
BEFORE THE
RÉGIE DE L'ÉNERGIE

IN THE MATTER OF:

HYDRO QUÉBEC

**ALLOCATION DU COÛT DE FOURNITURE
DE L'ÉLECTRICITÉ PATRIMONIALE
PAR CATÉGORIE DE CONSOMMATEURS
POUR LES ANNÉES 2001 ET 2002**

REQUÊTE R-3477-2001

Prepared Report of:

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On Behalf of:

**L'association québécoise des consommateurs
industriels d'électricité (AQCIE)**

**L'association des industries forestières du
Québec (AIFQ)**

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1.0 Overview

Industrial Economics, Incorporated (IEc) was retained by L'association québécoise des consommateurs industriels d'électricité (AQCIE) and L'association des industries forestières du Québec (AIFQ) to review the filing of Hydro Québec (HQ) regarding the "allocation of electric generating costs" to the various classes of domestic consumers, and to evaluate whether the methodology used by HQ is consistent with established cost allocation and rate design principles. To prepare this report, IEc reviewed the HQ filing, drafted information requests on behalf of AQCIE/AIFQ, and reviewed HQ's responses to those interrogatories as well as some additional informal discovery. IEc also prepared various analyses, attached to this report as Exhibits, that replicate the HQ methodology, depict the anomalies inherent in that methodology, and estimate the impacts of eliminating some of the inconsistencies between HQ's assumptions and reasonable cost allocation techniques. In addition, as shown at Exhibits 13 through 16, IEc constructed a cumulative impact scenario that adjusts for errors and biases in HQ's model. In the absence of key data regarding peak demand loss factors from HQ, IEc recommends that the Régie adopt the cost rates derived from these analyses.

IEc's findings can be summarized as follows:

- IEc's understanding is that the object of this exercise is to define a pool of generation-related "costs" for each rate class. These allocated "costs" will then be used as an input to the rate design process for developing bundled tariff rates for electric service.
- HQ's description of this proceeding is something of a misnomer in that no costs are being allocated. Instead, this filing develops cost rates for energy in the absence of any cost information, based on the interpretation of the *Loi sur la Régie de l'énergie*¹ (the Act).
- The fundamental position of HQ in this proceeding is that it has used the same methodology as that used to develop the rates specified in Annexe 1 of the Act, and therefore the Act requires the use of this methodology. IEc offers no legal opinion as to whether HQ's methodology is mandated by the Act. This report provides an analysis of HQ's methodology based on fundamental economics and cost allocation principles.
- IEc confirms that the summary methodology used by HQ in this proceeding for 2001 and 2002 cost allocation matches that used to develop the legislated rates specified in Annexe 1 of the Act. However, because HQ generally refused to provide supporting workpapers, IEc cannot confirm whether the methodologies used by HQ in this proceeding to develop load profiles, load factors and loss ratios are consistent with those analyses used for 2000.

¹ *Loi sur la Régie* (L.R.Q., c. R-6.01), modified by *Loi modifiant la Loi sur la Régie de l'énergie et d'autres dispositions législatives* (2000, chapter 22).

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- In reviewing the information available, IEC has concerns that the weather normalization procedure used by HQ may understate weather effects, although the direction of the related bias is unknown. Moreover, the data inputs to HQ's methodology show some significant changes between 2000 and 2001 that are unexplained.
 - HQ's interpretation of the Act is that the cost rates for all domestic rate classes (including "virtual" cost rates for the special contracts class) must produce a weighted average energy cost rate of 2.79 cents per kWh consumed (as opposed to generated) for the "heritage pool" load. Without necessarily faulting HQ's overall methodology, IEC notes that this requirement, as implemented by HQ, can produce anomalous results over time. For example:
 - If the mix of overall load shifts from low load factor residential classes to higher load factor industrial classes (e.g., as a result of reductions in electric heat), *rates for all rate classes will increase, with no net change to the 2.79 cents per kWh average.* This result is particularly bizarre, because an increase in the mix of high load factor industrial load tends to reduce the per-unit cost of generation.
 - Improvements in the distribution system to reduce losses at low voltage levels will cause rates for industrial customers to increase. This result also is peculiar, in that industrial customers generally do not use the distribution system, and reductions in distribution losses will reduce the overall costs incurred by a distribution utility which purchases the power for its customers.
 - Improvements in the load factor for one class will cause rates to increase for all other classes, despite concurrent decreases in the unit costs of supply.
 - HQ's methodology includes the special contracts class in computing the average rate of 2.79 cents per kWh. However, because the special contracts class has rates that are specified by contract, the cost rate computed by HQ for the special contracts class is a "virtual" rate; that is, it is not the actual cost rate incurred by the special contracts class. This virtual rate has limited relevance, as it is used only for computing a 2.79 cents per kWh average. While IEC has no opinion about the legal requirements for including or excluding the special contracts class in the calculations, we note that excluding the class will reduce the cost rates for all other rate classes. In other words, excluding the special contracts class from the rate schedule allows for cost rate decreases to each class in order to achieve the statutory average of 2.79 cents per kWh.
 - HQ proposes to classify generation costs on the basis of system load factor. While various methods may be used to classify electric generation costs, we note that HQ's proposed method produces a classification split that is more energy-related than that used historically by other Canadian utilities. Moreover, we note that the use of the system load factor classification method has the perverse effect of increasing unit rates for the higher load factor classes when the system load factor
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improves. This impact results despite the fact that increasing system load factor should reduce costs for the distributor. We recommend that a *fixed* classification split be used, at 60 percent energy, 40 percent demand.

- HQ proposes to determine coincident peak demand based on an average of the highest 300 hours of system demand. This proposal is not consistent with industry practice and is inconsistent with cost causation. HQ's proposal to use a 300-hour peak basis implies that generation is planned and constructed with insufficient capacity to meet some 150 hours of demand per year. In light of the distinct winter-peaking nature of HQ demand, we recommend that peak demand be determined based on a 1 CP method.
- HQ's methodology incorrectly includes interruptible load in peak demand. Because generating capacity is neither planned nor constructed to meet interruptible demand, any such peak load should not attract demand costs in a cost allocation methodology. While some jurisdictions choose to share the benefits of interruptible load between interruptible and firm customers, this sharing of benefits is better accomplished in the rate design process, rather than polluting the cost allocation analysis with policy considerations. IEc recommends that interruptible demand be excluded from HQ's calculation of peak demand for purposes of this proceeding.
- HQ's methodology incorrectly uses the same loss factors at peak demand as for average demand. Energy losses tend to increase with the square of the power transmitted, and therefore loss factors are higher at peak than on average. We recommend that HQ rely on time of use analyses of losses by rate class for both average and peak periods.

While IEc is unable to correct all of the economic and cost allocation errors in the HQ methodology, Table 1 below shows our estimate of the allocated unit energy costs by rate class. Note, results are reported under two assumptions; that is, including and excluding the special contracts class for the base years 2001 and 2002.

Table 1				
Summary of IEc Recommendations for Unit Costs				
(Cents per kWh)				
	<i>Including Cont. Spéc.</i>		<i>Excluding Cont. Spéc.</i>	
	<i>2001</i>	<i>2002</i>	<i>2001</i>	<i>2002</i>
D et DM	3.47	3.45	3.34	3.33
DH	3.25	3.24	3.13	3.13
G et à forfait	3.04	3.05	2.94	2.95
G-9	2.57	2.59	2.51	2.53
M	2.72	2.73	2.64	2.66
L	2.24	2.24	2.19	2.19
H	2.43	2.43	2.37	2.37
DT	2.79	2.80	2.71	2.72
Tdps	3.20	3.20	3.09	3.09
Contrats spéciaux	2.24	2.25	--	--
<i>Distributeur</i>	<i>2.79</i>	<i>2.79</i>	<i>2.79</i>	<i>2.79</i>

IEc anticipates that this report will be introduced by AQCIE/AIFQ as expert evidence in the referenced proceedings. This report has been prepared by and under the direction of Mr. Robert D. Knecht of IEc. Mr. Knecht's *curriculum vitae* and a schedule of his appearances before regulatory authorities is attached to this report as Exhibit 18. A spreadsheet version of IEc's analysis is presented in Exhibits 1 through 16 and is submitted with this report. We summarize the basis for our conclusions in more detail below.

2.0 Implications of the Hydro Québec Methodology

2.1 The HQ Methodology

The HQ methodology for allocating generating costs can be summarized as follows. HQ develops an average loss factor and a coincident peak load factor (measured at the generator) for each intra-provincial rate class, including the special contracts class. Load factors are derived from weather normalized average and peak demands, with the peak demand measurement being averaged over the top 300 hours in the year. Average loss factors are developed for three voltage groupings (BT, MT, and HT) based on average annual losses. Loss factors for each rate class are derived based on energy consumption by voltage group within each rate class.

Based on its interpretation of the Act, HQ requires that the average delivered per-kWh allocated cost be 2.79 cents. HQ "classifies" the 2.79 cents per kWh cost into energy and demand components, based on the coincident peak load factor for the "heritage pool" load. Each class' allocated energy costs are set equal to the average energy share multiplied by the ratio of one plus the class loss factor to one plus the system loss factor. Each class' share of the demand

costs is set equal to the average demand share multiplied by the ratio of system load factor to class load factor and by one plus the class loss factor to one plus the system load factor. Algebraically, the formula is as follows:

$$C_i = C_T * U_T * \frac{(1+L_i)}{(1+L_T)} + C_T * (1-U_T) * \frac{U_T}{U_i} * \frac{(1+L_i)}{(1+L_T)}$$

--- Energy --- ----- Demand -----

where C represents the unit allocated cost per kWh, U the load factor (at the generator), L the average loss factor, i the rate class designation and T the system total.

IEc agrees that HQ's formula is methodologically consistent with traditional cost allocation approaches. This conclusion can be demonstrated algebraically. If we substitute cost divided by energy consumed (K/E) for C, energy generated divided by energy consumed (G/E) for (1+L), average energy generated divided by peak energy generated (G/P) for U, and we specify the energy and demand classification shares directly (E%, D%), the HQ formula defaults to a traditional cost allocation approach:

$$\frac{K_i}{E_i} = \frac{K_T}{E_T} * \left[\left(E\% * \frac{G_i/E_i}{G_T/E_T} \right) + \left(D\% * \frac{G_T/P_T}{G_i/P_i} * \frac{G_i/E_i}{G_T/E_T} \right) \right]$$

which reduces to:

$$K_i = K_T * \left[E\% * \frac{G_i}{G_T} + D\% * \frac{P_i}{P_T} \right]$$

That is, allocated energy costs are shared in proportion to the average energy generated requirement, and allocated peak demand costs are shared in proportion to peak generation requirements.² IEc replicated the aggregate calculations for 2000, 2001 and 2002 in Exhibits 1 through 3, using the information presented in HQ's filing and HQD-2, Document 3. As shown in those exhibits, HQ used the same methodology for 2001 and 2002 as that used for 2000. Note that, for the 2000 rates shown in Annexe 1 of the Act to average 2.79, a "virtual" rate for the special contracts class (or 2.39) must be included in the calculations.

IEc's replication consists of four tables.

- Using the 2001 replication shown in Exhibit 2 as an example, the first table, Loss Factor Calculation, computes the loss factors for each rate class,

² Note the formula specifies that load factor should be based on the ratio of energy load at the generator to peak demand at the generator (G/P), where different loss factors are used to derive the peak and energy data at the generator level. However, the loss factor adjustment (class v. system G/E) that is applied to the demand component of costs in this model should be the average loss factor, and not the peak loss factor, regardless of whether a different peak loss measure is used to derive load factors. Note, if the relative average loss factor is not used, the familiar allocation formula does not result.

replicating Tableau A4.1 in HQ's filing. The table takes, as inputs, loss factors by voltage grouping (BT, MT and HT) and energy consumed at each rate class by voltage grouping.

- The second table, Load Factor Calculation – Customer Basis, depicts annual energy consumed, peak demand, and load factor, as measured at the customers' meters. It is derived from the information in Tableau A3.1 and from the loss factors derived in the first table.
- The third table, Load Factor Calculation – Generator Basis, shows the same average and peak demand information, but at the generator level. In the 2001 example, the load factors for each class are the same as at the customer meter, because HQ uses the same loss factors for average and peak demand. (Note, the system average load factor is a little different, due to the change in "mix" arising from the different average loss factors among the rate classes.)
- Finally, the fourth table, Calculation of Energy Rates, computes the average energy rate pursuant to HQ's formula discussed above; that is, based on the 2.79 cents per kWh statutory rate and class-specific load factors and loss factors.

2.1 Information Limitations and Unresolved Issues

Developing the various input parameters to the HQ algebraic formulation is a complex analytical process. Due to information, time, and budget limitations, IEC has not prepared a detailed evaluation of HQ's methodology for deriving the specific parameters. In particular, we did not conduct detailed analyses regarding the following topics.

While historical metered energy consumption information is usually readily available on a monthly basis, cost allocation requires the development of hourly peak demand estimates. Such estimates generally are not available from the meters used by smaller customers. Thus, load research usually is used to estimate peak demands for the various rate classes. This research typically is based on stratified samples of customers in each class. While HQ apparently performed similar analyses in developing hourly load profiles by rate class, it has not shared these analyses with the intervenors.³

In addition, because the demand for electricity in Québec is sensitive to temperature, HQ correctly recognizes that it is necessary to normalize the historical loads for weather factors. As we understand, HQ uses a regression model to perform the normalization, but this analysis also is not available to the intervenors. Although IEC has not reviewed this analysis, we raise two concerns about the HQ methodology that may tend to understate weather effects. First, HQ normalizes the load profiles based on a 30-year temperature average. However, supply planning

³ See Réponses à la Demande de Renseignements de AQCIE/AIFQ, HQD-2, Document 3. Réponse for Question 1.e.i. and 1.e.ii (pp. 5 to 6 of 13). See also Réponses à la Demande de Renseignements de la Régie, HQD-2, Document 1. Réponse for Question 2,1 (pp. 9 to 10 of 27). We note that HQ submitted coincident peak demand allocation parameters after the completion of the first version of this report, causing IEC to incur additional cost and produce this revised report.

requires that generation capacity be built to meet more extreme temperatures than the average. Generation planners include a reserve margin to meet extreme weather conditions, generator outages, and other reliability concerns. Second, HQ appears to normalize based on monthly data, and thus misses the effects of more extreme weather on individual days within the month.⁴ We recommend that the Régie require HQ to demonstrate that its weather normalization calculations do not unduly dampen weather effects for the temperature sensitive rate classes.

In addition, we note that some data shifts appear to have occurred between the 2000 and 2001 inputs. These include:

- A significant shift to low voltage (BT) connections from medium voltage (MT) connections in the Rate M class; for example, annual metered energy for medium voltage connection under the Rate M class totaled 11,507 GWh during 2000 as compared to 6,878 GWh during 2001. Concurrently, low voltage connections under the same class increased from 10,622 GWh during 2000 to 16,443 GWh during 2001.
- Substantial increases in load factor in the Rate M and (to a lesser extent) Rate G classes.

Exhibit 4 provides a comparison of the percent changes in all factors in the HQ methodology between 2000 and 2001.

2.2 *Methodological Anomalies*

Utility cost allocation is often described as a zero-sum game -- there is a fixed pool of costs to be recovered from customers, and any costs that are not allocated to one class of customer must be recovered from the other classes. However, even in traditional cost allocation analyses, improvements in system load factor and reductions in losses will reduce the average per-unit delivered cost of energy between rate proceedings.

This is not so with the HQ methodology.

HQ's methodology is premised on the assumption that the weighted-average, delivered, per-unit cost of power across all customer classes must remain the same; that is, at the 2.79 cents per kWh statutory value. With this constraint, HQ's methodology can produce counter-intuitive results, as detailed further below. While it is not clear that these anomalies can be resolved within the boundaries of the Act without relaxing the constraint on the 2.79 cents per kWh average, we highlight these anomalies for consideration in evaluating alternatives.

Energy Consumption Mix

⁴ See Réponses à la Demande de Renseignements de AQCIE/AIFQ, HQD-2, Document 3. Réponse for Question 1.c.ii. and 1.c.iii (pp. 4 to 5 of 13). See also Réponses à la Demande de Renseignements de la Régie, HQD-2, Document 1. Réponse for Question 2,6 (pp. 11 of 27).

First, we consider the impact of a shift in the "mix" of energy consumption. For demonstration purposes, we prepared an alternative version of the 2001 base analysis. This simulation is shown in Exhibit 5. The only input change from the 2001 base year is a 20 percent increase in Rate L energy consumption and a corresponding kWh reduction in Rate D consumption, as shown in the Loss Factor Calculation table at the top of the first page of Exhibit 5. For an actual utility with real costs to be allocated, an increase in the mix of high load factor customers will reduce average unit costs for the system as a whole. However, the HQ methodology yields a very different result. As shown in Table 2 below and Exhibit 5, *average allocated costs increase for all rate classes!* This result occurs, because the share of lower unit cost energy has increased and, to maintain the fixed system average of 2.79 cents per kilowatt hour, rates for all classes must increase to compensate.

Table 2			
Impact of Increase in High Load Factor Energy Mix			
Major Rate Classes, cents per kWh			
	<i>2001 Base</i>	<i>Scenario</i>	<i>Percent</i>
D et DM	3.23	3.25	0.7%
G et à forfait	2.91	2.95	1.3%
M	2.70	2.74	1.7%
L	2.48	2.53	2.0%
DT	2.70	2.75	1.7%
Contrats spéciaux	2.44	2.49	2.1%
Distributeur	2.79	2.79	0.0%
<i>Notes: In this and subsequent tables, some of the smaller rate classes are not reported separately, but are included in the "Distributeur" average. Also, the percentage change values are based on the spreadsheet analysis of cost rates, and are therefore based on more significant digits than those shown in these tables.</i>			

In addition to the first order impact of the change in mix, we note that a second order effect causes the rate increases for the high load factor classes to be higher than for low load factor classes. For example, increasing the mix of Rate L load increases the overall system load factor. When the system load factor increases, more costs are classified as energy-related under HQ's methodology, and therefore more costs get allocated to the higher load factor classes. Thus, as shown in Table 2, the percentage increase for Rate L and the special contracts class is considerably higher than the increase for Rate D. As such, the HQ methodology produces the perverse result that load growth for the industrial classes causes rates for these classes to increase disproportionately. Conversely, an increase in mix toward the lower load factor, temperature sensitive classes tends to reduce rates for all classes, and disproportionately favors the higher load factor classes.

We have one final observation with respect to this anomaly. HQ's position is that the Act only provides for changes based on load factors and loss factors. This simulation changes

neither load, nor loss factors, and yet the rates change. As such, we note that an argument can be made that HQ's methodology is not consistent with its interpretation of the Act.⁵

Loss Factors

A second anomaly arises with HQ's treatment of losses. Reductions in loss factors cause the costs for delivered energy to decline, even for a distributor who purchases energy from competitive generators. (Reducing losses means that the distributor needs to purchase less energy from the generators to meet the same delivered energy requirements. Thus, reducing losses reduces the cost of delivered energy.) However, under the HQ methodology, not only do costs not decline, but some rate classes are penalized for the improvement.

