RÉGIE DE L'ÉNERGIE

HYDRO-QUÉBEC DISTRIBUTION'S
RATE APPLICATION
FOR 2008-2009

FILE: R-3644-2007

EVIDENCE OF

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ON BEHALF OF:
OPTION CONSOMMATEURS

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1 INTRODUCTION

On August 1st, 2007 Hydro-Québec Distribution (HQD) filed an Application with the Régie de l'énergie (the "Régie") for approval of a revised revenue requirement and distribution rates effective April 1st, 2008. The Application requests approval for a revenue requirement of $10,542 M based on a 2008 test year, which translates into an average overall rate increase of 2.9%[1]. The Application also includes a cost allocation study that allocates the requested revenue requirement to customer classes and proposes a 2.9% increase for all customer classes. Finally, the Application includes a proposed set of rates for each customer class that continues the rate design evolution initiated in earlier proceedings, along with a request for approval of a residential time of use (TOU) rate pilot project.

2 PURPOSE OF EVIDENCE

After reviewing HQD's Application and the Procedural Order[2] issued by the Régie, Option Consommateurs (OC) retained Econalysis Consulting Services (ECS), a Canadian consulting firm offering regulatory services to clients in the electricity and natural gas sectors to provide evidence that would assist OC and the Régie in assessing various aspects of HQD's proposal.

The Evidence was prepared by Bill Harper who, prior to joining ECS in July 2000, worked for over 25 years in the energy sector in Ontario, first with the Ontario Ministry of Energy and then, with Ontario Hydro and its successor company Hydro One. Since joining ECS, he has assisted various clients participating in regulatory proceedings on issues related to electricity and natural gas utility revenue requirements, cost allocation/rate design and supply planning. Mr. Harper has served as an expert witness in public hearings before the Manitoba Public Utilities Board, the Manitoba Clean

[1] HQD-1, Document 1, pages 5-6
[2] D-2007-96

Environment Commission, the Régie, the Ontario Energy Board, the Ontario Environmental Assessment Board and a Select Committee of the Ontario Legislature on matters dealing with electricity regulation, rates and supply planning. His most recent experience with cost allocation and rate design matters includes:

- The preparation of evidence and appearance as an expert witness on behalf of OC in the Régie proceeding (R-3541-2004) dealing with HQD's rate design proposals for 2005.
- The preparation of evidence and appearance as an expert witness on behalf of OC in the Régie proceedings (R-3579-2005 and R-3610-2006) dealing with HQD's cost allocation and rate design proposals for 2006 and 2007.
- The preparation of evidence and appearance as an expert witness before the Manitoba Public Utilities Board with respect to its review of proposals filed by Manitoba Hydro in both 2002 and 2004 regarding cost allocation and rate design.
- The preparation of evidence and appearance as an expert witness before the Manitoba Public Utilities Board with respect the Board's Generic Review of Manitoba Hydro's 2006 Cost Allocation Proposals.
- Providing expert evidence and support to clients regarding BC Hydro's 2006 Application for Experimental Residential Time of Use Rates.
- Providing expert advice and support to clients in British Columbia participating in the BCUC proceeding dealing with BCHydro's 2007 Rate Design Application[3].
- Member of the OEB's 2005/06 Technical Advisory Team regarding cost allocation and rate design for Ontario electricity distributors.

A full copy of Mr. Harper's CV is attached in Appendix A.

The evidence specifically addresses the following aspects of HQD's Application:

- HQD's determination of the account balances for the Pass-On and Transmission Deferral Accounts.

[3] The Application, which also included a proposed cost allocation methodology, was filed with the BCUC on March 15, 2007. An Interim Order (Order G-111-07) was issued by the BCUC on September 20, 2007.

- HQD's proposed recovery plans for the Pass-On and Transmission Deferral Account balances,
- HQD's proposed cost allocation methodology changes, including PGEÉ costs, Transmission costs and various deferral account refund/recoveries.
- HQD's methodology for assessing the need for differentiated rate increases by customer class.
- HQD's proposed rate design changes for the residential customer class.
- HQD's proposed residential time of use pilot project.

Applicable comments are noted throughout the text and summarized in the concluding section.

3 PROPOSED TREATMENT OF SELECT DEFERRAL/VARIANCE ACCOUNTS

HQD has a number of Deferral/Variance Accounts which have been authorized by past decisions of the Régie[4]. For two of these accounts, namely the Pass-On Account for the purchase of Post-Heritage Electricity Supply and the Transmission Deferral Account, HQD is proposing changes in terms of how the balances are determined and/or recovered.

3.1 Pass-On Account for Post-Heritage Electricity Supply

3.1.1 Determination of Account Balances

Background

The Pass-On Account tracks the differences between forecast and actual supply costs (associated with both Heritage[5] and Post-Heritage Pool supplies) and records these in a deferral account for future refund/recovery. Approval for such an account was first

[4] HQD-9, Document 1, page 6
[5] Due to unutilized Heritage Supply

requested by HQD as part of its R-3541-2004 Application[6]. Under the proposal, the calculation of the variance would reflect (and report separately) the changes in cost of supply due to variations in volumes required and variations in the average cost of Post-Heritage supply. The account would also capture variances between forecast and actual revenues due to volume changes. In its decisions following the proceeding[7], the Régie ultimately adopted HQD's proposals and ordered that the information on the variances be collected on a monthly basis.

As part of its R-3610-2006 Application, HQD proposed[8] that the variance be calculated on an annual (as opposed to a monthly) basis. Furthermore, since the variance would be established on an annual basis, no interest would be accrued on the account (for the current year) until after year-end. In its subsequent Decision[9], the Régie approved this revised approach. However, in the same Decision, the Régie expressed concern regarding the possibility of large variances, particularly related to weather. It requested that HQD explain why it was not possible to distinguish between weather and demand driven variances[10].

HQD Proposal

In its current Application, HQD has addressed the Régie's request regarding the separation of weather and demand variances and concluded that it was not practical to separately distinguish these amounts in the Pass-On Account[11]. The Distributor has also put forward[12] three proposed changes to the Pass-On Account calculation:

i. HQD has identified the need to incorporate in the Pass-On Account balance for a particular year the billed/delivered adjustments that will only be known towards the end of the following year. The timing is such that impact of this adjustment

[6] See R-3541-2004, HQD-5, Document 3
[7] D-2005-34 and D-2005-132
[8] R-3610-2006, HQD-4, Document 2, page 8 and HQD-16, Document 1 Question 23.1
[9] D-2007-12, page 19
[10] D-2007-12, page 18
[11] HQD-4, Document 2, page 7
[12] HQD-4, Document 2, pages 19-23

on the Pass-On Account balance can only be factored into rates for the third year following the year concerned (e.g., the final billed/delivered adjustment for 2005 is not available until the end of November 2006 and, therefore, can not be considered (for rate setting purposes) until the filing made in mid-2007 for 2008 rates)[13].

ii. In previous filings the revenue deviation associated with the Pass-On Account was calculated based on the average projected cost of Heritage and Post-Heritage supply. However, for 2007 (and subsequent years) the cost of supply includes not only the projected cost of Heritage and Post-Heritage supply but also planned refund/recoveries of the Pass-On Account balances. HQD proposes that the unit revenue value used to determine the revenue deviation in the Pass-On Account should also take into account these refunds/recoveries[14].

iii. In previous proceedings, the Régie authorized[15] the creation of a deferral account to specifically track the variation between the fixed and variable interruptible option credits that were included in the setting of rates for a particular year versus the actual credits paid out. In the current Application, HQD has proposed to change the calculation of interest accrued to the Interruptible Account so that it is the same as that for the Pass-On Account. Interest on both accounts would be accrued starting January 1st of the subsequent year. HQD has also, since the effect is now captured separately, excluded the cost of the fixed and variable interruptible options credits from the cost of supply for purposes of determining the Pass-On Account balances[16].

Comments

In its evidence, HQD puts forward three reasons why it is impractical to separate weather and demand variances[17]. Of these reasons, the most compelling, is the one

[13] HQD-4, Document 2, pages 19-20
[14] HQD-4, Document 2, pages 20-22 and HQD-15, Document 1, Question 33.1
[15] D-2003-224, D-2004-213 and D-2006-149, page 10-11
[16] HQD-4, Document 2, page 24
[17] HQD-4, Document 2, pages 7-10

regarding the supply response to variations in load. As HQD explains, supply management takes place in real time and, within that timeframe, does not necessarily concern itself with whether the reason for a variation in demand is due to weather or other factors or a combination of the two.

In attempting to separate out the two effects, it is necessary to make assumptions regarding what supply actions were used to respond specifically to the portion of the load variation attributable to weather versus the variation attributable to other factors. This applies both to the selection of Heritage supply and the dispatch of Post-Heritage supplies. Also, the costs of the Post-Heritage supplies associated with each variance are likely to be different depending upon which supply actions are associated with weather driven versus demand driven variations in supply volumes required. For the Technical Working Group deliberations, HQD attempted to overcome these issues by making some simplifying assumptions. However, HQD claimed that the results were sometimes illogical[18].

Indeed the observation that the Pass-On Account attributable to weather can depend on how the calculation is performed is clearly demonstrated by the evidence provided by HQD in R-3610-2006:

- In response to an information request[19] from Régie staff, HQD initially estimated the impact of weather on the 2006 Pass-On Account balance by taking the difference between the projected Pass-On Account balance and a Pass-On Account balance calculated based on normal weather volumes. Using this approach the impact to weather variation was found to be $142.0 M, excluding Special Contracts.
- In a subsequent response[20], HQD calculated the weather impact based on the volume variance by customer class due to weather and concluded that the impact of weather variation was $161.3 M, excluding Special contracts.

[18] HQD-4, Document 2, pages 9-10
[19] R-3610-2006, HQD-16, Document 1, page 33
[20] R-3610-2006, HQD-16, Document 1.1, page 5

Thus while calculations can be performed by HQD to separate out weather impacts on the Pass-On Account balance, they should, at best, be considered as approximations.

HQD's three proposed adjustments to the calculation of the Pass-On Account balances all appear to be reasonable. The need to incorporate the final billed/delivered adjustment for a given year delays the final recovery for another rate year. However, since the adjustment does impact on HQD's overall financial results[21], it is appropriate to capture in the Pass-On Account. Furthermore, HQD has indicated that it is considering ways of shortening the delay in the adjustment[22].

The inclusion of any Pass-On Account refund/recovery in the determination of the unit revenue values used to determine the Pass-On Account balance is appropriate as it means that the balance for a given year will capture not only the variations in supply cost for that year but also any over/under refund/recovery of previous years' Pass-On Account balances. Without the unit revenue adjustment there would be a need to separately track the actual amounts refunded or recovered through rates in order to allow for a final reconciliation against the Pass-On Account balances.

In reality, the interruptible option can be viewed as another Post-Heritage supply option. As a result, it is reasonable that the associated deferral account be treated in a similar manner as the Pass-On Account. Indeed, it may be reasonable to merge the two deferral accounts at some future point in time.

[21] HQD-15, Document 8, Question 27 e)
[22] HQD-15, Document 1, Question 33.3

3.1.2 Recovery of Pass-On Account Balances

Background

In its R-3579-2005 Application[23], HQD expressed a preference for calculating the actual Pass-On Account at year end, based on actual data, and integrating the results into the rate filing for the second financial year subsequent to the year end. The rationale offered was that while this approach delayed the recovery of the costs differences posted to the Pass-On Account, certain variances are not known until year end and the mid-year calculation is subject to adjustment and change. As a result, the Application did not include any proposed refund/recovery of the mid-year 2005 balances calculated for the Pass-On Account. In its decision D-2006-34, the Régie accepted HQD's proposal that the integration method for the Pass-On Account should be based on actual data covering a 12 month period (January to December) and directed HQD to provide proposals for recovery of the 2005 balance in its next rate case[24].

In last year's R-3610-2006 Application, HQD proposed to dispose of both the actual balance in the Pass-On Account determined for 2005 (i.e., debit of $36 M including interest) and the forecast balance determined for 2006[25]. In its Decision, the Régie agreed that it was preferable to take into account values based on four real months and eight projected months with regards to variances in the Pass-On Account as it improves intergenerational equity and reduces interest costs[26]. HQD was directed to adopt this approach in future filings[27] on a permanent basis. In its Decision, the Régie also

[23] R-3579-2005, HQD-4, Document 3
[24] D-2006-34, pages 21-23
[25] At the time of the Application the Pass-On Account balance for 2006 was estimated to be $182 M (excluding special contracts) based on four months real and eight months projected. During the proceeding this value was updated to $250.9 M based on nine months real and three months projected. See R-3610-2006, HQD-16, Document 1.1, Question 1.3
[26] D-2007-12, page 16
[27] On an exception basis, the Régie directed HQD to use the $251 M reflecting nine months real and three months forecast in setting 2007 rates.

directed HQD to explore options to protect customers from significant fluctuations in the Pass-On Account, particularly due to weather variances[28].

