equipment that is needed to coordinate the activities of the larger power system with those of distributed energy resources.

6.3. Efficient Pricing of Distributed Energy Resources

The compensation enjoyed by owners of distributed energy resources has a large effect on investment in and operation of those resources. Higher compensation leads to more investment. For dispatchable resources, higher compensation also leads to greater use of resources; and time-varying prices can induce resources to produce more power when it is needed most, and less power when it is needed least. For all resources, time-varying prices can induce maintenance to be scheduled at those times when power is needed least.

Ideally, the compensation enjoyed by owners of distributed energy resources should induce investment in such resources when they are cheaper than other resources, and should discourage investment when they are more expensive. Furthermore, this compensation should induce resources to dispatch themselves or be available when the power system is in greatest need of power.

6.4. Equitable Pricing of Distributed Energy Resources

If the compensation enjoyed by owners of distributed energy resources approximates the net benefits of the services provided by those resources, then non-participating customers (i.e., those without their own distributed energy resources) would be financially indifferent to the activities of the resource owners. In other words, the non-participating customers would pay the distributed energy resource owners about the same amount of money as they would have paid to the utility in the absence of such resources. As for the resource owners, they would invest in and operate distributed energy resources only to the extent that they are better off doing so. Consequently, there would be no cross-subsidization among customers due to distributed energy resources; some customers (namely the resource owners) would benefit from these resources; and no customers would be made worse off.

By contrast, compensation in excess of net benefits will result in cross-subsidization of resource owners by non-participants. In this case, the non-participating customers will pay the resource owners more than they would have paid the utility for the services provided by the distributed energy resources; and non-participating customers will therefore be made worse off by these resources.

6.5. Net Metering

NB Power's net metering program is available to customers who are capable of generating up to 100 kW of their own electricity from renewable energy sources (e.g., biogas, biomass, solar, small hydro, wind). Under this program, customers remain in their rate class and pay for their *net* electrical energy consumption in each month – that is, the amount by which their gross electricity consumption exceeds their electricity production. The customer is not paid for any monthly excess of their production over their gross consumption; but the excess is carried forward to subsequent months until March of each year, after which the excess balance, if any, is reduced to zero. The customer is responsible for certain metering and communication costs.[66]

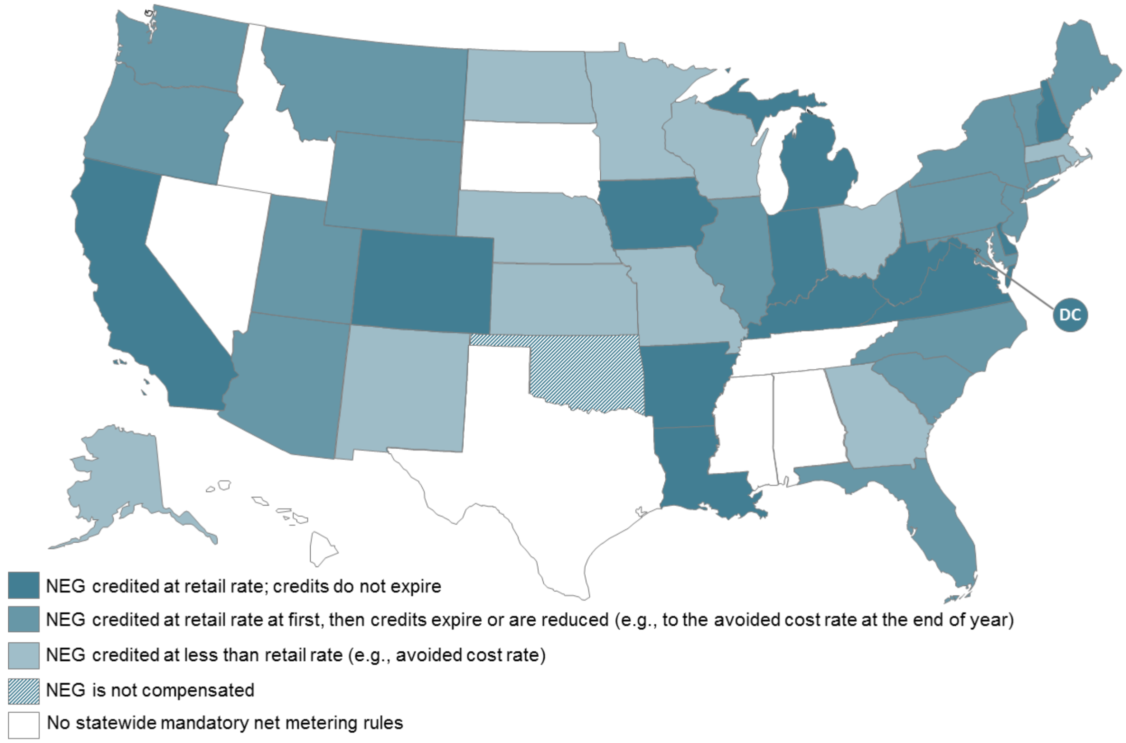
As of January 2016, NB Power had 52 net metering customers, who had 232 kW of solar capacity and 47 kW of wind capacity.[67]