To demonstrate this anomaly, Exhibit 6 depicts a scenario (again relative to the 2001 base) in which the loss factor for the low voltage (or BT) distribution system is reduced from 10.21 percent to 9.50 percent. The logical result of this change would be a reduction in costs for the classes served by low voltage facilities, and no impact on those classes which are connected at higher voltage (MT and HT). However, as shown below in Table 3 and in Exhibit 6, this change reduces rates for some classes, but does so at the expense of the higher voltage classes which are not serviced by the distribution system. Moreover, HQ's methodology dampens the benefit on the low voltage classes. In this example, the energy purchased at the generator for the Rate D class declines by 0.6 percent (from 54,163 GWh in the 2001 case to 53,816 GWh in this simulation), but the allocated cost for Rate D declines by only 0.3 percent. In effect, because a 2.79 cents per kWh average is required, the cost benefit of reduced losses cannot be passed through fully to the relevant customers.

Table 3			
Impact of Reduction in BT Loss Factor			
Major Rate Classes, cents per kWh			
	<i>2001 Base</i>	<i>Scenario</i>	<i>Percent</i>
D et DM	3.23	3.22	-0.3%
G et à forfait	2.91	2.90	-0.3%
M	2.70	2.69	-0.1%
L	2.48	2.49	+0.4%
DT	2.70	2.70	-0.3%
Contrats spéciaux	2.44	2.45	+0.4%
Distributeur	2.79	2.79	0.0%

⁵ This problem could potentially be avoided by retaining the 2000 class mix of energy consumed for deriving the average 2.79 cents per kWh rate. However, when applied to the actual mix, the average 2.79 cents per kWh stricture arguably would be violated.

Load Factors

Exhibit 7 depicts the implications of one other change, namely the effects of improving the load factor for the Rate D class. While load factor improvements should reduce the average system cost of power, HQ's methodology produces a different result. As shown in Table 4 below and in Exhibit 7, a 10 percent improvement in Rate D load factor, with no reduction in load factor for the higher load factor classes, causes rates for all other classes to increase, while rates for Rate D class decrease by 3.2 percent. Note again, the effect is exacerbated by the use of a system load factor classification methodology, and the impact on higher load factor classes is greater than that on other classes.

	<i>2001 Base</i>	<i>Scenario</i>	<i>Percent</i>
D et DM	3.23	3.12	-3.2%
G et à forfait	2.91	2.95	+1.3%
M	2.70	2.74	+1.8%
L	2.48	2.54	+2.1%
DT	2.70	2.75	+1.8%
Contrats spéciaux	2.44	2.49	+2.2%
Distributeur	2.79	2.79	0.0%

3.0 Special Contracts Class

Section 52.2 of the Act states that the "*cost attributed to each class of consumers is based on an average heritage pool electricity cost of 2.79 cents per kilowatt-hour . . .*," suggesting that if the special contracts class is part of the heritage pool, it should be included in the calculation, as HQ has done. However, Section 52.2 also states:

"In the case of special contracts entered into under the Hydro-Québec Act (chapter H-5), the cost of electric power corresponds to the rate stipulated in the contract, less the transmission and distribution costs applicable according to consumption characteristics, and does not affect the cost to the electric power distributor applicable to other classes of consumers for the purposes of section 52.1."

IEc is not qualified to offer a legal interpretation of Section 52.2, and defers to counsel in this matter. However, at the request of AQCIE/AIFQ, IEc has evaluated the impact of excluding the Special Contracts class from HQ's analysis. This analysis is shown in Exhibit 8.

IEc's analysis uses the 2001 HQ methodology as a base, and simply excludes energy and demand for the special contracts class. As shown in Table 5 below and in Exhibit 8, *excluding the special contracts class reduces rates for all other rate classes*. Note again, the effect is

greater for the higher load factor classes, due to HQ's load factor classification methodology. By excluding the higher load factor special contracts class, the system load factor declines and more costs are classified as demand-related, increasing the burden on the lower load factor classes.

	<i>2001 Base</i>	<i>Scenario</i>	<i>Percent</i>
D et DM	3.23	3.18	-1.4%
G et à forfait	2.91	2.85	-2.0%
M	2.70	2.63	-2.4%
L	2.48	2.42	-2.7%
DT	2.70	2.64	-2.5%
Contrats spéciaux	2.44	--	--
<i>Distributeur</i>	<i>2.79</i>	<i>2.79</i>	<i>0.0%</i>

4.0 Cost Classification

Historically, classification of generation costs has been one of the most contentious aspects of electric utility cost allocation, at least until the advent of competition in the generation sector. Nevertheless, there is near unanimous agreement that some generating costs vary with the amount of energy produced, and some costs vary with the capacity of the plant. As such, cost allocation analysts "classify" costs into energy and demand components, to properly assign those costs to the customers who cause those costs to be incurred. This is the key principle of cost causation.

If there existed only one type of generating plant with a specific cost structure, there (probably) would be reasonable agreement amongst cost analysts regarding how to allocate costs. Fixed costs related to the size of the plant would be classified as "demand-related," and variable fuel and O&M costs would be classified as "energy-related." Energy costs would have no time-of-use pattern, and demand costs would be the same for all plants. This classification methodology is known as "straight fixed-variable," and sometimes is used even in more complex circumstances.

However, in reality, many different types of generating plants exist. Generation planners (at traditional integrated utilities) make a tradeoff between high-capital, low-operating cost baseload plants and low-capital, high-operating cost peaking units. Because peaking plants have low capital costs, some analysts advocate only that the cost of peaking units be considered demand costs, and that all capital-related costs in excess of peaking units be deemed energy-related. While that approach has some merit, it is reasonable only if energy costs are allocated on a time-of-use basis. Because energy costs for peakers are higher than the energy costs for baseload plants, the per unit energy cost during peak periods is higher than during off-peak

periods.⁶ Thus, per-unit energy costs for low load factor classes should be higher than per-unit energy costs for high load factor classes. Because HQ proposes to allocate energy costs on an energy consumed basis, and not on a time-of-use basis, a demand classification methodology such as "equivalent peaker" is not consistent with cost causation.

For this exercise, the problem is compounded by two factors. First, like several other Canadian utilities, HQ's generating capacity is dominated by hydroelectric facilities. Hydro facilities incur high capital cost and very low energy cost. Any effort to use a straight fixed-variable methodology will result in an extraordinary cost differential between high and low load factor classes. Second, as noted earlier, no actual generating cost information was provided in these proceedings.

HQ's solution to this problem is to use a load factor classification methodology, based on its interpretation of an APPA manual.⁷ IEC has two concerns regarding this methodology. First, as suggested in the preceding section, the use of a system load factor classification methodology penalizes the higher load factor classes if load factor improves, and rewards the higher load factor classes if system load factor declines. At a minimum, IEC strongly recommends that the Régie require HQ to use a fixed classification methodology, to avoid these perverse impacts. Relying on a fixed classification split will in no way violate the 2.79 cent per kWh requirement, nor need it even conflict with HQ's interpretation of the Act.

In addition, HQ's methodology tends to classify a relatively high share of costs to energy-related, because of the relatively high share of industrial load in Québec. For a 1991 generic cost allocation proceeding for New Brunswick Power, IEC prepared a comparative study of cost classification at most of the major integrated electric utilities in Canada. Excerpts from that study are copied in Exhibit 17. That study concluded that the average classification of generation plus transmission costs was approximately 50 percent demand, 50 percent energy across Canada at that time.⁸

⁶ It can be mathematically demonstrated that (for a utility with an optimal combination of baseload, intermediate load, and peaking units) costs can be exactly recovered by imposing: (1) a demand charge equal to the fixed cost of the peaking units; and (2) an energy charge equal to the variable cost of the marginal operating unit for each hour of the year. See Turvey, Ralph, Optimal Pricing and Investment in Electricity Supply, The MIT Press, 1968.

⁷ Unfortunately, the APPA manual is no longer listed by APPA on its publications list, and HQ has refused to provide a copy. However, based on the excerpt provided by HQ in HQD-2, Document 1, item 3.1, it appears that HQ has not correctly interpreted the APPA method. APPA suggests that hydro capacity costs can be classified on the basis of "plant factor," which is a utilization rate measure for the plant. Moreover, the APPA manual also suggests that a fixed-variable classification method be used for all non-hydro plant. Accordingly, HQ's interpretation contains two errors. First, HQ has not applied a fixed-variable approach to non-hydro capacity. Second, plant capacity must exceed peak demand, typically by a reserve margin of some 20 percent. Therefore, the system-wide plant factor is significantly lower than system-wide load factor; that is, by a factor of 1.2. If HQ were to adopt the APPA "plant factor" suggestion, a more reasonable estimate of the energy component of costs would be 56 percent (the 67.3 percent load factor from HQ's 2001 calculations, reduced by the 1.2 reserve margin factor).

⁸ Note, some utilities would implicitly incorporate a demand-energy split into their allocation methodology by using an "average-and-excess" or "peak-and-average" allocation factor. Our 1991 analysis adjusted for this approach by computing the implied classification split within the allocators. IEC believes that it is simpler and more

We recommend that the Régie establish a fixed cost classification split, based on 60 percent energy-related and 40 percent demand-related. Such a classification split is somewhat more favorable to the temperature sensitive classes than the average produced by IEC's 1991 analysis, and it is reasonably consistent with HQ's historical cost classification practice.⁹ The implications for a base year of 2001 of adopting such a change are shown in Table 6 below and in Exhibit 9.¹⁰

	<i>2001 Base</i>	<i>Scenario</i>	<i>Percent</i>
D et DM	3.23	3.31	+2.6%
G et à forfait	2.91	2.92	+0.5%
M	2.70	2.67	-1.0%
L	2.48	2.43	-2.2%
DT	2.70	2.67	-1.2%
Contrats spéciaux	2.44	2.37	-2.6%
<i>Distributeur</i>	<i>2.79</i>	<i>2.79</i>	<i>0.0%</i>

5.0 Peak Demand Allocation

5.1 Definition of Peak Demand

As shown in the formulae presented in Section 2.1 above, allocation of demand-related costs requires that a peak period be defined. Because generating capacity is sized to meet the peak system demand, most analysts recommend that system "coincident peak" demand measures be used to allocate demand-related costs. In its purest form, a single coincident peak (1CP) methodology is used, whereby demand costs are allocated to rate classes based on the single highest point of demand during the year. However, for some load patterns, multiple CP methods make more sense. For example, some utilities experience pronounced winter and summer peaks, and the customer contribution mix at the different peaks varies considerably. For example, commercial classes tend to be larger contributors to air conditioning peaks in the summer than to heating-related peaks in the winter. Such utilities may use a combination summer-winter CP method. A 12 CP method, relying on the single CP in each month, recognizes that peaks in

accurate to classify demand and energy costs explicitly than to hide such classification in the allocation stage of the process.

⁹ See, for example, "Coûts de fourniture d'électricité, Principes et méthodologie," Novembre 1995, page 44, which suggests a classification split of 41 percent demand, 59 percent energy, in 1994.

¹⁰ As discussed further below, HQ's methodology for defining peak demand causes the system load factor to be incorrectly overstated. The impact of a 60/40 classification methodology is smaller, if a more reasonable definition of peak demand is used.

spring and fall months also can strain the generating plant capacity, because generating plants tend to be down for maintenance in those periods.

HQ proposes to use (or proposes to continue to use) a 300 CP method, based on the 300 top hours of the year. IEC finds no cost causation basis for this method. HQ's methodology implies that a generation planner builds capacity to meet the average of the top 300 hours of demand in the year. If that actually were the case, HQ's customers would experience capacity shortfalls for approximately 150 hours, or about 6 full days, every year. IEC is unaware of any utility that allocates demand costs on a 300 hour peak basis (particularly in conjunction with a non-time-of-use energy allocation).

HQ's justification of this methodology does not rely on cost causation. Specifically, HQ argues that (a) use of a 300-hour peak basis is consistent with its cost methods since the 1970s, and (b) that the methodology produces an equitable, just, and representative result for Québec.¹¹ While IEC recognizes some value in maintaining stability associated with continued use of a methodology, it makes little sense to do so when the methodology is so at odds with cost causation. Second, IEC concludes that HQ's argument for equity means that lower load factor customers should be subsidized by higher load factor customers. While such an approach may be deemed in the public interest by regulators or government officials, IEC recommends that such a subsidy be established explicitly as part of the rate design process, and not concealed in the cost allocation quantitative analysis.

Because HQ's load shows a very pronounced winter peak (as shown in Annexe 2 to HQ's filing), IEC recommends that a 1 CP approach be adopted for cost allocation. We note also that a 1 CP allocation method is consistent with the methodology used by HQ for segregating transmission costs between network and point-to-point service customers.¹²

In its original responses to interrogatories, HQ refused to provide the load data underpinning its calculation of peak demand, and IEC could only estimate the impact of a 1 CP methodology. However, through informal discovery, HQ has provided 1 CP allocators, although it has not provided any supporting materials. Using this information, IEC estimated the impact of adopting a 1 CP methodology in Exhibit 10, the results of which are summarized in Table 7 below.¹³

¹¹ See Réponses à la Demande de Renseignements de AQCIE/AIFQ, HQD-2, Document 3. Réponse for Question 1.e.iii. (pp. 6 of 13). See also Réponses à la Demande de Renseignements de la Régie, HQD-2, Document 1. Réponse for Question 7.1 (pp. 22 of 27).

¹² See Demande révisée relative à la modification des tarifs de transport d'électricité, Dossier R-3401-98; Argumentation de Hydro-Québec. August 9, 2001. And, Plan d'Approvisionnement pour le Réseau Intégré; Requête R-3470-2001; HQD-2, Document 1.

¹³ Note that Exhibit 10 indicates that the "Tarifs d'éclairage public sentinelle" experiences a 17 percent increase in allocated costs using this methodology. This fairly extreme result presumably occurs because this lighting is on during single hourly coincident peaks, but not on constantly during the extended cold weather periods included in HQ's top 300 hours. Nevertheless, generating capacity must be in place to serve this load, if this load is firm. Thus, unless HQ can interrupt this load, it should pay for its share of generating demand costs.

Table 7
Impact of Using a 1 CP Allocation Methodology
Major Rate Classes, cents per kWh

	<i>2001 Base</i>	<i>Scenario</i>	<i>Percent</i>
D et DM	3.23	3.35	+4.0%
G et à forfait	2.91	2.98	+2.3%
M	2.70	2.69	-0.1%
L	2.48	2.38	-4.1%
DT	2.70	2.75	+1.8%
Contrats spéciaux	2.44	2.31	-5.4%
<i>Distributeur</i>	<i>2.79</i>	<i>2.79</i>	<i>0.0%</i>

5.2 *Interruptible Load*

A significant share of Rate L and special contracts load is interruptible, meaning that the electric utility can interrupt power flow to these customers when peak conditions warrant. Interruptible service is one of the oldest forms of demand-side management, because it is often more economic for a utility to interrupt customers rather than to construct new generation and transmission plants. (It is also more economic for such customers to accept a lower quality service for a lower price.) Moreover, utility planners assume in their planning studies that there will be load interruptions, and thus do not construct capacity to meet the full load. Thus, interruptible load does not cause the utility to incur demand-related costs. From a cost causation standpoint, demand costs should not be allocated to interruptible customers.¹⁴

HQ argues that interruptible load should not be deducted from peak demands, principally on the basis of its assertion that there were no actual interruptions in 2000.¹⁵ This argument misunderstands the nature of interruptible load. Because the *ability to interrupt* is available to the utility, it does not need to build (or purchase) capacity to meet that load. Thus, even if interruptible customers are not interrupted in a particular year, that interruptible capacity is

¹⁴ Note some caution is called for in this conclusion. In particular, if allocated "demand costs" include some of the higher energy costs associated with peaking units, as well as the capital costs of those units, the credit for interruptible service could be overstated. (In general, interruptible service provisions do not allow interruptions for all hours in which combustion turbines are on margin, particularly for efficiently configured generating systems with substantial peaker capacity.) Thus, some analysts advocate setting the interruptible cost credit at no more than the capital cost of a combustion turbine unit. However, the demand cost credit for HQ is approximately C\$50 to C\$60 per kW per year, which is below the fixed cost for a new combustion turbine unit. (The US Energy Information Agency reports capital costs of \$331 per kW for conventional combustion turbine units.) At a conservative capital recovery factor (depreciation, return, taxes) of 12 percent, plus the EIA reported \$6.30 per kW in fixed O&M costs, the fixed costs for a CT are about \$46 per kW, or C\$74 per kW. See www.eia.doe.gov/oiaf/archive/aeo01/assumption/tbl43.html.

¹⁵ See Réponses à la Demande de Renseignements de AQCIE/AIFQ, HQD-2, Document 3, Réponse for Question 1.e.v. (p. 6 of 13).

available to the utility if it is needed, and it reduces the costs that the utility would otherwise incur.

Finally, we note that HQ's argument is belied by its own rate design. Interruptible customers are granted demand charge discounts, ranging from \$27.65 to \$39.23 per kW per year, *whether or not they are interrupted*. Thus, HQ's methodology in this proceeding implicitly allocates costs to Rate L class as if all customers were firm. HQ then designs rates that provide discounts to interruptible customers within Rate L. Assuming that the rate class recovers all its costs, the interruptible rate discount is paid for by Rate L firm customers. In effect, HQ's method leads to rates for firm Rate L customers in excess of allocated firm costs, while all other rate classes benefit from the cost savings provided by the interruptible load.

Based on consultations with AQCIE/AIFQ, IEC has simulated the effect of excluding interruptible load from Rate L and the special contracts class, by deducting 1,000 MW of peak load from Rate L, and 200 MW of peak load from the special contracts class. The results of this analysis are shown in Exhibit 11, and Table 8 below.

	<i>2001 Base</i>	<i>Scenario</i>	<i>Percent</i>
D et DM	3.23	3.25	+0.6%
G et à forfait	2.91	2.94	+1.3%
M	2.70	2.74	+1.7%
L	2.48	2.42	-2.7%
DT	2.70	2.75	+1.8%
Contrats spéciaux	2.44	2.44	+0.3%
<i>Distributeur</i>	<i>2.79</i>	<i>2.79</i>	<i>0.0%</i>

6.0 Peak Loss Factors

In the HQ methodology, load factor is measured at the generator. This approach is consistent with cost causation, because both the peak demand and the average demand of various different types of consumers causes the generator to incur different costs, depending on the level of losses. However, HQ proposes to use the same loss factor for both peak and average demand, based on the loss factor derived for average demand. While IEC does not claim expertise in power system engineering, we note that HQ's approach is inconsistent with the laws of physics. Electric power losses tend to be incurred in proportion to the square of the power flow through a circuit, and thus loss factors tend to be higher on-peak than off-peak.¹⁶

¹⁶ See, for example, Power System Economics, Designing Markets for Electricity, Stoft, Steven, IEEE/Wiley, Forthcoming in May 2002, page 378, available at www.stoft.com.

As we understand, HQ declines to estimate peak period loss factors, citing concerns about instability in loss factor estimates that arise from a variety of technical factors.¹⁷ As other utilities are apparently able to estimate these factors, including hourly estimates in real time in some jurisdictions,¹⁸ IEC does not believe that such analysis is beyond the capabilities of HQ. As such, IEC recommends that the Régie require HQ to undertake this analysis and to use the results in its cost allocation procedures.

To provide a rough estimate of the impact of using peak loss factors, IEC used two different approaches, which produced reasonably similar results. Peak demand loss rates from each method were averaged, to produce an estimated impact.