HQD Proposal

In its current Application, HQD is forecasting a 2007 Pass-On Account balance of $7.5 M based on four months real/eight months forecast and, as directed by the Régie, has included the recovery of this amount in the proposed 2008 rates. In addition, HQD has finalized the 2006 Pass-On Account balance based on 12 month of actual sales and the results are a credit of $261.7 M (compared to the $251 M included in 2007 rates). HQD is proposing that the difference plus interest ($11.5 M) be returned to customers in the 2008 rates. Finally, HQD has estimated that the billed/delivered adjustment for the last half of 2005 reduces the Pass-On Account for that year by $5.5 M. HQD is proposing to credit this amount plus interest ($6.8 M in total) to customers through the 2008 rates. Overall, the total Pass-On Account adjustment included in rates for 2008 is a credit of $10.8 M[29].

HQD is also proposing to recover, in its 2008 rates, $4.2 M in deferred costs associated with interruptible power options recorded for 2006 and projected for 2007[30], based on four months of actual and eight months of forecast data.

Finally, in its Application, HQD has also addressed the Régie's direction that consideration be given to ways of stabilizing the impact of fluctuations in the Pass-On Account, particularly those due to weather. In its Evidence HQD concludes that there is no way of systematically approaching the treatment of the Pass-On Account balance that would promote rate stability. Instead, HQD has concluded that the issue of rate stability should be addressed on a case by case basis that recognizes the different

[28] D-2007-12, page 18
[29] HQD-4, Document 2, page 32
[30] HQD-9, Document 1, page 17

situations that can arise[31]. In this regard, HQD's proposed approach is to, in the interest of intergenerational equity, put first priority on the recovery of any balance in the Pass-On Account. However, if the rate impact of full cost recovery on rates is too severe then HQD seeks to be afforded the flexibility to propose an amelioration of the impacts by amortizing the recovery over several years[32].

Comments

HQD's proposal for recovery of the Pass-On Account balance is consistent with the Régie's direction from D-2007-12. Furthermore, the proposal to align the recovery of the balances in the Interruptible Account with the approach used for the Pass-On Account is reasonable. The interruptible power options can be viewed as an alternative to other Post-Heritage supply options and, as such, variations between forecast and actual costs should be treated in a similar manner. Finally, given the small size of the total credit balance for 2007 year end ($6.6 M[33]), there is no need to consider deferring any of the refund beyond 2008.

HQD's conclusions regarding mechanisms for stabilizing the impact of the Pass-On Account recovery on rates are also reasonable. In its Evidence, HQD explored two different approaches to stabilization. The first focused on mechanisms that could stabilize the weather effect on the Pass-On Account; while the second looked at mechanisms for stabilizing the overall impact of the Pass-On Account recovery on rates.

One possible mechanism considered for stabilizing the "weather effect" was to treat such effects in the same manner as the weather effects on transmission and distribution revenues are treated, i.e., track them in a variance account with the expectation that the balance will average out over time. However, it has already been noted that HQD can

[31] HQD-4, Document 2, page 17, line 21 to page 18, .line 3 and HQD-15, Document 8, Question 26 c)
[32] HQD-16, Document 8, Question 26 a)and c)
[33] HQD-11, Document 3, Table 9C and HQD-9, Document 1, pages 12-13 and 17. (Includes both Pass-On Account and Interruptible Account)

not clearly distinguish cost variances in the Pass-On Account arising due to weather as oppose to other sources of variation in demand. Furthermore, even if it could be done, it's is unlikely that the variations would average out overtime.

In the case of the Temperature Averaging account such an expectation is reasonable as the volume variations will average out over time and the impact on revenues is symmetric[34] – i.e., the same "rates" are used to establish over and under recoveries. However, in the case of the Pass-On Account, the balance is impacted not only by volume and revenue variations but also by variations in the cost of supply. Furthermore, supply cost impacts are not likely to be symmetric, i.e., the cost of meeting increased supply volumes is not likely to be the same (cents/kWh) as the savings from reduced supply volumes. This is because different supply options may be used to each case. As a result, there is no a priori expectation that the weather impacts on the Pass-On Account will "cancel out" over time.

Another approach explored by HQD[35] was to consider whether the weather effects on the Pass-On Account would "offset" the weather effects on the Temperature Averaging Account. However, since the weather effects on the Pass-On Account do not necessarily average out overtime, one can not expect the combination of the Pass-On Account and the Temperature Averaging Account to do so. The need to eventually clear any systematic bias would eventually lead to rate instability. Furthermore, during the technical sessions, HQD demonstrated that the effects of the two are not always offsetting[36].

Overall, HQD's claim that there is no reasonable expectation that the weather impacts on the Pass-On Account are self-correcting and can be removed from the normal refund/recovery considerations is credible.

[34] HQD-4, Document 2, page 10 and R-3579-2005, HQD-4, Document 4, pages 18-20
[35] HQD-4, Document 2, pages 11-12
[36] HQD-4, Document 2, page 12

As an alternative, HQD considered whether a formal mechanism could be introduced to stabilize the year over year impact of the total Pass-On Account refund/recovery on rates. All three of the mechanisms considered highlight the following:

- Any mechanism that defers and amortizes over more than just the next rate year some of the refund/recovery of the Pass-On Account balance creates issues with respect to inter-generational equity.
- Any rule/mechanism that focuses simply on the balance in the Pass-On Account will ignore the fact that consumers are concerned with the stability of the overall rate level, which will be influenced (up or down) by a host of other factors.

As a result, the potential exists that any rule or systematic approach adopted for purposes of stabilizing the rate impact attributable to the refund/recovery of the Pass-On Account could actually achieve the opposite effect. It could result in deferring refund/recovery when it is unnecessary for purposes of rate stability. In addition, unless the thresholds are low and the amortization periods extremely long, a mechanistic approach could still result in rate instability when combined with other factors. However, such a mechanism would be inconsistent with the principle of inter-generational equity. In conclusion, HQD's proposed approach appears reasonable.

As a final comment, it should be noted that the consideration of this issue was triggered by the size of the 2006 Pass-On Account balance. However, in this regard, there are two points worth noting. The first is that the large 2006 Pass-On Account variance was due in part to the extreme climate variance experienced in 2006[37]. In contrast, the total Pass-On Account balance for 2007 is significantly smaller. Second, while the Pass-On Account balance for 2006 was extraordinary, there were other offsetting events (i.e., the need to recover the Transmission Account balance) that meant full refund of the Pass-On Account balance would not lead to rate instability but rather facilitate cost recovery by HQD. Both of these points further illustrate the reasonableness of HQD's proposed approach.

[37] HQD-2, Document 2, page 6

3.2 Transmission Deferral Account

3.2.1 Determination of Account Balances

Background

Following R-3492-2002, the Régie approved[38] the creation of a deferral account to track the differences between the actual cost of transmission services (charged to HQD by HQT) and the costs included in rates. In April 2006, the Régie approved new rates for Transmission, including an increase in the charge to Native Load Service (i.e., HQD) retroactive to January 1, 2005[39]. Due to the timing, these increased Transmission charges ($170 M/ annum) were not included in HQD's application for rates effective April 1st, 2005 or April 1st 2006. Instead, the charges, totaling $340 M, were recorded in the Transmission Deferral Account.

This higher annual transmission cost (i.e., $2,483 M vs. $2,313 M) was reflected in HQD's Application for 2007 rates (R-3610-2006)[40]. However, the 2007 Distribution Rate application did not reflect HQT's proposal to further increase its rates to Native Load (i.e., HQD) by $115 M effective January 1, 2007[41]. The Régie actually approved[42] Native Load charge of $2,539.7 M effective January 1, 2007 and the $56.7 M increase was recorded in HQD's Transmission Deferral Account[43].

Comments

There are no apparent issues associated with the determination of the balances in this account.

[38] D-2003-93, page 21
[39] D-2006-66
[40] R-3610-2006, HQD-7, Document 2, pages 3 and 8
[41] R-3605-2006, HQT-12, Document 1, page 12
[42] D-2007-34
[43] HQD-4, Document 2, page 10.

3.2.2 Recovery of Transmission Deferral Account Balance

Background

In its D-2003-93 decision, the Régie approved the proposal by HQD that the balance in the Transmission Deferral Account be integrated into the next rate case without stabilization measures. However, in its 2007 Rate Application HQD did not make provision for any planned recovery of the outstanding balance in the Transmission Deferral Account. Rather it indicated that it would provide a strategy for disposition of the balance in its next rate filing year and that current plans were to amortize the balance over a maximum period of three years[44].

In its Decision regarding 2007 rates, the Régie directed HQD to recover $70 M of the outstanding Transmission Deferral Account balance in its 2007 rates[45]. In the same Decision, the Régie also expressed concerns regarding inter-generational equity and accumulated interest costs and directed HQD to recover the outstanding variance as quickly as possible. The net result is that the overall balance in the Transmission Deferral Account is expected to be $344.3 M as of December 31, 2007, including an interest accrual of $17.6 M[46]. This balance consists of $58.9 M (i.e., $56.7 M plus $2.2 M in interest) associated with the January 1st, 2007 Transmission rate increase and $285.4 M still remaining from the earlier retroactive Transmission rate increase.

Finally, and probably more significant in the long run, the Régie directed HQD to include in its next rate filing (i.e., for 2008 rates) its assessment of the Transmission costs that are likely to be applicable for the test year[47].

[44] R-3610-2006, HQD-4, Document 3, pages 6-7
[45] D-2007-12, page 20
[46] HQD-9, Document 1, page 10
[47] D-2007-12, page 21

HQD's Proposal

HQD proposes to recover in 2008 rates, the $58.9 M associated with the January 1st, 2007 Transmission rate increase and to also recover $107 M of the outstanding $285.4 M associated with the 2005-2006 Transmission rate increase. Thus the total 2008 recoveries associated with the Transmission Deferral Account are almost $166 M. Furthermore, as directed by the Régie, HQD has included in the current Application $2,540 M in Transmission costs, based on HQT's current Application for 2008 rates[48]. While this is only a marginal increase over 2007 Transmission costs, it does represent a $57 M increase over the transmission costs that were actually built into 2007 rates[49]. Finally, HQD has also included in the 2008 Transmission costs a $41.3 M credit reflecting the anticipated refund in 2008 from HQT arising from short-term and long-term point to point revenues in 2007 being higher than originally forecast[50].

Comments

HQD's approach in establishing the amount of the outstanding Transmission Deferral Account balance to be recovered in 2008 is consistent with its proposed approach for the Pass-On Account. In both cases[51], the approach is to try and make the necessary refund/recovery as quickly possible while being mindful of the resulting impact on rates. With respect to rate impacts, HQD has deemed that an increase of less than 3% would be acceptable[52]. Overall, the HQD approach is reasonable. It addresses the issue of inter-generational equity, while seeking to maintain a degree of rate stability.

Also, given the context of the current Application, the 3% value is reasonable. As an overall average rate increase, it is not out markedly out of line with either inflation or recent increases. However, from a rate stability perspective, its is also important to

[48] R-3640-2007
[49] HQD-15, Document 1, Question 36.1
[50] HQD-4, Document 3, pages 9-10
[51] For HQD's position regarding the Pass-On Account see HQD-15, Document 8, Question 26 a). For HQD's position regarding the Transmission Deferral Account see HQD-15, Document 8, Question 2 a)
[52] HQD-15, Document 8, Question 2 a)

consider the rate/bill impacts that individual customers will experience as a result of the revenue requirement increase and any shifts in revenue responsibility between customer classes or changes in rate design. In this regard, virtually all residential customers will see bill impacts of less than 4.5% and, for other customer classes, the maximum bill impacts are even less[53]. As a result, the bill impacts associated with the overall Application, including the Transmission Deferral Account recovery, should be considered acceptable[54].

Finally, HQD's proposal to include in the 2008 revenue requirement the anticipated refund from HQT related to point to point sales in 2007 is consistent with the Régie's overall direction to reflect projected transmission costs in its proposed 2008 rates.

4 COST ALLOCATION

4.1 PGEÉ

4.1.1 HQD Proposal

In previous cases, the Régie has approved the allocation of PGEÉ costs to customer classes (both the amortization and rate base) based on the relative supply costs for each customer class[55]. This reflected the view that energy efficiency programs reduce electricity demand and therefore reduce supply costs for all consumers[56]. However, this approval has been provisional, as the Régie also expressed an interest in revisiting the allocation of PGEÉ costs once the allocation methods for Post-Heritage supply and Transmission had been resolved[57]. Given that the Régie ruled on the allocation of Post-

[53] HQD-12, Document 1, Appendix B
[54] D-2006-34, pages 18-19
[55] For example, R-3610-2006, HQD-11, Document 4, page 35
[56] HQD-11, Document 1, page 7
[57] HQD-11, Document 1, page 8

Heritage supply costs earlier this year[58] and is seeking, in this case, to make a final determination regarding Transmission costs[59]; the regulator directed that HQD file a proposal as part of its next (i.e., 2008) rate case[60].

HQD's proposal is to allocate PGEÉ costs to customer classes proportionally – based on the costs avoided by the distributor. This will be done such that the proportion of the avoided costs generated by each customer class through PGEÉ programs will be used to allocate the total PGEÉ costs to that class[61]. Furthermore, in doing so, HQD proposes to include a consideration of all avoided costs including transmission and distribution not just supply costs[62] and to consider the cumulative savings from PGEÉ programs up to 2007[63].