NB Power's approach is fairly standard. In the U.S. jurisdictions that have net metering, it is virtually universal for customers to receive the full retail energy price as a credit for their electricity production up to the level of consumption. The differences among states lie mainly in the credits or payments for excess generation. As implied by Figure 5, the price paid for excess energy can either be zero, the full retail energy price, or prices that are based upon market conditions or marginal costs. For utilities that make no payment to the customer for the excess, there may or may not be a carryforward of the excess; and those utilities that offer a carryforward may or may not have the credit expire.

[66] https://www.nbpower.com/en/products-services/net-metering/faqs/.

[67] NB Power, *Solar Panel Net Metering Case Study*, 2016, p. 7.

Figure 5
Customer Credits for Monthly Net Excess Generation (NEG) Under Net Metering (as of July 2016)[68]



The problems with net metering are due to the fact that, as at NB Power, almost all utilities' energy charges significantly exceed their energy-related costs, since almost all utilities recover significant customer and demand costs through energy charges. For example, it is common for utilities to recover a substantial share of distribution system fixed costs through energy charges. The consequences of this over-reliance on energy charges are that net metering allows customers with self-generation to avoid paying for customer and demand costs on that portion of their consumption that is satisfied by self-generation, and that customers without self-generation end up paying – that is, subsidizing – these costs. This cross-subsidization is not a problem as long as there are few distributed energy resources, which is presently the case for NB Power, with a trivial 0.3 MW of such resources on a 4,200 MW system. But the cross-subsidization is becoming a problem in jurisdictions, such as Arizona, California, and Hawaii, in which distributed energy resources are attaining significant market share.

The cross-subsidization is not merely a problem of fairness among customers but is also a matter of efficiency. When the retail energy rate significantly exceeds the marginal cost of energy, two costly things happen.

First, net metering induces investment in expensive customer-owned resources rather than in less expensive resources owned by the utility or independent power producers. This occurs

[68] Database of State Incentives for Renewables & Efficiency, http://www.dsireusa.org/resources/detailed-summary-maps/, file NEG-1.20161.

because customers evaluate self-generation and energy efficiency investments according to the impacts these investments have on their bills. With net metering, the customer implicitly receives the retail energy rate for much or all of the electrical energy they generate; and since the retail energy rate significantly exceeds the utility's cost savings, expensive customer-owned resources can be profitable for the customer while being expensive for the power system overall. The overinvestment in distributed energy resources thus drives up total electricity costs relative to what they would otherwise be. The consequence is higher electricity costs for everyone except the customers making the costly investments.

Second, net metering induces inefficient dispatch of any customer-owned generation that is dispatchable. In principle, all dispatchable generators should see prices that vary hourly with power system conditions. Such real-time pricing would induce generators to produce quantities of power that are related to the power system's time-varying need for power. By contrast, net metering implicitly sets the dispatch price at a fixed price – usually the retail electrical energy price – in all hours of the month, giving no signal whatsoever of current power system conditions.

