P-886 ORIGINAL N-2(6)

Nova Scotia Utility and Review Board

IN THE MATTER OF *The Public Utilities Act,* R.S.N.S. 1989, c.380, as amended

- and -

IN THE MATTER OF an Application by Nova Scotia Power Incorporated for Approval of Certain Revisions to its Rates, Charges and Regulations

NSPI IR RESPONSES

UARB 70 - 84

AEC 1 - 26

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NOV 21 2006
Nova Scotia
Utility and Review Board

Volume 2

November 20, 2006

Redacted

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act,* R.S.N.S. 1989, c.380 as amended

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for Approval of Certain Revisions to its Rates, Charges and Regulations

RESPONSE TO INFORMATION REQUEST

TO: NSPI

FROM: UARB **REDACTED**

Question IR-70: **Reference Appendix B, Page 41. It is stated that:**

"Contracts increase due to high volume/IVR test component of telephone Technology improvements and HVCA (high volume call answering system) reporting, plus a transfer of the SEIS expense from Consulting."

a. Please provide forecasted 2007 level of costs for each of the referenced contracts including high volume/IVR test component of telephone Technology improvements and HVCA.

b. What is meant by the term SEIS expense and what is the forecasted level for 2007.

Response IR-70: a. The table below identifies the projected level of Contract expense for the items referenced.

Item	2007 Forecast (Thousands)
HVCA/IVR stress test	$250
HVCA Reporting	$10

b. Smart Energy Information Service (SEIS) is a web based application that provides subscribing commercial and industrial customers with load profile and cost information.

SEIS contract expense is forecast to be [redacted] in 2007 for on-going software maintenance support from an external software vendor.

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RESPONSE TO INFORMATION REQUEST

TO: NSPI

FROM: UARB

Question IR-71: **Reference Appendix B, Page 43. It is stated that:**

"Labour decrease due to realignment of bonuses and incentives associated with the realignment of staff to Emera."

a. Please provide forecasted 2007 level of costs for bonuses and incentives associated with the realignment of staff to Emera.

b. Please describe the work functions of the staff realigned to Emera in 2005, 2006 and 2007 as referred to on Page 43.

Response IR-71:

a. The forecasted 2007 level of costs for bonuses and incentives associated with the realignment of staff to Emera is $586,000.

b. The staff realigned to Emera, as referred to on page 43, is now focused solely on Emera. Previous NSPI responsibilities, that were provide by Emera, have been reassigned to NSPI staff. This would include work carried out by the following Emera Executives: Emera's CEO, CFO and VP of Human Resources.

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RESPONSE TO INFORMATION REQUEST

TO: NSPI

FROM: UARB

Question IR-72: **Reference Appendix F**

a. The title page of the Load Forecast report states Prepared September 2006. However, page 4, line 6 states it was prepared in the spring of 2006. In what month was the forecast prepared?

b. When it states on page 4, line 6 that it used "information available at the time", up to what date was information available and used in the preparation of the load forecast?

c. Page 4, line 29, what is the date of the quarterly Conference Board of Canada report used for the load forecast?

d. Page 6, Table 1: Provide the source for each projection, e.g. Conference Board, NSPI, other. For non-NSPI sources provide the reference to the specific documents used.

e. Page 8, line 3: Explain the apparent inconsistency between the quoted 7.0% system losses and the 7.41% used in Appendix G, Exhibit 9A, Column 2, line 17.

f. Page 12, line 2: Describe the adjustments for the effects of weather. Include the NSPI calculations performed and equations used to move from the actual 2.3% to the adjusted 1.8%.

g. Page 14, line14: Describe the adjustments for the effects of weather. Include the NSPI calculations performed and equations used to move from the actual 2.6% to the adjusted 2.3%.

Response IR-72: a. The Load Forecast was initially produced in May 2006. It was revised in September for 2008-2015. There was no change to 2007 as a result of this revision.

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RESPONSE TO INFORMATION REQUEST

TO: NSPI

FROM: UARB

Response IR-72: (cont'd)

b. Information available to mid-April 2006 was used in the forecast, with the exception of a September 2006 home heating oil price forecast for the years 2008-2015.

c. The economic data series used in the forecast models was released February 2, 2006.

d. The population and economic data was derived from the February 2006 Conference Board of Canada data. The forecast heating oil price change was developed using the Consumer Price Index from the Conference Board, the average Halifax retail price of household heating oil was from Statistics Canada, and the 2006-2007 NYMEX price strip for home heating oil, dated March 20, 2006.

e. The 7 percent quoted on page 8 expresses losses as a percentage of Net System Requirement (NSR), which includes sales plus losses. The calculation in Exhibit 9A of the Direct Evidence expresses losses as a percentage of sales.

f. The calculation reflects the average annual change in residential sector load between 2000 and 2005. As shown in Table 2, page 12, Appendix F, billed sales (not adjusted for weather) were 3672.1 GWh and grew to 4114.3 GWh by 2005, equivalent to 2.3 percent annually.

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TO: NSPI

FROM: UARB

Response IR-72: (cont'd)

The load adjustments due to weather are based on monthly heating degree-day (HDD) difference from normal multiplied by monthly factors which indicate the change in load per HDD. These monthly factors were calculated based on regressions of monthly energy sales with heating degree-days.

In the preparation of this response, an error in the calculation was discovered; the 1999 HDD series was inadvertently used in place of the correct 2000 HDD series. The growth rate should be 2.1 percent of the Direct Evidence when adjusted for weather, not the 1.8 percent noted in Appendix F. This correction to a historical year does not affect the 2007 Forecast.

The weather adjustment calculation is shown in the following table which shows the monthly HDD difference from normal and the estimated effect on residential sales.

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RESPONSE TO INFORMATION REQUEST

TO: NSPI

FROM: UARB

Response IR-72: (cont'd)

Month	Normal HDD	2000 HDD Difference	2005 HDD Difference	MWh/HDD	2000 GWh Difference	2005 GWh Difference
Jan	702.8	-35.7	72.1	359	-12.8	25.9
Feb	635.7	-29.8	-33.9	356	-10.6	-12.1
Mar	582.4	-75.6	-9.1	330	-24.9	-3.0
Apr	415.3	-36.5	-19.1	307	-11.2	-5.9
May	274.3	4.1	35.4	256	1.0	9.1
Jun	120.8	-16.6	-15.5	106	-1.8	-1.6
Jul	32.3	-1.4	-11.8	4	0.0	0.0
Aug	25.9	-11.7	-18.3	12	-0.1	-0.2
Sep	106.9	1.6	-61.8	68	0.1	-4.2
Oct	275.3	-45.4	-81.9	215	-9.8	-17.6
Nov	415.0	-45.3	-64.9	306	-13.9	-19.9
Dec	606.1	19.2	-60.3	307	5.9	-18.5
Total:	4192.9	-273.2	-269.2		-78.1	-48.1

Using this calculation, the weather-adjusted residential sector loads are:

For 2000 : 3672.1 + 78.1 = 3750.1 GWh
For 2005 : 4114.3 + 48.1 = 4162.4 GWh

The 412.3 GWh or 11.0 percent load growth in 5 years is equivalent to 2.1 percent annually.

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FROM: UARB

Response IR-72: (cont'd)

g) The calculation reflects the average annual change in commercial sector load between the years 2000 and 2005. As shown in Table 3 on page 14 of Appendix F, billed sales were 2829.4 GWh and grew to 3223.2 GWh by 2005, equivalent to 2.6 percent annually.

The load adjustments due to weather are based on monthly heating degree-day (HDD) difference from normal multiplied by monthly factors which indicate the change in load per HDD. These monthly factors were calculated based on regressions of monthly energy sales with heating degree-days.

When preparing this response, an error in the calculation was discovered; the 1999 HDD series was inadvertently used in place of the correct 2000 HDD series. The correct growth rate should be 2.6 percent when adjusted for weather, not the 2.4 percent noted in Appendix F of the Direct Evidence. This correction to a historical year does not affect the 2007 Forecast.

The weather adjustment calculation is shown in the following table which shows the monthly HDD difference from normal and the estimated effect on commercial sales.

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RESPONSE TO INFORMATION REQUEST

TO: NSPI

FROM: UARB

Response IR-72: (cont'd)

Month	Normal HDD	2000 HDD Difference	2005 HDD Difference	MWh/HDD	2000 GWh Difference	2005 GWh Difference
Jan	702.8	-35.7	72.1	98	-3.5	7.1
Feb	635.7	-29.8	-33.9	98	-2.9	-3.3
Mar	582.4	-75.6	-9.1	90	-6.8	-0.8
Apr	415.3	-36.5	-19.1	84	-3.1	-1.6
May	274.3	4.1	35.4	70	0.3	2.5
Jun	120.8	-16.6	-15.5	29	-0.5	-0.4
Jul	32.3	-1.4	-11.8	1	0.0	0.0
Aug	25.9	-11.7	-18.3	3	0.0	-0.1
Sep	106.9	1.6	-61.8	19	0.0	-1.1
Oct	275.3	-45.4	-81.9	59	-2.7	-4.8
Nov	415.0	-45.3	-64.9	84	-3.8	-5.4
Dec	606.1	19.2	-60.3	84	1.6	-5.1
Total:	4192.9	-273.2	-269.2		-21.4	-13.2

Using this calculation, the weather-adjusted commercial sector loads are:

- For 2000 : 2829.4 + 21.4 = 2850.7 GWh
- For 2005 : 3223.2 + 13.2 = 3236.4 GWh

The 385.6 GWh or 13.5 percent load growth in 5 years is equivalent to 2.6 percent annually.

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RESPONSE TO INFORMATION REQUEST

TO: NSPI

FROM: UARB

Question IR-73: **Appendix G**

a. Page 5, (last line but one): Provide an explanation of why wind assets are assigned 30% to 3CP demand and the remaining plant to energy.

b. Exhibit 7: Why isn't line 17 the same as Appendix A, Table 2, line 5, column 5?

c. Exhibit 9A, line 8: Column 2 shows energy sales of 2,076.1 GW.h, the same value as used by NSPI in the ELIIR-2 hearing (P-883) for the cost of service study in SEB IR-1a. Column 6 shows a coincident demand of 264,400 KW versus the SEB IR-1a value of 247,000 KW. This results in a drop in customer load factor from 95.85% in SEB IR-1a to 89.64% in the present filing. Please provide an explanation for the higher peak demand forecast for this customer in the present filing while leaving energy sales constant between the two cost of service studies.

Response IR-73:

a. Wind energy is a variable resource. In Nova Scotia, the current installed wind generation has generally achieved approximately a 30 percent capacity factor, compared to nameplate rating. NSPI has used these results in the Cost of Service Study to assign 30 percent of wind assets to demand, with the remainder being assigned to energy.

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FROM: UARB

Response IR-73: (cont'd)

b. The difference between Non-Rate Revenue of $9.3 million in Exhibit 7, line 17 and Misc. Revenue of $10.8 million in Table 2, line 5 of Appendix A is associated with $1.5 million in Retail Sales. This Retail Sales figure when netted against Cost of Goods Sold of $1.1 million in Table 2, line 10 of Appendix A results in a credit of $0.4 million that is identified in Exhibit 4, Line 24 of Appendix G.

c. The demand of 264,400 kW for 2007 is based on 2005 actual load shape information that was not available in the P-883 hearing.

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RESPONSE TO INFORMATION REQUEST

TO: NSPI

FROM: UARB

Question IR-74: **Appendix H: Please file the two 2007 proposed ELIIR tariffs.**

Response IR-74: See Attachment 1. This attachment contains the present (2006) and proposed (2007) Extra Large Industrial Two Part Real Time Pricing Tariff (ELI 2P-RTP). The Extra Large Industrial Interrruptible–2 Tariff (ELIIR-2) is not required because both customers eligible for this rate have chosen the ELI 2P-RTP rate. Availability Clause 4 of the ELI 2P-RTP Tariff excludes subsequent qualification for the ELIIR – 2 tariff. UARB Counsel has confirmed the ELIIR-2 Tariff need not be filed.

PRESENT TARIFFS

NOVA SCOTIA POWER INCORPORATED

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)

AVAILABILITY:

1. This tariff is available to customer load formerly served under the Extra Large Industrial Interruptible Rate (ELIIR) and 2P-RTP tariffs, specifically that of StoraEnso Port Hawkesbury Ltd (StoraEnso), and Bowater Mersey Paper Company Ltd (Bowater) other than load served based on the Mersey Agreement.

2. The service voltage shall not be less than 138kV, line to line, at each delivery point. Service is provided at the supply side of the customer's transformation equipment. The customer must own the transformation facilities and no transformer ownership credit is applicable.

3. Customers served under this tariff must accept priority supply interruption, meaning that customers on this tariff are interrupted after GRLF rate customers, and in advance of Interruptible Rider customers.

4. This tariff, as well as the ELIIR-2 tariff, is an alternative replacement tariff for the former ELIIR rate. Once having selected this tariff, the customer is no longer eligible for the ELIIR-2 tariff. Once on this tariff, the customer must commit to taking service under this rate for a minimum of twelve months.

5. This tariff cannot be taken in conjunction with the 1P-RTP rate.

CHARGES:

Customer Charge

The monthly customer charge under this tariff is **$20,700.00** per month, per customer.

Standard Energy Charge

The standard energy charge, before accounting for shifting credits or additional charges, is **5.506¢** per kWh. This charge will apply to all Customer Baseline Load (CBL) energy, regardless of actual consumption.

The energy charge is calculated using NSPI's approved Cost of Service Study (COSS) for the load forecast to be served under the ELIIR-2 and ELI 2P-RTP tariffs combined.

PRESENT TARIFFS

NOVA SCOTIA POWER INCORPORATED

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)

Changes to Rate Components

The customer charge and standard energy charge of this tariff shall be subject to change as approved by the UARB following general rate applications by the Company. For operational purposes, the annual CBL for each customer is reset for each calendar year.

RATE MECHANISM:

The intent of this rate is to create a mechanism enabling customers to gain benefit equal to the benefit created by altering load usage in accordance to hourly pricing signals.

The customer will be billed based on a pre-determined CBL at the Standard Energy Charge, regardless of energy actually taken during a billing period, with credits based on decremental energy taken below the CBL and costs added for energy taken above the CBL.

Incremental and Decremental energy deviations from the CBL will be billed/credited based on the 20-minute ahead marginal cost, as posted on NSPI's RTP website, adjusted according to the schedule stipulated in the Decremental Rebate section of this tariff.

Order in which Rates are Applied

Customers may elect to utilize other rates below the ELI 2P-RTP. In such case, the customer will make written request to the Company, specifying the MW level above which ELI 2P-RTP is to apply. Such changes will only be applied to the next full calendar year of billing.

With respect to the "stacking order" under which customers taking multiple rates are billed, no other rate may be taken above this rate.

DEFINITIONS:

Pricing Period

Each hour of the day is a distinct pricing period, the day starting at the 00:00:01, the first hour ending at 01:00:00. The applicable 20 minute ahead marginal price as posted on the RTP website will apply for each such period.

PRESENT TARIFFS

NOVA SCOTIA POWER INCORPORATED

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)

Customer Baseline Load (CBL)

This is a flat line load shape used for the operational purpose of calculating hourly Incremental Load (IL) and Decremental Load (DL). The CBL level (in MW) is to be calculated as the average hourly demand of the customer's annual forecast total energy requirement (excluding system losses) from the Company. The CBL level will be in effect from January 1st to December 31st of each year, and calculated according to the following formula:

$$\frac{\text{Forecast total energy requirement from the Company}}{\text{(Total number of hours in rate year)} - \text{(Total hours of major scheduled maintenance*)}}$$

*major scheduled maintenance as defined within this tariff

Forecast Total Energy Requirement

Forecast total energy requirement from the Company is determined using the customer's total actual annual energy requirement (excluding system losses) from the Company for the previous 12 month period ending October 31st of each year, subject to any correction for anomalies, as agreed between the Company and the customer. The Company shall provide the customer, on or before the 3rd normal working day of November each year, their previous 12 month energy consumption. On or before the 15th day of November each year, the customer shall provide the Company, in writing, the proposed CBL for the subsequent calendar year. This submission shall include justification for the proposed CBL, including the anticipated dates and durations of the major scheduled maintenance periods.

The parties will diligently, and in good faith, attempt to reach agreement. NSPI will have two weeks in which to accept or reject the proposal in writing, with stated reasons for its rejection. In the event of disagreement, either party may refer the matter to the UARB for resolution, with the request for an expedited decision on the issues between the parties.

Major Scheduled Maintenance Periods

Prior to the start of each calendar year, the customer will provide the Company with information on the timing and duration and magnitude of its anticipated periods of major scheduled maintenance. If the customer and the Company are unable to agree on periods of major scheduled maintenance, the matter will be referred to the UARB.

The customer will also provide the Company with three (3) weeks notice in advance of commencing each scheduled maintenance period, clearly indicating the date and time of the commencement and termination of the maintenance period.

PRESENT TARIFFS

NOVA SCOTIA POWER INCORPORATED

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)

During periods of major scheduled maintenance, the CBL will be reduced accordingly to match the operating conditions of the plant. Such events will be treated as cutouts and will not affect the CBL for the subsequent year.

Marginal Cost (MC)

The MC will be the 20-minute ahead forecast of hourly marginal fuel and variable O&M cost in any hour, excluding any impacts of electricity exports, but including imports when they impact marginal costs. The MC forecast for each hour will be calculated by NSPI based on in-province load requirements. The load level(s) assumed for customers on the ELI 2P-RTP tariff will be the CBL value.

Projections of the anticipated hourly energy price (week ahead and day ahead) will be provided to the customer according to the following schedule:

- By midnight each day, hourly price forecasts for each hour of the next seven days shall be provided to the customer.
- Major changes to the hourly price forecasts will be provided to the customer as soon as possible after they occur.

The actual price used for billing purposes will be the MC, adjusted as stipulated in the Decremental Rebate section of this tariff.