HQD has also included, in its Application, an alternative approach which allocates the cost of PGEÉ programs directly to customer classes based on the customer class the program was targeted to. However, HQD has indicated that, in its view, the avoided cost approach best reflects cost causation and is fairest to customers[64].

4.1.2 Comments

HQD's approach to the allocation of PGEÉ costs is correct at a "conceptual level" however the concept has been implemented incorrectly.

PGEÉ programs are undertaken if their costs are less than the costs that would have to be incurred to supply the associated kWh savings, i.e., less than HQD's avoided costs[65]. As a result, PGEÉ programs can be viewed as being initiated in order to provide HQD with cost-effective supply, transmission service and distribution network

[58] D-2007-12, page 73
[59] D-2007-12, pages 76-77
[60] D-2007-12, page 74
[61] HQD-11, Document 3, Table 25 C
[62] HQD-11, Document 1, pages 8-9
[63] HQD-15, Document 1, Question 53.1
[64] HQD-11, Document 1, page 11
[65] HQD-11, Document 1, page 9

service[66]. Furthermore, this is the case regardless of the customer class to which the PGEÉ program is targeted.

Given this perspective, HQD is correct in stating that it would be inappropriate to directly allocate the cost of PGEÉ to the customer classes[67]. From a cost causality perspective, such an approach assumes that the purpose of the program is to specifically benefit the customers in that particular class. However, that is not the case. HQD does not screen its PGEÉ programs from this perspective, but rather from an overall avoided cost perspective. The programs are undertaken because they reduce the costs associated with providing service to all customers and the cost of the PGEÉ programs should be shared accordingly.

The PGEÉ allocation method approved by the Régie in previous decisions reflects a similar perspective in that it allocates the cost of PGEÉ programs in proportion to the total supply costs. In doing so, the method treats PGEÉ programs as an alternative to supply that benefits all customers.

However the methodology proposed by HQD is inconsistent with the paradigm that considers PGEÉ to be an alternative to additional (Post-Heritage) supply contracts and new transmission & distribution facilities. The proposed methodology allocates PGEÉ program costs to customer classes in proportion to the avoided costs created by the kWh savings generated by the programs attributed to that class. The rationale is that if these programs did not exist each customer class would have to bear the equivalent of the avoided costs[68]. This is not correct. Rather, if the program did not exist, then HQD would have to incur the equivalent (if not higher costs) to provide supply, transmission and distribution and these costs would be allocated to all customer classes based on the cost allocation methodology approved by the Régie.

[66] HQD-15, Document 8, Question 56 a)
[67] HQD-15, Document 1, Question 53.4
[68] HQD-15, Document 1, Question 53.4

To correctly implement the "avoided cost" perspective that HQD (and the Régie) have espoused, the PGEÉ program costs should be broken down by Supply, Transmission and Distribution savings and each component allocated in a manner consistent with how HQD allocates the costs attributed to each of these functions to customer classes. This can be achieved by using the same avoided costs HQD has used in its proposed allocation methodology to determine the overall avoided costs of Supply, Transmission and Distribution. The cost of the PGEÉ can then be allocated to each of the three functions in proportion to the relative avoided costs associated with each. The costs in each function would then be allocated to customer classes.

A similar approach was recently approved by the British Columbia Utilities Commission after a review of BCHydro's cost allocation methodology. In a Decision[69] issued October 26, 2007, BCHydro was directed to functionalize DSM costs as 90% Generation and 10% Transmission.

Finally, it should be noted that the adoption of the approach outlined above does not rely as heavily on the identification of PGEÉ savings by rate class. As a result, it is not susceptible to the same problems and issues that HQD has noted as arising when assigning PGEÉ savings to rate classes[70] and therefore inherent in its proposed method.

Allocation of PGEÉ Costs to Function

In response to an Information Request, HQD provided direction on how to calculate the 2008 avoided costs for Supply, Transmission and Distribution[71] attributable to PGEÉ programs. Table 1 sets out the results.

[69] Decision, British Columbia Hydro and Power Authority, 2007 Rate Design Application Phase-1, pages 93-94
[70] HQD-15, Document 8, Question 55
[71] HQD-15, Document 8, Question 56 b)

Table #1 - Avoided Costs of PGEE Programs

Customer Class	Unit Avoided Costs (cents/kWh) Supply	Transm.	Distr.	PGEE Savings (GWh)	Total Avoided Costs($M) Supply	Transm.	Distr.
Domestic							
Tarff D	9.04	0.85	0.33	965.00	87.24	8.20	3.18
Tariff DH	9.03	0.78	0.30	0.00	0.00	0.00	0.00
Tariff DT	9.01	0.52	0.20	46.00	4.14	0.24	0.09
Small & Medium					0.00	0.00	0.00
Tariff G	9.04	0.65	0.25	154.00	13.92	1.00	0.39
Tariff G9	9.00	0.59	0.23	13.00	1.17	0.08	0.03
Tariff M	9.97	0.51	0.20	331.00	33.00	1.69	0.66
Lighting	8.62	0.47	0.18	7.00	0.60	0.03	0.01
Large							
Tariff L	8.64			315.00	27.22	0.00	0.00
Tariff H	8.77				0.00	0.00	0.00
Tariff LD & LP					0.00	0.00	0.00
					0.00	0.00	0.00
Special Contracts	8.60			196.00	16.86	0.00	0.00
Remote Cust.	12.30			1.00	0.12	0.00	0.00
Total					184.27	11.24	4.37
(%)					92.2%	5.6%	2.2%

There are two implementation issues associated with using these results to allocate PGEÉ costs to functions. The first is with respect to the PGEÉ for remote communities. Remote communities have different supply arrangements than grid-connected customers and, therefore, a different allocation methodology for the supply costs. In order to reflect this, the avoided cost of supply to Remote Communities should be separated from that of grid-connected customers.

Second, the avoided costs provided by HQD did not attribute any transmission avoided costs to the customers in the large power class. HQD's rationale is that the majority of these customers are served directly off HQT's network. However, the avoided cost for transmission (i.e., Transmission-Charge Locale) is calculated using the HQT's projected

investment costs for its network[72]. As a result, there should be avoided transmission costs associated with large power customers. The rationale provided by HQD is more applicable to explaining why there are no distribution avoided costs attributed to large power customers. Some of these large customers are served off the medium voltage distribution system[73] and, therefore, some avoided distribution costs could be attributed to these customers. However, the amount is likely small and recognition would not likely materially affect the allocation results.

The following Table recalculates Table 1 (above) after accounting for these two issues. Since avoid transmission costs are not published for large power customers the value for the Tariff M customers has been used as a proxy. This value would have to be refined by HQD to recognize the different load factor and loss characteristics of large power customers.

[72] R-3610-2006, HQD-15, Document 1, Annex A, pages 13-14
[73] HQD-11, Document 3, Table 51

Table #2 - Avoided Cost by Function Attritbuted to PGEE

Customer Class	Unit Avoided Costs (cents/kWh) Supply	Transm.	Distr.	PGEE Savings (GWh)	Total Avoided Costs $M) Supply	Transm.	Distr.	Remote
Domestic								
Tarff D	9.04	0.85	0.33	965	87.236	8.2025	3.1845	0
Tariff DH	9.03	0.78	0.3	0	0	0	0	0
Tariff DT	9.01	0.52	0.2	46	4.1446	0.2392	0.092	0
Small & Medium								
Tariff G	9.04	0.65	0.25	154	13.9216	1.001	0.385	0
Tariff G9	9	0.59	0.23	13	1.17	0.0767	0.0299	0
Tariff M	9.97	0.51	0.2	331	33.0007	1.6881	0.662	0
Lighting	8.62	0.47	0.18	7	0.6034	0.0329	0.0126	0
Large								
Tariff L	8.64	0.51		315	27.216	1.6065	0	0
Tariff H	8.77	0.51			0	0	0	0
Tariff LD & LP					0	0	0	0
Special Contracts	8.6	0.51		196	16.856	0.9996	0	0
					0	0	0	0
Remote Cust.	12.3			1	0	0	0	0.123
						0	0	
Total					**184.1483**	**13.8465**	**4.366**	**0.123**
(%)					**90.9%**	**6.8%**	**2.2%**	**0.1%**

Based on these results the amortization and rate base associated with PGEÉ would be assigned as follows:

- Grid Supply – 90.9%
- Transmission – 6.8%
- Distribution – 2.2%
- Remote Supply – 0.1%

Allocation to Customer Classes

In principle the PGEÉ costs associated with each of the above functions should be allocated to customer classes in a manner consistent with how the costs they are helping HQD to “avoid” are allocated to customer classes.

In the case of Grid Supply, PGEÉ avoids the need to obtain additional Post-Heritage supply. As a result, it would be appropriate to allocate this portion of the PGEÉ costs to the grid-connected customer classes based on their allocated share of Post-Heritage supply costs, as set out in HQD-11, Document 3, Table 9A, Column 7.

In the case of Transmission, PGEÉ should lead to lower cost for and lower charges from HQT. The appropriate allocation factor is therefore each customer class' share of HQT's costs, as set out in HQD-11, Document 3, Table 9D, Column 2.

In the case of Distribution, PGEÉ will reduce HQD's need to invest in future facilities attributable to meeting demand on the distribution network. The demand-related network cost attributable to each customer class (as set out in HQD-11, Document 3, Table 6, Columns 3[74] and 5) is therefore a reasonable allocation factor.

In the case of Remote Supply, the PGEÉ related costs should be allocated to the Remote customer classes in the same manner as Remote Supply costs, see HQD-11, Document 3, Table 33, Column 2.

4.2 Transmission Costs (HQT)

4.2.1 HQD's Proposal

Background

Following R-3492-2002 (Phase 1), the Régie concluded[75] that the cost of transmission service (as billed by HQT) should be allocated using the 1-CP method. However, the Régie's decision also noted that the Transmission Company's cost allocation study was

[74] The referenced Table has two columns which are labeled column 3 – both should be used to develop the allocation factors.
[75] D-2003-93, page 150

to be the subject of future review. Indeed, in its D-2006-34 decision[76] concerning HQD's 2006 Rate Application[77], the Régie noted that a review of the cost allocation treatment of transmission costs should be undertaken in the rate case following the decision on the allocation of transmission costs (for purposes of setting transmission rates).

As part of its 2005 Rate Application[78], HQT submitted for approval its proposed cost allocation methodology for transmission costs. In its decision regarding the Application, the Régie made a number of changes to HQT's proposal and established the methods that should be used by HQT in future cost allocation studies. However, in the same decision the Régie approved transmission rates for HQT based on the FERC pro-forma tariff as opposed to rates based on the results of the cost allocation methodology. In its decision the Régie noted[79] that:

> *La Régie considère que l'exercice de répartition des coûts permet de s'assurer d'un niveau adéquat des tarifs et d'une récupération équitable du revenu requis du Transporteur auprès de ses services. Cela n'oblige cependant pas à imposer une égalité parfaite entre les revenus produits par les tarifs et les résultats de l'étude d'allocation des coûts.*

The amount billed to Native Load differed from the amount allocated by roughly $81 M (3%). In the same decision, the Régie noted[80] that the cost of service allocation exercise which it had just completed for the Transmission Company was of particular importance with regard to the Distributor's transmission cost allocation.

One possible interpretation of the Régie's D-2006-34 decision is that the allocation method adopted by the Régie for HQT should be "imported" into HQD's allocation of transmission costs to customer classes. However, HQD rejected this approach for its

[76] See page 58
[77] R-3579-2005
[78] R-3549-2004 – Phase 2
[79] D-2006-66, page 22
[80] D-2006-66, page 20

2007 Rate Application and proposed[81] to continue to allocate transmission costs to customer classes based on 1-CP. At the same time, HQD included in its Application[82] a scenario which set out the allocation of transmission costs if the allocation methodology adopted for HQT was extended to HQD.

In its Decision regarding HQD's 2007 rates[83], the Régie noted that only two parties had examined the issue of allocating the Distributor's Transmission Cost in accordance with the method adopted by the Régie in D-2006-66 and indicated that the issue needed further examination. In the mean time, the Régie adopted HQD's proposal (1-CP) and directed HQD to file a scenario allocating Transmission costs as per D-2006-66 in the next Rate Case.

2008 Proposal

In its current Application, HQD has performed the allocation of transmission costs in a manner consistent with HQT's cost allocation methodology, adjusted for a couple of aspects specific to the Distributor[84]:

- First, since the actual transmission costs charged to HQD are less than the costs allocated to HQD under HQT's cost allocation methodology, the costs in each of the HQT functions allocated to HQD are reduced on a pro-rata basis so the total matches the anticipated charges from HQT[85].
- Second, the allocation makes a distinction between HQT connection facilities that serve high voltage versus medium and low voltage customers. The costs associated with serving high voltage customers are allocated solely to those customers on the basis of their non-coincident peak demands (NCP). The costs

[81] R-3610-2006, HQD-11, Document 1, pages 24-25
[82] R-3610-2006, HQD-11, Document 1, page 26
[83] D-2007-12, pages 76-77
[84] HQD-11, Document 1, page 12
[85] HQD-11, Document 3, Table 9 C and HQD-11, Document 1, page 13

associated with serving medium and low voltage customers are allocated solely to this group of customer based, again, on their non-coincident peak demands[86].

