Section 3: Finance/Fair Return

Q. (Section 3, pages 3-30 on) Newfoundland Power discusses the size of the investment in Muskrat Falls. Is not the only concern facing the Board the implication for electricity costs in Newfoundland and Labrador, and whether it causes customers to leave the system? Please provide the following:

a) Copies of any demand studies indicating the loss of sales as electricity costs increase.

b) A copy of the latest Hydro Quebec survey of electricity costs in major North American cities.

A. The Muskrat Falls Project has both cost and reliability implications for Newfoundland Power's customers.

The cost of the Muskrat Falls Project is substantial and represents almost four times the combined book value of the current utility investment of Newfoundland and Labrador Hydro ("Hydro") and Newfoundland Power.[1] The impact of the Muskrat Falls Project on customer electricity rates is subject to the finalization of government rate mitigation plans and Hydro's next general rate application.[2]

Reliability of supply that follows the Muskrat Falls Project is also a matter of concern. In its August 28, 2023 letter to Hydro, the Board commented:

> *"The issues and concerns in this RRAS [Reliability and Resource Adequacy Study] Review involve significant matters affecting the future adequacy, reliability and costs of the electrical system in the province. With a need for new capacity identified for as early as 2030, a construction schedule of up to ten years for any new generation source, and ongoing issues on the reliability implications of the Muskrat Falls assets, the Board has concerns on Hydro's proposed schedule to address these issues."*[3]

a) See Attachment A for the July 31, 2018 report of James P. Feehan, MSc(Econ), PhD entitled "*The Long-Run Price Elasticity of Demand for Electricity and the Feasibility of Raising Electricity Rates to Finance Muskrat Falls.*"[4]

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[1] See Newfoundland Power's *2025/2026 General Rate Application, Volume 1, Application, Company Evidence and Exhibits, Section 3, Finance*, page 3-31, lines 4 to 7.

[2] In Hydro's letter dated December 15, 2023, *Quarterly Update – Items Impacting the Delay of Hydro's Next General Rate Application*, page 3, Hydro stated: *"Contingent on the finalization of the details of the Government's rate mitigation plan, Hydro expects to file its next GRA in 2025."*

[3] See the Board's letter dated August 28, 2023, *Newfoundland and Labrador Hydro – Reliability and Resource Adequacy Study Review Planned Reports, Studies and Analyses*, page 7.

[4] The referenced report was provided as Exhibit P-00326 in relation to the Commission of Inquiry Respecting the Muskrat Falls Project.

See Attachment B for the December 17, 2018 report of James P. Feehan, MSc(Econ), PhD entitled "*The long-run price elasticity of residential demand for electricity: Results from a natural experiment.*"[5]

b) See Attachment C for the Hydro Quebec report "*2023 Comparison of Electricity Prices in Major North American Cities – Rates in effect April 1, 2023.*"

[5] The referenced report was provided as Exhibit P-00372 in relation to the Commission of Inquiry Respecting the Muskrat Falls Project.

The Long-Run Price Elasticity of Demand for Electricity and the Feasibility of Raising Electricity Rates to Finance Muskrat Falls

James P. Feehan, MSc(Econ), PhD
July 31, 2018

The Long-Run Price Elasticity of Demand for Electricity and the Feasibility of Raising Electricity Rates to Finance Muskrat Falls

A Report Prepared

for

Dennis Browne, QC

The Consumer Advocate

by

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July 31, 2018

I. Introduction

The Muskrat Falls project is expected to be completed in the third quarter of 2020. At that time, the immediate consequence will be an increase in the cost structure of Newfoundland and Labrador Hydro (Hydro). That is because that utility has entered into long-term arrangements to purchase power from the Muskrat Falls generating plant and to use the new transmission assets associated with that project to supply the island of Newfoundland's interconnected electrical system. Hydro is pre-committed to paying whatever price is needed to cover the MF project's costs regardless of how high those costs turn out to be. In turn, Hydro will pass along the cost burden to ratepayers, which means a huge increase in the wholesale price that it will be charging to Newfoundland Power (NP) the main distributor of electricity on the island. The retail price faced by NP's domestic and commercial customers will rise accordingly. Hydro's own retail customers on the island interconnected system will face the same increase since their rates are, as a matter of public policy, set equal to those of corresponding NP customers. Hydro's industrial customers would presumably face a proportionately similar rate shock.

As yet, it is not known by how much prices will increase. In the June 2017 update on the Muskrat Falls project, Nalcor – the provincial government crown corporation behind the Muskrat Falls project and the owner of Hydro - indicated that Hydro's costs would ratchet up considerably.[1] For 2021, the first full calendar year of Muskrat Falls operations, Nalcor estimated the domestic (i.e., residential) customer cost would be approximately 23 cents per kWh. In contrast, as of July 1, 2018, the domestic residential price was 11.4 cent per kWh. Practically all the potential more-than-100-percent increase in the domestic consumer price would be due to the increase in Hydro's cost structure resulting from its Muskrat Falls commitments. Whether the actual increase will be as large as estimated by Nalcor is uncertain. Nalcor's June 2017 figures were based on the full cost of the Muskrat Falls project being borne by island interconnected ratepayers. However, in its 2017 Budget, the provincial government

[1] See https://muskratfalls.nalcorenergy.com/wp-content/uploads/2017/06/Muskrat-Falls-Project-Update-Presentation-June-23_Final.pdf.

indicated that it intended to take steps to limit the price increase to keep the rates competitive with other Atlantic provinces.[2] Still, even such rate mitigation would entail significant increases in island rates.

The purpose of this report is to assess the impact of higher rates on electricity consumption. If higher electricity rates cause a substantial reduction in electricity consumption then paying for Muskrat Falls by imposing higher rates may not be practical or even feasible. Assessing how much higher rates will reduce consumption requires an assessment of the price-elasticity of demand for electricity.

The remainder of this report is organized as follows. The next section, Section II, defines the price elasticity of demand and provides evidence from various sources in order to ascertain a reasonable estimate of it for interconnected island electricity consumers. Section III then uses estimates of the long-run price elasticity to illustrate the implications that arise from the sorts of rate increases that might occur. Brief concluding remarks are given in Section IV.

II. Price Elasticity of Demand

a) The Concept

The price elasticity of demand is an index of consumers' responsiveness to a price change. Normally, when the price of a commodity goes down consumers will decide to purchase more of it, and if the price goes up then they would purchase less. Price elasticity is a measure of the magnitude of such responses. For example, if the price of electricity went up 10 percent and customers reduce their consumption by just 1 percent then that response would be considered small. In that case, demand for electricity is insensitive, or inelastic, with respect to the price change. The index value of that elasticity is measured by the ratio of the change in the amount purchased (1 percent in this example) to the price change (10 percent); the result is 1/10 or simply 0.1; technically the value takes a negative sign but a widely used convention is to express it in absolute value. In contrast, had the reaction to the price change been a 15 percent reduction in consumption then that would be considered a big response and demand would be

[2] See http://www.budget.gov.nl.ca/budget2018/speech/budget_speech2018.pdf, p.32.

classified as price-sensitive or price-elastic. The index value would then be 15/10 or equivalently 1.5. More generally, the measure of price elasticity (*e*) is calculated as:

e = (percentage change in consumption)/(percentage change in price).

The calculation is done under the assumption that other influences on consumption decisions, such as income and prices of other commodities, have not changed. In order words, it isolates the impact of a price change on consumption. Whenever the index value is more than 1, demand is classified as price-elastic, or price-sensitive, and the more that it exceeds one the greater is the price elasticity. When the ratio is a fraction then demand is said to be price-inelastic, and the smaller the fraction the more inelastic. Additionally, elasticity is not generally a constant; its value over one price range is usually not the same as over a different price range.

Price elasticity also has a time dimension. When a price changes, consumers are typically limited in how they can react over a short period of time. For example, a higher price of electricity might induce consumers who use electric spacing heating to turn back their thermostats but not much else over the course of a few months. However, if the price increase persists then consumers might over time decide to install more insulation, switch to other space heating sources or replace an electric hot water tank with one that uses propane. Such responses take more time and the consumer must be convinced that the upfront cost is worthwhile, i.e., that the future electricity cost savings would exceed those upfront costs. Thus, the index value of the price elasticity measured over a short period could be quite close to zero but much larger over time. Therefore, there is a distinction between the short-run and long-run price elasticity of demand. In the case at hand, it is the long-run that is relevant. That is because the Muskrat Falls project's high operating costs and debt repayments will continue for decades so pricing based on full or substantial cost recovery would mean persistently higher prices. The long-run is not a specific period of chronological time. Rather, it is the amount of time that consumers take to fully respond to a change in price. As may occur with the Muskrat Falls project, if consumers believe that a large price increase is coming and will persist then they may react at early stages or even prior to a price increase in anticipation of it. For this reason, in the case of Muskrat Falls, the long-run may be a fairly short period of time.

b) <u>Estimates of the Price-elasticity of Demand for Electricity in the Long Run</u>

There is an extensive literature on price elasticities for electricity but there does not seem to be any published estimates available for the island of Newfoundland's interconnected system. However, there is some evidence based on provincial data as well as findings from elsewhere that can provide a reasonable assessment of what that elasticity might be. They are discussed in this subsection.

(i) Some evidence from Newfoundland and Labrador

Domestic, i.e., residential, customers are the largest group of electricity consumers on the island's interconnected grid. They consume between 50 and 60 percent of the electricity delivered over that system. Table 1 provides two possible values for the long-run price elasticity of demand for electricity by island domestic consumers, and both are based on provincial data.

Table 1

Estimates of the Long-Run Price Elasticity

<u>of Average Residential Demand for Electricity</u>

Source	Estimate
Partial Adjustment Model (see Appendix)	0.42
Case Study of South Labrador Coast	1.20

The first estimate presented in Table 1 is 0.42. It was obtained from econometric estimation of a partial adjustment model of residential demand for electricity, the details of which are given in the Appendix to this report. Such a model incorporates the idea that consumers need time to fully adjust to a price change, which is the case with electricity. That model incorporates not just price but other relevant influences on average electricity consumption, notably the price of substitutes and household income, with appropriate adjustments for inflation.[3] Estimation was based on annual data for the average consumption by NP's domestic customers, and who make up the overwhelming majority of interconnected residential electricity consumers on the island. The data covered the years from 1992 to 2016 inclusive.

[3] Total residential consumption is also affected by the number of residential customers, which is influenced by demographics.

The estimate of 0.42 is a long-run figure. It suggests that following a price shock of, for example 20 percent, that, given enough time to fully adjust, a consumer's average annual consumption would fall by 8.4 percent (i.e., 0.42 multiplied by 20 percent); analogously, had the price decreased by 20 percent then an 8.4 percent eventual increase in electricity consumption would be the model's prediction. While a long-run elasticity of 0.4 is plausible, there are reasons to suggest that it may be low when considering a possible future Muskrat Falls price shock. First, that elasticity was estimated based on data from 1992 to 2016. The magnitude of price elasticity depends on the availability of substitutes for the commodity whose price has increased. In the early years of that time period, it may be that substitutes such as mini-splits were not as well-known nor as efficient as they have become in more recent years. Secondly, the figure was estimated based on the range of electricity prices that prevailed during the 1992 to 2016 period. None of those prices was as high as the prices suggested by the provincial government or Nalcor for the post-Muskrat Falls era so the analysis does not capture that high-price experience.

Some areas of the province do have high-price experience. The second estimate in Table 1 is relevant in that regard. That elasticity is 1.2, which indicates a high degree of price sensitivity. That figure is not based on an econometric estimate. It is from a recently published case study of residential consumption in communities located on the south Labrador coast. [4] Prior to 1997, all the communities on that coast were serviced by electricity from diesel plants and faced increasing block rates. However, from 1997 onwards, the communities in the L'Anse au Loup area of that coast began to be serviced from a nearby hydro plant in Quebec. As a result, their residential rates were reduced to those of island interconnected customers. Communities on that South Labrador coast further to the north remained on diesel rates. As of July 1, 2017 the rate for electricity per kWh for electricity in excess of 1,000 kWh in the isolated communities was 16.3 cents while those in the L'Anse au Loup system paid 10.6 cents.[5] That higher rate of 16.3 cents is similar to what the provincial government was alluding to in Budget 2018 for post-Muskrat Falls rates. The study showed that from 1992 to 1997 the two sets of

[4] James P. Feehan (2018) "The long-run price elasticity of residential demand for electricity: Results from a natural experiment," *Utilities Policy*, April.

[5] See https://nlhydro.com/wp-content/uploads/2018/07/July-1-2018-Rates-Rules-Regulationsv2.pdf

communities had very similar electricity consumption patterns but following the reduction in rates for L'Anse au Loup domestic customers in 1997 those patterns diverged. By 2016, average consumption was much higher among L'Anse au Loup customers – approximately double - and at least 50 percent of them had installed electric heat as their primary source of space heating. Before the price change, neither set of communities had significant use of electric heating and that has remained the case in the isolated diesel communities. The observed change in electricity consumption led to the 1.2 elasticity result.

While the south Labrador coast experience may not carry over exactly to communities on the island, the differences in distance and climate are not especially great. If the price elasticity on the island is similar then the implications are profound. For example, with an elasticity of 1.2, a 50 percent increase in price would imply a 60 percent reduction in consumption. Since, in proportions, the reduction in consumption exceeds the price increase, that would mean that the utilities would actually see a decline in their residential sales revenues; selling 60 percent less at a 50 percent higher price implies a revenue drop of approximately 10 percent.

(ii) Estimates from other Jurisdictions

Moving beyond Newfoundland and Labrador, there are many estimates of price elasticities. For example, in one study, by Espey and Espey, found from their survey of various sources that estimates of long-run price elasticities for residential electricity range from approximately 0 to 2.25 with an average of 0.85 and a median of 0.81.[6] This wide range is in part the result of the differences across various study areas and time periods. Climate, availability of substitutes, income levels, and pricing regimes all tend to influence price elasticity. Nevertheless, the Espey and Espey survey illustrates that the provincial values identified in the preceding subsection are generally consistent with results found elsewhere.

Another report, from the Electric Power Research Institute (EPRI), has a somewhat narrower range of values for long-run residential elasticities than in Espey and Espey. That may

[6] See James Espey and Molly Espey (2004) "Turning on the Lights: A Meta-Analysis of Residential Electricity Demand Elasticities," *Journal of Agricultural and Applied Economics*, Volume 36 (1), p.66.

be the result of EPRI surveying a smaller number of selected studies. Their findings are summarized in Table 2.[7]

Table 2

Long-Run Price Elasticities from Selected Studies: EPRI

	Mean	Low	High
Residential	0.9	0.7	1.4
Commercial	1.1	0.8	1.3
Industrial	1.2	0.9	1.4

The EPRI survey is interesting because it includes estimates for commercial and industrial customers, and their mean values imply that those groups are price sensitive. However, it is important to stress that the selected studies underlying them are from various areas and not from Newfoundland and Labrador. Both the industrial and commercial customers on the island are likely to have very different characteristics than elsewhere, so significantly higher or lower values for Newfoundland are possible.

Closer to Newfoundland in terms of both geography and climate, is Quebec. The result of two analyses of residential electricity demand there are summarized in Table 3 below. In both cases, the values are practically identical and greater than one. They indicate that electricity demand in Quebec is price-elastic.

Table 3

Estimates of the Long-Run Price Elasticity:

Residential Demand for Electricity in Quebec

Authors	Estimate
Bernard and Genest-Lapante (1995)[8]	1.33
Bernard, Bolduc and Yameogo (2011)[9]	1.32

[7] See EPRI (2008) "Price Elasticity of Demand for Electricity: A Primer and Synthesis," p.20. Available at https://www.epri.com/#/pages/product/1016264/

[8] J.T. Bernard and E. Genest-Laplante (1995) Les élasticités-prix et revenu des demandes sectorielles d'électricité au Québec: revue et analyse. Rapport final de recherche soumis à Hydro-Québec.

[9] Bernard, Jean-Thomas, Denis Bolduc and Nadège-Désirée Yameogo (2011) "A pseudo-panel data model of household electricity demand," *Resource and Energy Economics*, 33 (1):315-325.

It is possible to find many studies that present lower estimates of residential price elasticities than in Tables 1, 2 and 3. However, the range of estimates in those tables provide evidence that island residential customers may be quite price sensitive. A long-run elasticity similar to that found for the south Labrador coast or in Quebec is a distinct possibility for island residential customers.

(iii) Substitution Incentives and the Price of Electricity

The price elasticity of demand for a commodity depends on how important it is to the consumer and on the availability of substitutes for it, and, in particular, on the net savings that would result from substitution. Over a short period of time, a price increase may have little impact on consumption. That is because there may not be enough time to switch to a substitute or the consumer may be uncertain as to whether the price increase is permanent, in which case if there is a cost of substituting then the consumer may wait until convinced that the change is going to be long-lasting. Under the plan to incorporate Muskrat Falls costs into island electricity rates, customers will perceive any significant increase in price as long-lasting. That would provide an incentive for them to investigate alternatives. Generally, the more the alternatives, the greater the price elasticity. Tables 4 and 5 illustrate the possible alternatives for residential customers. The tables show the estimated annual costs of the different options available to customers. The costs are solely for fuel and do not include the upfront costs of installation/switching and maintenance or fixed charges.

Table 4 deals with space heating. It is based on the energy requirements for heating a 2,000 square foot house in St. John's built after 1990; the energy requirement is 80 million BTUs.[10] The table is also adapted from Efficiency Nova Scotia's energy conversion ratios used in its cost comparison methodology.[11] Table 4 shows the annual fuel costs of different types of space heating sources based on three different prices of electricity for residential customers on the island grid: the July 1, 2018 price of 11.4 cents per kWh, and then 17 cents, which is used as the approximation for a mitigated price, and 23 cents, the price that would otherwise be

[10] Natural Resources Canada gives 85 Gigajoules as being needed to heat such a dwelling, which is approximately 80.5 million BTUs. The calculations in Table 4 are based on 80 million BTUs. http://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/oee/files/pdf/publications/Heating_with_Electricity.pdf Table 3, p.37.

[11] See Efficiency Nova Scotia, https://www.efficiencyns.ca/guide/heating-comparisons/ (For February 2018)

implemented following completion of the Muskrat Falls project. Other fuel costs are those that prevailed in St. John's during mid-July 2018: 97.1 cents per litre for furnace oil and 79.6 cents per litre for propane.[12] Data on firewood costs was not readily available so prices from Nova Scotia were used: $246.96 per cord of wood and $312.99 per ton of pellets.

Table 4

Comparison of Annual Spacing Heating Fuel Costs (HST of 15% Included):

2,000 Square Foot Detached House Built after 1990 – St. John's

	Electricity Price at 11.4 cents/kWh	Electricity Price at 17 cents/kWh	Electricity Price at 23 cents/kWh
Electric Baseboard heat	$3,074	$4,584	$6,202
Electric Heat Pumps: Air-to-Air	$1,618	$2,413	$3,264
Electric Heat Pumps: Mini-splits	$1,230	$1,834	$2,481
Heat Pumps-Geothermal	$1,025	$1,528	$2,067
Oil Furnace: old at 70% efficiency	$3,497	$3,497	$3,497
Oil Furnace: new at 85% efficiency	$2,880	$2,880	$2,880
Propane (fireplace) at 70% efficiency	$4,305	$4,305	$4,305
Propane furnace at 80% efficiency	$3,767	$3,767	$3,767
Wood stove/furnace at 55% efficiency	$1,723	$1,723	$1,723
Wood stove/furnace at 70% efficiency	$1,353	$1,353	$1,353
Wood Pellets at 75% efficiency	$2,400	$2,400	$2,400

Table 4 shows that, at 11.4 cents per kWh, electric baseboard heating is more costly in terms of annual fuel cost than wood fueled heating and the other electricity-fueled, but more efficient, heat pump options, but less costly than alternatives fueled by either oil or propane. However, at 17 cent per kWh, electric baseboard heating would have the highest annual fuel

[12] See Petroleum Pricing Order of July 12, 2018, http://pub.nl.ca/orders/ppo/oil/HO-180712.pdf

costs of all the options in the table. The margins are quite large. For example, while electricity for baseboard heaters would cost $4,584 annually, the fuel cost for a new furnace would be $2,880 and even electricity for a mini-split would be $1,834. At 23 cents/kWh, as shown in the last column of Table 4, electric baseboard heating would be even more unattractive compared to all the other listed alternatives. In short, the figures in Table 4 suggest that even at 17 cents per kWh all the alternatives to electric baseboard heating offer large annual fuel costs savings, all of which being achieved through less consumption of electricity. At present, approximately 70 percent of residential customers on the island of Newfoundland have electric space heating. Thus, there is considerable room for reductions in residential electricity consumption.

Table 5, which is also adapted from Efficiency Nova Scotia's comparison tables. It is based on a four-person household shows that consumes 240 litres daily. The table shows electric hot water heating offers generally favourable annual costs compared to the oil or propane fired alternatives at 11.4 cent/kWh. However, at higher electricity prices, both propane and oil fueled alternatives offer annual fuel cost savings.

Table 5

Comparison of Annual Hot Water Heating Fuel Costs: 240 Litres Daily

	Electricity Price at 11.4 cents/kWh	Electricity Price at 17 cents/kWh	Electricity Price at 23 cents/kWh
Electric Hot Water Heater (old) at 85% efficiency	$701	$1,046	$1,415
Electric Hot Water Heater (new) at 90% efficiency	$663	$988	$1,337
Oil Stand-alone water heater at 55% efficiency	$ 868	$868	$868
Propane Stand-alone water heater at 55% efficiency	$1,068	$1,068	$1,068
Propane stand-alone/on-demand/ heater-high at 93% efficiency	$632	$632	$632

Tables 4 and 5 illustrate that there are substantial annual savings from switching either to less electricity-intensive space and water heating or to non-electric alternatives but customers will be aware that there are capital costs of doing so. The same observation applies to new construction. If the annual savings are large and expected to persist then the customer would have a very strong incentive to act. If the price increase is anticipated then the action may be taken in advance. In such circumstances the long-run for the price elasticity of demand may not be a lengthy period of chronological time, and that elasticity might be quite large. Furthermore, substitution possibilities go beyond space and water heating. Better house insulation and windows, and replacement of electric lights and appliances with more efficient ones would also be actions that customers could take.