Decremental Load (DL)

This is the hourly energy calculated as the difference between the CBL and the actual demand when actual demand is less than the CBL. When other tariffs are used below ELI 2P-RTP, DL in any hour is limited to the amount available between the lower ELI 2P-RTP threshold and the CBL.

Decremental Rebate (DR)

The Decremental Load (DL) each hour, is multiplied by the MC, or a fraction of the MC as defined below, adjusted for losses, in that hour, and summed to produce the Decremental Rebate (DR).

PRESENT TARIFFS

NOVA SCOTIA POWER INCORPORATED

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)

DL will be credited according to the following schedule:

- The credit for decrements, up to 30 MW for Bowater, and 75 MW for StoraEnso will be at MC as defined by this tariff.
- For the next 10MW for Bowater, and 30 MW for StoraEnso, the credits for decrements will be the greater of:
  - 80% of the MC; and
  - the ELI 2P-RTP Standard Energy Charge
- For further decrements in excess of the above amounts the credit will be the greater of:
  - 60% of MC; and
  - the ELI 2P-RTP Standard Energy Charge

Decremental Load eligible for DR is limited to 20% of the customer's annual CBL energy for the operating year. Once this limit is reached for the year, no further shifting rebates will be applied. Incremental load taken above the CBL will continue to be charged using incremental charges.

Incremental Load (IL)

This is the hourly energy calculated as the difference between the actual load and the CBL whenever the actual load exceeds the CBL.

Incremental Charges (IC)

The Incremental Load (IL) each hour, multiplied by the MC, adjusted for losses, in that hour, and summed to produce the Incremental Charge (IC).

Losses Adjustment:

A 2% adjustment to metered energy will be applied to determine requirement including system losses. This Loss adjustment will be applied in determining the IL and the DL.

Incremental Export Benefit Credit

Customers who take service under this rate will be given an Incremental Export Benefit Credit (IEBC) defined as follows:

IEBC = (Lesser of Customer's Monthly DL or NSPI's Actual Exports calculated monthly) x NSPI's Average Export Margin in the month

However, in no case shall the total annual IEBC exceed 15% of NSPI's total actual annual export margin.

PRESENT TARIFFS

NOVA SCOTIA POWER INCORPORATED

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)

CBL Base Cost (CBL_{bc})

The CBL_{bc} is the monthly cost of energy under the CBL. It is calculated according to the following formula:

Monthly CBL_{bc} = (Standard Energy Charge x Annual energy under CBL) / 12

Bill Calculation:

At the end of each month:

Total Bill = CBL_{bc} + Incremental Charges – Decremental Rebates - Incremental Export Benefit Credit

Applicable Energy Charges, rebates, penalties, and adjustments will be calculated by the Company and indicated on the customer's monthly bill.

SPECIAL CONDITIONS:

Modification of Existing CBL

If an existing ELI 2P-RTP customer undertakes significant physical plant modification, (as signified by a specific capital expenditure above and beyond normal annual capital spending) or other material change (such as a change in product line) the Company or the customer may propose suitable adjustments to the CBL.

In the event of significant load reductions that have not been reflected in the CBL (such as plant shut downs, labour issues or any other reason), the CBL will be lowered accordingly or by agreement the rate may be suspended altogether until the customer returns to normal operations.

If the customer and NSPI cannot agree on any of the above modifications to the CBL the matter will be submitted to the UARB for adjudication.

Use of Self-Generation

Unless existing customer-owned generation is to be retired, for purposes of determining forecast CBL energy, the continued use of such generation is to be appropriately accounted for in the customer's CBL energy requirement. Such self-generation shall continue to be used in a normal fashion. Beyond this, it is expected that customers will use their own existing generation in whatever fashion they see as appropriate.

PRESENT TARIFFS

NOVA SCOTIA POWER INCORPORATED

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)

Supply Interruption:

This tariff is interruptible for supply reasons. The customer will reduce its available interruptible system load by the amount requested by NSPI within ten (10) minutes of such request by the Company. Following interruption, service may only be restored by the customer with the approval of the Company.

The customer will make available suitable contact telephone numbers of a person or persons who are able to reduce the required load within ten minutes.

Supply Interruption calls will be made to all customers taking energy under this tariff and the ELIIR-2 tariff, on an equitable and transparent basis.

Customers are expected to comply with all calls for interruption. Failure to comply in whole or in part with a request to interrupt load will result in penalty charges. The penalty charge for each failure shall be twice the cost of the appropriate billing as per this rate, for the total load subscribed under this rate. Should the customer fail to respond during subsequent calls within the same month, the same penalties will apply for each failure to interrupt.

Supply interruptions will be limited to 16 hours per day and 5 days per week to a maximum of 30% of the hours per month and 15% of the hours per year.

Conversion of Interruptible Load to Firm

Should a customer under this rate desire to be served under any applicable firm service rate, a five (5) year advance written notice must be given to the company so as to ensure adequate capacity availability. Requests for a conversion to firm service will be treated in the same manner as all other requests for firm service received by the Company. The Company may, however, permit an earlier conversion. In the event that the Customer desires to return to Interruptible service in the future, the customer may convert to interruptible service following two (2) years service under the firm rate schedule. The Company may permit an earlier conversion from firm to interruptible service.

Order of Supply Interruption:

In the event of an interruption required in order to avoid shortfalls in electricity supply, rate classes will be called upon to provide capacity to NSPI in the following order:

1. Generation Replacement and Load Following (GRLF) Rate;
2. Extra Large Industrial Interruptible Rate-2, and ELI 2P-RTP Rate
3. Interruptible Rider to the Large Industrial Rate.

PRESENT TARIFFS

NOVA SCOTIA POWER INCORPORATED

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)

In recognition that this tariff will receive interruption calls in advance of Interruptible Rider customers, the ELI 2P-RTP tariff will receive an interruptible credit (as determined in NSPI's COSS) that is 15% higher than the credit provided to Interruptible Rider customers for supply interruptibility.

Suspension of 2P-RTP Billing Mechanism

The Rate will be suspended during any period in which the customer's load is reduced due to a disruption in the supply of electricity to the customer because of an interruption call or NSPI system conditions. The suspension shall apply until such time as the customer has received permission from the Company to resume operations.

The energy lost under the CBL will be estimated by the customer for the specific period from the start of the disruption to the time that NSPI notifies the customer that it can resume operation. An amount equivalent to the estimated lost energy, taken above the CBL immediately following the disruption, will be charged at the Standard Energy Charge rather than at IC.

If the customer and NSPI cannot agree on the amount of energy lost, the matter will be submitted to the UARB for adjudication.

Separate Service Agreement

The Company reserves the right to have a separate service agreement if, in the opinion of the Company, issues not specifically set out herein must be addressed for the ongoing benefit of the Company and its customers.

Maintain System Integrity

The customer will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. Specific requirements shall be stipulated by way of a separate operating agreement.

In assessing issues that might unduly affect the integrity of the power supply system, the following would be considered: reliability, harmonic Voltage and current levels, Voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

Sole Supplier

NSPI reserves the right to be the sole supplier of all external power requirements (i.e. excluding self-generation) for customers taking service under this tariff.

PRESENT TARIFFS

NOVA SCOTIA POWER INCORPORATED

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)

Power Factor Correction

Under normal operating conditions, an average power factor over the entire billing period, calculated for kWh consumed and lagging kVAR-h, as recorded, of not less than 90% lagging for the total customer load (under all rates) shall be maintained, or the following adjustment factors (Constant) will be applied to the Energy Charge in effect:

Power Factor	Constant	Power Factor	Constant
90-100%	1.0000	65-70%	1.1255
80-90%	1.0230	60-65%	1.1785
75-80%	1.0500	55-60%	1.2455
70-75%	1.0835	50-55%	1.3335

Metering Costs

Metering will normally be at the low side of the transformer and, for billing purposes, meter readings will be increased by 1.75%. Should the customer's requirements make it necessary for the Company to provide primary metering, the customer will be required to make a capital contribution equal to the additional cost of primary metering as opposed to the cost of secondary metering. The costs of any special metering or communication systems required by the customer to take service under this tariff shall be paid for by the customer as a capital contribution.

Special Consideration for Customer Purchasing Own Fuel

At the customer's option, the customer and NSPI shall use best efforts to enter into physical and/or financial purchases or hedges, the settlement of which shall be credited or charged to the customer's account. It is understood that the execution and settlement of these arrangements shall, under no circumstances, affect the rates or revenue requirements charged to the Company's other customers.

PROPOSED TARIFFS

NOVA SCOTIA POWER INCORPORATED

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)

AVAILABILITY:

1. This tariff is available to customer load formerly served under the Extra Large Industrial Interruptible Rate (ELIIR) and 2P-RTP tariffs, specifically that of StoraEnso Port Hawkesbury Ltd (StoraEnso), and Bowater Mersey Paper Company Ltd (Bowater) other than load served based on the Mersey Agreement.

2. The service voltage shall not be less than 138kV, line to line, at each delivery point. Service is provided at the supply side of the customer's transformation equipment. The customer must own the transformation facilities and no transformer ownership credit is applicable.

3. Customers served under this tariff must accept priority supply interruption, meaning that customers on this tariff are interrupted after GRLF rate customers, and in advance of Interruptible Rider customers.

4. This tariff, as well as the ELIIR-2 tariff, is an alternative replacement tariff for the former ELIIR rate. Once having selected this tariff, the customer is no longer eligible for the ELIIR-2 tariff. Once on this tariff, the customer must commit to taking service under this rate for a minimum of twelve months.

5. This tariff cannot be taken in conjunction with the 1P-RTP rate.

CHARGES:

Customer Charge

The monthly customer charge under this tariff is **$20,700.00** per month, per customer.

Standard Energy Charge

The standard energy charge, before accounting for shifting credits or additional charges, is **5.993¢** per kWh. This charge will apply to all Customer Baseline Load (CBL) energy, regardless of actual consumption.

The energy charge is calculated using NSPI's approved Cost of Service Study (COSS) for the load forecast to be served under the ELIIR-2 and ELI 2P-RTP tariffs combined.

NOVA SCOTIA POWER INCORPORATED

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)

Changes to Rate Components

The customer charge and standard energy charge of this tariff shall be subject to change as approved by the UARB following general rate applications by the Company. For operational purposes, the annual CBL for each customer is reset for each calendar year.

RATE MECHANISM:

The intent of this rate is to create a mechanism enabling customers to gain benefit equal to the benefit created by altering load usage in accordance to hourly pricing signals.

The customer will be billed based on a pre-determined CBL at the Standard Energy Charge, regardless of energy actually taken during a billing period, with credits based on decremental energy taken below the CBL and costs added for energy taken above the CBL.

Incremental and Decremental energy deviations from the CBL will be billed/credited based on the 20-minute ahead marginal cost, as posted on NSPI's RTP website, adjusted according to the schedule stipulated in the Decremental Rebate section of this tariff.

Order in which Rates are Applied

Customers may elect to utilize other rates below the ELI 2P-RTP. In such case, the customer will make written request to the Company, specifying the MW level above which ELI 2P-RTP is to apply. Such changes will only be applied to the next full calendar year of billing.

With respect to the "stacking order" under which customers taking multiple rates are billed, no other rate may be taken above this rate.

DEFINITIONS:

Pricing Period

Each hour of the day is a distinct pricing period, the day starting at the 00:00:01, the first hour ending at 01:00:00. The applicable 20 minute ahead marginal price as posted on the RTP website will apply for each such period.

PROPOSED TARIFFS

NOVA SCOTIA POWER INCORPORATED

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)

Customer Baseline Load (CBL)

This is a flat line load shape used for the operational purpose of calculating hourly Incremental Load (IL) and Decremental Load (DL). The CBL level (in MW) is to be calculated as the average hourly demand of the customer's annual forecast total energy requirement (excluding system losses) from the Company. The CBL level will be in effect from January 1st to December 31st of each year, and calculated according to the following formula:

$$\frac{\text{Forecast total energy requirement from the Company}}{\text{(Total number of hours in rate year)} - \text{(Total hours of major scheduled maintenance*)}}$$

*major scheduled maintenance as defined within this tariff

Forecast Total Energy Requirement

Forecast total energy requirement from the Company is determined using the customer's total actual annual energy requirement (excluding system losses) from the Company for the previous 12 month period ending October 31st of each year, subject to any correction for anomalies, as agreed between the Company and the customer. The Company shall provide the customer, on or before the 3rd normal working day of November each year, their previous 12 month energy consumption. On or before the 15th day of November each year, the customer shall provide the Company, in writing, the proposed CBL for the subsequent calendar year. This submission shall include justification for the proposed CBL, including the anticipated dates and durations of the major scheduled maintenance periods.

The parties will diligently, and in good faith, attempt to reach agreement. NSPI will have two weeks in which to accept or reject the proposal in writing, with stated reasons for its rejection. In the event of disagreement, either party may refer the matter to the UARB for resolution, with the request for an expedited decision on the issues between the parties.

Major Scheduled Maintenance Periods

Prior to the start of each calendar year, the customer will provide the Company with information on the timing and duration and magnitude of its anticipated periods of major scheduled maintenance. If the customer and the Company are unable to agree on periods of major scheduled maintenance, the matter will be referred to the UARB.

The customer will also provide the Company with three (3) weeks notice in advance of commencing each scheduled maintenance period, clearly indicating the date and time of the commencement and termination of the maintenance period.

NOVA SCOTIA POWER INCORPORATED

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)

During periods of major scheduled maintenance, the CBL will be reduced accordingly to match the operating conditions of the plant. Such events will be treated as cutouts and will not affect the CBL for the subsequent year.

Marginal Cost (MC)

The MC will be the 20-minute ahead forecast of hourly marginal fuel and variable O&M cost in any hour, excluding any impacts of electricity exports, but including imports when they impact marginal costs. The MC forecast for each hour will be calculated by NSPI based on in-province load requirements. The load level(s) assumed for customers on the ELI 2P-RTP tariff will be the CBL value.

Projections of the anticipated hourly energy price (week ahead and day ahead) will be provided to the customer according to the following schedule:

- By midnight each day, hourly price forecasts for each hour of the next seven days shall be provided to the customer.
- Major changes to the hourly price forecasts will be provided to the customer as soon as possible after they occur.

The actual price used for billing purposes will be the MC, adjusted as stipulated in the Decremental Rebate section of this tariff.

Decremental Load (DL)

This is the hourly energy calculated as the difference between the CBL and the actual demand when actual demand is less than the CBL. When other tariffs are used below ELI 2P-RTP, DL in any hour is limited to the amount available between the lower ELI 2P-RTP threshold and the CBL.

Decremental Rebate (DR)

The Decremental Load (DL) each hour, is multiplied by the MC, or a fraction of the MC as defined below, adjusted for losses, in that hour, and summed to produce the Decremental Rebate (DR).

NOVA SCOTIA POWER INCORPORATED

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)

DL will be credited according to the following schedule:

- The credit for decrements, up to 30 MW for Bowater, and 75 MW for StoraEnso will be at MC as defined by this tariff.
- For the next 10MW for Bowater, and 30 MW for StoraEnso, the credits for decrements will be the greater of:
  - 80% of the MC; and
  - the ELI 2P-RTP Standard Energy Charge
- For further decrements in excess of the above amounts the credit will be the greater of:
  - 60% of MC; and
  - the ELI 2P-RTP Standard Energy Charge

Decremental Load eligible for DR is limited to 20% of the customer's annual CBL energy for the operating year. Once this limit is reached for the year, no further shifting rebates will be applied. Incremental load taken above the CBL will continue to be charged using incremental charges.

Incremental Load (IL)

This is the hourly energy calculated as the difference between the actual load and the CBL whenever the actual load exceeds the CBL.

Incremental Charges (IC)

The Incremental Load (IL) each hour, multiplied by the MC, adjusted for losses, in that hour, and summed to produce the Incremental Charge (IC).

Losses Adjustment:

A 2% adjustment to metered energy will be applied to determine requirement including system losses. This Loss adjustment will be applied in determining the IL and the DL.

Incremental Export Benefit Credit

Customers who take service under this rate will be given an Incremental Export Benefit Credit (IEBC) defined as follows:

IEBC = (Lesser of Customer's Monthly DL or NSPI's Actual Exports calculated monthly) x NSPI's Average Export Margin in the month

However, in no case shall the total annual IEBC exceed 15% of NSPI's total actual annual export margin.

NOVA SCOTIA POWER INCORPORATED

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)

CBL Base Cost (CBL_{bc})

The CBL_{bc} is the monthly cost of energy under the CBL. It is calculated according to the following formula:

Monthly CBL_{bc} = (Standard Energy Charge x Annual energy under CBL) / 12

Bill Calculation:

At the end of each month:

Total Bill = CBL_{bc} + Incremental Charges – Decremental Rebates - Incremental Export Benefit Credit

Applicable Energy Charges, rebates, penalties, and adjustments will be calculated by the Company and indicated on the customer's monthly bill.

SPECIAL CONDITIONS:

Modification of Existing CBL

If an existing ELI 2P-RTP customer undertakes significant physical plant modification, (as signified by a specific capital expenditure above and beyond normal annual capital spending) or other material change (such as a change in product line) the Company or the customer may propose suitable adjustments to the CBL.

In the event of significant load reductions that have not been reflected in the CBL (such as plant shut downs, labour issues or any other reason), the CBL will be lowered accordingly or by agreement the rate may be suspended altogether until the customer returns to normal operations.

If the customer and NSPI cannot agree on any of the above modifications to the CBL the matter will be submitted to the UARB for adjudication.

Use of Self-Generation

Unless existing customer-owned generation is to be retired, for purposes of determining forecast CBL energy, the continued use of such generation is to be appropriately accounted for in the customer's CBL energy requirement. Such self-generation shall continue to be used in a normal fashion. Beyond this, it is expected that customers will use their own existing generation in whatever fashion they see as appropriate.