We recommend that, at its earliest opportunity, NB Power replace its net metering tariff with an alternative design that avoids or minimizes cross-subsidy.[69] The replacement tariff could make use of the introduction of interval data recorders by having customers with distributed energy resources pay a demand charge that recovers demand-related costs, adjusts the customer charge to fully recover customer-related costs, and, as a result, an energy charge that covers volumetric costs only.[70] The basis for the demand charge would be the customer's maximum net non-coincident flow of power through utility facilities during the billing period. Adding TOU pricing would further improve price accuracy. This tariff could be designed to be bill neutral to the standard tariff that the customer would otherwise adopt.

In the long run, NB Power should have the goal of redesigning its standard tariffs to recover energy costs through energy rates, customer costs through customer charges, and demand costs through demand charges. In other words, the standard tariff could be modified to be more or less identical to the net metering tariff as revised in the near term. This would entail the controversial step (among others) of introducing demand pricing to all Residential customers; but it would address the inevitable though erroneous claim that the near-term approach discriminates against customers with their own resources. A companion long-term goal would be to credit or pay customers for excess energy according to marginal costs, market conditions, or energy costs only.

[69] Immediate replacement is desirable because it would bring to an end the inefficient investment incentives that accompany the inefficient price signals inherent in net metering. The ratemaking process, however, will require time for regulatory decision making, customer education, and utility implementation of a rate change.

[70] Under this scheme, the energy charge might recover average energy costs rather than marginal energy costs, which is still an improvement on the current compensation scheme.

6.6. Standby Pricing

Standby tariffs typically apply to self-generating customers who are ineligible for net metering, regardless of their voltage delivery levels. The purpose of these tariffs is to assure cost recovery from customers with their own generation in the usual situation that the utility's standard tariffs do not accurately reflect cost causation. Standby tariffs then serve as a means of recovering, from self-generation customers, the costs of the ancillary services and transmission and distribution services upon which these customers rely. On the other hand, if standard tariffs accurately reflected cost causation, then self-generation customers could simply purchase power under the standard tariffs, which would be sufficient to recover costs caused by these customers.

Over the long term, standard tariffs should be reformed or unbundled so that they better reflect cost causation and so that standby tariffs are unnecessary. In the short term, however, and particularly as long as significant shares of customer- and demand-related costs are recovered through energy charges, standby tariffs are needed to assure that standby customers pay their fair shares of costs.

The design of a standby tariff needs to consider several elements:

- *Mandatory Standby Tariff Participation*: Utilities have no consensus about whether customers with self-generation must take standby service. Nonetheless, such a requirement would help assure recovery of costs associated with providing standby service.
- *Minimum Capacity Requirements*: Most utilities require that standby customers have minimum self-generation capacity of at least 100 kW. These minima relieve customers with small self-generation, like rooftop solar, of responsibility for paying for the costs of the standby service that they use.
- *Generator Siting Requirements*: Most utilities require that customer generation be located on the customer's site.
- *Generator Use Requirements*: Most utilities require that customer generation be used on a regular basis, not for emergencies only.
- *Contract Duration*: Most utilities require a standby service commitment of at least twelve months.
- *Cancellation Notice*: Few utilities specify minimum periods for cancellation notice.
- *Quantity Basis of Contract*: If the service includes a capacity charge, then it is necessary to specify the capacity amount. Possible bases include the maximum rating of the customer's generation, the customer's metered demand, or an amount reached through negotiation. Some utilities allow the contract quantity to change over time.
- *Maintenance Timing Requirements*: If distributed energy resources gain a significant market share, some mechanism will be needed to induce or coerce customers to schedule maintenance in off-peak periods. Such mechanisms include: peak period demand charges for standby service; discounts for standby service to customers who schedule

maintenance in off-peak periods; and specific tariff limits on the timing and duration of customer generation maintenance.

- *Safety*: Customers should be required to meet safety standards, particularly addressing problems related to power backflows on the distribution system.

We recommend that, to the extent feasible, NB Power's standby service pricing reflect the costs of the unbundled services – electrical energy, ancillary services, transmission, and distribution – that together comprise standby service. In addition, customers should also pay for any special costs of resolving problems, like voltage fluctuations, that customers' generation would otherwise cause. Since NB Power's rates (like those of other utilities) do not fully reflect cost causation, introducing a standby tariff would be desirable. An unbundled design is likely to be simpler than the many complicated and restrictive designs currently on the market. Such a design would be compatible with future conventional rate designs that utilize market-based pricing.