However, HQD has indicated that it continues to view the use of coincident peak to allocate transmission costs as being more appropriate[87].

4.2.2 Comments

The following comments address two issues. First, the question of whether the charges from HQT should be allocated to HQD's customer classes based on 1-CP or HQT's cost allocation methodology and, second, HQD's application of the HQT methodology.

Use of HQT's Cost Allocation Methodology

HQD appears to have interpreted the Régie's D-2007-12 Decision as directing it to adopt HQT's cost allocation methodology for purposes of preparing its 2008 Rate Application[88]. While the ultimate interpretation of the Decision lies with the Régie itself, an alternative interpretation is that HQD was directed to put forward both an allocation based on coincident peak and alternative based on HQT's methods, such that an informed debate could take place in this proceeding as to which method is more appropriate.

The evidence[89] prepared by ECS for R-3610-2006 addressed the question of which allocation method should be used by HQD and concluded that the coincident peak method was more appropriate. The key points from this evidence are summarized below:

[86] HQD-11, Document 1, page 13 and HQD-11, Document 3, page 17, Columns 7 & 8
[87] HQD-11, Document 6, Question 8.1
[88] HQD-11, Document 6, Question 8.1
[89] R-3610-2006, ECS Evidence, October 30, 2006, page 36

- The Québec electricity industry restructuring involved the functional separation of Hydro-Québec's Production, Transmission and Distribution activities. Similarly, the regulation of HQT and HQD by the Régie treats them as separate entities. Within this context, it is appropriate to view financial arrangements between HQD and HQT (and for that matter between HQD and HQP) as arm's length transactions between distinct entities.

  This means that, for purposes of assessing cost causality, it is appropriate to look at the contractual billing arrangements between the entities. This view is consistent with that put forward by ECS in its January 2003 Evidence[90] in R-3492-2002 Phase 1 concerning HQD's cost allocation practices. Therefore, since HQT determines the allocation/billing of transmission costs to HQD (i.e., Native Load) based on 1-CP and HQD's peak sets the timing of the HQT coincident peak, 1-CP (based on HQD's system performance) is the appropriate factor for HQD to use in assigning responsibility for transmission costs to customer classes. However, should the relationship between HQD's and HQT's peaks change in the future then the use of HQD's 1-CP as the allocation factor would have to be revisited.

- Very seldom are a regulated entities' rates set so as to perfectly match the results of their cost allocation studies (i.e., revenue to cost ratios are not typically 100% for all customers classes). Indeed, cost allocation study results are only one of the inputs/considerations that go into the development of a utility's rates and revenue recovery by customer class. Thus the fact that HQT's "rates" do not precisely recover from each of its customers the same amount as suggested by the cost allocation study should be considered neither as surprising nor abnormal. Unless the Régie was to decide that the results of HQT's cost allocation methodology should be the only factor in determining transmission rates – the HQT cost allocation methodology can not (and should not) be used to determine the responsibility of HQD's customer classes for the transmission costs billed to HQD by HQT.

[90] see page 27 of the referenced Evidence

- The Régie itself observed in its D-2003-93 decision[91] that it was not bound by Transmission Company's cost allocation method as regards to the choice to be made for the Distributor's transmission cost allocation method.

- Overall, the principle of cost causality (from the Distributor's perspective) supports the continued use of 1-CP for purposes of allocating transmission costs to customer classes.

HQD's Application of HQT's Methodology

If the Régie determines that the HQT methodology should be used to allocate the transmission charges HQD received from HQT to customer classes, then the approach put forward by HQD for applying the method at the Distributor's level is reasonable.

The difference between the costs allocated to HQD under HQT's cost allocation methodology and the charges levied based on the FERC's OATT methodology results from the two approaches being fundamentally different. As a result, there is no systematic way of attributing the difference to HQT's cost functions. A proportional adjustment to all functions' costs is the most expeditious and reasonable way to reconcile the two values.

HQT's allocation methodology identifies separately the connection facilities that serve only HQD and directly allocates the costs to HQD[92]. These directly allocated costs are associated with connection facilities for high voltage customers of HQD and sub-stations that step the power down to lower voltages supplying medium and low-voltage customers. HQD's proposal to allocate the first set of costs to high voltage customers and the second set of cost to medium and low-voltage reflects the customers requiring each type of facility and is therefore consistent with the principle of cost causality.

[91] page 150
[92] R-3640-2007, HQT-12, Document 2, page 23

4.3 Transmission Related Costs

4.3.1 HQD's Proposal

Background

Besides the annual charge from HQT, there are a number of other transmission related costs included in HQD's cost of service:

- The Transmission Deferral Account recovery proposed for 2008[93].
- The anticipated 2008 rebate from HQT related to 2007 Point to Point service revenues[94].
- Transmission-related working cash requirements related to payment of HQT's annual charges[95].
- Contributions that HQD has made to HQT related to specific connection projects[96].
- Deferred Charges related to the contributions to private switchyards connected to wind power projects[97].

2008 Proposal

For the first three items, HQD proposes to allocate the costs (both those associated with the cost of service and also rate base in the case of the Transmission Deferral Account) to customer classes based on the same relative allocation as derived for HQT's charges overall[98]. For the last two items, HQD is proposing to specifically functionalize the costs using HQT's cost allocation functions and then allocate the costs to classes using the same allocation factors as HQT uses for each function[99].

[93] HQD-9, Document 1, page 10
[94] HQD-4, Document 3, page 11
[95] HQD-8, Document 3, page 7
[96] HQD-15, Document 1, Question 47.1
[97] HQD-15, Document 1, Question 48.1
[98] HQD-11, Document 1, page 14
[99] HQD-11, Document 1, page 14 and HQD-15, Document 1, Question 51.1

4.3.2 Comments

If the 2005 through 2007 HQT charges had been known and recovered at the time HQD's rates were set in the respective years, then the full charge would have been allocated to HQD customers classes in accordance with the cost allocation methodology applicable for such costs. Therefore, to the extent the Deferral Account tracks variances between the HQT charges included in customers' rates and those actually billed to HQD, it is reasonable that they be allocated based on each customer class' share of HQT's costs for the test year.

The anticipated rebate from HQT arises from the fact that the actual Point to Point revenues in 2007 are currently expected to be higher than those used to establish HQT's rates for 2007. If the higher Point to Point volumes had been incorporated at the time HQT's 2007 rates were set then the charges to HQD would have been lower. As a result, also allocating the rebate based on each customer class' share of HQT's costs for the test year is reasonable.

The only issue is whether a more precise allocation would result if the costs associated with the Transmission Deferral Account and the Point to Point Revenue rebate were allocated to customer classes based on each class' share of HQT's costs as determined for the rate year the costs are actually associated with. This issue is discussed in Section 4.6.

The working cash requirements are directly associated with HQT's annual transmission charge and, therefore, it is reasonable to allocate this portion of rate base to customer classes using the same methodology as applied to transmission charges themselves. Indeed, the only reason why this change is required is because HQD has included in its cost allocation methodology a change in the way HQT's charge is allocated to customers classes.

HQD's capital contributions to HQT are made in accordance with the Transmitter's Terms and Conditions of Service and are designed to offset the costs of transmission facilities installed primarily to benefit the distributor. In choosing an allocation method for these costs, it is appropriate for HQD to look for precedents elsewhere in terms of how these costs should be allocated – particularly precedents set by the Régie. As a result, it is reasonable to allocate these costs to HQD's customer classes in a manner that reflects how the costs of similar facilities owned by HQT would be allocated to customer classes. A similar observation applies to the allocation of the deferred costs associated with private switchyards.

4.4 Other New Items and Cost Allocation Methodology Changes

4.4.1 HQD Proposal

There are a number of other new items impacting on the 2008 revenue requirement that must be dealt with by the cost allocation methodology:

- Schefferville Supply Project: As of 2008 HQD assumes responsibility for the supply of electricity to Schefferville and has reached an agreement with Newfoundland and Labrador Power (NLP) to supply the region. HQD proposes to treat the payments to NLP for the supply of electricity as remote community generation[100].
- Temperature Averaging Account: This deferral account is considered part of rate base for 2008 and therefore must be considered (for the first time) in the cost allocation methodology. The annual additions to this deferral account are determined by customer class, as part of the overall process of determining the overall annual addition to the account. HQD proposes to reflect this allocation in its cost allocation methodology.
- Development Costs: This item is associated with a development project to improve diagnostic methods for underground lines. HQD proposes to functionalize and

[100] HQD-11, Document 1, page 15

allocate the cost to customer classes in the same way as plant, equipment and intangible assets relating to underground lines are treated[101].

- Updates to Classification Rules and Allocation Factors: Consistent with past practice[102], HQD is proposing to update some of the classification rules and allocation factors used in its cost allocation process.

4.4.2 Comments

All of the foregoing proposed changes are reasonable. For each of the first three items, the proposed treatment tracks the basis on which the costs were incurred. The final item does not really represent a change in the cost allocation methodology itself but, rather, permits the methodology to reflect improvements in data availability[103].

4.5 Pass-On Account Recovery

4.5.1 HQD Proposal

Background

The allocation of the Pass-On Account to customer classes is performed as part of the determination of the year end balances themselves[104]. This process involves allocating the actual Heritage[105] and Post-Heritage volumes by customer class and also allocating the actual Post-Heritage supply costs to customer classes.

[101] HQD-11, Document 1, page 15
[102] D-2006-34, page 61
[103] HQD-15, Document 8, Question 64 a)
[104] HQD-11, Document 3, Table 9 B, Columns 5-7
[105] Actual Heritage supply volumes may differ from forecast due to unutilized Heritage energy and differences between forecast and actual loss factors

In previous Applications, Post-Heritage supply costs were assigned to customer classes (either monthly or annual) in proportion to the actual cost of Heritage supply by customer class[106]. This approach reflected the fact that the "global load factor method" was used by HQD to allocate both Heritage and Post-Heritage supply costs to customer classes. However, now that the Régie has directed that the hourly method should be used to allocate Post-Heritage supply costs to customer classes, the derivation of the Pass-On Account balances by customer class needed to be revised.

2008 Proposal

For the 2007 Pass-On Account calculation[107], HQD proposes to allocate Post-Heritage supply costs to customer classes so as to maintain the relativity between the unit Post-Heritage supply costs for the various customer classes as was established on a forecast basis when the 2007 rates were approved[108].

4.5.2 Comments

The approach adopted by HQD is reasonable. Since the prices of Heritage Pool supply by customer class are not updated to reflect actual customer class load factors[109], it is questionable as to whether attempts to refine the methodology for Post-Heritage supply further to reflect actual operations are warranted. Also, it must be borne in mind that the Pass-On Account calculations for a particular year are not just done once, but a number of times (e.g., with and without interruptible, with 4 months real/8 months forecast data and again with 12 months real and then finally with the billed/delivered adjustment). Any unwarranted complexity will increase the efforts involved for each of these calculations.

[106] R-3610-2006, HQD-16, Document 7, Question 16 and R-3579-2005, HQD-4, Document 3
[107] 2007 is the first year for which the Régie has authorized the use of the Hourly Method to allocate Post-Heritage supply costs to customer classes
[108] HQD-4, Document 2, page 29, Table 5, Footnote (C)
[109] To do so would likely require a new Government Regulation (Decree).

4.6 General Comments Regarding Allocation of Variance/Deferral Accounts

HQD's cost allocation methodology includes a number of instances where it is necessary to allocate either deferral/variance account balances (accrued in previous years) or their amortization (refunds/recoveries) to customer classes. In this regard there are two types of such accounts. The first involves accounts (such as PGEÉ) where costs are deferred and amortized in order to achieve a better matching over time of costs and benefits. The second involves accounts (such as the Pass-On Account) where the forecast used to set the rates was incorrect and a "true-up" is authorized by the Régie after the fact. For this later category of deferral/variance accounts a question of principle arises as whether these values should be assigned to customer classes using:

a) the allocation methodology and allocation factors that existed at the time the costs were accrued, or

b) the allocation methodology and allocation factors applicable for the test year under consideration.

HQD's practice in this regard has not been consistent throughout the Application as illustrated by the following table:

Table #3 – Cost Allocation Treatment of Deferral/Variance Accounts

	Allocation Methodology Used	Allocation Factors Used
Rate Base Items		
1) Transmission Cost Deferral Account[110]	Allocation based on HQT method (test year)	Allocation based on test year allocation factors (test year)
2) Temperature Averaging Account[111]	N/A	Allocation based on usage for year concerned (past year)
Cost of Service Items		
3) Pass-On Account[112]	2005 and 2006 allocations based on Global Method (past years) 2007 Allocation based on Hourly Method (past & test year)	Allocation based on usage for year concerned (past year)
4) Transmission Deferral Account Recovery[113]	Recovery of 2005 through 2007 balances allocated using HQT methodology (test year)	Allocation based on test year allocation factors (test year)
5) Rebate for PTP Revenues[114]	Allocation based on HQT method (test year)	Allocation based on test year allocation factors (test year)
6) Interruptible Deferral Account Recovery[115]	2006 and 2007 balances combined and both allocated as 2007 costs based on Hourly Method (past)	Allocation based on usage for year concerned (past year)

Based on the principle of cost causality, it would be appropriate to allocate such costs using the methodology and allocation factors associated with the year for which the costs were incurred (i.e. the past year). However, there are issues relating to

[110] HQD-11, Document 3, Table 9E
[111] Rapport annuel, HQD-4, Document 1, pages 12-17
[112] HQD-11, Document 3, Table 9 B
[113] HQD-11, Document 3, Table 9D
[114] HQD-11, Document 3, Table 9 D
[115] HQD-4, Document 2, pages 24-25

practicality and materiality that must also be considered. The following discussion looks at HQD's current treatment of each cost element from these perspectives.