PROPOSED TARIFFS

NOVA SCOTIA POWER INCORPORATED

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)

Supply Interruption:

This tariff is interruptible for supply reasons. The customer will reduce its available interruptible system load by the amount requested by NSPI within ten (10) minutes of such request by the Company. Following interruption, service may only be restored by the customer with the approval of the Company.

The customer will make available suitable contact telephone numbers of a person or persons who are able to reduce the required load within ten minutes.

Supply Interruption calls will be made to all customers taking energy under this tariff and the ELIIR-2 tariff, on an equitable and transparent basis.

Customers are expected to comply with all calls for interruption. Failure to comply in whole or in part with a request to interrupt load will result in penalty charges. The penalty charge for each failure shall be twice the cost of the appropriate billing as per this rate, for the total load subscribed under this rate. Should the customer fail to respond during subsequent calls within the same month, the same penalties will apply for each failure to interrupt.

Supply interruptions will be limited to 16 hours per day and 5 days per week to a maximum of 30% of the hours per month and 15% of the hours per year.

Conversion of Interruptible Load to Firm

Should a customer under this rate desire to be served under any applicable firm service rate, a five (5) year advance written notice must be given to the company so as to ensure adequate capacity availability. Requests for a conversion to firm service will be treated in the same manner as all other requests for firm service received by the Company. The Company may, however, permit an earlier conversion. In the event that the Customer desires to return to Interruptible service in the future, the customer may convert to interruptible service following two (2) years service under the firm rate schedule. The Company may permit an earlier conversion from firm to interruptible service.

Order of Supply Interruption:

In the event of an interruption required in order to avoid shortfalls in electricity supply, rate classes will be called upon to provide capacity to NSPI in the following order:

1. Generation Replacement and Load Following (GRLF) Rate;
2. Extra Large Industrial Interruptible Rate-2, and ELI 2P-RTP Rate
3. Interruptible Rider to the Large Industrial Rate.

NOVA SCOTIA POWER INCORPORATED

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)

In recognition that this tariff will receive interruption calls in advance of Interruptible Rider customers, the ELI 2P-RTP tariff will receive an interruptible credit (as determined in NSPI's COSS) that is 15% higher than the credit provided to Interruptible Rider customers for supply interruptibility.

Suspension of 2P-RTP Billing Mechanism

The Rate will be suspended during any period in which the customer's load is reduced due to a disruption in the supply of electricity to the customer because of an interruption call or NSPI system conditions. The suspension shall apply until such time as the customer has received permission from the Company to resume operations.

The energy lost under the CBL will be estimated by the customer for the specific period from the start of the disruption to the time that NSPI notifies the customer that it can resume operation. An amount equivalent to the estimated lost energy, taken above the CBL immediately following the disruption, will be charged at the Standard Energy Charge rather than at IC.

If the customer and NSPI cannot agree on the amount of energy lost, the matter will be submitted to the UARB for adjudication.

Separate Service Agreement

The Company reserves the right to have a separate service agreement if, in the opinion of the Company, issues not specifically set out herein must be addressed for the ongoing benefit of the Company and its customers.

Maintain System Integrity

The customer will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. Specific requirements shall be stipulated by way of a separate operating agreement.

In assessing issues that might unduly affect the integrity of the power supply system, the following would be considered: reliability, harmonic Voltage and current levels, Voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

Sole Supplier

NSPI reserves the right to be the sole supplier of all external power requirements (i.e. excluding self-generation) for customers taking service under this tariff.

NOVA SCOTIA POWER INCORPORATED

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)

Power Factor Correction

Under normal operating conditions, an average power factor over the entire billing period, calculated for kWh consumed and lagging kVAR-h, as recorded, of not less than 90% lagging for the total customer load (under all rates) shall be maintained, or the following adjustment factors (Constant) will be applied to the Energy Charge in effect:

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Metering will normally be at the low side of the transformer and, for billing purposes, meter readings will be increased by 1.75%. Should the customer's requirements make it necessary for the Company to provide primary metering, the customer will be required to make a capital contribution equal to the additional cost of primary metering as opposed to the cost of secondary metering. The costs of any special metering or communication systems required by the customer to take service under this tariff shall be paid for by the customer as a capital contribution.

Special Consideration for Customer Purchasing Own Fuel

At the customer's option, the customer and NSPI shall use best efforts to enter into physical and/or financial purchases or hedges, the settlement of which shall be credited or charged to the customer's account. It is understood that the execution and settlement of these arrangements shall, under no circumstances, affect the rates or revenue requirements charged to the Company's other customers.

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act,* R.S.N.S. 1989, c.380 as amended

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for Approval of Certain Revisions to its Rates, Charges and Regulations

RESPONSE TO INFORMATION REQUEST

TO: NSPI

FROM: UARB

Question IR-75: **Provide a copy of the latest Hydro Quebec report: "Comparison of Electricity Prices in Major North American Cities", showing rates effective April 1, 2006.**

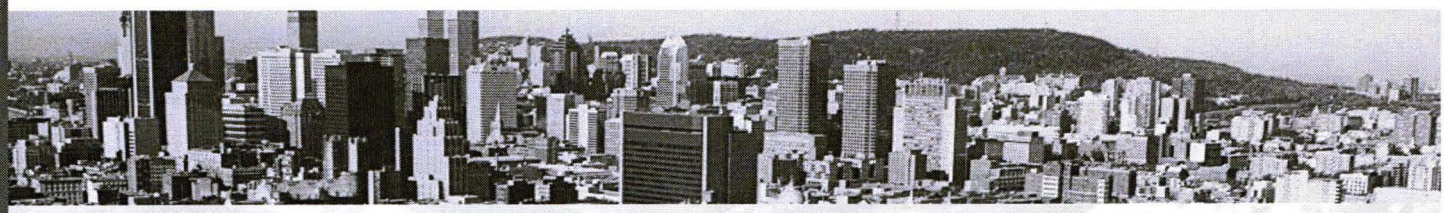
Response IR-75: Please refer to Attachment 1.

2006









Comparison of Electricity Prices in Major North American Cities

Rates in effect April 1, 2006

Hydro Québec

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Introduction

Every year, Hydro-Québec compares the monthly electricity bills of Québec customers in the residential, commercial, institutional and industrial sectors with those of customers of the various utilities serving 20 major North American cities.

This report details the principal conclusions of this comparative analysis of prices in effect on April 1, 2006. There are three sections. The first describes the methodology used to estimate electricity bills. The second examines the highlights of the seven consumption levels analyzed, with the help of charts. Finally, the third section 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, applicable taxes, as well as a profile of the utilities in the study are the subject of separate appendices.

Major North American Cities

Average Prices for Residential Customers[1]
(in ¢/kWh)[2]



1) For a monthly consumption of 1 000 kWh; rates in effect April 1, 2006.
2) In Canadian dollars.

Major North American Cities

Average Prices for Large Power Customers[1]
(in ¢/kWh)[2]



1) For a monthly consumption of 3,060,000 kWh and a power demand of 5,000 kW; rates in effect April 1, 2006.
2) In Canadian dollars.

Methodology

In addition to Hydro-Québec, this comparative analysis of electricity prices across North America includes 21 utilities: 11 serving the principal cities in the nine other Canadian provinces, and 10 utilities in as many American states. The results are based, in part, on a survey to which 15 utilities responded, and in part on estimates of bills calculated by Hydro-Québec and validated, for the most part, by the utility concerned.

- ***Period covered***
  Monthly bills have been calculated based on rates in effect on April 1, 2006. The most recent rate adjustments applied by the utilities in the study between April 1, 2005 and April 1, 2006 are indicated 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.

- ***Taxes***
  With the exception of the bills presented in Table 2, all the calculations exclude taxes. Appendix C lists taxes applicable on April 1, 2006 by customer category; those which may be partially or fully reimbursed are indicated.

- ***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 situation***
  Electricity distributors sometimes offer different rates in the different cities they serve. As well, taxes may vary from one region to another (this, however, is not the case in Québec, where, with the exception of territories north of the 53rd parallel, taxes and rates are applied uniformly). For 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 at April 1, 2006.

- ***Time-of-use rates***
  The rates offered by some utilities vary depending on the season and/or time when energy is consumed. In the United States, for example, several 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 needs. Thus, for some utilities, April 1 may correspond to a period in the year when the price is high, whereas for others it corresponds to a period when the price is low. An annual average price has thus been calculated in the case of utilities with time-of-use rates. Appendix B lists the utilities that apply time-of-use rates for various consumption levels.

- ***Adjustment clauses***
  The rates of some distributors include adjustment clauses which allow them to adjust their customers' electricity bills according to changes in different variables. Since these adjustments may be applied monthly, or over a longer period, the electricity bills issued by a given distributor may have varied between April 1, 2005 and April 1, 2006, even through base rates remained the same. Appendix B lists the adjustment clauses taken into account when calculating bills.

- ***Exchange rate***
  The exchange rate used to translate bills in U.S. dollars into Canadian dollars is $0.8533 (CA$1 = US$0.8533), the rate in effect at noon on April 3, 2006. The Canadian dollar has thus appreciated by about 3.5% relative to the U.S. dollar since April 1, 2005.

Highlights

The document entitled "Distribution Tariff" sets out Hydro-Québec's rates, as approved by the *Régie de l'énergie* (the Québec Energy Board) in accordance with Decision D-2006-46. Two types of rates are in effect: domestic rates, for residential customers, and general rates, for commercial, institutional and industrial customers. The last three customer categories are grouped according to their minimum billing demand: small power (less than 100 kW), medium power (between 100 and 5,000 kW), and large power (5,000 kW or more). For comparison purposes, the electricity bills of the utilities in the study have been analyzed according to these customer categories.

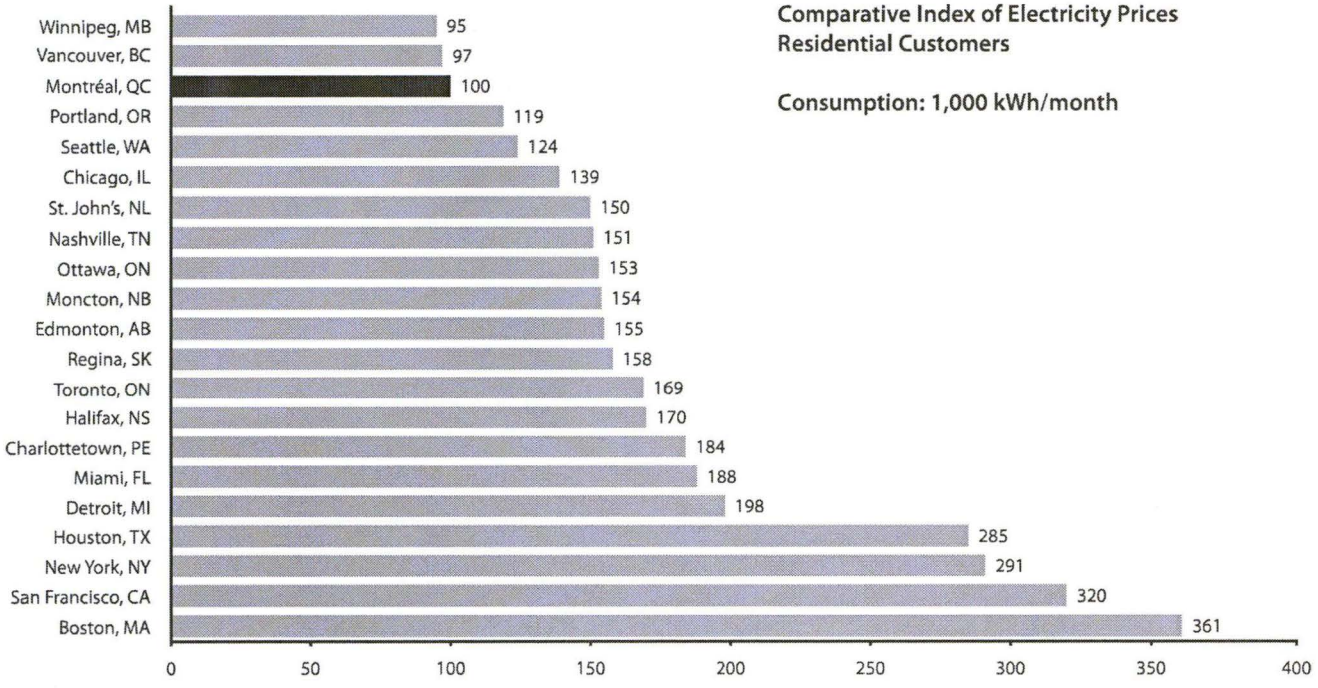
Residential Customers

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 kWh, Montréal currently ranks *third*, behind Winnipeg and Vancouver. It held third place from 1990 to 1998, and second place from 1999 to 2005. Chart 1 illustrates the results of this comparison.

Chart 1

Comparative Index of Electricity Prices
Residential Customers

Consumption: 1,000 kWh/month



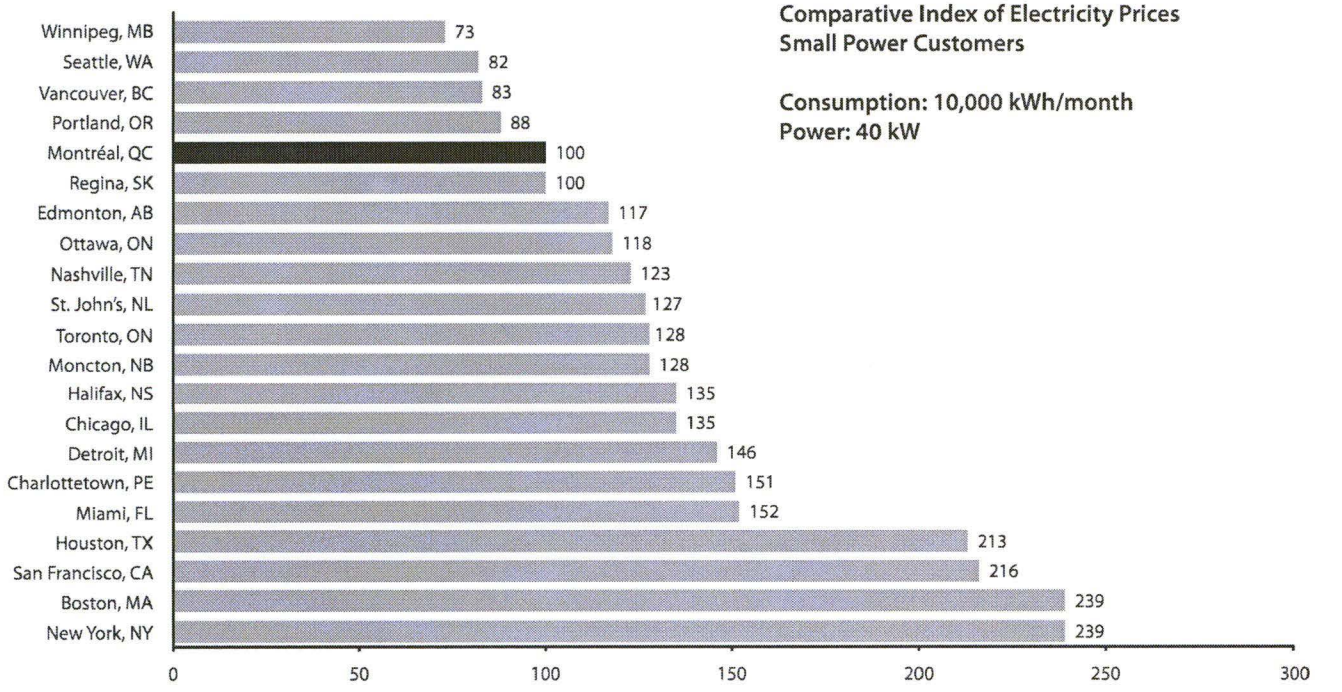
Hydro-Québec = 100

Monthly billings (excluding taxes)
Rates in effect April 1, 2006

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 kW. Montréal is now in *fifth* place. Chart 2 shows the comparative index of electricity prices.

Chart 2



Hydro-Québec = 100

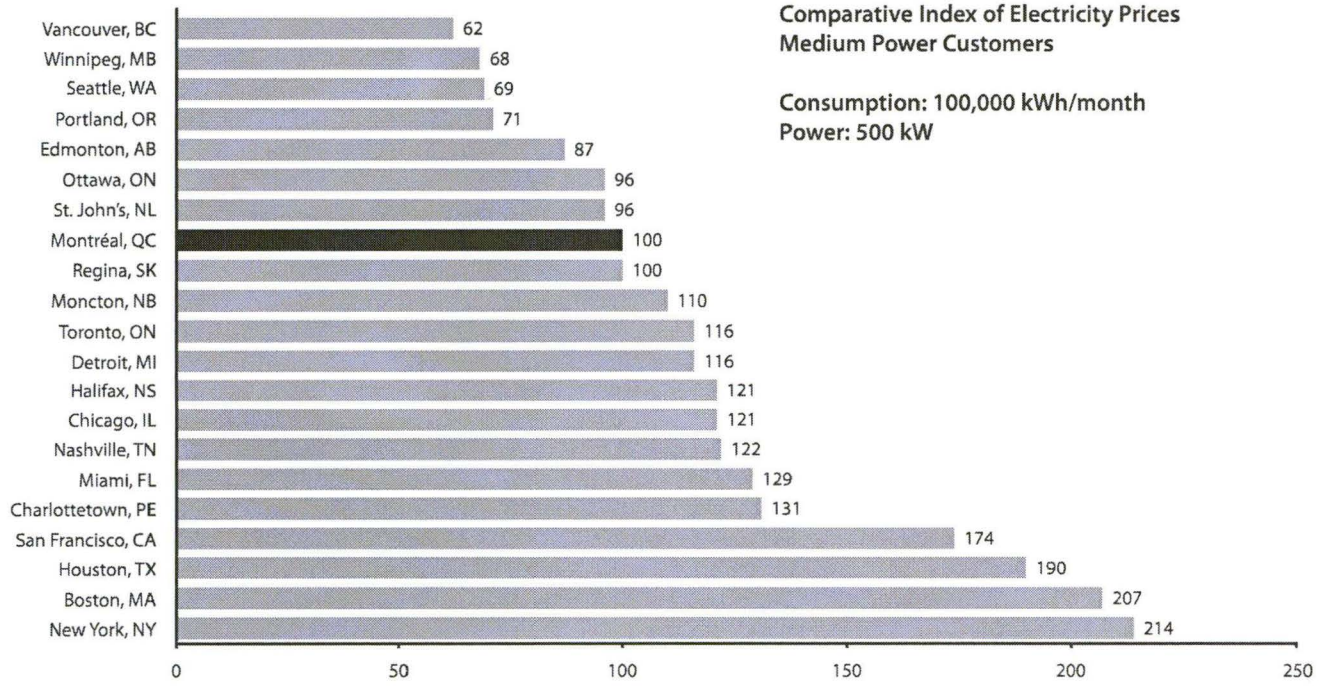
Monthly billings (excluding taxes)
Rates in effect April 1, 2006

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 observed in the other major North American cities. Charts 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 has gone from seventh to *eighth* rank.