For example, two-part RTP offers a platform for standby pricing. Customers with site generation that is regularly and fully utilized pay delivery charges based on a contract demand level that represents maximum usage in the absence of site generation. The customer's net load profile can then be used to establish a normal pattern of hourly usage. The customer pays for energy above the contract energy level at the RTP rate and is reimbursed for load reductions at the RTP rate. When the customer experiences outage, all of the customer's consumption is at the RTP rate; so customers will schedule planned maintenance for those times when RTP prices are expected to be low, thereby simplifying compliance requirements for customers and the utility. Georgia Power, for example, uses its RTP rate as the basis for standby pricing.

7. COST ALLOCATION ISSUES INFLUENCING UPDATED PRICING

This section discusses the allocation of grid modernization costs, the cost responsibilities of interruptible customers, and the costing and pricing of several non-energy products and services.

7.1. Grid Modernization Costs

In Appendix 12 of its *Integrated Resource Plan 2014*, NB Power describes the smart grid aspects of its grid modernization plan to provide a wide variety of improvements in the operation of its power system.[71] Much of this effort will produce benefits that will accrue to all customers on the grid. These benefits include improved efficiency in system operation, better integration of renewable generation, and more rapid outage detection and response. Other initiatives, such as improved communication between customers and the utility, will allow customer participants to benefit individually while delivering system reliability benefits to all customers on the grid. When certain elements of grid modernization accrue to all customers, it makes sense to assign the costs of those elements to all customers.

It is also possible for some elements of grid modernization to exclusively benefit only some customers. The construction of dedicated transmission spurs or substations for a single large

[71] NB Power, *Integrated Resource Plan 2014*, Appendix 12: Smart Grid.

customer are examples. In such cases, it would be fair and efficient to directly assign the costs of these elements to the customers who receive the benefits.

But complications occur when these enhancements provide indirect benefits to a wide range of customers in addition to the directly connected parties. This may occur, for example, in situations in which distributed energy resource owners and electric vehicle (EV) customers provide electricity storage benefits to the grid. In these situations, some of the incremental connection, communication, and customer service costs associated with these newer technologies will benefit both the owners of the technologies and customers in general. It is partly a matter of art to decide how much of these costs to assign to distributed energy resource owners and EV customers and how much to assign to customers more generally. For example, costs incurred at the secondary distribution level would be allocated to customers at that level.

The issue of system-level benefits from distributed energy resources is fraught with controversy at present. Advocates for rooftop solar systems have had some success in persuading regulators that utilities will reap not only generation operating cost and capacity cost savings but also transmission and distribution cost savings, along with environmental cost savings (such as reduced renewable purchases to meet customer demand for green power or the requirements of a renewable portfolio standard). Assuming that such savings are real, they argue utilities should pay for power at prices that are well above wholesale market prices for energy and reserves, and perhaps even higher than the retail price of electricity. Utilities, on the other hand, are reluctant to recognize any avoided costs that are not matched by corresponding cost reductions that appear in their income statements. Quantifying these cost savings and incorporating them in avoided-cost based prices will involve future research and debate.

We recommend that NB Power directly assign to participating customers the full cost of site-related upgrades related to customer initiatives such as distributed energy resources or EV charging. For the bulk of grid modernization costs, the utility should apply standard cost allocation techniques. Additionally, NB Power should monitor the debate on avoided costs associated with distributed energy resources to ensure that the price paid for distributed generation has a sound cost basis.

7.2. Interruptible Customer Cost Responsibilities

NB Power must meet a renewable energy requirement embodied in the province's Renewable Portfolio Standard, requiring that 40% of in-province sales be sourced from renewable generation by 2020.[72] This obligation can be met with utility renewable generation, power purchases, or renewable imports. NB Power may also be obligated to pay a carbon tax, if such becomes law.