The focus of Tables 4 and 5 has been on residential consumption. However, commercial (general service) customers of NL Hydro and NP as well as NL Hydro's industrial customers would have similar incentives to find less expensive alternative sources of energy if the price of electricity increases substantially for the long term. That would be especially so for those businesses for which electricity is a major component of their cost structure.

c) Overall Assessment of Elasticity

The evidence in the preceding subsections is not sufficient to establish a single estimate for the long-run price elasticity of demand for electricity on the island. However, based on that evidence, that elasticity is likely more than 0.4 and possibly more than 1.0 at current prices.

III. Implications

The range of values for the long-run price elasticity that has been suggested above has far-reaching implications for the post Muskrat Falls period.

a) Electricity Consumption

In 2017, the total customer load for NL Hydro island interconnected system was approximately 7 million megawatt hours (MWh), of which approximately 1.8 million were provided by its oil-fueled generating plant at Holyrood. Nalcor and government statements regarding Muskrat Falls have suggested that the price of electricity could rise by either 50 percent (to about 17 cents/kWh for residential customers) with rate mitigation or 100 percent (to about 23 cents/kWh for residential customers) otherwise, relative to current rates. Even values of the elasticity selected from the lower end of the range suggested herein have substantial implications for future electricity consumption. Table 6 shows how much NL Hydro's customer load might change as a result of the price increases currently in the public discourse and based on the long-run elasticity being either 0.4 or 0.6.

Table 6

Change in NL Hydro Customer Load Due to Electricity Price Increases,

at Selected Values of the Long-Run Price Elasticity of Demand

	Elasticity of 0.4	Elasticity of 0.6
50% Price Increase	-1.4 million MWh	-2.1 million MWh
100% Price Increase	-2.8 million MWh	-4.2 million MWh

Even with the low value of 0.4 for the elasticity and the smaller rate increase of 50 percent, Table 6 indicates that the reduction in customer load due to the price increase would be quite large, at 1.4 million MWh. At a 0.6 elasticity, which might well be lower than the true value, a 50 percent price increase, implies a 2.1 million MWh decrease in consumption. Higher price increases or greater elasticity would lead to even bigger reductions in customer loads. One caveat here is that other considerations will also influence electricity consumption. For instance, changes in income, prices of alternative fuels, technology and demographics would come into play. Some might exert upward movement on consumption and others might tend to lower consumption further. Those influences are not embodied in Table 6, which focuses exclusively on the impact of price changes.

b) Muskrat Falls Energy

Table 6 implies that if electricity prices increase by the magnitudes that have been discussed herein then the resulting fall in consumption could be nearly as large as or even much larger than the amount of energy produced at the Holyrood generating facility, which was approximately 1.8 million MWh in 2017. That is to say, the decline in consumption brought on by the price increase would make Holyrood largely redundant. Winter demand might require the plant to operate at times but, in net terms, the energy from Muskrat Falls could be largely or even totally unneeded to displace Holyrood. The implication is that Muskrat Falls would become primarily or entirely an export project. Practically all the energy that would be in excess of what has already been committed to Nova Scotia would also have to be exported since there would be no market for it on the island at high end-user rates. This is a perverse result because the rationale for the project was to displace Holyrood and meet growth in island electricity consumption.

Island customers would be consuming little or none of Muskrat Falls electricity, in net terms, but would be paying much higher prices for the purpose of financing it. Additionally, island consumers would be burdened with the cost associated with converting to other energy sources and NL Hydro would experience little in the way of revenue increases from island sales as customers there substitute away from electricity. Complicating the revenue challenges would be low prices for exports of energy in accessible external wholesale markets if prices there remain as low as they currently are. So the higher prices may also fail to generate sufficient funds to pay for Muskrat Falls, even with the sort of price mitigation suggested in Budget 2018.

c) Rate Design

The counterproductive impacts of raising electricity rates following completion of Muskrat Falls are a signal that simply raising the price-per-kWh is an incorrect approach to rate design. Setting prices in that way is not related to the core economic principle of marginal cost pricing and, as demonstrated herein, it fails to take account of consumer response to higher prices. The higher rates for island customers would push them away from consuming electricity even though the benefits to island consumers from using that electricity may well exceed the export revenue it earns.

IV. Concluding Remarks

This report has presented an assessment of relevant long-run price elasticities for electricity and fuel substitution possibilities. Based on that assessment, it appears that a large increase (e.g., by 50 percent or more) in the per-kWh price of electricity would be problematic. Not only would it be a burden to all island interconnected customer groups, it would cause a large decline in electricity consumption by those consumers. That would impede Nalcor's efforts to raise revenue through Hydro's rates to pay for Muskrat Falls. Island consumption could fall by so much that Muskrat Falls could become solely an export project. Since there has been no indication that such pricing is based on economic principles, there is no reason to believe that these outcomes are consistent with optimal economic use of the province's electrical energy.

APPENDIX

Estimating the Price Elasticity of Demand for Electricity by Households in Newfoundland: A Partial Adjustment Model

J. Feehan

July 2018

Introduction

Table 1 of the report refers to a 0.42 estimate for the long-run price elasticity of residential demand for electricity on the Newfoundland interconnected grid and indicates that it was obtained from a partial adjustment model. This appendix explains the methodology that was used to determine that estimate.

The Data

All interconnected residential customers on the island of Newfoundland face the same price of electricity even though areas are served by two utilities; Newfound Power serves the vast majority of customers while Newfoundland and Labrador Hydro serves the remainder. The data on consumption that is used in this exercise corresponds to that for Newfoundland Power's residential customers and was provided by Newfoundland Power on request. There is little reason to expect the NL Hydro's own customers' consumption patterns to be much different from NP's, given that they face the same prices and live on the same island.

In addition to consumption, expressed as average annual consumption per residential customer, the other core variables used are the price of electricity, the price of heating fuel and per capita personal disposable income (PDI). In the analysis that follows, the prices and income are all expressed in real terms (i.e., 2002 constant prices) using Statistics Canada's Consumer Price Index for Newfoundland and Labrador. The data for the price of heating fuel in the province and personal disposable income were obtained from Statistics Canada as well. While most of the data was available on a monthly basis, personal disposable income was annual and thus annual data was used for this exercise. The years covered were 1992 to 2016, inclusive. Table A1 describes the data.

Table A1
Core Data: 1992-2016

Variable	Mean	Std. Dev.	Minimum	Maximum
Weather –Adjusted Average Consumption in kWh	15309	529.6	14588	16206
Real Price of Electricity in cents per kWh	8.55	0.54	7.7	9.2
Real Price of Heating Fuel in cents per litre	62.9	18.4	37.9	95.7
Real Personal Disposable income per capita	$18,447	$3,979.5	$13,886	$24,945

Partial Adjustment Model

In general terms, a household's desired choice of electricity consumption Q^* is determined by the price of electricity (*P*), the price of any substitute (*PF*), and income (*I*). Thus,

(1) $Q^* = f(P, PF, I)$

where *f* denotes the functional relationship between Q^* and the variables that determine it; the other notation in the equation is as given in Table 1. That functional relationship may be written as:

(2) $Q^* = a + bP + cPF + dI + u$

where *a* is a constant and *b*, *c*, and *d* are coefficients, while *u* represents the impact of other possible factors and assumed to be a random error with a zero mean and constant variance.

In equations (1) and (2), Q^* denotes the household's choice but at any point in time achieving it may not be feasible. If the price or some other relevant variable changes then it may take some time for a household to fully adjust. Some actions can be undertaken fairly quickly, e.g., turning down thermostats when the price increases. However, other reactions take time because capital investment, e.g., switching from furnace to electric heat or purchasing electricity-efficient appliances, is costly and may not be undertaken until the price change is perceived as permanent. Such circumstances can be described by a partial adjustment process as below:

(3) $Q_t - Q_{t-1} = \lambda(Q_t^* - Q_{t-1})$.

where the subscripts denote time periods. Equation (3) says that the actual change in consumption over one period, $Q_t - Q_{t-1}$, is proportional to any gap between the desired level of consumption and last period's actual consumption, $(Q_t^* - Q_{t-1})$. The Greek letter λ denotes the adjustment parameter and would take the value of zero if complete adjustment takes place instantly. When that is not possible the adjustment parameter must be a positive number. It is assumed to be a fraction; otherwise the model would be unstable in the sense that consumption would never converge to the household's desired level. By substituting the expression for Q^* from (2) into (3), and simplifying yield the following:

(4) $Q_t = \alpha + \beta P_t + \gamma PF_t + \delta I_t + \varepsilon Q_{t-1} + v_t$

where $\alpha = a/\lambda$, $\beta = b/\lambda$, $\gamma = c/\lambda$, $\delta = \lambda d$, $\varepsilon = (1- \lambda)$, and $v = \lambda u$.

Equation (4) is the basis for the estimation undertaken in the next section. A double-logarithm specification is used; i.e., the variables in equation (4) are expressed in terms of their logarithmic values.

Results

Table 2 provides the results of the Ordinary Least Squares (OLS) estimation using the 1992-2016 dataset on the functional form given in equations (4). The results are quite good. All the right-hand-side variables are statistically significant; see the corresponding *t* values, all of which are statistically significant. Additionally, the regression test statistics are encouraging; the adjusted R^2 implies a good overall fit, with the regression accounting for 96 percent of the variation in consumption, and Durbin's h statistic suggests that the null hypothesis of no autocorrelation cannot be rejected. [13] Crucially the coefficient on the lag of consumption is a positive fraction, which means the model is stable. Perhaps most importantly, the signs of the coefficients are consistent with basic theory: the coefficient on the price of electricity is negative, the coefficient on the substitute fuel is positive and the coefficient on income is both positive and fractional, which is consistent with electricity being a normal necessity.[14]

[13] With time-series estimation, as this is, there is always a concern that a strong fit may be the result of spurious correlation. That means that the variables move along similar time trends but there is no causal relationship in play. This does not appear the case here because even though the variables are not stationary i.e., do have trends, the residuals from the regression appear to be stationary. Additionally, going beyond the statistical issues associated with spurious correlation, economic theory provides a sound theoretical foundation for consumption varying with the right-hand-side variables of equation (4) in a pattern consistent with the regression results.
[14] When an increase in consumers' income causes an increase in consumption of a good or service, but by less than the percentage increase in income, then that good or service is classified as a normal necessity.

Table A2

OLS Estimation Results

	Double-log Function
Dependent Variable	(Q)
Explanatory Variables	**Coefficients (t values)**
Constant	2.98 (3.27)
Price of Electricity	-0.15 (-2.93)
Price of Fuel	0.023 (2.33)
Disposable Income Per Capita	0.073 (3.39)
Lagged Consumption	0.64 (5.70)
Regression Test Statistics	
Adjusted R^2	0.96
Durbin's h statistic	Prob> chi^2 = 0.61

Based on the results in Table A2, it is straightforward to determine the implied short-run and long-run price elasticities of demand for electricity. These are presented in Table A3 below.

Table A3

Estimates of Price Elasticities from the OLS Results

Short-run Elasticity	-0.15
Long-run Elasticity	-0.417

The short-run price elasticity corresponds directly to the coefficient on the price of electricity as given in Table A2. (Analogously, the coefficient on income is the short-run income elasticity and the coefficient on the price of heating fuel is the short-run cross elasticity for that substitute.) Obtaining the long-run elasticity involves the coefficient on lagged consumption. When full adjustment is achieved, that lagged consumption and current consumption coincide so bringing like terms together and simplifying yields a long-run elasticity of -0.15/(1 - .64) = -0.417 or approximately -0.42.

Following a widely used convention, the short-run and long-run elasticities may be expressed in their absolute values of 0.15 and 0.42, respectively. The latter figure corresponds to the partial adjustment model estimate given in Table 1.

The long-run price elasticity of residential demand for electricity: Results from a natural experiment

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The long-run price elasticity of residential demand for electricity: Results from a natural experiment☆

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ABSTRACT

In one of two otherwise similar adjacent regions in a Canadian province, the price of electricity changed abruptly, substantially, and permanently. That natural experiment allows for a simple differences-in-differences calculation of the long-run price elasticity of residential demand for electricity. This analysis is of interest for two reasons. First, it is a rare circumstance when such a methodology can be used. Secondly, the magnitude of the elasticity estimate has substantial implications for utilities, regulators, and policymakers.

1. Introduction

Decisions about the electricity usage, pricing, and infrastructure investment depend on many considerations. Among them, the price elasticity of demand for electricity is especially crucial. The focus herein is on residential demand for electricity in the long run. Estimates of its price elasticity are plentiful and diverse, and reflect both differences in space and time but also in estimation techniques. In a frequently cited contribution, Espey and Espey (2004) carried out a meta-analysis of price and income elasticity estimates from 36 studies published over the period 1947 to 1997. From the 123 estimates that they analysed, short-run price elasticities ran from −2.01 to −0.004 with a mean of −0.35; and 125 estimates of long-run price elasticity fell in the range from −2.25 to −0.04 with a mean of −0.85.[1] Differences in econometric techniques may explain some of the variation, but even with the same methodology, a wide range of estimates can be obtained. For example Krishnamurthy and Kristöm (2015), using a common methodology, obtained a range of price elasticities between −0.27 and −1.4 for a set of 11 OECD countries.[2]

In more recent years, the feasibility of real-time pricing has sparked interest in determining near-immediate price elasticities when consumers have informational feedback. A great deal of this research is based on experiments (see Faruqui and Sergici (2010) and Jessoe and Rapson (2014) for experimental evidence with respect to residential demand). That is in contrast to econometric studies focusing on short-run and long-run price elasticities, which use either time series, cross-sectional, or panel data sets that are typically from surveys rather than from experiments. One exception is the study by Battalio et al. (1979), which dealt with short-run rather than real-time elasticity. Using a system of rebates and information, the researchers conducted a field experiment on a sample of residential customers in College Station, Texas, over a three-month period. By offering cash payments to a subset of customers for each percentage reduction in their electricity consumption compared to a year earlier, they obtained an estimate of short-run price elasticity of demand. While interesting, experiments of that type have severe limitations. The participants know that they are in an experiment and the experiment is for a short period of time, so there is no incentive for them to invest in changing heating and cooling systems or electrical appliances. Thus, such experiments give no insight into long-run price elasticity.

The findings reported in this paper are based on a very rare set of circumstances that yields a long-run elasticity via a natural experiment.[3] Among other things, the subjects involved do not perceive that they are in an experiment, nor was an experiment even intended. It is based on a homogeneous area in the Canadian province of Newfoundland and Labrador, where all residential customers initially faced the same price schedule, but then those in a geographic subset were switched to a different price regime. The change in price was abrupt,

☆ I am very grateful to two anonymous referees, whose thorough and constructive comments led to substantial improvements. I remain solely responsible for any errors.
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[1] Boogen et al. (2017) offer a very recent review of studies on the price elasticity of residential demand for electricity.

[2] Those differences are not surprising since the countries likely have numerous differences in terms of price-setting, housing stock, incomes, climates, demographics, and other factors that would influence the nature of their respective demand curves.

[3] Two recent applications of natural experiment data to electricity issues are reported in Choi et al. (2017) and Deryugina et al. (2017). However, the former is concerned with the impact of daylight-savings time, not price, on electricity demand. The latter's focus is on price elasticity but, because it involves many communities over a wide area of Illinois, a more sophisticated analysis was appropriately undertaken. By contrast, in this paper, the similarity of the two groups supports a common-trends assumption and therefore a direct calculation of price elasticity.

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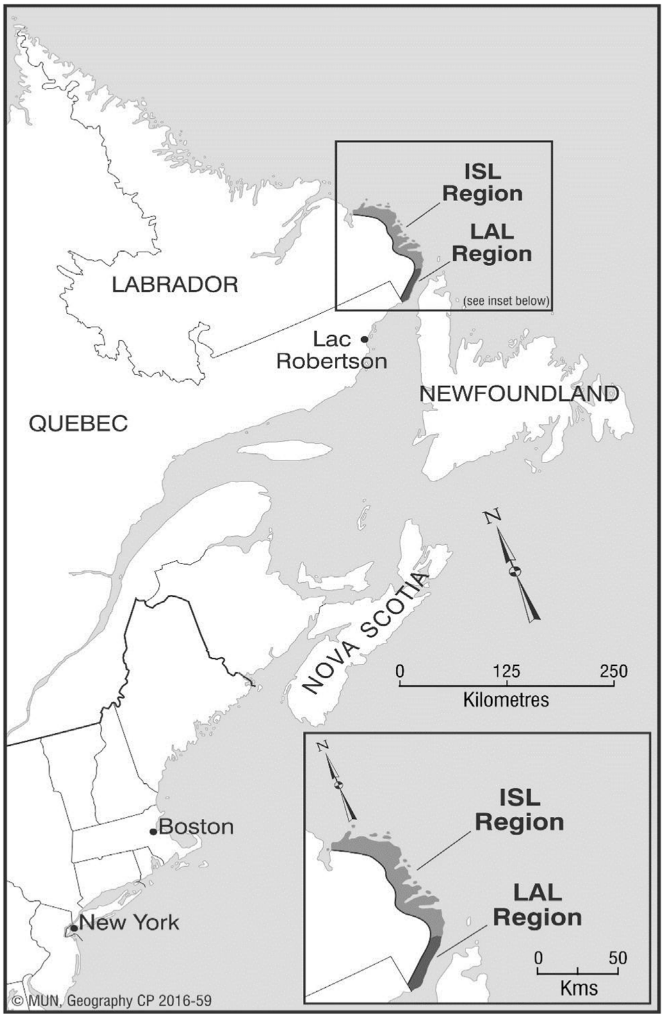

Fig. 1. Northeastern North America and the ISL and LAL regions.

substantial, and long lasting. Data on electricity consumption for both groups is available and provides insight into consumer adjustment. In particular, the similarity of the two groups allows for a simple differences-in-differences approach to estimating the long-run impact of the price change.

The next section provides the background on the natural experiment. Section 3 illustrates the magnitude of the price shock and how electricity consumption patterns changed in its aftermath. In Section 4, the long-run price elasticity is determined. Section 5 briefly discusses that result and policy implications, the latter of which are substantial if a similar elasticity value applies to residential customers elsewhere in the same province.

2. The setting

The focus is on residential demand in communities located on the south coast of the Labrador area of the province. That coastal area and the two regions of interest there are identified in the map of northeastern North America in Fig. 1. One of the two regions is L'Anse au Loup (LAL), named for the largest community within it. The other region will be referred to herein as the Isolated Southern Labrador (ISL) one.

Until late in 1996 all of their electricity demand was met by diesel turbines operated by the government-owned utility, Newfoundland and Labrador Hydro Corporation (NL Hydro). Diesel generation is expensive and, despite charging higher rates in isolated areas serviced in this way, NL Hydro incurred operating losses there. Full recovery was not possible because of provincial government policy that constrains NL Hydro in its rate design. The entire area's residential customers faced increasing-block pricing but subject to the government directive that the basic customer charge and per-kilowatt hour (KWh) rate for the first block of energy both be the same as those approved by the regulator for the residential customers on the interconnected grid in the Newfoundland area of the province. For illustration, as of July 1, 1996, all LAL and ISL residential customers faced the following monthly charges, in Canadian currency [4]:

Basic Customer Charge	$16.72
First Block (up to 700 KWh)	6.6 cents per KWh
Second Block (in excess of 700 KWh to 1000 KWh)	9.6 cents per KWh
Third Block (in excess of 1000 KWh)	13.0 cents per KWh

These rates also applied to other isolated communities that were served by diesel generators. Those communities were mostly further north on the Labrador coast but also included a small number on the island of Newfoundland. However, importantly, the pricing differed for the island interconnected residential customers. Those customers were charged the same basic charge but the 6.6 cent per KWh rate was a flat rate, regardless of consumption. The island basic charge and per kWh rate were set by the regulator but, as a policy, also automatically applied to the isolated systems up to the limit of those systems' first block. The higher second and third block rates applied only to the isolated customers and, while below the marginal cost of diesel generation, served to deter higher consumption in order to limit NL Hydro's cross-subsidization of diesel service.

In late 1996, there was a price shock. Residential customers in the LAL region were removed from the block-pricing scheme. NL Hydro entered into an agreement by which it would import electricity from Quebec. That province's utility, Hydro-Quebec, agreed to sell surplus electricity from its new small 22-MW hydro-electric plant at Lac Robertson, located on the Quebec side of the provincial border near the LAL system, to NL Hydro. [5] That amount of energy was sufficient to displace NL Hydro's diesel plants supplying the LAL system and was less expensive. Following that agreement, the government of Newfoundland and Labrador, through an order to the province's regulator, the Board of Commissioners of Public Utilities (the PUB), directed that once the connection was in place NL Hydro would charge the same residential rates in the LAL system as applied to interconnected customers on the island of Newfoundland.[6] NL Hydro had wanted to maintain separate rates for L'Anse au Loup ratepayers because the unit cost in the area, even with cost savings from connection to Lac Robertson, would still be much higher than the unit cost on the interconnected system; see PUB (1996, 32). However, the government order prevailed and the LAL residential customers were removed from having to pay the second and third block rates. This change did not apply to the ISL system, which was not connected to the Lac Robertson plant and continued under the block-rate regime. This policy remains in effect to the present. Hence, there was a marked, immediate and sustained deviation of the prices in the two neighbouring Labrador systems, where customers had previously faced exactly the same prices.

The price change set the stage for a natural experiment with the ISL region serving as the control group and the LAL region being the test

[4] These rates were provided by NL Hydro on request. For recent details of this pricing, see https://www.nlhydro.com/wp-content/uploads/2014/04/Schedule-of-Rates-and-Regulations.pdf.

[5] That plant was commissioned in 1995 (http://www.hydroquebec.com/generation/centrale-hydroelectrique.html).

[6] PUB, 1996/97 Order P.U.5 set this policy and it refers to Government order MC 96–0567 as the basis for doing so; see http://pub.nl.ca/orders/pu97.htm.

group. Such an approach is especially apt here because of the similarity of the two regions. They are served by the same utility and they are geographically adjacent along a coastline, so they experience identical weather conditions characterized by a northeastern Atlantic climate with very cold and lengthy winters and cool summers. Moreover, they share very similar demographic and socioeconomic characteristics and trends. This can be confirmed by reference to the Community Accounts maintained by the Government of Newfoundland and Labrador. Those accounts provide extensive statistical profiles for 20 economic zones corresponding to different areas of the province. Rather fortuitously, the LAL and the ISL region each correspond to two distinct economic zones.[7] Drawing on those accounts, the remainder of this section briefly highlights the regional similarities.