Chart 3

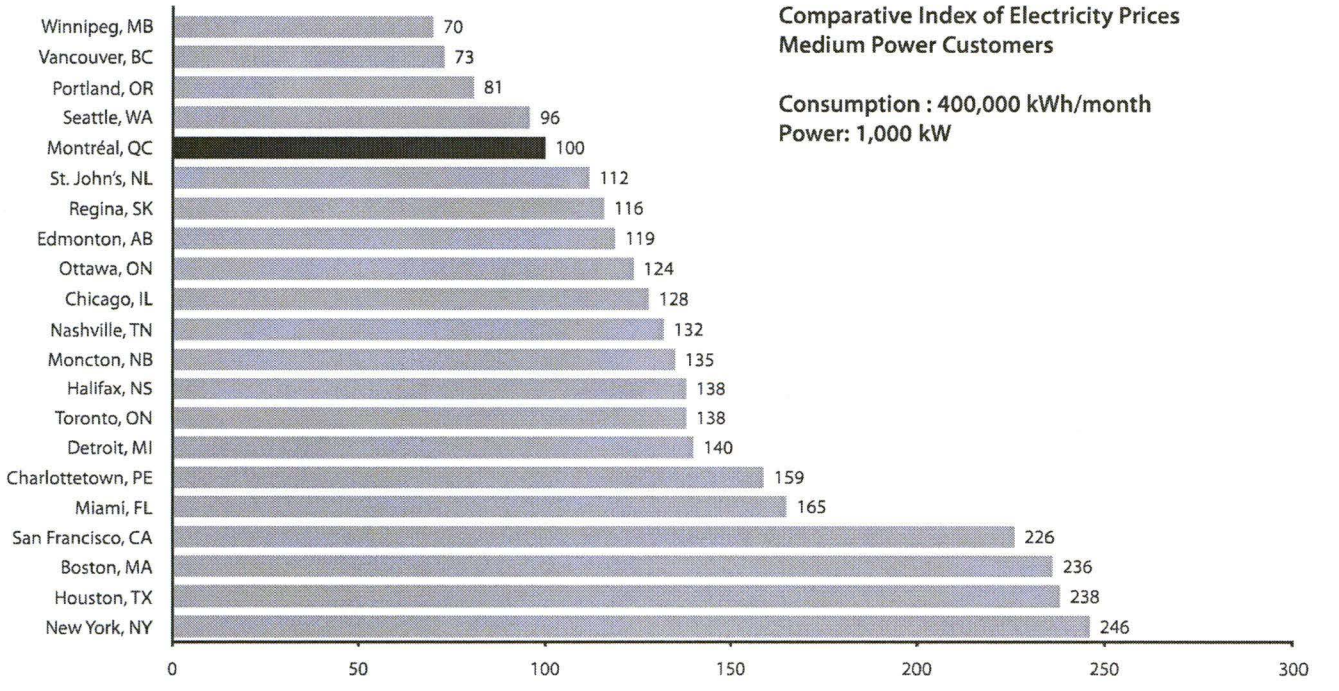


Hydro-Québec = 100

Monthly billings (excluding taxes)
Rates in effect April 1, 2006

For customers with a monthly consumption of 400,000 kWh and a power demand of 1,000 kW, Montréal is in *fifth* place.

Chart 4

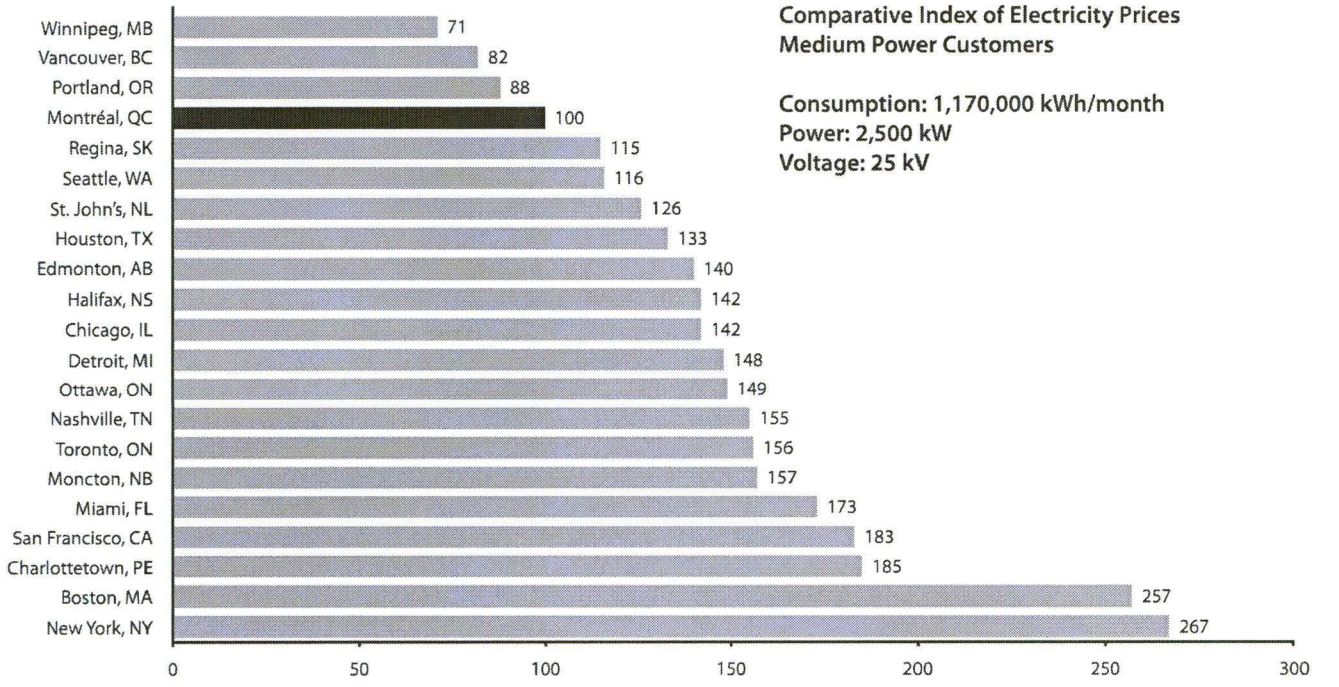


Hydro-Québec = 100

Monthly billings (excluding taxes)
Rates in effect April 1, 2006

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 *fourth* place.

Chart 5



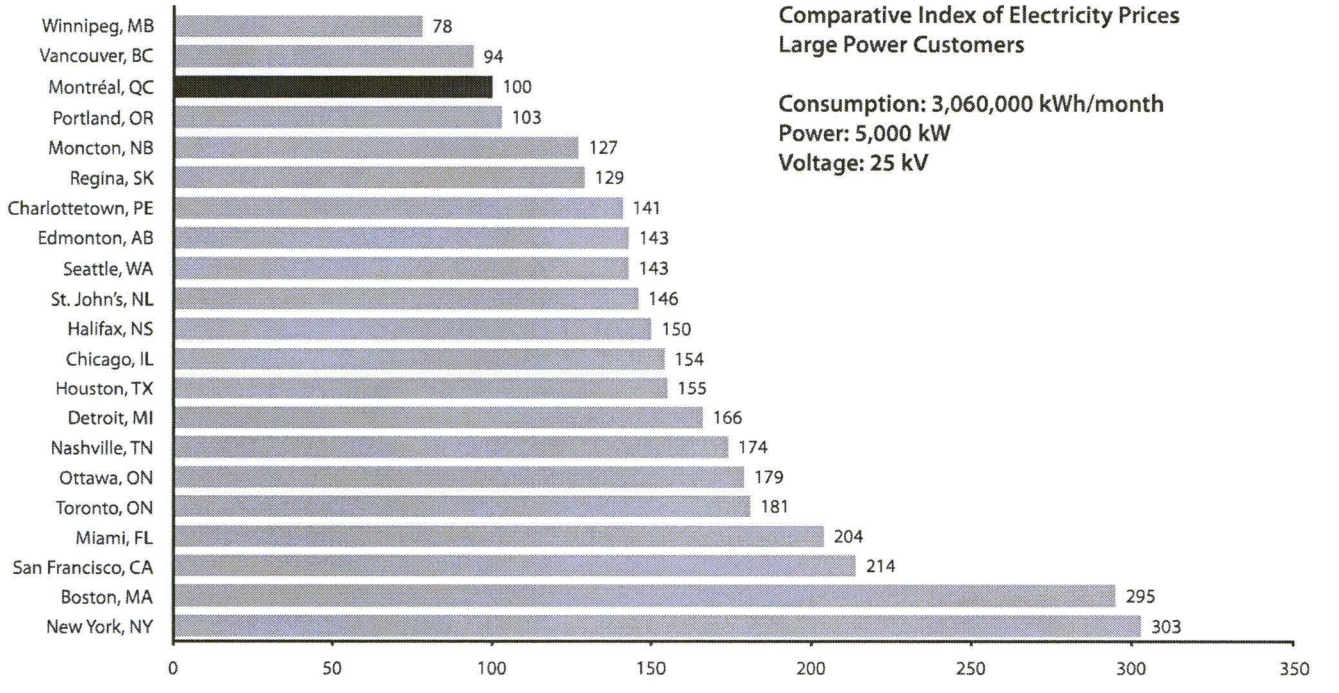
Hydro-Québec = 100

Monthly billings (excluding taxes)
Rates in effect April 1, 2006

Large power customers (5,000 kW or more)

Chart 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. Once again, Montréal is in *third* place.

Chart 6

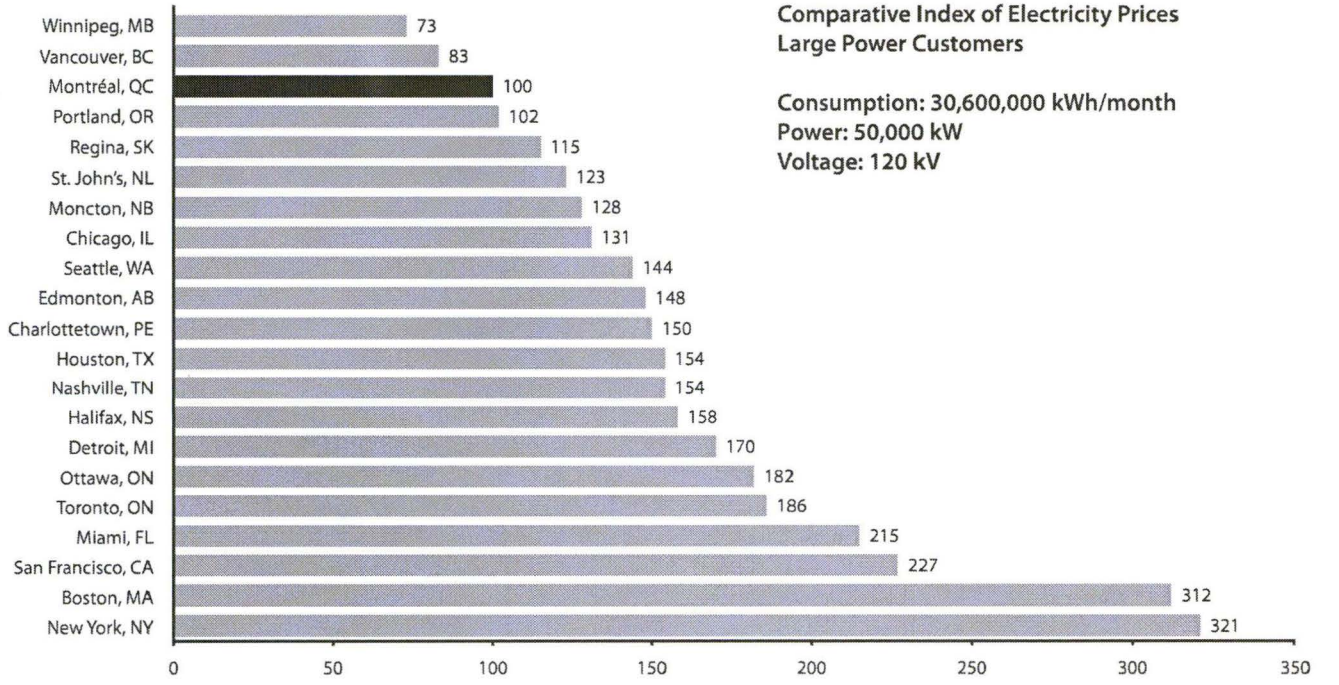


Hydro-Québec = 100

Monthly billings (excluding taxes)
Rates in effect April 1, 2006

For industrial customers with a power demand of 50,000 kW and a load factor of 85%, Montréal remains in *third* place.

Chart 7



Hydro-Québec = 100

Monthly billings (excluding taxes)
Rates in effect April 1, 2006



Summary Tables
(excluding taxes)

Monthly Billings

Average Prices

Comparative Index

Monthly Billings on April 1, 2006

(in CA$)

Summary Table (excluding taxes)

	Residential	General					
		Small Power	Medium Power			Large Power	
Power		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	66.00	842.33	10,490.00	27,106.00	65,276.25	137,998.50	1,304,685.00
Charlottetown, PE	121.45	1,275.15	13,704.95	42,964.95	120,617.95	195,130.00	1,951,300.00
Edmonton, AB[3]	102.18	983.70	9,102.21	32,190.37	91,078.71	197,061.80	1,930,014.87
Halifax, NS	112.13	1,133.60	12,650.00	37,460.00	92,614.62	206,648.62	2,066,503.68
Moncton, NB	101.44	1,077.54	11,555.94	36,470.94	102,518.94	174,768.30	1,667,120.00
Ottawa, ON[4]	100.87	995.33	10,059.90	33,651.07	97,238.92	247,337.74	2,368,293.79
Regina, SK	104.31	842.70	10,542.04	31,323.34	75,087.26	177,962.48	1,499,056.90
St. John's, NL[5]	98.77	1,069.01	10,114.56	30,336.51	82,384.54	201,762.89	1,599,820.00
Toronto, ON	111.39	1,076.61	12,118.68	37,522.06	101,520.06	249,638.32	2,427,672.99
Vancouver, BC	64.13	701.75	6,534.99	19,684.99	53,435.73	130,136.19	1,078,650.00
Winnipeg, MB	63.02	616.26	7,097.57	19,047.17	46,416.04	107,199.81	953,487.43
American Cities							
Boston, MA	238.19	2,009.39	21,728.60	63,949.02	167,558.26	407,160.88	4,069,108.38
Chicago, IL[6]	91.65	1,137.56	12,693.04	34,620.69	92,963.28	212,041.39	1,705,887.73
Detroit, MI[6]	130.39	1,229.73	12,204.20	37,819.67	96,679.20	228,425.37	2,213,616.85
Houston, TX[6]	188.35	1,796.10	19,924.87	64,454.99	86,980.64	213,291.68	2,005,727.14
Miami, FL[6]	124.09	1,276.49	13,539.96	44,664.33	112,998.70	281,391.82	2,810,054.83
Nashville, TN	99.47	1,038.03	12,783.78	35,731.92	101,088.35	240,213.98	2,010,818.68
New York, NY[6]	192.32	2,013.68	22,438.80	66,582.82	174,293.55	418,330.42	4,183,304.24
Portland, OR	78.52	744.40	7,498.53	22,016.91	57,634.50	142,482.50	1,332,797.86
San Francisco, CA[6]	210.97	1,821.55	18,266.07	61,296.21	119,645.65	295,562.74	2,955,690.39
Seattle, WA	81.95	686.73	7,248.20	25,962.67	75,743.18	197,382.18	1,884,978.54
AVERAGE	**118.17**	**1,160.36**	**12,490.33**	**38,326.51**	**95,894.02**	**221,996.55**	**2,096,123.30**

1) Supply voltage of 25 kV.
2) Supply voltage of 120 kV.
3) Bills corresponding to consumption levels of 250,000 kWh/year or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Bills corresponding to consumption levels not eligible for the Regulated Price Plan have been estimated by Hydro-Québec.
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.
6) These bills have been estimated by Hydro-Québec and may differ from actual bills.

