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Québec, le 20 novembre 2007

Me Véronique Dubois
Secrétaire
RÉGIE DE L'ÉNERGIE
Tour de la Bourse, C.P. 001
800, Place Victoria, 2e étage, bureau 255
Montréal (Québec) H4Z 1A2

OBJET: Demande relative à l'établissement des tarifs d'électricité pour l'année tarifaire 2008-2009
Votre dossier No : R-3644-2007
Notre dossier No : 1038697

Chère Consoeur,

Nous vous adressons en huit exemplaires les réponses de l'AQCIE et du CIFQ à la demande de renseignement de la Régie dans le cadre du dossier mentionné en rubrique.

Veuillez agréer, chère consœur, l'expression de nos sentiments les meilleurs.

Stein Monast S.E.N.C.R.L.

PIERRE PELLETIER

PP/lm
c.c. par courriel Hydro-Québec – Éric Fraser
Les intervenants

MEMBRE DE AVOCATS GESTIONNAIRES DE RISQUES DU CANADA (AGR/RMC)

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-3644-2007

20 November 2007

prepared on behalf of:

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

Conseil de l'industrie forestière du Québec (CIFQ)

prepared interrogatory responses of:

Robert D. Knecht

Industrial Economics, Incorporated

2067 Massachusetts Avenue

Cambridge, MA 02140

RÉGIE-AQCIE/CIFQ-1

Références : (i) Evidence of Robert D. Knecht, page 22 ;
(ii) Pièce HQD-15, document 1, pages 12 et 13, question 54.

Préambule :

Référence (i)

Table IEc-8 – Comparison of rate L energy costs and energy charges

Demandes :

1.1 Veuillez comparer les résultats de la référence (i) avec la réponse de HQD mentionnée en référence (ii) pour les clients du tarif L.

1.2 À la lumière des résultats fournis par HQD à la référence (ii), veuillez indiquer l'impact sur l'intra-financement possible entre les clients de tarif L à haut facteur d'utilisation et ceux à faible facteur d'utilisation.

1.3 Compte tenu des réponses aux questions précédentes, veuillez indiquer quelle serait votre recommandation quant aux ajustement tarifaires à apporter au tarif L.

Response :

1.1 In the referenced interrogatory response, HQD addresses both *embedded cost* and *marginal cost* demand-energy classification splits. These issues are addressed sequentially below.

Embedded Cost Demand/Energy Split

In HQD-15, Document 1, page 13, HQD indicates that some 69 percent of Rate L allocated costs are related to energy. Unfortunately, HQD provides no supporting analysis for this assertion, and it is demonstrably wrong. Total costs allocated to the Rate L class are $1,710.3 million (HQD-11, Document 3, Table 7, column18). HQD's analysis implies a range of $1,172 to $1,189 million of those costs are energy-related (0.685* $1,710.3 to 0.695*$1,710.3).

HQD's analysis appears to be based on the assumption that all generation costs are energy-related, and that all transmission and distribution costs are not energy-related. (Note that the allocated generation costs for Rate L are $1,174 million, which is 68.6 percent of total Rate L costs, within HQD's range)

As such, HQD's analysis is not consistent with the cost allocation study that it filed in this proceeding for two reasons. First, not all generation costs are energy-related. As I demonstrated in my evidence R-3477-2001, HQD's allocation method for patrimonial generation costs is equivalent to a cost classification scheme where the energy-component of overall patrimonial costs is based on the system load factor. Thus, it is simply wrong to assume that all generation costs are energy-related, since . At a minimum, some $268 million of the Rate L generation costs are demand-related. (See attached exhibit.)

Second, HQD analysis appears to ignore the reclassification of transmission costs that the Régie required it to file in this proceeding. As shown in Table 9C of HQD-11, Document 3, HQD demonstrates that some 42.9 percent of Rate L allocated transmission costs are energy-related, which amounts to about $201 million.

Thus, HQD's analysis *overstates* the energy component of generation costs by some $268 million, and *understates* the energy component of transmission costs by some $201 million.

By way of further response, when I reviewed the referenced calculations in my evidence, I noted that two small modifications could reasonably be made. First, the use of the Régie's hourly cost allocation method results in the very unusual (and possibly unique) conclusion that post-patrimonial costs have a *negative* demand component. Therefore, in the attached workpaper (Attachment 1-A), I modified my original analysis for that consideration. Second, it may be credibly argued that some of the energy efficiency costs should be considered energy-related, because they contribute to a reduction in both energy rates and demand rates. To be conservative, these costs are factored into the attached analysis as 100 percent energy-related.

As shown in Attachment 1-A, even making conservative assumptions about the demand component of costs for post-patrimonial generation, transmission, and PGEÉ costs, the analysis of embedded cost continues to demonstrate that HQD's current energy charge already overstates the test-year energy-related costs.