In terms of demographics, each region is rural, consisting of eight to ten small communities, mostly with populations in the hundreds and none with a population of a thousand or more. All are on or near the coast and connected by the sole coastal road. Residents have the same ethno-linguistic origins. Both regions are characterized by declining populations due to falling birth rates and out-migration. From 1996 to 2011, the LAL experienced a decline in population from 2885 to 2215, while the ISL went from 2060 to 1,645, which are declines of 23 percent and 20 percent, respectively. Household sizes are also alike and are characterized by similar trends as illustrated in Table 1.

Table 1
Household size by census year.[a]
Source: Census: Family Characteristics, Newfoundland and Labrador Community Accounts.

	1996	2001	2005	2011
LAL	3.87	3.37	3.29	3.18
ISL	3.52	3.24	3.23	3.07

[a] Calculated by dividing the population by the number of census families in private dwellings; data on both are from Newfoundland and Labrador Community Accounts; see note 7.

Economic conditions in both regions are also quite similar. Unemployment rates tend to be high and employment is highly seasonal. Sources of income are also the same. While median family income in the ISL region has been consistently lower than in the LAL region throughout the period of the following analysis, 1992 to 2016, at approximately 15 percent less, this differential has been quite consistent over that study period. Median family income in both regions has followed a common trend. In sum, conditions in the two regions are either identical or follow common trends. The outstanding exceptions to that observation are electricity prices and electricity consumption.

3. The price change and consumption patterns

The key change in the price regimes is illustrated in Fig. 2. It shows two time-series. One series, which begins in 1991 and goes to 2016, shows isolated systems' residential rates per KWh, expressed in 2015 dollars, for consumption in excess of 1000 KWh per month.[8] Those rates applied to the ISL region throughout the period and the LAL region only up to late in 1996. The second time-series comprises the rates, also in 2015 dollars, for the LAL region after the change in its price regime. The emphasis here is on the price of electricity in excess of 1000 KWh per month because that amount is the threshold above which the third-block rates apply and it is where the difference in post-1996 price regimes is substantial. For instance, in 2015 the third block rate was 16.3 cents per KWh, almost 55 percent higher than the LAL and island flat rate of 10.6 cents per KWh.[9]

A large and persistent change in price is expected to have an impact on consumption. In that regard, Fig. 3 illustrates the two sets of residential customers' consumption patterns before and after the price change. For the six years prior to the change, 1991–1996, the average consumption levels were very similar and tracked one another in parallel fashion.[10] As shown, average annual residential consumption on the LAL system was consistently and modestly higher than in the neighbouring ISL system its average consumption was (731 KWh higher or 9.2 percent). The persistent difference in family income, as noted in Section 2, may explain much of this phenomenon. However, as also noted, pattern of income in the two regions follows a common trend over the study period. In the period after the change in price regimes, the similarity in the consumption patterns was disrupted. At first, the change was small but by 1999–2000, the LAL system's average residential consumption had moved up significantly relative to the ISL system, at 11.3 percent higher. Thereafter, LAL consumption deviated from the ISL trend in a far more pronounced way. By 2016, average residential consumption in the LAL system was 103.4 percent higher than in the ISL system.

Associated with the large increase in LAL average annual residential consumption has been the adoption of electric space heating as the primary source of heat there. Annual penetration rates for electric heat in the LAL communities for the years from 1991 to 2016 are shown in Fig. 4. From 1991 to 1997, the use of electric space heating was negligible; oil and wood fuels were used for heating purposes; there are no natural gas pipeline distribution systems in those regions nor anywhere else in the province. By 2001, the penetration rate had risen modestly, from zero, to six percent but increased dramatically thereafter. This initial slowness in installing electric heat may well reflect the time needed by consumers to believe that the capital investment would pay off over time. Importantly, as Spees and Lave (2007, 81) observe, electricity consumers react to a change in price when they believe it will be long lasting. By 2015 half of the residential customers in the region had installed electrical heating systems. Since reliance on electric space heating remained negligible in the ISL communities, the clear implication is that the lower price motivated the move to electric heat. As long as the price regime continues, it is reasonable to expect that the trend in electric heat penetration will continue until it reaches a convergence point. In that regard, Fig. 4 seems to imply a move towards convergence as the growth in the penetration rate since 2011 has slowed, with very little change from 2014 to 2016.

Adoption of electric space heating has important implications in the cold climate of Newfoundland and Labrador coastal communities. Turning specifically to the communities in the LAL system, in 2016, average electricity consumption by residential customers relying primarily on electric space heating there was 26.4 thousand KWh. The other LAL residential customers, i.e., those who did not use electric heating systems, consumed much lower quantities of electricity; they averaged 11.4 thousand KWh. Nevertheless, even those non-electric heat consumers had much higher consumption that those in the ISL system. In 2016, non-electric heat LAL consumers used an average of 2.1 thousand more KWh than the 9.3 thousand KWh average in the ISL system (approximately 23 percent more). That is a substantially greater than the 9.2 percent differential in consumption that occurred when the two regions faced the same electricity prices. In short, the change in price regime for LAL residential consumers has over time led to a substantial and continuing increase in electricity consumption there, apparently driven by the increasing use of electric space heating, but also by a general increase in consumption for other uses.

[7] They are Zone 4 and Zone 5, respectively, and statistical profiles on each are available (see http://nl.communityaccounts.ca/profiles.asp?_=vb7En4WVgb2uzqVj).

[8] The Consumer Price Index (CPI) for Newfoundland and Labrador was used to express prices in 2015 constant dollars and all nominal price information, which is in Canadian currency, was provided by NL Hydro on request.

[9] The second-block rate, which applies to only a modest amount of consumption, was 12.0 cents per KWh.

[10] Over that six-year period, average annual consumption levels were 8655 KWh and 7924 KWh in the LAL and ISL systems, respectively. Consumption data prior to 1991 are not available.

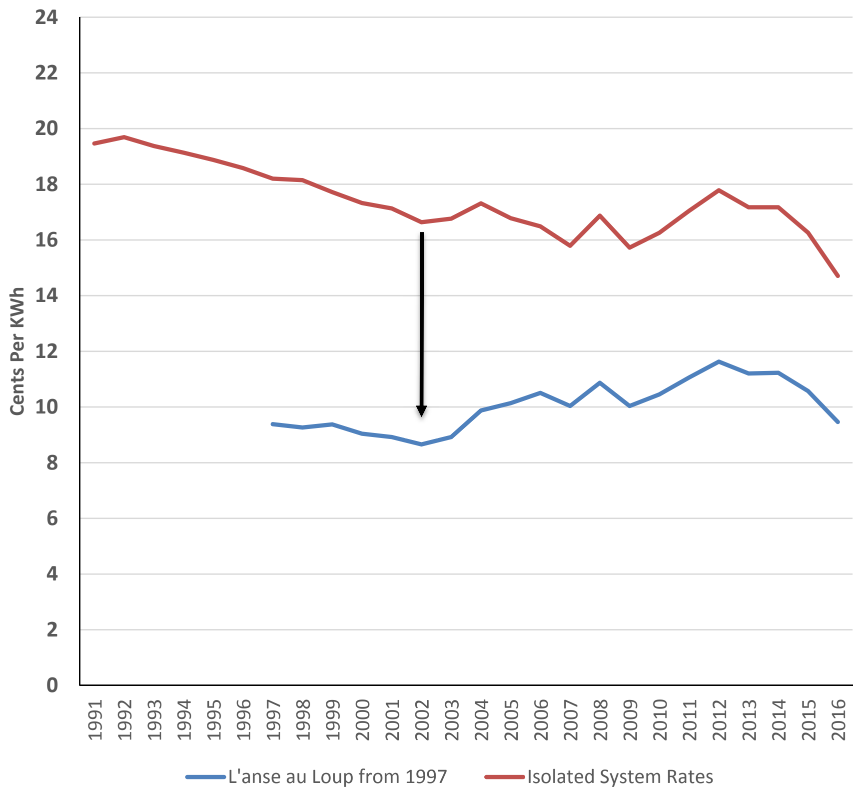

Fig. 2. Marginal price per KWh in excess of 1000 KWh per month, in 2015 constant Dollars.
Data Sources: Nominal Prices were provided by NL Hydro on request. Provincial CPI data used to express prices in constant dollars were obtained from http://www.stats.gov.nl.ca/statistics/Prices/PDF/CPI_Allitem.pdf.

4. Price elasticity of demand

The reaction to the price change by LAL residential consumers can be quantified by determining the price elasticity of demand (η), i.e., the ratio of the percentage change in consumption to the percentage change in price. Since those changes are large, the arc formula, by which a percentage change is measured relative to the mid-point of the start and end values, is used to calculate the percentage changes.

Estimating the percentage change in average consumption of electricity due to the price change, as opposed to other influences on consumption, requires some adjustments. In other words, the higher level of consumption in the post-price shock period may reflect influences other than price. In light of the similarity of the two groups, the common weather conditions, service being provided from the same utility, the identical alternate sources for space heating, and their common demographic and economic trends, a basic difference-in-differences approach can be used to determine that change in consumption attributable to the new price regime. The ISL customers serve as the control group and the LAL customers are the test group. The basis for the difference-in-difference methodology is that the similarities of the two groups and the common trends experienced by them mean that the pre-1997 consumption difference between them would have persisted in the absence of the price shock.

In what follows, the average consumption during the last three years of the pre-shock period, i.e., 1994–1996, and the average of consumption in the most recent three years, i.e., 2014–2016, are used as comparators. Relying on three-year averages lessens the impact of any one anomalous year and avoids using any of the many years that, as in Fig. 3, are times of transition. Table 2 provides the consumption averages for the pre-shock and post-shock periods. The table also shows the across-region and across-time differences in those consumption figures. The difference in those differences is 9,222 KWh, which is the amount of the LAL's region's overall increase in consumption of 10,375 KWh that can be attributed to the change in price. Based on that estimated price-induced change in consumption, the arc formula calculation yields 69.1 percent.

Table 2
Annual average electricity consumption (KWh): Difference-in-differences.

	Post-Shock: 2014–2016 Avg.	Pre-Shock: 1994–1996 Avg.	Difference
LAL Region	19,101	8,726	10,375
ISL Region	9,199	8,046	1,153
Difference	9,902	680	9,222

The change in the price in the LAL and the elasticity can be readily calculated. The average prices, in real terms, in the selected pre-shock and post-shock periods were 18.86 cents and 10.42 cents, respectively. The arc calculation expresses that as a −57.7 percent change. Hence, the implied price elasticity of demand is:

$$\eta = (69.1 / -57.7) = -1.20,$$

which indicates that residential demand for electricity in the LAL region is price-elastic (that is, a value greater than −1.0 in absolute value).[11]

This estimate of −1.20 is the 20-year price elasticity of demand, which can be taken as a reasonable estimate for the long-run price elasticity. Interestingly, this finding is consistent with results obtained for the neighbouring province of Quebec. Bernard et al. (2011) applied sophisticated econometric techniques to a large set of panel data to

[11] The result is little affected if the proportionate difference rather than absolute difference in consumption is used; the elasticity would be −1.15 in that case. Similarly, if only the end-years of 1996 and 2016 are used, demand remains elastic with a value of −1.06. Using a point estimate, the elasticity would be approximately −2.36 rather than the −1.20 given above.

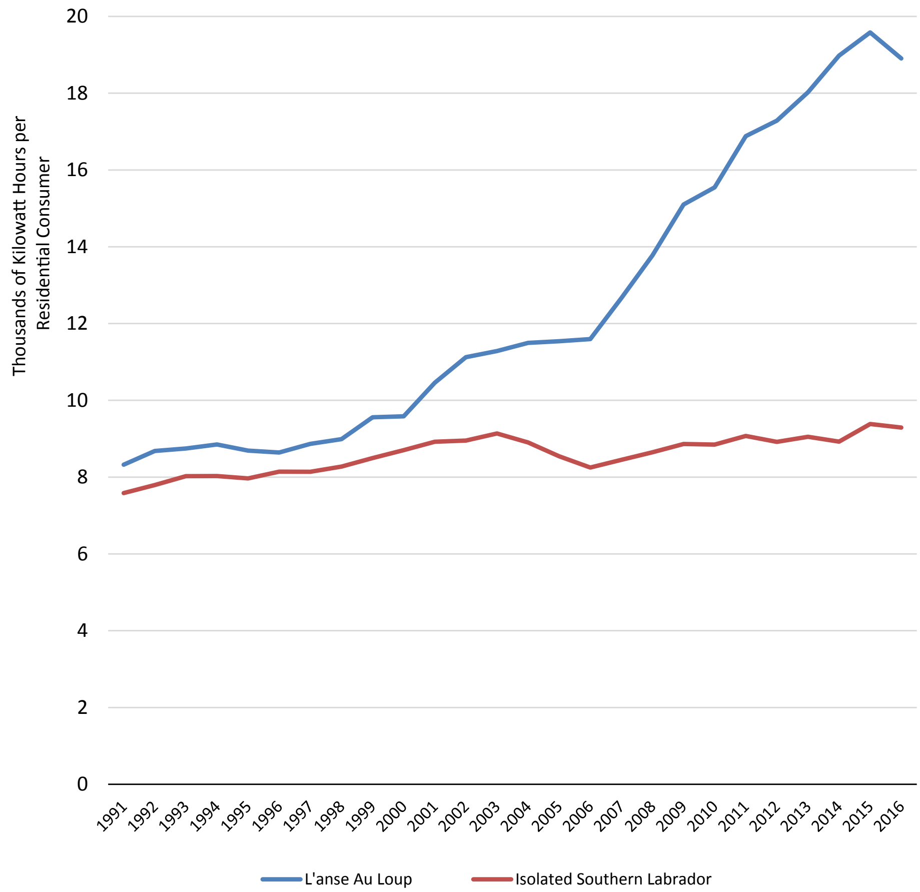

Fig. 3. Average annual residential electricity consumption.
Data Source: NL Hydro provided consumption data on request.

estimate price and income elasticities. That study concluded that residential demand for electricity in Quebec was price-elastic; the estimated long-run price elasticity of -1.32 is comparable to the results of this analysis.[12]

5. Discussion and policy implications

The finding that demand is price-elastic in the LAL region has direct policy implications for that region. As stated in Section 2, the rates for residential customers there must, as a matter of government policy, be equal to the PUB-approved rates for customers on the island's interconnected grid. That means that there is no connection between the price of electricity in the LAL region and the higher unit cost of providing service there. Price-elastic demand has led to a substantial increase in consumption in the area, which requires greater imports of electricity from Hydro-Quebec causing the initial savings from substitution away from diesel generation to be eroded. Specifically, total residential customer consumption there grew from 6,195 megawatt hours (MWh) in 1996 to 15,331 MWh in 2016.[13] This suggests that reconsideration of pricing policy may be in order. Linking the LAL price to the unit cost of purchased energy could improve efficiency and reduce cross-subsidization from NL Hydro's other customers.

There is another broader implication. There are no published estimates of the price-elasticity of demand for the entire province. Buttressed by the results of Bernard et al. (2011), the finding that residential demand in one region of Newfoundland and Labrador is price-elastic intimates that residential demand might well be price-elastic elsewhere in the province, with implications for consumers on the island portion of the province. The bulk of the province's population, approximately 500,000 out of 525,000, are located on the island of Newfoundland. These customers are mostly located near the coast and exposed to a North Atlantic climate, with similar options for space heating and where NL Hydro is also the main provider and transmitter of electricity.[14] Residential demand on the island of Newfoundland accounts for approximately 55 percent of electricity consumption there. A major new multi-billion dollar addition to generating capacity is under construction and due to be completed by 2020. While located at Muskrat Falls in central Labrador, that 824 MW hydro-electric facility will be dedicated to supplying the island and will be connected to it by direct-current transmission lines and subsea cables. Not everyone agrees on the merits of this project; for instance, Feehan (2012) argued that there were better alternatives, such as a mix of smaller projects, conservation measures, and marginal-cost pricing. In addition, there have been environmental and community concerns, and the PUB reported that it could not conclude that the project was the least-cost option for meeting Newfoundland's energy needs; see PUB (2012). However, despite the controversy, the provincial government, the owner of NL Hydro, exempted the project from PUB jurisdiction and in

[12] The finding here that residential demand for electricity is price-elastic is also consistent with the findings in econometric studies by Narayan et al. (2007) and Krishnamurthy and Kristöm (2015). However, those estimates are based on national data across countries rather than sub-regions as considered here.

[13] This information was provided by NL Hydro.

[14] NL Hydro is also the retailer in some rural areas on the island, as it is for all the Labrador region of the province. Most of the retail electricity distribution on the island is provided by Newfoundland Power Inc., which acquires most of its electricity from NL Hydro. However, both utilities charge the same residential prices on the island as required by the regulator, the PUB. The only exception is for a few isolated diesel systems which are served by NL Hydro and where increasing-block pricing is applied.

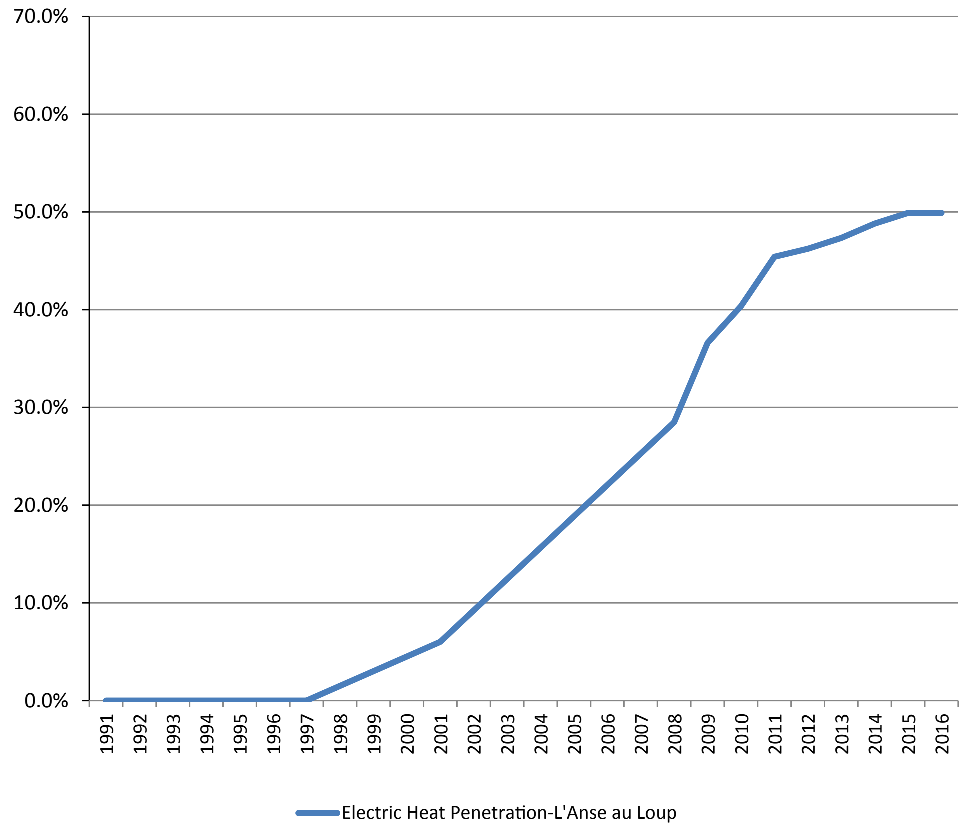

Fig. 4. Electric Heat Penetration-L'Anse au Loup.
Data Source: Provided by NL Hydro on request.

late 2012 made the policy decision to proceed. The project is being completed by another government owned entity, Nalcor, which is also the parent of NL Hydro and from which NL Hydro is contractually required to purchase the energy on a cost-plus basis.

Under current legislation, the PUB follows a traditional cost-of-service (COS) approach to setting rates. The estimated cost of that project has escalated so much, from $6.2 billion in 2011 to $12.7 billion by mid-2017, that under the regulatory COS system, the residential price of electricity on the island would more than double once the project is completed; see Nalcor (2016). That would make the flat per KWh price of electricity there even higher than the third-block rate in isolated diesel systems like the ISL one. If residential demand is price-elastic in the long run, then such a large change in price could affect the realization of revenues from that customer class. Thus, reconsideration of the regulatory approach to cost recovery appears inevitable.

In conclusion, the natural experiment aspect of this analysis is of methodological interest in its own right. However, the actual results are of practical importance. In the case at hand, the apparent response to change in price is large enough to suggest that residential electricity demand is indeed price-elastic. That finding sends a message to utilities, regulators, and policymakers. That is, when faced with a large permanent change in the real price of electricity, which customers perceive as long lasting, the long-run consumption response can be substantial.

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Hydro Quebec
2023 Comparison of Electricity Prices in Major North American Cities
Rates in effect April 1, 2023

2023
Comparison of Electricity Prices in Major North American Cities

Rates in effect April 1, 2023

TABLE OF CONTENTS

INTRODUCTION

Every year, Hydro-Québec compares the monthly electricity bills of Québec customers in the residential, commercial, institutional and industrial segments with those of customers of the various utilities serving 21 major North American cities.

This report details the principal conclusions of the comparative analysis of prices in effect on April 1, 2023. There are three sections. The first describes the method used to estimate electricity bills. The second examines the highlights of the seven consumption levels analyzed, with the help of charts. Finally, the third presents the results of the 21 consumption levels for which data were collected and compiled in the form of summary and detailed tables.

The most recent rate adjustments, time-of-use rates, adjustment clauses and applicable taxes, as well as a profile of the utilities in the study, appear in separate appendices.

MAJOR NORTH AMERICAN CITIES

AVERAGE PRICES FOR RESIDENTIAL CUSTOMERS[1, 2] (IN ¢/kWh)[3]

Abbreviations Used

AB	Alberta
BC	British Columbia
CA	California
FL	Florida
IL	Illinois
MA	Massachusetts
MB	Manitoba
MI	Michigan
NB	New Brunswick
NL	Newfoundland and Labrador
NS	Nova Scotia
NY	New York
ON	Ontario
OR	Oregon
PE	Prince Edward Island
QC	Québec
SK	Saskatchewan
TN	Tennessee
TX	Texas
WA	Washington

1) For a monthly consumption of 1,000 kWh; rates in effect April 1, 2023.
2) Average prices excluding taxes.
3) In Canadian currency.