In the first method, IEC constructed a simple loss model. For each voltage grouping (HT, MT, and BT), we assumed that losses at that level could be modeled in the form:

$$L_g = k_g * D_g^2$$

where L is losses in kW, D is demand, k is a constant term and g represents the three groupings of voltage service. By substituting the HQ values for L and average demand, IEC derived a k factor for each voltage level. Note, IEC modeled demand at each voltage level by assuming all load was subject to HT losses, and all MT and BT load incurred MT losses. Having derived the constant term k for each voltage group, IEC substituted the peak demand value into the equation, to derive L at peak. This analysis is shown in Exhibit 12, in the tables labeled "Loss Factor 1 Calculation" and "Loss Factor 1 Analysis."

Second, IEC employed a methodology used in a study prepared by UtiliCorp Networks Canada (UNC) that allocated average and peak demand distribution losses to the various rate classes.¹⁹ In that study, UNC employed the following formulation to relate average and peak losses for distribution feeders:²⁰

"Annual Energy Losses (GWhrs) = 8760 hrs x Peak Loss x Loss Factor (LsF)

Where Loss Factor (LsF) = 0.15 x Load Factor + .85 x (Load Factor)²"

Using that formula, the relationship between the annual loss factor and the peak loss factor can be derived as follows. Annual loss factor (A%) is annual energy losses (L_E) divided

¹⁷ See Réponses à la Demande de Renseignements de AQCIE/AIFQ, HQD-2, Document 3. Réponse for Question 2.g. (p. 9 of 13). See also Réponses à la Demande de Renseignements de la Régie, HQD-2, Document 1. Réponse for Question 4.2 (pp. 17 to 18 of 27). Also note that HQ's letter dated 30 April 2002 also indicated that an average loss factor was used to derive coincident peak demand allocators.

¹⁸ See, for example, http://www.sdge.com/cust_choice/pxinfo/dlf.html for the SDG&E policy.

¹⁹ "Distribution Loss Study," UtiliCorp Networks Canada, December 11, 2000.

²⁰ The UtiliCorp study used different formulations for transformer and secondary line losses, but these methods produced similar arithmetic relationships between average and peak loss factors.

by annual energy consumed (E). Peak loss factor (P%) is peak losses (L_P) divided by peak demand (P), and load factor (LF) is annual energy consumed (in GWh) divided by peak demand (in GW) divided by 8,760. Making the substitutions, the UtiliCorp equations can be combined as follows:

$$L_E = 8760 * L_P * [.15 * E/P/8760 + .85 * (E/P/8760)^2]$$

$$A\% * E = 8760 * P\% * P * [.15 * E/P/8760 + .85 * (E/P/8760)^2]$$

$$A\% = P\% * [.15 + .85 * E/P/8760] = P\% * [.15 + .85 * LF]$$

$$P\% = A\% / [.15 + .85 * LF]$$

The results of this methodology are shown in Exhibit 12, in the table labeled "Loss Factor 2 Calculation -- UNCA Method." The loss factors from this method are then averaged with those from the first method, and used to derive peak losses at the generator in the table labeled "Load Factor Calculation -- Generator Basis." The results are summarized in Table 9 below.

Table 9			
Impact of Incorporating Estimated Peak Demand Loss Factors			
Major Rate Classes, cents per kWh			
	<i>2001 Base</i>	<i>Scenario</i>	<i>Percent</i>
D et DM	3.23	3.29	+1.9%
G et à forfait	2.91	2.92	+0.4%
M	2.70	2.68	-0.7%
L	2.48	2.44	-1.7%
DT	2.70	2.69	-0.6%
Contrats spéciaux	2.44	2.39	-1.9%
<i>Distributeur</i>	<i>2.79</i>	<i>2.79</i>	<i>0.0%</i>

7.0 Summary

This report demonstrates that the methodology filed by HQ to allocate generation costs to the various rate classes produces illogical and counter-intuitive results. In our opinion, this result is due primarily to the statutory restriction that the average delivered cost of power for heritage pool service must be 2.79 cents per kWh. We note that these effects are exacerbated by HQ's choice of a system load factor classification method, which penalizes high load factor rate classes for any improvements in overall system load factor. Moreover, several of the assumptions made by HQ in developing the parameters for this calculation are inconsistent with cost causation, and appear to be based more on public policy than on established cost allocation and rate design principles. While IEc recognizes that there may be policy reasons for high load factor industrial customers to subsidize residential customers, we recommend that such a subsidy

be explicitly evaluated by the regulator, and not buried in the arithmetic of the cost allocation procedure.

To reduce the impact of the errors and biases in HQ's methodology, IEc constructed a cumulative impact scenario of the HQ model, for 2001 and 2002 base years, including the following changes:

- A fixed demand/energy classification split is used to eliminate the penalty on high load factor customers associated with improved load factor;
- The demand/energy classification split is set at 40 percent demand, 60 percent energy, based on the historical practices of Canadian electric utilities (including HQ);
- Peak demands and load factors are derived based on a 1 CP demand methodology, which is consistent with cost causation;
- Interruptible load is excluded from peak demand, which is consistent with cost causation and eliminates HQ's requirement that Rate L firm customers fund the rate credit for Rate L interruptible customers;
- Distinct loss factors for peak demand are estimated;
- The average 2.79 cents per kWh rates are derived both including and excluding the special contracts classes.

The results of the summary analyses are shown in Exhibits 13 through 16.

In the absence of additional information regarding peak demand loss factors from HQ, IEc recommends that the Régie adopt the cost rates shown in those summary analyses, and specified in the summary table in Section 1.0 of this report.

Report Prepared By and Under the Direction of:

Robert D. Knecht

Date

EXHIBITS

Simulations of Hydro Québec Energy Cost Rate Model

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Exhibit 17	Demand/Energy Cost Classification at Canadian Utilities	
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Exhibit 1: Hydro Québec Energy Rates

Scenario: Replication of Hydro Québec Rates for 2000

Loss Factor Calculation									
	<i>Basse tension (BT)</i>			<i>Moyenne tension (MT)</i>			<i>Haute tension (HT)</i>		
	<i>Loss Factor</i>	10.54%	7.00%	5.00%	<i>(Percent of Metered Energy)</i>				
<i>Rate Class</i>	<i>Annual Metered Energy (GWh)</i>				<i>Annual Losses (GWh)</i>				<i>Class Loss Factor</i>
	<i>BT</i>	<i>MT</i>	<i>HT</i>	<i>Total</i>	<i>BT</i>	<i>MT</i>	<i>HT</i>	<i>Total</i>	
D et DM	48,791			48,791	5,144	-	-	5,144	10.5%
DH	5			5	1	-	-	1	10.5%
G et à forfait	11,523	235		11,758	1,215	16	-	1,231	10.5%
G-9	902	94		996	95	7	-	102	10.2%
M	10,622	11,507	128	22,257	1,120	805	6	1,932	8.7%
L		9,681	30,401	40,083	-	678	1,520	2,198	5.5%
H	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DT	2,603			2,603	274	-	-	274	10.5%
Tarifs d'éclairage public sentinelle	539			539	57	-	-	57	10.5%
Contrats spéciaux			22,028	22,028	-	-	1,101	1,101	5.0%
Distributeur – électricité patrimoniale	74,984	21,517	52,557	149,059	7,905	1,506	2,628	12,039	8.1%

Source: HQD-2, Document 3, Réponse 2.c.

Load Factor Calculation – Customer Basis			
<i>Rate Class</i>	<i>Annual Energy Consumption (GWh)</i>	<i>Peak Period Demand (kW)</i>	<i>Load Factor</i>
	D et DM	48,791	11,789,158
DH	5	1,092	51.0%
G et à forfait	11,758	2,243,428	59.7%
G-9	996	164,604	68.9%
M	22,257	3,518,902	72.0%
L	40,083	5,068,863	90.0%
H	N/A	N/A	N/A
DT	2,603	367,715	80.6%
Tarifs d'éclairage public sentinelle	539	72,785	84.2%
Contrats spéciaux	22,028	2,528,649	99.2%
Distributeur - électricité patrimoniale	149,059	25,755,196	65.9%

Source: Derived from HQD-2, Document 3, Réponse 1.b. and 2.c.

Exhibit 1: Hydro Québec Energy Rates

Scenario: Replication of Hydro Québec Rates for 2000

Load Factor Calculation -- Generator Basis			
Rate Class	Annual Energy		
	Consumption (GWh)	Peak Period Demand (kW)	Load Factor
D et DM	53,935	13,031,984	47.1%
DH	5	1,207	51.0%
G et à forfait	12,989	2,478,344	59.7%
G-9	1,098	181,406	68.9%
M	24,189	3,824,290	72.0%
L	42,280	5,346,792	90.0%
H	N/A	N/A	N/A
DT	2,877	406,480	80.6%
Tarifs d'éclairage public sentinelle	595	80,458	84.2%
Contrats spéciaux	23,129	2,655,089	99.2%
Distributeur - électricité patrimoniale	161,098	28,006,050	65.5%

Source: HQD-2, Document 3, Réponse 1.b.

Calculation of Energy Rates			
Rate Class	Load Factor	Loss Factor	Energy Rate cents/kWh
D et DM	47.1%	10.5%	3.24
DH	51.0%	10.5%	3.13
G et à forfait	59.7%	10.5%	2.95
G-9	68.9%	10.2%	2.80
M	72.0%	8.7%	2.72
L	90.0%	5.5%	2.47
H	N/A	N/A	N/A
DT	80.6%	10.5%	2.67
Tarifs d'éclairage public sentinelle	84.2%	10.5%	2.63
Contrats spéciaux	99.2%	5.0%	2.39
Distributeur - électricité patrimoniale	65.5%	8.1%	2.79

Source: Derived per HQ formula in Annexe 1.

Exhibit 2: Hydro Québec Energy Rates

Scenario: Replication of Hydro Québec Filing for 2001

Loss Factor Calculation									
	<i>Basse tension (BT)</i>			<i>Moyenne tension (MT)</i>	<i>Haute tension (HT)</i>				
	Loss Factor			Loss Factor	Loss Factor				(Percent of Metered Energy)
	Annual Metered Energy (GWh)				Annual Losses (GWh)				Class Loss
Rate Class	BT	MT	HT	Total	BT	MT	HT	Total	Factor
D et DM	49,147			49,147	5,016	-	-	5,016	10.2%
DH	5			5	1	-	-	1	10.2%
G et à forfait	11,774	114		11,888	1,202	8	-	1,210	10.2%
G-9	876	92		968	89	7	-	96	9.9%
M	16,443	6,878	177	23,498	1,678	491	9	2,178	9.3%
L		9,141	32,797	41,938	-	652	1,705	2,357	5.6%
H		9	8	17	-	1	0	1	6.2%
DT	2,568			2,568	262	-	-	262	10.2%
Tarifs d'éclairage public sentinelle	542			542	55	-	-	55	10.2%
Contrats spéciaux			21,430	21,430	-	-	1,114	1,114	5.2%
Distributeur – électricité patrimoniale	81,355	16,234	54,412	152,001	8,303	1,158	2,829	12,290	8.1%

Source: HQ Filing, Tableau A4.1

Load Factor Calculation – Customer Basis			
Rate Class	Annual Energy Consumption (GWh)	Peak Period Demand (kW)	Load Factor
D et DM	49,147	11,757,971	47.7%
DH	5	1,093	52.2%
G et à forfait	11,888	2,155,443	63.0%
G-9	968	160,753	68.7%
M	23,498	3,442,954	77.9%
L	41,938	5,183,613	92.4%
H	17	2,225	88.1%
DT	2,568	369,389	79.4%
Tarifs d'éclairage public sentinelle	542	73,077	84.7%
Contrats spéciaux	21,430	2,494,416	98.1%
Distributeur - électricité patrimoniale	152,001	25,640,934	67.7%

Source: Derived from HQ Filing, Tableau A3.1 and A4.1

Exhibit 2: Hydro Québec Energy Rates

Scenario: Replication of Hydro Québec Filing for 2001

Load Factor Calculation – Generator Basis			
Rate Class	Annual Energy		Load Factor
	Consumption (GWh)	Peak Period Demand (kW)	
D et DM	54,163	12,957,989	47.7%
DH	6	1,205	52.2%
G et à forfait	13,098	2,374,792	63.0%
G-9	1,064	176,690	68.7%
M	25,676	3,762,075	77.9%
L	44,295	5,474,960	92.4%
H	18	2,363	88.1%
DT	2,830	407,089	79.4%
Tarifs d'éclairage public sentinelle	597	80,535	84.7%
Contrats spéciaux	22,544	2,624,101	98.1%
Distributeur - électricité patrimoniale	164,291	27,861,799	67.3%

Source: HQ Filing, Tableau 3.1

Calculation of Energy Rates			
Rate Class	Load Factor	Loss Factor	Energy Rate cents/kWh
D et DM	47.7%	10.2%	3.23
DH	52.2%	10.2%	3.11
G et à forfait	63.0%	10.2%	2.91
G-9	68.7%	9.9%	2.82
M	77.9%	9.3%	2.70
L	92.4%	5.6%	2.48
H	88.1%	6.2%	2.53
DT	79.4%	10.2%	2.70
Tarifs d'éclairage public sentinelle	84.7%	10.2%	2.65
Contrats spéciaux	98.1%	5.2%	2.44
Distributeur - électricité patrimoniale	67.3%	8.1%	2.79

Source: Derived per HQ formula in Annexe 1.

Exhibit 3: Hydro Québec Energy Rates

Scenario: Replication of Hydro Québec Rates for 2002

Loss Factor Calculation									
	<i>Basse tension (BT)</i>			<i>Moyenne tension (MT)</i>	<i>Haute tension (HT)</i>			<i>Total</i>	<i>Class Loss Factor</i>
	<i>Loss Factor</i>			<i>Loss Factor</i>	<i>Loss Factor</i>				
	10.37%			7.20%	5.20%				(Percent of Metered Energy)
<i>Rate Class</i>	<i>Annual Metered Energy (GWh)</i>				<i>Annual Losses (GWh)</i>				
	<i>BT</i>	<i>MT</i>	<i>HT</i>	<i>Total</i>	<i>BT</i>	<i>MT</i>	<i>HT</i>	<i>Total</i>	
D et DM	49,854			49,854	5,169	-	-	5,169	10.4%
DH	5			5	1	-	-	1	10.4%
G et à forfait	11,834	114		11,948	1,227	8	-	1,235	10.3%
G-9	881	93		974	91	7	-	98	10.1%
M	16,741	7,003	180	23,924	1,736	504	9	2,249	9.4%
L		8,805	33,696	42,501	-	634	1,752	2,386	5.6%
H		9	8	17	-	1	0	1	6.3%
DT	2,608			2,608	270	-	-	270	10.4%
Tarifs d'éclairage public sentinelle	540			540	56	-	-	56	10.4%
Contrats spéciaux			21,155	21,155	-	-	1,100	1,100	5.2%
Distributeur – électricité patrimoniale	82,463	16,025	55,039	153,526	8,550	1,153	2,862	12,565	8.2%

Source: HQ Filing, Tableau A4.2

Load Factor Calculation -- Customer Basis			
<i>Rate Class</i>	<i>Annual Energy Consumption (GWh)</i>	<i>Peak Period Demand (kW)</i>	<i>Load Factor</i>
D et DM	49,854	11,929,330	47.7%
DH	5	1,094	52.2%
G et à forfait	11,948	2,165,289	63.0%
G-9	974	161,099	69.0%
M	23,924	3,504,061	77.9%
L	42,501	5,240,494	92.6%
H	17	2,178	88.2%
DT	2,608	375,108	79.4%
Tarifs d'éclairage public sentinelle	540	73,190	84.2%
Contrats spéciaux	21,155	2,462,688	98.1%
Distributeur - électricité patrimoniale	153,526	25,914,530	67.6%

Source: Derived from HQ Filing, Tableau A3.2 and A4.2

Exhibit 3: Hydro Québec Energy Rates

Scenario: Replication of Hydro Québec Rates for 2002

Load Factor Calculation – Generator Basis			
Rate Class	Annual Energy		
	Consumption (GWh)	Peak Period Demand (kW)	Load Factor
D et DM	55,023	13,166,197	47.7%
DH	6	1,207	52.2%
G et à forfait	13,183	2,389,137	63.0%
G-9	1,072	177,314	69.0%
M	26,173	3,833,460	77.9%
L	44,887	5,534,661	92.6%
H	18	2,314	88.2%
DT	2,878	414,000	79.4%
Tarifs d'éclairage public sentinelle	596	80,779	84.2%
Contrats spéciaux	22,255	2,590,749	98.1%
Distributeur - électricité patrimoniale	166,091	28,189,818	67.3%

Source: HQ Filing, Tableau 3.2

Calculation of Energy Rates				
Rate Class	Load Factor	Loss Factor	Energy Rate cents/kWh	Pct. Change
				from 2001 Base
D et DM	47.7%	10.4%	3.23	0.1%
DH	52.2%	10.4%	3.12	0.0%
G et à forfait	63.0%	10.3%	2.91	0.0%
G-9	69.0%	10.1%	2.81	-0.1%
M	77.9%	9.4%	2.69	0.0%
L	92.6%	5.6%	2.48	-0.2%
H	88.2%	6.3%	2.53	-0.1%
DT	79.4%	10.4%	2.70	0.0%
Tarifs d'éclairage public sentinelle	84.2%	10.4%	2.66	0.2%
Contrats spéciaux	98.1%	5.2%	2.43	-0.1%
Distributeur - électricité patrimoniale	67.3%	8.2%	2.79	0.0%

Source: Derived per HQ formula in Annexe 1.