Average Prices on April 1, 2006

(in ¢/kWh)[1]

Summary Table (excluding taxes)

	Residential	General					
		Small Power	Medium Power			Large Power	
Power		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	6.60	8.42	10.49	6.78	5.58	4.51	4.26
Charlottetown, PE	12.15	12.75	13.70	10.74	10.31	6.38	6.38
Edmonton, AB[4]	10.22	9.84	9.10	8.05	7.78	6.44	6.31
Halifax, NS	11.21	11.34	12.65	9.37	7.92	6.75	6.75
Moncton, NB	10.14	10.78	11.56	9.12	8.76	5.71	5.45
Ottawa, ON[5]	10.09	9.95	10.06	8.41	8.31	8.08	7.74
Regina, SK	10.43	8.43	10.54	7.83	6.42	5.82	4.90
St. John's, NL[6]	9.88	10.69	10.11	7.58	7.04	6.59	5.23
Toronto, ON	11.14	10.77	12.12	9.38	8.68	8.16	7.93
Vancouver, BC	6.41	7.02	6.53	4.92	4.57	4.25	3.53
Winnipeg, MB	6.30	6.16	7.10	4.76	3.97	3.50	3.12
American Cities							
Boston, MA	23.82	20.09	21.73	15.99	14.32	13.31	13.30
Chicago, IL[7]	9.17	11.38	12.69	8.66	7.95	6.93	5.57
Detroit, MI[7]	13.04	12.30	12.20	9.45	8.26	7.46	7.23
Houston, TX[7]	18.84	17.96	19.92	16.11	7.43	6.97	6.55
Miami, FL[7]	12.41	12.76	13.54	11.17	9.66	9.20	9.18
Nashville, TN	9.95	10.38	12.78	8.93	8.64	7.85	6.57
New York, NY[7]	19.23	20.14	22.44	16.65	14.90	13.67	13.67
Portland, OR	7.85	7.44	7.50	5.50	4.93	4.66	4.36
San Francisco, CA[7]	21.10	18.22	18.27	15.32	10.23	9.66	9.66
Seattle, WA	8.20	6.87	7.25	6.49	6.47	6.45	6.16
AVERAGE	**11.82**	**11.60**	**12.49**	**9.58**	**8.20**	**7.25**	**6.85**

1) In Canadian dollars.
2) Supply voltage of 25 kV.
3) Supply voltage of 120 kV.
4) Bills corresponding to consumption levels of 250,000 kWh/year or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Bills corresponding to consumption levels not eligible for the Regulated Price Plan have been estimated by Hydro-Québec.
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.
7) These bills have been estimated by Hydro-Québec and may differ from actual bills.

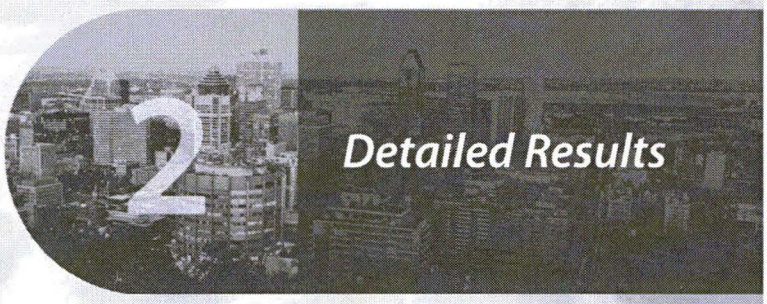
Comparative Index on April 1, 2006

(Hydro-Québec = 100)

Summary Table (excluding taxes)

	Residential	General					
		Small Power	Medium Power			Large Power	
Power		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
Charlottetown, PE	184	151	131	159	185	141	150
Edmonton, AB[3]	155	117	87	119	140	143	148
Halifax, NS	170	135	121	138	142	150	158
Moncton, NB	154	128	110	135	157	127	128
Ottawa, ON[4]	153	118	96	124	149	179	182
Regina, SK	158	100	100	116	115	129	115
St. John's, NL[5]	150	127	96	112	126	146	123
Toronto, ON	169	128	116	138	156	181	186
Vancouver, BC	97	83	62	73	82	94	83
Winnipeg, MB	95	73	68	70	71	78	73
American Cities							
Boston, MA	361	239	207	236	257	295	312
Chicago, IL[6]	139	135	121	128	142	154	131
Detroit, MI[6]	198	146	116	140	148	166	170
Houston, TX[6]	285	213	190	238	133	155	154
Miami, FL[6]	188	152	129	165	173	204	215
Nashville, TN	151	123	122	132	155	174	154
New York, NY[6]	291	239	214	246	267	303	321
Portland, OR	119	88	71	81	88	103	102
San Francisco, CA[6]	320	216	174	226	183	214	227
Seattle, WA	124	82	69	96	116	143	144
AVERAGE	**179**	**138**	**119**	**141**	**147**	**161**	**161**

1) Supply voltage of 25 kV.
2) Supply voltage of 120 kV.
3) Bills corresponding to consumption levels of 250,000 kWh/year or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Bills corresponding to consumption levels not eligible for the Regulated Price Plan have been estimated by Hydro-Québec.
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.
6) These bills have been estimated by Hydro-Québec and may differ from actual bills.



2 Detailed Results

Summary Tables
(including taxes)

Monthly Billings

Average Prices

Comparative Index

Monthly Billings on April 1, 2006

(in CA$)

Summary Table (including taxes)

	Residential	General					
		Small Power	Medium Power			Large Power	
Power		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	75.92	968.89	12,066.12	31,178.68	75,084.01	158,732.78	1,500,713.92
Charlottetown, PE	129.95	1,364.41	14,664.29	45,972.49	129,061.20	208,789.10	2,087,891.00
Edmonton, AB[3]	109.33	1,052.56	9,739.36	34,443.70	97,454.22	210,856.13	2,065,115.91
Halifax, NS	128.95	1,303.64	14,547.50	43,079.00	106,506.81	237,645.91	2,376,479.23
Moncton, NB	116.66	1,239.17	13,289.33	41,941.58	117,896.78	200,983.55	1,917,188.00
Ottawa, ON[4]	107.93	1,065.00	10,764.10	36,006.64	104,045.64	264,651.39	2,534,074.36
Regina, SK	122.04	1,050.85	13,145.92	39,060.20	93,633.81	221,919.21	1,869,323.95
St. John's, NL[5]	113.58	1,229.36	11,631.74	34,886.99	94,742.22	232,027.32	1,839,793.00
Toronto, ON	119.19	1,151.97	12,966.99	40,148.61	108,626.46	267,113.00	2,597,610.10
Vancouver, BC	70.65	799.99	7,449.89	22,440.89	60,916.73	148,355.25	1,229,661.00
Winnipeg, MB	73.42	733.35	8,446.11	22,666.13	55,235.08	127,567.78	1,081,254.74
American Cities							
Boston, MA	238.19	2,107.51	22,791.64	67,052.95	175,662.67	426,803.52	4,265,409.69
Chicago, IL[6]	102.88	1,228.55	13,521.62	37,762.60	101,798.28	234,150.27	1,898,014.92
Detroit, MI[6]	142.12	1,365.01	13,546.66	41,979.84	107,313.89	253,552.16	2,457,114.70
Houston, TX[6]	190.23	1,944.28	21,568.67	69,772.53	94,156.55	230,888.25	2,171,199.63
Miami, FL[6]	138.53	1,530.84	16,278.41	53,238.63	134,028.18	332,847.78	3,299,724.12
Nashville, TN	99.47	1,110.69	13,678.64	38,233.16	108,164.54	243,817.18	2,040,980.96
New York, NY[6]	206.95	2,237.43	24,932.03	73,981.02	193,659.74	464,812.17	4,648,121.72
Portland, OR	79.67	755.42	7,609.56	22,342.30	58,485.57	144,594.41	1,352,625.84
San Francisco, CA[6]	221.77	1,960.74	19,661.80	65,996.54	128,920.72	318,518.88	3,185,256.40
Seattle, WA	81.95	686.73	7,248.20	25,962.67	75,743.18	197,382.18	1,884,978.54
AVERAGE	**127.11**	**1,280.30**	**13,788.03**	**42,292.72**	**105,768.39**	**244,095.63**	**2,300,120.56**

1) Supply voltage of 25 kV.
2) Supply voltage of 120 kV.
3) Bills corresponding to consumption levels of 250,000 kWh/year or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Bills corresponding to consumption levels not eligible for the Regulated Price Plan have been estimated by Hydro-Québec.
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.
6) These bills have been estimated by Hydro-Québec and may differ from actual bills.

Average Prices on April 1, 2006

(in ¢/kWh)[1]

Summary Table (including taxes)

	Residential	General					
		Small Power	Medium Power			Large Power	
Power		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	7.59	9.69	12.07	7.79	6.42	5.19	4.90
Charlottetown, PE	13.00	13.64	14.66	11.49	11.03	6.82	6.82
Edmonton, AB[4]	10.93	10.53	9.74	8.61	8.33	6.89	6.75
Halifax, NS	12.90	13.04	14.55	10.77	9.10	7.77	7.77
Moncton, NB	11.67	12.39	13.29	10.49	10.08	6.57	6.27
Ottawa, ON[5]	10.79	10.65	10.76	9.00	8.89	8.65	8.28
Regina, SK	12.20	10.51	13.15	9.77	8.00	7.25	6.11
St. John's, NL[6]	11.36	12.29	11.63	8.72	8.10	7.58	6.01
Toronto, ON	11.92	11.52	12.97	10.04	9.28	8.73	8.49
Vancouver, BC	7.07	8.00	7.45	5.61	5.21	4.85	4.02
Winnipeg, MB	7.34	7.33	8.45	5.67	4.72	4.17	3.53
American Cities							
Boston, MA	23.82	21.08	22.79	16.76	15.01	13.95	13.94
Chicago, IL[7]	10.29	12.29	13.52	9.44	8.70	7.65	6.20
Detroit, MI[7]	14.21	13.65	13.55	10.49	9.17	8.29	8.03
Houston, TX[7]	19.02	19.44	21.57	17.44	8.05	7.55	7.10
Miami, FL[7]	13.85	15.31	16.28	13.31	11.46	10.88	10.78
Nashville, TN	9.95	11.11	13.68	9.56	9.24	7.97	6.67
New York, NY[7]	20.69	22.37	24.93	18.50	16.55	15.19	15.19
Portland, OR	7.97	7.55	7.61	5.59	5.00	4.73	4.42
San Francisco, CA[7]	22.18	19.61	19.66	16.50	11.02	10.41	10.41
Seattle, WA	8.20	6.87	7.25	6.49	6.47	6.45	6.16
AVERAGE	**12.71**	**12.80**	**13.79**	**10.57**	**9.04**	**7.98**	**7.52**

1) In Canadian dollars.
2) Supply voltage of 25 kV.
3) Supply voltage of 120 kV.
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5) Bills corresponding to consumption levels not eligible for the Regulated Price Plan have been estimated by Hydro-Québec.
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.
7) These bills have been estimated by Hydro-Québec and may differ from actual bills.

Comparative Index on April 1, 2006

(Hydro-Québec = 100)

Summary Table (including taxes)

	Residential	General					
		Small Power	Medium Power			Large Power	
Power		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
Charlottetown, PE	171	141	122	147	172	132	139
Edmonton, AB[3]	144	109	81	110	130	133	138
Halifax, NS	170	135	121	138	142	150	158
Moncton, NB	154	128	110	135	157	127	128
Ottawa, ON[4]	142	110	89	115	139	167	169
Regina, SK	161	108	109	125	125	140	125
St. John's, NL[5]	150	127	96	112	126	146	123
Toronto, ON	157	119	107	129	145	168	173
Vancouver, BC	93	83	62	72	81	93	82
Winnipeg, MB	97	76	70	73	74	80	72
American Cities							
Boston, MA	314	218	189	215	234	269	284
Chicago, IL[6]	136	127	112	121	136	148	126
Detroit, MI[6]	187	141	112	135	143	160	164
Houston, TX[6]	251	201	179	224	125	145	145
Miami, FL[6]	182	158	135	171	179	210	220
Nashville, TN	131	115	113	123	144	154	136
New York, NY[6]	273	231	207	237	258	293	310
Portland, OR	105	78	63	72	78	91	90
San Francisco, CA[6]	292	202	163	212	172	201	212
Seattle, WA	108	71	60	83	101	124	126
AVERAGE	**167**	**132**	**114**	**136**	**141**	**154**	**153**

1) Supply voltage of 25 kV.
2) Supply voltage of 120 kV.
3) Bills corresponding to consumption levels of 250,000 kWh/year or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Bills corresponding to consumption levels not eligible for the Regulated Price Plan have been estimated by Hydro-Québec.
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.
6) These bills have been estimated by Hydro-Québec and may differ from actual bills.



Detailed Tables
Residential

Monthly Billings

Average Prices

Comparative Index

Monthly Billings on April 1, 2006

(in CA$)

Residential

Consumption	625 kWh	750 kWh	1,000 kWh	2,000 kWh	3,000 kWh
Canadian Cities					
Montréal, QC	44.82	51.34	66.00	134.30	202.60
Charlottetown, PE	83.98	96.47	121.45	202.79	279.49
Edmonton, AB	69.44	80.36	102.18	189.48	276.78
Halifax, NS	74.14	86.81	112.13	213.43	314.73
Moncton, NB	70.05	80.52	101.44	172.96	239.26
Ottawa, ON	64.61	76.35	100.87	202.58	304.21
Regina, SK	70.60	81.84	104.31	194.21	284.11
St. John's, NL[1]	67.52	77.94	98.77	182.08	265.39
Toronto, ON	74.02	86.16	111.39	215.90	320.40
Vancouver, BC	41.44	49.00	64.13	124.63	185.13
Winnipeg, MB	41.81	48.88	63.02	119.56	176.10
American Cities					
Boston, MA	154.22	183.58	238.19	468.85	699.51
Chicago, IL[2]	70.28	81.27	91.65	160.22	226.69
Detroit, MI[2]	78.35	95.70	130.39	269.14	407.88
Houston, TX[2]	117.00	141.89	188.35	370.89	553.44
Miami, FL[2]	79.83	94.58	124.09	256.53	388.97
Nashville, TN	65.86	77.10	99.47	189.11	278.75
New York, NY[2]	125.12	147.52	192.32	371.53	550.72
Portland, OR	48.84	58.74	78.52	168.60	258.69
San Francisco, CA[2]	124.68	169.76	210.97	598.04	1,011.08
Seattle, WA	45.08	57.38	81.95	180.27	278.60
AVERAGE	**76.75**	**91.58**	**118.17**	**237.39**	**357.26**

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

Average Prices on April 1, 2006

(in ¢/kWh)[1]

Residential

Consumption	625 kWh	750 kWh	1,000 kWh	2,000 kWh	3,000 kWh
Canadian Cities					
Montréal, QC	7.17	6.85	6.60	6.72	6.75
Charlottetown, PE	13.44	12.86	12.15	10.14	9.32
Edmonton, AB	11.11	10.71	10.22	9.47	9.23
Halifax, NS	11.86	11.57	11.21	10.67	10.49
Moncton, NB	11.21	10.74	10.14	8.65	7.98
Ottawa, ON	10.34	10.18	10.09	10.13	10.14
Regina, SK	11.30	10.91	10.43	9.71	9.47
St. John's, NL[2]	10.80	10.39	9.88	9.10	8.85
Toronto, ON	11.84	11.49	11.14	10.80	10.68
Vancouver, BC	6.63	6.53	6.41	6.23	6.17
Winnipeg, MB	6.69	6.52	6.30	5.98	5.87
American Cities					
Boston, MA	24.68	24.48	23.82	23.44	23.32
Chicago, IL[3]	11.24	10.84	9.17	8.01	7.56
Detroit, MI[3]	12.54	12.76	13.04	13.46	13.60
Houston, TX[3]	18.72	18.92	18.84	18.54	18.45
Miami, FL[3]	12.77	12.61	12.41	12.83	12.97
Nashville, TN	10.54	10.28	9.95	9.46	9.29
New York, NY[3]	20.02	19.67	19.23	18.58	18.36
Portland, OR	7.82	7.83	7.85	8.43	8.62
San Francisco, CA[3]	19.95	22.63	21.10	29.90	33.70
Seattle, WA	7.21	7.65	8.20	9.01	9.29
AVERAGE	**12.28**	**12.21**	**11.82**	**11.87**	**11.91**

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

Comparative Index on April 1, 2006

(Hydro-Québec = 100)

Residential

Consumption	625 kWh	750 kWh	1,000 kWh	2,000 kWh	3,000 kWh
Canadian Cities					
Montréal, QC	100	100	100	100	100
Charlottetown, PE	187	188	184	151	138
Edmonton, AB	155	157	155	141	137
Halifax, NS	165	169	170	159	155
Moncton, NB	156	157	154	129	118
Ottawa, ON	144	149	153	151	150
Regina, SK	158	159	158	145	140
St. John's, NL[1]	151	152	150	136	131
Toronto, ON	165	168	169	161	158
Vancouver, BC	92	95	97	93	91
Winnipeg, MB	93	95	95	89	87
American Cities					
Boston, MA	344	358	361	349	345
Chicago, IL[2]	157	158	139	119	112
Detroit, MI[2]	175	186	198	200	201
Houston, TX[2]	261	276	285	276	273
Miami, FL[2]	178	184	188	191	192
Nashville, TN	147	150	151	141	138
New York, NY[2]	279	287	291	277	272
Portland, OR	109	114	119	126	128
San Francisco, CA[2]	278	331	320	445	499
Seattle, WA	101	112	124	134	138
AVERAGE	**171**	**178**	**179**	**177**	**176**

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



4 Detailed Results

Detailed Tables
General – Small Power

Monthly Billings

Average Prices

Comparative Index

Monthly Billings on April 1, 2006

(in CA$)

General – Small Power

Power	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	74.58	178.33	842.33	1,583.80	2,358.00
Charlottetown, PE	115.82	272.95	1,275.15	2,293.55	3,150.45
Edmonton, AB[1]	87.11	208.26	983.70	1,420.67	2,549.15
Halifax, NS	89.30	212.55	1,133.60	2,014.00	2,834.00
Moncton, NB	97.47	230.34	1,077.54	1,926.54	2,662.44
Ottawa, ON[2]	75.58	199.90	995.33	1,854.58	2,508.89
Regina, SK	80.50	183.50	842.70	1,743.46	2,388.34
St. John's, NL[3]	97.92	299.49	1,069.01	1,971.48	2,651.52
Toronto, ON	92.33	225.34	1,076.61	2,108.67	3,061.91
Vancouver, BC	55.35	140.35	701.75	1,182.55	1,570.49
Winnipeg, MB	60.89	135.94	616.26	1,303.76	1,656.00
American Cities					
Boston, MA	151.41	452.22	2,009.39	3,752.83	4,872.83
Chicago, IL[4]	104.12	328.93	1,137.56	2,212.01	2,814.14
Detroit, MI[4]	101.92	254.55	1,229.73	1,717.49	3,058.81
Houston, TX[4]	146.89	399.94	1,796.10	2,895.55	4,509.43
Miami, FL[4]	105.22	264.50	1,276.49	2,126.82	3,134.89
Nashville, TN	97.55	224.64	1,038.03	2,305.05	2,921.65
New York, NY[4]	166.55	540.86	2,013.68	3,832.03	5,034.20
Portland, OR	74.11	165.85	744.40	1,266.19	1,825.26
San Francisco, CA[4]	145.78	373.17	1,821.55	2,940.34	4,397.36
Seattle, WA	51.51	137.35	686.73	1,050.96	1,781.87
AVERAGE	**98.66**	**258.52**	**1,160.36**	**2,071.54**	**2,926.96**

1) Bills corresponding to consumption levels of 250,000 kWh/year or more have been estimated by Hydro-Québec based on the applicable general rate.
2) Bills corresponding to consumption levels not eligible for the Regulated Price Plan have been estimated by Hydro-Québec.
3) Newfoundland Power rates.
4) These bills have been estimated by Hydro-Québec and may differ from actual bills.

