IEc

INDUSTRIAL ECONOMICS, INCORPORATED

7 November 2006

Me Véronique Dubois
SECRÉTAIRE DE LA RÉGIE DE L'ÉNERGIE
Tour de la Bourse, Case Postale 001
800, Place Victoria, 2e étage
Bureau 2.55
Montréal (Québec) H4Z 1A2 CANADA

REFERENCE: Régie de l'énergie du Québec, Docket No. R-3610-2006

Dear Ms. Dubois:

Attached is Exhibit IEc-2 that was missing from my pre-filed evidence in the referenced proceeding. I recognize that this exhibit is being submitted well after the due date for the filing of evidence, and I apologize for the delay. At its discretion, the Régie may of course reject this submission. However, I note that this material is explanatory in nature and does not affect any of the conclusions or recommendations in the evidence that was submitted on 31 October 2006.

However, if the Régie is willing to accept this late submission, I propose the following procedure to avoid disadvantaging any party to this proceeding. First, please be assured that none of this material constitutes rebuttal evidence to any intervenor, as I have not reviewed any intervenor evidence at this writing. Second, I propose that the due date for interrogatories regarding this exhibit be delayed from 10 November to 17 November, to allow parties sufficient time to review this exhibit. Third, I will respond to any interrogatories received by 17 November regarding this exhibit by 20 November, thereby meeting the scheduled deadline for interrogatory responses. Fourth, I have included with this submission the electronic workpapers upon which this analysis is based. I believe that this process will protect the interests of Hydro Québec Distribution and the other intervenors from any disadvantages associated with the late submission.

Finally, my pre-filed evidence indicates that my analysis of HQD's proposed change to the allocation of post-patrimonial generation costs was ongoing. For the record, I will not offer any further opinion regarding the proposed change in methodology beyond that presented in my pre-filed evidence (at page 18, line 12).

Again, I apologize for any inconvenience caused by this delay.

Sincerely,

Robert D. Knecht
Principal

Industrial Economics, Incorporated
2067 Massachusetts Avenue
Cambridge, MA 02140 USA
617.354.0074 | 617.354.0463 fax
www.indecon.com

BEFORE THE RÉGIE DE L'ÉNERGIE

IEc

IN THE MATTER OF:

HYDRO QUÉBEC DISTRIBUTION

Demande du Distributeur relative à l'établissement des tarifs d'électricité pour l'année tarifaire 2007-2008

DOSSIER R-3610-2006

7 November 2006

prepared on behalf of:

l'Association québécoise des consommateurs industriels d'électricité (AQCIE)

Conseil de l'industrie forestière du Québec (CIFQ)

prepared supplemental evidence of:

Robert D. Knecht

Industrial Economics, Incorporated

2067 Massachusetts Avenue

Cambridge, MA 02140

EXHIBIT IEc-2

CONCEPTUAL ANALYSIS OF HQD'S HOURLY GENERATION COST ALLOCATION METHODOLOGY

INTRODUCTION

In this proceeding, Hydro Québec Distribution ("HQD") offers an hourly cost methodology as an alternative approach for allocating post-patrimonial generating costs among the various rate classes. It is my understanding that this approach is virtually identical to that presented by HQD to the technical committee earlier this year, and to the Alternative A presented in Docket No. R-3579-2005. Under this approach, HQD develops an hourly cost for each of its post-patrimonial generation sources, based on the total expected cost of that facility divided by its expected generation in each hour that it operates. HQD then derives a weighted average hourly generation cost for each hour of the year, based on the hourly costs of each post-patrimonial generation supply source. Post-patrimonial costs are then allocated to each rate class by multiplying the average hourly post-patrimonial generation cost in each hour by the class post-patrimonial load in that hour.[1]

In the absence of hard analysis, this methodology seems to have intuitive appeal. Costs for each generation supply option are assigned only to those hours in which the supply source is dispatched. However, this exhibit will demonstrate that this methodology will tend to over-allocate costs to high load factor customers, such that the allocated costs for a optimally configured utility will exceed the standalone costs. Thus, under HQD's alternative proposal, it is certainly possible that high load factor customers could procure post-patrimonial power at a lower cost than that allocated to them in the cost allocation study.