Exhibit 4: Hydro Québec Energy Rates

Scenario: Percent Changes, 2000 to 2001

Loss Factor Calculation									
	<i>Basse tension (BT)</i>			<i>Moyenne tension (MT)</i>			<i>Haute tension (HT)</i>		
	<i>Loss Factor</i>			<i>Loss Factor</i>			<i>Loss Factor</i>		
	-3.19%			1.91%			3.97%		
	<i>(Percent of Metered Energy)</i>								
<i>Rate Class</i>	<i>Annual Metered Energy (GWh)</i>				<i>Annual Losses (GWh)</i>				<i>Class Loss Factor</i>
	<i>BT</i>	<i>MT</i>	<i>HT</i>	<i>Total</i>	<i>BT</i>	<i>MT</i>	<i>HT</i>	<i>Total</i>	
D et DM	0.7%			0.7%	-2.5%			-2.5%	-3.2%
DH	2.2%			2.2%	-1.0%			-1.0%	-3.2%
G et à forfait	2.2%	-51.5%		1.1%	-1.1%	-50.6%		-1.7%	-2.8%
G-9	-2.9%	-2.1%		-2.8%	-6.0%	-0.3%		-5.6%	-2.9%
M	54.8%	-40.2%	38.3%	5.6%	49.9%	-39.1%	43.8%	12.8%	6.8%
L		-5.6%	7.9%	4.6%		-3.8%	12.2%	7.3%	2.5%
H									
DT	-1.3%			-1.3%	-4.5%			-4.5%	-3.2%
Tarifs d'éclairage public sentinelle	0.6%			0.6%	-2.6%			-2.6%	-3.2%
Contrats spéciaux			-2.7%	-2.7%			1.2%	1.2%	4.0%
Distributeur – électricité patrimoniaie	8.5%	-24.6%	3.5%	2.0%	5.0%	-23.1%	7.6%	2.1%	0.1%

Load Factor Calculation -- Customer Basis			
<i>Rate Class</i>	<i>Annual Energy</i>		
	<i>Consumption (GWh)</i>	<i>Peak Period Demand (kW)</i>	<i>Load Factor</i>
D et DM	0.7%	-0.3%	1.3%
DH	2.2%	0.1%	2.4%
G et à forfait	1.1%	-3.9%	5.5%
G-9	-2.8%	-2.3%	-0.2%
M	5.6%	-2.2%	8.2%
L	4.6%	2.3%	2.6%
H			
DT	-1.3%	0.5%	-1.5%
Tarifs d'éclairage public sentinelle	0.6%	0.4%	0.5%
Contrats spéciaux	-2.7%	-1.4%	-1.1%
Distributeur - électricité patrimoniale	2.0%	-0.4%	2.7%

Exhibit 4: Hydro Québec Energy Rates

Scenario: Percent Changes, 2000 to 2001

Load Factor Calculation – Generator Basis			
Rate Class	Annual Energy		Load Factor
	Consumption (GWh)	Peak Period Demand (kW)	
D et DM	0.4%	-0.6%	1.3%
DH	1.9%	-0.2%	2.4%
G et à forfait	0.8%	-4.2%	5.5%
G-9	-3.1%	-2.6%	-0.2%
M	6.1%	-1.6%	8.2%
L	4.8%	2.4%	2.6%
H			
DT	-1.6%	0.1%	-1.5%
Tarifs d'éclairage public sentinelle	0.3%	0.1%	0.5%
Contrats spéciaux	-2.5%	-1.2%	-1.1%
Distributeur - électricité patrimoniale	2.0%	-0.5%	2.8%

Calculation of Energy Rates			
Rate Class	Load Factor	Loss Factor	Energy Rate cents/kWh
D et DM	1.3%	-3.2%	-0.3%
DH	2.4%	-3.2%	-0.6%
G et à forfait	5.5%	-2.8%	-1.3%
G-9	-0.2%	-2.9%	0.8%
M	8.2%	6.8%	-0.8%
L	2.6%	2.5%	0.7%
H			
DT	-1.5%	-3.2%	1.3%
Tarifs d'éclairage public sentinelle	0.5%	-3.2%	0.7%
Contrats spéciaux	-1.1%	4.0%	1.9%
Distributeur - électricité patrimoniale	2.8%	0.1%	0.0%

Exhibit 5: Hydro Québec Energy Rates

Scenario: Rate Class Volume Mix Anomaly – Higher Rate L Energy Mix (2001 Base)

Loss Factor Calculation									
	<i>Basse tension (BT)</i>			<i>Moyenne tension (MT)</i>	<i>Haute tension (HT)</i>				
	Loss Factor			Loss Factor	(Percent of Metered Energy)				
	Annual Metered Energy (GWh)				Annual Losses (GWh)				Class Loss
Rate Class	BT	MT	HT	Total	BT	MT	HT	Total	Factor
D et DM	40,759			40,759	4,160	-	-	4,160	10.2%
DH	5			5	1	-	-	1	10.2%
G et à forfait	11,774	114		11,888	1,202	8	-	1,210	10.2%
G-9	876	92		968	89	7	-	96	9.9%
M	16,443	6,878	177	23,498	1,678	491	9	2,178	9.3%
L		10,969	39,356	50,326	-	782	2,046	2,829	5.6%
H		9	8	17	-	1	0	1	6.2%
DT	2,568			2,568	262	-	-	262	10.2%
Tarifs d'éclairage public sentinelle	542			542	55	-	-	55	10.2%
Contrats spéciaux			21,430	21,430	-	-	1,114	1,114	5.2%
Distributeur – électricité patrimoniale	72,967	18,062	60,971	152,001	7,447	1,288	3,170	11,905	7.8%

Source: HQ Filing, Tableau A4.1, Increase Industrial Energy by 20%

Load Factor Calculation – Customer Basis			
Rate Class	Annual Energy Consumption (GWh)	Peak Period Demand (kW)	Load Factor
D et DM	40,759	9,751,314	47.7%
DH	5	1,093	52.2%
G et à forfait	11,888	2,155,443	63.0%
G-9	968	160,753	68.7%
M	23,498	3,442,954	77.9%
L	50,326	6,220,335	92.4%
H	17	2,225	88.1%
DT	2,568	369,389	79.4%
Tarifs d'éclairage public sentinelle	542	73,077	84.7%
Contrats spéciaux	21,430	2,494,416	98.1%
Distributeur - électricité patrimoniale	152,001	24,671,000	70.3%

Source: Derived from HQ Filing, Tableau A3.1 and A4.1, Increase Industrial Demand by 20%

Exhibit 5: Hydro Québec Energy Rates

Scenario: Rate Class Volume Mix Anomaly – Higher Rate L Energy Mix (2001 Base)

Load Factor Calculation – Generator Basis			
Rate Class	Annual Energy		
	Consumption (GWh)	Peak Period Demand (kW)	Load Factor
D et DM	44,919	10,746,533	47.7%
DH	6	1,205	52.2%
G et à forfait	13,098	2,374,792	63.0%
G-9	1,064	176,690	68.7%
M	25,676	3,762,075	77.9%
L	53,154	6,569,952	92.4%
H	18	2,363	88.1%
DT	2,830	407,089	79.4%
Tarifs d'éclairage public sentinelle	597	80,535	84.7%
Contrats spéciaux	22,544	2,624,101	98.1%
Distributeur - électricité patrimoniale	163,907	26,745,335	70.0%

Source: HQ Filing, Tableau 3.1, adjusted for Rate L increases.

Calculation of Energy Rates				
Rate Class	Load Factor	Loss Factor	Energy Rate cents/kWh	Pct. Change
				from 2001 Base
D et DM	47.7%	10.2%	3.25	0.7%
DH	52.2%	10.2%	3.14	0.9%
G et à forfait	63.0%	10.2%	2.95	1.3%
G-9	68.7%	9.9%	2.86	1.5%
M	77.9%	9.3%	2.74	1.7%
L	92.4%	5.6%	2.53	2.0%
H	88.1%	6.2%	2.58	1.9%
DT	79.4%	10.2%	2.75	1.7%
Tarifs d'éclairage public sentinelle	84.7%	10.2%	2.70	1.8%
Contrats spéciaux	98.1%	5.2%	2.49	2.1%
Distributeur - électricité patrimoniale	70.0%	7.8%	2.79	0.0%

Source: Derived per HQ formula in Annexe 1.

Exhibit 6: Hydro Québec Energy Rates

Scenario: Loss Factor Anomaly – Reduce BT Loss Factor

Loss Factor Calculation

Rate Class	Annual Metered Energy (GWh)			Total	Annual Losses (GWh)			Total	Class Loss Factor
	BT	MT	HT		BT	MT	HT		
D et DM	49,147			49,147	4,669	-	-	4,669	9.5%
DH	5			5	0	-	-	0	9.5%
G et à forfait	11,774	114		11,888	1,119	8	-	1,127	9.5%
G-9	876	92		968	83	7	-	90	9.3%
M	16,443	6,878	177	23,498	1,562	491	9	2,062	8.8%
L		9,141	32,797	41,938	-	652	1,705	2,357	5.6%
H		9	8	17	-	1	0	1	6.2%
DT	2,568			2,568	244	-	-	244	9.5%
Tarifs d'éclairage public sentinelle	542			542	51	-	-	51	9.5%
Contrats spéciaux			21,430	21,430	-	-	1,114	1,114	5.2%
Distributeur – électricité patrimoniale	81,355	16,234	54,412	152,001	7,729	1,158	2,829	11,716	7.7%

Source: HQ Filing, Tableau A4.1, with lower BT loss factor applied.

Load Factor Calculation – Customer Basis

Rate Class	Annual Energy Consumption (GWh)	Peak Period Demand (kW)	Load Factor
D et DM	49,147	11,757,971	47.7%
DH	5	1,093	52.2%
G et à forfait	11,888	2,155,443	63.0%
G-9	968	160,753	68.7%
M	23,498	3,442,954	77.9%
L	41,938	5,183,613	92.4%
H	17	2,225	88.1%
DT	2,568	369,389	79.4%
Tarifs d'éclairage public sentinelle	542	73,077	84.7%
Contrats spéciaux	21,430	2,494,416	98.1%
Distributeur - électricité patrimoniale	152,001	25,640,934	67.7%

Source: Derived from HQ Filing, Tableau A3.1 and A4.1

Exhibit 6: Hydro Québec Energy Rates

Scenario: Loss Factor Anomaly -- Reduce BT Loss Factor

Load Factor Calculation -- Generator Basis			
Rate Class	Annual Energy		
	Consumption (GWh)	Peak Period Demand (kW)	Load Factor
D et DM	53,816	12,874,978	47.7%
DH	5	1,197	52.2%
G et à forfait	13,015	2,359,721	63.0%
G-9	1,058	175,663	68.7%
M	25,560	3,745,066	77.9%
L	44,295	5,474,960	92.4%
H	18	2,363	88.1%
DT	2,812	404,481	79.4%
Tarifs d'éclairage public sentinelle	593	80,019	84.7%
Contrats spéciaux	22,544	2,624,101	98.1%
Distributeur - électricité patrimoniale	163,717	27,742,548	67.4%

Source: HQ Filing, Tableau 3.1, with lower BT loss factor results.

Calculation of Energy Rates				
Rate Class	Load Factor	Loss Factor	Energy Rate cents/kWh	Pct. Change
				from 2001 Base
D et DM	47.7%	9.5%	3.22	-0.3%
DH	52.2%	9.5%	3.11	-0.3%
G et à forfait	63.0%	9.5%	2.90	-0.3%
G-9	68.7%	9.3%	2.81	-0.2%
M	77.9%	8.8%	2.69	-0.1%
L	92.4%	5.6%	2.49	0.4%
H	88.1%	6.2%	2.54	0.4%
DT	79.4%	9.5%	2.70	-0.3%
Tarifs d'éclairage public sentinelle	84.7%	9.5%	2.65	-0.3%
Contrats spéciaux	98.1%	5.2%	2.45	0.4%
Distributeur - électricité patrimoniale	67.4%	7.7%	2.79	0.0%

Source: Derived per HQ formula in Annexe 1.

Exhibit 7: Hydro Québec Energy Rates

Scenario: Load Factor Improvement Anomaly -- Improve Rate D Load Factor

Loss Factor Calculation									
	<i>Basse tension (BT)</i>			<i>Moyenne tension (MT)</i>			<i>Haute tension (HT)</i>		
	Loss Factor			10.21%			7.13%		
	5.20%			(Percent of Metered Energy)					
Rate Class	Annual Metered Energy (GWh)				Annual Losses (GWh)				Class Loss Factor
	BT	MT	HT	Total	BT	MT	HT	Total	
D et DM	49,147			49,147	5,016	-	-	5,016	10.2%
DH	5			5	1	-	-	1	10.2%
G et à forfait	11,774	114		11,888	1,202	8	-	1,210	10.2%
G-9	876	92		968	89	7	-	96	9.9%
M	16,443	6,878	177	23,498	1,678	491	9	2,178	9.3%
L		9,141	32,797	41,938	-	652	1,705	2,357	5.6%
H		9	8	17	-	1	0	1	6.2%
DT	2,568			2,568	262	-	-	262	10.2%
Tarifs d'éclairage public sentinelle	542			542	55	-	-	55	10.2%
Contrats spéciaux			21,430	21,430	-	-	1,114	1,114	5.2%
Distributeur -- électricité patrimoniale	81,355	16,234	54,412	152,001	8,303	1,158	2,829	12,290	8.1%

Source: HQ Filing, Tableau A4.1

Load Factor Calculation -- Customer Basis			
Rate Class	Annual Energy Consumption (GWh)	Peak Period Demand (kW)	Load Factor
D et DM	49,147	10,582,173	53.0%
DH	5	1,093	52.2%
G et à forfait	11,888	2,155,443	63.0%
G-9	968	160,753	68.7%
M	23,498	3,442,954	77.9%
L	41,938	5,183,613	92.4%
H	17	2,225	88.1%
DT	2,568	369,389	79.4%
Tarifs d'éclairage public sentinelle	542	73,077	84.7%
Contrats spéciaux	21,430	2,494,416	98.1%
Distributeur - électricité patrimoniale	152,001	24,465,137	70.9%

Source: Derived from HQ Filing, Tableau A3.1 and A4.1, lower Rate D peak demand.

Exhibit 7: Hydro Québec Energy Rates

Scenario: Load Factor Improvement Anomaly – Improve Rate D Load Factor

Load Factor Calculation – Generator Basis			
Rate Class	Annual Energy		Load Factor
	Consumption (GWh)	Peak Period Demand (kW)	
D et DM	54,163	11,662,190	53.0%
DH	6	1,205	52.2%
G et à forfait	13,098	2,374,792	63.0%
G-9	1,064	176,690	68.7%
M	25,676	3,762,075	77.9%
L	44,295	5,474,960	92.4%
H	18	2,363	88.1%
DT	2,830	407,089	79.4%
Tarifs d'éclairage public sentinelle	597	80,535	84.7%
Contrats spéciaux	22,544	2,624,101	98.1%
Distributeur - électricité patrimoniale	164,291	26,566,000	70.6%

Source: HQ Filing, Tableau 3.1, adjusted for lower Rate D demand.

Calculation of Energy Rates				
Rate Class	Load Factor	Loss Factor	Energy Rate cents/kWh	Pct. Change
				from 2001 Base
D et DM	53.0%	10.2%	3.12	-3.2%
DH	52.2%	10.2%	3.14	0.8%
G et à forfait	63.0%	10.2%	2.95	1.3%
G-9	68.7%	9.9%	2.86	1.5%
M	77.9%	9.3%	2.74	1.8%
L	92.4%	5.6%	2.54	2.1%
H	88.1%	6.2%	2.58	2.0%
DT	79.4%	10.2%	2.75	1.8%
Tarifs d'éclairage public sentinelle	84.7%	10.2%	2.71	1.9%
Contrats spéciaux	98.1%	5.2%	2.49	2.2%
Distributeur - électricité patrimoniale	70.6%	8.1%	2.79	0.0%

Source: Derived per HQ formula in Annexe 1.

Exhibit 8: Hydro Québec Energy Rates

Scenario: Exclude Special Contracts Class from Analysis (2001 Basis)

Loss Factor Calculation

Rate Class	Annual Metered Energy (GWh)			Total	Annual Losses (GWh)			Total	Class Loss Factor
	BT	MT	HT		BT	MT	HT		
D et DM	49,147			49,147	5,016	-	-	5,016	10.2%
DH	5			5	1	-	-	1	10.2%
G et à forfait	11,774	114		11,888	1,202	8	-	1,210	10.2%
G-9	876	92		968	89	7	-	96	9.9%
M	16,443	6,878	177	23,498	1,678	491	9	2,178	9.3%
L		9,141	32,797	41,938	-	652	1,705	2,357	5.6%
H		9	8	17	-	1	0	1	6.2%
DT	2,568			2,568	262	-	-	262	10.2%
Tarifs d'éclairage public sentinelle	542			542	55	-	-	55	10.2%
Contrats spéciaux				-	-	-	-	-	
Distributeur – électricité patrimoniale	81,355	16,234	32,982	130,571	8,303	1,158	1,715	11,176	8.6%

Source: HQ Filing, Tableau A4.1, excluding special contracts class.

Load Factor Calculation – Customer Basis

Rate Class	Annual Energy Consumption (GWh)	Peak Period Demand (kW)	Load Factor
D et DM	49,147	11,757,971	47.7%
DH	5	1,093	52.2%
G et à forfait	11,888	2,155,443	63.0%
G-9	968	160,753	68.7%
M	23,498	3,442,954	77.9%
L	41,938	5,183,613	92.4%
H	17	2,225	88.1%
DT	2,568	369,389	79.4%
Tarifs d'éclairage public sentinelle	542	73,077	84.7%
Contrats spéciaux	-	-	-
Distributeur - électricité patrimoniale	130,571	23,146,517	64.4%

Source: Derived from HQ Filing, Tableau A3.1 and A4.1, excluding special contracts class.

Exhibit 8: Hydro Québec Energy Rates

Scenario: Exclude Special Contracts Class from Analysis (2001 Basis)

Load Factor Calculation – Generator Basis			
Rate Class	Annual Energy		
	Consumption (GWh)	Peak Period Demand (kW)	Load Factor
D et DM	54,163	12,957,989	47.7%
DH	6	1,205	52.2%
G et à forfait	13,098	2,374,792	63.0%
G-9	1,064	176,690	68.7%
M	25,676	3,762,075	77.9%
L	44,295	5,474,960	92.4%
H	18	2,363	88.1%
DT	2,830	407,089	79.4%
Tarifs d'éclairage public sentinelle	597	80,535	84.7%
Contrats spéciaux	-	-	
Distributeur - électricité patrimoniale	141,747	25,237,698	64.1%

Source: HQ Filing, Tableau 3.1, excl. special contracts; note system load factor change.

Calculation of Energy Rates				
Rate Class	Load Factor	Loss Factor	Energy Rate cents/kWh	Pct. Change from 2001 Base
D et DM	47.7%	10.2%	3.18	-1.4%
DH	52.2%	10.2%	3.06	-1.6%
G et à forfait	63.0%	10.2%	2.85	-2.0%
G-9	68.7%	9.9%	2.76	-2.2%
M	77.9%	9.3%	2.63	-2.4%
L	92.4%	5.6%	2.42	-2.7%
H	88.1%	6.2%	2.46	-2.7%
DT	79.4%	10.2%	2.64	-2.5%
Tarifs d'éclairage public sentinelle	84.7%	10.2%	2.59	-2.6%
Contrats spéciaux				
Distributeur - électricité patrimoniale	64.1%	8.6%	2.7900	0.0%

Source: Derived per HQ formula in Annexe 1; note recalculation of system loss factor.

Exhibit 9

Exhibit 9: Hydro Québec Energy Rates

Scenario: Classification of Costs at 60% Energy, 40% Demand (2001 Base)

Loss Factor Calculation									
	Basse tension (BT)			Moyenne tension (MT)	Haute tension (HT)	(Percent of Metered Energy)			
	Loss Factor	10.21%	7.13%	5.20%					
Rate Class	Annual Metered Energy (GWh)				Annual Losses (GWh)				Class Loss Factor
	BT	MT	HT	Total	BT	MT	HT	Total	
D et DM	49,147			49,147	5,016	-	-	5,016	10.2%
DH	5			5	1	-	-	1	10.2%
G et à forfait	11,774	114		11,888	1,202	8	-	1,210	10.2%
G-9	876	92		968	89	7	-	96	9.9%
M	16,443	6,878	177	23,498	1,678	491	9	2,178	9.3%
L		9,141	32,797	41,938	-	652	1,705	2,357	5.6%
H		9	8	17	-	1	0	1	6.2%
DT	2,568			2,568	262	-	-	262	10.2%
Tarifs d'éclairage public sentinelle	542			542	55	-	-	55	10.2%
Contrats spéciaux			21,430	21,430	-	-	1,114	1,114	5.2%
Distributeur – électricité patrimoniale	81,355	16,234	54,412	152,001	8,303	1,158	2,829	12,290	8.1%

Source: HQ Filing, Tableau A4.1

Load Factor Calculation -- Customer Basis			
Rate Class	Annual Energy		
	Consumption (GWh)	Peak Period Demand (kW)	Load Factor
D et DM	49,147	11,757,971	47.7%
DH	5	1,093	52.2%
G et à forfait	11,888	2,155,443	63.0%
G-9	968	160,753	68.7%
M	23,498	3,442,954	77.9%
L	41,938	5,183,613	92.4%
H	17	2,225	88.1%
DT	2,568	369,389	79.4%
Tarifs d'éclairage public sentinelle	542	73,077	84.7%
Contrats spéciaux	21,430	2,494,416	98.1%
Distributeur - électricité patrimoniale	152,001	25,640,934	67.7%

Source: Derived from HQ Filing, Tableau A3.1 and A4.1

Exhibit 9: Hydro Québec Energy Rates

Scenario: Classification of Costs at 60% Energy, 40% Demand (2001 Base)

Load Factor Calculation – Generator Basis			
Rate Class	Annual Energy		
	Consumption (GWh)	Peak Period Demand (kW)	Load Factor
D et DM	54,163	12,957,989	47.7%
DH	6	1,205	52.2%
G et à forfait	13,098	2,374,792	63.0%
G-9	1,064	176,690	68.7%
M	25,676	3,762,075	77.9%
L	44,295	5,474,960	92.4%
H	18	2,363	88.1%
DT	2,830	407,089	79.4%
Tarifs d'éclairage public sentinelle	597	80,535	84.7%
Contrats spéciaux	22,544	2,624,101	98.1%
Distributeur - électricité patrimoniale	164,291	27,861,799	67.3%

Source: HQ Filing, Tableau 3.1

Calculation of Energy Rates				
Rate Class	Load Factor	Loss Factor	Energy Rate cents/kWh	Pct. Change from 2001 Base
D et DM	47.7%	10.2%	3.31	2.6%
DH	52.2%	10.2%	3.17	1.9%
G et à forfait	63.0%	10.2%	2.92	0.5%
G-9	68.7%	9.9%	2.81	-0.2%
M	77.9%	9.3%	2.67	-1.0%
L	92.4%	5.6%	2.43	-2.2%
H	88.1%	6.2%	2.48	-1.9%
DT	79.4%	10.2%	2.67	-1.2%
Tarifs d'éclairage public sentinelle	84.7%	10.2%	2.61	-1.6%
Contrats spéciaux	98.1%	5.2%	2.37	-2.6%
Distributeur - électricité patrimoniale	67.3%	8.1%	2.79	0.0%

Source: Derived per HQ formula in Annexe 1, modified for 60/40 classification.

