**RÉGIE DE L'ÉNERGIE**
**R-3552-2004**

# EVIDENCE ON

# Regulatory Treatment of the Costs of Hydro Quebec Distribution PGEÉ 2005-2010

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**FILED ON BEHALF OF**
**OPTION CONSOMMATEURS**

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# 1. INTRODUCTION

## 1.1 Background

Option Consommateurs (OC) engaged ECS[1] to assist them in their intervention in this proceeding by providing evidence on certain issues arising from Hydro Quebec Distribution's (HQD) application, Requête 3552-2004. The ECS consultants who prepared this evidence are Dr. Roger Higgin, with assistance from Ms. Brigid Rowan.

## 1.2 Qualifications of Consultants

Dr. Higgin has considerable experience in regulatory matters, including as a member of the Ontario Energy Board for seven years, and as a consultant. He has appeared as an expert witness before the Régie and other Canadian regulatory tribunals. Specifically, Dr. Higgin's experience is particularly relevant to provide the evidence in the current filing:

- He was an Assistant Deputy Minister responsible for Ontario's Energy Conservation and Renewable Energy Programs in the 1980s. He was also responsible for the City of Toronto Energy Conservation Office in the early 1990s.
- As a Member of the OEB for seven years, he sat on several OEB panels, which reviewed the Conservation Programs of Ontario Hydro and the Demand Side Management programs of the Ontario gas utilities.
- Since 2000, he has, inter alia, provided consulting advice to public interest intervenors on regulatory matters related to DSM and is a member of the DSM consultatives of Union Gas and Enbridge Gas Distribution.

[1] Dr. Roger Higgin is an Associate Senior Consultant and Ms. Brigid Rowan is an Associate Consultant with Econalysis Consulting Services Inc. ECS specializes in providing assistance and advice to public interest intervenors in Canadian regulatory proceedings. Please see www.econalysis.ca for information on ECS and the consultants' full curriculum vitae.

- Most recently he has testified in Manitoba on the Manitoba Hydro DSM Programs before the Clean Environment Commission and provided advice to clients on the regulatory treatment of the first generation C&DM (Conservation and Demand Management) programs of a Coalition of Six Large Utilities (CLU), as well as the C&DM programs of Hydro One Distribution.

Dr. Higgin's CV is attached as Appendix A.

Ms. Brigid Rowan has provided research and analysis in support.

### 1.3 Purpose of Evidence

OC requested that the evidence prepared by ECS focus on the following issues:

- Is the new HQD PGEÉ[2] designed in conformity with established regulatory principles and practice?
- Is HQD's PGEÉ designed with the goal that over the longer term of the program, customer bills are neutral, i.e. rate increases derived from the PGEÉ should be cancelled out by bill savings?
- Are the annual increases in rates resulting from the PGEÉ reasonable, given likely increases in other costs of service?
- Do lower-income consumers of HQD have an equal opportunity to participate in PGEÉ programs, or do they pay the costs, but do not proportionally enjoy the same direct benefits?

[2] Throughout this evidence, we have used EE/DSM, as a general term to describe Energy Efficiency/Demand Side Management programs. Generally, in North America EE (Energy Efficiency) includes programs that reduce the demand on the utility side of the meter (e.g., reduction of transmission/distribution line losses), whereas DSM (Demand Side Management) programs reduce demand on the customer side of the meter (e.g., weatherization measures). Conservation & Demand Management (C&DM) is the particular name for EE/DSM in Ontario that covers both utility and demand side programs.

- Are there mechanisms to protect consumers from under-spending of budgets and under-achievement of energy savings?

## 2. CANADIAN EE/DSM EXPERIENCE

In order to provide some context for the ECS review of HQD's new PGEÉ 2005-2010, the following Canadian distribution utility EE/DSM programs were briefly reviewed:

- British Columbia: BC Hydro and FortisBC
- Manitoba: Manitoba Hydro
- Ontario: Coalition of Large Utilities and Hydro One Distribution.

### 2.1 British Columbia

BC Hydro and FortisBC have EE/DSM programs approved by the British Columbia Utilities Commission.

The BC Hydro PowerSmart Program[3] has a horizon from 2002-2012. The 10-Year Plan has a target of 3.62 TWh of energy savings (base case) at an average utility cost of 2.1¢/kWh and a Total Resource Cost (TRC) of 4.4¢/kWh. The total utility investment is $690 million ($2003).

FortisBC instituted its Demand Side Management Program in 2003. The target is 141GWh by 2014[4]. The 2003 savings were 18.5 GWh and the budget $ 1.7 million[5] comprising just over 1% of gross revenues.

[3] BC Hydro PowerSmart 10-Year Plan as filed in Revenue Requirement Application 2004-05 and 2005-06.
[4] FortisBC 2005 Resource Plan filed with the British Columbia Utilities Commission (BCUC).
[5] FortisBC 2005 Revenue Requirement Application, Tab 10, Appendix B, page 2,filed with the BCUC.

## 2.2 Manitoba

As of the end of 2001-2002, the Manitoba Hydro PowerSmart Program had achieved a cumulative annual load reduction of 488 GWh and a 179.2 MW reduction in winter peak.

The 2003 Integrated Financial Forecast Sequence projects 299 MW of peak reduction and savings of 983 GWh by 2011-2012[6]. The Levelized Energy Costs associated with the current DSM PowerSmart Plan are projected by Manitoba Hydro to be in the range of $18.3 / MWh to $71.6 / MWh[7].

### *2.2.1 New 2005 DSM PowerSmart Program*

In 2004 Manitoba Hydro retained consultants to examine the potential for an expanded PowerSmart Program.[8] An extraction of the data is shown in Table 4. The consultants' studies considered the savings that can be achieved relative to a baseline for each sector. The savings resulting from utility DSM programs are categorized into:

- Economic Potential, representing technical potential based on certain tests, and
- Achievable (Market) Potential Upper and Achievable (Market) Potential Most Likely. The latter representing the practicable level.

Manitoba Hydro has not yet filed a detailed design of its new DSM PowerSmart Program. As a result, it has not determined either what the final targets will be or the utility cost of the new program. It is expected that a review of the expanded DSM PowerSmart programs and associated costs and benefits will occur in 2005 at the Manitoba Public Utilities Board (MPUB).

[6] Manitoba Hydro Review of the Wuskwatim Hydro Project before the Manitoba Clean Environment Commission, Need For And Alternatives To, Chapter 6, Page2, Section 6.1.1.
[7] Op.Cit Reference 3, Information Request Response CAC/MSOS/NFAAT /S/1a.
[8] Demand Side Energy Consultants Inc et al, DSM Market Potential Studies 2003, Residential, Commercial and Industrial/Agricultural Sectors.