In my evidence submitted in Docket No. R-3579-2005, I introduced a generation cost framework which I referred to at the "Peaker-MC" method, in which demand-related costs are based on the fixed costs of a peaker unit, and energy costs are related to the marginal generation cost in each hour of the year (for all energy generated in that hour). In that evidence, I commented briefly on the theoretical advantages of this methodology, and explained why HQD's proposed methodology was not consistent with that approach.

This exhibit provides a more detailed example of the implications of the HQD hourly methodology vis-à-vis the Peaker-MC method, and it explains why the HQD hourly methodology will over-allocate costs to high load factor customers. In addition, this exhibit also shows why the traditional fixed-variable method can under-allocate costs to high load factor customers.

THE PEAKER-MC METHOD

It can be demonstrated that, for an optimally configured electric utility generation system, the entire revenue requirement for that system can be recovered through the combination of a capacity charge based on the cost of a peaking unit (including reserve) and an energy charge based on the marginal energy cost for each hour of operation, applied to the total

[1] For the reasons presented in the body of this evidence, HQD's methodology for developing post-patrimonial load profiles by rate class does not produce sensible load profiles for cost allocation purposes in 2007.

load in that hour.[2] That is, demand-related costs can be considered to be the fixed costs related to a peaking unit, and energy-related costs can be the marginal generation costs for each hour of the year.

This methodology then implies that the cost allocation scheme for such a utility would be to allocate peaker-related capital costs to all rate classes based on their contribution to system peak demand, and to allocate energy costs on an hourly basis to each rate class based on the marginal cost of energy in that hour. Note that, in this method, the marginal cost in each hour applies to all energy consumed in that hour, even the energy that was generated using lower marginal cost generating sources. Thus, for example, during system peak hours, all consumption would be allocated the high marginal cost of the peaking unit, even though base and intermediate load plants also operate during that hour.

This methodology implicitly recognizes the nature of cost tradeoffs in generation planning. A utility that evaluates how to serve its overall load shape recognizes that it can meet its load with a variety of different generation options. Baseload plants, generally nuclear or coal-fired units, exhibit relatively high capacity-related costs and low fuel costs. Peaking plants, such as gas-fired combustion turbine units, exhibit the reverse cost structure, with relatively low capital costs but very high fuel costs. In between lie other types of capacity, "intermediate" units, which exhibit capacity and energy costs that lie in between the baseload and peaker extremes. Baseload plants are less costly if they run for a relatively large number of hours over the course of the year; peaker units are economical when they are needed to serve only relatively short peak periods. With this cost structure, it is relatively easy to compute a "break-even" point for each unit relative to the next technology, in terms of the number of hours of operation needed to make the unit economically viable.

Thus, for example, a breakeven analysis between an intermediate load unit and baseload unit might indicate that, if the unit will operate more than 60 percent of the hours in the year (5256 hours), that the baseload unit will be less expensive. Under 60 percent, the intermediate load unit is less expensive. Using the breakeven capacity factors, it is then possible to derive the optimal amount of generating capacity of each type is optimal for this utility, given the utility's load duration curve.

In Table IEc-A (attached to this exhibit), I present an example of the calculation of break-even capacity factors for a system consisting of three types of generating units: baseload plants, intermediate load plants, and peaking units. That table also shows the assumed fixed and variable operating costs for each type of plant. Note that the numerical figures in this example are hypothetical, but are illustrative of real world tradeoffs.

With the breakeven capacity factors defined, the optimal amount of generating capacity can be derived from the utility's load duration curve. A graphical depiction of this analysis is shown in Figure IEc-B, using a load duration curve similar to that for HQD. A

[2] See, for example, Optimal Pricing and Investment in Electricity Supply, An Essay in Welfare Economics, Turvey, Ralph, The MIT Press, 1968.

summary of the numerical implications for capacity and generation are shown in Table IEc-C.

This analysis has implications for generation cost allocation. The traditional approach for generation cost allocation is the "fixed-variable" method, in which all capacity costs are allocated based on peak demand and all variable costs are allocated based on annual energy. It is often argued that the fixed-variable method does not recognize that the utility incurs extra capacity costs for baseload units, in order to reduce its energy costs. These analysts then argue that the cost allocation study should re-classify some of the baseload fixed costs as "energy-related," and allocate them accordingly. Other analysts respond that the cost tradeoff works both ways. That is, while the utility incurs baseload capital costs to reduce fuel costs, the utility also incurs higher fuel costs from peaker units in an effort to reduce capacity costs.