Marginal Cost Demand-Energy Split

HQD argues that the marginal cost demand-energy split would show the same results as the embedded cost analysis, though it presents no supporting quantitative analysis. However, if HQD is continuing to assume that all generation costs are energy-related in this assessment, it is again in error. Current markets for power contain both peak demand-related costs (witness the RPM auction in PJM, referenced at footnote 5, page 7 of my evidence in this proceeding) as well as time-differentiated energy charges. Moreover, as the Régie recognized in Decision D-2007-12, HQD exhibits a current over-supply of capacity, but this situation will eventually change, likely increasing the capacity-related component of costs in the longer term.

For transmission, much of the energy-related costs are related to 'generation integration' costs. For future generation supply sources, a competitive balance is better maintained by making generators responsible for generation integration, rather than the transmission utility. Thus, future transmission costs are likely to be *more* related to peak demand than are embedded transmission costs.

Future distribution and customer service costs are unlikely to have any energy component.

Thus, it is not likely that marginal costs will exhibit any greater *pure* (i.e., not time-differentiated) energy component for Rate L service than do embedded costs.

1.2 Hypothetically, if the HQD results were accurate, lower load factor customers within the Rate L class would be overpaying relative to higher load factor customers. However, HQD's analysis is not accurate. An accurate analysis demonstrates that higher load factor customers are overpaying.

1.3 Based on my pre-filed evidence, the responses to items 1.1 and 1.2 above, and the attached analysis, my recommendation is that no increase should be imposed on the Rate L energy charge in this proceeding, and that any increase in Rate L revenues be made through net increases to demand charges and credits.

RÉGIE-AQCIE/CIFQ-2

Référence : Evidence of Robert D. Knecht, pages 25 et 26.

Préambule :

« For example, suppose that the stepped rate mechanism results in a significant reduction in large industrial load, with the concomitant loss of revenue at the high replacement cost rate. Thus, overall post-patrimonial revenues and costs decline. However, in HQD's reconciliation mechanism, the reduction of industrial load will reduce the class's entitlement to the patrimonial load. In effect, the cost savings will be shared among all classes, but the lost revenues will relate only to the large industrial class. Thus, the net effect of a successful stepped rate would be a substantial re-assignment of costs to the large industrial class. »

Demandes:

2.1 Veuillez indiquer si l'impact sur la répartition des coûts des différentes catégories tarifaires serait différent qu'il s'agisse d'une mesure d'économie d'énergie découlant d'un PGEÉ ou d'un «stepped rate».

2.2 Veuillez illustrer par un exemple chiffré l'impact d'une réduction des coûts importante des clients du tarif L tel qu'indiqué en référence sur la répartition des coûts entre les différentes catégories tarifaires.

2.3 Veuillez commenter et mettre en relation les impacts pour les clients du tarif L et les clients des autres catégories tarifaires.

Response :

2.1 The net effect of a reduction in Rate L load, be it from customer-financed investment or from HQD-financed investment, will generally have the same *inter-class* impact. That is, the patrimonial entitlement will be shifted to the other rate classes. However, the intra-class impact on Rate L customers will be very different between the two approaches. Please see response to item 2.2 below.

2.2 To respond to this request, IEc modified the two-class example presented in Exhibit IEc-2, that evaluated the allocative implications of PGEÉ load reductions. This revised analysis is attached as Attachment 2-A.

Attachment 2-A shows the same base case as that presented in Exhibit IEc-2. It also models two scenarios with an Industrial class load reduction that is similar to the 'Scenario 2' in Exhibit IEc-2, namely a reduction of some 1500 GWh of industrial load at 95 percent load factor.

To show *intra-class* effects as well as *inter-class* effects, the example in Exhibit IEc-2 was modified to split the Industrial class into 'Industrial 1' (the sub-class with no load reduction) and 'Industrial 2' (the sub-class with the load reduction). Exhibit IEc-2 was also modified to include class revenues at both flat and stepped rates, and to recognize the costs of the avoided load as incurred either by the customer (with stepped rates) or HQD (with PGEÉ).

For simplicity, rates are modeled as energy charges only. This simplification does not have any impact on inter-class effects, and it would only affect the intra-class results if the load factors are different between the two industrial sub-classes. Note also that no cross-subsidization between rate classes is assumed, also for simplicity.

The base case assumes that patrimonial entitlement represents 90 percent of each class's load, and that post-patrimonial generating cost is $90 per MWh (for all classes). It also assumes that the base case stepped rates are 90 percent Tier 1 and 10 percent Tier 2. Under flat rates, the base case residential rate is $73.67 per MWh, and the industrial rate is $44.31. Under stepped rates, the base case Industrial Tier 2 rate is set to $90 per MWh, the post-patrimonial generation cost. The Tier 1 Industrial rate is derived by residual such that rates fully recover costs, to be $39.24 per MWh.

