

**IEc**

BEFORE THE RÉGIE DE L'ÉNERGIE

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

30 October 2007

prepared on behalf of:

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

Conseil de l'industrie forestière du Québec (CIFQ)

prepared evidence of:

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**INTRODUCTION** 1 My name is Robert D. Knecht. I am a Principal and the Treasurer of Industrial  
 2 Economics, Incorporated (“IEc”), a consulting firm located at 2067 Massachusetts  
 3 Avenue, Cambridge, MA 02140. As part of my consulting practice, I prepare analyses  
 4 and expert testimony in the field of regulatory economics. In Canada, I have submitted  
 5 expert evidence in regulatory proceedings in Québec, Ontario, Alberta, New Brunswick,  
 6 Nova Scotia, Manitoba, and Prince Edward Island. In matters regarding Hydro Québec  
 7 Distribution (“HQD”), I have submitted evidence before the Régie in dockets R-3477-  
 8 2001, R-3492-2002 (Phases 1 and 2), R-3541-2004, 3563-2005, R-3579-2005, and R-  
 9 3610-2006. I obtained a B.S. degree in Economics from the Massachusetts Institute of  
 10 Technology in 1978, and a M.S. degree in Management from the Sloan School of  
 11 Management at M.I.T. in 1982, with concentrations in applied economics and finance.  
 12 My *curriculum vitae* and a schedule of my expert evidence presented to regulatory  
 13 tribunals are attached as Exhibit RDK-1.

14 I was retained by l'Association québécoise des consommateurs industriels d'électricité  
 15 (“AQCIÉ”) and the Conseil de l'industrie forestière du Québec (“CIFQ”) to evaluate the  
 16 following aspects of HQD’s filing:

- 17 • Allocation of post-patrimonial generating costs;
- 18 • Allocation of transmission costs;
- 19 • Allocation of HQD’s energy efficiency program (“PGEÉ”) costs;
- 20 • Revenue allocation, and tracking historical cross-subsidies;
- 21 • Rate design for Rate L.

22 At this writing, I believe that the conclusions in this evidence are final, although my  
 23 analysis of certain topics is continuing. If this ongoing analysis requires me to modify  
 24 my primary conclusions and recommendations or to modify the substance of my analysis,  
 25 I will notify the Régie and the other parties promptly.

**1. POST-PATRIMONIAL 26 PLEASE PROVIDE THE BACKGROUND FOR YOUR EVIDENCE IN RESPECT OF THE  
 GENERATING COST 27 ALLOCATION OF POST-PATRIMONIAL GENERATION COSTS.**

**ALLOCATION 28** In Decision D-2007-12, the Régie directed that HQD implement “the hourly method” for  
 29 allocating post-patrimonial generating costs in this proceeding. HQD indicates that it has  
 30 adopted that methodology.

31 My clients have asked me to address this issue for two reasons. First, they have asked  
 32 that I confirm that HQD has correctly implemented the methodology approved by the  
 33 Régie. In my experience, it is very unusual for a regulator to not permit parties (and  
 34 presumably its own staff) to check the work of a utility in its *implementation* of an  
 35 approved *methodology*.

36 Second, my clients have asked me to evaluate whether the results of the methodology as  
 37 implemented in this case are consistent with the economic assumptions that underpin the

1 Régie's D-2007-12 decision. Most regulatory decisions, particularly cost allocation  
 2 decisions, are based on the economic context in which they were made. If those  
 3 economic circumstances change, the methodology may no longer be appropriate. Thus,  
 4 even if the Régie requires that the hourly method be applied in this proceeding, it may  
 5 wish to understand whether the economic assumptions that underpin that methodology  
 6 remain valid going into the future.

7 ARE THE RESULTS OF HQD'S ALLOCATION OF POST-PATRIMONIAL GENERATING  
 8 COSTS IN THIS PROCEEDING CONSISTENT WITH THE RESULTS PRESENTED IN  
 9 DOCKET R-3610-2006, UPON WHICH THE RÉGIE MADE ITS DECISION?

10 They are not. A summary of the results of the hourly cost allocation methodology,  
 11 applied in 2007 and 2008, are shown in Table IEC-1 below, for the major rate classes.

TABLE IEC-1 POST-PATRIMONIAL DELIVERED SUPPLY COSTS HOURLY METHOD CENTS PER KWH			
	<i>2007</i>	<i>2008</i>	<i>Percent</i>
Rate D	8.95	9.08	1.5%
Rate G	9.01	9.26	2.8%
Rate M	8.66	9.19	6.1%
Rate L	8.47	9.29	9.7%
<b>Total HQD</b>	<b>8.71</b>	<b>9.21</b>	<b>5.7%</b>

12 However, Table IEC-1 does not give a completely accurate picture of the results of the  
 13 hourly cost allocation method, because it does not adjust for transmission and distribution  
 14 losses. Because larger customers take service at a higher voltage than smaller customers,  
 15 the transformation and line loss rates are noticeably lower. Thus, a more accurate  
 16 comparison would be the price paid by each class per kWh of energy supplied to the  
 17 transmission grid, rather than price per kWh paid at the meter. This comparison is shown  
 18 in Table IEC-2 below.

TABLE IEC-2 POST-PATRIMONIAL SUPPLY COSTS AT THE GENERATOR HOURLY METHOD CENTS PER KWH			
	<i>2007</i>	<i>2008</i>	<i>Percent</i>
Rate D	8.20	8.32	1.5%
Rate G	8.25	8.49	2.8%
Rate M	7.98	8.47	6.1%
Rate L	8.02	8.80	9.7%
<b>Total HQD</b>	<b>8.10</b>	<b>8.57</b>	<b>5.7%</b>

1 These tables give rise to two observations. First, the hourly method is an unstable cost  
2 allocation methodology. The increase in allocated unit costs for Rate L customers is  
3 more than six times that for Rate D customers. Second, the 2008 allocation exhibits a  
4 pattern that is extremely unusual, namely one in which the cost of serving high load  
5 factor industrial load is deemed to be more expensive per kWh than the cost of serving  
6 low load factor Rate D load.

7 In 2007, the cost allocation pattern is, for the most part, *directionally* consistent with  
8 normal cost allocation results, in which the low load factor residential and small  
9 commercial classes exhibit higher rates than the higher load factor medium and large  
10 industrial rate classes.<sup>1</sup>

11 However, although the 2007 results are *directionally* reasonable, there is very little  
12 variation in the magnitude of the unit costs. There is only a 3 percent range from lowest  
13 to highest average cost per kWh, far lower than that for all electric utility cost allocation  
14 studies with which I am familiar.<sup>2</sup> Thus, the 2007 results indicate that (a) there is very  
15 little peak-demand related cost being allocated, and (b) there is very little energy cost  
16 differentiation from hour to hour, either between on-peak and off-peak hours and from  
17 season to season.

18 The 2008 results are *not* directionally reasonable. Unless class post-patrimonial load  
19 profiles have changed substantially since R-3610-2006, the large industrial post-  
20 patrimonial load exhibits a higher load factor than the other rate classes, and much higher  
21 than that for the residential class.<sup>3</sup> Moreover, large industrial loads represent a larger  
22 portion of off-peak demands than residential customers, and off-peak power costs are  
23 lower than on-peak power costs.

24 In contrast to the normal cost allocation (or market) results, the hourly method for 2008  
25 suggests that high load factor Rate L customers are the most expensive customers to  
26 serve, followed by the low load factor Rate G and medium load factor Rate M customers.

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<sup>1</sup> Of note, however, is the fact that the Rate L unit cost rate, once adjusted for line losses, is higher than that for the Rate M customers, despite the fact that the load factor for Rate L customers is considerably higher than that for Rate M customers. In 2007, the 300 CP load factor for Rate L was 94.8 percent and for Rate M it was 77.8 percent.

<sup>2</sup> For example, New Brunswick uses a cost allocation methodology that is quite favorable to low load factor customers, relative to many jurisdictions. However, in its current filing, the allocated unit cost for residential customers is 13 percent higher than that for transmission voltage large industrial customers.

<sup>3</sup> Note that this conclusion is applicable whether peaks are measured at overall system peak demand periods or at periods when post-patrimonial loads peak. Because the Régie has determined that HQD is essentially procuring post-patrimonial supplies specifically to serve only post-patrimonial load, independent of patrimonial supplies, my analysis in this proceeding focuses only on post-patrimonial load shapes (to the extent available).

1 Most paradoxically, the low load factor Rate D customers have the lowest allocated unit  
2 cost.

3 In short, the hourly method in 2008 is producing results that are not consistent with the  
4 most basic principles of electricity supply economics, namely that at least some  
5 component of costs is related to peak demands, and that energy costs in on-peak periods  
6 are higher than energy costs in off-peak periods.

7 **WHAT FACTORS ARE CAUSING THE POST-PATRIMONIAL RESULTS TO CHANGE SO  
8 DRAMATICALLY FROM LAST YEAR'S RESULTS?**

9 I do not know.

10 In reviewing HQD's application, I had developed a set of hypotheses about why HQD's  
11 methodology produced the counter-intuitive results shown above, including the  
12 following:

- 13 • The overall post-patrimonial load shape is "thin" and unstable, in that it  
14 represents a small residual difference between the overall HQD load and the  
15 patrimonial load specified in Decree 1277-2001, and that the patrimonial load  
16 shape does not match the actual load shape;
- 17 • As it showed in the 2007 filing, HQD may be attempting to time its "take" of its  
18 patrimonial entitlement in order to reduce post-patrimonial supply costs;
- 19 • HQD's allocation of its hourly patrimonial entitlements, including its still  
20 undocumented and unexplained "smoothing" mechanism, may be producing  
21 class post-patrimonial load patterns that are even less reasonable than they have  
22 been in the past;
- 23 • HQD's treatment of its stranded costs, associated with losses on the resale of the  
24 excess supply that it has procured, are being disproportionately assigned to off-  
25 peak hours, thereby unfairly burdening high load factor customers;
- 26 • Because the hourly cost method includes both fixed and variable costs in the  
27 hourly cost of supply, HQD may (correctly) decide to take more volume from  
28 the supply option that offers the lowest *variable* cost during off-peak periods,  
29 but which actually costs more per kWh in the hourly cost allocation method.

30 Unfortunately, I am not able to evaluate which of these issues contribute to the unusual  
31 results, due to insufficient information.

32 **IS HQD'S METHOD OF ALLOCATING THE STRANDED COSTS ASSOCIATED WITH  
33 EXCESS CAPACITY CONSISTENT WITH COST CAUSATION?**

34 As I understand HQD's hourly methodology, the costs and revenues associated with  
35 energy that is purchased from suppliers and re-sold to off-system customers are assigned  
36 to the specific hours in which those sales and purchases were made. In effect, any net  
37 losses on those re-sales will be assigned to a particular set of hours.