The three items that are currently allocated using the "past year" approach are the Temperature Averaging Account balance and the Pass-On Account & Interruptible Option refund/recoveries. In each case, the determination of the customer class allocation is made as part of the overall process for establishing the balance to be accrued in the account at year end. As a result, there are no practical issues associated with using the "past year" approach. It should be noted that HQD's decision to combine the 2005 and 2006 Interruptible Option balances and treat them all as 2006 costs was done for simplicity purposes and does not have a material impact on the allocation results[116].

With respect to the treatment of the Transmission Deferral Account balance and recoveries, the current accumulated balance represents shortfalls in recovery of transmission costs for a couple of years (i.e. 2005 through 2007). Furthermore, the 2008 proposed $70M recovery of balances from 2005 and 2006 is not linked or apportioned to particular years. As a result, it may be more practical (at this point in time) to allocate the related costs using the test year methodology and allocation factors. However, in the future, any new accruals to the Transmission Deferral Account should be smaller (i.e., reflecting only variances between the forecast HQT cost and those ultimately authorized by the Régie) and recoverable in the next year. As a result, it should be relatively easy to allocate them to customer classes based on the allocation factors used in the previous year.

With respect to the Rebate anticipated from HQT with respect to 2007 Point to Point revenues, this should be allocated to customer classes based on the allocation methodology used in 2007 for allocating HQT charges (i.e., CP) and the allocation factors should be those used in setting 2007 rates. A similar approach should also be

[116] HQD-15, Document 8, Question 30 a) & b)

used in future HQD Rate Applications for any rebates or recoveries. This approach is easy to implement and using 2007 loads parallels the allocation the Régie directed[117] HQT to use in allocating the variance in Point to Point Revenues between Native Load and Long Term Point to Point Service.

5 THE CROSS-SUBSIDIZATION INDEX

5.1 HQD Proposal

Background

The Act respecting the Régie de l'énergie ("the Act") states that when setting the rates to be charged to consumers for electricity by HQD, the regulator shall consider the cost of electric power to the distributor, transmission costs as well as the costs incurred by electricity distributor itself[118]. However, the Act also requires that "the Régie shall not modify the rates applicable to a class of consumers in order to alleviate the cross-subsidization of rates applicable to classes of consumers"[119].

In order to give effect to these requirements the Régie, following Phase 1 of R-3492-2002, adopted the revenue-to-cost ratio index proposed[120] by HQD as an appropriate "cross subsidization index" and also adopted 2002 as the "reference year" for purposes of establishing a "reference" revenue to cost ratio against which to judge the cross-subsidization applicable to classes of consumers. In a subsequent decision, the Régie noted[121] that modifications to the cost allocation methodology can have an impact on the cross-subsidization index and concluded that such impacts should be excluded for purposes of comparing the current cross-subsidization index for each customer class

[117] R-3640-2007, HQT-4, Document 3, page 8
[118] Section 52.1, 1st paragraph of the Act
[119] Section 52.1, 4th paragraph of the Act
[120] HQD's index is described in R-3492-2002, HQD-2, Document 4.2
[121] D-2005-34, pages 122-123

with the reference values for 2002. This led to the introduction of a process whereby the reference cross-subsidization index for each customer class was adjusted each year to reflect changes in the cost allocation methodology[122].

In its D-2006-34 decision, the Régie indicated that it would like to hear from stakeholders during the next rate case, on the various avenues that will allow a better reflection, specifically of the costs of new supply in the rates of each of the customer classes and on the interpretation to give to the provisions of the Act with respect to cross subsidization in this new context[123]. In last year's Application, HQD proposed a uniform rate increase for all customer classes. However, it also put forward a proposal whereby increases in costs would be attributed to individual customer classes but the cross-subsidization inherent in the existing rates would be retained[124]. In its decision, the Régie concluded that:

> *In a context in which the costs to serve different customer classes would not evolve uniformly, nothing impedes the Régie from carrying out rate adjustments that are differentiated between customer classes. An alternative interpretation of the Act would deprive several of its provisions of their impact, and that would be detrimental in terms of equity, economic or environmental rigor, all of which the Régie must consider when exercising its power "within a sustainable development perspective". Consequently, every time it files an application to modify the rates of one customer class, the Distributor will have to demonstrate that the adjustment is in a causal relationship with the variations in supply costs for that class. Beginning with the 2008 rate application, the Distributor can propose rate adjustments that are differentiated by customer class, each of them reflecting the evolution of costs attributable to that class."*[125]

2008 Proposal

For 2008 HQD has requested, in its Application[126], a set of rates based on a uniform increase of 2.9%. However, it has also included in the application the differentiated rate increases that would result from the application of the methodology it suggested last

[122] R-3579-2005, HQD-12, Document 3
[123] D-2006-34, pages 77-78
[124] HQD-12, Document 1, pages 7-8 and R-3610-2006, HQD-12, Document 1, pages 65-66
[125] D-2007-12, page 77 – Translation
[126] HQD Requete – 3644, page 7

year[127] and suggests that the final decision with respect to the application of differentiated rate increases lies with the Régie[128].

5.2 Comments

The following comments focus on two issues. The first is HQD methodology for testing the need for differentiated rate increases and second is the implications of implementing the 4.4% residential rate increase that falls out of HQDs methodology.

5.2.1 HQD's Rate Differential Methodology

The mechanics of HQD's rate differential methodology are set out in Exhibit 12, Document 1, Annex A. The methodology has three basic steps to it:

i. Determine the increase in costs attributable to each customer class: The objective here is to determine the extent which the cost allocation for the test year has yielded a shift in cost responsibility across the customer classes – excluding cost allocation methodology changes. This is done by starting with the previous test year's cost allocation based on both the revenue requirement and cost allocation methodology approved by the Régie that year[129] and further adjusting the results for any changes in cost allocation methodology proposed for the current test year[130]. The results, by customer class, are then extrapolated to current test year based on the change in kWhs for the customer class and compared with the cost allocation results for the test year. The difference is deemed to be the change in costs attributable to each customer class.

ii. Reconcile the total cost increase from (i) with the overall increase in revenues: The objective here is to ensure that increases proposed for the various customer classes yield the total revenue increase requested by HQD. The reconciliation is done in two parts. First the change in regulatory provision incorporated into the

[127] HQD-12, Document 1, Annex A
[128] HQD-1, Document 1, page 17
[129] In the current Application this is the cost allocation from R-3610-2006, adjusted for D-2007-12.
[130] In the current Application this is the three cost allocation methodology changes identified in HQD-11, Document 1, Table 1. See also HQD-15, Document 8, Question 65 b).

test year's rate increase versus that incorporated into the previous year's rate increase is determined. In each case the calculation of the provision was done by customer class and therefore the change for each customer class can be readily determined. The second part of the reconciliation identifies the residual difference that remains and allocates it to customer classes based on the relative revenues anticipated from each customer class prior to any rate change (i.e., revenues at existing rates).

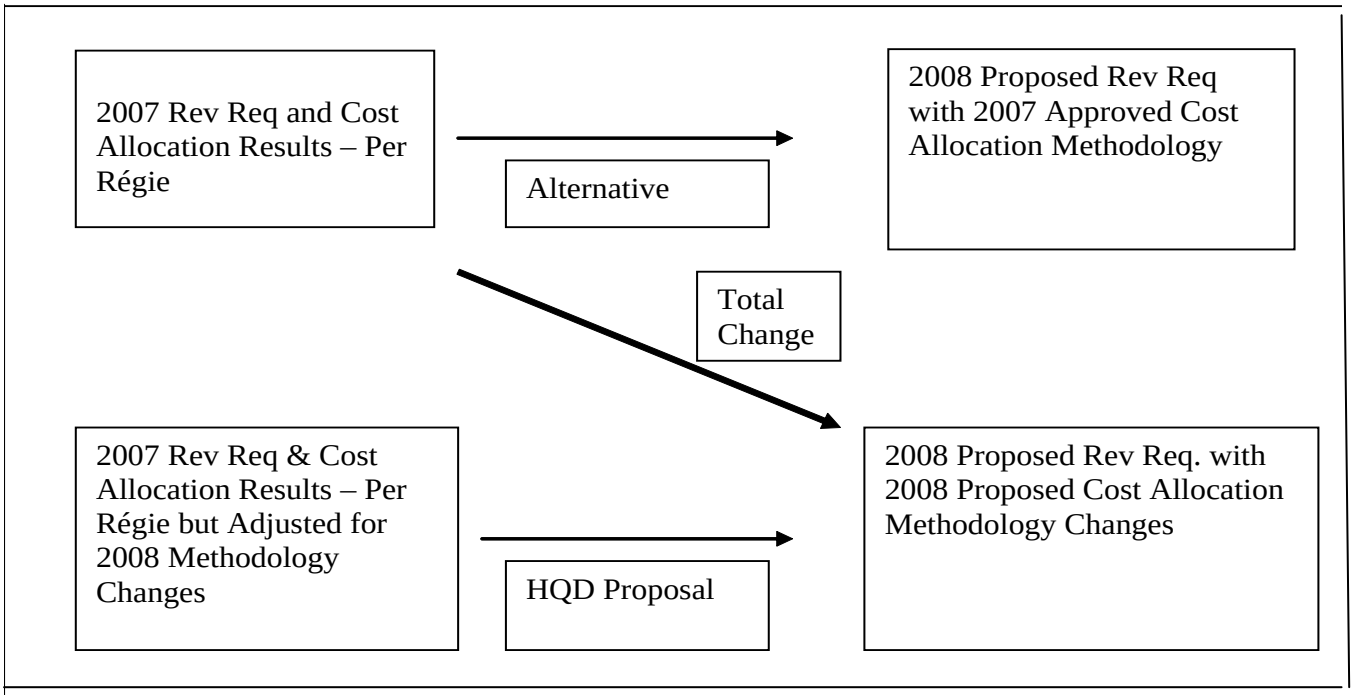
iii. Determine the Differentiated Class Rate Increases and New Revenue to Cost Ratios: The additional revenue to be collected from each customer class is established by summing the results of steps (i) and (ii) for each class. The associated rate increase is determined by comparing this result with each class' revenue at existing rates. Finally, the revenue to cost ratio is calculated for each customer class by comparing the revenues by class with the costs allocated to each customer class.

Separation of Methodological versus Cost Change Impacts

There are several points worth noting about the approach HQD has taken for Step 1. First, HQD removes the impact of changes in cost allocation methodology between the prior year and the test year by adjusting the results for the previous year to also capture the cost allocation methodology changes for the test year. In the Application currently before the Régie this meant changing the cost allocation approved by the Régie in D-2007-12 to also capture the three cost allocation methodology changes proposed for 2008.

An alternative approach would have been to determine the cost changes attributable to each customer class by comparing the results of D-2007-12 – as approved by the Régie – with the results for 2008 prior to the implementation of any of the newly proposed cost allocation changes. Conceptually, as illustrated in Table 4, this appears as simply another way of getting at the same result.

Table #4 – Determination of Cost Driven Changes



However, as illustrated in Table 5, which replicates the format used in HQD's evidence[131] to present the alternative methodology, the results are significantly different. For example, the differentiate rate increase for the residential class is 3.3% as opposed to the 4.4% arising from the HQD methodology.

[131] HQD-12, Document 1, Annex A

Table 5 - Alternative Method for Determining Differentiated Rate Increases

Class	2007 D-2007-12 ($M)	2008 Before 2008 Meth. Changes ($M)	Volumes (GWh) 2007	Volumes (GWh) 2008	Unit Costs (cents/kWh) 2007	Unit Costs (cents/kWh) 2008	Cost Increase ($M)	Prov Reg ($M)	Adjust ($M)	Total ($M)	Rate Increase
Domestic	4975.3	5236.4	59232	59760	8.40	8.76	216.75	-44.00	-34.45	138.30	3.32%
SP	1028.9	1047.3	14620	14600	7.04	7.17	19.81	-11.00	-10.70	-1.90	-0.15%
MP	1390.9	1476.3	27129	27331	5.13	5.40	75.04	-15.00	-15.54	44.50	2.37%
LP	1709.3	1696.1	45567	43569	3.75	3.89	61.75	-16.00	-15.96	29.79	1.54%
Total	9104.4	9456.1	146548	145261	6.21	6.51	431.66	-86.00	-76.66	269.00	2.90%

Sources: HQD-15, Document 8, Question 65 d); HQD-11, Document 1, page 17 and HQD-12, Document 1, Annex A

As suggested by Table 4, both approaches lead to the same overall result (i.e. the 2008 Proposal) – when combined with the cost allocation methodology changes. The difference, conceptually, is that one calculates the contribution of methodology changes using 2007 values while the other calculates the impact of methodological changes using 2008 values. At this point, one approach does not appear to be conceptually superior to the other for purposes of identifying the extent to which the various customer classes are responsible for cost increases. Indeed, at this early stage in the consideration of differentiated rate increases by customer class it may be most useful for the Régie to consider the results of both approaches.