Average Price on April 1, 2006

(in ¢/kWh)[1]

General – Small Power

Power	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	9.94	8.92	8.42	11.31	9.43
Charlottetown, PE	15.44	13.65	12.75	16.38	12.60
Edmonton, AB[2]	11.61	10.41	9.84	10.15	10.20
Halifax, NS	11.91	10.63	11.34	14.39	11.34
Moncton, NB	13.00	11.52	10.78	13.76	10.65
Ottawa, ON[3]	10.08	10.00	9.95	13.25	10.04
Regina, SK	10.73	9.18	8.43	12.45	9.55
St. John's, NL[4]	13.06	14.97	10.69	14.08	10.61
Toronto, ON	12.31	11.27	10.77	15.06	11.15
Vancouver, BC	7.38	7.02	7.02	8.45	6.28
Winnipeg, MB	8.12	6.80	6.16	9.31	6.62
American Cities					
Boston, MA	20.19	22.61	20.09	26.81	19.49
Chicago, IL[5]	13.88	16.45	11.38	15.80	11.26
Detroit, MI[5]	13.59	12.73	12.30	12.27	12.24
Houston, TX[5]	19.59	20.00	17.96	20.68	18.04
Miami, FL[5]	14.03	13.22	12.76	15.19	12.54
Nashville, TN	13.01	11.23	10.38	16.46	11.69
New York, NY[5]	22.21	27.04	20.14	27.37	20.14
Portland, OR	9.88	8.29	7.44	9.04	7.30
San Francisco, CA[5]	19.44	18.66	18.22	21.00	17.59
Seattle, WA	6.87	6.87	6.87	7.51	7.13
AVERAGE	**13.16**	**12.93**	**11.60**	**14.80**	**11.71**

1) In Canadian dollars.
2) Bills corresponding to consumption levels of 250,000 kWh/year or more have been estimated by Hydro-Québec based on the applicable general rate.
3) Bills corresponding to consumption levels not eligible for the Regulated Price Plan have been estimated by Hydro-Québec.
4) Newfoundland Power rates.
5) These bills have been estimated by Hydro-Québec and may differ from actual bills.

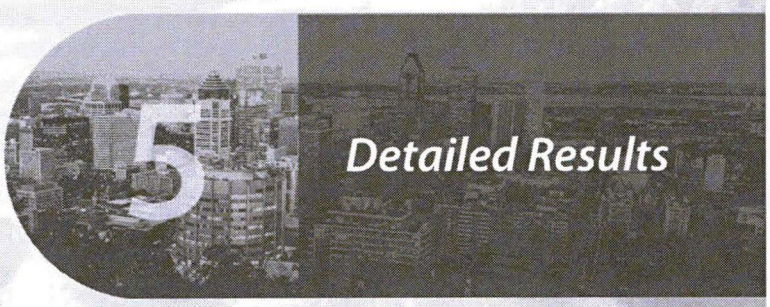
Comparative Index on April 1, 2006

(Hydro-Québec = 100)

General – Small Power

Power	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
Charlottetown, PE	155	153	151	145	134
Edmonton, AB[1]	117	117	117	90	108
Halifax, NS	120	119	135	127	120
Moncton, NB	131	129	128	122	113
Ottawa, ON[2]	101	112	118	117	106
Regina, SK	108	103	100	110	101
St. John's, NL[3]	131	168	127	124	112
Toronto, ON	124	126	128	133	118
Vancouver, BC	74	79	83	75	67
Winnipeg, MB	82	76	73	82	70
American Cities					
Boston, MA	203	254	239	237	207
Chicago, IL[4]	140	184	135	140	119
Detroit, MI[4]	137	143	146	108	130
Houston, TX[4]	197	224	213	183	191
Miami, FL[4]	141	148	152	134	133
Nashville, TN	131	126	123	146	124
New York, NY[4]	223	303	239	242	213
Portland, OR	99	93	88	80	77
San Francisco, CA[4]	195	209	216	186	186
Seattle, WA	69	77	82	66	76
AVERAGE	**132**	**145**	**138**	**131**	**124**

1) Bills corresponding to consumption levels of 250,000 kWh/year or more have been estimated by Hydro-Québec based on the applicable general rate.
2) Bills corresponding to consumption levels not eligible for the Regulated Price Plan have been estimated by Hydro-Québec.
3) Newfoundland Power rates.
4) These bills have been estimated by Hydro-Québec and may differ from actual bills.



Detailed Tables
General – Medium Power

Monthly Billings

Average Prices

Comparative Index

Monthly Billings on April 1, 2006

(in CA$)

General – Medium Power

Power	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	10,490.00	14,940.00	20,980.00	27,106.00	65,276.25
Charlottetown, PE	13,704.95	21,494.95	27,384.95	42,964.95	120,617.95
Edmonton, AB[2]	9,102.21	16,192.26	18,010.26	32,190.37	91,078.71
Halifax, NS	12,650.00	18,730.00	25,300.00	37,460.00	92,614.62
Moncton, NB	11,555.94	18,245.94	23,090.94	36,470.94	102,518.94
Ottawa, ON[3]	10,059.90	16,919.82	20,235.02	33,651.07	97,238.92
Regina, SK	10,542.04	15,682.04	21,043.34	31,323.34	75,087.26
St. John's, NL[4]	10,114.56	15,666.02	19,434.53	30,336.51	82,384.54
Toronto, ON	12,118.68	18,927.78	23,903.87	37,522.06	101,520.06
Vancouver, BC	6,534.99	9,804.99	13,144.99	19,684.99	53,435.73
Winnipeg, MB	7,097.57	9,541.57	14,159.17	19,047.17	46,416.04
American Cities					
Boston, MA	21,728.60	32,072.17	43,261.86	63,949.02	167,558.26
Chicago, IL[5]	12,693.04	17,026.02	26,718.10	34,620.69	92,963.28
Detroit, MI[5]	12,204.20	19,071.01	24,398.06	37,819.67	96,679.20
Houston, TX[5]	19,924.87	32,500.66	39,309.92	64,454.99	86,980.64
Miami, FL[5]	13,539.96	22,354.17	27,035.91	44,664.33	112,998.70
Nashville, TN	12,783.78	17,933.11	25,433.27	35,731.92	101,088.35
New York, NY[5]	22,438.80	33,367.59	44,725.25	66,582.82	174,293.55
Portland, OR	7,498.53	11,985.21	13,688.12	22,016.91	57,634.50
San Francisco, CA[5]	18,266.07	31,278.03	36,317.52	61,296.21	119,645.65
Seattle, WA	7,248.20	13,892.87	13,213.83	25,962.67	75,743.18
AVERAGE	**12,490.33**	**19,410.77**	**24,799.47**	**38,326.51**	**95,894.02**

1) Supply voltage of 25 kV.
2) Bills corresponding to consumption levels of 250,000 kWh/year or more have been estimated by Hydro-Québec based on the applicable general rate.
3) Bills corresponding to consumption levels not eligible for the Regulated Price Plan have been estimated by Hydro-Québec.
4) Newfoundland Power rates.
5) These bills have been estimated by Hydro-Québec and may differ from actual bills.

Average Prices on April 1, 2006

(in ¢/kWh)[1]

General – Medium Power

Power	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	10.49	7.47	10.49	6.78	5.58
Charlottetown, PE	13.70	10.75	13.69	10.74	10.31
Edmonton, AB[3]	9.10	8.10	9.01	8.05	7.78
Halifax, NS	12.65	9.37	12.65	9.37	7.92
Moncton, NB	11.56	9.12	11.55	9.12	8.76
Ottawa, ON[4]	10.06	8.46	10.12	8.41	8.31
Regina, SK	10.54	7.84	10.52	7.83	6.42
St. John's, NL[5]	10.11	7.83	9.72	7.58	7.04
Toronto, ON	12.12	9.46	11.95	9.38	8.68
Vancouver, BC	6.53	4.90	6.57	4.92	4.57
Winnipeg, MB	7.10	4.77	7.08	4.76	3.97
American Cities					
Boston, MA	21.73	16.04	21.63	15.99	14.32
Chicago, IL[6]	12.69	8.51	13.36	8.66	7.95
Detroit, MI[6]	12.20	9.54	12.20	9.45	8.26
Houston, TX[6]	19.92	16.25	19.65	16.11	7.43
Miami, FL[6]	13.54	11.18	13.52	11.17	9.66
Nashville, TN	12.78	8.97	12.72	8.93	8.64
New York, NY[6]	22.44	16.68	22.36	16.65	14.90
Portland, OR	7.50	5.99	6.84	5.50	4.93
San Francisco, CA[6]	18.27	15.64	18.16	15.32	10.23
Seattle, WA	7.25	6.95	6.61	6.49	6.47
AVERAGE	**12.49**	**9.71**	**12.40**	**9.58**	**8.20**

1) In Canadian dollars.
2) Supply voltage of 25 kV.
3) Bills corresponding to consumption levels of 250,000 kWh/year or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Bills corresponding to consumption levels not eligible for the Regulated Price Plan have been estimated by Hydro-Québec.
5) Newfoundland Power rates.
6) These bills have been estimated by Hydro-Québec and may differ from actual bills.

Comparative Index on April 1, 2006

(Hydro-Québec = 100)

General – Medium Power

Power	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
Charlottetown, PE	131	144	131	159	185
Edmonton, AB[2]	87	108	86	119	140
Halifax, NS	121	125	121	138	142
Moncton, NB	110	122	110	135	157
Ottawa, ON[3]	96	113	96	124	149
Regina, SK	100	105	100	116	115
St. John's, NL[4]	96	105	93	112	126
Toronto, ON	116	127	114	138	156
Vancouver, BC	62	66	63	73	82
Winnipeg, MB	68	64	67	70	71
American Cities					
Boston, MA	207	215	206	236	257
Chicago, IL[5]	121	114	127	128	142
Detroit, MI[5]	116	128	116	140	148
Houston, TX[5]	190	218	187	238	133
Miami, FL[5]	129	150	129	165	173
Nashville, TN	122	120	121	132	155
New York, NY[5]	214	223	213	246	267
Portland, OR	71	80	65	81	88
San Francisco, CA[5]	174	209	173	226	183
Seattle, WA	69	93	63	96	116
AVERAGE	**119**	**130**	**118**	**141**	**147**

1) Suply voltage of 25 kV.
2) Bills corresponding to consumption levels of 250,000 kWh/year or more have been estimated by Hydro-Québec based on the applicable general rate.
3) Bills corresponding to consumption levels not eligible for the Regulated Price Plan have been estimated by Hydro-Québec.
4) Newfoundland Power rates.
5) These bills have been estimated by Hydro-Québec and may differ from actual bills.



6 Detailed Results

Detailed Tables
General – Large Power

Monthly Billings

Average Prices

Comparative Index

Monthly Billings on April 1, 2006

(in CA$)

General – Large Power

Power	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	25 kV	25 kV	120 kV	120 kV	120 kV	120 kV
Load factor	65%	85%	80%	81%	65%	85%
Canadian Cities						
Montréal, QC	118,270.50	137,998.50	251,073.00	759,795.00	1,107,405.00	1,304,685.00
Charlottetown, PE	164,170.00	195,130.00	374,780.00	1,134,660.00	1,641,700.00	1,951,300.00
Edmonton, AB[1]	156,073.30	197,061.80	360,064.18	1,066,732.67	1,526,421.65	1,930,014.87
Halifax, NS	168,848.62	206,648.62	394,397.24	1,195,800.46	1,688,503.68	2,066,503.68
Moncton, NB	147,217.14	174,768.30	319,852.00	968,604.00	1,395,680.00	1,667,120.00
Ottawa, ON[2]	200,272.50	247,337.74	459,466.90	1,370,737.21	1,897,641.36	2,368,293.79
Regina, SK	144,122.48	177,962.48	289,166.93	866,583.31	1,198,744.90	1,499,056.90
St. John's, NL[3]	161,918.09	201,762.89	377,232.74	924,444.00	1,295,980.00	1,599,820.00
Toronto, ON	201,052.66	249,638.32	464,093.80	1,402,073.64	1,949,748.33	2,427,672.99
Vancouver, BC	106,945.35	130,136.19	205,917.42	624,297.39	882,435.60	1,078,650.00
Winnipeg, MB	90,755.01	107,199.81	182,822.13	553,720.58	796,023.43	953,487.43
American Cities						
Boston, MA	334,838.71	407,160.88	777,882.84	2,357,200.29	3,345,886.70	4,069,108.38
Chicago, IL[4]	185,335.33	212,041.39	407,152.30	1,028,842.72	1,440,479.45	1,705,887.73
Detroit, MI[4]	193,036.05	228,425.37	425,497.52	1,287,503.70	1,863,942.52	2,213,616.85
Houston, TX[4]	171,749.61	213,291.68	380,803.79	1,153,735.78	1,574,494.19	2,005,727.14
Miami, FL[4]	225,568.13	281,391.82	534,442.53	1,621,076.97	2,251,817.92	2,810,054.83
Nashville, TN	203,341.31	240,213.98	404,854.89	1,179,107.65	1,768,066.62	2,010,818.68
New York, NY[4]	348,587.09	418,330.42	801,789.18	2,428,615.32	3,485,870.93	4,183,304.24
Portland, OR	114,298.21	142,482.50	254,127.79	768,997.48	1,065,903.07	1,332,797.86
San Francisco, CA[4]	238,782.51	295,562.74	562,742.37	1,707,167.83	2,387,888.07	2,955,690.39
Seattle, WA	151,486.36	197,382.18	355,093.15	1,079,881.16	1,446,927.40	1,884,978.54
AVERAGE	**182,222.33**	**221,996.55**	**408,726.32**	**1,213,313.20**	**1,714,836.23**	**2,096,123.30**

1) Bills corresponding to consumption levels of 250,000 kWh/year or more have been estimated by Hydro-Québec based on the applicable general rate.
2) Bills corresponding to consumption levels not eligible for the Regulated Price Plan have been estimated by Hydro-Québec.
3) 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.
4) These bills have been estimated by Hydro-Québec and may differ from actual bills.

Average Prices on April 1, 2006

(in ¢/kWh)[1]

General – Large Power

Power	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	25 kV	25 kV	120 kV	120 kV	120 kV	120 kV
Load factor	65%	85%	80%	81%	65%	85%
Canadian Cities						
Montréal, QC	5.05	4.51	4.36	4.34	4.73	4.26
Charlottetown, PE	7.02	6.38	6.51	6.48	7.02	6.38
Edmonton, AB[2]	6.67	6.44	6.25	6.09	6.52	6.31
Halifax, NS	7.22	6.75	6.85	6.83	7.22	6.75
Moncton, NB	6.29	5.71	5.55	5.53	5.96	5.45
Ottawa, ON[3]	8.56	8.08	7.98	7.82	8.11	7.74
Regina, SK	6.16	5.82	5.02	4.95	5.12	4.90
St. John's, NL[4]	6.92	6.59	6.55	5.28	5.54	5.23
Toronto, ON	8.59	8.16	8.06	8.00	8.33	7.93
Vancouver, BC	4.57	4.25	3.57	3.56	3.77	3.53
Winnipeg, MB	3.88	3.50	3.17	3.16	3.40	3.12
American Cities						
Boston, MA	14.31	13.31	13.50	13.45	14.30	13.30
Chicago, IL[5]	7.92	6.93	7.07	5.87	6.16	5.57
Detroit, MI[5]	8.25	7.46	7.39	7.35	7.97	7.23
Houston, TX[5]	7.34	6.97	6.61	6.59	6.73	6.55
Miami, FL[5]	9.64	9.20	9.28	9.25	9.62	9.18
Nashville, TN	8.69	7.85	7.03	6.73	7.56	6.57
New York, NY[5]	14.90	13.67	13.92	13.86	14.90	13.67
Portland, OR	4.88	4.66	4.41	4.39	4.56	4.36
San Francisco, CA[5]	10.20	9.66	9.77	9.74	10.20	9.66
Seattle, WA	6.47	6.45	6.16	6.16	6.18	6.16
AVERAGE	**7.79**	**7.25**	**7.10**	**6.93**	**7.33**	**6.85**

1) In Canadian dollars.
2) Bills corresponding to consumption levels of 250,000 kWh/year or more have been estimated by Hydro-Québec based on the applicable general rate.
3) Bills corresponding to consumption levels not eligible for the Regulated Price Plan have been estimated by Hydro-Québec.
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.
5) These bills have been estimated by Hydro-Québec and may differ from actual bills.