The advantage of the Peaker-MC method is that it explicitly recognizes both aspects of this tradeoff. By allocating only costs related to peaker units on a peak demand basis, the higher fixed costs of baseload units are not allocated on that basis, thereby recognizing the "capital for fuel" tradeoff. Low load factor customers thereby avoid the substantial allocation of capacity-related costs associated with the fixed-variable method. Similarly, the Peaker-MC method allocates fuel costs based on the marginal costs in each hour, thereby assigning high fuel costs to peak periods, in which the low load factor classes contribute disproportionately to the load. It therefore also recognizes the "fuel for capital" aspect of the generation planning framework.

Finally, the Peaker/MC method is much more consistent with the way that unregulated electricity markets now function. Energy prices vary on an hourly (or even five-minute) basis, often with significant differences between on-peak and off-peak prices. If the generation market is competitive, economic theory indicates that these energy costs reflect the marginal cost of the last unit dispatched. Moreover, the high peak period hourly prices apply to all of the load in the peak hours, much in the same way the Peaker/MC approach allocates costs.

GENERATION COST ALLOCATION EXAMPLE

Within this framework, we can then evaluate the performance of various standard allocation methods, with a simple numerical example based on a two-class utility system. In the example presented, I assume that there is a "Rate I" class that has a 100 percent load factor load of 10,000 MW, and a "Rate D" class that represents the balance of the load with approximately 43 percent load factor.

I first calculate the standalone cost of providing service to each class. For simplicity, I exclude any reserve margin requirement. Note also that, because there is no peak diversity between the two classes, the sum of the standalone costs for each class will equal the cost for the system. (These assumptions facilitate the comparison of the methodologies. However, because HQD's large industrial customers operate at a very high load factor, the assumption that the industrial customers contribute little to load diversity is not unreasonable.) If an allocation methodology, even in this very simple example, does not assign costs equal to the standalone cost for each rate class, it necessarily contains a bias.

Table IEc-D shows the standalone costs for each rate class. For the Rate I class, the standalone cost is based on the cost of baseload units; for Rate D, the cost is based on a mixture of all three technologies.

Continuing with this example, the first method that I test is one of the most common approaches used in embedded cost allocation studies for generation cost allocation, namely the fixed-variable method. In this approach, all of the fixed costs are allocated to each rate class based on class contribution to the annual peak (a 1 CP approach), and the energy costs are allocated based on each class' contribution to annual kWh energy consumption.

The results of this analysis are shown in Table IEc-E. As shown, the fixed-variable method tends to over-allocate costs to the low load factor Rate D class, and under-allocate costs to the Rate I class, relative to the standalone approach.

I then turn to HQD's proposed hourly cost method. For each hour of the year in this example, I calculated the average hourly cost per MWh generated from each of the three technologies, based on the variable cost plus the fixed cost divided by the MWh generated over the course of the year as optimally dispatched. I then applied each cost figure to the generation from each technology in each hour of the year, to get an hourly generation cost for each hour. This generation cost was then allocated between the rate classes in each hour in proportion to energy consumed in that hour.[3]

The results are summarized in Table IEc-F. As shown in that table, the HQD methodology exhibits the reverse bias to that of the fixed-variable method. That is, it over-allocates costs to the high load factor rate class and under-allocates costs to the low load factor rate class, relative to the standalone calculation. As such, it also fails this simple test.

For that reason, I conclude that HQD's proposed hourly cost allocation methodology is not an acceptable cost allocation methodology, *even if the post-patrimonial load profiles are reasonable, and even if the average hourly cost values showed some reasonable seasonal load pattern.* This approach has the effect of shifting peak-related costs off the peak, and it has the effect of understating the hourly differentiation in energy costs. As such, it should not be adopted under any circumstances.

Finally, I apply the Peaker-MC allocation approach to this example. Demand costs, based only on the cost of a peaker unit, are allocated to each class based on class contribution to the system peak. Energy costs are allocated based on applying the marginal energy cost in each hour to each class' consumption in that hour, and summed over the course of the year.

---

[3] This calculation is detailed in the electronic workpaper submitted with this evidence.

The results of this analysis are summarized in Table IEc-G. As shown, the Peaker-MC methodology results in allocated costs that are exactly equal to the standalone cost methodology. Thus, if and when HQD reaches some stability with its post-patrimonial generation supplies, and its post-patrimonial load shapes are reasonably reflective of long term conditions, I suggest that an approach that is conceptually consistent with the Peaker-MC method be pursued.