## 2.3 Ontario

### *2.3.1 Distribution Utility Conservation & Demand Management Initiatives*

The Ontario Minister of Energy directed Ontario's electricity distributors to embark on Conservation and Demand Management (C&DM)[9] initiatives as a condition of removing the Government's 2003 rate freeze and increasing 2005 distribution rates to include a full market-based rate of return on equity.

On November 4, 2004, the Ontario Energy Board received C&DM applications from six utilities: Enersource Hydro Mississauga, Hamilton Hydro, Hydro Ottawa Limited, PowerStream Inc., Toronto Hydro Electric System Limited and Veridian Connections Inc. Those applicants applied as a group known as the Coalition of Large Distributors or CLD.

Collectively, the CLD utilities provide service to over 1.5 million customers or 40 percent of the Ontario total. The C&DM plans, which reflect the amounts just referred to, represent a total of over $70 million over the period 2005-2007. In approving the cost consequences, the OEB noted that these programs are essentially pilot programs. There have been no kWh targets established or any cost/benefit analysis using the Total Resource Cost (TRC) and Rate Impact Measure (RIM) tests.

In December 2004, Hydro One Distribution/Brampton Hydro (Hydro One D) with 1.2 million customers, applied for its first generation 2005 C&DM program. The Hydro One D C&DM plan proposes expenditures of $42.5 million over the period 2005 to 2007. A significant percentage of expenditures are on utility-side load management and loss reduction programs. These programs are also pilot

[9] Minister's letter of May 10, 2004. C&DM includes both utility-side and customer-side initiatives

programs and there have been no kWh targets established or any cost/benefit analyses using the TRC and RIM tests.

### *2.3.2 2006 Electricity Distribution Rates*

All 90 Ontario electricity distribution utilities will be required to file for new rates for the 2006 fiscal year. The applications will be made in a cost of service framework based on a new rate handbook and rate model. As part of those applications, utilities are eligible to include costs related to Conservation and Demand Management programs for 2006. For utilities that have approved first generation C&DM programs, the incremental costs may be recovered in rates in 2006; for others, new programs may be initiated. The OEB is expected to issue a C&DM Manual and Guidelines to accompany the 2006 Rate Handbook.

## 2.4 Level of Investment in EE/DSM

The appropriate range of EE/DSM investment is a function of several key factors:

- Whether the utility is publicly-owned or investor-owned
- Supply/demand plan
- Avoided cost
- Gross and sectoral EE/DSM targets
- Measures/programs that pass the TRC and RIM/RNT (Rate Impact Measure/Rate Neutrality Test) based on conservative assumptions
- Number of participants/cofunders
- Resources and delivery capacity.

**TABLE 1**

**COMPARISON OF *ANNUAL* CANADIAN UTILITY EE/DSM INVESTMENTS**

| Utility | Annual Energy Sales MWh | Annual EE/DSM Savings MWh | Annual Savings as % of sales | Investment as % of Gross Revenue |
|---|---|---|---|---|
| BC Hydro 2003 | 47,800,000 | 388,000 | 0.81 | 1.9 |
| FortisBC 2003 | 2,800,000 | 18,500 | 0.66 | 1.1 |
| Manitoba Hydro 2003 | 17,000,000 | 108,000 | 0.64 | 1.0 |
| CLD Ontario 2005-07 | 53,300,000 | n/a | n/a | 0.2 |
| Hydro One D 2005-07 | 26,200,000 | n/a | n/a | 0.2 |
| HQD 2004[10] | 166,400,000 | 167,000 | 0.1 | 0.5 |
| HQD2005 | 169,300,000 | 221,000 | 0.13 | 1.3 |

The above data show that the HQD PGEÉ 2005-2010 is second in Canada to the BC Hydro PowerSmart Program in terms of investment as a percentage of revenue.

HQD provides benchmark data for EE/DSM in the United States and for the BC Hydro PowerSmart Program in IR 3.1 from the Régie in HQD-5 Doc1, pp 7-9. This shows EE/DSM investments per capita and as a percentage of revenues.

HQD also reproduces a Scorecard on US utility EE/DSM investments, including savings expressed as ¢/kWh in HQD-5, Doc 7, Page 6, IR 2.2 from Union des consommateurs to HQD.

[10] Calculations by ECS using Data from R-3552-2004, HQD-1, Doc 1, Tables 3.2 and 3.4.

In HQD-1, Document 1, page 24, HQD states that it is "in the top 10 rank of US utilities" on the basis of EE/DSM investments/capita and on the basis of the ratio of EE/DSM investments to electricity sales revenue.

## 3. REGULATORY AND ACCOUNTING TREATMENT OF EE/DSM COSTS

### 3.1 Regulatory Models for EE/DSM Programs

There are two broad types of regulatory models for EE/DSM: 1) the Rate Integrated Model and 2) the Segregated Model.

#### *3.1.1 Rate Integrated Model*

This model is most common. The costs (O&M and Capital) and revenues associated with the utility EE/DSM program are part of the overall utility cost of service and annual revenue requirement and the assets are part of the rate base of the utility. There is usually a reduction in load forecast and distribution revenues as a result of EE/DSM and there may be a corresponding revenue loss offset adjustment.

The EE/DSM component of the revenue requirement is functionalized and allocated to rate classes through the utility cost allocation model. If the utility is bundled then the allocator is often kWh usage.

If the regulator has approved lost revenue mechanism and/or an incentive scheme, then tracking of costs and energy savings and deferral accounting is required with periodic recovery of eligible costs.

### *3.1.2 Segregated Rate Model*

The segregated rate model retains and accounts for the EE/DSM costs separately from the utility cost of service. The utility charges each customer an amount on a per customer, or energy use basis for the marginal or fully allocated costs of the DSM program. Alternatively, the utility applies a surcharge, often referred to as a Public Benefit Charge (PBC) similar to an uplift charge on a per kWh or per customer basis.

The lost revenue payment and any utility incentive are part of the monthly charge.

*The review in this section of the report addresses the rate-integrated model, which is the regulatory model currently used for HQD.*

## 3.2 Regulatory Principles

The regulatory principles applicable to EE/DSM are no different than those applicable to other utility costs:

- Costs must be prudently incurred.
- Rate base assets acquired by the utility must be used and useful.
- Utility costs are allocated to classes based on principles of cost causality.
- Costs and benefits should be matched (where applicable).