MAJOR NORTH AMERICAN CITIES

AVERAGE PRICES FOR LARGE-POWER CUSTOMERS[1, 2] (IN ¢/KWH)[3]

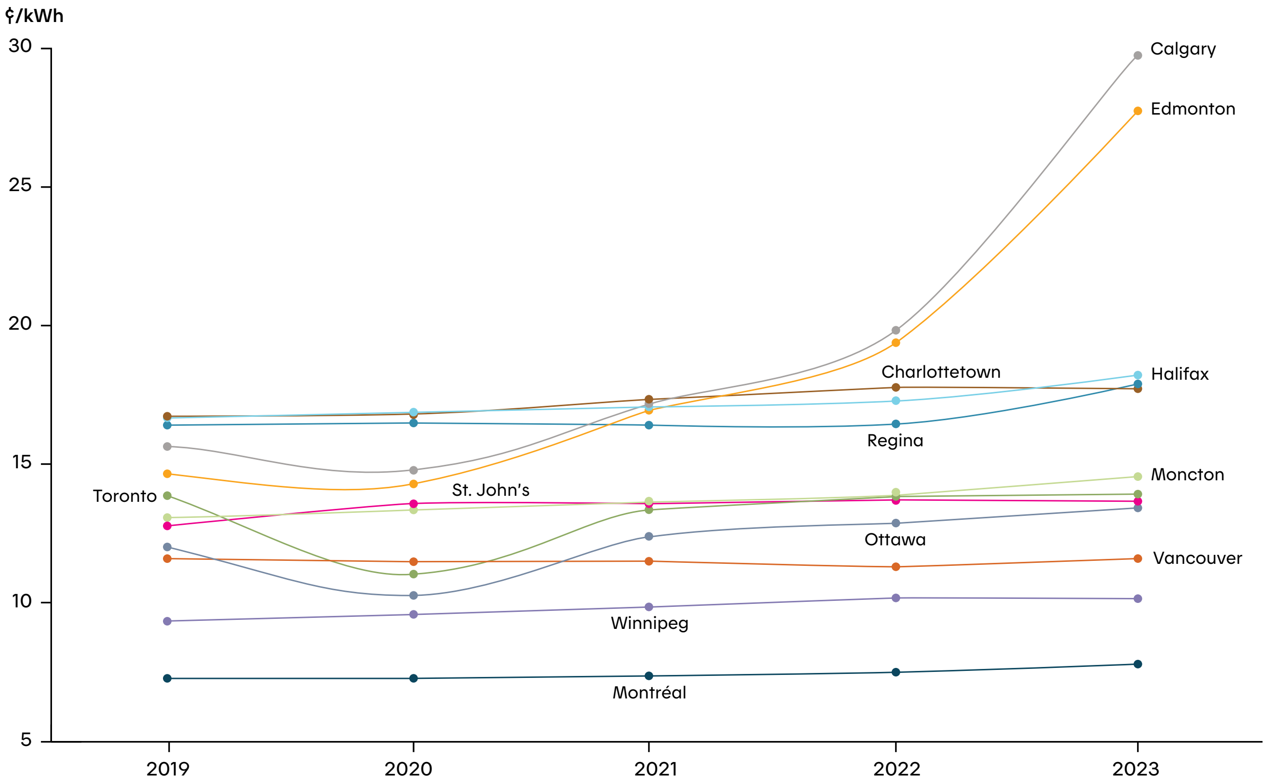
Abbreviations Used

AB	Alberta
BC	British Columbia
CA	California
FL	Florida
IL	Illinois
MA	Massachusetts
MB	Manitoba
MI	Michigan
NB	New Brunswick
NL	Newfoundland and Labrador
NS	Nova Scotia
NY	New York
ON	Ontario
OR	Oregon
PE	Prince Edward Island
QC	Québec
SK	Saskatchewan
TN	Tennessee
TX	Texas
WA	Washington

1) For a monthly consumption of 3,060,000 kWh and a power demand of 5,000 kW; rates in effect April 1, 2023.
2) Average prices excluding taxes.
3) In Canadian currency.

MAJOR CANADIAN CITIES

OVERVIEW OF CHANGES IN AVERAGE PRICES FOR RESIDENTIAL CUSTOMERS (IN ¢/kWh) – 2019–2023[1, 2, 3, 4]



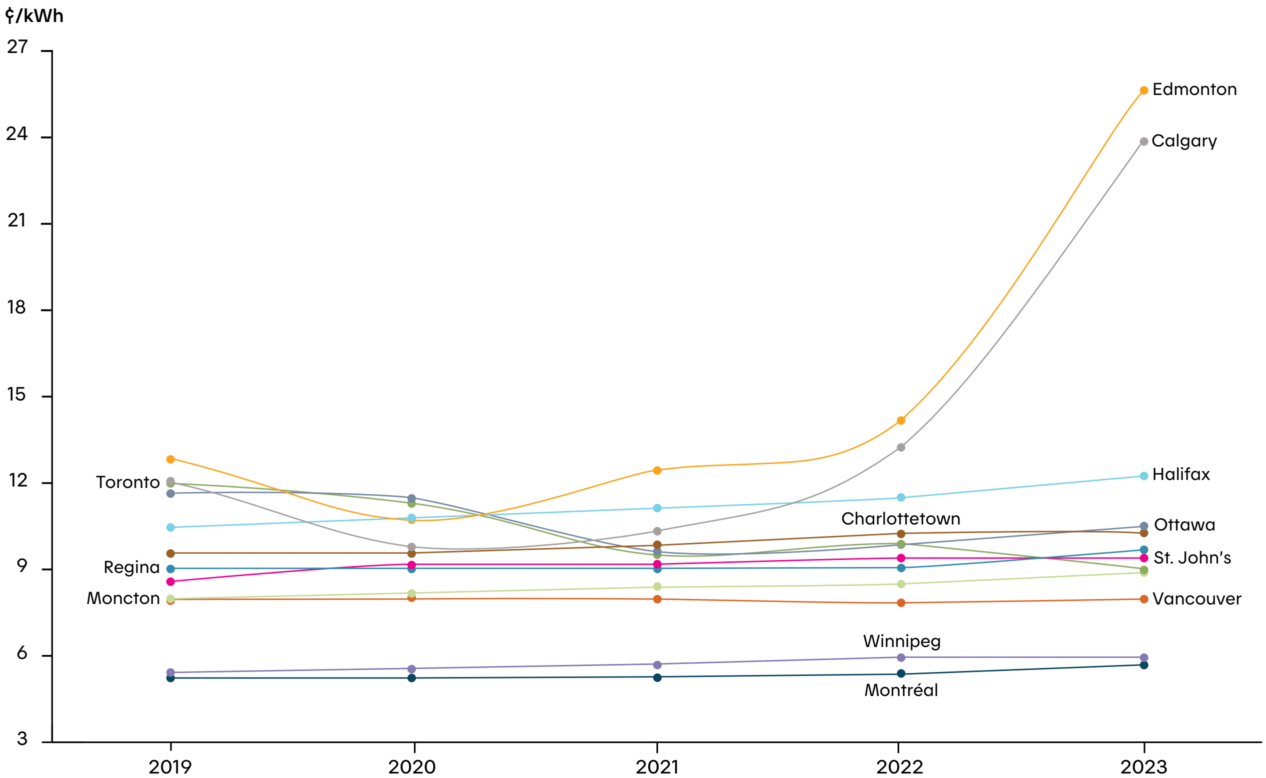
AVERAGE PRICES FOR RESIDENTIAL CUSTOMERS (IN ¢/kWh)[1, 2, 3, 4]

	2019	2020	2021	2022	2023
Canadian Cities					
Montréal, QC	7.30	7.30	7.39	7.59	7.81
Calgary, AB	15.74	14.83	17.26	19.94	29.80
Charlottetown, PE	16.83	16.83	17.38	17.78	17.78
Edmonton, AB	14.68	14.29	16.99	19.48	27.78
Halifax, NS	16.69	16.89	17.09	17.30	18.27
Moncton, NB	13.10	13.42	13.66	13.94	14.61
Ottawa, ON	12.04	10.29	12.45	12.94	13.48
Regina, SK	16.51	16.51	16.51	16.51	17.89
St. John's, NL	12.80	13.60	13.60	13.76	13.73
Toronto, ON	13.89	11.10	13.43	13.88	13.88
Vancouver, BC	11.62	11.51	11.58	11.39	11.62
Winnipeg, MB	9.37	9.60	9.87	10.24	10.24

1) For a monthly consumption of 1,000 kWh.
2) In Canadian currency.
3) Data from *Comparison of Electricity Prices in Major North American Cities* publications, Hydro-Québec, 2019–2023.
4) Average prices excluding taxes.

MAJOR CANADIAN CITIES

OVERVIEW OF CHANGES IN AVERAGE PRICES FOR LARGE-POWER CUSTOMERS (IN ¢/kWh) – 2019–2023[1, 2, 3, 4]



AVERAGE PRICES FOR LARGE-POWER CUSTOMERS (IN ¢/kWh)[1, 2, 3, 4]

	2019	2020	2021	2022	2023
Canadian Cities					
Montréal, QC	5.20	5.20	5.24	5.33	5.55
Calgary, AB	11.97	9.73	10.25	13.16	23.77
Charlottetown, PE	9.51	9.51	9.77	10.17	10.17
Edmonton, AB	12.80	10.64	12.35	14.08	25.62
Halifax, NS	10.39	10.72	11.05	11.40	12.13
Moncton, NB	7.93	8.13	8.28	8.44	8.81
Ottawa, ON	11.57	11.36	9.57	9.78	10.39
Regina, SK	8.98	8.98	8.98	8.98	9.57
St. John's, NL	8.52	9.12	9.12	9.32	9.28
Toronto, ON	11.91	11.23	9.45	9.76	8.88
Vancouver, BC	7.91	7.84	7.88	7.76	7.91
Winnipeg, MB	5.39	5.53	5.68	5.90	5.90

1) For a monthly consumption of 3,060,000 kWh and a power demand of 5,000 kW.
2) In Canadian currency.
3) Data from *Comparison of Electricity Prices in Major North American Cities* publications, Hydro-Québec, 2019–2023.
4) Average prices excluding taxes.

METHOD

In addition to Hydro-Québec, this comparative analysis of electricity prices across North America includes 22 utilities: 12 serving the principal cities in the 9 other Canadian provinces, and 10 utilities in American states. The results are based in part on a survey to which 14 utilities responded, and in part on estimates of bills calculated by Hydro-Québec.

The results presented here show the total bill for various consumption levels. If the bill is calculated according to an unbundled rate, it includes all components, including supply, transmission and distribution.

PERIOD COVERED

Monthly bills have been calculated based on the rates in effect on April 1, 2023. The most recent rate adjustments applied by the Canadian utilities in the study between April 1, 2022, and April 1, 2023, are shown in Appendix A.

CONSUMPTION LEVELS

Seven consumption levels were selected for analysis. However, data were collected for 21 consumption levels and those results are presented in the detailed tables.

OPTIONAL PROGRAMS

The bills have been calculated according to base rates. Optional rates or programs offered by some utilities to their residential, commercial, institutional or industrial customers have not been taken into account, since the terms and conditions vary considerably from one utility to the next.

GEOGRAPHIC LOCATION

Electricity distributors sometimes apply different rates in the various cities they serve. As well, taxes may vary from one region to another. This, however, is not the case in Québec, where rates and taxes are applied uniformly except in territories located north of the 53rd parallel.
For the purposes of this study, the bill calculations estimate as closely as possible the actual electricity bills of consumers in each target city, based on rates in effect on April 1, 2023.

TIME-OF-USE RATES

The rates applied by some utilities vary depending on the season and/or time of day when energy is consumed. In the United States, for example, a number of utilities set a higher price in summer, when demand for air-conditioning is stronger.
In Québec, on the other hand, demand increases in winter because of heating requirements.
Thus, for some utilities, April 1 may fall within a period in the year when the price is high, whereas for others it falls in a period when the price is low.
An annual average price has therefore been calculated in the case of utilities with time-of-use rates. These utilities and the consumption levels to which time-of-use rates apply are listed in Appendix B.

ADJUSTMENT CLAUSES

The rates of some distributors include clauses that allow them to adjust their customers' electricity bills according to different variables. Since these adjustments may be applied monthly or over a longer period, the bills issued by a given distributor may have varied between April 1, 2022, and April 1, 2023, even though base rates remained the same. Appendix B lists the adjustment clauses taken into account when calculating bills.

TAXES

With the exception of the bills presented in Section 2, taxes are not included in any of the calculations. Appendix C lists the taxes applicable on April 1, 2023, by customer category; those which may be partially or fully refundable are indicated.

EXCHANGE RATE

The exchange rate used to convert bills in U.S. dollars into Canadian dollars is $0.7442 (CA$1 = US$0.7442), the rate in effect at noon on April 3, 2023. The Canadian dollar had thus depreciated by 6.88% relative to the U.S. dollar on April 1, 2022.

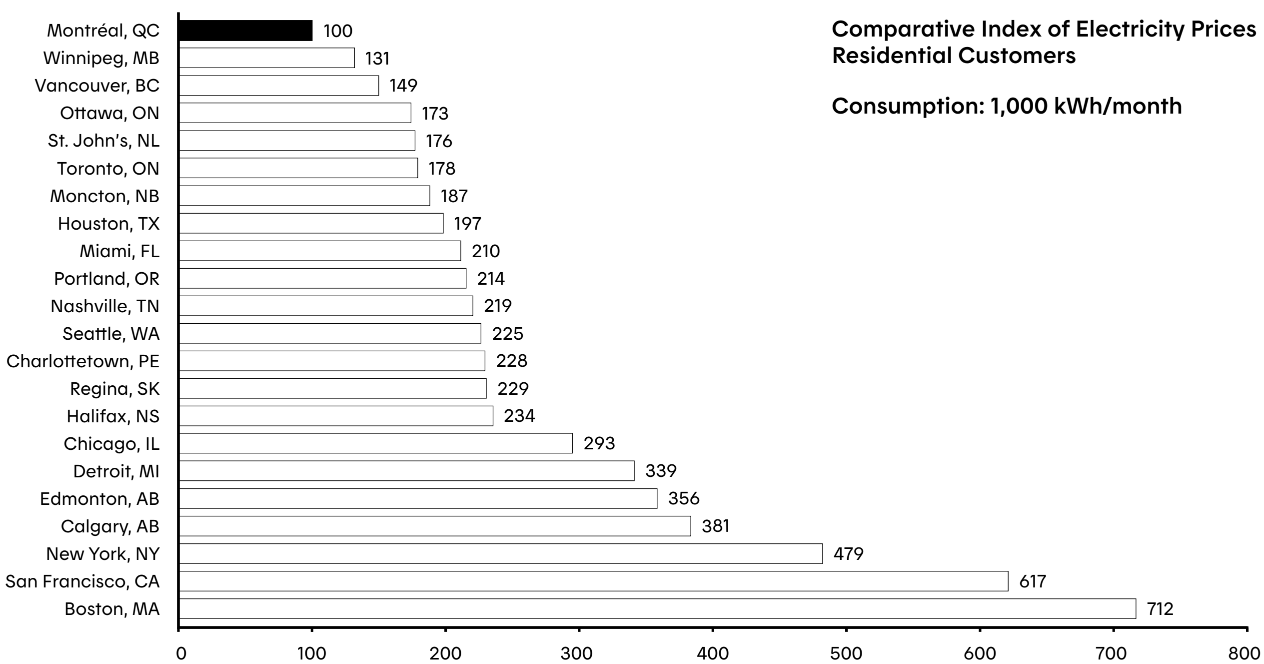
HIGHLIGHTS

The document *Electricity Rates effective April 1, 2023*, sets out Hydro-Québec's rates established in accordance with Schedule 1 of the *Hydro-Québec Act*. Three types of rates are in effect: domestic rates, for residential and farm customers (hereinafter, "residential customers"); the industrial rate, for large-power industrial customers; and general rates, for other customers. General rates are applied according to minimum billing demand: small power, medium power and large power. For comparison purposes, the electricity bills of the utilities in the study have been analyzed according to these categories. The industrial rate has been used to calculate the bills of large-power customers.

RESIDENTIAL CUSTOMERS

The rate applicable to Hydro-Québec's residential customers is among the most advantageous in North America. For customers whose monthly consumption is 1,000 kilowatthours (kWh), Montréal is once again in *first* place. Figure 1 illustrates the results of this comparison.

FIGURE 1

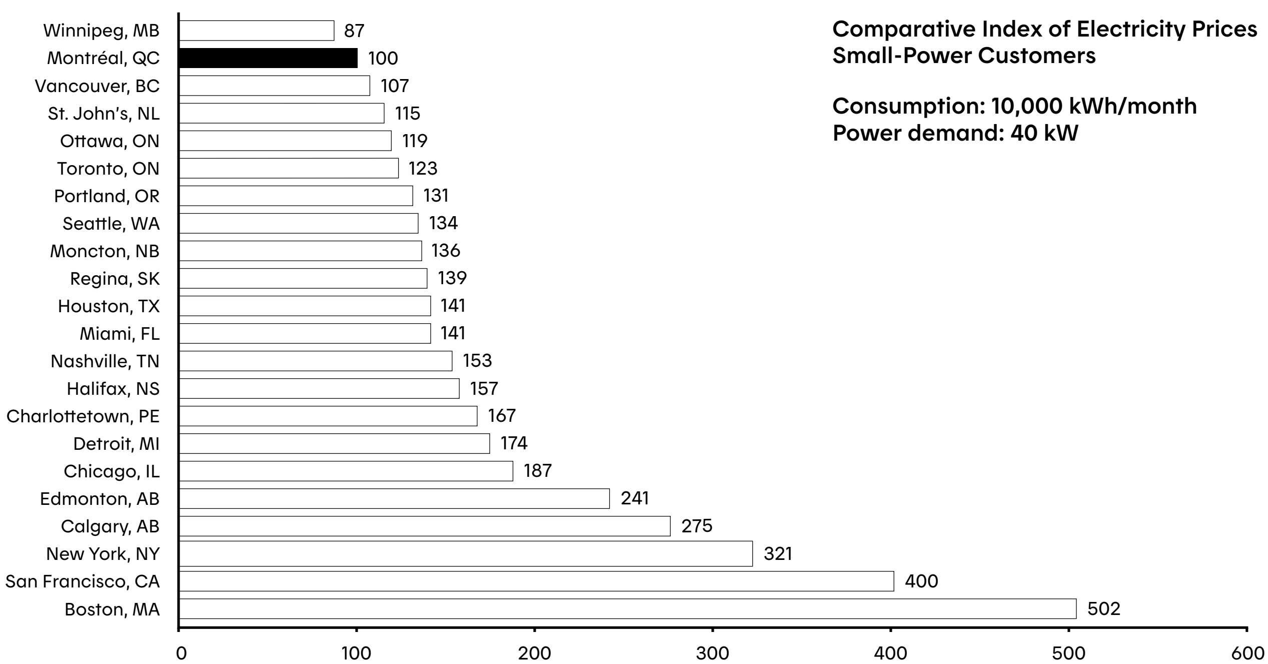


Hydro-Québec = 100
Monthly bill (excluding taxes)
Rates in effect April 1, 2023

SMALL-POWER CUSTOMERS (LESS THAN 100 kW)

The comparison of bills for small-power customers is based on a monthly consumption of 10,000 kWh and a power demand of 40 kilowatts (kW).
Again this year, Montréal is in *second* place. Figure 2 shows the comparative index of electricity prices.

FIGURE 2



Hydro-Québec = 100

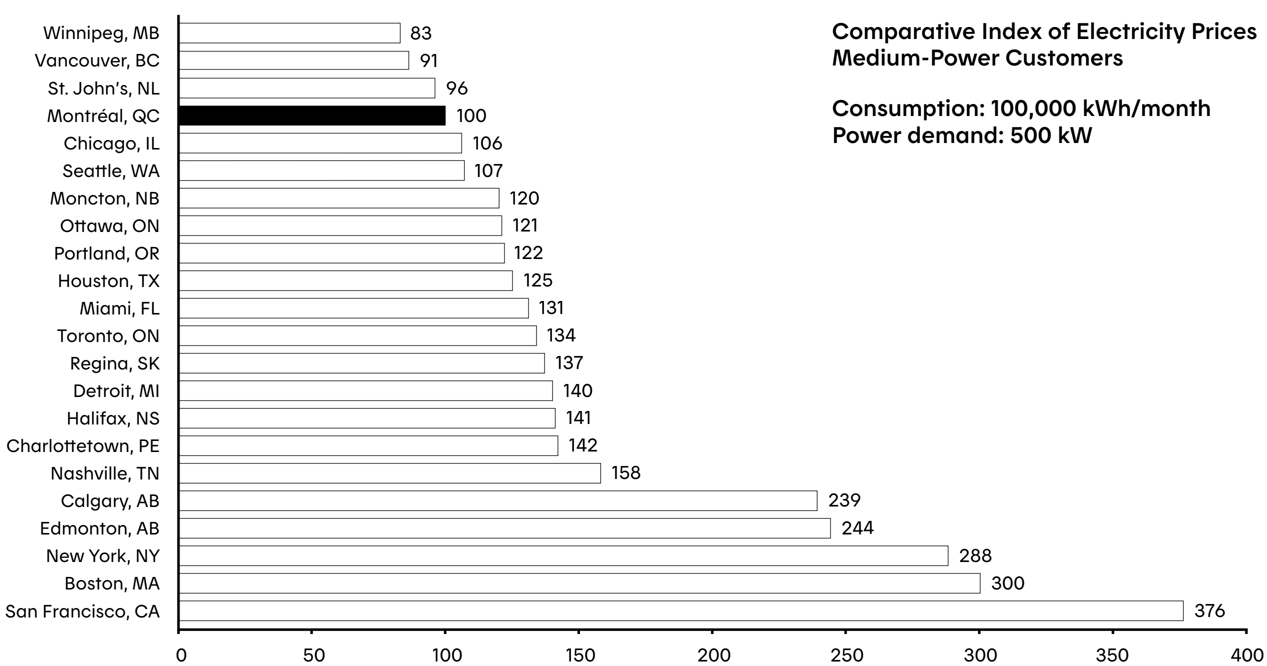
Monthly bill (excluding taxes)
Rates in effect April 1, 2023

MEDIUM-POWER CUSTOMERS (100 TO 5,000 kW)

Three consumption levels were analyzed for medium-power customers. In all three cases, the bills of Hydro-Québec's customers have remained below the average of the other major North American cities. Figures 3, 4 and 5 show the comparative index of electricity prices for these consumption profiles.