1 This approach is not consistent with cost causation. The need to re-sell excess power is  
2 not *caused by loads* from any particular customer or class -- that need results from  
3 inaccurate forecasting. In effect, it is not the loads in any particular hour that give rise to  
4 those losses -- it is the *absence* of the expected loads. It is not logical to assign the costs  
5 associated with loads that did not appear to an arbitrary subset of the loads that are now  
6 expected.

7 In the alternative (and under the assumption that I have correctly interpreted HQD's  
8 approach despite the lack of information), I recommend that any net losses on capacity  
9 re-sales be allocated broadly to all customer classes. While there is no theoretically  
10 perfect method for allocating stranded costs (because they are not caused by loads at all),  
11 I suggest that these costs be allocated in proportion to all other post-patrimonial  
12 generation costs, or in proportion to all other generation costs.

13 Also, it is not clear to me that that this *specific* aspect of the hourly cost allocation  
14 methodology was fully vetted by the Régie in its D-2007-12 decision. It is certainly  
15 possible that "tweaking" the hourly cost allocation methodology in this respect will result  
16 in an allocation that is more consistent with that in the R-3610-2006 proceeding.

17 ARE THE RESULTS FROM HQD'S IMPLEMENTATION OF THE HOURLY METHOD IN THIS  
18 PROCEEDING CONSISTENT WITH THE ECONOMIC LOGIC IN THE RÉGIE'S D-2007-12  
19 DECISION?

20 They do not appear to be.

21 In reaching its decision, the Régie made the following conclusions with respect to cost  
22 causation:

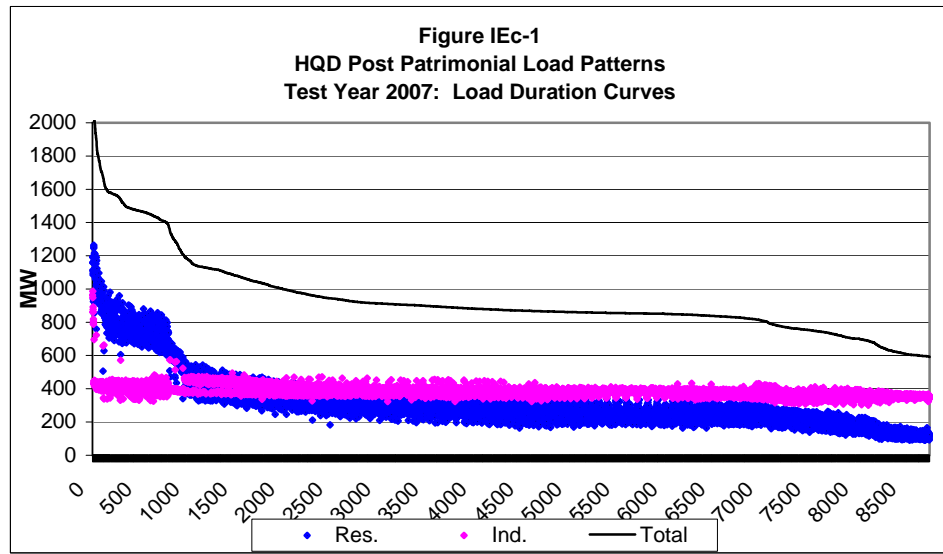
- 23 • The hourly method of cost allocation recognizes that the overall post-patrimonial  
24 load profile is different from the patrimonial load profile, while the global load  
25 factor method does not.
- 26 • The hourly method produced cost allocation results that were consistent with a  
27 capacity cost of \$10 per kW per year in the test year. By way of contrast, the  
28 global load factor method produced cost allocation results that were reasonably  
29 consistent with the avoided capacity cost of a combustion turbine unit of some  
30 \$80 per kW per year.
- 31 • In the short-run, the capacity cost of \$10 per kW per year was consistent with the  
32 cost of capacity as measured by HQD's short-term contracts and interruptible  
33 credits. The Régie observed that a low-cost of power in the short-run is not  
34 surprising due to the excess capacity situation that HQD faces through 2009-  
35 2010.
- 36 • The hourly method is more consistent with the realities of the market, and that it  
37 will adapt to seasonal and time-of-use supply and market fluctuations.

38

1 COULD THE DIFFERENCE BETWEEN THE OVERALL HQD LOAD AND THE LEGISLATED  
2 PATRIMONIAL LOAD GIVE RISE TO THE RESULTS SHOWN IN TABLE IEC-2?

3 At the outset, I note that the Régie's argument is very well taken that, by government  
4 decree, the patrimonial load comprises a larger proportion of on-peak hours than it does  
5 for off-peak hours. As such, if I assume that post-patrimonial load is independently  
6 procured under a least-cost supply plan, it is reasonable to reflect that difference in the  
7 cost allocation methodology.<sup>4</sup>

8 However, while it is theoretically possible for this situation to cause bizarre results, the  
9 only reasonable way for that to happen would be if HQD's allocation of patrimonial load  
10 somehow results in post-patrimonial load shapes in which large industrial demand has a  
11 lower load factor than residential demand. That result was certainly not the case in the  
12 last proceeding, as shown in Figure IEC-1 below. (Note that I have used last year's post-  
13 patrimonial load shape because the 2008 data are not available.)



14 As shown in Figure IEC-1, the load pattern for the residential class shows that it varies  
15 considerably from hour to hour over the course of the year, and it matches fairly closely  
16 the overall HQD post-patrimonial load shape. Thus, if HQD is purchasing power to meet  
17 this specific load shape, it must recognize that it must secure sufficient capacity to meet  
18 the residential system demand. The industrial demand, by contrast, exhibits a much more  
19 stable load shape. Thus, unless load shapes have changed significantly in 2008, the load

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<sup>4</sup> Because HQD purchases its post-patrimonial load on an integrated basis with its patrimonial load, and because HQD's post-patrimonial purchases appear to be subject to a number of policy constraints that would more appropriately be absorbed by all loads, I have in the past argued that it is not reasonable to allocate the two pools of costs separately. For this proceeding, I accept the Régie's determination that separate cost allocation methods should be used.

1 factor for the large industrial class is considerably higher than that for the residential  
2 class.

3 Based on the load shapes shown in Figure IEc-1, the difference in load patterns between  
4 patrimonial and post-patrimonial loads could very well result in a *narrowing of the gap* in  
5 rates between customers who consume little during off-peak hours and customers who  
6 consume more during off-peak hours, as it did in the 2007 proceeding. Nevertheless, this  
7 difference most certainly does not justify a finding that post-patrimonial costs appear to  
8 be *higher* for off-peak hours than for on-peak hours.

9 **COULD THE RÉGIE’S CONCLUSION THAT THE CAPACITY-RELATED COSTS OF POST-**  
10 **PATRIMONIAL SUPPLY ARE RELATIVELY LOW CAUSE THE UNUSUAL RESULTS?**

11 No. Again, the Régie’s conclusion is well taken that capacity costs are currently lower  
12 than the cost of a new combustion turbine unit.<sup>5</sup>

13 However, the Régie’s conclusion that near-term peaking costs for HQD supply are  
14 relatively low would also justify a *narrowing* of the gap between unit costs for high load  
15 factor and low load factor customers. In the last proceeding, the Régie observed that the  
16 hourly cost allocation methodology produced results that were reasonably consistent with  
17 a \$10 per kW per year of peak demand cost.<sup>6</sup>

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<sup>5</sup> I retain concerns about the use of short-term capacity costs for cost allocation purposes. Over the longer-term, it is unlikely that HQD will be able to rely on spot supplies or interruptible loads for all its post-patrimonial peaking needs, and it will need to enter into longer-term arrangements for peaking supplies. With a \$10 per kW per year peak demand price signal, customers will have very little economic incentive to flatten their loads or reduce consumption during peak demand periods. By way of follow-up to last year’s proceeding, I note that PJM (the enormous regional transmission organization that manages the electricity markets for the U.S. Middle Atlantic states and beyond) has recently modified its market pricing system to include a capacity “RPM” auction, in order to better assure resource adequacy. The RPM auction sets an upper bound capacity cost based on the cost of a new combustion turbine unit. That limit is set at approximately \$200 per MW-day, or about US\$75 per annual kW, which is reasonably consistent with the values used by HQD and me in last year’s proceeding for capacity. Moreover, the market auction prices for 2008-2009 capacity in the largest portion of PJM have recently been approximately half of that, while prices in selected areas have been as high as \$200 per MW-day. Thus, over time, the Régie can probably expect that market prices for capacity will rise considerably, and will be higher than the \$10 per kW that served as the economic basis for D-2007-12. As noted elsewhere, it is apparent that HQD has been paying a substantial premium to retain secure capacity.

<sup>6</sup> While I agree that, in 2007, the hourly method produced results that were similar to an “alternative methodology” with a \$10 per kW demand cost, that “alternative methodology” had virtually no variation in time-of-use energy costs. Thus, the “alternative methodology” would also understate the higher energy costs for on-peak periods that occur in all deregulated electricity markets. Nevertheless, for the purpose of this proceeding, I accept the Régie’s implicit conclusion

1 Moreover, the Régie appeared to recognize that, at some point in the future, the cost of  
2 capacity may increase.

3 However, in this proceeding, the results of HQD's implementation of the hourly method  
4 imply that capacity costs are actually less than zero! That is, HQD's method implies that  
5 it would be *less* expensive to procure capacity during on-peak periods than during off-  
6 peak periods.

7 DOES THE CONCLUSION THAT THE HOURLY METHOD IS MORE CONSISTENT WITH  
8 MARKET REALITIES APPLY TO THE ANALYTICAL RESULTS PRESENTED BY HQD IN  
9 THIS PROCEEDING?

10 It does not. Market prices tend to exhibit peak demand charges as well as hourly energy  
11 prices that are higher during on-peak than off-peak periods. The hourly method produces  
12 the opposite results in 2008.

13 As noted above, I currently do not know why the hourly method is not producing rational  
14 results for 2008. Nevertheless, the "big picture" is that the hourly method is producing a  
15 cost allocation result for 2008 that is *not consistent* with the economic rationale used by  
16 the Régie in adopting that method in D-2007-12, it is *not consistent* with market price  
17 patterns, it is *not consistent* with cost allocation results at any electric utility rate  
18 proceeding that I have participated in, and it *defies common sense*.

19 HOW DO THE RESULTS OF HQD'S ALLOCATION COMPARE WITH MARKET PRICE  
20 PATTERNS?

21 HQD's results are inconsistent with market price patterns. To evaluate the impact, I  
22 applied the forecast post-patrimonial load for 2007-2008 from last year's proceeding to  
23 the actual locational marginal prices ("LMPs") for the NYISO, for both residential and  
24 large industrial loads. A comparison of the average rates is shown in the table below.  
25 Please note that this analysis does not include any demand-related costs -- including  
26 demand-related costs would substantially increase the relative cost of residential rates in  
27 the NYISO analysis.

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that the energy costs should reflect the specifications in HQD's supply contracts, rather than real-  
life market conditions.