## 3.3 Capitalization of EE/DSM Costs

The regulatory approach to expensing or capitalizing/amortization of utility EE/DSM expenses varies widely across jurisdictions. Apart from the issue of rate base treatment of utility-owned assets that are used and useful, there is a key issue. This issue addresses whether capitalization/amortization of other EE/DSM

costs (e.g., incentive payments to participants and administration costs) provides a better temporal matching of costs and benefits (savings).

For example, the BCUC requires FortisBC to capitalize all direct EE/DSM costs and then to apply straight-line depreciation of 12.5% (equivalent to a seven-year amortization period), subject to certain conditions:

- The EE/DSM to be capitalized must be net of income taxes.
- FortisBC must file semi-annual reports.
- Projects must meet the TRC test.

*The capitalization approach approved for HQD is outlined in Section 4.*

### 3.4 Cost Allocation and Rate Design

A study commissioned by the National Association of Regulatory Utility Commissioners[11] outlined four equity principles in allocating costs and benefits of EE/DSM programs:

- cost causation
- equal opportunities to participate in EE/DSM programs
- direct allocation to actual participants
- allocation to participating customer classes.

The study concluded that marginal cost may be the fairest approach.

In general, EE/DSM program costs can be allocated in one of the following constructs:

- On an energy basis: $/kWh
- On a demand basis: $/kW

[11] Cost Allocation for Electric Utility Conservation and Load Management Programs, NARUC, March 1993.

- On a per customer basis: $/customer
- Specific assignment to rate class or participant.

### 3.5 Program Cost Effectiveness Tests

Certain tools have been used by EE/DSM program designers and regulators in order to assist in determining whether regulatory principles are met for proposed and actual EE/DSM program expenditures. These include:

- Calculation of the utility avoided cost
- Calculation of a  Cost of Conserved Energy (CCE)
- Total Resource Cost (TRC)Test for EE/DSM measures
- Participant Cost (PC)Test
- Rate Impact Measure (RIM) or Rate Neutrality Test (RNT).

The choice of which test(s) to apply depends on the objective of the EE/DSM program (e.g., the reduction of energy use or coincident peak demand). The avoided cost for the EE/DSM program depends on whether the utility is integrated or unbundled.

EE/DSM programs generally reduce demand and lower marginal costs of electricity to consumers. However, the EE/DSM program costs increase the utility revenue requirement and price of electricity (or in the case of unbundled distribution utility, the cost of distribution service).

For utility customers, the introduction of EE/DSM programs often means that the utility revenue requirement and unit rates increase in the short term. If the TRC is positive when considered either overall or on a class basis, then over the term of the EE/DSM program, utility costs will decrease, provided the avoided cost is correctly calculated based on long-run marginal cost. However, there can be

significant timing differences between paying for EE/DSM costs in rates and receiving the benefit of lower electricity bills.

Another issue is whether the RIM/RNT should be positive either overall or on a class basis. The significance of the RIM/RNT is that even though rates increase, customers should, on average, use less energy and have lower bills.

## 3.6 Lost Revenue Adjustment (LRAM) Mechanisms

When utilities engage in EE/DSM, they not only incur the cost of those programs, but they are also subject to a potential loss in revenues. Utilities therefore need mechanisms in place that address this loss in order to remove the financial disincentive of implementing EE/DSM. LRAMs compensate utilities for revenues that they would have recovered had they not promoted energy efficiency.

LRAMs compensate for the fact that utility costs are still incurred but are spread over a smaller sales base as a result of EE/DSM activities. LRAMs are designed to make EE/DSM a revenue-neutral activity and keep the utility financially whole, regardless of the level of EE/DSM that is achieved.

There are two main types of lost revenue adjustment mechanisms: a surcharge account and a deferral account.[12]

### *3.6.1 Surcharge Account Mechanism*

Surcharges are reflected on customer bills as rate adjustments that are generally rolled into an overall C&DM surcharge. Deferral accounts allow the utility to track

[12] Baxter, L. "Understanding net lost revenue adjustment mechanisms and their effects on utility finances". *Utilities Policy* Vol. 5, No. 3/4, pp. 175-184. 1995.

net lost revenue and recover it at the next rate case. A hybrid LRAM uses a forecast and variance account with a true-up.

There are two types of surcharges: *prospective and retrospective*. The decision as to which is adopted is often linked to the use of a forward or historic rate year.

*A prospective surcharge* mechanism recovers the lost revenue as a result of the current year's C&DM activities. In other words, this means that net lost revenue is recovered in the same period the utility incurs these losses. Under a prospective surcharge mechanism, the utility files a forecast of C&DM savings and associated net loss revenue for the upcoming program year.

The projected C&DM savings and consequent net loss revenue forecast are translated into a rate surcharge. The surcharge may be levied on all customers, or allocated across customer classes. A subsequent reconciliation is undertaken with the initial net lost revenue forecast. An assessment or audit of EE/DSM program performance is then needed. With this mechanism, a utility will typically include the net lost revenue reconciliation from earlier program years with its forecast of net lost revenue for the upcoming program year. This is often called an LRAM Variance Account.

Alternatively, the surcharge may also be designed to amortize net lost revenue recovery for the current program year over a series of years. A typical time period in use is the estimated average life of the measures installed that year.

*A retrospective surcharge*, on the other hand, is designed to recover revenue lost from C&DM activity in a previous year or years. In all other respects, the retrospective and prospective surcharges are very similar. A retrospective surcharge is also similar to a deferral account, except that the retrospective

surcharge does not necessarily require waiting until the next rate case before recovery can begin, increasing certainty of recovery for the utility.

### *3.6.2 Deferral Account Mechanism*

The most common LRAM used to compensate for lost revenues is the deferral account. In a given year, the utility calculates the amount of volume or kWh losses due to its own C&DM initiatives. (This must be calculated net of any general efficiency trends).

A deferral account uses a tracking system that records monthly net lost revenue estimates. The utility then receives authorization to recover this estimated net lost revenue at its next rate case.

Many investor-owned utilities are allowed to use an LRAM and/or an LRAM variance account. It is less common for crown-owned utilities.

## 3.7 Shared Savings and Other Shareholder Incentive Mechanisms

Unbundled distribution utilities have less incentive to invest in C&DM from an avoided cost of new generation perspective[13], unless the TRC is appropriately structured such that the cost-benefit analysis incorporates avoided generation costs.

The ultimate objective of incentive mechanisms is to provide the utility with the incentive to maximize resource savings per dollar spent on energy efficiency measures. There are three basic incentive mechanisms employed for EE/DSM programs: shared savings, bonuses, and mark-ups. There are also hybrid

[13] This is true because unbundled distribution utilities do not have control on the generation side.

mechanisms that combine elements of these types.[14] In the present regulatory context, a detailed discussion of shareholder incentives is not as relevant in the case of a crown corporation such as HQD.