Use of Energy to Extrapolate Previous Results

Another point to be noted is HQD's use of energy to extrapolate the previous year's cost allocation results to the test year. The cost allocation methodology uses a variety of allocation factors (e.g. demand, energy and customer count). While the choice of energy volumes is probably the most reasonable single measure to use for this purpose, it should be recognized that the results are, at best, an approximation of what the results would look like if there was no shift in cost responsibility between customer classes. As a result, while the calculated differentiated rate increases may suggest there has been a shift in cost responsibility, they should not be considered a precise calculation of this shift.

Treatment of Pass-On Account

Finally, an issue arises as to how to treat the Pass-On Account refund/recoveries. In last year's Application, HQD proposed[132] that the Pass-On Account refund/recovery be treated as a "methodology change". This was done primarily in the interest of rate stability. However, in the current Application, HQD has not treated the proposed Pass-On Account recovery as a "methodology change". For this Application, the impact is

[132] R-3610-2006, HQD-11, Document 1, page 30

likely to be small, given that the total refund is in the order of $11 M[133]. However, the Pass-On Account refund/recovery could be quite large in any given year and its treatment should be resolved. In last year's proceeding, ECS agreed[134] with the HQD proposal to treat the Pass-On Account refund/recovery as a "methodological change" and, for the same reasons, believes it should continue to be viewed as such. As an aside, it is worth noting that if this perspective is adopted then the HQD approach to separating out the impact of methodology changes in the cost allocation process becomes problematic (i.e., how would one remove the impact of the 2008 Pass-On Account recovery from the 2007 results?).

5.2.2 Implications of a 4.4% Residential Rate Increase

During the information request phase of the current proceeding, parties requested that HQD provided the bill impact dispersion associated with a 4.4% rate increase for the residential class. The response[135] indicated that over 13% of residential customers would see bill impact in excess of 5%.

HQD's proposal to recover $166 M associated with the Transmission Deferral Account was designed within a context where not only was the average rate increase less than 3% but there was a uniform rate increase across all customer classes such that bill impacts for virtually all customers were less than 5%. If differentiated rate increases are to be considered then it will be important for the Régie to determine if the 5% plus rate increase that will be experienced by a material number of residential customers is acceptable.

[133] HQD-1, Document 1, page 7
[134] See pages 40-41 of ECS Evidence filed in R-3610-2006
[135] HQD-15 Document 7, Question 10.2

6 RESIDENTIAL RATE DESIGN

6.1 Overall Rate Structure

6.1.1 HQD's Proposal

In its current Application[136], HQD proposes to continue the rate strategy first outlined in its R-3541-2004 Application[137] whereby:

- The daily fixed charge is held constant (at 40.64 cents),
- The rate for the second block is increased by 4.2% which is double the increase of the rate for the first usage block, and
- The winter demand charge (for usage over 50 kW) is increased by $0.75 ($0.18/kW for bulk metered contracts).

The current residential rates and those proposed to be effective April 1, 2007 are set out in Table 6.

Table 6

Domestic Rates (Rate D)
2007 versus 2008

	2007	2008
Fixed Charge (cents/day)	40.64	40.64
30 kWh/day (cents/kWh))	5.29	5.4
Remaining Use (cents/kWh)	7.03	7.33
Demand Charge ($/kW)	5.46	6.21

Source: HQD-12, Document 1, Table 10

[136] HQD-12, Document 1, pages 24-25
[137] R-3541-2004 (Phase 1), HQD-1, Document 2, page 23

HQD also discusses the issues identified by the Régie in Decision D-2007-12[138] and the Québec Government in its Energy Strategy document[139] regarding the need to better reflect marginal cost in rates. In this regard, the Application discusses:

- The difference between short-run and long-run marginal costs and concludes that long-run costs should be used to benchmark customers' rates[140].
- The rationale[141] for including a monthly fixed customer charge and concludes that the current (2007) level of the fixed charge is reflective of costs[142].
- Issues associated with the selection of the number and size of the energy blocks and concludes that the use of two energy blocks and the current 30 kWh/day definition for the first block[143] best reflect to customers the marginal cost of electricity.
- The application of any price adjustments to the two energy blocks and concludes that its proposal best balances the objectives of improving price signals while limiting rate impacts to customers[144].

6.1.2 Comments

Fixed Customer Charge

In support of the proposed freeze of the current residential customer charge of 40.64 cents/day, HQD correctly notes that there are other objectives to rate design besides encouraging the efficient use of electricity through marginal cost-based pricing signals[145]. While the Government's Energy Strategy suggests that considerable weight must be given to the objective of efficient pricing, fairness in pricing is also an important objective. In this regard, the current level of the customer charge reflects average cost

[138] D-2007-12, pages 83-84
[139] English Version, pages 53-54
[140] HQD-12, Document 2, pages 9-10
[141] HQD-12, Document 2, page 11
[142] HQD-12, Document 3, page 10
[143] HQD-12, Document 3, pages 40-41 and pages 54-55
[144] HQD-12, Document 3, page 43
[145] HQD-12, Document 3, pages 5-9

embedded in the revenue requirement to service a customer – regardless of the level of consumption[146]. Furthermore, the 40.64 cents per day is roughly equivalent to the marginal cost of adding a new customer to the HQD system[147]. As a result, HQD's proposal to maintain the service charge at the 2007 level is reasonable.

Principles in Selecting First Usage Block

The basis for setting the first energy block has been discussed in previous HQD Applications, including R-3579-2005[148] and R-3610-2006[149]. In the current application the principles put forward by HQD are generally the same and include the following considerations:

a) The first block is meant to capture the more inelastic uses of electricity, whereas the second block (which will be priced closer to marginal cost) is meant to capture the more elastic uses of electricity[150].
b) The marginal cost price signal should apply to a significant volume of kWh and to a significant number of customers[151],
c) Selection of the first usage block should avoid billing basic uses in the second energy block[152], and
d) Customers do not understand the residential rate structure and therefore rate design changes must be analysed by taking into account the change in the total bill. This requires that a sufficiently high price be applied to a large volume of kWh[153].

In general these considerations provide a reasonable framework for the determination of the appropriate size of the first energy block. However, there are a couple of points that should be noted.

[146] HQD-12, Document 3, page 10 and HQD-12, Document 3, page 34
[147] HQD-15, Document 8, Question 94 a) and HQD-12, Document 3, Table 1
[148] HQD-13, Document 1, page 23
[149] HQD-12, Document 3, page 17
[150] HQD-16, Document 7, Question 58 a).and Question 84 a)
[151] HQD-12, Document 3, page 54
[152] HQD-12, Document 3, page 40
[153] HQD-12, Document 3, page 8

First, while HQD emphasizes throughout its Application that the first energy block is not designed to include or exclude any specific uses[154], the Application also indicates that, with the exception of space heating, the demand for electricity is not very elastic[155]. As a result, as we'll see below, in benchmarking the size of the first block HQD presents various data setting out the average use per customer for non-space heating uses[156].

Second, there are trade-offs required between the various considerations. The amount of electricity used by residential customers for specific end uses will vary. As a result, selection of a higher threshold for the first energy block is likely to ensure that more customers are not billed at the higher (second energy block) rate for their non-space heating use but is also more likely to mean that the first energy block rate is applied to some space heating use. However, what is truly important in this consideration is the question of whether incremental use, for those customers with electric space heating, is billed at the second block energy rate.

There is also a trade-off between the size of the first energy block and the price level that can be charged in the first and second energy blocks. An increase in the size of the first energy block means that more energy will be billed at the (lower) first energy block rate. This means that the rate for either the first or the second energy block can be increased while still recovering the same amount of revenue overall. If the increase is applied to the second energy block then price signal for the second energy block will be improved, as it will be closer to marginal costs. However, since the first energy block is larger, the number of customers that will see the improved price signal will decrease.

Finally, HQD has suggested that customers do not understand their rates and, therefore, the volumes that the higher second block energy rates are applicable to are

[154] HQD-12, Document 3, page 17 and HQD-
[155] HQD-12, Document 3, page 40
[156] HQD-12, Document 3, pages 17-20

also important as this means the total bill will increase[157]. There are two points to be made in response to this concern. The first is that the theory underlying marginal cost pricing is that customers will react to the price they are charged for incremental use[158]. Indeed, HQD appears to have misinterpreted the NERA quote it references to support its position[159]. Careful reading of the quote will show that NERA's concern with increasing the size of the block is not that additional energy volumes are exposed to the first block price but rather that additional customers are exposed to the first block price and, therefore, do not see the second block energy price as their price signal for incremental use. It should also be emphasized that this focus on incremental use also underlies the Government's Energy Strategy[160]. As a result, what should be considered important, from an economic theory perspective, is the number of customers that are billed at the second energy block and therefore see the second block price as the marginal price for consuming electricity. The second point is that if HQD is concerned that customers do not understand their rate structure then HQD should consider implementing a customer education program regarding its rates as part of its DSM initiatives.

Determination of First Block Size

To support the 30 kWh/day threshold, HQD uses data available from a customer sample, to show that the average use per customer without space heating is 28 kWh per day when considered over an entire year. Using another data source[161], HQD reports that the average use for all households for non-space heating use is 29 kWh per month[162]. As a result, when looked at on an annual basis the 30 kWh value proposed by HQD appears to be a reasonable demarcation between space heating and non-space heating use. Indeed, it can be viewed as providing a small cushion in recognition of the fact that non-space use heating will vary by customer.

[157] HQD-12, Document 3, page 8
[158] HQD-12, Document 3, page 16 (NERA Quote)
[159] HQD-12, Document 3, page 16
[160] English version – page 53
[161] HQD-12, Document 16, Question 87 a)
[162] HQD-12, Document 3, page 19.

However, the average use value for non-space heating households increases to over 30 kWh per day during the core winter months of December to March and declines to roughly 25 kWh per day during the summer months[163]. This has given rise to the discussions in previous proceedings as to the merit of varying the threshold by season. In the current Application HQD discusses both the option of increasing the winter threshold to 35 kWh/day and reducing the summer threshold to 25 kWh per day.

- Increasing Winter 1st Block to 35 kWh

In dismissing the suggestion that the winter threshold be increased to 35 kWh/day, HQD suggests that this would "dilute" the price signal in that it would lead to more winter kWh being billed at the lower (first block energy rate). The evidence also claims that the number of customers billed only in the first block would increase by 10%[164]. At the same time, HQD notes that the increase in the threshold would only have a small impact on the price of the second energy block.

As noted earlier, the important consideration is the change in number of bills that will capture consumption in the second energy block. Based on an analysis of billing data for all HQD's Rate D and DM residential customers[165], increasing the first size of the first block from 30 to 35 kWh in the core winter months would mean that only 70.7% of them would fall into the second energy block (as opposed to 75.8%). This represents a five percentage point change. HQD claims that there is no economic justification to bill more kWh in the first block and only to then increase the energy prices in the second block[166]. This is incorrect. If the additional kWh being captured by the first energy block are generally for inelastic uses and the second energy block is still capturing the "elastic" uses of electricity then increasing the first block size in order to enable a increase in the price applicable to inelastic use makes economic sense. Given that the average use for electricity use for non-space heating (i.e., inelastic) applications ranges

[163] HQD-12, Document 3, page 18
[164] HQD-12, Document 3, pages 34-35
[165] HQD-15, Document 8, Question 74 a)
[166] HQD-12, Document 3, pages 36-37

between 30-33 kWh/day in these months, it is reasonable to assume[167] that, with a 35 kWh threshold, a portion of the additional bills falling into the first block would be associated solely with inelastic uses.

Overall, increasing the winter threshold to 35 kWh will have a couple of positive effects:

- The price for the second energy block will increase, albeit slightly.
- More customers solely with inelastic use will be captured entirely in the first block, albeit the number is unknown.

At the same time, there will be a negative effect in that the portion of bills exposed to the second threshold price will decline from 76% to 71%, and some of these bills will involve customers using electricity for space heating. These are the same issues and tradeoffs identified in ECS's evidence last year[168]. Whether or not the threshold should change will depend on the weight the Régie places on each of these issues.

- Decreasing Summer 1st Block to 25 kWh

HQD has also presented an assessment of decreasing the energy block to 25 kWh in the non-core winter months and concluded that the 30 kWh/day should be retained for the summer time. ECS presented the same conclusions[169] in its Evidence for R-3610-2006, although the rationale was not exactly the same. Decreasing the threshold in the summer has the following positive effects:

- It increases the portion of bills exposed to the second energy block from 49.5% to 57.5%. However, these bills are all in the summer months and non-core winter months, which are the less critical months for HQD in terms of supply.

At the same time it has a couple of negative effects:

- It will trigger a need to reduce the rates for either the first or second energy block.

[167] HQD was asked for additional data regarding the distribution of results around the average non-space heating use, but was unable to provide any data. HQD-15, Document 8, Question 88 a)
[168] R-3610-2006, ECS Evidence, October 30, 2006, pages 51-52
[169] See previous footnote

- It could increase the extent to which inelastic uses of electricity are billed at the second energy block, particularly in the shoulder months of April, May and November.