TABLE IEC-3 COMPARISON OF 2007 SUPPLY COSTS CENTS PER KWH			
	2008 Post-Patrimonial	Jan-Oct 2007 NYISO LMPs	Percent Difference
Rate D	8.32	5.60	48.6 %
Rate G	8.49	5.70	48.9%
Rate M	8.47	5.59	51.5%
Rate L	8.80	5.50	60.0%
Source: HQD-11, Document 3, Table 9A, R-3610-2006 HQD-16, Document 3, Question 2, NYISO, HQ Zone.			

1 Note that Table IEC-3 demonstrates two issues. First, the NYISO LMPs, when applied to  
2 post-patrimonial load, do not indicate that average variable rates should be higher for  
3 large industrial customers than for residential customers. Second, Table IEC-3 indicates  
4 that if HQD had purchased its post-patrimonial supplies on the spot market, its costs  
5 would likely have been substantially lower than those incurred in 2007 (which average  
6 approximately 9.34 cents per kWh). Moreover, if HQD were to allocate this enormous  
7 premium, which was incurred to insure that HQD had sufficient *capacity* to meet its  
8 needs, on the basis of post-patrimonial peak demands, the residential unit costs would far  
9 exceed those for the large industrial costs.

10 **ARE THE RESULTS CONSISTENT WITH HQD'S LONGER-TERM ASSESSMENT OF**  
11 **AVOIDED COSTS ASSOCIATED WITH ITS PG&E PROGRAMS?**

12 No they are not. As shown in HQD-11, Document 3, Table 25C, columns (2) and (3),  
13 and confirmed in AQCIE/CIFQ-II-16, the avoided cost for longer term supplies to large  
14 industrial customers is lower than that for any other rate class. Thus HQD's long-run  
15 replacement cost calculations are directionally consistent with market price patterns,  
16 while the 2008 allocation of post-patrimonial costs is not. A summary for the major rate  
17 classes is shown in Table IEC-4 below.

TABLE IEC-4 COMPARISON OF FUTURE SUPPLY COSTS CENTS PER KWH			
	2008 Post-Patrimonial	LR Avoided Costs	Percent Difference
Rate D	8.32	9.04	8.7%
Rate G	8.49	9.04	6.5%
Rate M	8.47	8.97	5.9%
Rate L	8.80	8.64	-1.8%
Source: HQD-11, Document 3, Tables 9A and 25C			

1 WHAT ARE THE IMPLICATIONS OF THE HOURLY COST ALLOCATION METHOD FOR  
2 FUTURE HQD POST-PATRIMONIAL SUPPLY PROCUREMENTS?

3 As I indicated last year, the hourly cost allocation method essentially transfers cost  
4 allocation responsibility from the Régie to the parties who enter into supply contracts.  
5 Consider the case of a baseload supply contract. One way to structure that contract would  
6 be to negotiate a high fixed charge and constant variable charge for all hours of supply.  
7 An alternative way to structure that contract would be to set a lower fixed charge, with  
8 variable charges that vary between on- and off-peak periods or even based on market spot  
9 prices. Even if these two alternatives are structured to result in the same overall cost to  
10 HQD, they will result in very different cost allocation schemes.

11 In contrast to HQD's current post-patrimonial supply procurement policy, the following  
12 attributes of a supply policy would be more consistent with the hourly cost allocation  
13 methodology:

- 14 • HQD should not be paying inordinate costs for capacity in off-peak periods.  
15 Capacity is readily available for off-peak periods and there is no need to pay  
16 premiums.
- 17 • Prices paid for energy should vary between on-peak and off-peak periods,  
18 reflecting market conditions.
- 19 • HQD should purchase a significant share of its supplies at spot market prices,  
20 rather than entering into fixed long-term contracts (which can result in stranded  
21 cost problems).
- 22 • HQD should not be paying demand charges for capacity that exceed the \$10 or  
23 \$20 per kW per year, in light of the excess capacity situation identified by the  
24 Régie.

25 OVERALL, WHAT ARE YOUR RECOMMENDATIONS IN THIS PROCEEDING REGARDING  
26 POST-PATRIMONIAL GENERATION COST ALLOCATION?

27 Because there is no information available regarding the reasons for the bizarre and  
28 counter-intuitive results produced by HQD's implementation of the hourly method in this  
29 proceeding, I can only suggest that the Régie direct HQD to modify the allocation of  
30 stranded costs to eliminate the unreasonable assignment of costs to off-peak periods. If  
31 that correction does not result in post-patrimonial unit costs that are directionally  
32 consistent with those presented in R-3610-2006, I recommend that post-patrimonial  
33 generation unit costs for each class be derived in proportion to the long-run avoided cost  
34 of generation.

35

2. ALLOCATION OF  
TRANSMISSION  
COSTS

1 PLEASE PROVIDE YOUR UNDERSTANDING OF THE REGULATORY BACKGROUND  
2 REGARDING THE ALLOCATION OF TRANSMISSION COSTS FOR THIS PROCEEDING.

3 In R-3549-2004, the Régie considered the issues of how to allocate TransÉnergie's  
4 transmission costs between in-province customers (HQD) and point-to-point service, as  
5 well as the issue of designing the rates for both types of customers.

6 With respect to cost allocation, the Régie determined in D-2006-66 that transmission  
7 costs should be sub-functionalized into generation integration, network, attachment and  
8 other interconnection categories. The Régie directed that these cost categories then be  
9 classified and allocated separately.<sup>7</sup>

10 Regarding rate design, however, the Régie decided that it would not rely on the cost  
11 allocation methodology, either for determining the overall magnitude of the costs or for  
12 designing the rates by which those revenue requirements are collected, at least for the test  
13 period. The charge to HQD is based on a flat dollar amount, which was determined by  
14 sharing the costs between HQD and point-to-point customers on a 1 CP basis. The rates  
15 for point-to-point customers are based only on demand charges, and do not reflect the  
16 energy cost classification method determined by the Régie.<sup>8</sup>

17 In Docket R-3610-2006, the issue arose as to how the Régie's decisions regarding  
18 transmission cost allocation and transmission rate design should be reflected in the  
19 distributor's cost allocation study. Parties to that proceeding generally advocated either  
20 (a) reflecting the transmission utility's rate design and retaining the 1 CP method; or (b)  
21 reflecting the transmission cost allocation methodology that has no impact on  
22 transmission rate design. These two alternatives display the dilemma faced by HQD in  
23 last year's proceeding.

24 In D-2007-12, the Régie concluded that the determination of the transmission tariff  
25 charge was not based on a 1 CP tariff design, but was in fact more akin to a lump sum  
26 charge. The Régie further concluded that the allocation of these costs on a single  
27 coincident peak basis was not consistent with cost causation, and it directed HQD to  
28 make its filing for the 2008 test year based on the transmission cost allocation decision.  
29 However, the Régie indicated that it believed that the subject merits further debate in this  
30 proceeding.

31 DID HQD ADDRESS THE RÉGIE'S CONCERNS IN THE CURRENT PROCEEDING?  
32 HQD made its filing using a cost allocation method that is consistent with the Régie's  
33 cost allocation decision, supplemented by a more detailed allocation of the customer

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<sup>7</sup> The specifics are detailed in my evidence in R-3610-2006, at pages 13-14.

<sup>8</sup> Hydro-Québec Open Access Transmission Tariff, Decisions D-2007-08 and D-2007-34, Schedules 9 and 10.

1 attachment costs that was not clearly defined in D-2006-66.<sup>9</sup> However, HQD has not  
2 provided any additional analysis with respect to the Régie’s request for a more detailed  
3 debate.

4 **WHAT ARE YOUR THOUGHTS AND RECOMMENDATIONS REGARDING THIS ISSUE?**

5 I continue to believe that cost causation at the distribution level for regulated transmission  
6 service should reflect the tariff design of the transmission utility. While the Régie’s  
7 conclusion is very well taken that the tariff charge paid by HQD is essentially a lump  
8 sum, it is also clear that the *magnitude* of that lump sum is determined by a coincident  
9 peak allocation. And by “revealed preference,” the Régie has also concluded that point-  
10 to-point transmission service tariffs should not reflect cost causation, because point-to-  
11 point tariffs are 100 percent demand-based.

12 In addition, as a general rule, the cost causation implications for transmission costs are  
13 best addressed in a transmission rate proceeding, not a distribution rate proceeding. In a  
14 transmission proceeding, the experts who are best acquainted with cost causation on the  
15 transmission grid are available, as are transmission rate design experts. That evidence is  
16 available only partially (and that indirectly) in a distribution rate proceeding. As such, it  
17 is very difficult to develop an approach for distribution cost causation that is somehow  
18 different than that reflected in the rates that the distribution utility pays.

19 Finally, I note that one reason that a cost-based transmission tariff may not have been  
20 developed in a transmission rate proceeding is that the transmission utility was concerned  
21 about over- or under-recovery of its costs, if something other than a lump sum charge  
22 were adopted for native load service. However, I am advised that the Régie has now  
23 adopted a reconciliation mechanism (“compte d’écart”) for transmission service in D-  
24 2007-08. With a reconciliation mechanism in place, it may be much easier for  
25 TransÉnergie to accept a cost-based transmission tariff.

26 However, if, in the end, the Régie does not accept the principle that cost causation should  
27 reflect the rates paid, I accept the cost allocation methodology offered by HQD because it  
28 is consistent with the Régie’s decision in the transmission proceeding. Moreover, I do  
29 not believe that a distribution rate proceeding is the appropriate venue to develop a third  
30 methodology that is not consistent with either the transmission cost causation decision or  
31 the transmission rate design decision.

32

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<sup>9</sup> As in R-3610-2006, HQD proposes to segregate the specific facilities associated with customers who are interconnected at transmission voltage from those connected at distribution voltage. These cost pools are then allocated among the separate groups on the basis of class NCP.

3. PGEÉ COST  
ALLOCATION

1 HOW DOES HQD PROPOSE TO ALLOCATE PGEÉ COSTS IN THIS PROCEEDING?

2 Up to the present filing, HQD allocated PGEÉ costs on the basis of overall generation  
3 costs. The apparent economic rationale for that approach was that any reduction in load  
4 associated with conservation programs would allow other customers to benefit from the  
5 use of the low-cost patrimonial pool.

6 In the current filing, HQD proposes to allocate the costs of the PGEÉ program on the  
7 basis of avoided costs actually achieved by the programs, based both on the reduced  
8 volumes and on the long-run incremental cost of supplying each class. In the alternative,  
9 HQD suggests that a direct assignment of the costs of the programs to each rate class  
10 would be reasonable.