## 4. REVIEW OF HQD'S ECONOMIC ANALYSIS OF PGEÉ 2005-2010

HQD's investment in the PGEÉ 2005-2010 is summarized in Table 2.

This shows the budgets and the utility and participant/utility cost split for each sector. The average cost is 4.4 ¢/kWh and varies from sector to sector. This cost compares to the avoided cost, which again varies across each sector but averages about 7.6 ¢/kWh.

**TABLE 2**

**INVESTMENTS IN PGEÉ 2005-2010**

| | PGEÉ 2005–2010 | | Total Investment 2005-2010 | | Total Savings | Cost cents per kWh |
|---|---|---|---|---|---|---|
| ¢/kWh | **HQD investment** | **Participant/ partner investment** | **TOTAL investment cents/kWh** | **Total Investment $ m[1]** | Total savings 2005-2010 GWh | |
| Residential market | 3.09 | 1.54 | **4.63** | **435.3** | 900 | 4.8 |
| Commercial and institutional markets | 2.97 | 2.33 | **5.3** | **496.9** | 1063 | 4.7 |
| Small and medium industries market | 2.79 | 1.61 | **4.4** | **64.7** | 185 | 3.5 |
| Large industries market | 1.66 | 1.25 | **2.91** | **110** | 505 | 2.2 |
| Subtotal for all markets | 2.80 | 1.65 | **4.45** | **1107** | 2653 | 4.2 |
| Core components for all markets (over all GWh of the plan) | 0.48 | 0.40 | **0.88** | **234.1** | 200 | 1.2 |
| For entire PGEÉ | 3.00 | 2.02 | **5.02** | **1341.9** | 2853 | 4.4 |

[1] Data from R-3552-2004, HQD-1, Doc 1, Tables 3.2, 3.3, 3.4, 5.2, and Annex 3, Table 3.1.

[14] Eto, J., Stoft, S., Kito, S. "*C&DM shareholder incentives: recent designs and economic theory*", Utilities Policy 7, pp 47-62, 1998.

## 4.1 HQD's Economic Analysis of PGEÉ 2005-2010

HQD has evaluated cost effectiveness of the PGEÉ 2005-2010 by the application of the standard EE/DSM tests:

- Total Resource Cost (TRC) test applied at the individual measure or program level:

  *TRC= Utility cost + participant cost - utility avoided cost*

- Participant Costs (PC) Test applied at the individual measure/program level or sectoral/rate class:

  *PCT= Participant benefit - participant cost*

- Rate Impact Measure/Rate Neutrality Test (RIM/RNT) at the individual measure and sectoral/rate class level.

  *RIMRNT= Avoided cost + lost revenues[15] - utility cost.*

The results are reported in R-3552-2004, HQD-1, Doc 1, Table 5.4 and Annex 3, Tables 3.1-3.3.

These results appear to indicate that:

- For each sector program, there is a positive benefit/cost based on the TRC test.

- For participants in the PGEÉ programs, there is a positive benefit/cost based on the PC Test.

- The result of the RIM/RNT is a <u>negative</u> $113 million[16]. This indicates that for all customers, the PGEÉ 2005-2010 rates will increase over the period 2005-2010 with the greatest impact on the revenue requirement ($138 million) occurring in 2010.[17]

[15] Lost Revenue is included in the calculation as a "negative" value.
[16] R-3552-2004, HQD-1, Doc 1, Table 5.3, Column 4.
[17] R-3552-2004, HQD-1, Doc 1, Table 5.4

## 4.2 Discussion of HQD's Economic Analysis

The RIM/RNT result is not surprising, given the fact that often the result of an EE/DSM program is to increase the utility revenue requirement in the relatively short term. This may be because of timing differences between EE/DSM expenditures and the reduction in costs of service due to deferral of marginal investments in generation, transmission and distribution. However, if the avoided cost is correctly set to account for the long-range marginal cost of generation, transmission and distribution, then costs should decrease over the life of the EE/DSM measures installed.

The main issue arising from the result of the RIM/RNT is whether it is acceptable that the new PGEÉ 2005-2010 does not meet the RIM/RNT over the long term. A second issue is whether the rate increase is reasonable. Finally, a third issue is what regulatory options are there to address this negative result if it is a concern?

With regard to the failure to meet the RIM/RNT, from a customer perspective, ignoring timing and cash flow considerations and all other things being equal, customers who participate in the PGEÉ programs should have lower bills as evidenced by the results of the PCT. However it is critical to recognize that customers, who do not, or perhaps more importantly cannot, due to *accessibility barriers,* participate, will experience an increase in their electricity costs and bills.

Discussion of the accessibility issues related to lower- income customers follows in Section 7.

# 5. REVIEW OF HQD'S FINANCIAL ANALYSIS AND IMPACT OF PGEÉ ON THE UTILITY REVENUE REQUIREMENT

## 5.1 HQD's Financial Analysis and Rate Impact of PGEÉ 2003-2006

The projected impact of PGEÉ 2003-2006 on the revenue requirement to the year 2011 was set out in the table on page 36 of HQD-1 Doc 1 Demand R-3519-2003. This shows that the maximum impact of the PGEÉ 2003-2006 on the revenue requirement would be $22.2 million in 2007.

In R-3519-2003, HQD estimated that the PGEÉ 2003-2006 would increase the 2004 revenue requirement by $7.0 million and the 2005 revenue requirement by $12.9 million[18]. In D-2004-47[19], the Régie approved a 2004 revenue requirement of $ 8,982 million including an allowance of $2.8 million for the amortized costs of PGEÉ 2003-2006 (Table 25, column 19, line 26, of R-3492-2002 – Phase 2, HQD-8, Doc4, p 31, Revised: 2003-11-10).

In R-3541-2004, HQD requested approval for a 2005 revenue requirement of $9,265 million[20] including an allowance of $10.8 million for the amortized costs of PGEÉ 2003-2006 (Table 25A, column 8, line 18 and Table 25B, column 19, line 26 of R-3541-2004, HQD-12, Doc4, pp 35-36).

## 5.2 HQD's Financial Analysis and Rate Impact of PGEÉ 2005-2010

### *5.2.1 Program Budgets*

The program budgets for PGEÉ 2005-2010 are shown in Table 3.2, R-3552-2004, HQD-1, Doc 1, page 21. This table shows that that the 2005 Budget for the

[18] R-3519-2003, HQD-1-Doc 1, Page 36 of 53 (Original: 2003-10-17)
[19] p 87.
[20] R-3541, HQD-3, Doc 1, p 17, Table 1.