Exhibit 10: Hydro Québec Energy Rates

Scenario: Estimate Impact of 1CP Methodology (2001 Base)

Loss Factor Calculation									
	Basse tension (BT)			Moyenne tension (MT)	Haute tension (HT)			(Percent of Metered Energy)	
	Loss Factor	10.21%	7.13%	5.20%					
Rate Class	Annual Metered Energy (GWh)				Annual Losses (GWh)				Class Loss Factor
	BT	MT	HT	Total	BT	MT	HT	Total	
D et DM	49,147			49,147	5,016	-	-	5,016	10.2%
DH	5			5	1	-	-	1	10.2%
G et à forfait	11,774	114		11,888	1,202	8	-	1,210	10.2%
G-9	876	92		968	89	7	-	96	9.9%
M	16,443	6,878	177	23,498	1,678	491	9	2,178	9.3%
L		9,141	32,797	41,938	-	652	1,705	2,357	5.6%
H		9	8	17	-	1	0	1	6.2%
DT	2,568			2,568	262	-	-	262	10.2%
Tarifs d'éclairage public sentinelle	542			542	55	-	-	55	10.2%
Contrats spéciaux			21,430	21,430	-	-	1,114	1,114	5.2%
Distributeur – électricité patrimoniale	81,355	16,234	54,412	152,001	8,303	1,158	2,829	12,290	8.1%

Source: HQ Filing, Tableau A4.1

Load Factor Calculation – Customer Basis			
Rate Class	Annual Energy		Load Factor
	Consumption (GWh)	Peak Period Demand (kW)	
D et DM	49,147	13,456,729	41.7%
DH	5	1,203	47.5%
G et à forfait	11,888	2,498,573	54.3%
G-9	968	136,049	81.2%
M	23,498	3,901,992	68.7%
L	41,938	5,350,814	89.5%
H	17	2,283	85.8%
DT	2,568	442,951	66.2%
Tarifs d'éclairage public sentinelle	542	126,718	48.8%
Contrats spéciaux	21,430	2,481,696	98.6%
Distributeur - électricité patrimoniale	152,001	28,399,009	61.1%

Sources: HQ Filing Tableau A3.1, derived from loss factors and 1 CP demands.

Exhibit 10: Hydro Québec Energy Rates

Scenario: Estimate Impact of ICP Methodology (2001 Base)

Load Factor Calculation – Generator Basis				
Rate Class	Annual Energy		1 CP Load Factor	1 CP Allocator
	Consumption (GWh)	Peak Period Demand (kW)		
D et DM	54,163	14,830,123	41.7%	48.009%
DH	6	1,325	47.5%	0.004%
G et à forfait	13,098	2,752,842	54.3%	8.912%
G-9	1,064	149,537	81.2%	0.484%
M	25,676	4,263,660	68.7%	13.803%
L	44,295	5,651,559	89.5%	18.296%
H	18	2,425	85.8%	0.008%
DT	2,830	488,158	66.2%	1.580%
Tarifs d'éclairage public sentinelle	597	139,650	48.8%	0.452%
Contrats spéciaux	22,544	2,610,720	98.6%	8.452%
Distributeur - électricité patrimoniale	164,291	30,890,000	60.7%	100.0000%

Source: HQ Filing, Tableau 3.1. HQ Letter dated 30 April 2002

Calculation of Energy Rates				
Rate Class	Load Factor	Loss Factor	Energy Rate cents/kWh	Pct. Change from 2001 Base
D et DM	41.7%	10.2%	3.35	4.0%
DH	47.5%	10.2%	3.16	1.4%
G et à forfait	54.3%	10.2%	2.98	2.3%
G-9	81.2%	9.9%	2.56	-9.3%
M	68.7%	9.3%	2.69	-0.1%
L	89.5%	5.6%	2.38	-4.1%
H	85.8%	6.2%	2.43	-4.1%
DT	66.2%	10.2%	2.75	1.8%
Tarifs d'éclairage public sentinelle	48.8%	10.2%	3.12	17.4%
Contrats spéciaux	98.6%	5.2%	2.31	-5.4%
Distributeur - électricité patrimoniale	60.7%	8.1%	2.79	0.0%

Source: Derived per HQ formula in Annexe 1.

Exhibit 11: Hydro Québec Energy Rates

Scenario: Exclude Interruptible Load from Peak Demand Allocator (2001 Base)

Loss Factor Calculation									
	<i>Basse tension (BT)</i>			<i>Moyenne tension (MT)</i>	<i>Haute tension (HT)</i>				
	Loss Factor			Loss Factor	Loss Factor			(Percent of Metered Energy)	
	10.21%			7.13%	5.20%				
Rate Class	Annual Metered Energy (GWh)				Annual Losses (GWh)				Class Loss Factor
	BT	MT	HT	Total	BT	MT	HT	Total	
D et DM	49,147			49,147	5,016	-	-	5,016	10.2%
DH	5			5	1	-	-	1	10.2%
G et à forfait	11,774	114		11,888	1,202	8	-	1,210	10.2%
G-9	876	92		968	89	7	-	96	9.9%
M	16,443	6,878	177	23,498	1,678	491	9	2,178	9.3%
L		9,141	32,797	41,938	-	652	1,705	2,357	5.6%
H		9	8	17	-	1	0	1	6.2%
DT	2,568			2,568	262	-	-	262	10.2%
Tarifs d'éclairage public sentinelle	542			542	55	-	-	55	10.2%
Contrats spéciaux			21,430	21,430	-	-	1,114	1,114	5.2%
Distributeur – électricité patrimoniale	81,355	16,234	54,412	152,001	8,303	1,158	2,829	12,290	8.1%

Source: HQ Filing, Tableau A4.1

Load Factor Calculation – Customer Basis			
Rate Class	Annual Energy Consumption (GWh)	Peak Period Demand (kW)	Load Factor
D et DM	49,147	11,757,971	47.7%
DH	5	1,093	52.2%
G et à forfait	11,888	2,155,443	63.0%
G-9	968	160,753	68.7%
M	23,498	3,442,954	77.9%
L	41,938	4,183,613	114.4%
H	17	2,225	88.1%
DT	2,568	369,389	79.4%
Tarifs d'éclairage public sentinelle	542	73,077	84.7%
Contrats spéciaux	21,430	2,294,416	106.6%
Distributeur - électricité patrimoniale	152,001	24,440,934	71.0%

Source: Derived from HQ Filing, Tableau A3.1 and A4.1, exclude estimated interr. peak.

Exhibit 11: Hydro Québec Energy Rates

Scenario: Exclude Interruptible Load from Peak Demand Allocator (2001 Base)

Load Factor Calculation -- Generator Basis			
Rate Class	Annual Energy		
	Consumption (GWh)	Peak Period Demand (kW)	Load Factor
D et DM	54,163	12,957,989	47.7%
DH	6	1,205	52.2%
G et à forfait	13,098	2,374,792	63.0%
G-9	1,064	176,690	68.7%
M	25,676	3,762,075	77.9%
L	44,295	4,418,755	114.4%
H	18	2,363	88.1%
DT	2,830	407,089	79.4%
Tarifs d'éclairage public sentinelle	597	80,535	84.7%
Contrats spéciaux	22,544	2,413,703	106.6%
Distributeur - électricité patrimoniale	164,291	26,595,196	70.5%

Source: HQ Filing. Tableau 3.1, adjusted to exclude estimated interruptible peak.

Calculation of Energy Rates				
Rate Class	Load Factor	Loss Factor	Energy Rate cents/kWh	Pct. Change from 2001 Base
D et DM	47.7%	10.2%	3.25	0.6%
DH	52.2%	10.2%	3.14	0.8%
G et à forfait	63.0%	10.2%	2.94	1.3%
G-9	68.7%	9.9%	2.86	1.5%
M	77.9%	9.3%	2.74	1.7%
L	114.4%	5.6%	2.42	-2.7%
H	88.1%	6.2%	2.58	2.0%
DT	79.4%	10.2%	2.75	1.8%
Tarifs d'éclairage public sentinelle	84.7%	10.2%	2.70	1.9%
Contrats spéciaux	106.6%	5.2%	2.44	0.3%
Distributeur - électricité patrimoniale	70.5%	8.1%	2.79	0.0%

Source: Derived per HQ formula in Annexe 1.

Exhibit 12: Hydro Québec Energy Rates

Scenario: Implications of Using Separate Peak Loss Factors

Loss Factor 1 Calculation									
	Basse tension (BT)			Moyenne tension (MT)	Haute tension (HT)				
	16.6%			11.0%	7.7%			(Percent of Metered Demand)	
Rate Class	Annual Metered Peak (kW)				Peak Losses (kW)				Class Loss Factor 1
	BT	MT	HT	Total	BT	MT	HT	Total	
D et DM	11,757,971	-	-	11,757,971	1,949,659	-	-	1,949,659	16.6%
DH	1,093	-	-	1,093	181	-	-	181	16.6%
G et à forfait	2,134,773	20,670	-	2,155,443	353,979	2,272	-	356,251	16.5%
G-9	145,475	15,278	-	160,753	24,122	1,679	-	25,802	16.1%
M	2,409,248	1,007,773	25,934	3,442,954	399,492	110,780	1,992	512,264	14.9%
L	-	1,129,844	4,053,769	5,183,613	-	124,199	311,437	435,635	8.4%
H	-	1,177	1,047	2,225	-	129	80	210	9.4%
DT	369,389	-	-	369,389	61,251	-	-	61,251	16.6%
Tarifs d'éclairage public sentinelle	73,077	-	-	73,077	12,117	-	-	12,117	16.6%
Contrats spéciaux	-	-	2,494,416	2,494,416	-	-	191,637	191,637	7.7%
Distributeur – électricité patrimoniale	16,891,025	2,174,742	6,575,167	25,640,934	2,800,801	239,059	505,147	3,545,007	13.8%
	9.29	1.85	6.21		0.95	0.13	0.32		

Source: Derived from 2001 customer peaks in proportion to annual energy split by voltage group.

Load Factor Calculation – Customer Basis				
Rate Class	Annual Energy		Peak Period Demand (kW)	Load Factor
	Consumption (GWh)	Peak Period Demand (kW)		
D et DM	49,147	11,757,971	47.7%	
DH	5	1,093	52.2%	
G et à forfait	11,888	2,155,443	63.0%	
G-9	968	160,753	68.7%	
M	23,498	3,442,954	77.9%	
L	41,938	5,183,613	92.4%	
H	17	2,225	88.1%	
DT	2,568	369,389	79.4%	
Tarifs d'éclairage public sentinelle	542	73,077	84.7%	
Contrats spéciaux	21,430	2,494,416	98.1%	
Distributeur - électricité patrimoniale	152,001	25,640,934	67.7%	

Source: 2001 Base Year Analysis

Load Factor Calculation – Generator Basis				
Rate Class	Annual Energy		Peak Period Demand (kW)	Load Factor
	Consumption (GWh)	Average Peak Loss Factor		
D et DM	54,163	17.5%	13,812,764	44.8%
DH	6	16.9%	1,278	49.2%
G et à forfait	13,098	15.7%	2,493,639	60.0%
G-9	1,064	14.8%	184,506	65.8%
M	25,676	13.1%	3,895,531	75.2%
L	44,295	7.2%	5,557,225	91.0%
H	18	8.2%	2,407	86.5%
DT	2,830	14.5%	422,875	76.4%
Tarifs d'éclairage public sentinelle	597	14.2%	83,423	81.7%
Contrats spéciaux	22,544	6.5%	2,656,157	96.9%
Distributeur - électricité patrimoniale	164,291	13.5%	29,109,805	64.4%

Source: Average Loss Factor 1 and Loss Factor 2, applied to 2001 Base.

Exhibit 12: Hydro Québec Energy Rates

Scenario: Implications of Using Separate Peak Loss Factors

Calculation of Energy Rates					<i>Pct. Change</i>
<i>Rate Class</i>	<i>Load Factor</i>	<i>Energy Loss Factor</i>	<i>Energy Rate cents/kWh</i>	<i>Base</i>	<i>from 2001</i>
D et DM	44.8%	10.2%	3.29		1.9%
DH	49.2%	10.2%	3.16		1.4%
G et à forfait	60.0%	10.2%	2.92		0.4%
G-9	65.8%	9.9%	2.82		-0.1%
M	75.2%	9.3%	2.68		-0.7%
L	91.0%	5.6%	2.44		-1.7%
H	86.5%	6.2%	2.49		-1.5%
DT	76.4%	10.2%	2.69		-0.6%
Tarifs d'éclairage public sentinelle	81.7%	10.2%	2.63		-0.9%
Contrats spéciaux	96.9%	5.2%	2.39		-1.9%
Distributeur - électricité patrimoniale	64.4%	8.1%	2.7900		0.0%

Source: Derived per HQ formula in Annexe 1.

Loss Factor 1 Analysis			
	<i>BT</i>	<i>MT</i>	<i>HT</i>
<i>Avg. Delivered Energy</i>	81,355	97,589	152,001
<i>Avg. Losses</i>	2,500	1,887	7,903
<i>Non-cum energy loss factor</i>	3.07%	1.93%	5.20%
<i>Constant</i>	0.00331	0.00174	0.00300
<i>Peak Demand</i>	16.89	19.07	25.64
<i>Peak Losses</i>	0.94	0.63	1.97
<i>Non-cum peak loss factors</i>	5.59%	3.31%	7.68%

Loss Factor 2 Calculation – UNCA Method

UNCA Loss Factor Study for Conductor Losses Method:

$$\text{Annual Energy Losses (GWh)} = 8760 * \text{Pk Loss} * \text{LSF}$$

$$\text{LSF} = .15 * \text{LF} + .85 * \text{LF}^2$$

If A% = AEL/Annual Energy, and P% = Pk Loss/Peak Demand

$$\text{AEL/AE} = 8760 * \text{PkLoss} * (.15 * \text{LF} + .85 * \text{LF}^2) / (\text{LF} * \text{Pk} * 8760)$$

$$\text{A\%} = \text{P\%} * (.15 + .85 * \text{LF})$$

	<i>A%</i>	<i>LF</i>	<i>P%</i>	<i>Factor 1</i>	<i>Average</i>
D et DM	10.2%	47.7%	18.4%	16.6%	17.5%
DH	10.2%	52.2%	17.2%	16.6%	16.9%
G et à forfait	10.2%	63.0%	14.9%	16.5%	15.7%
G-9	9.9%	68.7%	13.5%	16.1%	14.8%
M	9.3%	77.9%	11.4%	14.9%	13.1%
L	5.6%	92.4%	6.0%	8.4%	7.2%
H	6.2%	88.1%	6.9%	9.4%	8.2%
DT	10.2%	79.4%	12.4%	16.6%	14.5%
Tarifs d'éclairage public sentinelle	10.2%	84.7%	11.7%	16.6%	14.2%
Contrats spéciaux	5.2%	98.1%	5.3%	7.7%	6.5%

Exhibit 13: Hydro Québec Energy Rates

Scenario: Cumulative Effects, Including Special Contracts Class (2001 Base)

Loss Factor 1 Calculation									
	<i>Basse tension (BT)</i>			<i>Moyenne tension (MT)</i>			<i>Haute tension (HT)</i>		
	<i>Peak Loss Factor</i>			<i>18.3%</i>			<i>11.9%</i>		
	<i>8.1%</i>			<i>(Percent of Metered Demand)</i>					
<i>Rate Class</i>	<i>Annual Metered Peak (kW)</i>				<i>Peak Losses (kW)</i>				<i>Class Loss Factor 1</i>
	<i>BT</i>	<i>MT</i>	<i>HT</i>	<i>Total</i>	<i>BT</i>	<i>MT</i>	<i>HT</i>	<i>Total</i>	
D et DM	13,456,729	-	-	13,456,729	2,460,411	-	-	2,460,411	18.3%
DH	1,203	-	-	1,203	220	-	-	220	18.3%
G et à forfait	2,474,613	23,960	-	2,498,573	452,455	2,846	-	455,301	18.2%
G-9	123,119	12,930	-	136,049	22,511	1,536	-	24,047	17.7%
M	2,730,465	1,142,136	29,392	3,901,992	499,235	135,677	2,395	637,307	16.3%
L	-	948,324	3,402,491	4,350,814	-	112,654	277,285	389,939	9.0%
H	-	1,208	1,075	2,283	-	144	88	231	10.1%
DT	442,951	-	-	442,951	80,989	-	-	80,989	18.3%
Tarifs d'éclairage public sentinelle	126,718	-	-	126,718	23,169	-	-	23,169	18.3%
Contrats spéciaux	-	-	2,281,696	2,281,696	-	-	185,946	185,946	8.1%
<i>Distributeur – électricité patrimoniale</i>	<i>19,355,797</i>	<i>2,128,558</i>	<i>5,714,654</i>	<i>27,199,009</i>	<i>3,538,989</i>	<i>252,857</i>	<i>465,715</i>	<i>4,257,561</i>	<i>15.7%</i>

Source: Peak Loss Factor Scenario Analysis

Load Factor Calculation – Customer Basis				
<i>Rate Class</i>	<i>Annual Energy Consumption (GWh)</i>		<i>Peak Period Demand (kW)</i>	<i>Load Factor</i>
	<i>Consumption</i>	<i>Peak Period Demand</i>		
D et DM	49,147	13,456,729	41.7%	
DH	5	1,203	47.5%	
G et à forfait	11,888	2,498,573	54.3%	
G-9	968	136,049	81.2%	
M	23,498	3,901,992	68.7%	
L	41,938	4,350,814	110.0%	
H	17	2,283	85.8%	
DT	2,568	442,951	66.2%	
Tarifs d'éclairage public sentinelle	542	126,718	48.8%	
Contrats spéciaux	21,430	2,281,696	107.2%	
<i>Distributeur - électricité patrimoniale</i>	<i>152,001</i>	<i>27,199,009</i>	<i>63.8%</i>	

Source: 2001 Base, 1 CP and Excl. Int. Analysis.