For medium-power customers with a monthly consumption of 100,000 kWh and a power demand of 500 kW, Montréal is in *fourth* place.

FIGURE 3

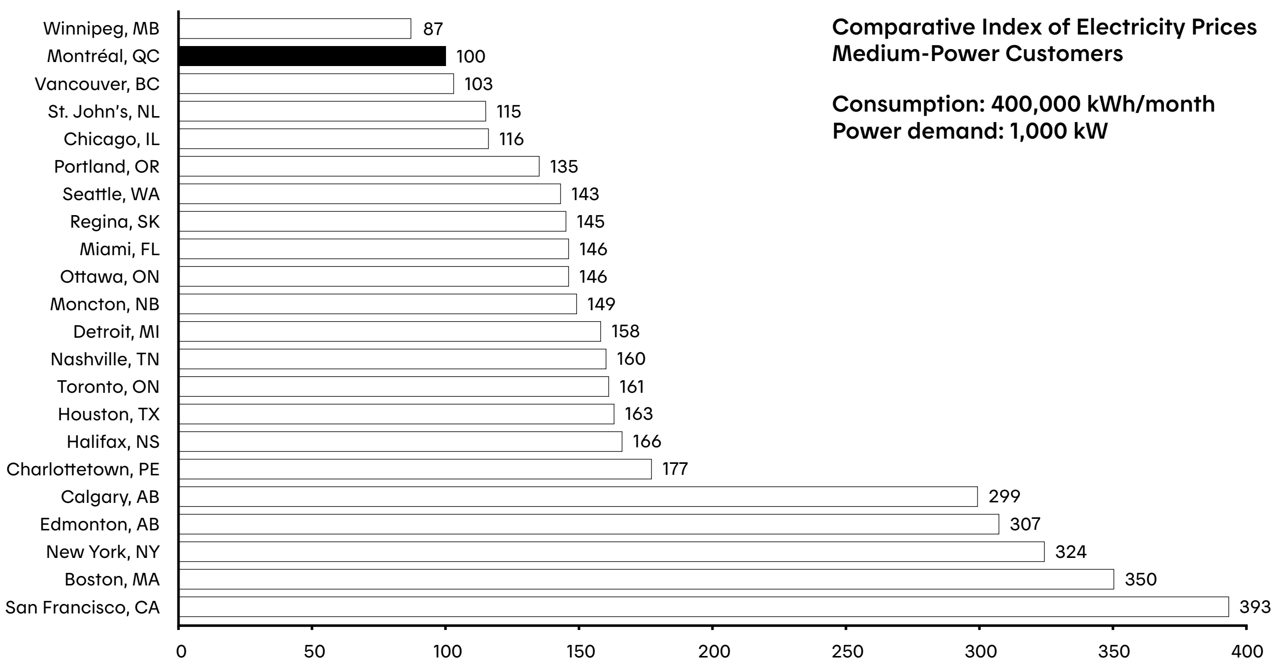


Hydro-Québec = 100

Monthly bill (excluding taxes)
Rates in effect April 1, 2023

For customers with a monthly consumption of 400,000 kWh and a power demand of 1,000 kW, Montréal ranks *second*.

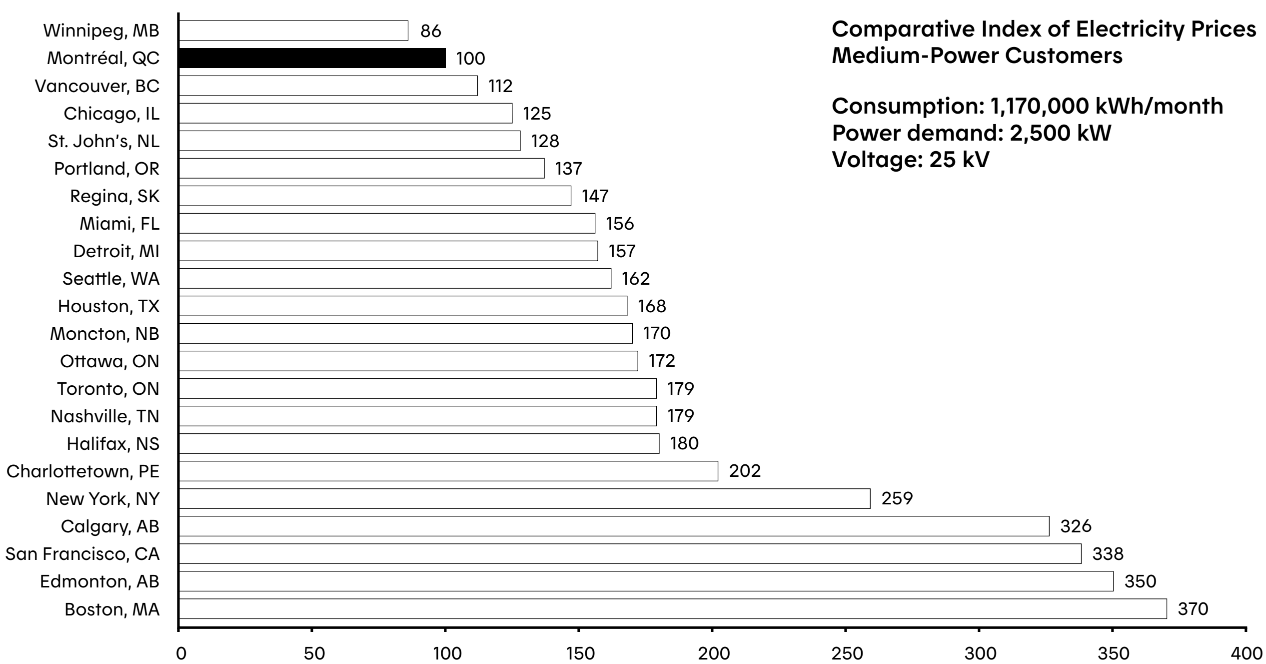
FIGURE 4



Hydro-Québec = 100
Monthly bill (excluding taxes)
Rates in effect April 1, 2023

In the case of customers with a monthly consumption of 1,170,000 kWh and a power demand of 2,500 kW, Montréal remains in *second* place.

FIGURE 5



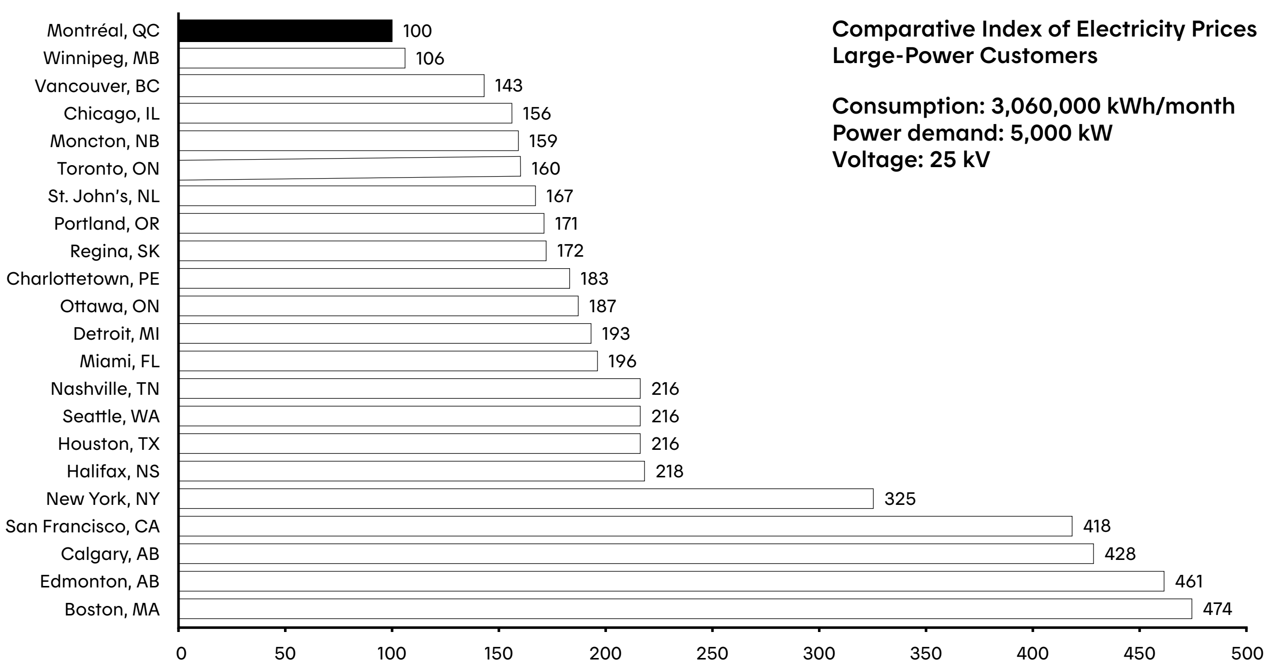
Hydro-Québec = 100

Monthly bill (excluding taxes)
Rates in effect April 1, 2023

LARGE-POWER CUSTOMERS (5,000 kW OR MORE)

Figure 6 illustrates the comparative index of electricity prices for large-power customers with a monthly consumption of 3,060,000 kWh and a power demand of 5,000 kW. Montréal ranks *first*.

FIGURE 6

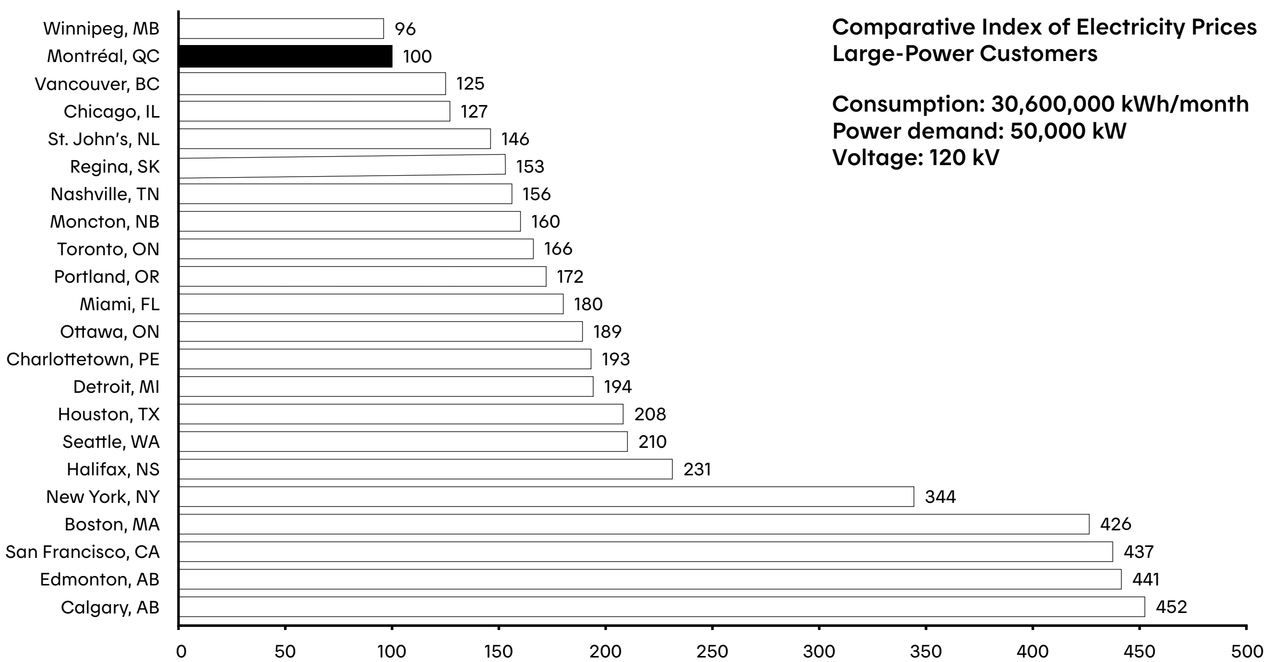


Hydro-Québec = 100

Monthly bill (excluding taxes)
Rates in effect April 1, 2023

For industrial customers with a power demand of 50,000 kW and a load factor of 85%, Montréal is in *second* place, coming in just behind Winnipeg.

FIGURE 7



Hydro-Québec = 100
Monthly bill (excluding taxes)
Rates in effect April 1, 2023

01

Detailed Results

Summary Tables (excluding taxes)

Monthly Bills

Average Prices

Comparative Index

MONTHLY BILLS ON APRIL 1, 2023
(in C$)

Summary Table (excluding taxes)

	Residential Customers	Small-Power Customers	Medium-Power Customers			Large-Power Customers	
Power demand		40 kW	500 kW	1,000 kW	2,500 kW[1]	5,000 kW[1]	50,000 kW[2]
Consumption	1,000 kWh	10,000 kWh	100,000 kWh	400,000 kWh	1,170,000 kWh	3,060,000 kWh	30,600,000 kWh
Load factor		35%	28%	56%	65%	85%	85%
Canadian Cities							
Montréal, QC	78.14	1,109.55	13,498.00	35,672.90	88,573.23	169,899.25	1,608,302.50
Calgary, AB	298.03	3,054.71	32,240.33	106,777.54	288,785.92	727,269.31	7,265,025.42
Charlottetown, PE[3]	177.77	1,849.17	19,195.97	63,140.97	178,842.97	311,180.00	3,111,800.00
Edmonton, AB[4]	277.81	2,677.91	32,891.06	109,651.48	310,078.30	784,033.88	7,086,820.07
Halifax, NS	182.71	1,737.94	19,094.00	59,230.00	159,732.15	371,217.46	3,712,199.83
Moncton, NB	146.07	1,510.65	16,244.65	53,164.65	150,482.65	269,721.65	2,571,800.00
Ottawa, ON	134.80	1,323.89	16,285.70	52,229.46	152,765.84	317,974.46	3,042,660.49
Regina, SK	178.94	1,542.78	18,549.00	51,770.10	129,917.75	292,824.48	2,461,848.10
St. John's, NL[5]	137.27	1,272.22	12,905.27	41,122.04	113,776.15	284,067.48	2,347,714.00
Toronto, ON[3]	138.76	1,368.86	18,055.74	57,599.93	158,158.43	271,742.09	2,676,116.54
Vancouver, BC	116.19	1,191.57	12,234.62	36,578.72	99,589.82	242,140.64	2,016,114.17
Winnipeg, MB	102.44	969.24	11,140.77	31,010.37	76,447.80	180,415.65	1,539,767.52
American Cities							
Boston, MA	556.28	5,567.19	40,546.90	124,912.66	327,681.13	805,395.59	6,856,234.88
Chicago, IL	228.63	2,079.43	14,259.92	41,401.49	110,815.36	265,328.70	2,044,727.72
Detroit, MI[3]	264.56	1,925.67	18,962.17	56,287.14	138,753.02	327,115.72	3,126,342.70
Houston, TX[3]	153.98	1,562.51	16,923.38	58,277.68	148,830.12	367,612.77	3,346,720.10
Miami, FL[3]	164.16	1,565.55	17,636.39	51,996.78	138,183.82	333,541.92	2,893,894.91
Nashville, TN	170.99	1,701.12	21,324.36	57,187.48	158,217.79	366,603.44	2,510,345.40
New York, NY[3]	373.94	3,560.85	38,883.99	115,499.95	229,557.91	553,011.14	5,528,365.44
Portland, OR[3]	167.04	1,452.47	16,470.57	48,106.65	120,954.16	290,630.95	2,771,249.41
San Francisco, CA[3]	481.80	4,433.47	50,722.53	140,030.08	299,259.17	709,477.74	7,022,847.58
Seattle, WA	175.73	1,491.00	14,386.46	51,007.71	143,712.90	366,666.34	3,372,915.80
AVERAGE	**213.91**	**2,043.08**	**21,475.08**	**65,575.26**	**169,232.56**	**391,266.85**	**3,586,991.48**

1) Supply voltage of 25 kV, customer-owned transformer.
2) Supply voltage of 120 kV, customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

AVERAGE PRICES ON APRIL 1, 2023

(in ¢/kWh)[1]

Summary Table (excluding taxes)

	Residential Customers	Small-Power Customers	Medium-Power Customers			Large-Power Customers	
Power demand		40 kW	500 kW	1,000 kW	2,500 kW[2]	5,000 kW[2]	50,000 kW[3]
Consumption	1,000 kWh	10,000 kWh	100,000 kWh	400,000 kWh	1,170,000 kWh	3,060,000 kWh	30,600,000 kWh
Load factor		35%	28%	56%	65%	85%	85%
Canadian Cities							
Montréal, QC	7.81	11.10	13.50	8.92	7.57	5.55	5.26
Calgary, AB	29.80	30.55	32.24	26.69	24.68	23.77	23.74
Charlottetown, PE[4]	17.78	18.49	19.20	15.79	15.29	10.17	10.17
Edmonton, AB[5]	27.78	26.78	32.89	27.41	26.50	25.62	23.16
Halifax, NS	18.27	17.38	19.09	14.81	13.65	12.13	12.13
Moncton, NB	14.61	15.11	16.24	13.29	12.86	8.81	8.40
Ottawa, ON	13.48	13.24	16.29	13.06	13.06	10.39	9.94
Regina, SK	17.89	15.43	18.55	12.94	11.10	9.57	8.05
St. John's, NL[6]	13.73	12.72	12.91	10.28	9.72	9.28	7.67
Toronto, ON[4]	13.88	13.69	18.06	14.40	13.52	8.88	8.75
Vancouver, BC	11.62	11.92	12.23	9.14	8.51	7.91	6.59
Winnipeg, MB	10.24	9.69	11.14	7.75	6.53	5.90	5.03
American Cities							
Boston, MA	55.63	55.67	40.55	31.23	28.01	26.32	22.41
Chicago, IL	22.86	20.79	14.26	10.35	9.47	8.67	6.68
Detroit, MI[4]	26.46	19.26	18.96	14.07	11.86	10.69	10.22
Houston, TX[4]	15.40	15.63	16.92	14.57	12.72	12.01	10.94
Miami, FL[4]	16.42	15.66	17.64	13.00	11.81	10.90	9.46
Nashville, TN	17.10	17.01	21.32	14.30	13.52	11.98	8.20
New York, NY[4]	37.39	35.61	38.88	28.87	19.62	18.07	18.07
Portland, OR[4]	16.70	14.52	16.47	12.03	10.34	9.50	9.06
San Francisco, CA[4]	48.18	44.33	50.72	35.01	25.58	23.19	22.95
Seattle, WA	17.57	14.91	14.39	12.75	12.28	11.98	11.02
AVERAGE	**21.39**	**20.43**	**21.48**	**16.39**	**14.46**	**12.79**	**11.72**

1) In Canadian currency.
2) Supply voltage of 25 kV, customer-owned transformer.
3) Supply voltage of 120 kV, customer-owned transformer.
4) These bills have been estimated by Hydro-Québec and may differ from actual bills.
5) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
6) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

COMPARATIVE INDEX ON APRIL 1, 2023

(Hydro-Québec = 100)

Summary Table (excluding taxes)

	Residential Customers	Small-Power Customers	Medium-Power Customers			Large-Power Customers	
Power demand		40 kW	500 kW	1,000 kW	2,500 kW[1]	5,000 kW[1]	50,000 kW[2]
Consumption	1,000 kWh	10,000 kWh	100,000 kWh	400,000 kWh	1,170,000 kWh	3,060,000 kWh	30,600,000 kWh
Load factor		35%	28%	56%	65%	85%	85%
Canadian Cities							
Montréal, QC	100	100	100	100	100	100	100
Calgary, AB	381	275	239	299	326	428	452
Charlottetown, PE[3]	228	167	142	177	202	183	193
Edmonton, AB[4]	356	241	244	307	350	461	441
Halifax, NS	234	157	141	166	180	218	231
Moncton, NB	187	136	120	149	170	159	160
Ottawa, ON	173	119	121	146	172	187	189
Regina, SK	229	139	137	145	147	172	153
St. John's, NL[5]	176	115	96	115	128	167	146
Toronto, ON[3]	178	123	134	161	179	160	166
Vancouver, BC	149	107	91	103	112	143	125
Winnipeg, MB	131	87	83	87	86	106	96
American Cities							
Boston, MA	712	502	300	350	370	474	426
Chicago, IL	293	187	106	116	125	156	127
Detroit, MI[3]	339	174	140	158	157	193	194
Houston, TX[3]	197	141	125	163	168	216	208
Miami, FL[3]	210	141	131	146	156	196	180
Nashville, TN	219	153	158	160	179	216	156
New York, NY[3]	479	321	288	324	259	325	344
Portland, OR[3]	214	131	122	135	137	171	172
San Francisco, CA[3]	617	400	376	393	338	418	437
Seattle, WA	225	134	107	143	162	216	210
AVERAGE	**274**	**184**	**159**	**184**	**191**	**230**	**223**

1) Supply voltage of 25 kV, customer-owned transformer.
2) Supply voltage of 120 kV, customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

02

Detailed Results

Summary Tables (including taxes)

MONTHLY BILLS ON APRIL 1, 2023
(in C$)

Summary Table (including taxes)