PGEÉ is increased to $119 million from $41.8 million in 2004. The budget then increases to a maximum of $181 million a year in 2009 and 2010.

### *5.2.2 Amortized Costs*

HQD proposes that the Régie approve the same treatment of the costs of PGEÉ 2005-2010 as approved for PGEÉ 2003-2006 in R-3519-2003. In the most recent rate case, the costs of PGEÉ 2003-2006 are deferred and the average of averages of the rate base amount is amortized over five years and then allocated to the rate classes based on the FF11 allocator.[21] The amortized amount for 2005 is $10.8 million.

### *5.2.3 Financial Analysis*

HQD's Financial Analysis of PGEÉ 2005-2010 is based on an update of the assumptions used in R-3519-2003. These are summarized in R-3552-2004, HQD-1, Doc 1, pp 90-91.

HQD's evidence indicates that the 2005 revenue requirement is slightly reduced (R-3552-2004, HQD-1, Doc 1, Table 5.4, Column 2). This result appears to take into account the amortized costs of the PGEÉ 2003-2006 of $10.8 million noted above and to reflect the fact that there is no incremental financial effect of the PGEÉ 2005-2010 relative to PGEÉ 2003-2005.

As noted earlier, HQD's financial projections show that the greatest impact of the PGEÉ 2005-2010 on the revenue requirement is $138 million occurring in 2010.[22]

The increase in the Revenue Requirement due to the PGEÉ 2005-2010 appears to be driven by three major factors:

[21] R-3541-2004, HQD-12, Doc 4, pp 33-34, Tables 24A&B and pp 35-36, Tables 25A&B
[22] R-3552-2004, HQD-1, Doc 1, p 95, Table 5.4.

- As PGEÉ budgets increase from $120 million in 2005 to nearly $200 million in 2010, then the amortized PGEÉ costs increase.
- As PGEÉ savings increase, this reduces sales revenues and results in lost revenue into the future.
- The avoided costs resulting from the PGEÉ offset the other costs; but the projections of HQD show that starting in 2011, the revenue requirement associated with the PGEÉ starts to decline. However, this is based on the assumption that new utility PGEÉ investment stops in 2010. This is not likely and a more reasonable assumption would be that investment was maintained at 2010 level beyond 2010. Under this assumption then the revenue requirement and rates would not significantly decrease in 2011-2013 as shown in Table 5.4.[23]

## 5.3 Comparison of Impacts of PGEÉ 2003-2005 and PGEÉ 2005-2010

**TABLE 3**

**COMPARISON OF RR IMPACTS OF PGEÉ 2003-2006 AND PGEÉ 2005-2010**

| Year | PGEÉ 2003-2006 Impact on RR | | PGEÉ 2005-2010 Impact on RR | |
|---|---|---|---|---|
| | Residential ($M) (%of 2004 RR) | Total ($M) (%of 2004 RR) | Residential ($M) (%of 2004 RR) | Total ($M) (%of 2004 RR) |
| **2003** | 0.3 (0.008%) | 0.6 (0.007%) | n/a | |
| **2004** | 3.0 (0.08%) | 7.0 (0.008%) | n/a | |
| **2005** | 4.3 (0.12%) | 12.9 (0.14%) | -1.5 (-0.042%) | -2.8 (0.032%) |
| **2006** | 6.4 (0.17%) | 18.6 (0.21%) | 10.5 (0.29%) | 27.4 (0.31%) |
| **2007** | 7.0 (0.2%) | 22.2 (0.25%) | 22.1 (0.62%) | 58.0 (0.65%) |
| **2008** | 5.9 (0.16%) | 19.0 (0.21%) | 33.9 (0.95%) | 87.6 (0.98%) |
| **2009** | 3.9 (0.11%) | 13.6 (0.15%) | 42.1 (1.17%) | 113.7 (1.28%) |
| **2010** | 0.3 (0.008%) | 2.9 (0.032%) | 49.7 (1.39%) | 138.6 (1.56%) |
| **2011** | -3.0 (-0.08%) | 6.6 (0.074%) | 42.3 (1.18%) | 120.9 (1.36%) |
| **2012** | n/a | n/a | 25.5 (0.71%) | 74.5 (0.84%) |
| **2013** | n/a | n/a | 7.9 (0.22%) | 27.6 (0.32%) |

Sources: R-3519-2003, HQD-1, Doc 1, p 36 of 53 (Original: 2003-10-17)..
R-3552-2004, HQD-1-Doc 1, p 95 of 96.
R-3492-2002-Phase 2, HQD-14 Doc 1, p 21.

[23] Ibid.

The question of whether the increase in the revenue requirement and rates resulting from the PGEÉ 2005-2010, is reasonable, is a judgment call that can only be made in the context of historic and future expected rate increases from other causes. From 2005 onward, Quebec will begin to rely more extensively on post-heritage supply. It is our understanding that supply costs are expected to increase due to the much higher post-heritage supply costs to be incurred once the heritage pool amount, currently estimated at 166.4 TWh[24], is exceeded.

In considering the results in Table 3, it should be noted that:

- Over period 2005-2010, customer growth will increase overall sales
- Avoided costs may increase due to higher marginal supply costs than currently forecast.

From our rough analysis of HQD's data, as shown in Table 3, it appears that the total average *residential* rate increase over the PGEÉ period 2005-2010 is about 1.5 %. The *annual* residential revenue requirement increase is less than 0.5%.

The above assumes that the PGEÉ cost allocation of about 38% to residential customers does not change materially.

In its Decision R-2004-47[25], related to R-3492-2002 – Phase 2, the Régie approved allocating the costs of the PGEÉ for 2004 on the basis of the supply cost of energy (kWh) forecast for each class of customers. In the same Decision, the Régie made it clear that the cost allocation may be reviewed in future rate cases because of factors such as the post-heritage supply costs.

If there is a concern about the rate increase resulting from the PGEÉ 2005-2010, this concern should focus on non-participating customers and particularly non-

[24] R-3541-2004, HQD-12, Doc 1, pp 22-23.
[25] pp 120-121.

participating customers who face higher barriers to participation, such as lower-income and fixed-income customers.

## 5.4 Regulatory Approaches to Mitigate Rate Impacts from the PGEÉ

There are several regulatory approaches that could be considered to address concerns about the impact of rate increases resulting from the negative RIM/RNT. These approaches can be applied individually or collectively and include:

(i) A requirement that PGEÉ 2005-2010 investments be reduced, especially in areas with a lower level of savings per dollar invested, in order to make the overall program meet the RIM/RNT. The danger is that this could result in HQD not meeting the Government-mandated 2010 EE/DSM target of 2.4 TWh load reduction.