11 WHAT ARE THE ECONOMIC AND COST-CAUSATION CONSIDERATIONS ASSOCIATED  
12 WITH ALLOCATING PGEÉ COSTS?

13 Three factors should be considered: the rate effect, the net incremental cost effect, and  
14 the allocative effect.

15 If HQD subsidizes a conservation program for a particular customer, that customer  
16 receives the benefit of the program in the form of lower electric bills. For example, a  
17 subsidized weatherization program will leave the customer with just as warm a house but  
18 with lower utility bills.<sup>10</sup> This effect suggests that the costs of the program should be  
19 directly assigned to the customer or customer class that benefits from the program.

20 The net incremental cost effect is the net savings to the utility associated with the  
21 program. That savings represents the difference between the costs avoided by the utility  
22 (the incremental cost of supply, transmission and distribution) and the lost revenues  
23 associated with the load reduction. To the extent that the incremental tariff rates are set  
24 lower than the avoided cost, there is a net benefit to the utility. That is, if the marginal  
25 tariff charge is 7 cents per kWh, and the incremental cost of service is 9 cents per kWh,  
26 the net incremental cost effect is 2 cents per kWh.

27 The allocative effects represent the shifts in allocated costs that are associated with a  
28 particular demand reduction program. These effects include both the allocation of the net  
29 incremental cost effect, as well as the reallocation of generation, transmission and  
30 distribution costs that result from the program. For HQD, the allocative effects are

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<sup>10</sup> From a technical perspective, the rate effect is offset by the contribution that the customer must make to the conservation program. If HQD's PGEÉ programs are designed only for programs that would not be otherwise economically viable for the customer, and only to the extent necessary to make them viable, the rate effect would be zero. In practice, however, such fine tailoring is impossible. For example, if HQD were to set the tail block charge for its residential rates at the long-run incremental cost of service, there would be very little economic justification for *any* utility-subsidized demand side management program, because the customers would face the correct economic signals to make their own decisions.

1 particularly complex, given the nature of the patrimonial generation cost allocation  
2 mechanism.

3 It is important to recognize that the allocative effects are the primary motivation for the  
4 current methodology, namely that all classes are benefiting proportionally from any  
5 reductions in loads. Without a clear justification for allocative cross-benefits, the current  
6 method is not supported by economic principles.

7 **WHAT ARE THE SPECIFIC ALLOCATIVE EFFECTS THAT CAN OCCUR IN HQD'S COST**  
8 **ALLOCATION METHODOLOGY?**

9 To address this issue, I constructed a simple two-class model, shown in Exhibit IEc-2. It  
10 consists of a relatively low load factor residential class and a high load factor industrial  
11 class, with the "base case" parameters shown in the left-most third of the exhibit.

12 I then consider the effects of two types of demand reduction programs. The first is a  
13 program targeted at winter season consumption for the residential class (which would be  
14 fairly typical for a demand management program). The second is a program targeted at  
15 an overall reduction for the industrial class (which would also be fairly typical).

16 Consider the first example, shown in the middle of the exhibit. In HQD's cost allocation  
17 methodology, the first effect of any conservation program is the reduction of the  
18 patrimonial load entitlement (assuming that government decrees continue to follow the  
19 historical pattern). Thus, in this example, the conservation program causes a reduction in  
20 both residential load and residential patrimonial load, and an increase in industrial  
21 patrimonial load.

22 However, the load reduction has a second, more complicated effect, on patrimonial load  
23 average costs. The reduction in peak season demand for the residential class improves  
24 the load factor for that class. Under the approved patrimonial generation cost allocation  
25 methodology (which I use in this exhibit), this improved load factor, in conjunction with  
26 the volume mix shift, results in a slight reduction in the unit cost of patrimonial load for  
27 the residential class, and *an increase in the patrimonial load unit cost* for the industrial  
28 class.

29 With respect to *post-patrimonial generation* costs, I have modeled those costs as a  
30 constant variable amount, because the hourly method of generation cost allocation has  
31 virtually no time of use signal at all.

32 In addition, note that the reduction in load for the residential class causes transmission  
33 and distribution demand-related and energy-related costs to be shifted to the industrial  
34 class.

35 In the end, the net cost savings associated with a reduction in the residential winter load  
36 primarily benefits the residential class, although there is a relatively small allocative  
37 benefit to the industrial class (only about 14 percent of the total benefit).

38 Let me turn to the second example. In this case, the conservation program does not result  
39 in any improvement in the load factor for the industrial class, because there is very little

1 room for any improvement to be made. (Industrial demand-side management programs  
2 generally cannot target peak period demand, because there is no pronounced peak.) It is  
3 simply an across-the-board reduction in demand. (I have structured this second example  
4 such that the overall MWh reduction is about the same as in the residential example.)

5 In this case, paralleling the previous example, the reduction in industrial load causes the  
6 patrimonial entitlement to shift from the industrial class to the residential class.

7 However, in this example, the reduction in industrial load causes the patrimonial unit  
8 costs *for both residential and industrial customers to decline*.

9 As in the previous example, this example shows that demand-related and energy-related  
10 transmission and distribution costs will shift from the industrial class to the residential  
11 class.

12 The net impact in this example is that the majority of the cost savings to HQD are related  
13 to the industrial class, but that the residential exhibits a material allocative benefit (of  
14 about 27 percent).

#### 15 **WHAT DO YOU CONCLUDE FROM YOUR ANALYSIS OF ALLOCATIVE EFFECTS?**

16 Obviously, the magnitude of the allocative benefits will depend on the specific  
17 parameters of each PGEÉ program. However, I believe that my examples are  
18 directionally representative of the impacts and reasonably representative of the relative  
19 magnitude of the impacts.

20 Based on the examples shown, as well as alternative simulations of those examples, I  
21 conclude that the net allocative benefits to classes other than those for which the PGEÉ  
22 programs are targeted is relatively small. Therefore, I conclude that the economic  
23 rationale for the existing mechanism is weak, under current economic conditions and cost  
24 allocation methodologies. For that reason, I conclude that either the avoided cost  
25 approach proposed by HQD or the direct assignment approach are far superior to the  
26 current method.

27 However, if an allocative method is pursued, it must recognize the fundamental  
28 differences between programs targeted at high load factor customers and those targeted at  
29 low load factor customers. That is, there is a much stronger economic rationale for low  
30 load factor customers to contribute to the costs of programs targeted at high load factor  
31 customers than there is for high load factor customers to contribute to programs targeted  
32 at low load factor customers.

#### 33 **WHAT IS YOUR ASSESSMENT OF THE TWO ALTERNATIVES OFFERED BY HQD?**

34 HQD's avoided cost method assigns the costs of the programs based on the specific  
35 volumes avoided for a particular class, priced at the long-run incremental cost of supply.  
36 The direct assignment method simply assigns the specific costs of the program to each  
37 rate class.

38 It is important to recognize that, if the programs are equally cost effective (as measured  
39 by dollars invested to achieve a dollar reduction in avoided cost), the results of these two

1 methods will be identical.<sup>11</sup> However, if, for example, the PGEÉ program for the Rate L  
2 class is less cost-effective than one for the Rate D class, then the Rate D class will  
3 contribute to the cost for the Rate L program under HQD's proposed methodology.

4 **WHICH APPROACH DO YOU RECOMMEND?**

5 I recommend that the direct assignment method be adopted, for three reasons.

6 First, there is no reason why one class should cross-subsidize the program for a different  
7 class, merely because load reductions can be achieved more efficiently at the first class  
8 than for the other class. As I demonstrated above, the allocative effects of a PGEÉ  
9 program are relatively small, and therefore there is little reason to redistribute the costs of  
10 the program.

11 Second, it is my understanding that part of the focus of HQD's effort for load reduction  
12 will be targeted at low-income customers. As such, it may become difficult to segregate  
13 expenditures designed for load reduction with simple economic transfers to low-income  
14 residential customers. Because business customers do not contribute in any causal way to  
15 the need for residential assistance programs, no such costs should be assigned to those  
16 customers. For that reason, it would be simpler and less contentious to simply assign the  
17 costs of each program directly to the class that benefits from it.

18 Third, the direct assignment method is much simpler, in that it does not require a  
19 somewhat subjective evaluation of how much energy has been reduced from any  
20 particular conservation program. Under HQD's method, the parties to a regulatory  
21 proceeding would need to scrutinize the savings associated with each and every PGEÉ  
22 program, to insure that HQD's assessment of the kWh savings for each rate class are  
23 reasonable. Under a direct assignment method, the regulator need only look at HQD's  
24 books, to see where the money was spent.

4. REVENUE  
ALLOCATION AND  
CROSS-  
SUBSIDIZATION

25 **PLEASE PROVIDE A BRIEF BACKGROUND OF THE REGULATORY ISSUES**  
26 **SURROUNDING REVENUE ALLOCATION FOR THIS PROCEEDING.**

27 As the Régie is well-aware, the regulation of HQD is subject to the unusual (and quite  
28 possibly unique) requirement that rates may not be adjusted in order to cause changes in  
29 historical levels of cross-subsidization. How that cross-subsidization is measured has  
30 been a matter of some debate over the past several rate proceedings.

31 Nevertheless, in the last proceeding (R-3610-2006), the Régie approved a methodology  
32 proposed by HQD which measures the increase in allocated per-kWh cost from  
33 proceeding to proceeding, based on a consistent cost allocation methodology. That is,  
34 HQD simulates its cost allocation methodology for the prior test year and for the

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<sup>11</sup> Exhibit HQD-11, Document 3, Table 25C appears to suggest that the PGEÉ programs for the special contracts class have been particularly cost-effective, while those for the Rates G and M classes are relatively less so. The two methods produce reasonably similar allocation effects for Rates D and L.

1 proposed test year with the same cost allocation methodology. The difference in the per-  
 2 kWh allocated costs between those two simulations is deemed, under this methodology,  
 3 to be the necessary difference in rates that would result in *no change in cross-subsidies*.  
 4 Thus, in Docket R-3610-2006, the Régie implicitly adopted a new base level of cross-  
 5 subsidies.  
 6 In the last proceeding, however, the Régie did not use its new cross-subsidy approach for  
 7 revenue allocation. Instead, it approved an across-the-board rate increase for all rate  
 8 classes. The effect of this decision on the increases or decreases in cross-subsidies, is  
 9 shown in Table IEC-5 below, as measured as a percent of rates. (Note that this table is  
 10 based on values updated for D-2007-12 issued by the Régie.)

TABLE IEC-5 CROSS-SUBSIDY ANALYSIS DECISION D-2007-12				
	No Subsidy Change Increase	Across-the-Board Increase	Change in Cross-Subsidy (%)	Change in Cross-Subsidy (\$mm)
Domestique	2.8%	1.9%	-0.9%	(36)
Petite Puissance	1.7%	1.9%	0.2%	3
Moyenne Puissance	1.1%	1.9%	0.8%	15
Grande Puissance	1.0%	1.9%	0.9%	18
<b>Total</b>	<b>1.9%</b>	<b>1.9%</b>	<b>0.0%</b>	<b>0</b>
Source: Exhibit IEC-3				

11 As Table IEC-5 shows, the effect of applying the across-the-board rate increase in the  
 12 previous docket resulted in an increase in cross-subsidies to the residential rate classes of  
 13 approximately \$36 million, primarily from the medium and large demand classes. Unless  
 14 that increase is reversed in the current or future proceedings, this would represent a  
 15 permanent increase in cross-subsidies paid by those classes.