First/Second Usage Block Rate Differential

HQD's proposal to increase the rate applicable to the second usage block by twice as much as the rate applicable to the first block is a continuation of the policy adopted by HQD (and the Régie) following previous rate applications. In the current Application, HQD also presents an assessment of an alternative whereby all of the increase is applied to the rate for the second energy block and concludes that it would be inappropriate.

While such an approach would allow the rate for second energy block to increase (towards marginal costs) at a faster rate, it would mean that there would be no change in price for those customers whose usage all falls into the first energy block. This means that over 40% of the bills issued by HQD would not see a change in rates[170]. Furthermore, even in the critical core winter months, almost 25% of the bills issued would not see a change in rates. Such a price signal is inappropriate in a context where the cost of supply and overall distribution service are increasing annually. As a result, HQD's conclusions on this issue are reasonable.

Third Energy Block

The Government's Energy Strategy[171] raised the possibility of introducing a third energy block. In its current Application, HQD looks at the implications of introducing a third energy block at 60, 100 or 150 kWh per day. The perceived benefit from introducing a third energy block is that consumption falling into this third block would be billed at a higher rate, closer to marginal cost. The problem (or drawback) is that, in order to be

[170] HQD-15, Document 8, Question 74 a)
[171] Page 53 of English Version

revenue neutral, the rates for the first and/or second energy blocks must be reduced. There is not much scope for reducing the rate applicable to the first energy block while still maintaining a progressive signal to customers, since HQD's rate strategy already calls for a less than average increase to this block's rate. Reducing the rate in the second energy block (relative to what it would have been with no third energy block) means that customers whose incremental use falls into the second block will see a lower price and have less incentive to respond. The net result is that increasing the price for the marginal elastic uses of some customers will reduce the price for the marginal elastic usage consumption of others. A compounding problem (which is illustrated in Table 7) is that the more bills that are captured by the 3rd block, the larger the energy volume in the third block.

Table #7 - Implications of Introducing a Third Energy Block

	Percent of Bills			Percent of Volume		
3rd Block Size	**1st Block**	**2nd Block**	**3rd Block**	**1st Block**	**2nd Block**	**3rd Block**
No 3rd Block	42.4%	57.6%	N/A	52.6%	47.4%	N/A
60 kWh/day	42.4%	31.1%	26.5%	52.6%	25.5%	21.9%
100 kWh/day	42.4%	48.0%	9.6%	52.6%	39.5%	7.9%
150 kWh/day	42.4%	55.4%	2.2%	52.6%	44.7%	2.7%

Source: HQD-15, Document 8, Question 74 a)

This means that for a given energy price in the third block, if one tries to capture more customers in the third energy block by lowering its threshold then the price for the second energy block must also be reduced. This point is illustrated in the following Table using an illustrative 3rd block energy price of 7.5 cents/kWh.

Table #8 -Illustrative Energy Rates (cents/kWh)

	First Block	2nd Block	3rd Block
Current Rates	5.29	7.03	N/A
Proposed Rates	5.4	7.33	N/A
With 3rd Block			
60 kWh	5.4	7.18	7.5
100 kWh	5.4	7.30	7.5
150 kWh	5.4	7.32	7.5

Another issue is that if bill impact dispersion is used as a measure of acceptable impacts then the higher dispersion associated with the introduction of a third energy block may reduce progress towards achieving a marginal cost-based price signals overall.

Overall, HQD's conclusion not to add a third energy block is reasonable.

6.2 Demand Charges for Residential Customers

6.2.1 HQD Proposal

Currently, HQD applies a demand charge to residential customers for any demand in excess of 50 kW during the four core winter months[172]. In the current Application, HQD has proposed a number of reforms to the way demand charges are applied to residential customers. However the changes would not come into effect until April 1, 2009. These changes include:

- Applying the demand charge to power use in excess of 50 kW in any month of the year. To limit annual rate impacts, the winter demand charge would be "frozen" at

[172] HQD-12, Document 1, page 18

the 2008 level and the summer demand charge increased by $0.63/kW/annum until it reached the winter demand charge (roughly 10 years)[173].

- Introduction of a minimum billing demand equal to 65 % of the maximum demand in the previous 12 months[174].
- Billing customers whose power factor is below 90% based on kVA as opposed to kW[175].

6.2.2 Comments

HQD rationalizes the extension of the demand charge to the summer months on the basis that there is not a large difference between the avoided costs for the two seasons[176]. Indeed, the only difference is the $10/kW premium associated with winter use. Furthermore, avoided distribution costs (which are also included in the benchmark for the demand charge[177]) are likely to be driven in part by localized demands, as opposed to just those at the time of the system peak. As a result, extension of demand charge to all months of the year is reasonable at this stage.

Minimum bills (based on minimum demand provisions) are meant to reflect the fact that facilities have to be in place all year around to meet a customer's maximum demand for the year. As a result customers whose overall demand varies widely from month to month may not make (through the application of standard monthly demand charges) a fair contribution to the costs based on the facilities required to serve them. This is particularly the case when compared to customers (in the same customer class) whose demands are fairly constant on a month to month basis. Introduction of a minimum demand charge helps to address this equity in extreme circumstances. For most demand billed residential customers, their summer demand exceeds 65% of winter

[173] HQD-12, Document 3, page 56
[174] HQD-15, Document 8, Question 105 a)
[175] HQD-12, Document 3, page 57
[176] HQD-12, Document 3, page 55
[177] HQD-12, Document 3, pages 28-29

demands and the "additional" minimum billing charge will not be incurred[178]. Finally, the implementation of minimum demand bills for large residential customers is consistent with HQD's treatment of demand billed Rate G customers.

With respect to the third change, the inclusion of a power factor adjustment also simply reflects for the larger residential customers, a practice that is currently in place for Rate G and M customers[179] and should be considered acceptable. HQD has indicated that all demand-billed residential customers do not have meters capable of measuring kVA. However, HQD does not intend to incur additional costs by accelerating the replacement of these meters. Rather, they will be replaced with the appropriate meter at the end of their useful life[180].

6.3 Closure of Rate DM

6.3.1 HQD Proposal

Currently bulk metered apartment buildings[181] can choose to be billed on Rate DM or the applicable general rate[182]. The underlying principle was to permit residential customers in bulk-metered buildings to be subject to similar rates to those applied to residential customers who were individually metered[183].

In its current Application, HQD is proposing to close Rate DM to new customers. After April 1, 2008, any owner of a new bulk metered building will have a choice of being billed on Rate D or the applicable general rate. Buildings currently on Rate DM or those

[178] HQD-15, Document 8, Question 105 c)
[179] HQD-13, Document 3, page55
[180] HQD-15, Document 8, Question 106 a)
[181] Or, more specifically, the owners of bulk metered apartment buildings
[182] HQD-15, Document 8, Question 107 b)
[183] HQD-12, Document 3, page 59

where construction started before April 1, 2008 will continue to be eligible for the Rate DM after April 1, 2008[184].

6.3.2 Comments

HQD's rationale is that occupants of bulk metered buildings do not see the rates (i.e., they do not pay the electricity bill directly based on their individual usage). As a result, in today's circumstance where the focus is to encourage efficient use through proper price signals, there is a need to discourage the adoption of bulk metering for new apartment buildings.

While not stated explicitly, the Application of Rate DM is likely to produce a lower electricity bill for an Apartment building than the simple application of Rate D. This is because the reduced monthly energy charges resulting from Rate DM's application of the 1st energy block rate per apartment unit more than offsets the increase in monthly charges due to the application of the monthly service charge on a per unit basis. Furthermore, under HQD's rate strategy, this difference will grow in the future, since the customer charge remains fixed but the differential in energy rates for the two blocks will increase. This difference could incent new apartment owners to choose bulk metering. As a result, in today's context, HQD's proposal is reasonable.

[184] HQD-15, Document 8, Question 107 b)

7 RESIDENTIAL TOU RATE EXPERIMENT

7.1 HQD Proposal

Both the Government's Energy Strategy and the Régie have expressed a strong interest in time of use (TOU) pricing[185]. In the current Application, HQD has put forward a proposal for a residential TOU experiment. The experiment would involve over 2,000 customers and test[186], not only customers' response to different TOU rate forms, but also test:

- Whether the impact of TOU rates can be increased through energy efficiency coaching,
- The extent to which load response depends on the climate zone involved and
- The use of different technologies for metering and communication.

HQD anticipates that the actual experiment will run from October 2008 to March 2010, following which an economic evaluation will be performed.

7.2 Comments

Need for a Pilot

Time of use rates are used in a number of jurisdictions and interest in them is growing in other Canadian jurisdictions[187]. As a result, it is reasonable for both the Québec Government and the Régie to inquire as to what role TOU pricing could play in supporting the efficient use of electricity in Québec. On the other hand, implementation of TOU rates and, in particular, the supporting metering and communication systems can be fairly expensive. Indeed, preliminary estimates provided by HQD suggest a

[185] HQD-12, Document 5, page 5
[186] HQD-12, Document 5, pages 40-46
[187] Canadian jurisdictions with some degree of interest in TOU rates include Ontario, British Columbia and Manitoba.

range of $60 to $450 / customer / year[188]. In addition, the likely response to TOU rates, within the Québec context, is not known. This gives rise to the need for some caution going forward and suggests that HQD's proposal for a TOU rate experiment is prudent.

Basis for Evaluation

There are at least three different types of evaluation that need to be carried out following the completion of the experiment. The first is to evaluate customers' response to TOU rates, this would include the assessment of such issues as the extent to which customer's shift load between peak and off-peak periods and/or change total energy use in response to TOU rates. This analysis will be multi-dimensional as it will also consider the impact of complimentary initiatives such as energy efficiency coaching and the provision of real-time information (e.g. critical peak pricing). It will also need to evaluate the issue of free-riders, an inherent problem in any program that is voluntary.

The second evaluation relates to the options available for metering and communications. The experiment should provide some insight into not only the costs of such options but their success in supporting TOU pricing.

The third evaluation would use the results of the first two and look at the overall economics of a TOU program for Québec residential customers. This should initially be done on global basis without regard as to who would pay for the meters and supporting communication technology. Within this context, it will need to compare the anticipated savings from load changes induced by TOU rates with the incremental costs required in order to implement TOU rates. If TOU program is not cost-effective there is little merit in engaging in debates as to who should pay for it, since (from an economic perspective) the program should not proceed.

[188] HQD-12, Document 5, page 39

HQD's avoided costs do not exhibit significant variation between the peak and off-peak periods and the definition of the peak period is fairly broad. Both of these factors are likely to reduce the amount of load shifting that customers undertake in response to TOU rates and, thereby, produce lower benefits. However, it is important to recognize that the implementation of the advanced metering and communication technologies required to support TOU rates can have other system benefits[189]. To the extent possible, these benefits should also be quantified and included in the economic evaluation.

[189] BCHydro's Conservation Research Initiative Residential Time of Use Rate Application, August 2006, page 4

8 CONCLUSIONS

A summary of the key comments and conclusions is set out below.

8.1 Treatment of Select Deferral/Variance Accounts

8.1.1 Pass-On Account

Determination of Account Balances

- HQD's claim that it is unable to accurately separate out the impact of weather variations is credible.
- The three adjustments that HQD has proposed regarding the calculation of the Pass-On Account balance are all reasonable.
- Future consideration should be given to merging the Pass-On and Interruptible Option Deferral Accounts

Refund/Recovery of Pass-On Account Balances

- HQD proposal that the refund/recovery of Pass-On Account balances be considered on a case by case basis is reasonable. Furthermore, the approach that HQD has proposed, which considers inter-generational equity and rate stability, is appropriate.

8.1.2 Transmission Deferral Account

- There are no issues with HQD's approach to either the determination of the balances or its proposal for refund/recovery of the Account's balances.

8.2 Cost Allocation

8.2.1 PGEÉ Program Costs

- HQD's proposed approach is correct at a "conceptual level" but the concept has been implemented incorrectly.
- PGEÉ programs are a cost-effective way of meeting customers' needs with respect to Supply, Transmission and Distribution Service. HQD should use the cumulative savings from PGEÉ programs and its avoided costs for Supply, Transmission and Distribution to determine the total avoided costs associated with each function. PGEÉ program s should then be allocated to these functions in proportion to the total cost avoided by function. The PGEÉ costs attributed to each of these functions should then be allocated to customer classes in the same manner as other costs assigned to the respective functions.

8.2.2 HQT's Transmission Costs

- HQT's transmission charges should continue to be allocated on the basis of 1-CP.

8.2.3 Transmission Related Costs

- HQD's proposed cost allocation treatment of various Transmission-related costs is reasonable. However, there is a need to assess the general cost allocation approach used for deferral/ variance accounts related to forecast error.

8.2.4 New Cost Items/Allocation Methodology Changes

- HQD's proposed cost allocation treatments for Schefferville supply costs; the Temperature Averaging Account, and Development costs are all appropriate.
- HQD's proposal to refine its cost allocation methodology to reflect data availability improvements is consistent with past practices approved by the Régie.

8.2.5 Pass-On Account Recovery

- The approach used by HQD to allocate actual Post-Heritage supply costs to customer classes, as part of the Pass-On Account balance determination, is reasonable.