TABLE IEc-A				
BREAKEVEN ANALYSIS FOR EXAMPLE UTILITY				
	Baseload Unit	***Intermediate Load Unit***	***Peaking Unit***	
Fixed Cost ($/kW/year)	$300.00	$116.04	$81.00	
Variable Cost ($/MWh)	$25.00	$60.00	$100.00	
Baseload/Intermediate Breakeven Hours	5,256			
Intermediate/Peaker Breakeven Hours		876		
Baseload/Intermediate Breakeven Load Factor	60.0%			
Intermediate/Peaker Breakeven Load Factor		10.0%		
Breakeven Hours Formula between technolgy "a" and "b": (FCa - FCb)/(VCb-VCa)*1000				
where FC represents fixed costs in $/MW/year and VC represents variable costs in $/MWh				

FIGURE IEc-B
Optimal Generation Planning Example

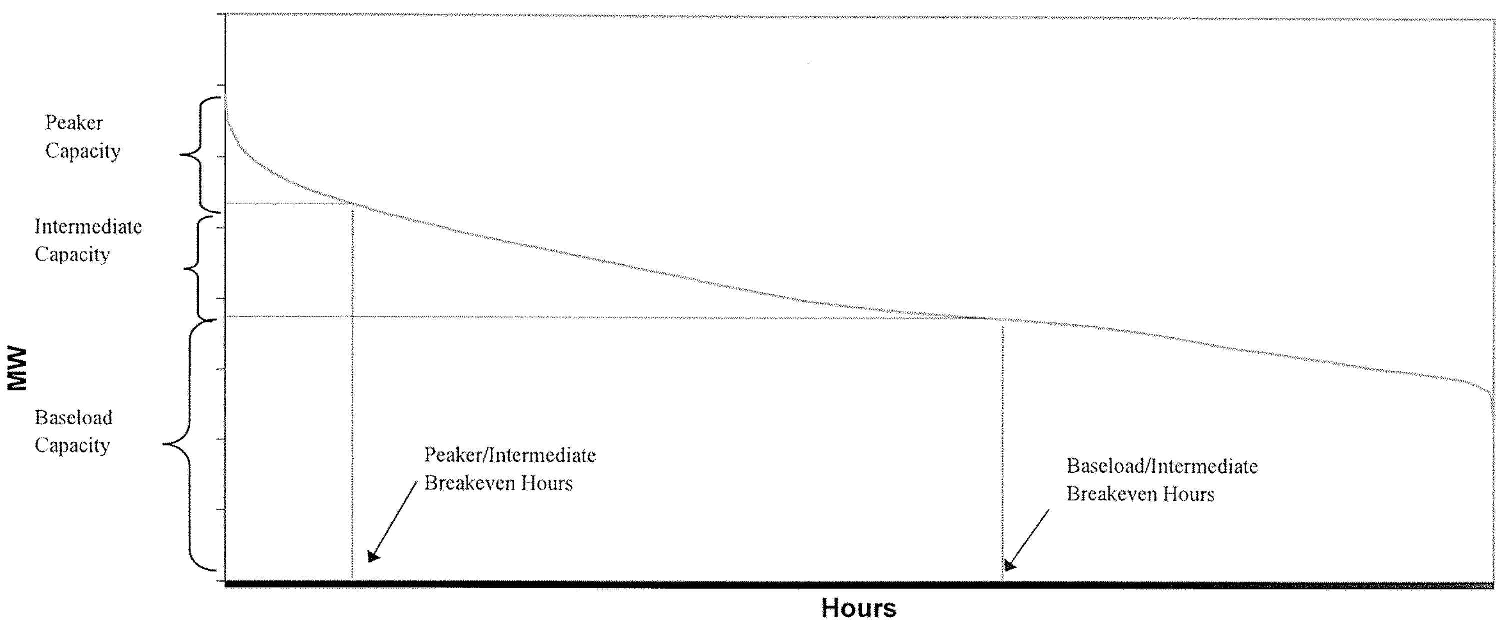

TABLE IEc-C

OPTIMAL CAPACITY AND GENERATION FOR EXAMPLE UTILITY

	Baseload Units	***Intermediate Load Units***	***Peaking Units***	***Total***
Maximum Hours of Operation	8,760	5,256	876	
Optimal Capacity (MW)	18,734	7,976	7,632	34,342
Optimal Generation (GWh)	156,427	21,369	1,725	179,521
Capacity Factor	95.3%	30.6%	2.6%	59.7%
Fixed Costs ($mm)	$5,620	$926	$618	$7,164
Variable Costs ($mm)	$3,911	$1,282	$173	$5,365
Total Costs ($mm)	***$9,531***	***$2,208***	***$791***	***$12,529***

Note: Costs reflect unit costs shown in Table IEc-A.