Load Factor Calculation – Generator Basis				
<i>Rate Class</i>	<i>Annual Energy Consumption (GWh)</i>		<i>Peak Period Demand (kW)</i>	<i>Load Factor</i>
	<i>Consumption</i>	<i>Average Peak Loss Factor</i>		
D et DM	54,163	19.3%	16,048,395	38.5%
DH	6	18.4%	1,424	44.2%
G et à forfait	13,098	17.4%	2,934,072	51.0%
G-9	1,064	14.7%	156,097	77.8%
M	25,676	14.5%	4,466,903	65.6%
L	44,295	7.1%	4,658,443	108.5%
H	18	8.6%	2,480	83.9%
DT	2,830	16.3%	515,168	62.7%
Tarifs d'éclairage public sentinelle	597	18.2%	149,746	45.5%
Contrats spéciaux	22,544	6.5%	2,430,554	105.9%
<i>Distributeur - électricité patrimoniale</i>	<i>164,291</i>	<i>15.3%</i>	<i>31,363,282</i>	<i>59.8%</i>

Source: 2001 Base, Average of Factor 1 and Factor 2, Peak Demand adjustments.

Exhibit 13: Hydro Québec Energy Rates

Scenario: Cumulative Effects, Including Special Contracts Class (2001 Base)

Calculation of Energy Rates					<i>Pct. Change</i>
<i>Rate Class</i>	<i>Load Factor</i>	<i>Energy Loss Factor</i>	<i>Energy Rate cents/kWh</i>	<i>Base</i>	<i>from 2001</i>
D et DM	38.5%	10.2%	3.47		7.6%
DH	44.2%	10.2%	3.25		4.3%
G et à forfait	51.0%	10.2%	3.04		4.6%
G-9	77.8%	9.9%	2.57		-8.6%
M	65.6%	9.3%	2.72		0.9%
L	108.5%	5.6%	2.24		-10.0%
H	83.9%	6.2%	2.43		-4.1%
DT	62.7%	10.2%	2.79		3.3%
Tarifs d'éclairage public sentinelle	45.5%	10.2%	3.20		20.6%
Contrats spéciaux	105.9%	5.2%	2.24		-8.0%
Distributeur - électricité patrimoniale	59.8%	8.1%	2.7900		0.0%

Source: Derived per HQ formula in Annexe 1.

Loss Factor 1 Analysis			
	<i>BT</i>	<i>MT</i>	<i>HT</i>
<i>Avg. Delivered Energy</i>	81,355	97,589	152,001
<i>Avg. Losses</i>	2,500	1,887	7,903
<i>Non-cum energy loss factor</i>	3.07%	1.93%	5.20%
<i>Constant</i>	0.00331	0.00174	0.00300
<i>Peak Demand</i>	19.36	21.48	27.20
<i>Peak Losses</i>	1.24	0.80	2.22
<i>Non-cum peak loss factors</i>	6.40%	3.73%	8.15%

Loss Factor 2 Calculation – UNCA Method

UNCA Loss Factor Study for Conductor Losses Method:

$$\text{Annual Energy Losses (GWh)} = 8760 * \text{Pk Loss} * \text{LSF}$$

$$\text{LSF} = .15 * \text{LF} + .85 * \text{LF}^2$$

If A% = AEL/Annual Energy, and P% = Pk Loss/Peak Demand

$$\text{AEL/AE} = 8760 * \text{PkLoss} * (.15 * \text{LF} + .85 * \text{LF}^2) / (\text{LF} * \text{Pk} * 8760)$$

$$\text{A\%} = \text{P\%} * (.15 + .85 * \text{LF})$$

	<i>A%</i>	<i>LF</i>	<i>P%</i>	<i>Factor 1</i>	<i>Average</i>
D et DM	10.2%	41.7%	20.2%	18.3%	19.3%
DH	10.2%	47.5%	18.4%	18.3%	18.4%
G et à forfait	10.2%	54.3%	16.6%	18.2%	17.4%
G-9	9.9%	81.2%	11.8%	17.7%	14.7%
M	9.3%	68.7%	12.6%	16.3%	14.5%
L	5.6%	110.0%	5.2%	9.0%	7.1%
H	6.2%	85.8%	7.1%	10.1%	8.6%
DT	10.2%	66.2%	14.3%	18.3%	16.3%
Tarifs d'éclairage public sentinelle	10.2%	48.8%	18.1%	18.3%	18.2%
Contrats spéciaux	5.2%	107.2%	4.9%	8.1%	6.5%

Exhibit 14: Hydro Québec Energy Rates

Scenario: Cumulative Effects, Excluding Special Contracts Class (2001 Base)

Loss Factor 1 Calculation									
	<i>Basse tension (BT)</i>			<i>Moyenne tension (MT)</i>	<i>Haute tension (HT)</i>				
	<i>Peak Loss Factor</i>			<i>18.8%</i>	<i>12.4%</i>	<i>8.7%</i>			<i>(Percent of Metered Demand)</i>
<i>Rate Class</i>	<i>Annual Metered Peak (kW)</i>				<i>Peak Losses (kW)</i>				<i>Class Loss Factor 1</i>
	<i>BT</i>	<i>MT</i>	<i>HT</i>	<i>Total</i>	<i>BT</i>	<i>MT</i>	<i>HT</i>	<i>Total</i>	
D et DM	13,456,729	-	-	13,456,729	2,533,303	-	-	2,533,303	18.8%
DH	1,203	-	-	1,203	226	-	-	226	18.8%
G et à forfait	2,474,613	23,960	-	2,498,573	465,860	2,976	-	468,836	18.8%
G-9	123,119	12,930	-	136,049	23,178	1,606	-	24,784	18.2%
M	2,730,465	1,142,136	29,392	3,901,992	514,025	141,864	2,555	658,443	16.9%
L	-	948,324	3,402,491	4,350,814	-	117,791	295,716	413,507	9.5%
H	-	1,208	1,075	2,283	-	150	93	244	10.7%
DT	442,951	-	-	442,951	83,388	-	-	83,388	18.8%
Tarifs d'éclairage public sentinelle	126,718	-	-	126,718	23,855	-	-	23,855	18.8%
Contrats spéciaux									
<i>Distributeur – électricité patrimoniale</i>	<i>19,355,797</i>	<i>2,128,558</i>	<i>3,432,958</i>	<i>24,917,313</i>	<i>3,643,835</i>	<i>264,387</i>	<i>298,364</i>	<i>4,206,586</i>	<i>16.9%</i>

Source: Peak Loss Factor Scenario Analysis

Load Factor Calculation – Customer Basis				
<i>Rate Class</i>	<i>Annual Energy</i>		<i>Peak Period Demand (kW)</i>	<i>Load Factor</i>
	<i>Consumption (GWh)</i>	<i>Peak Period Demand (kW)</i>		
D et DM	49,147	13,456,729	41.7%	
DH	5	1,203	47.5%	
G et à forfait	11,888	2,498,573	54.3%	
G-9	968	136,049	81.2%	
M	23,498	3,901,992	68.7%	
L	41,938	4,350,814	110.0%	
H	17	2,283	85.8%	
DT	2,568	442,951	66.2%	
Tarifs d'éclairage public sentinelle	542	126,718	48.8%	
<i>Distributeur - électricité patrimoniale</i>	<i>130,571</i>	<i>24,917,313</i>	<i>59.8%</i>	

Source: 2001 Base, 1 CP and Excl. Int. Analysis.

Load Factor Calculation – Generator Basis				
<i>Rate Class</i>	<i>Annual Energy</i>		<i>Peak Period Demand (kW)</i>	<i>Load Factor</i>
	<i>Consumption (GWh)</i>	<i>Average Peak Loss Factor</i>		
D et DM	54,163	19.5%	16,084,841	38.4%
DH	6	18.6%	1,427	44.1%
G et à forfait	13,098	17.7%	2,940,839	50.8%
G-9	1,064	15.0%	156,466	77.6%
M	25,676	14.7%	4,477,471	65.5%
L	44,295	7.3%	4,670,227	108.3%
H	18	8.9%	2,486	83.7%
DT	2,830	16.6%	516,367	62.6%
Tarifs d'éclairage public sentinelle	597	18.4%	150,090	45.4%
<i>Distributeur - électricité patrimoniale</i>	<i>141,747</i>	<i>16.4%</i>	<i>29,000,214</i>	<i>55.8%</i>

Source: 2001 Base, Average of Factor 1 and Factor 2, Peak Demand adjustments.

Exhibit 14: Hydro Québec Energy Rates

Scenario: Cumulative Effects, Excluding Special Contracts Class (2001 Base)

Calculation of Energy Rates					<i>Pct. Change</i>
<i>Rate Class</i>	<i>Load Factor</i>	<i>Energy Loss Factor</i>	<i>Energy Rate cents/kWh</i>	<i>Base</i>	<i>from 2001</i>
D et DM	38.4%	10.2%	3.34		3.6%
DH	44.1%	10.2%	3.13		0.6%
G et à forfait	50.8%	10.2%	2.94		1.2%
G-9	77.6%	9.9%	2.51		-11.0%
M	65.5%	9.3%	2.64		-2.0%
L	108.3%	5.6%	2.19		-11.9%
H	83.7%	6.2%	2.37		-6.5%
DT	62.6%	10.2%	2.71		0.2%
Tarifs d'éclairage public sentinelle	45.4%	10.2%	3.09		16.5%
Contrats spéciaux					
Distributeur - électricité patrimoniale	55.8%	8.6%	2.7900		0.0%

Source: Derived per HQ formula in Annexe 1.

Loss Factor 1 Analysis			
	<i>BT</i>	<i>MT</i>	<i>HT</i>
<i>Avg. Delivered Energy</i>	81,355	97,589	130,571
<i>Avg. Losses</i>	2,500.04	1,887.37	6,788
<i>Non-cum energy loss factor</i>	3.07%	1.93%	5.20%
<i>Constant</i>	0.00331	0.00174	0.00349
<i>Peak Demand</i>	19.36	21.48	24.92
<i>Peak Losses</i>	1.24	0.80	2.17
<i>Non-cum peak loss factors</i>	6.40%	3.73%	8.69%

Loss Factor 2 Calculation – UNCA Method

UNCA Loss Factor Study for Conductor Losses Method:

$$\text{Annual Energy Losses (GWh)} = 8760 * \text{Pk Loss} * \text{LSF}$$

$$\text{LSF} = .15 * \text{LF} + .85 * \text{LF}^2$$

If A% = AEL/Annual Energy, and P% = Pk Loss/Peak Demand

$$\text{AEL/AE} = 8760 * \text{PkLoss} * (.15 * \text{LF} + .85 * \text{LF}^2) / (\text{LF} * \text{Pk} * 8760)$$

$$\text{A\%} = \text{P\%} * (.15 + .85 * \text{LF})$$

	<i>A%</i>	<i>LF</i>	<i>P%</i>	<i>Factor 1</i>	<i>Average</i>
D et DM	10.2%	41.7%	20.2%	18.8%	19.5%
DH	10.2%	47.5%	18.4%	18.8%	18.6%
G et à forfait	10.2%	54.3%	16.6%	18.8%	17.7%
G-9	9.9%	81.2%	11.8%	18.2%	15.0%
M	9.3%	68.7%	12.6%	16.9%	14.7%
L	5.6%	110.0%	5.2%	9.5%	7.3%
H	6.2%	85.8%	7.1%	10.7%	8.9%
DT	10.2%	66.2%	14.3%	18.8%	16.6%
Tarifs d'éclairage public sentinelle	10.2%	48.8%	18.1%	18.8%	18.4%

Exhibit 15: Hydro Québec Energy Rates

Scenario: Cumulative Effects, Including Special Contracts Class (2002 Base)

Loss Factor Calculation									
	Basse tension (BT)			Moyenne tension (MT)	Haute tension (HT)				
	Peak Loss Factor	18.6%	12.0%	8.2%	(Percent of Metered Demand)				
Rate Class	Annual Metered Peak (kW)				Peak Losses (kW)				Class Loss Factor I
	BT	MT	HT	Total	BT	MT	HT	Total	
D et DM	13,649,366	-	-	13,649,366	2,542,309	-	-	2,542,309	18.6%
DH	1,204	-	-	1,204	224	-	-	224	18.6%
G et à forfait	2,485,734	23,946	-	2,509,680	462,989	2,877	-	465,866	18.6%
G-9	123,801	13,069	-	136,869	23,059	1,570	-	24,629	18.0%
M	2,778,737	1,162,435	29,877	3,971,049	517,563	139,661	2,438	659,662	16.6%
L	-	908,202	3,475,496	4,383,699	-	109,116	283,608	392,725	9.0%
H	-	1,185	1,052	2,237	-	142	86	228	10.2%
DT	447,427	-	-	447,427	83,337	-	-	83,337	18.6%
Tarifs d'éclairage public sentinelle	126,299	-	-	126,299	23,524	-	-	23,524	18.6%
Contrats spéciaux	-	-	2,274,793	2,274,793	-	-	185,628	185,628	8.2%
Distributeur - électricité patrimoniale	19,612,567	2,108,837	5,781,218	27,502,622	3,653,005	253,367	471,760	4,378,132	15.9%

Source: Base 2002 customer peak analysis, allocated by voltage per energy consumption.

Load Factor Calculation - Customer Basis				
Rate Class	Annual Energy		Peak Period Demand (kW)	Load Factor
	Consumption (GWh)	Peak Period Demand (kW)		
D et DM	49,854	13,649,366	41.7%	
DH	5	1,204	47.4%	
G et à forfait	11,948	2,509,680	54.3%	
G-9	974	136,869	81.2%	
M	23,924	3,971,049	68.8%	
L	42,501	4,383,699	110.7%	
H	17	2,237	85.8%	
DT	2,608	447,427	66.5%	
Tarifs d'éclairage public sentinelle	540	126,299	48.8%	
Contrats spéciaux	21,155	2,274,793	106.2%	
Distributeur - électricité patrimoniale	153,526	27,502,622	63.7%	

Source: 1 CP and Excl. Int. Analysis, HQ Letter dated 30 April 2002.

Load Factor Calculation - Generator Basis						
Rate Class	Annual Energy		Average Peak Loss Factor	Peak Period Demand (kW)	Load Factor	1 CP Allocator
	Consumption (GWh)	Average Peak Loss Factor				
D et DM	55,023	19.6%	16,191,675	38.8%	48.199%	
DH	6	18.7%	1,428	44.1%	0.004%	
G et à forfait	13,183	17.7%	2,975,546	50.6%	8.860%	
G-9	1,072	15.0%	161,498	75.8%	0.482%	
M	26,173	14.7%	4,630,711	64.5%	13.900%	
L	44,887	7.1%	4,776,423	107.3%	18.192%	
H	18	8.7%	2,465	82.8%	0.008%	
DT	2,878	16.6%	530,764	61.9%	1.580%	
Tarifs d'éclairage public sentinelle	596	18.5%	149,823	45.4%	0.446%	
Contrats spéciaux	22,255	6.6%	2,460,421	103.3%	8.330%	
Distributeur - électricité patrimoniale	166,091	15.9%	31,880,755	59.5%	100.000%	

Source: HQ Letter dated 30 April 2002, loss factor analysis, interruptible load adjustment

Exhibit 15: Hydro Québec Energy Rates

Scenario: Cumulative Effects, Including Special Contracts Class (2002 Base)

Calculation of Energy Rates				
Rate Class	Load Factor	Energy Loss Factor	Energy Rate cents/kWh	Pct. Change
				Base
D et DM	38.8%	10.4%	3.45	7.0%
DH	44.1%	10.4%	3.24	4.1%
G et à forfait	50.6%	10.3%	3.05	4.7%
G-9	75.8%	10.1%	2.59	-7.9%
M	64.5%	9.4%	2.73	1.4%
L	107.3%	5.6%	2.24	-9.9%
H	82.8%	6.3%	2.43	-3.9%
DT	61.9%	10.4%	2.80	3.6%
Tarifs d'éclairage public sentinelle	45.4%	10.4%	3.20	20.5%
Contrats spéciaux	103.3%	5.2%	2.25	-7.6%
Distributeur - électricité patrimoniale	59.5%	8.2%	2.7900	0.0%

Source: Derived per HQ formula in Annexe 1.

Loss Factor Analysis			
	BT	MT	HT
Avg. Delivered Energy	82,463	98,488	153,526
Avg. Losses	2,617	1,965	7,983
Non-cum energy loss factor	3.17%	1.99%	5.20%
Constant	0.00337	0.00177	0.00297
Peak Demand	19.61	21.72	27.50
Peak Losses	1.30	0.84	2.24
Non-cum peak loss factors	6.61%	3.85%	8.16%

Loss Factor 2 Calculation – UNCA Method					
UNCA Loss Factor Study for Conductor Losses Method:					
Annual Energy Losses (GWh) = 8760 * Pk Loss * LSF					
LSF = .15 * LF + .85 * LF ²					
If A% = AEL/Annual Energy, and P% = Pk Loss/Peak Demand					
AEL/AE = 8760*PkLoss*(.15*LF+.85*LF ²)/(LF*Pk*8760)					
A% = P% * (.15 + .85*LF)					
	A%	LF	P%	Factor 1	Average
D et DM	10.4%	41.7%	20.6%	18.6%	19.6%
DH	10.4%	47.4%	18.7%	18.6%	18.7%
G et à forfait	10.3%	54.3%	16.9%	18.6%	17.7%
G-9	10.1%	81.2%	12.0%	18.0%	15.0%
M	9.4%	68.8%	12.8%	16.6%	14.7%
L	5.6%	110.7%	5.1%	9.0%	7.1%
H	6.3%	85.8%	7.1%	10.2%	8.7%
DT	10.4%	66.5%	14.5%	18.6%	16.6%
Tarifs d'éclairage public sentinelle	10.4%	48.8%	18.4%	18.6%	18.5%
Contrats spéciaux	5.2%	106.2%	4.9%	8.2%	6.6%

Exhibit 16: Hydro Québec Energy Rates

Scenario: Cumulative Effects, Excluding Special Contracts Class (2002 Base)

Loss Factor Calculation									
	<i>Basse tension (BT)</i>			<i>Moyenne tension (MT)</i>	<i>Haute tension (HT)</i>				
	<i>Peak Loss Factor</i>			<i>12.5%</i>	<i>8.7%</i>			<i>(Percent of Metered Demand)</i>	
	<i>19.1%</i>								
<i>Rate Class</i>	<i>Annual Metered Peak (kW)</i>			<i>Total</i>	<i>Peak Losses (kW)</i>			<i>Total</i>	<i>Class Loss Factor</i>
	<i>BT</i>	<i>MT</i>	<i>HT</i>		<i>BT</i>	<i>MT</i>	<i>HT</i>		
D et DM	13,649,366	-	-	13,649,366	2,613,465	-	-	2,613,465	19.1%
DH	1,204	-	-	1,204	230	-	-	230	19.1%
G et à forfait	2,485,734	23,946	-	2,509,680	475,947	3,002	-	478,949	19.1%
G-9	123,801	13,069	-	136,869	23,704	1,638	-	25,343	18.5%
M	2,778,737	1,162,435	29,877	3,971,049	532,049	145,721	2,594	680,364	17.1%
L	-	908,202	3,475,496	4,383,699	-	113,851	301,727	415,577	9.5%
H	-	1,185	1,052	2,237	-	149	91	240	10.7%
DT	447,427	-	-	447,427	85,670	-	-	85,670	19.1%
Tarifs d'éclairage public sentinelle	126,299	-	-	126,299	24,183	-	-	24,183	19.1%
<i>Distributeur – électricité patrimoniale</i>	<i>19,612,567</i>	<i>2,108,837</i>	<i>3,506,426</i>	<i>25,227,830</i>	<i>3,755,249</i>	<i>264,361</i>	<i>304,412</i>	<i>4,324,021</i>	<i>17.1%</i>

Source: Base 2002 customer peak analysis, allocated by voltage per energy consumption.