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[72] New Brunswick Regulation 2015-60, Part 1, paragraph 3(1) states, "On December 31, 2020, and for each subsequent fiscal year, the Corporation shall ensure that 40% of the total in-province electricity sales in kilowatt-hours is electricity from renewable resources." Paragraph 3(2) requires that the share of renewable resource generation achieved in 2014 be exceeded through 2020. See https://www.canlii.org/en/nb/laws/regu/nb-reg-2015-60/latest/nb-reg-2015-60.html.

A question has arisen about whether and how the costs of the Renewable Portfolio Standard and the prospective carbon tax should be incorporated into the prices paid by Large Industrial customers for interruptible energy. Such energy is presently priced at NB Power's incremental cost plus a small margin.

The Renewable Portfolio Standard and an actual carbon tax would not necessarily change the basis for the price of the Large Industrial interruptible rate – it could still be incremental cost plus a small adder – but the calculation of incremental cost would be modified to include the incremental costs of these two environmental measures. Indeed, the incremental cost applicable to firm power would also need to be modified to include the incremental costs of these two measures.

For each MWh of retail energy sold, the incremental cost of a 40% Renewable Portfolio Standard would be approximately as follows:[73]

$$IC_{RPS} \approx 40\% * LF * max\{0, LRIC_{RE} - LRIC_{CE}\} \quad (4)$$

where IC_{RPS} is the incremental cost of the Renewable Portfolio Standard with respect to a 1 MWh increase in retail energy sales, LF is a factor representing incremental energy losses between wholesale and retail transactions, $LRIC_{RE}$ is the long-run incremental cost (per MWh) of a new investment in renewable energy, and $LRIC_{CE}$ is the long-run incremental cost (per MWh) of a new investment in conventional energy. In theory, the price of renewable energy certificates should approximate the term $max\{0, LRIC_{RE} - LRIC_{CE}\}$.

The incremental cost of a carbon tax would depend upon the form of the tax. If it were a tax of $X per MWh consumed, then the incremental cost for each MWh of retail energy sold would simply be $X. If it were a tax of $X per MWh produced, then the incremental cost for each MWh of retail energy sold would be LF times $X, that is, the tax times a factor that accounts for energy losses between wholesale and retail. If it were a tax of $Y per ton of carbon dioxide equivalent emissions, then the incremental cost for each MWh of retail energy sold in hour *h* would be approximately as follows:

$$IC_{CT,h} \approx LF * Y * CI_h \quad (5)$$

where $IC_{CT,h}$ is the incremental cost of the tax in hour *h*, LF is the wholesale-to-retail energy loss factor, Y is the tax, and CI_h is the carbon intensity in hour h in tons of carbon dioxide equivalent per MWh. The carbon intensity varies by hour (or, more accurately, by dispatch interval) depending upon the identity of the marginal source of power in that hour, with coal-fired generators having carbon intensity roughly twice that of natural gas-fired generators, and hydro and wind generators having carbon intensity of zero. Equation 5 is less daunting than it might look, because in a competitive market, each generator *g* will automatically up its bids by the amount $Y*CI_g$, where CI_g is the carbon intensity of generator *g*; and in a non-competitive market,

[73] Note that the determination of incremental costs is not affected by the Renewable Portfolio Standard being an annual requirement in form, because each hour's energy production and consumption is ultimately responsible for meeting that requirement. Because the Renewable Portfolio Standard is a long-term requirement, we believe that it is reasonable for the equation to ignore annual fluctuations in compliance around the discontinuity by which costs must be incurred up to the 40% mark, after which incremental costs drop to zero.

cost-minimizing system operators will include Y^*CI_g in the incremental cost of each generator in the course of determining optimal system dispatch.[74]

We recommend that interruptible customers continue to pay prices based upon incremental costs, but that the incremental cost calculation be updated to include the incremental costs of environmental policies along the lines indicated by equations 4 and 5. We further recommend that these two equations also serve as a basis for allocating the embedded costs of these policies among customers, though that cost allocation will also depend upon the costs of the resources that NB Power uses to minimize the costs of meeting these two sets of environmental policy requirements. Finally, we recommend that green pricing rates be based upon the same combination of incremental costs and embedded costs as applies to the cost allocation just described.