Consider first Scenario 2-A, which is the PGEÉ scenario. It involves a 1500 GWh reduction, which represents 10 percent of the Industrial 2 sub-class. It is assumed that this demand reduction is effected through an HQD PGEÉ program, and that the total cost for load avoided is $60 per MWh. (Note that the program would not be economic for the customer to undertake, because the flat rate is only $44.31 per MWh. However, the cost of the program is below the $90 post-patrimonial cost, and it is therefore cost-effective system-wide.) It is also assumed that the cost of the program is split between the Industrial 2 customers and HQD. The Industrial 2 customer contribution is set at $44.31 per MWh, which is the rate savings to the customer under flat rates (some $66 million) while the balance of the costs ($23 million) are assumed to be incurred by HQD.

For allocation purposes, the HQD PGEÉ costs are all assigned to the Industrial class, which is consistent with either HQD's avoided cost methodology or with the direct assignment method. The costs are implicitly allocated between the two sub-classes based on volume.

Scenario 2-A is very similar to Scenario 2 in Exhibit IEc-2, with the exception that PGEÉ costs are included. The industrial load reduction causes patrimonial generation unit costs to fall for both rate classes, and the T&D costs are modestly re-allocated to the residential class.

The net effect of this scenario, like that in Exhibit IEc-2, is that the *inter-class* allocative effects result in a material reduction in residential rates. The costs incurred by both Industrial 1 and Industrial 2 customers are also slightly lower than base. The Industrial rates are lower than base because the overall savings of the program, namely the $30 per MWh difference between incremental costs and program costs, outweigh the allocative effects of the volume reduction for Industrial customers. (Note that if an alternative example is run in which the program costs are more than $65 per MWh, the allocative effects will wipe out any savings to the Industrial class, and the net effect of the program on industrial customers will be an increase in costs.) In magnitude, the impact of the load reduction is about the same on each sub-component of the Industrial class.

Turn now to Scenario 2-B, which is the stepped rate implications. In this case, the allocative *inter-class* effects of the load reduction are exactly the same as in Scenario 2-A, with the residential class experiencing a reduction of 0.9 percent. However, in this case, it is necessary to assume that the Tier 1 entitlement of both Industrial sub-classes remains the same as the base. (If the entitlement changes, stepped rates do not create any useful incentives at all. As such, this alternative is not modeled.) Thus, in this case, the Industrial 2 sub-class incurs the full $60 per MWh in costs, while its revenues decline by the Tier 2 rate of $90 per MWh. This reduction in Industrial 2 Tier 2 revenues, combined with the allocative effects of the volume reduction, force the Tier 1 industrial rates to rise to make up the difference (from $39.24 to $40.28 per MWh).

In this scenario, the Industrial 2 customers benefit from the net savings (offset by the allocative effects) with a 4.6 percent cost reduction, the residential customers benefit from the allocative effects with a 0.9 percent cost reduction, and the Industrial 1 customers see only the re-assigned costs in the form of a 2.1 percent *increase*. In effect, the stepped rate approach can result in a substantial rate increase for those Industrial customers who do not or cannot react to the price signals, even though all other classes benefit from the net cost reduction.

In short, the *intra-class* effects of a load reduction from PGEÉ are more equitable than the intra-class effects of a load reduction under a stepped rates tariff design, given Québec government policy to allocate the heritage pool proportionately. Therefore, I confirm the conclusion in my evidence that any effort to incorporate stepped rates into HQD's tariff must necessarily address the intra-class effects, such as those shown in this example.

2.3 Please see response to item 2.2.

Attachment 1-A to IEc Response to Régie Staff IR # 1		
Energy Component of Generation: Rate L		
	2007	**2008**
Load Factor Method Generation Costs	4,971.2	4,603.5
Energy Component of Generation (300 CP)	67.2%	67.1%
Energy-Related Patrimonial Costs ($mm)	3,340.6	3,088.9
Rate L Share of LF Method Energy	25.8%	24.8%
Rate L LF Method Energy Cost	861.6	767.5
Rate L Hourly Method Energy		141.8
Total Generation Energy Costs	861.6	909.3
Rate L Transmission Costs		469.5
Rate L Energy Share of Transmission	0.0%	42.9%
Rate L Transmission Energy Costs	-	201.3
Total Rate L PGEÉ Costs	10.7	8.9
Total Rate L Energy Costs	872.3	1,119.4
Rate L Consumption (GWh)	45,708.0	43,623.0
Rate L Unit Energy Cost (cts/kWh)	1.91	2.57
Rate L Revenue/Cost Ratio	115.6%	110.0%
Cost-Based Rate L Energy Charge (cents/kWh)	2.21	2.82
HQD Proposed Energy Charge (cents/kWh)	2.84	2.91