Load Factor Calculation – Customer Basis			
<i>Rate Class</i>	<i>Annual Energy</i>		
	<i>Consumption (GWh)</i>	<i>Peak Period Demand (kW)</i>	<i>Load Factor</i>
D et DM	49,854	13,649,366	41.7%
DH	5	1,204	47.4%
G et à forfait	11,948	2,509,680	54.3%
G-9	974	136,869	81.2%
M	23,924	3,971,049	68.8%
L	42,501	4,383,699	110.7%
H	17	2,237	85.8%
DT	2,608	447,427	66.5%
Tarifs d'éclairage public sentinelle	540	126,299	48.8%
<i>Distributeur - électricité patrimoniale</i>	<i>132,371</i>	<i>25,227,830</i>	<i>59.9%</i>

Source: I CP and Excl. Int. Analysis, HQ Letter dated 30 April 2002.

Load Factor Calculation – Generator Basis					
<i>Rate Class</i>	<i>Annual Energy</i>			<i>Load Factor</i>	<i>I CP Allocator</i>
	<i>Consumption (GWh)</i>	<i>Average Peak Loss Factor</i>	<i>Peak Period Demand (kW)</i>		
D et DM	55,023	19.9%	16,262,831	38.6%	48.199%
DH	6	18.9%	1,434	43.9%	0.004%
G et à forfait	13,183	18.0%	2,988,629	50.4%	8.860%
G-9	1,072	15.2%	162,212	75.4%	0.482%
M	26,173	15.0%	4,651,413	64.2%	13.900%
L	44,887	7.3%	4,799,276	106.8%	18.192%
H	18	8.9%	2,477	82.4%	0.008%
DT	2,878	16.8%	533,097	61.6%	1.580%
Tarifs d'éclairage public sentinelle	596	18.8%	150,482	45.2%	0.446%
<i>Distributeur - électricité patrimoniale</i>	<i>143,836</i>	<i>17.1%</i>	<i>29,551,851</i>	<i>55.6%</i>	<i>91.670%</i>

Source: HQ Letter dated 30 April 2002, loss factor analysis, interruptible load adjustment

Exhibit 16: Hydro Québec Energy Rates

Scenario: Cumulative Effects, Excluding Special Contracts Class (2002 Base)

Calculation of Energy Rates					Pct. Change
Rate Class	Load Factor	Energy Loss Factor	Energy Rate cents/kWh	Base	from 2001
D et DM	38.6%	10.4%	3.33	3.33	3.2%
DH	43.9%	10.4%	3.13	3.13	0.6%
G et à forfait	50.4%	10.3%	2.95	2.95	1.4%
G-9	75.4%	10.1%	2.53	2.53	-10.3%
M	64.2%	9.4%	2.66	2.66	-1.4%
L	106.8%	5.6%	2.19	2.19	-11.8%
H	82.4%	6.3%	2.37	2.37	-6.2%
DT	61.6%	10.4%	2.72	2.72	0.7%
Tarifs d'éclairage public sentinelle	45.2%	10.4%	3.09	3.09	16.5%
Distributeur - électricité patrimoniale	55.6%	8.7%	2.7900	2.7900	0.0%

Source: Derived per HQ formula in Annexe 1.

Loss Factor Analysis			
	BT	MT	HT
Avg. Delivered Energy	82,463	98,488	132,371
Avg. Losses	2,617	1,965	6,883
Non-cum energy loss factor	3.17%	1.99%	5.20%
Constant	0.00337	0.00177	0.00344
Peak Demand	19.61	21.72	25.23
Peak Losses	1.30	0.84	2.19
Non-cum peak loss factors	6.61%	3.85%	8.68%

Loss Factor 2 Calculation -- UNCA Method					
UNCA Loss Factor Study for Conductor Losses Method:					
Annual Energy Losses (GWh) = 8760 * Pk Loss * LSF					
LSF = .15 * LF + .85 * LF^2					
If A% = AEL/Annual Energy, and P% = Pk Loss/Peak Demand					
AEL/AE = 8760*PkLoss*(.15*LF+.85*LF^2)/(LF*Pk*8760)					
A% = P% * (.15 + .85*LF)					
	A%	LF	P%	Factor 1	Average
D et DM	10.4%	41.7%	20.6%	19.1%	19.9%
DH	10.4%	47.4%	18.7%	19.1%	18.9%
G et à forfait	10.3%	54.3%	16.9%	19.1%	18.0%
G-9	10.1%	81.2%	12.0%	18.5%	15.2%
M	9.4%	68.8%	12.8%	17.1%	15.0%
L	5.6%	110.7%	5.1%	9.5%	7.3%
H	6.3%	85.8%	7.1%	10.7%	8.9%
DT	10.4%	66.5%	14.5%	19.1%	16.8%
Tarifs d'éclairage public sentinelle	10.4%	48.8%	18.4%	19.1%	18.8%

**BOARD OF COMMISSIONERS OF PUBLIC UTILITIES
PROVINCE OF NEW BRUNSWICK**

**IN THE MATTER OF AN APPLICATION BY
THE NEW BRUNSWICK ELECTRIC POWER
COMMISSION FOR APPROVAL OF A CHANGE
IN ITS CHARGES, RATES AND TOLLS**

**EVIDENCE OF INDUSTRIAL ECONOMICS, INCORPORATED
ON BEHALF OF THE LARGE POWER USERS GROUP**

Consisting of:

Brunswick Mining and Smelting Corporation, Ltd.
Fraser, Inc.
Irving Oil, Ltd.
Irving Paper, Ltd.
Miramichi Pulp & Paper, Inc.
NBIP Forest Products, Inc.
Potacan Mining Company
St. Anne-Nackawic Pulp Company, Ltd.
Stone-Consolidated, Inc.

24 September 1991

NB Power recommends a cost allocation method that classifies the majority (60 percent) of all non-fuel costs of generation as energy costs. The remaining 40 percent of these costs are classified as demand-related costs. Fuel and purchased power costs are classified as energy-related costs. The costs of the transmission system are classified as demand related.

NB Power witness Mr. Vander Veen argues that the classification of a substantial share of fixed generation costs as energy costs is appropriate for the following two reasons: (Cost of Service Evidence, p. 4-7)

1. Several Canadian utilities classify a share of the fixed costs of generation as energy-related costs. Thus, NB Power's method is consistent with the practices of other Canadian utilities.
2. Review of NB Power's system indicates that substantial capital investments have been made to realize lower fuel costs. Other classification methodologies, which recognize this "capital for fuel" tradeoff, indicate that energy classifications in the range of 45% to 69% are reasonable for NB Power's system.

As described below, we have reviewed each of the above reasons and conclude that these reasons do not support the classification of 60 percent of the fixed generation costs as energy-related costs.

1. Practices of Other Canadian Utilities

Contrary to Mr. Vander Veen's testimony, NB Power's classification method is not consistent with the practices of the other Canadian utilities. While it is true that some of the Canadian utilities classify a significant portion of fixed generation costs as energy-related costs, these utilities also classify a significant portion of their fuel costs as demand-related costs. The overall result is that other Canadian utilities classify between 46 and 58 percent of total generation and transmission expenses as energy-related costs, as shown in Table 1 below.¹

¹For a more detailed description of the classification of costs of the other Canadian utilities, please refer to Appendix I.

TABLE 1

**DEMAND/ENERGY SPLIT FOR GENERATION AND TRANSMISSION COSTS
Canadian Utilities**

Utility	Demand	Energy
BC Hydro	52.2%	47.8%
TransAlta Utilities	54.0%	46.0%
Saskatchewan Power	47.4%	52.6%
Manitoba Hydro	43.5%	56.5%
Ontario Hydro	42.0%	58.0%
Nova Scotia Power	41.5%	58.4%
Newfoundland & Labrador Hydro	45.1%	54.9%
Average for Other Canadian Utilities	46.5%	53.5%
New Brunswick Power (Monenco Study)	59.7%	40.3%
New Brunswick Power (Proposed)	31.4%	68.6%

As shown in this table, NB Power proposes to classify 69 percent of its total generation and transmission costs as energy-related costs and the remaining 31 percent as demand-related costs.

This classification is in sharp contrast to the other Canadian utilities which classify an average of 53.5 percent of total generation and transmission costs as energy related and the remaining 46.5 percent as demand related. It also represents a significant change from the methodology employed by NB Power consultants in March, 1988, when NB Power was not subject to regulatory review.

In most cases, the difference lies in the other Canadian utilities classification of the variable costs of generation including fuel. For example, while Mr. Vander Veen is technically correct in pointing out that Ontario Hydro classifies 42 percent of its fixed generation costs as demand-related costs, he fails to note that 42 percent of the variable costs of generation, including fuel, are also classified as demand-related costs. Similarly, Manitoba Hydro (on whose behalf Mr. Vander Veen has testified) classifies both its fixed and variable costs of generation and transmission as 43.5 percent demand/56.5 percent energy. BC Hydro classifies its fixed and variable costs of generation as 39/61 demand/energy for its hydraulic facilities and its transmission costs as 100 percent demand. While Mr. Vander Veen's treatment of the fixed costs of generation may be similar to the treatment accorded these costs by Ontario Hydro, Manitoba Hydro and BC Hydro, he neglects to point out that he is recommending that NB Power classify its variable O&M and fuel costs as 100 percent energy related -- a practice that is not consistent

with the treatment accorded these costs by the utilities he cites in support of his proposed methodology. Thus, his proposed cost allocation results in an overall demand/energy split of 31/69 for total generation and transmission costs.

2. The "Capital for Fuel" Tradeoff

Mr. Vander Veen also states that other methods used to classify generation and transmission costs support his classification treatment. The details underlying each of these methods are provided in the response to Interrogatory NBP (LPU) 47 Supplemental. This interrogatory response shows that four alternative classification methods for fixed generation costs result in classifying between 45 to 69 percent of these fixed costs as energy-related costs.

The basic philosophy underlying each of these classification methods is that capital can be substituted for fuel in order to minimize total production costs. (See page 3 of NB Power's response to Interrogatory NBP (LPU) 47 Supplemental.) Thus, proponents of these methods contend that a portion of the fixed capital-related costs are incurred to reduce fuel costs and are therefore "caused" by total energy requirements and are not related to peak demands.

However, once again, Mr. Vander Veen ignores the other side of the picture. If a portion of the capital costs are incurred to reduce fuel costs, it is equally true that a portion of the fuel costs are incurred to reduce capital costs on peak. A utility chooses to pay the relatively higher costs of fuel oil during its peak periods in order to minimize the capital costs of building plants to meet peak period demands. Thus, a utility relies on combustion turbine units (with low capital costs and high operating costs) to meet a portion of the demand during the peak periods. Therefore, a portion of the higher cost of fuel oil is caused by peak period demands rather than total energy production. Thus, a portion of the fuel costs should be classified as demand-related costs.

NB Power is not aware of any jurisdictions that rely specifically on any of these alternative methodologies. (NBP (LPU) 47 Supplemental, parts (b) and (c)) In fact, both Manitoba Hydro and Ontario Hydro have employed these methodologies to provide an indication of the range of demand/energy splits for total generation costs, rather than only non-fuel generation costs. The other Canadian utilities that classify a portion of the fixed generation and transmission costs as energy-related costs also classify a portion of the fuel and other variable operating costs as demand-related costs. In contrast, Mr. Vander Veen proposes to classify all of NB Power's fuel costs as energy-related costs.

Thus, economic theory does not support Mr. Vander Veen's classification of a large portion of fixed generation costs as energy-related costs while none of the variable costs are classified as demand related. Mr. Vander Veen's proposed method is also not supported by the characteristics of NB Power's system. The argument that capital costs have been substituted for fuel costs is traditionally applied to utility generating systems with substantial portions of hydraulic or nuclear generation.² These systems have substantially lower fuel costs than predominantly

²For example, see the Manitoba Hydro Discussion Document attached to PUB Interrogatory 7(a) where

APPENDIX I

REVIEW OF COST ALLOCATION METHODS EMPLOYED BY OTHER CANADIAN UTILITIES

This appendix reviews the cost allocation methods employed by other Canadian utilities with respect to the classification of generation (production) and transmission costs and the subsequent allocation of these costs to the customer classes of the utility. We then compare the cost allocation methods proposed by NB Power in this proceeding and the past cost allocation methods employed by NB Power.

British Columbia Hydro and Power Authority (BC Hydro)

BC Hydro filed a cost allocation study for the year 88/89 as a part of their January 1991 rate design application. As shown in this study, BC Hydro classifies both the fixed and variable costs of its hydraulic generating facilities, which represent the bulk of its generating capability, as 39 percent demand/61 percent energy. The fixed and variable costs of the few thermal generating facilities are classified as 5 percent demand/95 percent energy. All transmission costs are classified as demand-related costs. The overall demand/energy split for generation and transmission costs resulting from this classification system is 52.2 percent demand/47.8 percent energy.

BC Hydro allocates the demand-related generation and transmission costs to customer classes on the basis of a coincident peak. The energy-related costs are allocated to customer classes based upon domestic sales volumes at generation.

TransAlta Utilities Corporation

In its May 1991 Cost of Service study, TransAlta divides its total cost of service into upstream (the costs related to generation and transmission) and downstream (the distribution system costs) costs.¹¹ TransAlta's upstream cost is the cost of purchasing power from the Alberta Electric Energy Marketing Agency (EEMA). The generation and transmission costs of TransAlta Utilities, Alberta Power and Edmonton Power are pooled by EEMA and each utility then purchases power at an averaged price.

TransAlta's upstream costs comprise approximately 81 percent of the total cost of service. These costs are classified as demand and energy costs using a fixed/variable method. Fuel and other

¹¹The methods used in the 1991 study are generally the same as those used in the 1990 Cost of Service study, filed in the 1988/89/90 Rate Review proceedings. The changes to the approved methods have no effect on the classification and allocation of generation and transmission costs.

variable O&M costs (approximately 50% of O&M costs are deemed to be variable) are classified as energy-related costs; the remaining costs are classified as demand-related costs. In the 1991 study, this classification method results in approximately 54.0 percent of these upstream costs being classified as demand-related and the remaining 46.0 percent as energy-related costs.

The demand-related upstream costs are allocated to customer classes based on a weighted average coincident peak.¹² Energy-related upstream costs are allocated based on annual energy volumes measured at the pooling interface.

Saskatchewan Power Corporation (SaskPower)

SaskPower's Cost of Service Study for test year 1987 allocates costs in accordance with Commission Order SPC 6-86 dated April 3, 1986. Thermal generation costs are classified as 100 percent demand-related costs. Hydro generation costs are divided into demand-related and energy-related costs based upon an analysis of the firm and average stream flow by plant. All transmission costs are classified as demand related. This classification system results in an overall demand/energy split of 55.7/44.3 for total generation and transmission costs.

Demand-related generation costs are allocated to customer classes using an "average and excess demand" factor. Thus, while these costs are classified as "demand-related" costs, the costs are allocated, in part, based upon the average demands of the customer classes. Allocating costs based on an average and excess factor is equivalent to classifying a portion of these costs as energy related.¹³ The average and excess allocator employed by SaskPower is equivalent to

¹²The weighted coincident peak used by TransAlta gives equal weight to the average of the coincident peaks in each of the three winter months and the average of the coincident peaks in each of the nine non-winter months.

¹³Average and excess demand (AED) allocation factors are a weighted average of the average demand and the excess demand of a customer class. The excess demand is computed by subtracting the average demand of the customer class from its peak (generally, the non-coincident peak) demand. In simplified terms, the average and excess demand allocation factors can be expressed, as follows:

$$\text{AED} = a * \text{Average Demand} + b * \text{Excess Demand}$$

where a and b are the weights accorded the average and the excess demands

This equation is equivalent to:

$$\text{AED} = a * \text{Average Demand} + b * (\text{Peak Demand} - \text{Average Demand})$$

Or:

$$\text{AED} = (a-b) * \text{Average Demand} + b * \text{Peak Demand}$$

Thus, the use of an AED factor to allocate demand-related costs is equivalent to first classifying a portion (a-b) of these costs as energy-related costs and then allocating these energy costs on the basis of average annual demands. The remaining portion (b) of the demand-related costs are actually treated as demand

classifying 19 percent of these demand-related generation costs as energy related. After adjusting for the demand-related costs implicitly treated as energy-related costs through the use of the average and excess factor, SaskPower's cost allocation methodology results in an overall demand/energy split of 47.4/52.6 for total generation and transmission costs.

Transmission costs are allocated based on the coincident peaks on the main grid, and the non-coincident peaks on lower voltage portions of the system. Energy costs are allocated based on total energy output at generation.

Manitoba Hydro Electric Board (Manitoba Hydro)

Manitoba Hydro's Prospective Cost of Service Study dated December 1990 provides the allocated costs for the test year ending March 31, 1992. Power supply costs which include generation, transmission, substations and lines, transformer inventory, and related common plant are classified as 43.5 percent energy and 56.5 percent energy. This 43.5/56.5 split is based on the system load factor excluding exports and Winnipeg Hydro's generation. This classification applies to both the fixed and variable costs of generation and transmission. Manitoba Hydro argues that this load factor classification is appropriate in the context of its largely hydraulic system.¹⁴

The demand-related generation and transmission costs are allocated to customer classes on the basis of a coincident peak. Energy-related generation and transmission costs are allocated based on kilowatt-hours generated.

costs and are allocated on the basis of peak demands.

¹⁴ The Public Utilities Board accepted this classification approach in its March 31, 1988 Report to the Minister. However, Manitoba Hydro recently reviewed its classification of generation and transmission costs as indicated in the attachment to Interrogatory NBP (PUB) 7(a). Based on this review, Manitoba Hydro concludes that the "current approach is a reasonable middle ground among several reasonable alternatives."

Ontario Hydro

Ontario Hydro's cost of service study filed in its most recent rate proceeding (establishing rates for 1992) classifies 42 percent of all common bulk power costs as demand related and the remaining 58 percent of these costs as energy related. The common bulk power costs include the fixed and variable generation and transmission costs of the utility, excluding any costs directly assigned to specific customers. This classification was negotiated between Ontario Hydro and its customers, as part of an overall agreement to adopt time-of-use rates.

The demand and energy costs are then assigned to time-of-use periods based upon targeted time-of-use differentials. Finally, the demand costs are allocated to customer classes based upon their relative peak loads in the peak periods and the energy costs are allocated to customer classes based upon their respective energy use by time-of-use period.

Nova Scotia Power Corporation (NS Power)

NS Power's cost of service study for the year ending March 31, 1992 was submitted as evidence in its 1991 rate hearing. NS Power classifies its costs using a fixed/variable approach; that is, fuel and other variable operating and maintenance costs are classified as energy related and fixed costs including depreciation and interest are classified as demand related.