	Residential Customers	Small-Power Customers	Medium-Power Customers			Large-Power Customers	
Power demand		40 kW	500 kW	1,000 kW	2,500 kW[1]	5,000 kW[1]	50,000 kW[2]
Consumption	1,000 kWh	10,000 kWh	100,000 kWh	400,000 kWh	1,170,000 kWh	3,060,000 kWh	30,600,000 kWh
Load factor		35%	28%	56%	65%	85%	85%
Canadian Cities							
Montréal, QC	89.84	1,275.71	15,519.33	41,014.92	101,837.07	195,341.66	1,849,145.80
Calgary, AB	312.93	3,207.45	33,852.35	112,116.42	303,225.22	763,632.78	7,628,276.69
Charlottetown, PE[3]	204.44	2,126.55	22,075.37	72,612.12	205,669.42	357,857.00	3,578,570.00
Edmonton, AB[4]	291.70	2,811.81	34,535.61	115,134.06	325,582.21	823,235.57	7,441,161.07
Halifax, NS	191.85	1,998.63	21,958.10	68,114.50	183,691.97	426,900.08	4,269,029.80
Moncton, NB	167.98	1,737.25	18,681.35	61,139.35	173,055.05	310,179.90	2,957,570.00
Ottawa, ON	154.64	1,518.80	18,402.85	59,019.29	172,625.40	359,311.14	3,438,206.36
Regina, SK	216.41	1,982.01	23,615.45	67,191.92	169,590.54	386,440.64	3,297,267.92
St. John's, NL[5]	157.86	1,463.05	14,841.06	47,290.35	130,842.57	326,677.60	2,699,871.10
Toronto, ON[3]	159.19	1,570.40	20,402.98	65,087.92	178,719.03	307,068.57	3,024,011.69
Vancouver, BC	124.00	1,251.15	12,846.36	38,407.66	104,569.31	254,247.67	2,116,919.88
Winnipeg, MB	117.42	1,136.44	13,062.55	36,359.66	85,353.97	201,434.07	1,719,150.45
American Cities							
Boston, MA	556.28	5,905.71	42,986.76	132,342.45	347,057.75	852,846.86	7,255,889.88
Chicago, IL	241.50	2,183.75	15,209.98	45,004.07	120,945.75	290,679.20	2,265,024.74
Detroit, MI[3]	288.38	2,137.49	21,048.01	62,478.73	154,015.86	363,098.45	3,470,240.40
Houston, TX[3]	155.52	1,687.67	18,264.71	62,975.98	161,016.46	397,756.56	3,620,980.78
Miami, FL[3]	191.34	1,953.38	22,063.75	64,570.55	171,161.74	412,077.67	3,536,110.77
Nashville, TN	170.99	1,820.20	22,817.06	61,190.60	169,293.04	392,265.68	2,686,069.58
New York, NY[3]	406.32	3,970.19	43,353.96	128,777.36	255,946.96	616,582.94	6,163,882.70
Portland, OR[3]	169.33	1,472.53	16,700.47	48,773.85	122,708.03	294,858.93	2,811,647.98
San Francisco, CA[3]	482.21	4,659.18	53,298.97	147,192.83	314,693.78	746,185.17	7,386,325.36
Seattle, WA	175.73	1,491.00	14,386.46	51,007.71	143,712.90	366,666.34	3,372,915.80
AVERAGE	**228.45**	**2,243.65**	**23,632.89**	**72,172.83**	**186,150.64**	**429,333.84**	**3,935,830.40**

1) Supply voltage of 25 kV, customer-owned transformer.
2) Supply voltage of 120 kV, customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

AVERAGE PRICES ON APRIL 1, 2023

(in ¢/kWh)[1]

Summary Table (including taxes)

	Residential Customers	Small-Power Customers	Medium-Power Customers			Large-Power Customers	
Power demand		40 kW	500 kW	1,000 kW	2,500 kW[2]	5,000 kW[2]	50,000 kW[3]
Consumption	1,000 kWh	10,000 kWh	100,000 kWh	400,000 kWh	1,170,000 kWh	3,060,000 kWh	30,600,000 kWh
Load factor		35%	28%	56%	65%	85%	85%
Canadian Cities							
Montréal, QC	8.98	12.76	15.52	10.25	8.70	6.38	6.04
Calgary, AB	31.29	32.07	33.85	28.03	25.92	24.96	24.93
Charlottetown, PE[4]	20.44	21.27	22.08	18.15	17.58	11.69	11.69
Edmonton, AB[5]	29.17	28.12	34.54	28.78	27.83	26.90	24.32
Halifax, NS	19.19	19.99	21.96	17.03	15.70	13.95	13.95
Moncton, NB	16.80	17.37	18.68	15.28	14.79	10.14	9.67
Ottawa, ON	15.46	15.19	18.40	14.75	14.75	11.74	11.24
Regina, SK	21.64	19.82	23.62	16.80	14.49	12.63	10.78
St. John's, NL[6]	15.79	14.63	14.84	11.82	11.18	10.68	8.82
Toronto, ON[4]	15.92	15.70	20.40	16.27	15.28	10.03	9.88
Vancouver, BC	12.40	12.51	12.85	9.60	8.94	8.31	6.92
Winnipeg, MB	11.74	11.36	13.06	9.09	7.30	6.58	5.62
American Cities							
Boston, MA	55.63	59.06	42.99	33.09	29.66	27.87	23.71
Chicago, IL	24.15	21.84	15.21	11.25	10.34	9.50	7.40
Detroit, MI[4]	28.84	21.37	21.05	15.62	13.16	11.87	11.34
Houston, TX[4]	15.55	16.88	18.26	15.74	13.76	13.00	11.83
Miami, FL[4]	19.13	19.53	22.06	16.14	14.63	13.47	11.56
Nashville, TN	17.10	18.20	22.82	15.30	14.47	12.82	8.78
New York, NY[4]	40.63	39.70	43.35	32.19	21.88	20.15	20.14
Portland, OR[4]	16.93	14.73	16.70	12.19	10.49	9.64	9.19
San Francisco, CA[4]	48.22	46.59	53.30	36.80	26.90	24.39	24.14
Seattle, WA	17.57	14.91	14.39	12.75	12.28	11.98	11.02
AVERAGE	**22.84**	**22.44**	**23.63**	**18.04**	**15.91**	**14.03**	**12.86**

1) In Canadian currency.
2) Supply voltage of 25 kV, customer-owned transformer.
3) Supply voltage of 120 kV, customer-owned transformer.
4) These bills have been estimated by Hydro-Québec and may differ from actual bills.
5) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
6) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

COMPARATIVE INDEX ON APRIL 1, 2023

(Hydro-Québec = 100)

Summary Table (including taxes)

	Residential Customers	Small-Power Customers	Medium-Power Customers			Large-Power Customers	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW[1]**	**5,000 kW[1]**	**50,000 kW[2]**
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal, QC	100	100	100	100	100	100	100
Calgary, AB	348	251	218	273	298	391	413
Charlottetown, PE[3]	228	167	142	177	202	183	194
Edmonton, AB[4]	325	220	223	281	320	421	402
Halifax, NS	214	157	141	166	180	219	231
Moncton, NB	187	136	120	149	170	159	160
Ottawa, ON	172	119	119	144	170	184	186
Regina, SK	241	155	152	164	167	198	178
St. John's, NL[5]	176	115	96	115	128	167	146
Toronto, ON[3]	177	123	131	159	175	157	164
Vancouver, BC	138	98	83	94	103	130	114
Winnipeg, MB	131	89	84	89	84	103	93
American Cities							
Boston, MA	619	463	277	323	341	437	392
Chicago, IL	269	171	98	110	119	149	122
Detroit, MI[3]	321	168	136	152	151	186	188
Houston, TX[3]	173	132	118	154	158	204	196
Miami, FL[3]	213	153	142	157	168	211	191
Nashville, TN	190	143	147	149	166	201	145
New York, NY[3]	452	311	279	314	251	316	333
Portland, OR[3]	188	115	108	119	120	151	152
San Francisco, CA[3]	537	365	343	359	309	382	399
Seattle, WA	196	117	93	124	141	188	182
AVERAGE	**254**	**176**	**152**	**176**	**183**	**220**	**213**

1) Supply voltage of 25 kV, customer-owned transformer.
2) Supply voltage of 120 kV, customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

03

Detailed Results

RESIDENTIAL CUSTOMERS

Monthly Bills on April 1, 2023
(in C$)

Consumption	625 kWh	750 kWh	1,000 kWh	2,000 kWh	3,000 kWh
Canadian Cities					
Montréal, QC	53.73	61.87	78.14	171.49	271.90
Calgary, AB	197.21	230.82	298.03	566.89	835.74
Charlottetown, PE[1]	120.32	139.47	177.77	330.97	453.77
Edmonton, AB	183.49	214.94	277.81	529.34	780.87
Halifax, NS	121.38	141.83	182.71	346.25	509.79
Moncton, NB	100.51	115.70	146.07	267.57	389.07
Ottawa, ON	95.21	108.41	134.80	240.42	346.04
Regina, SK	123.08	141.70	178.94	327.89	476.84
St. John's, NL[2]	91.67	106.87	137.27	258.86	380.45
Toronto, ON[1]	100.16	113.03	138.76	241.70	344.63
Vancouver, BC	65.69	81.00	116.19	256.97	397.75
Winnipeg, MB	67.48	79.13	102.44	195.68	288.92
American Cities					
Boston, MA	352.71	420.59	556.28	1,099.11	1,641.95
Chicago, IL	150.26	176.37	228.63	437.67	646.72
Detroit, MI[1]	165.10	198.25	264.56	529.81	795.05
Houston, TX[1]	111.82	130.33	153.98	302.06	450.14
Miami, FL[1]	107.38	126.31	164.16	342.35	520.55
Nashville, TN	118.74	136.16	170.99	310.33	460.41
New York, NY[1]	242.12	286.06	373.94	725.45	1,076.96
Portland, OR[1]	110.55	129.38	167.04	317.67	481.38
San Francisco, CA[1]	280.68	352.10	481.80	1,053.10	1,624.40
Seattle, WA	109.88	131.82	175.73	351.36	526.98
AVERAGE	**139.51**	**164.64**	**213.91**	**418.31**	**622.74**

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.
2) Newfoundland Power rates.

RESIDENTIAL CUSTOMERS

Average Prices on April 1, 2023
(in ¢/kWh)[1]

Consumption	625 kWh	750 kWh	1,000 kWh	2,000 kWh	3,000 kWh
Canadian Cities					
Montréal, QC	8.60	8.25	7.81	8.57	9.06
Calgary, AB	31.55	30.78	29.80	28.34	27.86
Charlottetown, PE[2]	19.25	18.60	17.78	16.55	15.13
Edmonton, AB	29.36	28.66	27.78	26.47	26.03
Halifax, NS	19.42	18.91	18.27	17.31	16.99
Moncton, NB	16.08	15.43	14.61	13.38	12.97
Ottawa, ON	15.23	14.45	13.48	12.02	11.53
Regina, SK	19.69	18.89	17.89	16.39	15.89
St. John's, NL[3]	14.67	14.25	13.73	12.94	12.68
Toronto, ON[2]	16.03	15.07	13.88	12.08	11.49
Vancouver, BC	10.51	10.80	11.62	12.85	13.26
Winnipeg, MB	10.80	10.55	10.24	9.78	9.63
American Cities					
Boston, MA	56.43	56.08	55.63	54.96	54.73
Chicago, IL	24.04	23.52	22.86	21.88	21.56
Detroit, MI[2]	26.42	26.43	26.46	26.49	26.50
Houston, TX[2]	17.89	17.38	15.40	15.10	15.00
Miami, FL[2]	17.18	16.84	16.42	17.12	17.35
Nashville, TN	19.00	18.15	17.10	15.52	15.35
New York, NY[2]	38.74	38.14	37.39	36.27	35.90
Portland, OR[2]	17.69	17.25	16.70	15.88	16.05
San Francisco, CA[2]	44.91	46.95	48.18	52.66	54.15
Seattle, WA	17.58	17.58	17.57	17.57	17.57
AVERAGE	**22.32**	**21.95**	**21.39**	**20.92**	**20.76**

1) In Canadian currency.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Newfoundland Power rates.

RESIDENTIAL CUSTOMERS

Comparative Index on April 1, 2023
(Hydro-Québec = 100)

Consumption	625 kWh	750 kWh	1,000 kWh	2,000 kWh	3,000 kWh
Canadian Cities					
Montréal, QC	100	100	100	100	100
Calgary, AB	367	373	381	331	307
Charlottetown, PE[1]	224	225	228	193	167
Edmonton, AB	342	347	356	309	287
Halifax, NS	226	229	234	202	187
Moncton, NB	187	187	187	156	143
Ottawa, ON	177	175	173	140	127
Regina, SK	229	229	229	191	175
St. John's, NL[2]	171	173	176	151	140
Toronto, ON[1]	186	183	178	141	127
Vancouver, BC	122	131	149	150	146
Winnipeg, MB	126	128	131	114	106
American Cities					
Boston, MA	656	680	712	641	604
Chicago, IL	280	285	293	255	238
Detroit, MI[1]	307	320	339	309	292
Houston, TX[1]	208	211	197	176	166
Miami, FL[1]	200	204	210	200	191
Nashville, TN	221	220	219	181	169
New York, NY[1]	451	462	479	423	396
Portland, OR[1]	206	209	214	185	177
San Francisco, CA[1]	522	569	617	614	597
Seattle, WA	204	213	225	205	194
AVERAGE	**260**	**266**	**274**	**244**	**229**

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.
2) Newfoundland Power rates.

04

Detailed Results

Small-Power Customers

Monthly Bills

Average Prices

Comparative Index

SMALL-POWER CUSTOMERS

Monthly Bills on April 1, 2023
(in C$)

Power demand	6 kW	14 kW	40 kW	100 kW	100 kW
Consumption	750 kWh	2,000 kWh	10,000 kWh	14,000 kWh	25,000 kWh
Load factor	17%	20%	35%	19%	35%
Canadian Cities					
Montréal, QC	95.84	232.83	1,109.55	2,030.18	3,005.65
Calgary, AB	243.47	555.94	3,054.71	4,823.11	7,225.11
Charlottetown, PE[1]	164.90	398.77	1,849.17	3,151.37	4,516.47
Edmonton, AB	222.92	554.67	2,677.91	4,826.86	7,070.48
Halifax, NS	138.42	327.89	1,737.94	2,989.78	4,344.85
Moncton, NB	135.45	318.45	1,510.65	2,632.25	3,769.65
Ottawa, ON	117.69	280.68	1,323.89	2,491.47	3,913.80
Regina, SK	153.80	341.50	1,542.78	2,955.12	3,867.60
St. John's, NL[2]	111.99	293.97	1,272.22	2,194.97	3,163.87
Toronto, ON[1]	136.59	303.12	1,368.86	2,639.74	4,206.78
Vancouver, BC	105.00	261.55	1,191.57	1,902.79	2,966.74
Winnipeg, MB	91.88	210.44	969.24	1,985.12	2,632.42
American Cities					
Boston, MA	333.93	1,038.51	5,567.19	10,097.53	14,600.85
Chicago, IL	221.98	514.11	2,079.43	3,429.68	5,150.27
Detroit, MI[1]	158.90	411.31	1,925.67	2,682.84	4,765.08
Houston, TX[1]	111.87	402.20	1,562.51	2,760.79	3,885.29
Miami, FL[1]	136.19	334.78	1,565.55	2,842.57	3,853.44
Nashville, TN	197.15	424.41	1,701.12	3,991.33	4,869.55
New York, NY[1]	317.66	1,013.61	3,560.85	6,705.12	8,784.69
Portland, OR[1]	143.53	343.32	1,452.47	2,440.44	3,582.07
San Francisco, CA[1]	351.33	914.81	4,433.47	7,198.74	10,668.25
Seattle, WA	120.03	305.29	1,491.00	2,235.69	3,463.99
AVERAGE	**173.21**	**444.64**	**2,043.08**	**3,591.25**	**5,195.77**

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.
2) Newfoundland Power rates.

SMALL-POWER CUSTOMERS

Average Prices on April 1, 2023
(in ¢/kWh)[1]

Power demand	6 kW	14 kW	40 kW	100 kW	100 kW
Consumption	750 kWh	2,000 kWh	10,000 kWh	14,000 kWh	25,000 kWh
Load factor	17%	20%	35%	19%	35%
Canadian Cities					
Montréal, QC	12.78	11.64	11.10	14.50	12.02
Calgary, AB	32.46	27.80	30.55	34.45	28.90
Charlottetown, PE[2]	21.99	19.94	18.49	22.51	18.07
Edmonton, AB	29.72	27.73	26.78	34.48	28.28
Halifax, NS	18.46	16.39	17.38	21.36	17.38
Moncton, NB	18.06	15.92	15.11	18.80	15.08
Ottawa, ON	15.69	14.03	13.24	17.80	15.66
Regina, SK	20.51	17.08	15.43	21.11	15.47
St. John's, NL[3]	14.93	14.70	12.72	15.68	12.66
Toronto, ON[2]	18.21	15.16	13.69	18.86	16.83
Vancouver, BC	14.00	13.08	11.92	13.59	11.87
Winnipeg, MB	12.25	10.52	9.69	14.18	10.53
American Cities					
Boston, MA	44.52	51.93	55.67	72.13	58.40
Chicago, IL	29.60	25.71	20.79	24.50	20.60
Detroit, MI[2]	21.19	20.57	19.26	19.16	19.06
Houston, TX[2]	14.92	20.11	15.63	19.72	15.54
Miami, FL[2]	18.16	16.74	15.66	20.30	15.41
Nashville, TN	26.29	21.22	17.01	28.51	19.48
New York, NY[2]	42.35	50.68	35.61	47.89	35.14
Portland, OR[2]	19.14	17.17	14.52	17.43	14.33
San Francisco, CA[2]	46.84	45.74	44.33	51.42	42.67
Seattle, WA	16.00	15.26	14.91	15.97	13.86
AVERAGE	**23.09**	**22.23**	**20.43**	**25.65**	**20.78**

1) In Canadian currency.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Newfoundland Power rates.

SMALL-POWER CUSTOMERS

Comparative Index on April 1, 2023
(Hydro-Québec = 100)

Power demand	6 kW	14 kW	40 kW	100 kW	100 kW
Consumption	750 kWh	2,000 kWh	10,000 kWh	14,000 kWh	25,000 kWh
Load factor	17%	20%	35%	19%	35%
Canadian Cities					
Montréal, QC	100	100	100	100	100
Calgary, AB	254	239	275	238	240
Charlottetown, PE[1]	172	171	167	155	150
Edmonton, AB	233	238	241	238	235
Halifax, NS	144	141	157	147	145
Moncton, NB	141	137	136	130	125
Ottawa, ON	123	121	119	123	130
Regina, SK	160	147	139	146	129
St. John's, NL[2]	117	126	115	108	105
Toronto, ON[1]	143	130	123	130	140
Vancouver, BC	110	112	107	94	99
Winnipeg, MB	96	90	87	98	88
American Cities					
Boston, MA	348	446	502	497	486
Chicago, IL	232	221	187	169	171
Detroit, MI[1]	166	177	174	132	159
Houston, TX[1]	117	173	141	136	129
Miami, FL[1]	142	144	141	140	128
Nashville, TN	206	182	153	197	162
New York, NY[1]	331	435	321	330	292
Portland, OR[1]	150	147	131	120	119
San Francisco, CA[1]	367	393	400	355	355
Seattle, WA	125	131	134	110	115
AVERAGE	**181**	**191**	**184**	**177**	**173**

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.
2) Newfoundland Power rates.

05

Detailed Results

Medium-Power Customers

Monthly Bills

Average Prices

Comparative Index

MEDIUM-POWER CUSTOMERS

Monthly Bills on April 1, 2023
(in C$)

Power demand	500 kW	500 kW	1,000 kW	1,000 kW	2,500 kW[1]
Consumption	100,000 kWh	200,000 kWh	200,000 kWh	400,000 kWh	1,170,000 kWh
Load factor	28%	56%	28%	56%	65%
Canadian Cities					
Montréal, QC	13,498.00	19,203.50	26,996.00	35,672.90	88,573.23
Calgary, AB	32,240.33	53,768.27	63,721.66	106,777.54	288,785.92
Charlottetown, PE[2]	19,195.97	31,605.97	38,320.97	63,140.97	178,842.97
Edmonton, AB[3]	32,891.06	55,856.02	63,721.57	109,651.48	310,078.30
Halifax, NS	19,094.00	29,615.00	38,188.00	59,230.00	159,732.15
Moncton, NB	16,244.65	26,584.65	32,484.65	53,164.65	150,482.65
Ottawa, ON	16,285.70	26,214.85	32,371.16	52,229.46	152,765.84
Regina, SK	18,549.00	25,771.00	37,326.10	51,770.10	129,917.75
St. John's, NL[4]	12,905.27	21,248.22	24,593.74	41,122.04	113,776.15
Toronto, ON[2]	18,055.74	29,121.83	35,689.06	57,599.93	158,158.43
Vancouver, BC	12,234.62	18,293.42	24,461.12	36,578.72	99,589.82
Winnipeg, MB	11,140.77	15,632.77	22,026.37	31,010.37	76,447.80
American Cities					
Boston, MA	40,546.90	62,563.83	80,878.80	124,912.66	327,681.13
Chicago, IL	14,259.92	20,789.80	28,341.71	41,401.49	110,815.36
Detroit, MI[2]	18,962.17	28,272.86	37,891.63	56,287.14	138,753.02
Houston, TX[2]	16,923.38	27,146.06	37,832.33	58,277.68	148,830.12
Miami, FL[2]	17,636.39	26,057.51	35,154.53	51,996.78	138,183.82
Nashville, TN	21,324.36	28,739.93	42,356.34	57,187.48	158,217.79
New York, NY[2]	38,883.99	57,789.12	77,689.68	115,499.95	229,557.91
Portland, OR[2]	16,470.57	23,804.51	31,663.78	48,106.65	120,954.16
San Francisco, CA[2]	50,722.53	70,500.19	101,978.28	140,030.08	299,259.17
Seattle, WA	14,386.46	25,552.81	28,802.70	51,007.71	143,712.90
AVERAGE	**21,475.08**	**32,915.10**	**42,840.46**	**65,575.26**	**169,232.56**

1) Supply voltage of 25 kV, customer-owned transformer.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Newfoundland Power rates.

MEDIUM-POWER CUSTOMERS

Average Prices on April 1, 2023
(in ¢/kWh)[1]

Power demand	500 kW	500 kW	1,000 kW	1,000 kW	2,500 kW[2]
Consumption	100,000 kWh	200,000 kWh	200,000 kWh	400,000 kWh	1,170,000 kWh
Load factor	28%	56%	28%	56%	65%
Canadian Cities					
Montréal, QC	13.50	9.60	13.50	8.92	7.57
Calgary, AB	32.24	26.88	31.86	26.69	24.68
Charlottetown, PE[3]	19.20	15.80	19.16	15.79	15.29
Edmonton, AB[4]	32.89	27.93	31.86	27.41	26.50
Halifax, NS	19.09	14.81	19.09	14.81	13.65
Moncton, NB	16.24	13.29	16.24	13.29	12.86
Ottawa, ON	16.29	13.11	16.19	13.06	13.06
Regina, SK	18.55	12.89	18.66	12.94	11.10
St. John's, NL[5]	12.91	10.62	12.30	10.28	9.72
Toronto, ON[3]	18.06	14.56	17.84	14.40	13.52
Vancouver, BC	12.23	9.15	12.23	9.14	8.51
Winnipeg, MB	11.14	7.82	11.01	7.75	6.53
American Cities					
Boston, MA	40.55	31.28	40.44	31.23	28.01
Chicago, IL	14.26	10.39	14.17	10.35	9.47
Detroit, MI[3]	18.96	14.14	18.95	14.07	11.86
Houston, TX[3]	16.92	13.57	18.92	14.57	12.72
Miami, FL[3]	17.64	13.03	17.58	13.00	11.81
Nashville, TN	21.32	14.37	21.18	14.30	13.52
New York, NY[3]	38.88	28.89	38.84	28.87	19.62
Portland, OR[3]	16.47	11.90	15.83	12.03	10.34
San Francisco, CA[3]	50.72	35.25	50.99	35.01	25.58
Seattle, WA	14.39	12.78	14.40	12.75	12.28
AVERAGE	**21.48**	**16.46**	**21.42**	**16.39**	**14.46**

1) In Canadian currency.
2) Supply voltage of 25 kV, customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland Power rates.