8. SUMMARY OF RECOMMENDATIONS

In general, the following recommendations should be implemented as soon as practical, where practicalities (like mitigating rate shock) may require gradual implementation over up to a decade. In some instances, the recommendations explicitly recognize that some reforms will take longer to implement than will others.

8.1. General Issues

Time-Varying Prices. We recommend that, when appropriate metering, communication, and data management are available, NB Power offer time-varying rates to large customers on a mandatory basis and to mass-market customers on a voluntary conversion with opt-out basis.

Revenue-to-Cost Ratios. We recommend that NB Power attempt to move Residential and General Service revenue-to-cost ratios closer together.

Standby Pricing. We recommend that, to the extent feasible, NB Power's standby service pricing reflect the costs of the unbundled services – electrical energy, ancillary services, transmission, and distribution – that together comprise standby service. In addition, customers should also pay for any special costs of resolving problems, like voltage fluctuations, that customers' generation would otherwise cause. Since NB Power's rates (like those of other utilities) do not fully reflect cost causation, introducing a standby tariff in the upcoming filing would be both desirable and timely.

Allocation of Grid Modernization Costs. We recommend that NB Power directly assign to participating customers the full cost of site-related upgrades related to customer initiatives such as distributed energy resources or EV charging. Otherwise, the utility should apply standard cost allocation techniques to the bulk of grid modernization costs.

Interruptible Service Pricing. We recommend that interruptible customers continue to pay prices based upon incremental costs, but that the incremental cost calculation be updated to include

[74] In the perhaps inconsistent notation, CI_h equals each hour *h*'s CI_g of the generator *g* that is marginal in that hour.

the incremental costs of environmental policies and that incremental costs serve as a basis for allocating the embedded costs of these policies among customers.

Green Pricing. We recommend that green pricing rates be based upon the same combination of incremental costs and embedded costs as applies to interruptible service as just described.

8.2. Residential Customer Issues

Residential Time-Varying Prices. We recommend that NB Power revise its Residential tariff to include at least a seasonal element with constant prices within each season. Once interval load data are available, NB Power can consider a seasonal TOU design with pricing periods and price ratios based on NB Power's marginal cost patterns. Two seasons with the same two pricing periods in both seasons (though not necessarily the same prices in both seasons) should be sufficient to capture most of the benefits of time-varying prices.

Heating versus Non-Heating Residential Customers. Time-varying prices are the best solution to the problem of recognizing cost differences between heating and non-heating residential customers; and particularly with NB Power's proposed investment in AMI, it is the solution that NB Power should adopt. A separate heating rate is unnecessary in a world in which technology is sufficient to cheaply implement time-varying prices.

Charitable Organizations. We recommend that NB Power phase out the grandfathered charitable organization service under the Residential tariff.

Farms. We recommend that NB Power consider a maximum size limitation (such as 2 kW, excluding space heating or cooling) on the farms that are allowed on the Residential rate. This limitation could be combined with a TOU pricing option for small GS customers that might reduce bill increases for farms that use energy predominantly in off-peak periods.

AMI. We recommend that NB Power allow Residential customers to opt out of AMI service subject to the caveat that opt-out customers pay the incremental costs of their decision.

Residential Customer Cost Recovery. We recommend that NB Power consider increasing the recovery of fixed Residential customer-related costs through its Residential customer charges and/or through a demand charge. Such increases may be introduced on a phased-in basis so that customer charges eventually fully recover customer-related costs and demand charges eventually fully recover fixed costs of transmission and distribution facilities. The phase-in of higher customer charges can probably be accompanied over a shorter time period than the phase-in of demand charges.

8.3. Business Customer Issues

Business Customer Classifications. We recommend that NB Power remove the distinction in rates between commercial and industrial customers, replacing it with a size-based classification that splits business customers into three or four subclasses differentiated by peak loads and voltage levels. This would require a cost-of-service study based on the candidate rate classifications, review of alternative base rate designs tailored to NB Power's updated pricing objectives, and determination of the timing and path of rate level revision. The timeframe for the transition might depend upon the sizes of the impacts, with larger impacts implying a longer transition period; though it may be advisable to aim for the fiscal year 2027/28 target that NB Power has already set for moving all rate classes' revenue-to- cost ratios to within the range of reasonableness. A scheme of transition discounts and premia specific to the type of transition would provide a relatively simple price transition mechanism.