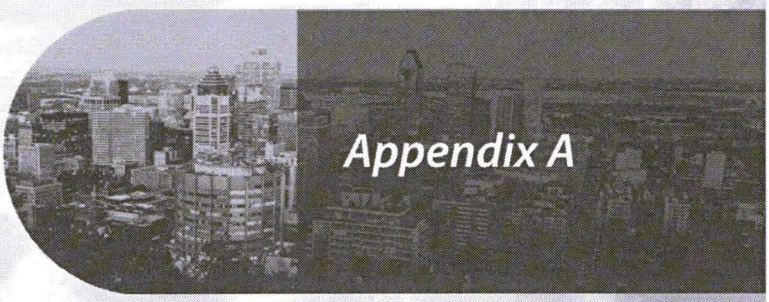
Comparative Index on April 1, 2006

(Hydro-Québec = 100)

General – Large Power

Power	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	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
Charlottetown, PE	139	141	149	149	148	150
Edmonton, AB[1]	132	143	143	140	138	148
Halifax, NS	143	150	157	157	152	158
Moncton, NB	124	127	127	127	126	128
Ottawa, ON[2]	169	179	183	180	171	182
Regina, SK	122	129	115	114	108	115
St. John's, NL[3]	137	146	150	122	117	123
Toronto, ON	170	181	185	185	176	186
Vancouver, BC	90	94	82	82	80	83
Winnipeg, MB	77	78	73	73	72	73
American Cities						
Boston, MA	283	295	310	310	302	312
Chicago, IL[4]	157	154	162	135	130	131
Detroit, MI[4]	163	166	169	169	168	170
Houston, TX[4]	145	155	152	152	142	154
Miami, FL[4]	191	204	213	213	203	215
Nashville, TN	172	174	161	155	160	154
New York, NY[4]	295	303	319	320	315	321
Portland, OR	97	103	101	101	96	102
San Francisco, CA[4]	202	214	224	225	216	227
Seattle, WA	128	143	141	142	131	144
AVERAGE	**154**	**161**	**163**	**160**	**155**	**161**

1) Bills corresponding to consumption levels of 250,000 kWh/year or more have been estimated by Hydro-Québec based on the applicable general rate.
2) Bills corresponding to consumption levels not eligible for the Regulated Price Plan have been estimated by Hydro-Québec.
3) 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.
4) These bills have been estimated by Hydro-Québec and may differ from actual bills.



Appendix A

Rate Adjustments

Average Adjustments

Adjustments by Customer Category

Rate Adjustments

Average Adjustments

	Before April 2005		Between April 1, 2005 and April 1, 2006		
	Year	%	Date	%	Comments
Canadian Utilities					
Hydro-Québec, QC	2005	1.2	April 1, 2006	5.33	
Maritime Electric, PE	2003	2.5	July 1, 2005	2.0	
EPCOR, AB	2005	-3.72	January 1, 2006 April 1, 2006	36.89 -17.04	Modifications applicable to customers whose accounts are subject to regulated rates (all residential customers and those commercial customers whose annual consumption is less than or equal to 250,000 kWh/year).
Nova Scotia Power, NS	2005	5.3	March 10, 2006	8.7	
NB Power, NB	2005	3.0	July 7, 2005	3.0	
Hydro Ottawa, ON	2005	n.a.	—	—	The new Regulated Price Plan, as well as new distribution rates, came into effect May 1, 2006.
SaskPower, SK	2004	5.65	January 1, 2006	4.91	
Newfoundland Power, NL[1]	2003	-0.15	—	—	
Newfoundland and Labrador Hydro, NL[1]	2004	9.6	—	—	
Toronto Hydro, ON	2005	2.1	—	—	The new Regulated Price Plan, as well as new distribution rates, came into effect May 1, 2006. In 2005: Adjustment applicable to the distribution component only.
BC Hydro, BC	2004	4.85	—	—	
Manitoba Hydro, MB	2005	2.25	—	—	
American Utilities					
Boston Edison, MA	2005	n.a.	July 1, 2005 January 1, 2006	-5.3 5-10	
Commonwealth Edison, IL	2001	n.a.	—	—	
Detroit Edison, MI	2004	4.7	—	—	
Reliant Energy, TX	2002	n.a.	—	—	
Florida Power and Light, FL	2005	1.5	—	—	
Nashville Electric Service, TN	2003	5.4	October 1, 2005 April 1, 2006	8.9 9.0	
Consolidated Edison, NY	2005	2.0	—	—	
Pacific Power and Light, OR	2003	1.1	October 4, 2005	3.2	
Pacific Gas and Electric, CA	2004	-8.0	—	—	
Seattle City Light, WA	2004	-2.1	November 1, 2005	-2.2	Bonneville Power Administration Pass-Through.

n.a. = not available

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

Rate Adjustments (between April 1, 2005 and April 1, 2006)

Adjustments by Customer Category

	Date	Residential %	General %	Industrial %	Average %
Canadian Utilities					
Hydro-Québec, QC	April 1, 2006	5.33	5.33	5.33	5.33
Maritime Electric, PE	July 1, 2005	2.0	2.0	2.0	2.0
EPCOR, AB	January 1, 2006	36.89	30.88[1] 39.85[2]	n.a.	36.89[3]
	April 1, 2006	-17.04	-18.37[1] -19.04[2]	n.a.	-17.04[3]
Nova Scotia Power, NS	March 10, 2006	8.6	7.6	12.1	8.7
NB Power, NB	July 7, 2005	3.0	3.0	3.0	3.0
Hydro Ottawa, ON	—	—	—	—	—
SaskPower, SK	January 1, 2006	6.21	4.20	5.58	4.91
Newfoundland Power, NL[4]	—	—	—	—	—
Newfoundland and Labrador Hydro, NL[4]	—	N/A	N/A	—	—
Toronto Hydro, ON	—	—	—	—	—
BC Hydro, BC	—	—	—	—	—
Manitoba Hydro, MB	—	—	—	—	—
American Utilities					
Boston Edison, MA	July 1, 2005	n.a.	n.a.	n.a.	-5.3
	January 1, 2006	n.a.	n.a.	n.a.	5-10
Commonwealth Edison, IL	—	—	—	—	—
Detroit Edison, MI	—	—	—	—	—
Reliant Energy, TX	—	—	—	—	—
Florida Power and Light, FL	—	—	—	—	—
Nashville Electric Service, TN	October 1, 2005	8.9	8.9	7.4	8.9
	April 1, 2006	8.9	8.9	9.4	9.0
Consolidated Edison, NY	—	—	—	—	—
Pacific Power and Light, OR	October 4, 2005	1.8	1.7	10.2	3.2
Pacific Gas and Electric, CA	—	—	—	—	—
Seattle City Light, WA	November 1, 2005	n.a.	n.a.	n.a.	-2.2

N/A = not applicable
n.a. = not available

1) Less than 50 kVA.
2) More than 50 kVA.
3) Modifications applicable to customers whose accounts are subject to regulated rates (all residential customers and those commercial customers whose annual consumption is less than or equal to 250,000 kWh/year).
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.

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.



Appendix B

Time-of-Use Rates

Adjustment Clauses

Time-of-Use Rates

The utilities listed below apply time-of-use rates for different consumption levels. An average has been calculated for the purpose of this study.

Boston Edison, MA	Residential: 1,000 - 3,000 kWh General: All levels
Commonwealth Edison, IL	All levels
Consolidated Edison, NY	All levels
Detroit Edison, MI	500 - 50,000 kW
EPCOR, AB	100 - 50,000 kW
Newfoundland Power, NL	14 - 10,000 kW
Hydro Ottawa, ON	Residential: All levels
Pacific Gas and Electric, CA	All levels
Pacific Power and Light, OR	5,000 - 50,000 kW
Reliant Energy, TX	All levels
Seattle City Light, WA	All levels
Toronto Hydro, ON	Residential: 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.

Boston Edison, MA	Demand-Side Management Charge Energy Efficiency Charge Pension Adjustment Renewable Energy Charge Residential Assistance Adjustment Clause Standard Offer/Default Service Adjustment
Commonwealth Edison, IL	Renewable Energy Resources and Energy Assistance Charge Franchise Cost Additions Decommissioning Expense Adjustment Clause
Consolidated Edison, NY	System Benefits Charge Market Supply Charge Monthly Adjustment Charge Renewable Portfolio Standard Charge
Detroit Edison, MI	Nuclear Decommissioning Surcharge Power Supply Cost Recovery Clause Securization Bond Charge and Securization Bond Tax Charge Regulatory Asset Recovery Surcharge Choice Implementation Surcharge Renewable Energy Program Surcharge
EPCOR, AB	Franchise Fee Charge
Florida Power and Light, FL	Energy Conservation Cost Recovery Clause Capacity Payment Recovery Clause Fuel Cost and Purchase Power Recovery Clause Environmental Cost Recovery Clause Storm Restoration Charge
Maritime Electric, PE	Energy Cost Adjustment Mechanism
Newfoundland and Labrador Hydro, NL	Rate Stabilization Plan Adjustment
Newfoundland Power, NL	Rate Stabilization Adjustment Municipal Tax Adjustment
Pacific Gas and Electric, CA	Energy Rate Adjustments Rate Reduction Bond Credit Department of Water and Resources Bond Charge Fixed Transition Amount Charge Nuclear Decommissioning Reliability Services Public Purpose Programs Competition Transition Charge

Pacific Power and Light, OR	Miscellaneous Deferred Accounts Credit Public Purpose Charge Rate Mitigation Adjustment SB 1149 Adjustment Trail Mountain Mine Closure Costs Surcharge
Toronto Hydro, ON	Recovery of Regulatory Assets
Reliant Energy, TX	Fuel Charge Transition Charge System Benefit Fund Charge Nuclear Decommissioning Competition Transition Charge Transmission Cost Recovery Factor Municipal Account Franchise Credit Rate Case Expenses Surcharge



Appendix C

Taxes Applicable

Residential

General and Industrial Customers

Taxes Applicable to Residential Customers

On April 1, 2006

	Tax	% (or other)	Applicable
Canadian Cities			
Montréal, QC	Goods and Services Tax (GST)	7	to base amount of bill
	Provincial Sales Tax	7.5	to base amount of bill + GST
Charlottetown, PE	Goods and Services Tax	7	to base amount of bill
Edmonton, AB	Goods and Services Tax	7	to base amount of bill
Halifax, NS	Harmonized Sales Tax	15	to base amount of bill
Moncton, NB	Harmonized Sales Tax	15	to base amount of bill
Ottawa, ON	Goods and Services Tax	7	to base amount of bill
Regina, SK	Municipal Tax	10	to base amount of bill
	Goods and Services Tax	7	to base amount of bill
St. John's, NL	Harmonized Sales Tax	15	to base amount of bill
Toronto, ON	Goods and Services Tax	7	to base amount of bill
Vancouver, BC	Regional Transit Levy	$1.90	monthly
	Goods and Services Tax	7	to base amout of bill + Regional Transit Levy
Winnipeg, MB	Provincial Sales Tax	7	to base amount of bill (heating other than electric)
		1.4	to base amount of bill (electric heating)
	Municipal Tax	2.5	to base amount of bill (heating other than electric)
		0.5	to base amount of bill (electric heating)
	Goods and Services Tax	7	to base amount of bill
American Cities			
Boston, MA	None		
Chicago, IL	State Tax	¢/kWh	tax varies by energy block
	Municipal Tax	¢/kWh	tax varies by energy block
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	2.5641	to base amount of bill
	Franchise Fee	3.333	to base amount of bill + Gross Receipts Tax
	Utility Tax	10	to a portion of base amount of bill
Nashville, TN	None		
New York, NY	Commodity Gross Receipts Tax	2.5248	to supply
	Delivery Gross Receipts Tax	4.6711	to other components
	Sales Tax	4	to base amount of bill + Gross Receipts Tax
Portland, OR	Multnomah County Franchise Tax	0.033	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	0.022¢	to energy consumption
	San Francisco Utility Users' Tax	5	to base amount of bill
Seattle, WA	State Utility Tax	3.873	tax included in rate schedule prices
	Seattle Occupation Tax	6	tax included in rate schedule prices

Taxes Applicable to General Customers

On April 1, 2006

	Tax	% (or other)	Applicable
Canadian Cities			
Montréal, QC	Goods and Services Tax (GST)	7	to base amount of bill (tax reimbursable)
	Provincial Sales Tax	7.5	to base amount of bill + GST (tax reimbursable[1])
Charlottetown, PE	Goods and Services Tax	7	to base amount of bill (tax reimbursable)
Edmonton, AB	Goods and Services Tax	7	to base amount of bill
Halifax, NS	Harmonized Sales Tax	15	to base amount of bill (tax reimbursable)
Moncton, NB	Harmonized Sales Tax	15	to base amount of bill (tax reimbursable)
Ottawa, ON	Goods and Services Tax	7	to base amount of bill (tax reimbursable)
Regina, SK	Municipal Tax	10	to base amount of bill
	Provincial Sales Tax	7	to base amount of bill + municipal tax (tax reimbursable[2])
	Goods and Services Tax	7	to base amount of bill + municipal tax (tax reimbursable)
St. John's, NL	Harmonized Sales Tax	15	to base amount of bill (tax reimbursable)
Toronto, ON	Goods and Services Tax	7	to base amount of bill (tax reimbursable)
Vancouver, BC	Provincial Sales Tax	7	to base amount of bill (tax reimbursable)
	Goods and Services Tax	7	to base amount of bill (tax reimbursable)
Winnipeg, MB	Provincial Sales Tax	7	to base amount of bill
	Municipal Tax	5	to base amount of bill (heating other than electric)
		1	to base amount of bill (electric heating)
	Goods and Services Tax	7	to base amount of bill (tax reimbursable)
American Cities			
Boston, MA	State Sales Tax	5	to a portion of base amount of bill
Chicago, IL	State Tax	¢/kWh	tax varies by energy block
	Municipal Tax	¢/kWh	tax varies by energy block
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
Miami, FL	Gross Receipts Tax	2.5641	to base amount of bill
	Franchise Fee	3.333	to base amount of bill + Gross Receipts Tax
	Utility Tax	10	to a portion of base amount of bill
	State Sales Tax	7	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	2.5248	to supply
	Delivery Gross Receipts Tax	2.5248	to other components
	Sales Tax	8.375	to base amount of bill + Gross Receipts Tax
Portland, OR	Multnomah County Franchise Tax	0.033	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	0.022¢	to energy consumption
	San Francisco Utility Users' Tax	7.5	to base amount of bill
Seattle, WA	State Utility Tax	3.873	tax included in rate schedule prices
	Seattle Occupation Tax	6	tax included in rate schedule prices

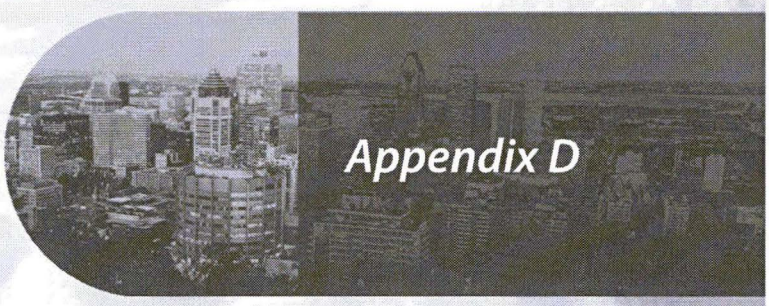
1) Commercial customers with revenue below $6 M, as well as customers in the manufacturing sector, are entitltled to a reimbursement of this tax.
2) Customers in the manufacturing sector are entitled to a partial reimbursement of this tax, based on their taxable income.