(ii) Given that the HQD 3.0 TWh target is above the Government's target, another alternative is to ramp up the program more slowly and extend the time frame to 2012.

(iii) A change in the capitalization/amortization policy for utility PGEÉ costs with the amortization of the capitalized costs (or application of straight-line depreciation) over either:
(a) the weighted average life of the PGEÉ measures, or
(b) the overall program horizon – eight years (2003-2010).
This change in capitalization/amortization may have the effect of creating a better matching of costs and benefits over time, but creates an additional cost due to carrying more assets in rate base. The impact of a higher capitalization percentage and longer amortization period should be assessed by HQD.

(iv) One other approach is to mitigate the impact on customers most affected by PGEÉ-driven rate increases. The primary target group

for such mitigation is *lower-income customers*. Mitigation measures would be aimed at improving the accessibility of the PGEÉ in two ways. First, by providing more targeted programs and, second, by increasing financial assistance in order to ensure that a high percentage of lower-income and others with informational and financial accessibility problems, can lower their electricity bills to offset the effect of the higher costs of the PGEÉ.

There are utility cost consequences from higher participation rates and higher levels of financial assistance and these should be evaluated prior to the finalization of the program.

A combination of the above approaches may lead to a balancing of the broad public interest with the interests of the utility, as well as those of its customers.

## 6. PROTECTING RATEPAYERS

The new PGEÉ 2005-2010 constitutes a relatively aggressive increase in EE/DSM targets and budgets compared to the PGEÉ 2003-2006.

Experience with other EE/DSM programs indicates that there is often potential for under-spending of budgets and under-achievement of savings targets, particularly in the early years of a new EE/DSM program.

### 6.1 Adjustment Mechanisms

It is suggested that in recognition of this potential, the regulator put in place regulatory mechanisms to protect both the utility and the ratepayers from the cost consequences of over-budgeting and under-achievement.

There are a number of approaches, which can be employed in the regulatory process, but in general, there are two considerations aimed at ensuring that (i) rates are just and reasonable; and (ii) over- or under-spending of budgets and over- or under-achievement of EE/DSM savings does not penalize either the utility or the ratepayers. The two main approaches are the following:

- *A mechanism to true-up budgets and expenditures*.

In the case of HQD, this would address differences in forecast and actual capitalized costs in the historic year and adjust the amortized costs included in the forward rate year revenue requirement.

- *Some type of lost revenue adjustment mechanism (LRAM)*.

In the case of HQD, this would be some type of LRAM Variance Account to:

(i) address the difference between the forecast and actual energy savings in the historic year; and

(ii) true-up the rate year revenue requirement and forward savings forecast.

There could be concern about special treatment of PGEÉ expenditures when other utility costs associated with a forward test year are fixed following regulatory review. The answer to this concern is two-fold. First, the PGEÉ is not a core distribution utility function. Second, PGEÉ programs have a higher risk than normal distribution operations because they are so dependent on the response of customers, which, in turn, is a function of the program design and economic conditions. Many regulators employ adjustment mechanisms; however we acknowledge that the practice is more common with investor-owned utilities. The OEB has adopted an LRAM Variance Account as part of the incentive scheme for the first generation of Electricity Distributors' C&DM programs.

## 6.2 Budget True-up Mechanism

As noted earlier, the Régie has directed that the costs of implementing the PGEÉ be recorded in a deferral account and amortized over five years, starting in the year following cost incurrence. Therefore, there is already a built-in mechanism that would allow for a true-up for actual expenditures during the setting of rates for the forward rate year. The mechanism would ensure that the revenue requirement for the rate year only includes costs actually incurred in the prior year.

If budgets were under-spent in the historic rate year, then there are two options:

- allow a catch-up in the following year(s) or
- make a downward adjustment to amortization in the next year's revenue requirement to reflect the lower amount in rate base.

If budgets were over-spent in the historic year, again there are two options:

- allow a catch-up in the following year(s) or
- make an upward adjustment to amortization in the next year's revenue requirement to reflect the higher amount in rate base.

One important concern is the matter of *regulatory lag*. Actual PGEÉ expenditures for the historic rate year will not be known until January of the rate year. It is ECS' understanding that rates are changed effective January 1, but the rate order is not implemented until April of the rate year. The regulatory lag related to the true-up could be accommodated in the January-April, the period of the final rate-setting process.

## 6.3 Lost Revenue Adjustment Mechanism Variance Account

As noted earlier, the usual purpose of an LRAM is to compensate the utility for lost revenue as a result of undertaking EE/DSM programs that reduce load and energy sales.

For several utilities in Canada, regulators have approved building the annual forecast EE/DSM savings into the load/sales forecast and revenue requirement. This is the case for HQD. The 2003 Supply Plan Update[26] indicates that the demand forecast takes into account the effect of energy savings on the sales and power requirements. In addition, the savings resulting from PGEÉ 2003-2006 are shown in the Commercial Intervention Sales Forecast.[27]

For HQD, the consideration is therefore how to address *variations* from the PGEÉ savings forecasts that are included in the determination of the rate year revenue requirement and rates. As noted above, one regulatory approach requires an *LRAM Variance Account,* in which to record the difference between forecast and actual PGEÉ savings and the resulting adjustment to the approved revenue requirement for the rate year.

Some LRAM variance accounts operate with un-audited estimates of EE/DSM savings, in which case resulting adjustments to revenue requirement and rates can be made with little regulatory lag. Other regulators require that the actual EE/DSM savings be determined based on a certified independent auditor's evaluation. The requirements to operate the PGEÉ 2005-2010 with a LRAM variance adjustment mechanism include:

- Load forecast and financial forecast without PGEÉ demand and revenues

[26] État d'avancement du Plan d'approvisionnement 2002-2011, Original 2003-10-31, p. 16, s. 3.2.1
[27] HQD R-3541-2004, HQD-3, Doc 2, pp 8-9.

- LRAM Variance Account (LRAMVA)
- Post-fiscal year *independent* audit of actual achieved savings using regulator-approved audit protocol
- Entry of the revenue difference into the LRAM deferral account for disposition under direction from the regulator
- True-up of the forward load forecast for actual achieved savings.

One significant regulatory benefit of an LRAM process is the use of independent EE/DSM auditors and the provision of certified data for regulatory use as well as engagement of key stakeholders in the audit process. This should increase transparency and accountability as well as reduce regulatory burden related to review of future PGEÉ budgets and results.

R-3552-2004, HQD-2, Doc 1, sets out the proposal Evaluation Plan for the PGEÉ. The majority of this plan can be implemented with an LRAM with just three adjustments:

- Establishment of a stakeholder consultation group
- Hiring of independent auditor(s) to certify
- Creation on an LRAM Variance account.