TABLE IEc-D			
STANDALONE COST ANALYSIS FOR EXAMPLE UTILITY			
	RATE D	***RATE I***	***TOTAL***
Peak Demand (MW)	24,342	10,000	34,342
Energy Consumed (GWh)	91,921	87,600	179,521
Optimal Baseload Capacity (MW)	8,734	10,000	18,734
Optimal Intermediate Capacity (MW)	7,976		7,976
Optimal Peaker Capacity (MW)	7,632		7,632
Total Capacity	*24,342*	*10,000*	*34,342*
Baseload Generation	68,827	87,600	156,427
Intermediate Generation	21,369		21,369
Peaker Generation	1,725		1,725
Total Energy	*91,921*	*87,600*	*179,521*
Capacity Costs ($mm)	4,164	3,000	7,164
Energy Costs ($mm)	3,175	2,190	5,365
Total Standalone Costs ($mm)	***7,339***	***5,190***	***12,529***
Note: Costs are based on cross-product of capacity/energy values in this table and unit costs from Table IEc-A.			

TABLE IEc-E			
FIXED-VARIABLE COST ALLOCATION ANALYSIS FOR EXAMPLE UTILITY			
	RATE D	***RATE I***	***TOTAL***
Peak Demand (MW)	24,342	10,000	34,342
Energy Consumed (GWh)	91,921	87,600	179,521
Allocated Fixed Costs ($ mm)	5,078	2,086	7,164
Allocated Variable Costs ($mm)	2,747	2,618	5,365
Total Allocated Cost ($mm)	***7,825***	***4,704***	***12,529***
Standalone Costs ($mm)	*7,339*	*5,190*	*12,529*
Difference	6.6%	-9.4%	0.0%

TABLE IEc-F

HQD HOURLY METHOD COST ALLOCATION ANALYSIS FOR EXAMPLE UTILITY

	RATE D	***RATE I***	***TOTAL***
Average Baseload Cost ($/MWh)			$60.93
Average Intermediate Cost ($/MWh)			$103.31
Average Peaker Cost ($/MWh)			$458.33
Total Allocated Cost ($mm)	***6,600***	***5,929***	***12,529***
Standalone Costs ($mm)	*7,339*	*5,190*	*12,529*
Difference	-10.1%	14.2%	0.0%

Note: Allocated cost is derived by multiplying average generation cost by generation in each hour for each class associated with each technology. See workpapers for detail.

TABLE IEc-G			
PEAKER-MC METHOD COST ALLOCATION ANALYSIS FOR EXAMPLE UTILITY			
	RATE D	***RATE I***	***TOTAL***
Peak Demand (MW)	24,342	10,000	34,342
Peaker Fixed Cost ($/kW)	$81.00	$81.00	$81.00
Capacity Costs ($mm)	1,972	810	2,782
Marginal Cost Energy ($mm)	5,368	4,380	9,748
Total Allocated Cost ($mm)	***7,339***	***5,190***	***12,529***
Standalone Costs ($mm)	*7,339*	*5,190*	*12,529*
Difference	0.0%	0.0%	0.0%

Note: Allocated marginal cost is derived by multiplying marginal cost for each hour by class energy requirement in each hour. See workpapers for detail.

TABLE IEc-G

PEAKER-MC METHOD COST ALLOCATION ANALYSIS FOR EXAMPLE UTILITY

	RATE D	***RATE I***	***TOTAL***
Peak Demand (MW)	24 342	10 000	34 342
Peaker Fixed Cost ($/kW)	$81,00	$81,00	$81,00
Capacity Costs ($mm)	1 972	810	2 782
Marginal Cost Energy ($mm)	5 368	4 380	9 748
Total Allocated Cost ($mm)	***7 339***	***5 190***	***12 529***
Standalone Costs ($mm)	*7 339*	*5 190*	*12 529*
Difference	0,0%	0,0%	0,0%

Note: Allocated marginal cost is derived by multiplying marginal cost for each hour by class energy requirement in each hour. See workpapers for detail.