ATTACHMENT 2-A TO IEc RESPONSE TO RÉGIE STAFF INTERROGATORY 2

ALLOCATIVE IMPLICATIONS OF STEPPED RATE VERSUS DEMAND-SIDE MANAGEMENT LOAD REDUCTIONS

	Base Case Scenario				Scenario 2-A: Reduce Industrial 2 Load by 10%; PGEÉ Approach				Scenario 2-B: Reduce Industrial 2 Load by 10%; Stepped Rate Approach			
	Residential	Industrial 1	Industrial 2	Total	Residential	Industrial 1	Industrial 2	Total	Residential	Industrial 1	Industrial 2	Total
Total Load (GWh)	60,000	25,000	15,000	100,000	60,000	25,000	13,500	98,500	60,000	25,000	13,500	98,500
Patrimonial	54,000	22,500	13,500	90,000	54,822	22,843	12,335	90,000	54,822	22,843	12,335	90,000
Post-Patrimonial	6,000	2,500	1,500	10,000	5,178	2,157	1,165	8,500	5,178	2,157	1,165	8,500
Load Factor	50.0%	95.0%	95.0%	61.7%	50.0%	95.0%	95.0%	61.4%	50.0%	95.0%	95.0%	61.4%
Energy Loss Factor	9.1%	5.6%	5.6%	7.7%	9.1%	5.6%	5.6%	7.7%	9.1%	5.6%	5.6%	7.7%
Demand Loss Factor	9.1%	5.6%	5.6%	8.2%				8.2%	9.1%	5.6%	5.6%	8.2%
Peak Demand (MW)	13,699	3,004	1,802	18,505	13,699	3,004	1,622	18,325	13,699	3,004	1,622	18,325
Patrimonial Unit Cost	$ 30.51	$ 23.48	$ 23.48	$ 27.70	$ 30.45	$ 23.41	$ 23.41	$ 27.70	$ 30.45	$ 23.41	$ 23.41	$ 27.70
Post-Patrimonial Unit Cost	$ 90.00	$ 90.00	$ 90.00	$ 90.00	$ 90.00	$ 90.00	$ 90.00	$ 90.00	$ 90.00	$ 90.00	$ 90.00	$ 90.00
Total ($/MWh)	$ 36.46	$ 30.13	$ 30.13		$ 35.59	$ 29.15	$ 29.15		$ 35.59	$ 29.15	$ 29.15	
Patrimonial Cost	1,648	528	317	2,493	1,670	535	289	2,493	1,670	535	289	2,493
Post-Patrimonial Cost	540	225	135	900	466	194	105	765	466	194	105	765
Total ($mm)	2,188	753	452	3,393	2,136	729	394	3,258	2,136	729	394	3,258
T&D Energy	486	196	118	800	493	199	107	800	493	199	107	800
T&D Demand	746	158	95	1,000	754	160	86	1,000	754	160	86	1,000
T&D Customer	1,000	-	-	1,000	1,000	-	-	1,000	1,000	-	-	1,000
HQD PGEÉ Costs	-	-	-	-		15	8	-	-	-	-	-
Total Costs ($mm)	**4,420**	**1,108**	**665**	**6,193**	**4,383**	**1,103**	**596**	**6,058**	**4,383**	**1,088**	**587**	**6,058**
Tier 1 Load	60,000	22,500	13,500	96,000	60,000	25,000	13,500	98,500	60,000	22,500	13,500	96,000
Tier 2 Load		2,500	1,500	1,500	-	-	-	-		2,500	-	2,500
Tier 1 Rate	$ 73.67	$ 39.24	$ 39.24	$ 60.76	$ 73.05	$ 44.12	$ 44.12	$ 61.74	$ 73.05	$ 40.28	$ 40.28	$ 60.76
Tier 2 Rate		$ 90.00	$ 90.00	$ 240.00						$ 90.00	$ 90.00	$ 90.00
Revenue	**4,420**	**1,108**	**665**	**6,193**	**4,383**	**1,103**	**596**	**6,082**	**4,383**	**1,131**	**544**	**6,058**
Average Rate per MWh	***$ 73.67***	***$ 44.31***	***$ 44.31***	***$ 61.93***	***$ 73.05***	***$ 44.12***	***$ 44.12***	***$ 61.74***	***$ 73.05***	***$ 45.26***	***$ 40.28***	***$ 61.50***
Cust. DSM Cost ($/MWh)							$ 44.31				$ 60.00	
Program Cost ($mm)							**66**	**66**			**90**	**90**
Revenue Plus Cost	**4,420**	**1,108**	**665**	**6,193**	**4,383**	**1,103**	**662**	**6,148**	**4,383**	**1,131**	**634**	**6,148**
Percent Change					**-0.9%**	**-0.4%**	**-0.4%**	**-0.7%**	**-0.9%**	**2.1%**	**-4.6%**	**-0.7%**