## 7. UNIVERSALITY AND ACCESSIBILITY OF PGEÉ 2005-2010

An important issue resulting from the new PGEÉ is whether there is adequate provision for universality and accessibility of the programs by lower-income and fixed-income customers in the residential sector. Universality means geographic coverage and accessibility implies that all programs are equally accessible to all customers within a rate class or sector, such as residential.

An important question for the Régie to consider is whether the new PGEÉ 2005-2010 is accessible to vulnerable consumers. In other words, has the design of

the HQD PGEÉ 2005-2010 adequately recognized that lower-income customers are most vulnerable to increases in electricity costs and higher bills?

The lower-income segment of the residential customer class also faces much higher motivational, informational and financial barriers to participation in EE/DSM programs than average customers. Targeted programs, in combination with a higher level of customer education and financial assistance, are required to facilitate participation by vulnerable lower-income customers.

*ECS was not asked to compare, in detail, the accessibility and assistance available for lower-income customers relative to other utility programs in other jurisdictions, or between PGEÉ 2003-2006 and PGEÉ 2005-2010.*

However, the following comments and observations are made based on experience with lower-income EE/DSM programs elsewhere:

- Even though the overall PGEÉ meets the TRC and PC Tests, non-participants such as vulnerable lower-income customers, will not be able to offset the increased revenue requirement and rate increases, indicated by the negative RIM/RNT.

- HQD forecasts that, as a result of the PGEÉ 2005-2010, the revenue requirement and rates will increase much more than the PGEÉ 2003-2006. It is therefore even more imperative to assist lower- and fixed-income customers to lower their energy bills, either directly, if they pay the utility bill, or indirectly if the utilities are included in the rent (e.g., “chauffage inclus” apartments).

- The proposed modifications to the targeted lower-income and social housing programs are directionally consistent with the need to offset the impact of the higher rates resulting directly from the PGEÉ 2005-2010 in the short term.

- Experience in other jurisdictions has shown that there are a number of critical success factors for increasing accessibility and participation by lower-income customers in EE/DSM programs
    - Identifying and targeting vulnerable consumers
    - Directed education/communication
    - Delivery channels and partners that have gateways into the lower-income and Social Housing Sectors
    - A menu of cost-effective free standard measures
    - High levels of financial assistance
    - On-bill financing for more costly measures such as new heating systems and fuel switching
    - Special approaches to the rental housing market, especially bulk metered multi-residential apartments.

The enhancements to the HQD Low Income Program proposed in the new PGEÉ 2005-2010 are directionally consistent with the goal of achieving high levels of participation by vulnerable lower-income customers.

There are some remaining Low Income Program design and administrative challenges for HQD including customer education, geographic coverage, the rental housing market and the provision of on-bill financing**.**

## 8. CONCLUSIONS

*The following conclusions result from ECS' review of the regulatory treatment of the costs of the HQD PGEÉ 2005-2010:*

- The new HQD PGEÉ 2005-2010 represents an aggressive increase in EE/DSM spending and targets relative to PGEÉ 2003-2006.

- The economic analysis presented by HQD indicates that PGEÉ 2005-2010 meets the Total Resource Cost Test and Participant Cost Test based on the assumptions used by HQD regarding utility and participant costs.

- However, the economic analysis presented by HQD indicates the PGEÉ fails the Rate Neutrality Test and therefore over the term of the program, for *non-participants* customer bills are not neutral, i.e. rate increases derived from the PGEÉ are not cancelled out by bill savings.

- HQD's financial analysis indicates that taken in isolation, the annual increases in the revenue requirement and rates resulting from the PGEÉ are not unreasonable, but given likely increases in other costs of service, there is concern for the impact on vulnerable consumers. A number of regulatory approaches can be considered to address this concern and balance the broad public interest and the interests of the utility and its customers including:
    - Reducing budgets for marginal programs
    - Extending the term of the program
    - Increasing the amortization periods from five years to seven or eight years

- Increasing the participation rate of lower-income customers through even more targeted information and financial assistance.

- Because the HQD PGEÉ 2005-2010 is aggressive relative to PGEÉ 2003-2006, there is an increased chance that budgets will be under-spent and more importantly, EE/DSM savings are not achieved. Consideration should be given to applying regulatory mechanisms to protect consumers from under-spending of budgets and under-achievement of energy savings. Two such mechanisms are a budget true-up mechanism and a Lost Revenue Variance Account.

- The HQD program design has recognized that HQD's lower-income consumers may not have an equal opportunity to participate in EE/DSM programs. The proposed enhancements to the Low Income Program directionally address this issue, but challenges remain to achieving high levels of participation by lower-income customers. Additional measures such as more education, higher incentives and on-bill financing should be evaluated by HQD.

## APPENDIX A

## CV OF DR. ROGER HIGGIN

# Dr. Roger M.R. Higgin

Roger Higgin brings over 30 years of senior executive experience in the energy and environment sectors in both the public and private sectors. He combines his policy, strategic business planning and regulatory experience in his consulting work. His recent appointments include regulation of gas and electric utilities with the Ontario Energy Board. His other executive positions include COO in a high-tech firm, CEO in natural gas R&D, Assistant Deputy Minister of Energy Ontario Government, Deputy Commissioner of Environmental Services City of Toronto.

## EXPERIENCE

**Econalysis Consulting Services- Managing Associate Consultant**
**2000 to present**

- Provision of consulting and advisory services and regulatory intervention support for Electricity, Gas and Telecommunications Regulatory Proceedings

- Electricity
  - Hydro Quebec Interruptible Power Rate
  - OEB RUD Model for Distribution Rates
  - Stakeholder Consultative-Independent Market Operator (IMO)
  - Review of IMO 2002 Fees Submission
  - Review of IMO 2004 Fees Submission
  - Review of IESO 2005 Fees Submission
  - Review of Manitoba Hydro Wuskwatim Project*
  - OEB Review of Electric C&DM Programs
  - OEB Review of 2006 EDR Rate Handbook

- Natural Gas
  - OEB Gas Distribution Access Rule
  - Enbridge Consumers Gas (OEB)
    - Consultative on Comprehensive PBR Plan
    - Quarterly Rate Adjustment Mechanism Applications
    - Consultative on Demand Side Management
    - Review of 2002 Rates
    - Review of 2003 Rates
    - Review of 2004 Rates
    - Review of 2005 Rates
  - Union Gas (OEB)
    - Unbundling of Rates and Services
    - Consultative on Demand Side Management
    - Quarterly Gas Cost Adjustment Mechanism Applications