NS Power allocates its energy-related costs based on total annual consumption. Demand-related generation and transmission costs are allocated using an average and excess demand factor. As explained above, allocation using an average and excess factor is equivalent to classifying a portion of these demand-related costs as energy costs. NS Power's average and excess factor is equivalent to classifying almost 15 percent of its demand-related costs as energy costs. Taking the average and excess factor into account, NS Power's overall demand/energy split is 41.6/58.4 for its total generation and transmission costs.

Newfoundland & Labrador Hydro (N&L Hydro)

Newfoundland & Labrador Hydro's evidence in its February 1990 rate filing includes a Cost of Service study for the 1992 test year. The costs of N&L Hydro's hydraulic facilities are classified as demand and energy-related costs based upon the capacity factor of each plant. Overall, hydraulic facilities are classified as 46.64 percent demand and 53.36 percent energy in the 1992 test year. Gas turbines are classified as 99 percent demand and 1 percent energy. The costs of other generation facilities and the transmission system are classified as 50 percent demand/50 percent energy. This classification results in 47 percent of the common costs being classified as demand related and the remaining 53 percent of common costs being classified as energy related.

N&L Hydro allocates its demand-related costs using an average and excess demand factor. Thus, as explained above, a portion of the costs classified as demand related are actually allocated on an energy basis. N&L Hydro's average and excess factor is equivalent to treating 8 percent of the costs designated as demand related as energy-related costs. Thus, the implicit

overall demand/energy split for N&L Hydro's total common costs is 45.1/54.9.

New Brunswick Power (NB Power) -- Proposed Method

New Brunswick Power proposes to classify 40 percent of the fixed costs and the non-fuel operating and maintenance costs of generation as demand-related costs and the remaining 60 percent as energy related. Transmission costs are classified as 100 percent demand related, and fuel costs are classified as energy related. The resulting overall demand/energy split for generation and transmission costs proposed by NB Power can be derived from Schedule 7.1 of Exhibit HJV-3. This schedule shows the following breakdown for common generation (production) and transmission costs:

	Costs (\$'000)	% of Total
Demand -- Production	\$118,315	
Demand -- Transmission	34,406	
Total Demand	\$152,721	31.4%
Fuel & Purchased Power	\$169,111	
Other Energy	164,234	
Total Energy	\$333,345	68.6%
Total Common Production and Transmission Costs	\$486,066	100.0%

Thus, NB Power proposes to classify almost 69 percent of its total generation and transmission costs as energy related. In contrast, the Canadian utilities discussed above classify between 46 and 58 percent, with an average of 53.5 percent, of total generation and transmission costs as energy related.

New Brunswick Power -- Monenco Study

Prior to the cost allocation method proposed in this proceeding, NB Power commissioned a cost allocation study by Monenco Consultants Limited in 1987. The Monenco study, produced in response to Interrogatory NBP(PUB) 1, states that its study "follows the procedures recommended in the NARUC Cost Allocation Manual..." As shown in Schedules 4.1 through 4.3, Monenco classified production and transmission plant and the associated depreciation and interest costs as demand-related costs. Fuel and purchased power costs are classified as energy-related costs. Non-fuel production operating and maintenance costs are classified as 70 percent demand/30 percent energy. All transmission O&M costs are classified as demand related.

The energy-related costs are allocated to customer classes on total annual sales volumes. The demand-related costs are allocated using an average and excess demand factor. Use of the average and excess demand factor described in Schedule 1.1a to allocate demand-related costs is equivalent to classifying 6.6 percent of these costs as energy related. After accounting for the use of the AED factor, the implicit demand/energy split is 59.7/40.3 for NB Power's total production and transmission costs, quite a contrast to the 31/69 demand/energy split proposed in this proceeding.

ROBERT D. KNECHT

Robert D. Knecht specializes in the practical application of economics, finance and management theory to issues facing public and private sector clients. Mr. Knecht has more than twenty years of consulting experience, focusing primarily on the energy, metals, and mining industries. He has consulted to industry, law firms, and government clients, both in the U.S. and internationally. He has participated in strategic and business planning studies, project evaluations, litigation and regulatory proceedings and policy analyses. As Treasurer of IEc, Mr. Knecht is responsible for the firm's accounting, finance and tax planning, as well as administration of the firm's retirement plans. Mr. Knecht's recent consulting assignments include the following projects:

- For the Pennsylvania Office of Small Business Advocate, Mr. Knecht provides analysis and expert testimony in industry restructuring, base rates and purchased energy cost proceedings involving electric, steam and natural gas distribution utilities. Mr. Knecht has analyzed the economics and financial issues of electric industry restructuring, stranded cost determination, industry economics, cost allocation methods and rate design issues.
- For the New Jersey Board of Public Utilities, Mr. Knecht audited the cost and rate unbundling, cost allocation and rate design aspects of the industry restructuring filing of an investor-owned electric utility.
- For the U.S. Department of Justice, Mr. Knecht participated in an evaluation of the economic damage claims of a large forest products concern, in a breach of contract lawsuit. Mr. Knecht's analysis included a review of the economic claims of the plaintiff, and an evaluation of settlement alternatives.
- For the Independent Power Producers Society of Alberta and the Senior Petroleum Producers Association, Mr. Knecht provides analysis and recommendations regarding electric industry restructuring strategies. Mr. Knecht also provided expert testimony with respect to industry restructuring, cost allocation, rate unbundling methodologies and rate design.
- For a major South American iron ore mining company, Mr. Knecht assembled and managed an international team of consultants to review and evaluate the company's strategic plan. Mr. Knecht oversaw the development of recommendations in the areas of markets, the resource base, development of the resource, processing operations and finance.

Mr. Knecht holds a M.S. in Management from the Sloan School of Management at M.I.T., with concentrations in applied economics and finance. He also holds a B.S. in Economics from M.I.T. Prior to joining Industrial Economics as a principal in 1989, Mr. Knecht worked for seven years as an economic and management consultant at Marshall Bartlett, Incorporated. He also worked for two years as an economist in the Energy Group of Data Resources, Incorporated.

ROBERT D. KNECHT

Regulatory Economics

Mr. Knecht consults and provides expert testimony in the field of regulatory economics, focusing primarily on issues of industry restructuring, cost allocation and rate design. His clients include both utilities and the consumers, competitors, and regulators of public utilities. Representative assignments are listed below.

- For the Independent Power Producers Society of Alberta and the Senior Petroleum Producers Association, in a variety of regulatory proceedings, analysis and expert testimony regarding electric industry restructuring, market power mitigation, stranded cost determination, cost allocation, rate unbundling and tariff design for transmission and distribution utilities.
- Participation in an audit of the electric industry restructuring filing of the Atlantic City Electric Company, for the NJ Board of Public Utilities, evaluating the company's rate unbundling filing.
- For the Pennsylvania OSBA, evaluation of all aspects of the electric industry restructuring filings of Pennsylvania Power & Light and West Penn Power, focusing on impacts to customers in general and small businesses in particular.
- Analysis and expert testimony regarding system expansion and related customer contribution requirements of Centra Gas Manitoba, for a large industrial customer.
- For the Industrial Gas Users Association, analysis and expert testimony of the cost unbundling methods of Gaz Metropolitan.
- Analysis and expert testimony of cost allocation and rate design practices of the three major Ontario natural gas distribution utilities over several years, on behalf of the Ontario Energy Board staff and the Canadian Independent Gas Marketing Association.
- Cost allocation and rate design study and expert testimony for a small Ontario gas distribution utility.
- Analysis and litigation support regarding accounting, financial and capacity planning procedures of New Brunswick Power Corporation, and presentation of expert testimony on cost allocation and rate design, in a series of generic regulatory hearings, on behalf of a group of large industrial customers.
- Analysis of the cost allocation and rate design procedures of Consumers' Gas, Ltd., for the Canadian Independent Gas Marketing Association.
- Analysis of the cost allocation and rate design procedures of the three major Ontario natural gas utilities, for the staff of the Ontario Energy Board.
- Economic analysis and modeling of U.S. Postal Service proposals for allocation of peak load labor and equipment costs in 1987 and 1990, for the American Newspaper Publishers Association.
- Evaluation of the cost allocation and cost recovery procedures of a domestic telecommunications firm providing aircraft to ground data communications.
- Assessment of alternative methodologies for defining the electric rate classes of Maritime Electric Corporation, for the Prince Edward Island Ministry of Energy and Forestry.

ROBERT D. KNECHT

Regulatory Economics (continued)

- Evaluation of the cost allocation and rate design procedures of the Nova Scotia Power Corporation, for a group of interruptible electricity consumers, and in a later proceeding, for a large industrial customer.
- Assessment of a proposed class-specific, risk-adjusted rate of return methodology for natural gas distribution utilities, for the staff of the Ontario Energy Board.
- Preparation of rebuttal analysis regarding management prudence in the construction of the River Bend Nuclear Generating Station, for Gulf States Utilities.

Economic Consulting

Mr. Knecht's practice includes the application of economics, finance and decision analysis theory to practical problems facing businesses, law firms and government. His assignments include industry and company planning, market forecasting, policy analysis and economic damage assessment. Representative assignments are listed below.

- For the US Department of Justice Civil Division, analysis of economic damages and participation in settlement negotiations associated with alleged breach of contract involving long-term timber supply contracts between the U.S. government and a large forest products company in Southeast Alaska.
- For the Electric Power Research Institute, analysis and adaptation of models that compute the economic costs of environmental externalities associated with electric generating stations.
- Economic, market and cost analysis for a team of international consultants preparing a restructuring study of the Polish steel industry, in conjunction with the World Bank.
- Economic and policy analysis for a U.S. engineering firm preparing a strategic planning study for the state-owned steel company in Venezuela.
- For the U.S. Environmental Protection Agency, evaluation of the impact of Clean Air Act amendments on major industrial facilities that are closing or are threatened with closure.
- Econometric analysis of world steel consumption patterns for a major international iron ore producer.
- Litigation support services relating to the business planning activities of a major West Coast construction and fabrication concern, in a fraudulent conveyance lawsuit.
- Review and analysis of direct and rebuttal evidence regarding economic damages to recreational activities, for the U.S. Department of Justice.
- Decision analysis and calculation of economic damages in an ERISA discrimination lawsuit, for a major domestic manufacturing company.
- Financial, econometric and strategic planning analyses for an international engineering firm, engaged in the preparation of a strategic plan for the steel industry of Nigeria.

ROBERT D. KNECHT

Economic Consulting (continued)

- Economic analysis and econometric modeling of import behavior in the domestic carbon steel and wire rope markets, for hearings before the U.S. International Trade Commission.
- Financial analysis and damage assessment for a major domestic law firm, in support of a major anti-trust suit involving the potential construction of a coal slurry pipeline.
- Economic analysis of imports of iron ore pellets into the U.S., for a major international iron ore producer.
- Construction of an economic model of domestic metallurgical coke demand, for the U.S. Environmental Protection Agency.
- Econometric analysis of energy demand, by energy type, region and sector, and management of a sectoral supply-demand model of energy production and use.

Management Consulting

Mr. Knecht has also provided management consulting services to various basic industrial clients, focusing primarily on planning and decision-making. Representative assignments are listed below.

- Competitive dynamics analysis of the world iron ore industry and preparation of strategic recommendations for a major South American mining company.
- Task leader in a management audit of a New Jersey natural gas local distribution company.
- Development of a strategic plan and various business plans for a domestic specialized producer of carbon and alloy steel bars.
- Economic analysis and financial modeling of labor and employee benefits costs for a large integrated steel producer. Preparation of recommendations for labor relations and bargaining strategies.
- Analysis for the restructuring of the marketing function of a large domestic manufacturing company, including market segmentation analysis, field interviews and competitor comparisons.
- Market survey and analysis of the domestic hot finished seamless steel tube markets, for a U.S. producer.
- Strategic and business plan development for a major Polish steel producer.

ROBERT D. KNECHT

SCHEDULE OF APPEARANCES BEFORE REGULATORY AUTHORITIES

Docket #	Regulator	Utility	Date of Testimony	Client	Topic of Testimony
1248859	Alberta Energy and Utilities Board	ESBI Alberta Limited	March 2002	IPPSA	Transmission congestion management principles
R-00016378	Pennsylvania Public Utility Commission	Philadelphia Gas Works	August 2001	Pennsylvania Office of Small Business Advocate	Cost of gas; commodity price forecasting
R-00016179	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2001	Pennsylvania Office of Small Business Advocate	Recovery of CAP costs; PGC treatment of pipeline credits
R-005277	Pennsylvania Public Utility Commission	PFG Gas Inc. and North Penn Gas Company	November 2000	Pennsylvania Office of Small Business Advocate	Cost allocation, rate design.
R-3443-2000	Régie de l'Énergie, Québec	Société en commandite Gaz Métropolitain	November 2000	Industrial Gas Users Association	Tariff unbundling
990005	Alberta Energy and Utilities Board	ESBI Alberta Limited	November 2000	IPPSA	Location-based credits for transmission rates
R-005119	Pennsylvania Public Utility Commission	PG Energy (Southern Union)	July 2000	Pennsylvania Office of Small Business Advocate	Cost allocation, rate design, weather normalization
R-994788	Pennsylvania Public Utility Commission	PFG Gas, Inc. and North Penn Gas Company	February 2000	Pennsylvania Office of Small Business Advocate	Natural gas restructuring, retail access, tariff design
R-994785	Pennsylvania Public Utility Commission	National Fuel Gas Distribution Corp.	December 1999	Pennsylvania Office of Small Business Advocate	Natural gas restructuring, retail access, tariff design
R-994783	Pennsylvania Public Utility Commission	PG Energy, Inc.	November 1999	Pennsylvania Office of Small Business Advocate	Natural gas restructuring, retail access, tariff design
99005	Alberta Energy and Utilities Board	ESBI Alberta Limited (Transmission Administrator)	September 1999	IPPSA	Transmission tariff cost allocation, rate design, industry restructuring

ROBERT D. KNECHT

SCHEDULE OF APPEARANCES BEFORE REGULATORY AUTHORITIES

Docket #	Regulator	Utility	Date of Testimony	Client	Topic of Testimony
RE95080	Alberta Energy and Utilities Board	Alberta Power Limited	December 1998	Independent Power Producers Society of Alberta and SPPA	Electric industry restructuring, rate unbundling, cost allocation and rate design.
RE95081	Alberta Energy and Utilities Board	TransAlta Utilities Corporation	November 1998	IPPSA and Senior Petroleum Producers Assn.	Industry restructuring, cost allocation, rate design.
Expansion Feasibility Test	Public Utilities Board of Manitoba	Centra Gas Manitoba	August 1998	Simplot Canada Limited	Expansion feasibility and customer contribution methodology
R-984280	Pennsylvania Public Utility Commission	PG Energy, Inc.	August 1998	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue deficiency assignment, rate design
EO97070455	New Jersey Board of Public Utilities	Atlantic City Electric Company	February 1998	New Jersey Board of Public Utilities	Industry restructuring, audit of unbundled rates
R-973981	Pennsylvania Public Utility Commission	Allegheny Power (West Penn Power)	January 1998	Pennsylvania Office of Small Business Advocate	Industry restructuring, cost unbundling, cost allocation, and rate design.
R-973954	Pennsylvania Public Utility Commission	Pennsylvania Power & Light	August 1997	Pennsylvania Office of Small Business Advocate	Restructuring, stranded costs, market price forecasting, cost allocation, and rate design.
1996 Electric Utility Tariff Applications	Alberta Energy & Utilities Board	TransAlta Utilities Alberta Power Edmonton Power Grid Company of Alberta	October 1996	Independent Power Producers Society of Alberta (IPPSA)	Industry restructuring; transmission cost allocation and rate design.
R-963612	Pennsylvania Public Utility Commission	PG Energy, Inc.	October 1996	Pennsylvania Office of Small Business Advocate	Cost allocation and rate design -- direct and rebuttal.

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SCHEDULE OF APPEARANCES BEFORE REGULATORY AUTHORITIES

Docket #	Regulator	Utility	Date of Testimony	Client	Topic of Testimony
R-953444	Pennsylvania Public Utility Commission	Trigen-Philadelphia Energy Corp.	November 1995	Pennsylvania Office of Small Business Advocate	Steam energy cost rate -- direct and rebuttal.
R-953406	Pennsylvania Public Utility Commission	T.W. Phillips Gas & Oil Company	October 1995	Pennsylvania Office of Small Business Advocate	Weather normalization, cost allocation and rate design.
R-953297	Pennsylvania Public Utility Commission	UGI Utilities, Inc. (Gas Division)	May 1995	Pennsylvania Office of Small Business Advocate	Cost allocation and rate design -- direct and rebuttal.
R-943271	Pennsylvania Public Utility Commission	Pennsylvania Power & Light	April/May 1995	Pennsylvania Office of Small Business Advocate	Cost allocation and rate design -- direct and rebuttal
EBRO 488	Ontario Energy Board	Natural Resource Gas Limited	November 1994	Natural Resource Gas Limited	Customer classification, cost allocation and rate design.
RE92071	Alberta Public Utilities Board	Alberta Power Limited	November 1994	Independent Power Producers Society of Alberta	Cost allocation and rate design for export transmission service.
R-942986	Pennsylvania Public Utility Commission	West Penn Power Company	August 1994	Pennsylvania Office of Small Business Advocate	Cost allocation and rate design.
R-932862	Pennsylvania Public Utility Commission	UGI Utilities, Inc. (Electric Division)	March 1994	Pennsylvania Office of Small Business Advocate	Cost allocation and rate design -- direct, rebuttal and surrebutal.
EBRO 485, and Generic Direct Purchase Hearings	Ontario Energy Board	Consumers' Gas Company, Ltd.	August 1993, September 1993.	Canadian Independent Gas Marketing Association	Classification and allocation of marketing and administrative costs.
Hearings for Cost of Service and Rate Design	Nova Scotia Utility and Review Board	Nova Scotia Power, Inc.	May 1993	Bowater Mersey Paper Company, Ltd.	Classification of bulk power costs, rate design for interruptible service and other rate design issues.

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SCHEDULE OF APPEARANCES BEFORE REGULATORY AUTHORITIES

Docket #	Regulator	Utility	Date of Testimony	Client	Topic of Testimony
Generic Hearing #4	Board of Commissioners of Public Utilities, Province of New Brunswick	New Brunswick Power Corporation	November 1991	Large Power Users Group	Review of cost allocation and rate design.
EBRO-470	Ontario Energy Board	Union Gas, Ltd.	February 1991	Ontario Energy Board Staff	Cost allocation and rate design; evaluation of load shifting study.
Rate Area Boundaries Hearings	Prince Edward Island Public Utilities Commission	Maritime Electric Co., Ltd.	February 1991	Prince Edward Island Department of Energy and Forestry	Customer classification by geographical area.
EBRO-467	Ontario Energy Board	Centra Gas, Ltd.	January 1991	Ontario Energy Board Staff	Cost allocation and rate design for technology, cogen and bypass.
Arbitration Hearings	Arbitrator	ARINC, Inc.	July 1990	ARINC Inc.	Cost allocation and rate design for aircraft to ground data communications service.
EBRO-462	Ontario Energy Board	Union Gas, Ltd.	January 1990	Ontario Energy Board Staff	Seasonal cost allocation study, and allocation of costs to export markets.
NSPC-857	Nova Scotia Board of Commissioners of Public Utilities	Nova Scotia Power Corp.	February 1989	Interruptible industrial customers	Cost allocation and rate design of interruptible electric service.

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