Taxes Applicable to Industrial Customers

On April 1, 2006

	Tax	% (or other)	Applicable
Canadian Cities			
Montréal, QC	Goods and Services Tax (GST)	7	to base amount of bill (tax reimbursable)
	Provincial Sales Tax	7.5	to base amount of bill + GST (tax reimbursable[1])
Charlottetown, PE	Goods and Services Tax	7	to base amount of bill (tax reimbursable)
Edmonton, AB	Goods and Services Tax	7	to base amount of bill
Halifax, NS	Harmonized Sales Tax	15	to base amount of bill (tax reimbursable)
Moncton, NB	Harmonized Sales Tax	15	to base amount of bill (tax reimbursable)
Ottawa, ON	Goods and Services Tax	7	to base amount of bill (tax reimbursable)
Regina, SK	Municipal Tax	10	to base amount of bill
	Provincial Sales Tax	7	to base amount of bill + municipal tax (tax reimbursable[2])
	Goods and Services Tax	7	to base amount of bill + municipal tax (tax reimbursable)
St. John's, NL	Harmonized Sales Tax	15	to base amount of bill (tax reimbursable)
Toronto, ON	Goods and Services Tax	7	to base amount of bill (tax reimbursable)
Vancouver, BC	Provincial Sales Tax	7	to base amount of bill (tax reimbursable)
	Goods and Services Tax	7	to base amount of bill (tax reimbursable)
Winnipeg, MB	Provincial Sales Tax	7	to base amount of bill (industries other than mining and manufacturing)
		1.4	to base amount of bill (mining and manufacturing industries)
	Municipal Tax	5	to base amount of bill (heating other than electric)
		1	to base amount of bill (electric heating)
	Goods and Services Tax	7	to base amount of bill (tax reimbursable)
American Cities			
Boston, MA	State Sales Tax	5	to a portion of base amount of bill
Chicago, IL	State Tax	¢/kWh	tax varies by energy block
	Municipal Tax	¢/kWh	tax varies by energy block
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
Miami, FL	Gross Receipts Tax	2.5641	to base amount of bill
	Franchise Fee	3.333	to base amount of bill + Gross Receipts Tax
	Utility Tax	10	to a portion of base amount of bill
	State Sales Tax	7	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	1.5	to base amount of bill (other than manufacturing companies)
New York, NY	Commodity Gross Receipts Tax	2.5248	to supply
	Delivery Gross Receipts Tax	2.5248	to other components
	Sales Tax	8.375	to base amount of bill + Gross Receipts Tax
Portland, OR	Multnomah County Franchise Tax	0.033	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	0.022¢	to energy consumption
	San Francisco Utility Users' Tax	7.5	to base amount of bill
Seattle, WA	State Utility Tax	3.873	tax included in rate schedule prices
	Seattle Occupation Tax	6	tax included in rate schedule prices

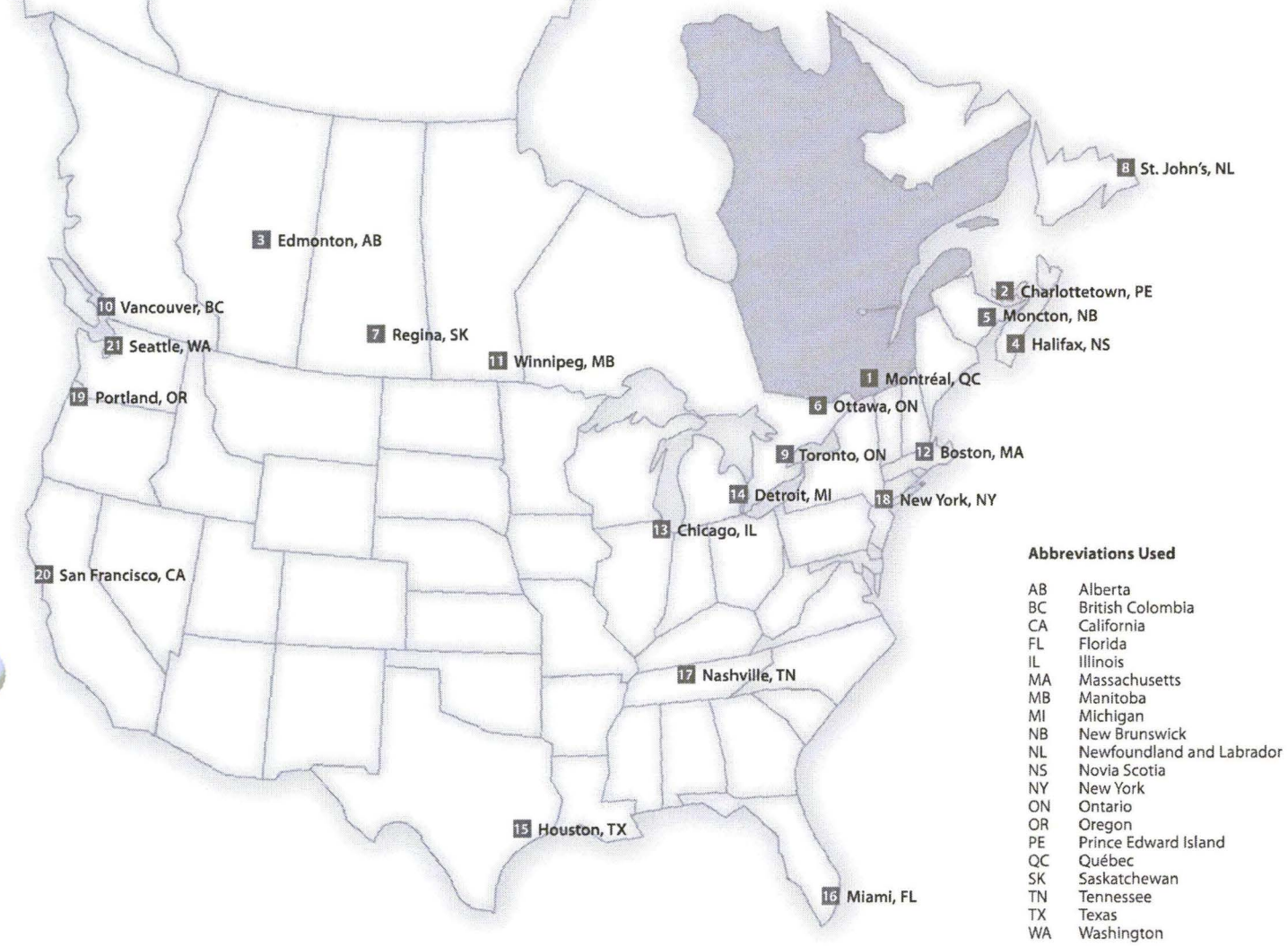
1) Commercial customers with revenue below $6 M, as well as customers in the manufacturing sector, are entitled to a reimbursement of this tax.
2) Customers in the manufacturing sector are entitled to a partial reimbursement of this tax, based on their taxable income.



Appendix D

Utilities in the Study

Utilities in the Study



Abbreviations Used

AB	Alberta
BC	British Colombia
CA	California
FL	Florida
IL	Illinois
MA	Massachusetts
MB	Manitoba
MI	Michigan
NB	New Brunswick
NL	Newfoundland and Labrador
NS	Novia 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. Maritime Electric
3. EPCOR
4. Nova Scotia Power
5. NB Power
6. Ottawa Hydro
7. SaskPower
8. Newfoundland and Labrador Hydro
   (customers with a power demand of 30,000 kW or more)
   Newfoundland Power
   (all other customer categories)
9. Toronto Hydro
10. BC Hydro
11. Manitoba Hydro

American Utilities

12. Boston Edison
13. Commonwealth Edison
14. Detroit Edison
15. Reliant Energy
16. Florida Power and Light
17. Nashville Electric Service
18. Consolidated Edison
19. Pacific Power and Light
20. Pacific Gas and Electric
21. Seattle City Light

Canadian Utilities

Hydro-Québec

Montréal, Québec

A state-owned company whose activities have been unbundled, Hydro-Québec is one of the largest electric utilities in North America, with an installed capacity of 34,571 MW, of which 93% comes from hydropower. Its transmission and distribution activities are regulated. The utility distributes electricity to more than 3.7 million residential, commercial, institutional and industrial customers throughout Québec and delivers electricity to nine municipal systems and one regional cooperative. Hydro-Québec also does business with many electric utilities in the Northeastern United States, Ontario and New Brunswick.

The Act respecting the *Régie de l'énergie* (Québec Energy Board) established an annual maximum heritage pool of 165 TWh that Hydro-Québec Production must supply to Hydro-Québec Distribution at an average cost of 2.79¢ per kilowatthour. Above that volume, which was exceeded in 2005, needs have to be met through tender calls. In addition, the *Régie de l'énergie* approved an increase of 5.33% in the rates of Hydro-Québec Distribution, which took effect April 1, 2006.

Maritime Electric

Charlottetown, Prince Edward Island

A subsidiary of Fortis, Maritime Electric is the principal supplier of electricity on Prince Edward Island, with about 66,000 customers. Since it operates its two power plants, which have a total capacity of 103 MW, strictly for reserve purposes, it purchases most of its electricity from NB Power.

In December 2003, the Prince Edward Island government reviewed the regulations governing electricity prices. Before, Maritime Electric's rates had to be aligned with those of NB Power, with a maximum variance of 10%. Since January 1, 2004, Maritime Electric has had to submit all requests for rate increases to the Island Regulatory & Appeals Commission.

EPCOR Energy

Edmonton, Alberta

EPCOR Energy is a subsidiary of EPCOR Utilities, whose shareholder is the City of Edmonton. It sells electricity on behalf of EPCOR Distribution to more than 300,000 customers, whose accounts are subject to regulated rates (Regulated Rate Tariff).

On January 1, 2001, free competition was introduced for all retail market customers. To limit the impact of monthly fluctuations in the price of electricity, all residential customers and those commercial customers whose annual consumption is less than or equal to 250,000 kWh can take advantage of these regulated rates, for which the electricity commodity price is adjusted every quarter. The Alberta government has decided to extend for five more years their eligibility for these rates, which were slated to end in June 2006.

Nova Scotia Power

Halifax, Nova Scotia

Nova Scotia Power, a subsidiary of Emera, is the principal supplier of electricity in Nova Scotia, meeting most of the province's needs for electricity generation, transmission and distribution. It supplies electricity to 460,000 customers. Its generating facilities have an installed capacity of almost 2,300 MW.

The open access transmission tariff to the Nova Scotia Power grid – approved by the Nova Scotia Utility and Review Board in May 2005 – came into effect November 1, 2005. Third parties who subscribe have non-discriminatory access to the utility's transmission system, in accordance with the province's energy policy.

NB Power

Moncton, New Brunswick

A subsidiary of state-owned NB Power Group, NB Power Distribution and Customer Service Corporation directly serves more than 325,000 customers and sells electricity to the province's municipal systems, which supply almost 42,000 customers. NB Power has at its disposal a generating capacity of about 4,000 MW, whose production is under the management of NB Power Generation and NB Power Nuclear.

The New Brunswick electricity market has been partially open to competition since October 1, 2004. Large industrial customers and three municipal electricity distribution utilities are now free to choose their supplier. However, retail market customers will continue to be served by NB Power.

SaskPower

Regina, Saskatchewan

SaskPower is a state-owned utility. It directly serves more than 439,000 customers and sells wholesale electricity to municipal systems in Saskatchewan. The utility operates 15 power plants with a net installed capacity of 3,056 MW.

In Saskatchewan, the wholesale electricity market has been open to competition since 2001. In 2003, SaskPower adopted a procurement strategy to ensure that all the province's new electricity needs until 2010 are met from environmentally friendly sources (Green Power Portfolio).

Newfoundland and Labrador Hydro (customers with a power demand of 30,000 kW or more) Newfoundland Power (all other customer categories)

St. John's, Newfoundland & Labrador

Newfoundland Power, a subsidiary of Fortis, serves about 227,000 customers on the island of Newfoundland. Since it operates only small generating stations, whose installed capacity totals 145.5 MW, it purchases 90% of its electricity from state-owned Newfoundland and Labrador Hydro, which operates generating facilities with an installed capacity of 7,289 MW, a transmission system that serves the whole province. It also supplies remote regions, Labrador, and large industrial customers.

In November 2005, the Newfoundland and Labrador government made public a discussion paper that serves as the basis for the province's energy policy. Security of supply and the regulatory framework are among the topics covered in the section on electricity.

Toronto Hydro Ottawa Hydro

Toronto, Ontario
Ottawa, Ontario

A subsidiary of Hydro Ottawa Holding, whose sole shareholder is the City of Ottawa, Hydro Ottawa serves more than 275,000 customers. Toronto Hydro-Electric System, a subsidiary of Toronto Hydro Corporation, whose shareholder is the City of Toronto, serves about 670,000 customers.

In Ontario, the wholesale and retail markets have been open to competition since May 2002. Faced with the increase in the price of electricity that followed, on December 9, 2002, the government imposed a freeze on the electricity commodity price for small consumers. On April 1, 2004, the freeze was lifted and an inverted rate introduced. Following the adoption of the Electricity Restructuring Act in December 2004, the Ontario Energy Board was given the mandate to set the electricity commodity price (Regulated Price Plan). Two new rates came into effect April 1, 2005: an inverted rate for consumers with a standard meter, and an optional time-of-use rate for consumers with a new-generation meter (Ontario Energy Board Smart Meter Initiative). Starting in 2006, the electricity commodity price is to be revised on May 1 of each year and adjusted six months later, if necessary.

BC Hydro

Vancouver, British Columbia

State-owned BC Hydro operates generating facilities which produce more than 11,000 MW, of which more than 90% comes from hydropower. It distributes electricity to about 1.6 million customers.

While the wholesale market is open to competition, the retail market is only accessible to some large industrial customers. A stepped rate for BC Hydro's large industrial customers came into effect April 1, 2006. The price of the second step reflects long-term supply costs.

Manitoba Hydro

Winnipeg, Manitoba

Manitoba Hydro is a state-owned utility serving about 506,000 customers throughout the province. Nearly all the electricity it produces and distributes comes from its 14 hydroelectric generating stations, which have a total capacity of almost 5,500 MW.

The wholesale electricity market has been open to competition since 1997. On September 27, 2001, Manitoba Hydro became a member of Midwest ISO, a Regional Transmission Organization.

American Utilities

Boston Edison

Boston, Massachusetts

Boston Edison, a subsidiary of NStar, serves almost 1.1 million residential and commercial customers in Boston as well as in eastern Massachusetts. Having divested its last generating assets in July 1999, the utility now purchases electricity on the market from other suppliers and concentrates its activities on the transmission and distribution of electricity.

Since March 1, 2005, Boston Edison has applied basic service rates for the electricity commodity component to customers who have chosen not to purchase electricity from a competitor. These rates are adjusted every six months, or every three months in the case of large industrial customers. The rates reflect the average price of electricity on the market.

Commonwealth Edison (ComEd)

Chicago, Illinois

Since it sold its generating assets, ComEd, a subsidiary of Exelon Corporation, purchases, transmits and distributes electricity on the wholesale and retail markets. On the retail market, it serves more than 3.7 million customers in northern Illinois.

Since May 1, 2002, the retail market has been fully open for residential, commercial and industrial customers. Under the legislation restructuring the electricity market adopted in 1997, base rates for residential customers were first reduced by 20%, then frozen until January 2007.

Detroit Edison

Detroit, Michigan

Detroit Edison operates generating facilities with a total installed capacity of almost 11,000 MW. A subsidiary of DTE Energy, it serves 2.1 million customers in southeastern Michigan.

In accordance with the legislation restructuring the electricity industry adopted in June 2000, all retail market customers in Michigan have been able to choose their electricity supplier since January 1, 2002. The rates applicable to residential customers were frozen until December 31, 2005. The rate freeze that applied to large commercial and industrial consumers ended in December 2003, while the freeze that applied to small power customers ended in 2004.

Reliant Energy

Houston, Texas

A subsidiary of Reliant Energy, Reliant Energy HL&P serves approximately 1.9 million customers practically all across Texas, whereas before, its territory covered only Houston and environs. The utility concentrates its activities on electricity transmission and distribution.

The majority of consumers have had access to the retail market since January 1, 2002. Effective January 2007, electric utilities with exclusive distribution rights are expected to discontinue their 'price-to-beat' practice; this practice had been introduced in order to facilitate the transition from a regulated to a competitive market and encourage participation by retail electric providers.

Florida Power and Light (FPL)

Miami, Florida

FP&L's vast transmission and distribution system, which covers more than 111,000 km (69,000 m), supplies more than 4.3 million customers. A subsidiary of FPL Group, the utility operates generating facilities with an installed capacity of 20,777 MW.

In May 2006, the Florida Public Service Commission concluded that it was not in the best interests of consumers to set up a Regional Transmission Organization. The Commission will, however, examine the possibilities of developing the wholesale market.

Consolidated Edison (ConEd)

New York, New York

ConEd of New York serves more than 3.2 million customers in New York City and Westchester County. The Consolidated Edison subsidiary operates the largest underground system in the world, which represents 72% of its distribution system.

When the electricity market was opened to competition in 1998, ConEd had to dispose of a large part of its production capacity, which is now limited to just 630 MW. Rates, which continue to be regulated by the New York State Public Service Commission, are adjusted monthly (adjustment clauses) to reflect the market price of electricity.

Nashville Electric Service

Nashville, Tennessee

Nashville Electric Service, whose shareholder is the City of Nashville, distributes the electricity that it purchases from the Tennessee Valley Authority (TVA) to more than 340,000 customers. A federal agency, the TVA operates generating facilities that produce about 33,000 MW and supplies 158 distributors as well as some 60 large industrial and federal customers.

In 1959, when private utilities had difficulties competing with the TVA, the U.S. government limited the federal agency to selling the electricity it produced within a given territory. Currently, that territory extends over seven U.S. states. In return, the TVA obtained the exclusive right to supply distributors on the territory served and thus was guaranteed not to have to grant other producers access to its transmission system. In the last two years, some electricity distributors have indicated their desire to purchase electricity from suppliers other than the TVA and thus take advantage of the opening of neighboring markets. Discussions are now under way.

Pacific Power and Light

Portland, Oregon

Pacific Power and Light, a subsidiary of PacifiCorp, serves more than 818,000 customers across four states, including 527,000 in Oregon. PacifiCorp operates generating facilities with an installed capacity of 8,260 MW.

On March 1, 2002, the government of Oregon opened its retail market to large commercial and industrial customers. Residential and small commercial customers have more restricted access to the retail market, but they can take advantage of a range of options, including rates based on market prices, regulated rates, or rates applicable to green energy.

Pacific Gas and Electric (PG&E)

San Francisco, California

PG&E concentrates its activities on the transmission and distribution of electricity and natural gas. A subsidiary of PG&E Corporation, it has 5 million customer accounts.

In 2001, California adopted emergency measures to mitigate the price volatility that followed the opening of the electricity market. Those measures allowed it to reinstate regulatory authority over production costs and to give responsibility for electricity purchases to the California Department of Water and Resources. Since January 1, 2003, PG&E has been authorized to again purchase energy and directly supply its customers.

Seattle City Light

Seattle, Washington

Seattle City Light, whose shareholder is the City of Seattle, serves about 376,000 customers. It purchases the majority of the electricity it needs from Bonneville Power Administration (BPA), a northwestern U.S. federal agency that wholesales electricity produced by some 30 hydroelectric generating stations.

Six electric utilities, including Seattle City Light and BPA, got together in early 2006 to form the non-profit ColumbiaGrid. The group's objective is to develop an integrated approach to the use and expansion of the region's interconnected transmission system.

Sources: 1. Annual Reports and Internet sites of the Canadian and American utilities in the study.
2. Edison Electric Institute.

Produced by *Direction principale– Communications*
for *Direction – Affaires réglementaires et tarifaires*

Legal deposit – 4th quarter 2006
Library and Archives Canada
Bibliothèque et Archives nationale du Québec
ISBN 2-550-47949-1
ISBN 978-2-550-47949-9

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Ce document est également publié en français.

2006G854A,2M

Hydro Québec