8.2.6 General Treatment of Deferral/Variance Account Balances

- For accounts where the purpose is to "true-up" forecast errors, a question of principle arises as to whether related costs should be assigned to customer classes using:
    - The allocation methodology and allocation factors that existed at the time the costs were accrued, or
    - The allocation methodology and allocation factors applicable for the test year under consideration.

  HQD's practice in this area is not consistent throughout the Application.
- The principle of cost causality would suggest that costs related to such deferral/variance accounts should be allocated to customer classes based on the methodology and allocation factors associated with the year for which the costs were incurred. However, issues of materiality and practicality must also be considered.

- Overall, the cost allocation treatment of future Transmission Deferral Account accruals and PTP rebates/recoveries by HQT should be based on the allocation methodology and factors for the year the costs are associated with.

8.3 Cross-Subsidization Index

8.3.1 HQD's Rate Differential Methodology

- Pass-On Account refund/recoveries should be treated as a "methodological change" in the determination of shifts in cost responsibility among customer classes.
- HQD's proposed approach should not be considered a precise calculation of the shift in costs responsibility among customer classes in the test year. Indeed, there are variations of the calculation that yield materially different results.

8.3.2 Implications of a 4.4% Residential Rate Increase

- When considering the merit of a differentiated rate increase by customer class, the Régie should take into account not only available information on shifts in cost responsibility but also the resulting average rate increase and range of bill impacts by customer classes.

8.4 Residential Rate Design

8.4.1 Overall Rate Structure

- HQD's approach to adjusting residential rates for 2008 is reasonable.
- There are trade-offs involved in introducing a third energy block or altering the threshold of the second energy block by season. The only potential change that

may have merit is an increase to 35 kWh/day in the threshold for the 1st energy block for the winter core months.

8.4.2 Closure of Rate DM and Changes to the Residential Demand Charge

- HQD's proposal to close the DM rate to new customers effective April 1, 2008 is reasonable.
- HQD's proposed changes in the application of demand charges to large residential customers are also reasonable.

8.5 Residential TOU Experiment

- HQD's proposal for a residential TOU experiment is a prudent first set in assessing the merits of time of use pricing.
- HQD's evaluation of TOU pricing should carefully consider all of the costs and benefits of introducing advanced metering and communication technologies.

APPENDIX A

CV FOR ECS CONSULTANT

William O. Harper

Mr. Harper has over 25 years experience in the design of rates and the regulation of electricity utilities. While employed by Ontario Hydro, he has testified as an expert witness on rates before the Ontario Energy Board from 1988 to 1995, and before the Ontario Environmental Assessment Board. He was responsible for the regulatory policy framework for Ontario municipal electric utilities and for the regulatory review of utility submissions from1989 to 1995. Mr. Harper also coordinated the participation of Ontario Hydro (and its successor company Ontario Hydro Services Company) in major public reviews involving Committees of the Ontario Legislature, the Ontario Energy Board and the Macdonald Committee. He has served as a speaker on rate and regulatory issues for seminars sponsored by the APPA, MEA, EPRI, CEA, AMPCO and the Society of Management Accountants of Ontario. Since joining ECS, Mr. Harper has provided consulting support for client interventions on energy and telecommunications issues before the Ontario Energy Board, Manitoba Public Utilities Board, Québec's Régie de l'énergie, British Columbia Utilities Commission, and CRTC. He has also appeared before the Manitoba's Public Utilities Board, the Manitoba Clean Environment Commission, the Ontario Energy Board and Quebec's Régie de l'énergie. Bill is currently a member of the Ontario Independent Electricity System Operator's Technical Panel.

EXPERIENCE

Econalysis Consulting Services- Senior Consultant
2000 to present

- Responsible for supporting client interventions in regulatory proceedings, including issues analyses & strategic direction, preparation of interrogatories, participation in settlement conferences, preparation of evidence and appearance as expert witness (where indicated by an asterix). Some of the more significant proceedings included:

- <u>Electricity (Ontario)</u>
  - IMO 2000 Fees (OEB)
  - Hydro One Remote Communities Rate Application 2002-2004
  - OEB - Transmission System Code Review (2003)
  - OEB - Distribution Service Area Amendments (2003)
  - OEB - Regulated Asset Recovery (2004)
  - OEB - 2006 Electricity Rate Handbook Proceeding*
  - OEB - 2006 Rate Applications by Various Electricity Distributors
  - OEB - 2006 Guidelines for Regulation of Prescribed Generation Assets
  - OEB -2007 Rate Applications by Various Electricity Distributors
  - OEB- 2007 Cost of Capital and 2nd Generation Incentive Regulation Proceeding
  - OEB - Hydro One Networks 2007/2008 Transmission Rate Application

- Electricity (British Columbia)
  - BC Hydro IPP By-Pass Rates
  - BC Hydro Heritage Contract Proposals
  - BC Hydro's 2004/05 and 2005/06 Revenue Requirement Application
  - BC Hydro's CFT for Vancouver Island Generation – 2004
  - BC Hydro's 2005 Resource Expenditure and Acquisition Plan
  - BC Hydro's 2006 Residential Time of Use Rate Experiment Application
  - BC Hydro's 2006 Integrated Electricity Plan
  - BC Hydro's 2007 Rate Design Application
  - BC Transmission Corporation – Open Access Transmission Tariff Application -2004
  - BCTC's 2005/06 Revenue Requirement Application
  - BCTC's – 2005 Vancouver Island Tranmission Reinforcement Project
  - BCTC's 2006/07 Revenue Requirement Application
  - WKP Generation Asset Sale
  - Fortis BC's 2005 Revenue Requirement and System Development Application
  - Fortis BC's 2006 Revenue Requirement Application
  - Fortis BC's 2007/08 Capital Plan and System Development Plan
  - Fortis BC's 2007 Revenue Requirement Application
  - FortisBC's 2007 Rate Design Application

- Electricity (Quebec)
  - Hydro Québec-Distribution's 2002-2011 Supply Plan*
  - Hydro Quebec-Distribution's 2002-2003 Cost of Service and Cost Allocation Methodology*
  - Hydro Québec - Distribution's 2004-2005 Tariffs*
  - Hydro Québec - Distribution's 2005/2006 Tariff Application*
  - Hydro Québec - Distribution's 2005-2014 Supply Plan*
  - Hydro Québec - Distribution's 2006/2007 Tariff Application*
  - Hydro Québec - Transmission's 2005 Tariff Application*
  - Hydro Québec - Distribution's 2006 Interruptible Tariff Application
  - Hydro Québec - Distribution's 2006 Cost Allocation Work Group
  - Hydro-Québec - Transmission's 2007 Tariff Application
  - Hydro-Québec - Distribution's 2007/08 Tariff Application*

- Electricity (Manitoba)
  - Manitoba Hydro's Status Update Re: Acquisition of Centra Gas Manitoba Inc.*
  - Manitoba Hydro's Diesel 2003/04 Rate Application
  - Manitoba Hydro's 2004/05 and 2005/06 Rate Application*
  - Manitoba Hydro/NCN NFAAT Submission re: Wuskwatim*
  - Manitoba Hydro's 2005 Cost of Service Methodology Submission*
  - Manitoba Hydro's 2007 Rate Adjustment Application

- Natural Gas Distribution
  - Enbridge Consumers Gas 2001 Rates
  - BC Centra Gas Rate Design and Proposed 2003-2005 Revenue Requirement
  - Rate of Return on Common Equity (BCUC)

- Terasen Gas (Vancouver Island) LNG Storage Project (2004)

- Telecommunications Sector
  - Access to In-Building Wire (CRTC)
  - Extended Area Service (CRTC)
  - Regulatory Framework for Small Telecos (CRTC)

- Other
  - Acted as Case Manager in the preparation of Hydro One Networks' 2001-2003 Distribution Rate Applications
  - Supported the implementation of OPG's Transition Rate Option program prior to Open Access in Ontario
  - Prepared Client Studies on various issues including:
    - The implications of the 2000/2001 natural gas price changes on natural gas use forecasting methodologies.
    - The separation of electricity transmission and distribution businesses in Ontario.
    - The business requirements for Ontario transmission owners/operators.
    - Various issues associated with electricity supply/distribution in remote communities
  - Member of the OEB's 2004 Regulated Price Plan Working Group
  - Member of the OEB's 2005/06 Cost Allocation Technical Advisory Team
  - Member of the IESO Technical Panel (April 2004 to Present)

Hydro One Networks
Manager - Regulatory Integration, Regulatory and Stakeholder Affairs
(April 1999 to June 2000)

- Supervised professional and administrative staff with responsibility for:
  - providing regulatory research and advice in support of regulatory applications and business initiatives;
  - monitoring and intervening in other regulatory proceedings;
  - ensuring regulatory requirements and strategies are integrated into business planning and other Corporate processes;
  - providing case management services in support of specific regulatory applications.
- Acting Manager, Distribution Regulation since September 1999 with responsibility for:
  - coordinating the preparation of applications for OEB approval of changes to existing rate orders; sales of assets and the acquisition of other distribution utilities;
  - providing input to the Ontario Energy Board's emerging proposals with respect to the licences, codes and rate setting practices setting the regulatory framework for Ontario's electricity distribution utilities;
  - acting as liaison with Board staff on regulatory issues and provide regulatory input on business decisions affecting Hydro One Networks' distribution business.
- Supported the preparation and review before the OEB of Hydro One Networks' Application for 1999-2000 transmission and distribution rates.

Ontario Hydro
Team Leader, Public Hearings, Executive Services (Apr. 1995 to Apr. 1999)

- Supervised professional and admin staff responsible for managing Ontario Hydro's participation in specific public hearings and review processes.
- Directly involved in the coordination of Ontario Hydro's rate submissions to the Ontario Energy Board in 1995 and 1996, as well as Ontario Hydro's input to the Macdonald Committee on Electric Industry Restructuring and the Corporation's appearance before Committees of the Ontario Legislature dealing with Industry Restructuring and Nuclear Performance.

Manager – Rates, Energy Services and Environment (June 1993 to Apr. 95)
Manager – Rate Structures Department, Programs and Support Division
(February 1989 to June 1993)

- Supervised a professional staff with responsibility for:
    - Developing Corporate rate setting policies;
    - Designing rates structures for application by retail customers of Ontario Hydro and the municipal utilities;
    - Developing rates for distributors and for the sale of power to Hydro's direct industrial customers and supporting their review before the Ontario Energy Board;
    - Maintaining a policy framework for the execution of Hydro's regulation of municipal electric utilities;
    - Reviewing and recommending for approval, as appropriate, municipal electric utility submissions regarding rates and other financial matters;
    - Collecting and reporting on the annual financial and operating results of municipal electric utilities.
- Responsible for the development and implementation of Surplus Power, Real Time Pricing, and Back Up Power pricing options for large industrial customers.
- Appeared as an expert witness on rates before the Ontario Energy Board and other regulatory tribunals.
- Participated in a tariff study for the Ghana Power Sector, which involved the development of long run marginal cost-based tariffs, together with an implementation plan.

Section Head – Rate Structures, Rates Department
November 1987 to February 1989

- With a professional staff of eight responsibilities included:
    - Developing rate setting policies and designing rate structures for application to retail customers of municipal electric utilities and Ontario Hydro;
    - Designing rates for municipal utilities and direct industrial customers and supporting their review before the Ontario Energy Board.
- Participated in the implementation of time of use rates, including the development of retail rate setting guidelines for utilities; training sessions for Hydro staff and customers presentations.
- Testified before the OEB on rate-related matters.

Superintendent – Rate Economics, Rates and Strategic Conservation Department
February 1986 to November 1987

- Supervised a Section of professional staff with responsibility for:
    - Developing rate concepts for application to Ontario Hydro's customers, including incentive and time of use rates;
    - Maintaining the Branch's Net Revenue analysis capability then used for screening marketing initiatives;
    - Providing support and guidance in the application of Hydro's existing rate structures and supporting Hydro's annual rate hearing.

Power Costing/Senior Power Costing Analyst, Financial Policy Department
April 1980 to February 1986

- Duties included:
    - Conducting studies on various cost allocation issues and preparing recommendations on revisions to cost of power policies and procedures;
    - Providing advice and guidance to Ontario Hydro personnel and external groups on the interpretation and application of cost of power policies;
    - Preparing reports for senior management and presentation to the Ontario Energy Board.
- Participated in the development of a new costing and pricing system for Ontario Hydro. Main area of work included policies for the time differentiation of rates.

Ontario Ministry of Energy
Economist, Strategic Planning and Analysis Group
April 1975 to April 1980

- Participated in the development of energy demand forecasting models for the province of Ontario, particularly industrial energy demand and Ontario Hydro's demand for primary fuels.
- Assisted in the preparation of Ministry publications and presentations on Ontario's energy supply/demand outlook.
- Acted as an economic and financial advisor in support of Ministry programs, particularly those concerning Ontario Hydro.

EDUCATION
Master of Applied Science – Management Science

- University of Waterloo, 1975
- Major in Applied Economics with a minor in Operations Research
- Ontario Graduate Scholarship, 1974

Honours Bachelor of Science

- University of Toronto, 1973
- Major in Mathematics and Economics
- Alumni Scholarship in Economics, 1972