16 In the current proceeding, HQD has again prepared its cross-subsidization analysis. For  
 17 demonstration purposes, HQD has assumed that an across-the-board rate increase will  
 18 again be applied. However, HQD has suggested that any differential increase be the  
 19 subject of debate among the parties and the decision of the Régie. The cross-  
 20 subsidization effects based on HQD's filing are shown in Table IEC-6 below. Of course,  
 21 changes in the cost allocation methodology may have an effect on the cross-subsidization  
 22 factors.

TABLE IEC-6 CROSS-SUBSIDY ANALYSIS R-3644-2007 HQD FILED				
	No Subsidy Change Increase	HQD Proposed Increase	Change in Cross- Subsidy (%)	Change in Cross- Subsidy (\$mm)
Domestique	4.4%	2.9%	(1.5%)	(61)
Petite Puissance	0.9%	2.9%	2.0%	26
Moyenne Puissance	2.6%	2.9%	0.3%	5
Grande Puissance	1.4%	2.9%	1.6%	30
<b>Total</b>	<b>2.9%</b>	<b>2.9%</b>	<b>0.0%</b>	<b>0</b>

Source: Exhibit IEC-3

1 As Table IEC-6 shows, if HQD’s “straw man” proposal for a near across-the-board  
 2 increase were to be adopted in this proceeding, it would result in an increase in cross-  
 3 subsidies to the residential classes of some \$60 million, provided this time by the small  
 4 and large demand rate classes.

5 **WHAT ARE THE PRIMARY CONSIDERATIONS OF REGULATORS FOR EVALUATING**  
 6 **REVENUE ALLOCATION DECISIONS?**

7 As a general rule, regulators consider three primary factors when determining how a rate  
 8 increase is shared among the various rate classes. First, most regulators consider cost to  
 9 be the primary consideration, and that the objective of revenue allocation is to move rates  
 10 more into line with allocated costs under future rates than under prior rates.

11 This objective of “moving toward cost-based rates” is tempered by two other  
 12 considerations. These are the principle of “rate gradualism” (often referred to as avoiding  
 13 “rate shock”) and the principle of “value of service.”

14 While it is difficult to pin down exactly what the principle of gradualism requires, many  
 15 regulators rely on a “rule of thumb” that the rate increase for a particular class be no more  
 16 than 1.5 or 2.0 times the system average increase. (Generally, for smaller overall  
 17 increases, regulators are more comfortable with a higher multiple.) Thus, for example,  
 18 under a “two-times” rule, if the system average rate increase is 3.2 percent, no class is  
 19 assigned more than a 6.4 percent increase.

20 The principle of “value of service” is that classes who place a higher value on the utility  
 21 service may be assigned a larger increase than those classes that value the service less  
 22 highly. This criterion is generally interpreted to mean that customers whose demand will  
 23 be less affected by a rate increase (i.e., the demand is less price *elastic*) may be assigned a  
 24 larger increase. In practice, this criterion is often used to justify lower rate increases for  
 25 customers or customer classes who are likely to lose load (e.g., *bypass* rates).

26

1 IN THE CONTEXT OF HQD'S REGULATORY ENVIRONMENT, WHAT ARE YOUR  
2 REVENUE ALLOCATION RECOMMENDATIONS IN THIS PROCEEDING?

3 If the Régie determines that the traditional principle of *moving* rates more into line with  
4 allocated costs is, at least in part, precluded by the legislation for HQD, the next best  
5 alternative would simply be to *keep* rates in line with allocated costs (including the  
6 historical cross-subsidy), as tempered by the principles of gradualism and value of  
7 service.

8 In the context of this proceeding, both the increase in the cross-subsidies in the last  
9 proceeding and the potential increases in cross-subsidies in this proceeding should be  
10 recognized. In addition, the Régie should recognize the increase in cross-subsidies paid  
11 by each of the classes in the prior year.

12 To get rates back into line with the base level cross-subsidies, as established in the prior  
13 proceeding, the rate increases shown in Table IEC-7 would be required.

TABLE IEC-7 2008 REVENUE ALLOCATION NO CHANGE TO 2007 OR 2008 CROSS-SUBSIDIES			
	Cumulative 07-08 Increase	Less: 2007 Increase	Net 2008 Increase
Domestique	7.3%	1.9%	5.3%
Petite Puissance	2.6%	1.9%	0.7%
Moyenne Puissance	3.7%	1.9%	1.8%
Grande Puissance	2.4%	1.9%	0.4%
Total	4.9%	1.9%	2.9%

14 Thus, to keep cross-subsidies at constant level relative to those in place *going into* the R-  
15 3610-2006 proceeding, it would be necessary to assign a 5.3 percent increase to the  
16 domestic class, with lower increase to the other rate classes. The 5.3 percent factor would  
17 be about 1.8 times the system average increase, which I would consider to be within the  
18 usual constraints for rate gradualism. I also note that this approach results in a relatively  
19 low rate increase for the large industrial classes. Such an increase is consistent with the  
20 value of service principle, in that it recognizes the losses of industrial load from plant  
21 shutdowns that HQD has experienced over the past few years, as well as the precarious  
22 condition of a number of forest products and chemical operations.<sup>12</sup>

23 DO YOU HAVE ANY OTHER RECOMMENDATIONS WITH RESPECT TO REVENUE  
24 ALLOCATION?

25 HQD appears to conclude that the methodology approved by the Régie in last year's  
26 proceeding should apply only one year at a time, and be evaluated on a separate basis in

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<sup>12</sup> See Exhibit IEC-4 for a list of partial and full plant closures of large industrial customers.

1 each year. While I agree that the change in cross-subsidies should be *measured* on a year  
2 by year basis, I recommend that the effects of any variations in cross-subsidies be *tracked*  
3 on a cumulative basis.

4 Participants in rate proceedings often have short memories. It may be easy for some  
5 participants to forget that the business rate classes paid an extra \$35 million in cross-  
6 subsidies in 2007, and are at some risk of adding \$60 million on top of that in 2008. In  
7 total, that would amount to some \$130 million in *extra* cross-subsidies over the two years,  
8 even without accumulating interest on the overpayments.<sup>13</sup>

9 Conversely, there will likely come a time in the future when the “no change in cross-  
10 subsidy” rate increases imply that the rate increases for the business classes are higher  
11 than those for the residential class. At that time, it may be politically expedient for HQD  
12 to propose to assign disproportionate rate increases to the business classes, while ignoring  
13 the history of increasing cross-subsidy payments from those classes.

14 If a tracking mechanism is in place, the Régie will be well aware of the history of cross-  
15 subsidies, and it may choose to mitigate the rate increases to the business classes and  
16 draw down the accumulated cross-subsidy excesses.

17 **WHAT OTHER CONSIDERATIONS EXIST WITH RESPECT TO REVENUE ALLOCATION IN**  
18 **THIS PROCEEDING, THAT RELATE TO THE NEED FOR A TRACKING MECHANISM FOR**  
19 **INCREASES AND DECREASES IN CROSS-SUBSIDIES?**

20 First, even if the rate increase that I recommend in this proceeding is adopted, the  
21 overpayment from 2007 is not returned to those customers. If a tracking mechanism is in  
22 place, this overpayment will be remembered in the future.

23 Second, HQD’s overall rate increase may be modified in this proceeding, as may its cost  
24 allocation results. Changes to either or both of these assumptions will affect the  
25 magnitude of the class rate increases shown in Table IEC-7 above. It is certainly possible  
26 that these changes will cause the class rate increases to violate the principle of  
27 gradualism.<sup>14</sup> The Régie may therefore need to move away from a strict cost-based  
28 approach, and adopt a judgmental approach.

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<sup>13</sup> Note that the \$35 million applies to 2007. Without a differential increase in 2008, the cross-subsidies would *increase* by \$60 million, thereby implying 2008 cross-subsidies of \$95 million. When added to the \$35 million in 2007, the total is \$130 million. Technically, of course, it would be correct to add interest to the overpayments, much in the way HQD adds interest to its under-recoveries in its reconciliation (also called “pass through”) calculations.

<sup>14</sup> For example, correcting or modifying the allocation of post-patrimonial generating costs to produce directionally reasonable results in 2008 may require the cost-based rate increase for the residential classes to be higher than that shown in Table IEC-7.

1 Third, the Régie may determine that it would prefer a phased approach to recognizing  
2 changes in historical cross-subsidies, and opt for a more gradual approach than that  
3 shown in Table IEC-7.

4 By establishing a tracking mechanism, the Régie will be able to apply its regulatory  
5 judgment, while providing explicit recognition of the increases in the cross-subsidies that  
6 result from the use of that judgment.

5. TARIFF DESIGN  
FOR RATE L

7 WHAT ARE THE IMPORTANT FEATURES OF THE RATE L TARIFF DESIGN FOR THIS  
8 PROCEEDING?

9 The Rate L tariff consists of both demand and energy charges. As a general rule, demand  
10 charges are designed to recover costs that are classified as demand-related, and energy  
11 charges are designed to recover costs that are classified as energy-related. (Some utilities  
12 will set demand charges modestly below allocated demand costs, in recognition that the  
13 individual customer peak does not always match up with the coincident peak measure  
14 used in the cost allocation study. The need for this adjustment is less appropriate for  
15 HQD, because it already uses such a broad peak for allocating the demand-related  
16 portion of generation costs in the load factor method.)

17 It is important to recognize that, if rates are not designed in this way, the tariff design will  
18 result in *intra-class* cross-subsidization.

19 For example, suppose HQD decided to eliminate the Rate L demand charge entirely, and  
20 collect all revenue from an energy charge. However, because HQD's cost allocation  
21 methodology classifies costs into demand components and energy components, the cost  
22 of service per kWh is different from customer to customer. Thus, for example, under  
23 HQD's methodology (as filed in this proceeding), a customer with a 100 percent load  
24 factor would cost approximate 3.9 cents per kWh to serve, while a customer with a 60  
25 percent load factor would cost about 4.8 cents per kWh to serve, a 24 percent difference.

26 If rates for both types of customer were set at the same average per-kWh rate, it is clear  
27 that the high load factor customer would cross-subsidize the low load factor customer.  
28 While this is obviously an extreme example, a similar but less extreme pattern would  
29 result if HQD simply over-recovered the energy-related costs in its energy charge.

30 However, over the last several rate proceedings, HQD has been following a pattern of  
31 assigning disproportionate increases to the Rate L energy charges and lower increases to  
32 the demand charges. This policy will necessarily result in larger rate increases for high  
33 load factor rate customers than for lower load factor customers.