Business Time-Varying Prices. We recommend that NB Power put small business customers on a standard seasonal tariff or seasonal TOU tariff (with an opt-out), and that it put medium and large business customers on a seasonal TOU rate. All business customers should be offered optional dynamic pricing programs (like CPP and RTP) and an optional interruptible rate. To facilitate implementation, the optional programs could be offered on a phased-in basis starting with the largest customers.

Customer Charges. We recommend that NB Power consider charging all classes for customer-related costs via a customer charge.

Demand Charges. We recommend that demand charges be extended to apply to all business customers with at least 5 kW of demand. Because of issues related to distributed energy resources, we recommend that these demand charges be mandatory.

Wright Tariff. We recommend that the Wright tariff be phased out over a period of a few years.

Economic Development. NB Power could continue offering a declining discount demand price for large industrial customers who add load in excess of a 5,000 kW threshold, based upon an updated rate portfolio with a base seasonal TOU tariff. On the other hand, if NB Power seeks increased ability to use discounting to attract new load, it could reduce this threshold. If this change is not desirable for some reason, but expanded eligibility is desired, NB Power could permit customers to meet this threshold through load expansions at multiple facilities or in specified phases. Alternatively, NB Power could offer an EDR product based on RTP, under which energy above current consumption levels is sold to the customer at market-based prices and fixed charges are recovered through a demand charge that rises to the normal tariff level after (say) five years.

Load Retention. For customers on current, seasonal, or seasonal TOU rates, we recommend that discounts be in the form of energy prices that move closer to marginal cost. For customers on RTP, we recommend that discounts be in the form of reductions in the charge on the contract quantity.

To limit the subsidization of participating customers, participation in EDR and LRR programs should be limited to those customers whose businesses offer substantial benefits to the Provincial economy and who can demonstrate such benefits.

Export Subsidies. We do not recommend offering subsidies to exporters.

8.4. Distributed Energy Resource Pricing

We recommend that, at its earliest opportunity, NB Power replace its net metering tariff with an alternative design that avoids or minimizes cross-subsidy. The replacement tariff could make use of the introduction of interval data recorders by having customers with distributed energy resources pay a demand charge that recovers demand-related costs, adjusts the customer charge to fully recover customer-related costs, and, as a result, an energy charge that covers volumetric costs only. The basis for the demand charge would be the customer's maximum net non-coincident flow of power through utility facilities during the billing period. Adding TOU pricing would further improve price accuracy. This tariff could be designed to be bill neutral to the standard tariff that the customer would otherwise adopt.

In the long run, NB Power should have the goal of redesigning its standard tariffs to recover energy costs through energy rates, customer costs through customer charges, and demand costs through demand charges. In other words, the standard tariff could be modified to be more or less identical to the net metering tariff as revised in the near term. This would entail the controversial step (among others) of introducing demand pricing to all Residential customers; but it would address the inevitable though erroneous claim that the near-term approach discriminates against customers with their own resources. A companion long-term goal would be to credit or pay customers for excess energy according to marginal costs, market conditions, or energy costs only.

APPENDIX A.
ABBREVIATIONS

AMI	advanced metering infrastructure
BAA	Balancing Authority Area
COS	cost-of-service
CPP	critical-peak pricing
EDR	economic development rate
EV	electric vehicle
GS	General Service
GWh	gigawatt-hour (one billion watt-hours of electrical energy)
LID	large industrial customers served at the distribution level
LIT	large industrial customers served at the transmission level
LRIC	long-run incremental cost
LRR	load retention rate
MC	marginal cost
MW	megawatt (one million watts of electrical power)
MWh	megawatt-hour (one million watt-hours of electrical energy)
NEG	net excess generation
PEI	Prince Edward Island
PPA	power purchase agreement
RC	revenue-to-cost
RTP	real-time pricing
SI	small industrial
SID	small industrial customers not included in the SI class, but served at the distribution level
SIT	small industrial customers not included in the SI class, but served the transmission level
SIC	standard industrial classification
TOU	time-of-use