MEDIUM-POWER CUSTOMERS

Comparative Index on April 1, 2023
(Hydro-Québec = 100)

Power demand	500 kW	500 kW	1,000 kW	1,000 kW	2,500 kW[1]
Consumption	100,000 kWh	200,000 kWh	200,000 kWh	400,000 kWh	1,170,000 kWh
Load factor	28%	56%	28%	56%	65%
Canadian Cities					
Montréal, QC	100	100	100	100	100
Calgary, AB	239	280	236	299	326
Charlottetown, PE[2]	142	165	142	177	202
Edmonton, AB[3]	244	291	236	307	350
Halifax, NS	141	154	141	166	180
Moncton, NB	120	138	120	149	170
Ottawa, ON	121	137	120	146	172
Regina, SK	137	134	138	145	147
St. John's, NL[4]	96	111	91	115	128
Toronto, ON[2]	134	152	132	161	179
Vancouver, BC	91	95	91	103	112
Winnipeg, MB	83	81	82	87	86
American Cities					
Boston, MA	300	326	300	350	370
Chicago, IL	106	108	105	116	125
Detroit, MI[2]	140	147	140	158	157
Houston, TX[2]	125	141	140	163	168
Miami, FL[2]	131	136	130	146	156
Nashville, TN	158	150	157	160	179
New York, NY[2]	288	301	288	324	259
Portland, OR[2]	122	124	117	135	137
San Francisco, CA[2]	376	367	378	393	338
Seattle, WA	107	133	107	143	162
AVERAGE	**159**	**171**	**159**	**184**	**191**

1) Supply voltage of 25 kV, customer-owned transformer.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Newfoundland Power rates.

06

Detailed Results

Large-Power Customers

Monthly Bills

Average Prices

Comparative Index

LARGE-POWER CUSTOMERS

Monthly Bills on April 1, 2023
(in C$)

Power demand	**5,000 kW**	**5,000 kW**	**10,000 kW**	**30,000 kW**	**50,000 kW**	**50,000 kW**
Consumption	**2,340,000 kWh**	**3,060,000 kWh**	**5,760,000 kWh**	**17,520,000 kWh**	**23,400,000 kWh**	**30,600,000 kWh**
Voltage[1]	**25 kV**	**25 kV**	**120 kV**	**120 kV**	**120 kV**	**120 kV**
Load factor	**65%**	**85%**	**80%**	**81%**	**65%**	**85%**
Canadian Cities						
Montréal, QC	144,677.65	169,899.25	309,049.70	935,556.30	1,356,086.50	1,608,302.50
Calgary, AB	572,819.71	727,269.31	1,376,458.90	4,179,163.35	5,720,529.35	7,265,025.42
Charlottetown, PE[2]	255,020.00	311,180.00	594,280.00	1,801,560.00	2,550,200.00	3,111,800.00
Edmonton, AB[3]	617,091.23	784,033.88	1,349,662.96	4,083,453.09	5,586,728.15	7,086,820.07
Halifax, NS	299,476.66	371,217.46	706,564.53	2,143,619.78	2,994,791.83	3,712,199.83
Moncton, NB	227,335.25	269,721.65	493,480.00	1,494,360.00	2,154,200.00	2,571,800.00
Ottawa, ON	261,976.72	317,974.46	592,718.48	1,766,358.23	2,482,683.10	3,042,660.49
Regina, SK	247,802.88	292,824.48	477,397.99	1,429,858.04	2,028,048.10	2,461,848.10
St. John's, NL[4]	224,565.60	284,067.48	532,289.08	1,358,908.80	1,921,546.00	2,347,714.00
Toronto, ON[2]	254,084.47	271,742.09	530,064.51	1,586,904.37	2,499,540.30	2,676,116.54
Vancouver, BC	199,171.63	242,140.64	384,882.58	1,166,880.94	1,649,378.57	2,016,114.17
Winnipeg, MB	150,038.85	180,415.65	294,392.96	892,224.64	1,268,615.52	1,539,767.52
American Cities						
Boston, MA	654,865.09	805,395.59	1,299,857.57	3,946,436.44	5,420,491.80	6,856,234.88
Chicago, IL	220,635.43	265,328.70	389,042.25	1,175,140.16	1,597,795.01	2,044,727.72
Detroit, MI[2]	276,837.62	327,115.72	601,022.20	1,818,250.47	2,630,721.10	3,126,342.70
Houston, TX[2]	294,355.85	367,612.77	634,093.59	1,923,796.55	2,620,062.30	3,346,720.10
Miami, FL[2]	276,025.13	333,541.92	555,156.93	1,676,795.20	2,373,196.17	2,893,894.91
Nashville, TN	312,224.51	366,603.44	461,350.78	1,352,159.24	2,030,708.17	2,510,345.40
New York, NY[2]	458,921.83	553,011.14	1,058,783.63	3,207,326.01	4,587,472.41	5,528,365.44
Portland, OR[2]	236,708.38	290,630.95	530,810.14	1,603,430.87	2,251,988.62	2,771,249.41
San Francisco, CA[2]	589,740.05	709,477.74	1,351,094.44	4,077,211.46	5,825,470.69	7,022,847.58
Seattle, WA	287,149.57	366,666.34	640,762.71	1,940,997.66	2,645,783.32	3,372,915.80
AVERAGE	**320,978.37**	**391,266.85**	**689,237.09**	**2,070,926.89**	**2,918,001.68**	**3,586,991.48**

1) Customer-owned transformer.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

LARGE-POWER CUSTOMERS

Average Prices on April 1, 2023
(in ¢/kWh)[1]

Power demand	5,000 kW	5,000 kW	10,000 kW	30,000 kW	50,000 kW	50,000 kW
Consumption	2,340,000 kWh	3,060,000 kWh	5,760,000 kWh	17,520,000 kWh	23,400,000 kWh	30,600,000 kWh
Voltage[2]	25 kV	25 kV	120 kV	120 kV	120 kV	120 kV
Load factor	65%	85%	80%	81%	65%	85%
Canadian Cities						
Montréal, QC	6.18	5.55	5.37	5.34	5.80	5.26
Calgary, AB	24.48	23.77	23.90	23.85	24.45	23.74
Charlottetown, PE[3]	10.90	10.17	10.32	10.28	10.90	10.17
Edmonton, AB[4]	26.37	25.62	23.43	23.31	23.87	23.16
Halifax, NS	12.80	12.13	12.27	12.24	12.80	12.13
Moncton, NB	9.72	8.81	8.57	8.53	9.21	8.40
Ottawa, ON	11.20	10.39	10.29	10.08	10.61	9.94
Regina, SK	10.59	9.57	8.29	8.16	8.67	8.05
St. John's, NL[5]	9.60	9.28	9.24	7.76	8.21	7.67
Toronto, ON[3]	10.86	8.88	9.20	9.06	10.68	8.75
Vancouver, BC	8.51	7.91	6.68	6.66	7.05	6.59
Winnipeg, MB	6.41	5.90	5.11	5.09	5.42	5.03
American Cities						
Boston, MA	27.99	26.32	22.57	22.53	23.16	22.41
Chicago, IL	9.43	8.67	6.75	6.71	6.83	6.68
Detroit, MI[3]	11.83	10.69	10.43	10.38	11.24	10.22
Houston, TX[3]	12.58	12.01	11.01	10.98	11.20	10.94
Miami, FL[3]	11.80	10.90	9.64	9.57	10.14	9.46
Nashville, TN	13.34	11.98	8.01	7.72	8.68	8.20
New York, NY[3]	19.61	18.07	18.38	18.31	19.60	18.07
Portland, OR[3]	10.12	9.50	9.22	9.15	9.62	9.06
San Francisco, CA[3]	25.20	23.19	23.46	23.27	24.90	22.95
Seattle, WA	12.27	11.98	11.12	11.08	11.31	11.02
AVERAGE	**13.72**	**12.79**	**11.97**	**11.82**	**12.47**	**11.72**

1) In Canadian currency.
2) Customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

LARGE-POWER CUSTOMERS

Comparative Index on April 1, 2023
(Hydro-Québec = 100)

Power demand	5,000 kW	5,000 kW	10,000 kW	30,000 kW	50,000 kW	50,000 kW
Consumption	2,340,000 kWh	3,060,000 kWh	5,760,000 kWh	17,520,000 kWh	23,400,000 kWh	30,600,000 kWh
Voltage[1]	25 kV	25 kV	120 kV	120 kV	120 kV	120 kV
Load factor	65%	85%	80%	81%	65%	85%
Canadian Cities						
Montréal, QC	100	100	100	100	100	100
Calgary, AB	396	428	445	447	422	452
Charlottetown, PE[2]	176	183	192	193	188	193
Edmonton, AB[3]	427	461	437	436	412	441
Halifax, NS	207	218	229	229	221	231
Moncton, NB	157	159	160	160	159	160
Ottawa, ON	181	187	192	189	183	189
Regina, SK	171	172	154	153	150	153
St. John's, NL[4]	155	167	172	145	142	146
Toronto, ON[2]	176	160	172	170	184	166
Vancouver, BC	138	143	125	125	122	125
Winnipeg, MB	104	106	95	95	94	96
American Cities						
Boston, MA	453	474	421	422	400	426
Chicago, IL	153	156	126	126	118	127
Detroit, MI[2]	191	193	194	194	194	194
Houston, TX[2]	203	216	205	206	193	208
Miami, FL[2]	191	196	180	179	175	180
Nashville, TN	216	216	149	145	150	156
New York, NY[2]	317	325	343	343	338	344
Portland, OR[2]	164	171	172	171	166	172
San Francisco, CA[2]	408	418	437	436	430	437
Seattle, WA	198	216	207	207	195	210
AVERAGE	**222**	**230**	**223**	**221**	**215**	**223**

1) Customer-owned transformer.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

A

Appendix

Rate Adjustments

Across-the-Board Adjustments

Adjustments by
Customer Category

RATE ADJUSTMENTS

Across-the-Board Adjustments

	Before April 2022		Between April 1, 2022 and April 1, 2023		
	Year	%	Date	%	Comments
Canadian Utilities					
Hydro-Québec, QC	2022	2.60	April 1, 2023	3.00	Applicable to residential customers
ENMAX, AB	2022	−1.97	January 1, 2023	7.53	Average of distribution (9.26%) and transmission (5.80%) components
Maritime Electric, PE	2022	2.00	March 1, 2023	—	
EPCOR, AB	2022	—	—	—	
Nova Scotia Power, NS	2022	n.a.	February 2, 2023	6.90	
NB Power, NB	2022	2.00	April 1, 2023	5.61	Rate increase of 5.70% and variance account credit of −0.09%
Hydro Ottawa, ON	2022	n.a.	May 1, 2022	n.a.	
			November 1, 2022	n.a.	
			January 1, 2023	n.a.	
SaskPower, SK	2022	n.a.	September 1, 2022	4.00	
			April 1, 2023	4.00	
Newfoundland Power, NL[1]	2022	−1.10	July 1, 2022	−0.30	
Newfoundland and Labrador Hydro, NL[1]	2022	12.70	July 1, 2022	n.a.	
			January 1, 2023	n.a.	
Toronto Hydro, ON	2022	n.a.	January 1, 2023	n.a.	
BC Hydro, BC	2022	0.62	April 1, 2023	0.97	
Manitoba Hydro, MB	2022	3.60	—	—	
Data concerning American utilities not available.					

n.a.: Not available.

1) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

RATE ADJUSTMENTS (Between April 1, 2022, and April 1, 2023)

Adjustments by Customer Category

	Date	Residential Customers %	General-Rate Customers %	Industrial Customers %	Average %
Canadian Utilities					
Hydro-Québec, QC	April 1, 2023	3.00	6.50[1] 6.50[2] 6.50[3]	4.20	4.75
ENMAX, AB	January 1, 2023	8.92[4]	0.38[1] 10.77[2] 8.79[3]	n.a.	7.53[4]
Maritime Electric, PE	—	—	—	—	—
EPCOR, AB	—	—	—	—	—
Nova Scotia Power, NS	February 2, 2023	6.90	8.40[1] 7.10[2] 8.30[3]	8.10[5] 7.90[6]	6.90
NB Power, NB	April 1, 2023	5.61	5.61	5.61	5.61
Hydro Ottawa, ON	May 1, 2022	−0.12	−0.04	—	n.a.
	November 1, 2022	−0.78	−1.07	—	n.a.
	January 1, 2023	4.88	5.01	0.66	n.a.
SaskPower, SK	September 1, 2022	n.a.	n.a.	n.a.	4.00
	April 1, 2023	n.a.	n.a.	n.a.	4.00
Newfoundland Power, NL[7]	July 1, 2022	−0.20	−0.30	−0.40	−0.30
Newfoundland and Labrador Hydro, NL[7]	July 1, 2022	—	—	0.01	—
	January 1, 2023	—	—	15.40	—
Toronto Hydro, ON	January 1, 2023	n.a.	n.a.	n.a.	n.a.
BC Hydro, BC	April 1, 2023	0.97	0.97	0.97	0.97
Manitoba Hydro, MB	—	—	—	—	—
Data concerning American utilities not available.					

n.a.: Not available.
1) Small-power customers.
2) Medium-power customers.
3) Large-power customers.
4) Average of distribution and transmission components.
5) Small industrial companies.
6) Midsize industrial companies.
7) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

Note: Because of adjustment clauses (see list in Appendix B), electricity bills issued by a utility may vary, even though base rates have not changed.

B

Appendix

Time-of-Use Rates

Adjustment Clauses

TIME-OF-USE RATES

The utilities listed below apply time-of-use rates for different consumption levels. For the purposes of this study, an annual average has been calculated for utilities whose rates vary according to the season or time of day (or both). In the case of utilities whose supply costs are determined by the market, the average for the month of March 2023 was used.

CenterPoint Energy, TX	All levels
Commonwealth Edison, IL	All levels
Consolidated Edison, NY	All levels
DTE Electric, MI	500–50,000 kW
ENMAX, AB	All levels
EPCOR, AB	All levels
Eversource Energy, MA	General-rate customers: All levels
Hydro Ottawa, ON	All levels
Nashville Electric Service, TN	All levels
Newfoundland Power, NL	Residential customers General-rate customers: 14–10,000 kW
Pacific Gas and Electric, CA	All levels
PacifiCorp, OR	1,000–50,000 kW
Seattle City Light, WA	Residential customers General-rate customers: 1,000–50,000 kW
Toronto Hydro, ON	All levels

ADJUSTMENT CLAUSES

Below is a list of utilities whose rates include adjustment clauses that may cause fluctuations in the price of electricity even though base rates have not been adjusted.

BC Hydro, BC	Deferral Account Rate Rider
CenterPoint Energy, TX	Accumulated Deferred Federal Income Tax Credit Distribution Cost Recovery Factor Energy Efficiency Cost Recovery Factor Nuclear Decommissioning Charge Rate Case Expenses Surcharge Transition Charges Transmission Cost Recovery Factor Unprotected Excess Deferred Income Tax
Commonwealth Edison, IL	Carbon-Free Resource Adjustment Energy Efficiency Pricing & Performance Energy Transition Assistance Charge Environmental Cost Recovery Adjustment Excess Deferred Income Tax Adjustment Franchise Cost Additions Renewable Energy Adjustment Renewable Energy Distributed Generation Rebate Retail Customer Assessments Zero Emission Adjustment
Consolidated Edison, NY	Adjustment Factors – MSC Billing and Payment Processing Charge Clean Energy Standard Delivery Surcharge Clean Energy Standard Supply Surcharge Delivery Revenue Surcharge Dynamic Load Management Surcharge Market Supply Charge Merchant Function Charge Monthly Adjustment Clause Revenue Decoupling Mechanism Adjustment System Benefits Charge Tax Sur-Credit Value of Distributed Energy Resources Cost Recovery
DTE Electric, MI	Energy Waste Reduction Surcharge Low Income Energy Assistance Fund Factor Nuclear Surcharge Power Supply Cost Recovery Clause Renewable Energy Plan Surcharge
ENMAX, AB	Balancing Pool Allocation Rider Local Access Fee Regulated Rate Option Rider Transmission Access Charge Deferral Account Rider Adjustment

EPCOR, AB	Balancing Pool Allocation Rider DAS True-Up Rider Deferral Rate Local Access Fee SAS True-Up Rider Transmission Charge Deferral Account True-Up Rider
Eversource Energy, MA	Advanced Metering Infrastructure Factor Attorney General Consultant Expense Basic Service Cost Adjustment Electronic Payment Recovery Factor Energy Efficiency Charge Farm Discount Grid Modernization Factor Long Term Renewable Contract Adjustment Low Income Discount Miscellaneous Charges Net Metering Recovery Surcharge Pension Adjustment Mechanism Performance Based Revenue Adjustment Renewable Energy Charge Residential Assistance Adjustment Clause Revenue Decoupling Adjustment Mechanism Solar Expansion Cost Recovery Mechanism Solar Massachusetts Renewable Target Solar Program Cost Adjustment Storm Cost Recovery Adjustment Storm Reserve Adjustment Mechanism Transition Cost Adjustment Transmission Service Cost Adjustment Vegetation Management 2017 Tax Act Credit
Florida Power and Light, FL	Capacity Payment Recovery Clause Consolidated Interim Storm Restoration Recovery Surcharge Energy Conservation Cost Recovery Clause Environmental Cost Recovery Clause Fuel Cost and Purchase Power Recovery Clause Storm Protection Charge Transition Rider Credit
Hydro Ottawa, ON	Capacity Based Recovery Charge Disposition of Deferral/Variance Accounts Disposition of Global Adjustment Account (2023) Lost Revenue Adjustment Mechanism Recovery Rate Rider for Disposition of Class B Rural or Remote Electricity Rate Protection Charge Smart Metering Entity Charge
Maritime Electric, PE	Energy Cost Adjustment Mechanism
Nashville Electric Service, TN	COVID-19 Relief Credit Small Manufacturing Credit Tax Exemption Status

Newfoundland and Labrador Hydro, NL	CDM Cost Recovery Adjustment Rider Rate Stabilization Plan Adjustment Rider
Nova Scotia Power, NS	Fuel Adjustment Mechanism (AA/BA)
Pacific Gas and Electric, CA	Bundled Power Charge Indifference Adjustment California Climate Credit Competition Transition Charges Energy Cost Recovery Amount New System Generation Charge Nuclear Decommissioning Public Purpose Programs Recovery Bond Charge/Credit Reliability Services Transmission Rate Adjustments Wildfire Fund Charge Wildfire Hardening Charge
PacifiCorp, OR	Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act Base Supply Service Community Solar Start-Up Cost Recovery Adjustment Deer Creek Mine Closure Deferred Amounts Adjustment Deferred Accounting Adjustment Independent Evaluator Cost Adjustment Intervenor Funding Adjustment Net Power Costs, Cost-Based Supply Service Oregon Solar Incentive Program Deferral Power Cost Adjustment Mechanism Property Sales Balancing Account Adjustment Public Purpose Charge Rate Mitigation Adjustment Renewable Adjustment Clause Renewable Resource Deferral Adjustment Replaced Meter Deferred Amounts Adjustment System Benefits Charge TAM Adjustment for Other Revenues Wildfire Mitigation and Vegetation Management Cost Recovery Adjustment Wildfire Protection Plan Cost Recovery Adjustment
Toronto Hydro, ON	Capacity Based Recovery (CBR) Disposition of Accounts Receivable Credits Disposition of Derecognition Variance Account Disposition of Expansion Deposits Disposition of Stranded Meter Assets Disposition of Wireless Pole Attachment Revenue Recovery of Monthly Billing Transition Costs Rural or Remote Electricity Rate Protection Charge Smart Metering Entity Charge

C

Appendix

Applicable Taxes

Residential Customers

General-Rate Customers

Industrial Customers

TAXES APPLICABLE TO RESIDENTIAL CUSTOMERS

On April 1, 2023

	Tax	% (or other)	Applicable
Canadian Cities			
Montréal, QC	Goods and services tax	5	To base amount of bill
	Québec sales tax	9.975	To base amount of bill
Calgary, AB	Goods and services tax	5	To base amount of bill
Charlottetown, PE	Harmonized sales tax	15	To base amount of bill
Edmonton, AB	Goods and services tax	5	To base amount of bill
Halifax, NS	Harmonized sales tax	5	To base amount of bill
Moncton, NB	Harmonized sales tax	15	To base amount of bill
Ottawa, ON	Harmonized sales tax	13	To base amount of bill
Regina, SK	Municipal tax	10	To base amount of bill
	Carbon levy	¢/kWh	To energy consumption
	Goods and services tax	5	To base amount of bill (excluding municipal surcharge)
St. John's, NL	Harmonized sales tax	15	To base amount of bill
Toronto, ON	Harmonized sales tax	13	To base amount of bill
Vancouver, BC	Regional transit levy	$1.90	Monthly
	Goods and services tax	5	To base amount of bill + regional transit levy
Winnipeg, MB	Provincial sales tax	1.4	To base amount of bill (customers with electric heating)
		7	To base amount of bill (customers with heating other than electric)
	Municipal tax	0.5	To base amount of bill (customers with electric heating)
		2.5	To base amount of bill (customers with heating other than electric)
	Goods and services tax	5	To base amount of bill + municipal tax
American Cities			
Boston, MA	None		
Chicago, IL	State tax	¢/kWh	As a function of energy consumption
	Municipal tax	¢/kWh	As a function of energy consumption
	State tax on electricity distribution	$/kWh	As a function of monthly consumption
Detroit, MI	State sales tax	4	To base amount of bill
	City of Detroit utility users' tax	5	To base amount of bill
Houston, TX	Municipal tax	1	To base amount of bill
Miami, FL	Gross receipts tax/ Regulatory assessment fee	2.6381	To base amount of bill
	Franchise fee	5.473	To base amount of bill + gross receipts tax
	Municipal tax	10	To a portion of base amount of bill
Nashville, TN	None		
New York, NY	Commodity gross receipts tax	2.4066	To commodity component
	Delivery gross receipts tax	4.9097	To other components
	Sales tax	4.5	To base amount of bill + gross receipts tax
Portland, OR	Multnomah County business income tax	−0.02	To a portion of base amount of bill
	City of Portland franchise tax	1.5	To a portion of base amount of bill
San Francisco, CA	Energy Commission tax	¢/kWh	To energy consumption
Seattle, WA	State utility tax	3.8734	Tax included in rate schedule prices
	City of Seattle occupation tax	6	Tax included in rate schedule prices

TAXES APPLICABLE TO GENERAL-RATE CUSTOMERS

On April 1, 2023

	Tax	% (or other)	Applicable
Canadian Cities			
Montréal, QC	Goods and services tax	5	To base amount of bill (tax refundable)
	Québec sales tax	9.975	To base amount of bill (tax refundable[1])
Calgary, AB	Goods and services tax	5	To base amount of bill
Charlottetown, PE	Harmonized sales tax	15	To base amount of bill (tax refundable)
Edmonton, AB	Goods and services tax	5	To base amount of bill
Halifax, NS	Harmonized sales tax	15	To base amount of bill (tax refundable)
Moncton, NB	Harmonized sales tax	15	To base amount of bill (tax refundable)
Ottawa, ON	Harmonized sales tax	13	To base amount of bill
Regina, SK	Municipal tax	10	To base amount of bill
	Provincial sales tax	6	To base amount of bill + municipal tax
	Carbon levy	¢/kWh	To energy consumption
	Goods and services tax	5	To base amount of bill (excluding municipal surcharge)
St. John's, NL	Harmonized sales tax	15	To base amount of bill (tax refundable)
Toronto, ON	Harmonized sales tax	13	To base amount of bill (tax refundable)
Vancouver, BC	Goods and services tax	5	To base amount of bill
Winnipeg, MB	Provincial sales tax	1.4	To base amount of bill (mining and manufacturing companies)
		7	To base amount of bill (industries other than mining and manufacturing)
	Municipal tax	1	To base amount of bill (customers with electric heating)
		5	To base amount of bill (customers with heating other than electric)
	Goods and services tax	5	To base amount of bill + municipal tax (tax refundable)
American Cities			
Boston, MA	State sales tax	6.25	To a portion of base amount of bill
Chicago, IL	State tax	¢/kWh	As a function of energy consumption
	Municipal tax	¢/kWh	As a function of energy consumption
	State tax on electricity distribution	$/kWh	As a function of monthly consumption
Detroit, MI	State sales tax	6	To base amount of bill
	City of Detroit utility users' tax	5	To base amount of bill
Houston, TX	State tax	6.25	To base amount of bill
	Municipal tax	1	To base amount of bill
	Transit tax	1	To base amount of bill

1) Business customers with revenue below $10 million and all customers in the manufacturing sector are entitled to a refund of this tax.