34 In last year's proceeding, I demonstrated that HQD's proposed changes were not  
35 consistent with the cost classification in its own cost allocation study. Based on my  
36 analysis, HQD should have been imposing larger increases on its demand charges than on  
37 its energy charges.

38 However, it is my understanding that HQD has defended its approach on the grounds that  
39 (a) the change in transmission cost methodology will increase the energy-related portion

1 of costs allocated to Rate L customers significantly, and (b) it wanted to increase energy  
 2 charges in order to create a greater incentive for conservation by Rate L customers.

3 Neither of these defenses stands up to scrutiny.

4 First, I have updated my analysis from last year in Table IEC-8 below, which shows my  
 5 derivation of the estimated energy-related costs assigned to Rate L on a per kWh basis.  
 6 In my 2006 analysis, only generation costs were classified as energy-related under the  
 7 load factor method, and both patrimonial and post-patrimonial generation costs were split  
 8 between demand and energy components using the load factor method. As updated, I  
 9 have now assumed that only patrimonial generation costs require a split, and that all post-  
 10 patrimonial costs are assumed to be energy-related. I also have reclassified energy costs  
 11 pursuant to HQD's filed methodology.

TABLE IEC-8		
COMPARISON OF RATE L ENERGY COSTS AND ENERGY CHARGES		
	2006-2007	2007-2008
HQD Patrimonial Cost (\$mm)	\$4,063.5	\$4,063.5
Energy Component of Patrimonial Costs (300 CP)	67.2%	67.1%
HQD Post-Patrimonial Costs (\$mm)	\$ 367.7	\$ 555.9
Energy Component of Post-Patrimonial Costs	67.2%	100%
HQD Energy-Related Generation Costs (\$mm)	\$3,341	\$3,644.8
Rate L Share of Energy	25.8%	24.8%
Rate L Generation Energy Costs (\$mm)	\$ 861.6	\$ 905.6
Rate L Transmission Energy Costs (\$mm)	--	\$ 201.3
Rate L Energy Costs \$mm	\$ 861.6	\$1,106.8
Rate L Consumption (GWh)	45,708	43,623
Rate L Unit Energy Cost (cts/kWh)	1.89	2.54
Rate L Revenue/Cost Ratio	115.6%	110.0%
Cost-Based Rate L Energy Charge (cents/kWh)	2.18	2.79
HQD Proposed Energy Charge (cents/kWh)	2.84	2.91
Note: 2006-2007 post-patrimonial costs are offset by deferral account amount.		

12 Thus, HQD is proposing to set the energy charge for Rate L some 4.3 percent higher than  
 13 energy-related costs, even using very generous assumptions about the classification of  
 14 costs. As such, this proposal is not justified on a cost basis.

15 HQD's other argument, namely that this approach will encourage conservation, is also  
 16 unpersuasive. At large industrial operations, energy efficiency programs generally target  
 17 loads during all hours of the year, including both peak and off-peak consumption levels.  
 18 Shifting costs from demand charges to energy charges will likely not create any  
 19 meaningful additional incentives to conserve.

1 What it will do, however, is reduce the incentive for large industrial customers from  
2 maintaining a level load. That is, customers will have less incentive to use energy  
3 efficiently. Under HQD's tariff, the energy charge is the same regardless of whether it is  
4 a peak period or an off-peak period, or whether it applies to a customer with a very high  
5 load factor or to a customer with a more temperature sensitive peak demand. The  
6 demand charge, by contrast, applies only to the customer's peak demand. Thus, by  
7 proposing disproportionate increases to the energy charge, HQD encourages less efficient  
8 behavior by Rate L customers.

9 Therefore, I recommend that, in this proceeding, HQD assign no increase at all to the  
10 Rate L energy charge, and recover its revenue requirement increase entirely from  
11 increases in the demand charge.

12 **IS THERE AN ALTERNATIVE APPROACH FOR ACHIEVING THE SAME ENDS OF**  
13 **REDUCING INTRA-CLASS CROSS-SUBSIDIZATION?**

14 As I noted earlier, the problem with the HQD approach is that it will exacerbate cross-  
15 subsidization within the Rate L class. Establishing excessively high energy charges will  
16 cause high load factor industrial customers to subsidize lower load factor wholesale and  
17 institutional customers.

18 If the Régie decides that HQD's conservation argument should trump cost causality as  
19 modeled in the cost allocation study, the intra-class cross-subsidization problem can be  
20 addressed by splitting the Rate L class into separate rate classes. By segregating lower  
21 load factor institutional and wholesale customers from high load factor industrial  
22 customers, the problem of intra-class cross-subsidization is much reduced. In that way,  
23 HQD and the Régie can continue to impose disproportionate increases to energy charges  
24 for high load factor Rate L customers without increasing subsidies to the other customer  
25 classes.

26 Unfortunately, I am unable to assess the potential impacts of such an approach, as HQD  
27 has declined to provide intra-class information about different segments within the Rate L  
28 class. Thus, if the Régie wishes to continue to impose disproportionate increases to the  
29 Rate L energy charge beyond this proceeding, I recommend that it establish a working  
30 group to determine how best to segregate the Rate L class between high and lower load  
31 factor customers.

32 **IN YOUR EVIDENCE LAST YEAR, YOU ENCOURAGED HQD TO EXPLORE INNOVATIVE**  
33 **APPROACHES TO RATE DESIGN, INCLUDING THE POSSIBILITY OF A STEPPED-RATE**  
34 **SUCH AS THAT IN PLACE IN BRITISH COLUMBIA. PLEASE COMMENT ON THE**  
35 **APPLICABILITY OF THE STEPPED RATE FOR THE CURRENT PROCEEDING.**

36 I begin with a caveat. In this proceeding, AQCIE/CIFQ have retained Dr. El-Ramly to  
37 explain more fully the nature of the stepped rate in British Columbia, and to identify the  
38 issues and concerns that apply to such a rate. Based on his direct experience with those  
39 rates, Dr. El-Ramly has a better understanding of the specifics and I defer to him. My

1 comments are more theoretical in nature, and they apply to the regulatory régime in  
2 Québec.

3 As the Régie is well-aware, under HQD's existing tariff structure, the marginal tariff  
4 charge for an additional unit of electrical energy in Rate L is well below the incremental  
5 cost of supplying that unit of electricity, for many hours in the year.<sup>15</sup> As such, customers  
6 are receiving inefficient price signals with respect to decisions to increase or decrease  
7 their consumption levels. The stepped rate is a tariff device that is intended to reduce that  
8 problem.

9 At the outset, I observe that a large industrial operation may achieve the potential *avoided*  
10 *cost* savings of a stepped rate in two ways. First, it may invest in conservation  
11 equipment, thereby reducing its energy consumption with no reduction in plan output.  
12 Second, the plant may simply reduce its overall output. For example, a large pulp and  
13 paper manufacturer may simply shut down one of its paper machines, because it will be  
14 able to save 9 or 10 cents a kWh by doing so. Of course, shutting down an operating line  
15 will result in job loss and other economic disruptions, that may not have been the intent  
16 of the policymaker.

17 Also, by way of introduction, I observe that a stepped rate is not a perfect solution, but is  
18 one that represents a balancing act. Under a stepped rate, a customer is able to obtain  
19 low-cost power for some significant portion of its baseline demand level, and it pays a  
20 higher, replacement cost charge for consumption above that level. Thus, the stepped rate  
21 really only provides the proper economic signals for that portion of a customer's demand  
22 that is priced at the replacement cost rate.

23 In effect, the stepped rate, at best, can only affect incremental decisions involving a  
24 relatively small amount of energy consumption at large industrial facilities. This is  
25 certainly not the most economically efficient solution. For example, suppose HQD  
26 serves 20 large industrial customers, each with 50 MW of load, for a total load of 1,000  
27 MW. If each of those customers reduced its load by 10 percent, HQD's need to procure  
28 post-patrimonial energy would be reduced by 100 MW. However, HQD would see the  
29 same reduction in post-patrimonial energy if two of those plants were to simply shut  
30 down.

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<sup>15</sup> Note that the tariff charge for an incremental unit of electricity for a Rate L customer should generally include both the demand and energy charges for that class. If the goal of a stepped rate is to give industrial concerns the economic incentives to invest in energy-saving equipment, such equipment will reduce both demand and energy charges. Of course, if the goal is to simply give industrial concerns an incentive to intermittently reduce plant output during high cost periods, a stepped rate based on long-run incremental cost is not the correct mechanism. Under those conditions, an hourly time-of-use rate based on the marginal cost of post-patrimonial supply would be the correct approach. As Dr. El-Ramly indicates, both of those options are available in BC, thereby adding complexity and administrative cost to such a program.

1 Unfortunately, to make the economic signals for all types of decisions consistent, HQD  
2 would need to price all energy at the marginal replacement cost. To the extent that HQD  
3 needed to continue to share the benefits of the patrimonial entitlement, it would need to  
4 do so through a fixed and permanent entitlement. Under such an approach, if a plant shut  
5 down, it would be able to sell its historical entitlement to other customers.

6 Of course, such an approach would be politically unacceptable. Under such a program,  
7 customers would effectively be paid to shut down. However, without such a program, it  
8 must be recognized that a stepped rate is by no means a panacea. It will only affect  
9 marginal production and marginal investment decisions, and will not send reasonable  
10 price signals for major expansions or plant closures.

11 Second, it is important to recognize that a stepped rate implies that there is a historical  
12 entitlement to low-cost patrimonial load for every customer. As Dr. El-Ramly notes, the  
13 nature and length of that entitlement are critically important for evaluating the  
14 effectiveness of the stepped rate, for marginal decisions.

15 To understand this issue, consider the possibility of a conservation investment. Suppose  
16 the firm could reduce its energy consumption by 10 percent with no loss of plant output  
17 by making an investment in its processes. In practice, it is likely that the firm would  
18 require several years of savings, even at replacement cost pricing, for it to undertake that  
19 investment. Thus, for the stepped rate to work properly, *the historical entitlement of that*  
20 *firm to low-cost power must remain in effect for many years.* If the historical entitlement  
21 is reduced in only a few years, the firm will not have the economic incentive to make the  
22 conservation investment.

23 However, this approach creates something of a problem in the Québec context.  
24 Heretofore, patrimonial entitlements are reallocated *each year* amongst the various rate  
25 classes based on forecast load (within the government decree). Thus, if some large  
26 industrial customers reduce their loads in response to the price signal, the overall volume  
27 of patrimonial load assigned to large industrial customers will decline almost  
28 immediately. Since the proper economic signals for a stepped rate require that historical  
29 entitlements remain constant, the stepped rate concept creates something of a dilemma in  
30 the Québec context.<sup>16</sup> That is, a stepped rate would require a non-proportional allocation  
31 of the patrimonial load *within* a rate class, thereby re-opening the policy question  
32 regarding the overall allocation of the patrimonial load *among* the rate classes.