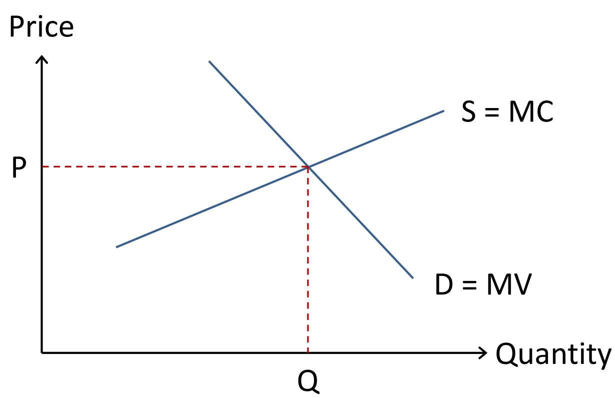
APPENDIX B.
THE EFFICIENCY OF MARGINAL COST-BASED PRICING

The marginal cost of a service is defined as the change in the cost of producing and delivering that service that accompanies a small change in the quantity consumed of that service. Formally, this relationship can be expressed as follows:

$$Marginal\ Cost\ \equiv \frac{\Delta Cost}{\Delta Consumption}$$

Since the late 1800s, the economics profession has recognized that the price of a service is most efficient when price equals that service's marginal cost, and that competitive markets drive prices toward marginal cost. This finding is illustrated in Figure 6. In this figure, the aggregate market supply curve S is upward-sloping because a good or service (like electricity) will be provided first from the sources that have the lowest marginal costs MC, so that successively higher prices are required to bring forth greater quantities of the good or service. The aggregate market demand curve D is downward-sloping because the uses that have the highest marginal values MV will be served first, and successively lower prices will induce greater levels of demand.[75]

Figure 6
Supply, Demand, Price, and Marginal Cost



At the intersection of the supply and demand curves, where the quantity produced and the quantity consumed are both Q, the marginal cost of production equals the marginal value of consumption. A level of production and consumption that was higher than Q would be wasteful because the extra cost of additional production would be greater than the extra value of additional consumption: the extra costs of additional production would not be justified by the extra value to consumers. Conversely, a level of production and consumption that was lower

[75] Marginal value is defined in a manner symmetric to that of marginal cost: MV is the change in value (benefit) to a customer of a small change in the quantity consumed.

than Q would be wasteful because the savings from reduced production would be less than the lost value of reduced consumption: given the loss to consumers, it would not be worth avoiding some production costs.

At the intersection of the supply and demand curves, the price P equals both the marginal cost of production and the marginal value to consumers. At the price P, producers could profitably produce quantity Q; but it would be unprofitable for them to produce more than Q because, for production greater than Q, the additional cost of production would exceed P. At the price P, consumers would benefit from the first Q units of consumption; but they would not buy more than Q because the marginal value of additional consumption would be less than P. Thus, the price P that "clears the market" is efficient in the sense of maximizing the benefits of consumption net of the costs of production. When utility rate designers seek efficient pricing, they seek regulated retail pricing that, as nearly as possible, produces this outcome of a competitive market.

Marginal costs change over time with changes in power system conditions. These conditions include load levels, generator availability, and transmission and distribution facility availability. This variability of marginal costs over time is illustrated in Figure 7, which shows a marginal cost curve MC that is the same for all hours – meaning that the same generation fleet is available in all hours – but also shows demand for two different time periods, with demand D_1 in period 1 being lower than demand D_2 in period 2. Not surprisingly, the equilibrium quantity Q_2 in period 2 is higher than the equilibrium quantity Q_1 in period 1; and marginal cost MC_2 in period 2 is higher than the marginal cost MC_1 in period 1. This pattern of marginal costs implies that, for efficiency reasons explained for Figure 6, price should be higher in period 2 than in period 1.

Figure 7
Marginal Cost with Demand That Varies Over Time