TAXES APPLICABLE TO GENERAL-RATE CUSTOMERS (cont'd)

On April 1, 2023

	Tax	% (or other)	Applicable
Miami, FL	Gross receipts tax/ Regulatory assessment fee	2.6381	To base amount of bill
	Franchise fee	5.473	To base amount of bill + gross receipts tax
	Municipal tax	10	To a portion of base amount of bill
	State sales tax	6.95	To base amount of bill + gross receipts tax + franchise fee
	Local tax	1	To base amount of bill + gross receipts tax + franchise fee
Nashville, TN	State sales tax	7	To base amount of bill
New York, NY	Commodity gross receipts tax	2.4066	To commodity component
	Delivery gross receipts tax	2.4073	To other components
	Sales tax	8.875	To base amount of bill + gross receipts tax
Portland, OR	Multnomah County business income tax	−0.02	To a portion of base amount of bill
	City of Portland franchise tax	1.5	To a portion of base amount of bill
San Francisco, CA	Energy Commission tax	¢/kWh	To energy consumption
	San Francisco utility users' tax	5	To base amount of bill
Seattle, WA	State utility tax	3.8734	Tax included in rate schedule prices
	City of Seattle occupation tax	6	Tax included in rate schedule prices

TAXES APPLICABLE TO INDUSTRIAL CUSTOMERS

On April 1, 2023

	Tax	% (or other)	Applicable
Canadian Cities			
Montréal, QC	Goods and services tax	5	To base amount of bill (tax refundable)
	Québec sales tax	9.975	To base amount of bill (tax refundable[1])
Calgary, AB	Goods and services tax	5	To base amount of bill
Charlottetown, PE	Harmonized sales tax	15	To base amount of bill (tax refundable)
Edmonton, AB	Goods and services tax	5	To base amount of bill
Halifax, NS	Harmonized sales tax	15	To base amount of bill (tax refundable)
Moncton, NB	Harmonized sales tax	15	To base amount of bill (tax refundable)
Ottawa, ON	Harmonized sales tax	13	To base amount of bill
Regina, SK	Municipal tax	10	To base amount of bill
	Provincial sales tax	6	To base amount of bill + municipal tax
	Carbon levy	¢/kWh	To energy consumption
	Goods and services tax	5	To base amount of bill (excluding municipal surcharge)
St. John's, NL	Harmonized sales tax	15	To base amount of bill (tax refundable)
Toronto, ON	Harmonized sales tax	13	To base amount of bill (tax refundable)
Vancouver, BC	Goods and services tax	5	To base amount of bill
Winnipeg, MB	Provincial sales tax	1.4	To base amount of bill (mining and manufacturing companies)
		7	To base amount of bill (industries other than mining and manufacturing)
	Municipal tax	1	To base amount of bill (customers with electric heating)
		5	To base amount of bill (customers with heating other than electric)
	Goods and services tax	5	To base amount of bill + municipal tax (tax refundable)
American Cities			
Boston, MA	State sales tax	6.25	To a portion of base amount of bill
Chicago, IL	State tax	¢/kWh	As a function of energy consumption
	Municipal tax	¢/kWh	As a function of energy consumption
	State tax on electricity distribution	$/kWh	As a function of monthly consumption
Detroit, MI	State sales tax	6	To base amount of bill
	City of Detroit utility users' tax	5	To base amount of bill
Houston, TX	State tax	6.25	To base amount of bill
	Municipal tax	1	To base amount of bill
	Transit tax	1	To base amount of bill

1) Business customers with revenue below $10 million and all customers in the manufacturing sector are entitled to a refund of this tax.

TAXES APPLICABLE TO INDUSTRIAL CUSTOMERS (cont'd)

On April 1, 2023

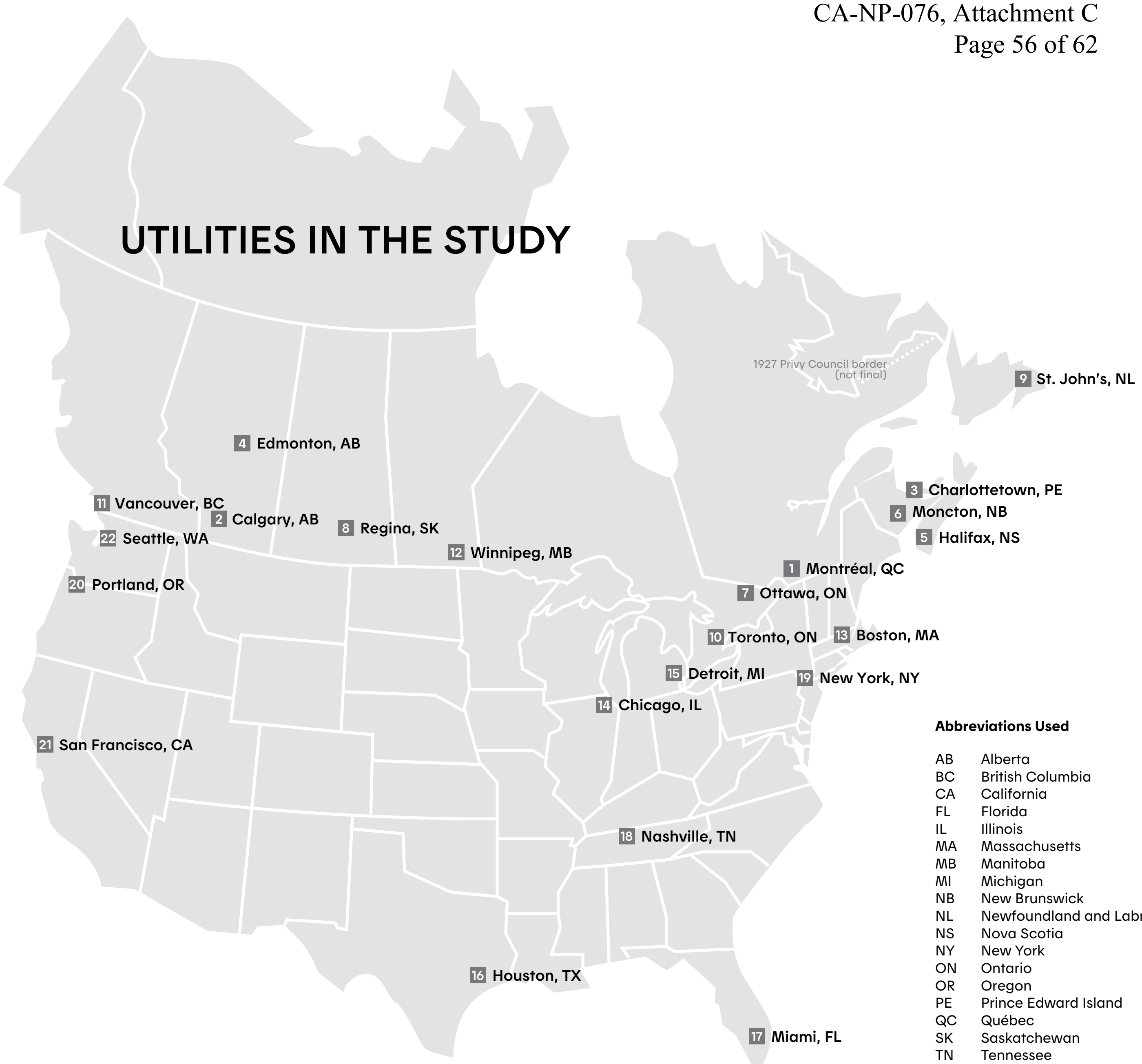
	Tax	% (or other)	Applicable
Miami, FL	Gross receipts tax/ Regulatory assessment fee	2.6381	To base amount of bill
	Franchise fee	5.473	To base amount of bill + gross receipts tax
	Municipal tax	10	To a portion of base amount of bill
	State sales tax	6.95	To base amount of bill + gross receipts tax + franchise fee
	Local tax	1	To base amount of bill + gross receipts tax + franchise fee
Nashville, TN	State sales tax	7	To base amount of bill
New York, NY	Commodity gross receipts tax	2.4066	To commodity component
	Delivery gross receipts tax	2.4073	To other components
	Sales tax	8.875	To base amount of bill + gross receipts tax
Portland, OR	Multnomah County business income tax	−0.02	To a portion of base amount of bill
	City of Portland franchise tax	1.5	To a portion of base amount of bill
San Francisco, CA	Energy Commission tax	¢/kWh	To energy consumption
	San Francisco utility users' tax	5	To base amount of bill
Seattle, WA	State utility tax	3.8734	Tax included in rate schedule prices
	City of Seattle occupation tax	6	Tax included in rate schedule prices

D

Appendix

Utilities in the Study

UTILITIES IN THE STUDY



Abbreviations Used

AB	Alberta
BC	British Columbia
CA	California
FL	Florida
IL	Illinois
MA	Massachusetts
MB	Manitoba
MI	Michigan
NB	New Brunswick
NL	Newfoundland and Labrador
NS	Nova Scotia
NY	New York
ON	Ontario
OR	Oregon
PE	Prince Edward Island
QC	Québec
SK	Saskatchewan
TN	Tennessee
TX	Texas
WA	Washington

CANADIAN UTILITIES

1- Hydro-Québec
2- ENMAX
3- Maritime Electric
4- EPCOR
5- Nova Scotia Power
6- NB Power
7- Hydro Ottawa
8- SaskPower
9- Newfoundland and Labrador Hydro (customers with a power demand of 30,000 kW or more)
Newfoundland Power (all other customer categories)
10- Toronto Hydro
11- BC Hydro
12- Manitoba Hydro

AMERICAN UTILITIES

13- Eversource Energy
14- Commonwealth Edison
15- DTE Electric
16- CenterPoint Energy
17- Florida Power and Light
18- Nashville Electric Service
19- Consolidated Edison
20- PacifiCorp
21- Pacific Gas and Electric
22- Seattle City Light

CANADIAN UTILITIES

HYDRO-QUÉBEC
Montréal, Québec

Hydro-Québec, a government-owned company, is one of the largest electric utilities in North America. In accordance with the *Act respecting the Régie de l'énergie* [Québec energy board], it provides a maximum of 165 TWh of heritage pool electricity per year to the Québec market and also purchases power on the markets to meet its customers' needs. The average supply cost of heritage pool electricity, set at 2.79¢/kWh in 1998, has been indexed annually on January 1 since 2014 at a rate corresponding to the annual variation in the average overall Consumer Price Index for Québec. The large-power industrial rate (Rate L) is exempt from this indexation.

Pursuant to *An Act mainly to cap the indexation rate for Hydro-Québec domestic distribution rate prices and to further regulate the obligation to distribute electricity*, the company's distribution rates were increased as follows on April 1, 2023:

- 3,0% for residential customers;
- 6.5% for all other customers except large-power industrial customers;
- 4.2% for large-power industrial customers (6.5% increase multiplied by an adjustment factor of 0.65 set by the Régie de l'énergie).

Activities: Generation, transmission and distribution

Installed capacity: 37,439 MW

Main sources: Hydropower generating stations and wind power purchases (more than 99% of power supplied is clean and renewable)

Number of accounts: About 4.5 million residential, commercial, institutional and industrial customer accounts, nine municipal systems and one regional cooperative

Distribution regulator: Régie de l'énergie

Wholesale market: Open

Retail market: –

ENMAX
Calgary, Alberta

Activities: Generation, transmission and distribution

Installed capacity: 1,638 MW

Main sources: Natural gas (91%) and wind (9%)

Number of accounts: More than 725,000

Distribution regulator: Alberta Utilities Commission

Wholesale market: Open

Retail market: Open

MARITIME ELECTRIC
Charlottetown, Prince Edward Island

Activities: Distribution

Installed capacity: 129 MW

Main sources: Purchases from NB Power and PEI Energy Corporation

Number of accounts: About 86,000

Distribution regulator: Island Regulatory and Appeals Commission

Wholesale market: –

Retail market: –

EPCOR
Edmonton, Alberta

Activities: Transmission and distribution

Installed capacity: –

Main sources: Market purchases

Number of accounts: About 435,000 customers in Edmonton

Distribution regulator: Alberta Utilities Commission

Wholesale market: Open

Retail market: Open

NOVA SCOTIA POWER
Halifax, Nova Scotia

Activities: Generation, transmission and distribution

Installed capacity: 2,420 MW

Main sources: Thermal (coal, natural gas, petroleum and petroleum coke), hydropower, wind and other

Number of accounts: More than 541,000 residential, commercial and industrial customers

Distribution regulator: Nova Scotia Utility and Review Board

Wholesale market: –

Retail market: –

NB POWER
Moncton, New Brunswick

Activities: Generation, transmission and distribution

Installed capacity: 3,790 MW

Main sources: Thermal (1,716 MW), hydropower (889 MW), nuclear (660 MW) and combustion turbines (525 MW)

Number of accounts: More than 400,000

Distribution regulator: New Brunswick Energy and Utilities Board

Wholesale market: –

Retail market: –

HYDRO OTTAWA
Ottawa, Ontario

Activities: Generation and distribution

Installed capacity: 131 MW (renewable energy)

Main sources: Purchases from Ontario Power Generation

Number of accounts: About 359,000

Distribution regulator: Ontario Energy Board

Wholesale market: Open

Retail market: Open, but electricity supply rate regulated by the Ontario Energy Board

SASKPOWER
Regina, Saskatchewan

Activities: Generation, transmission and distribution

Installed capacity: 5,246 MW

Main sources: Natural gas (41%), coal (26%), hydropower (19%), wind (12%), solar (1%) and other (1%)

Number of accounts: About 550,000

Distribution regulator: Saskatchewan Rate Review Panel

Wholesale market: Partially open

Retail market: Partially open

NEWFOUNDLAND AND LABRADOR HYDRO
(customers with a power demand of 30,000 kW or more)
St. John's, Newfoundland and Labrador

Activities: Generation, transmission and distribution

Installed capacity: 2,378 MW

Main sources: Hydropower (87%) and thermal (13%)

Number of accounts: More than 38,000

Distribution regulator: Newfoundland and Labrador Board of Commissioners of Public Utilities

Wholesale market: –

Retail market: –

NEWFOUNDLAND POWER
(all other customer categories)
St. John's, Newfoundland and Labrador

Activities: Generation, transmission and distribution

Installed capacity: 140 MW

Main sources: Purchases from Newfoundland and Labrador Hydro (93%)

Number of accounts: More than 274,000 customers throughout the island of Newfoundland

Distribution regulator: Newfoundland and Labrador Board of Commissioners of Public Utilities

Wholesale market: –

Retail market: –

TORONTO HYDRO
Toronto, Ontario

Activities: Distribution

Installed capacity: –

Main sources: Purchases from Ontario Power Generation

Number of accounts: About 790,000

Distribution regulator: Ontario Energy Board

Wholesale market: Open

Retail market: Open, but electricity supply rate regulated by the Ontario Energy Board

BC HYDRO
Vancouver, British Columbia

Activities: Generation, transmission and distribution

Installed capacity: About 12,204 MW

Main sources: Hydropower (about 98%)

Number of accounts: Nearly 2.2 million

Distribution regulator: British Columbia Utilities Commission

Wholesale market: Open

Retail market: –

MANITOBA HYDRO
Winnipeg, Manitoba

Activities: Generation, transmission and distribution

Installed capacity: 5,860 MW

Main sources: Hydropower (about 96%), natural gas and diesel

Number of accounts: About 609,000

Distribution regulator: Manitoba Public Utilities Board

Wholesale market: –

Retail market: –

AMERICAN UTILITIES

EVERSOURCE ENERGY
Boston, Massachusetts

Activities: Transmission and distribution

Installed capacity: –

Main sources: Purchases from ISO New England

Number of accounts: Nearly 3.3 million residential, commercial and industrial customers in Massachusetts, Connecticut and New Hampshire

Distribution regulator: Massachusetts Department of Public Utilities

Wholesale market: Open

Retail market: Open

COMMONWEALTH EDISON (ComEd)
Chicago, Illinois

Activities: Transmission and distribution

Installed capacity: –

Main sources: Purchases from Midcontinent Independent System Operator

Number of accounts: Nearly 4 million customers in northern Illinois

Distribution regulator: Illinois Commerce Commission

Wholesale market: Open

Retail market: Open

DTE ELECTRIC
Detroit, Michigan

Activities: Generation, transmission and distribution

Installed capacity: 11,717 MW

Main sources: Coal, nuclear, natural gas, hydropower and other (wind and solar)

Number of accounts: 2.3 million customers in southeastern Michigan

Distribution regulator: Michigan Public Service Commission

Wholesale market: Open

Retail market: Partially open

CENTERPOINT ENERGY
Houston, Texas

Activities: Generation, transmission and distribution

Installed capacity: About 1,300 MW in Indiana

Main sources: Purchases from the Electric Reliability Council of Texas

Number of accounts: Nearly 2.9 million

Distribution regulator: Public Utility Commission of Texas

Wholesale market: Open

Retail market: Open

FLORIDA POWER AND LIGHT (FPL)
Miami, Florida

Activities: Generation, transmission and distribution

Installed capacity: Over 30,800 MW

Main sources: Natural gas, nuclear, solar and coal

Number of accounts: More than 5.8 million

Distribution regulator: Florida Public Service Commission

Wholesale market: Open

Retail market: –

NASHVILLE ELECTRIC SERVICE
Nashville, Tennessee

Activities: Distribution

Installed capacity: –

Main sources: Purchases from Tennessee Valley Authority

Number of accounts: More than 430,000

Distribution regulator: Tennessee Valley Authority

Wholesale market: –

Retail market: –

CONSOLIDATED EDISON (ConEd)
New York, New York

Activities: Distribution

Installed capacity: –

Main sources: Purchases from New York Independent System Operator

Number of accounts: About 3.6 million customers in the New York metropolitan area and 0.3 million customers in Westchester County

Distribution regulator: New York State Public Service Commission

Wholesale market: Open

Retail market: Open

PACIFICORP
Portland, Oregon

Activities: Generation, transmission and distribution

Installed capacity: 11,504 MW

Main sources: Natural gas, hydropower, wind, solar, geothermal, natural gas and coal

Number of accounts: 800,000 customers across three states (Oregon, Washington and California)

Distribution regulator: Public Utility Commission of Oregon

Wholesale market: Open

Retail market: Partially open

PACIFIC GAS AND ELECTRIC (PG&E)
San Francisco, California

Activities: Generation, transmission and distribution

Installed capacity: 7,832 MW

Main sources: Purchases from California ISO and fuel-fired, hydropower, solar and other generating stations

Number of accounts: 5.5 million

Distribution regulator: California Public Utilities Commission

Wholesale market: Open

Retail market: Partially open

SEATTLE CITY LIGHT
Seattle, Washington

Activities: Generation, transmission and distribution

Installed capacity: 2,006.4 MW

Main sources: Hydropower, wind, biogas and other generating stations, agreement with BC Hydro and purchases from Bonneville Power Administration

Number of accounts: Nearly 480,000 customers in Seattle and surrounding communities

Distribution regulator: City of Seattle

Wholesale market: Open

Retail market: –

Information sources
Annual reports and websites of the Canadian and American utilities in the study.

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