33 This problem is compounded by the approved *reconciliation* mechanism for post-  
34 patrimonial generation costs. For example, suppose that the stepped rate mechanism  
35 results in a significant reduction in large industrial load, with the concomitant loss of

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<sup>16</sup> In theory, this problem might be addressed by ratcheting up the rate for the lower-cost component of the stepped rate, to reflect the lost patrimonial load. However, this approach will also weaken the economic signals for conservation, particularly for multi-plant firms. If a firm recognizes that conservation investments at one plant are going to increase the rates at all its other plants, it will be less inclined to make those investments.

1 revenue at the high replacement cost rate. Thus, overall post-patrimonial revenues and  
2 costs decline. However, in HQD's reconciliation mechanism, the reduction of industrial  
3 load will reduce the class's entitlement to the *patrimonial* load. In effect, the cost  
4 savings will be shared among all classes, but the lost revenues will relate only to the large  
5 industrial class. Thus, the net effect of a *successful* stepped rate would be a substantial  
6 re-assignment of costs to the large industrial class.

7 Thus, before adopting any such program, I encourage the Régie to fully consider the  
8 potential inconsistencies between the *variable* patrimonial entitlement policy of the  
9 government and the need for a *fixed* entitlement in the stepped rate design. In  
10 conjunction with the observations presented by Dr. El-Ramly, to the extent that the Board  
11 deems that a continued evaluation of this possibility is merited, I suggest that this  
12 evaluation be made in the context of a collaborative effort between HQD, the large  
13 industrial customers, and other interested parties.

CONCLUSIONS AND  
RECOMMENDATIONS

14 Based on my analysis completed to date, my recommendations are as follows:

- 15 • Correct the HQD hourly cost allocation methodology for a mis-allocation of  
16 stranded costs. If this correction does not produce allocation results that are  
17 reasonably consistent with the results for the R-3610-2006 proceeding, replace  
18 the hourly cost allocation methodology with unit costs that are proportional to  
19 HQD's longer-term avoided generation costs;
- 20 • Continue to use the ICP method for allocating transmission costs, until the Régie  
21 determines how transmission cost causation should most reasonably be reflected  
22 in transmission rates, in the context of a transmission rate proceeding;
- 23 • Allocate PGEÉ costs using the direct assignment method, unless and until the  
24 inter-class cost allocation effects can be properly reflected in an avoided cost  
25 allocation method;
- 26 • Assign different rate increases to the various classes, based on maintaining a  
27 constant level of cross-subsidies consistent with the Régie's D-2007-12 decision;
- 28 • Establish a procedure for monitoring dollar cross-subsidy changes by rate class,  
29 beginning with the R-3610-2006 proceeding;
- 30 • Assign the entire Rate L increase to the demand charges in that tariff, or, in the  
31 alternative, establish a collaborative effort between HQD and large industrial  
32 customers to evaluate the potential for segregating the Rate L class between large  
33 industrial loads and other customers.
- 34 • If it is deemed necessary, begin a collaborative effort between HQD, large  
35 industrial customers, and other interested parties to evaluate a potential stepped  
36 rate for Rate L, and its implications for the allocation of patrimonial loads.

EXHIBIT IEc-1

*CURRICULUM VITAE AND  
EXPERT TESTIMONY SCHEDULE  
OF  
ROBERT D. KNECHT*

## 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. His practice currently focuses primarily on utility regulation, and he has provided analysis and expert testimony in numerous U.S. and Canadian jurisdictions. In addition, as Treasurer of IEc since 1995, 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 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, fair rate of return, claimed utility expenses, cost allocation methods and rate design issues.
- For independent power producers and industrial customers in Alberta, Mr. Knecht has provided analysis and expert testimony in a variety of electric industry proceedings, including industry restructuring, cost unbundling, stranded cost recovery, transmission rate design, cost allocation and rate design.
- For industrial customers in Québec, Mr. Knecht has prepared economic analysis and expert testimony in regulatory proceedings regarding cost allocation, compliance with legislative requirements for cross-subsidization, and rate design.
- As part of international teams of experts, Mr. Knecht has prepared the economic and financial analysis for industry restructuring studies involving the steel and iron ore industries in Venezuela, Poland, and Nigeria.
- For the U.S. Department of Justice and for several private sector clients, Mr. Knecht has prepared analyses of economic damages in a variety of litigation matters, including ERISA discrimination, breach of contract, fraudulent conveyance, natural resource damages and anti-trust cases.
- Mr. Knecht participates in numerous projects with colleagues at IEc preparing economic and environmental analyses associated with energy and utility industries for the U.S. Environmental Protection Agency.

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.

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INDUSTRIAL ECONOMICS, INCORPORATED

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
P-00072305	Pennsylvania Public Utility Commission	Pennsylvania Power Corporation	July 2007	Pennsylvania Office of Small Business Advocate	Default electric service procurement.
R-00072334	Pennsylvania Public Utility Commission	UGI Penn Natural Gas, Inc.	July 2007	Pennsylvania Office of Small Business Advocate	Asset management arrangement, gas procurement.
R-00072333	Pennsylvania Public Utility Commission	PPL Gas Utilities Corporation	July 2007	Pennsylvania Office of Small Business Advocate	Design day forecasting, gas procurement.
R-00072155	Pennsylvania Public Utility Commission	PPL Electric Utilities Corporation	July 2007	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design, energy efficiency.
R-00049255 (Remand)	Pennsylvania Public Utility Commission	PPL Electric Utilities Corporation	May 2007	Pennsylvania Office of Small Business Advocate	Revenue allocation
R-00072175	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania, Inc.	May 2007	Pennsylvania Office of Small Business Advocate	Gas procurement.
R-00072110	Pennsylvania Public Utility Commission	Philadelphia Gas Works	April 2007	Pennsylvania Office of Small Business Advocate	Gas procurement, margin sharing mechanisms.
R-00061931	Pennsylvania Public Utility Commission	Philadelphia Gas Works	April 2007	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, retail gas competition
P-00072245	Pennsylvania Public Utility Commission	Pike County Light & Power Company	March 2007	Pennsylvania Office of Small Business Advocate	Default service procurement, rate design
R-00072043	Pennsylvania Public Utility Commission	National Fuel Gas Distribution Company	March 2007	Pennsylvania Office of Small Business Advocate	Design day requirements
C-20065942	Pennsylvania Public Utility Commission	Pike County Light & Power Company	November 2006	Pennsylvania Office of Small Business Advocate	Wholesale power procurement by provider of last resort
R-3610-2006	Régie de l'Énergie, Québec	Hydro Québec Distribution	November 2006	AQCIE/CIFQ	Post-patrimonial generation cost allocation; cross-subsidization; rate design
P-00052188	Pennsylvania Public Utility Commission	Pennsylvania Power Company	September 2006	Pennsylvania Office of Small Business Advocate	Affidavit: POLR rates, wholesale to retail.

## EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
R-00061493	Pennsylvania Public Utility Commission	National Fuel Gas Distribution Corporation	September 2006	Pennsylvania Office of Small Business Advocate	Rate of return, load forecasting, cost allocation, revenue allocation, rate design, revenue decoupling.
R-00061398	Pennsylvania Public Utility Commission	PPL Gas Utilities Corporation	August 2006	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design
R-00061365	Pennsylvania Public Utility Commission	PG Energy/Southern Union Company	July 2006	Pennsylvania Office of Small Business Advocate	Merger savings, cost allocation, revenue allocation, rate design.
R-00061519	Pennsylvania Public Utility Commission	PPL Gas Utilities Corporation	July 2006	Pennsylvania Office of Small Business Advocate	Design day weather and throughput forecasts; gas supply hedging.
R-00061518	Pennsylvania Public Utility Commission	PG Energy/Southern Union Company	July 2006	Pennsylvania Office of Small Business Advocate	Design day weather and throughput forecasts; gas supply hedging.
A-125146	Pennsylvania Public Utility Commission	UGI Utilities, Inc., Southern Union Company	June 2006	Pennsylvania Office of Small Business Advocate	Public benefits of proposed sale of PG Energy to UGI; asset management agreement.
R-00061355	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2006	Pennsylvania Office of Small Business Advocate	Gas supply and hedging plan; procedural issues
R-00061296	Pennsylvania Public Utility Commission	Philadelphia Gas Works	April 2006	Pennsylvania Office of Small Business Advocate	Gas procurement and procedural issues.
R-00061246	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	March 2006	Pennsylvania Office of Small Business Advocate	Gas procurement; unaccounted for gas retention rates
2005-002 Refiling	New Brunswick Board of Commissioners of Public Utilities	New Brunswick Power Distribution and Customer Service Company	February 2006	New Brunswick Public Intervenor	Cost allocation, rate design
P-00052188	Pennsylvania Public Utility Commission	Pennsylvania Power Company	December 2005	Pennsylvania Office of Small Business Advocate	Cost allocation and rate design for POLR supplies.
R-3579-2005	Régie de l'Énergie, Québec	Hydro Québec Distribution	November 2005	AQCIE/CIFQ	Generation cost allocation; cross-subsidization; revenue allocation
2005-002	New Brunswick Board of Commissioners of Public Utilities	New Brunswick Power Distribution and Customer Service Company	August 2005	New Brunswick Public Intervenor	Cost allocation, rate design
R-00050538	Pennsylvania Public Utility Commission	PG Energy	July 2005	Pennsylvania Office of Small Business Advocate	Gas procurement diversification

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
R-00050540	Pennsylvania Public Utility Commission	PPL Gas Utilities Corporation	July 2005	Pennsylvania Office of Small Business Advocate	Gas procurement, hedging, retention rates, sharing mechanism
R-00050340	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2005	Pennsylvania Office of Small Business Advocate	Gas procurement, hedging and diversification.
R-3563-2005	Régie de l'Énergie, Québec	Hydro Québec Distribution	April 2005	AQCIE/CIFQ	Generation cost allocation; industrial demand response
R-00050264	Pennsylvania Public Utility Commission	Philadelphia Gas Works	April 2005	Pennsylvania Office of Small Business Advocate	Gas procurement, risk hedging, financing costs in the gas cost rate.
R-00050216	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	March 2005	Pennsylvania Office of Small Business Advocate	Gas supply procurement and forward pricing policies.
EB-2004-0542	Ontario Energy Board	Union Gas Limited	March 2005	Tribute Resources Inc.	Cost allocation and rate design for service to embedded storage pools.
R-00049884	Pennsylvania Public Utility Commission	Pike County Light and Power (Gas Service)	January 2005	Pennsylvania Office of Small Business Advocate	Fair rate of return, cost allocation, class revenue assignment.
R-00049656	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	December 2004	Pennsylvania Office of Small Business Advocate	Fair rate of return, uncollectibles costs, automatic rate adjustments, cost allocation, rate design.
R-3541-2004	Régie de l'Énergie, Québec	Hydro Québec Distribution	November 2004	AQCIE, CIFQ	Allocation of post-patrimonial generation costs.
C-20031302	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	July 2004	Pennsylvania Office of Small Business Advocate	Customer assistance program funding and cost allocation.
R-049255	Pennsylvania Public Utility Commission	PPL Electric Utilities Corporation	June 2004	Pennsylvania Office of Small Business Advocate	Transmission and distribution cost allocation, rate design, automatic distribution increases.
P-042090 et al.	Pennsylvania Public Utility Commission	Philadelphia Gas Works	June 2004	Pennsylvania Office of Small Business Advocate	Collections and universal service cost issues.
RP-2003-0203	Ontario Energy Board	Enbridge Gas Distribution	May 2004	Vulnerable Energy Consumers Coalition et al.	Cost allocation, rate design for pipeline and storage costs
R-049157 P-042090	Pennsylvania Public Utility Commission	Philadelphia Gas Works	April 2004	Pennsylvania Office of Small Business Advocate	Cash receipts reconciliation clause

## EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
R-049108	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	March 2004	Pennsylvania Office of Small Business Advocate	Uncollectible cost responsibility for standby charges
Application 1306819	Alberta Energy and Utilities Board	ENMAX Power Corporation	January 2004	Calgary Industrial Group Calgary Building Owners	T&D cost allocation, rate design, ratepayer equity funding
R-3492-2002 Phase 2	Régie de l'Énergie, Québec	Hydro Québec Distribution	November 2003	AQCIE, CIFO	Rate policy, cross-subsidization
R-038168	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	July 2003	Pennsylvania Office of Small Business Advocate	Cost allocation, deficiency assignment, rate design, pension cost reconciliation, rate of return
R-3492-2002 Phase 1	Régie de l'Énergie, Québec	Hydro Québec Distribution	January 2003	AQCIE, AIFO	Cost allocation; maintenance of historical cross-subsidization
M-021612	Pennsylvania Public Utility Commission	Philadelphia Gas Works	September 2002	Pennsylvania Office of Small Business Advocate	Natural gas restructuring, cost allocation, rate unbundling
R-027385	Pennsylvania Public Utility Commission	PG Energy (Southern Union)	July 2002	Pennsylvania Office of Small Business Advocate	Purchased gas cost incentive mechanisms.
1250932	Alberta Energy and Utilities Board	Aquila Networks Canada (Alberta) Ltd.	July 2002	Senior Petroleum Producers Association	Distribution plant and cost allocation, rate design.
R-027204	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2002	Pennsylvania Office of Small Business Advocate	Purchased gas cost incentive mechanisms, rate design
R-3477-2001	Régie de l'Énergie, Québec	Hydro Québec Distribution	May 2002	AQCIE, AIFO	Classification/allocation of generation costs, subject to constant unit cost constraint.
1248859	Alberta Energy and Utilities Board	ESBI Alberta Limited	March 2002	IPPSA	Transmission congestion management principles
R-016378	Pennsylvania Public Utility Commission	Philadelphia Gas Works	August 2001	Pennsylvania Office of Small Business Advocate	Cost of gas; commodity price forecasting
R-016179	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 (ACIG)	Tariff unbundling

## EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
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
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.

## EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
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.
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 surrebuttal.
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 surrebuttal.
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.
Generic Hearing #4	Board of Commissioners of Public Utilities, New Brunswick	New Brunswick Power Corporation	November 1991	Large Power Users Group	Review of cost allocation and rate design.
EBRO-473	Ontario Energy Board	Consumers' Gas Company, Ltd.	October 1991	Ontario Energy Board Staff	Cost allocation and rate design



INDUSTRIAL ECONOMICS, INCORPORATED

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
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	PEI 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.

EXHIBIT IEc-2

*ALLOCATION OF PGEÉ COSTS*  
*TWO-CLASS EXAMPLE*

EXHIBIT Iec-2

ALLOCATIVE IMPLICATIONS OF DEMAND SIDE MANAGEMENT PROGRAMS: SCENARIO ANALYSIS

	Base Case Scenario			Scenario 1: Reduce Residential Load by 500 MW for 3000 Winter Hours			Scenario 2: Reduce Industrial Load by 180 MW for All Hours @ 95% LF		
	Residential	Industrial	Total	Residential	Industrial	Total	Residential	Industrial	Total
Total Load (GWh)	60,000	40,000	100,000	58,500	40,000	98,500	60,000	38,502	98,502
Patrimonial	54,000	36,000	90,000	53,452	36,548	90,000	54,821	35,179	90,000
Post-Patrimonial	6,000	4,000	10,000	5,048	3,452	8,500	5,179	3,323	8,502
Load Factor	50.0%	95.0%	61.7%	50.6%	95.0%	62.5%	50.0%	95.4%	61.4%
Energy Loss Factor	9.1%	5.6%	7.700%	9.1%	5.6%	7.679%	9.1%	5.6%	7.732%
Demand Loss Factor	9.1%	5.6%	8.191%	9.1%	5.6%	8.166%			8.219%
Peak Demand (MW)	13,699	4,807	18,505	13,199	4,807	18,005	13,699	4,607	18,305
Patrimonial Unit Cost	\$ 30.51	\$ 23.48	\$ 27.70	\$ 30.48	\$ 23.64	\$ 27.70	\$ 30.46	\$ 23.39	\$ 27.70
Post-Patrimonial Unit Cost	\$ 90.00	\$ 90.00	\$ 90.00	\$ 90.00	\$ 90.00	\$ 90.00	\$ 90.00	\$ 90.00	\$ 90.00
Total (\$/MWh)	\$ 36.46	\$ 30.13		\$ 35.61	\$ 29.37		\$ 35.60	\$ 29.14	
Patrimonial Cost	1,648	845	2,493	1,629	864	2,493	1,670	823	2,493
Post-Patrimonial Cost	540	360	900	454	311	765	466	299	765
Total (\$mm)	2,188	1,205	3,393	2,083	1,175	3,258	2,136	1,122	3,258
T&D Energy	486	314	800	481	319	800	493	307	800
T&D Demand	746	254	1,000	739	261	1,000	754	246	1,000
T&D Customer	1,000	-	1,000	1,000	-	1,000	1,000	-	1,000
<b>Total Costs (\$mm)</b>	<b>4,420</b>	<b>1,773</b>	<b>6,193</b>	<b>4,304</b>	<b>1,754</b>	<b>6,058</b>	<b>4,384</b>	<b>1,674</b>	<b>6,058</b>
<b>Change in Costs</b>				<b>(116)</b>	<b>(19)</b>	<b>(135)</b>	<b>(36)</b>	<b>(99)</b>	<b>(135)</b>

EXHIBIT IEc-3

*ANALYSIS OF CUMULATIVE CHANGES IN  
CROSS-SUBSIDIES AMONG RATE CLASSES*

**EXHIBIT IEC-3**

**ANALYSIS OF CUMULATIVE CHANGES IN CROSS-SUBSIDIES**

	<b>Increase with No Change in Cross- Subsidy</b>	<b>Régie Approved Increase</b>	<b>Increase in Cross- Subsidy (Percent)</b>	<b>Base Revenues (\$mm)</b>	<b>Increase in Cross- Subsidy (\$mm)</b>
<b>2007 Test Year</b>					
Domestique	2.80%	1.92%	-0.88%	4,050	(35.6)
Petite Puissance	1.70%	1.92%	0.22%	1,275	2.8
Moyenne Puissance	1.10%	1.92%	0.82%	1,830	15.0
Grande Puissance	1.00%	1.92%	0.92%	1,971	18.1
<b>Total</b>	<b>1.92%</b>	<b>1.92%</b>	<b>0.00%</b>	<b>9,126</b>	<b>0.3</b>

		<b>HQD Proposed Increase</b>			
<b>2008 Test Year</b>					
Domestique	4.4%	2.9%	-1.5%	4,165	(60.6)
Petite Puissance	0.9%	2.9%	2.0%	1,294	26.1
Moyenne Puissance	2.6%	2.9%	0.3%	1,879	5.0
Grande Puissance	1.4%	2.9%	1.6%	1,929	30.0
<b>Total</b>	<b>2.91%</b>	<b>2.91%</b>	<b>0.00%</b>	<b>9,267</b>	<b>0.4</b>

**2008 Increase to Reverse 2007/2008 Cross-Subsidy Changes**

	<b>Gross</b>	<b>Less 2007</b>	<b>Net 2008</b>	<b>Proposed Revenue</b>
Domestique	7.28%	1.92%	5.26%	4,384
Petite Puissance	2.64%	1.92%	0.70%	1,303
Moyenne Puissance	3.74%	1.92%	1.78%	1,913
Grande Puissance	2.36%	1.92%	0.44%	1,937
<b>Total</b>	<b>4.89%</b>	<b>1.92%</b>	<b>2.91%</b>	<b>9,537</b>

**Sources**

HQD-15 Document 4, Tables R-22 c) and R-22 d), pages 60-61.  
R-3610-2006, HQD-12, Document 1, Table 28.

Note: It is not clear why HQD's cross-subsidy change figures do not total to zero, but the difference is likely due to rounding and adjustments for the differences between test year and rate revenue years. The effects of this discrepancy are small.

EXHIBIT IEc-4

*PARTIAL AND FULL PLANT CLOSURES  
IN QUÉBEC*

**EXHIBIT IEC-4  
LARGE INDUSTRIAL PLANT CLOSURES**

<b>Facility</b>	<b>Location</b>	<b>Year</b>	<b>Complete</b>	<b>Partial</b>
<b>Fonte et affinage</b>				
Norsk Hydro Canada Inc.	Becancour	2007	X	
<b>Divers manufacturiers</b>				
Goodyear Canada, Inc.	Salaberry-Valleyfield	2007		X
<b>Industrie du bois</b>				
Louisiana Pacific Canada Ltée	St-Michel-Des-Saints	2006	X	
<b>Métaux - autres</b>				
CFA Société en Commandite	Granby	2005	X	
Wolverine Tube (Canada) Inc.	Montreal Est	2006	X	
<b>Pâtes et papiers</b>				
Domtar	Lebel sur Quevillon	2005	X	
Katahdin Pâte Québec Inc.	Port-Cartier	2006		X
Cascades Canada Inc.	Jonquiere	2006		X
Bowater Forest Products	Dolbeau	2007		X
Bowater Forest Products	Gatineau	2007		X
Kruger Wayagamack Inc.	Trois-Rivieres	2007		X
Domtar Inc.	Gatineau	2007	X	
Smurfit Stone	New Richmond	2005	X	
<b>Textiles</b>				
Les Services Drummondville Inc.	Drumondvill	2006	X	
<b>Minéraux non métalliques</b>				
Owens Corning Canada	Candiac	2007	X	
<b>Industries chimiques</b>				
Basell Canada Inc.	Varenes	2008	X	
<b>Sidérurgie</b>				
Domfer Poudres Métalliques Ltée	Montréal	2007	X	
Source: AQCIE, CIFQ				