        - Review of 2004 Rates
        - Review of 2005 DSM Program
    - Other
        - Regie Societe en Commandite Gaz Metropolitain Unbundling *
        - Natural Resource Gas 2001 and 2002 rates ADR Settlement
        - BCUC Gas- Gas Cost Adjustment Mechanism Staff Paper
        - BCUC Outsourcing of Customer Care to CustomerWorks LLP
        - Sithe Energies Canada Application for natural gas Supply Pipeline
        - ATCO Gas/Electric Transfer of Default Supply to Direct Energy *
        - Gazifere 2005 Rate Application*

- Telecommunications Sector
    - CRTC PN 00 27 Restructured Bands
    - CRTC PN 00 99 Scope of Price Cap Review
    - CRTC PN 01 125 Monitoring Canadian Telecommunications Industry

    * Expert Witness

**Ontario Energy Board**
**Board Member 1996 to 2000 (Retired June 2000)**

- Regulation of gas and electric utilities in Ontario. Holding proceedings, writing and rendering Decisions and Orders. Scope included facilities, rates, gas cost and generic proceedings. Examples are rates for Enbridge Consumers Gas and Union Gas, PBR plan for Enbridge Consumers Gas, standard supply service for electricity distributors, revenue requirement and transmission rates for Ontario Hydro Services Company (now Hydro One)**.**
- Member of Rates and Licensing Committees of Board and team member for development of Codes**.**
- Deregulation
    - Chaired/Participated in the Following Regulatory Proceedings:
        - 1999 and 2000 revenue requirements and rates for Ontario Hydro Networks (now Hydro One) – Transmission and Distribution
        - Hearing on Standard Supply Service (SSS)
        - Rates for unbundled Transmission tariffs for Hydro One
    - Member of Internal Committee on Codes and Standards:
        - Transmission Access Code
        - Retail Settlement Code
        - Affiliate Relations Code
        - Performance Based Regulation for Electricity Distributors
- Cost of Service Regulation
    - Review of Ontario Hydro Rates 1988-91
    - Review of Ontario Hydro Conservation Programs
    - Presided over and wrote numerous Rates and Facilities Decisions
    - Targeted PBR Decision for Enbridge Consumers Gas
    - Outsourcing of CIS-Union Gas Limited
    - Separation of Ancillary Programs – Union Gas Limited

- Merger of Union Gas and Centra Gas Ontario
- Affiliate Relations Rule
- Gas Marketing Code
- Member Internal Rates Committee

**Unisearch Associates Inc.**
**General Manager and Chief Operating Officer 1995 to 1996**

- Responsible for Business Planning, Reorganization, Refinancing and Restructuring of $2 million high technology environmental instrumentation and service growth company. Establishment of marketing, production, financial management and securing new bank and equity financing. Strategic & Distribution alliances.

**Gas Technology Canada and CGRI**

**President and Chief Executive Officer 1992 to 1995**

- On behalf of Canadian Natural Gas Distribution Sector, operated $8 million Natural Gas Research and Development program including Canadian Gas Research Institute Laboratory and the Gas Technology Canada technology development investment portfolio.

**Toronto Department of Public Works and the Environment**

**Deputy Commissioner Environmental Services Division**
**1991 to 1992**

- Responsible for new Environmental Services Division with 600 staff dealing with waste management, air and water quality, transportation systems management, infrastructure planning and development, Office of Energy Efficiency, departmental IT planning and capital budgeting.

**Ontario Energy Board**
**Board Member 1988 to 1991**

- Regulatory/Administrative Commissioner. Chairing Public Hearings-Electric & Gas Utilities. Review of Ontario Hydro Rates and Capital Plans.
- Writing Decisions and Orders.
- Representing Board at meetings & conferences.

**Ontario Ministry of Energy**

**Assistant Deputy Minister- Programs & Technology Division**
**1984 to 1988**

- Staff complement 74, annual budget - $35 million.
- Input to Policy and Strategy on all aspects of Energy Supply and Demand
- Allocation of over 80% of the Ministry's budget to Conservation and Renewable Energy program priorities.
- Organizational design and organizational development in the Division.

- Federal/Provincial relations. Representing the Ministry at numerous public events involving speaking engagements, TV and radio.

**Ontario Energy Ventures**

**President 1986 to 1988**

- In charge of the wind-up of Ontario Energy Corporation's subsidiary (OEV) and $100 Million in venture capital investments in technology companies.
- Director of eight of the subsidiary companies. Responsible for portfolio management, strategy and negotiations leading to divestiture, conversion of investments into carried interest or folding of companies.

**Ontario Ministry of Energy**

**Executive Coordinator 1980 to 1984**

- Alternative and Renewable Energy Group.

**Ontario Ministry of Energy**

**Senior Advisor 1974 to 1980**

- Special Studies and Renewable Energy.

**Ontario Ministry of Environment**

**1973 to 1974 Branch Head**

- Special Studies and Program Planning, Air Resources Branch.

**Ontario Ministry of Environment**

**1971 to 1973 District Engineer**

- Air Pollution Abatement Section

**1970 to 1971-Consulting Engineer**

**1968 to 1970 Univ. of Toronto Post-graduate Research Fellow and Lecturer**

- Chemical Engineering Department

**Directorships & Committee Memberships Held**

**1995-96 Director-**Unisearch Associates Inc.
**1991-1995 Director -**Gas Technology Canada, CGRI,
**1984-88 Director -** Ontario Energy Ventures
**1984-88 Chairman of the Board-**Ontario Energy Consortium Kenya/Canada Energy Project
**1991 Chairman Energy and Minerals Task Force**
**Ontario Round Table Environment and Economy**

**1982-1988 Member-**University Research Incentive Fund Selection Committee
**Scientific Advisor-**Premiers Council Tech Fund and NSERC

**Professional Affiliations**

Professional Engineers of Ontario PEO

**Education**

**Masters of Business Administration**
University of Toronto, Faculty of Management Studies, Dean's List 1986

**Ph.D.**
Fuel Science and Applied Chemistry, University of Leeds, England, 1968.
Thesis: "Shock Tube Ignition of Hydrocarbon Fuels" - high speed chemical reactions and computer simulation of reactions.

**B.Sc. with 1st Class Honours**
Fuel Science and Combustion Engineering, University of Leeds, England, 1965.
Majors: Heat Transfer, Chemical Reactions, Coal, Oil and Gas Production and Utilization.

**Selected Publications/Presentations**

- Demand Side Management A Customer Perspective. CAMPUT Educational Conference Whistler BC April 2003
- Higgin, R.M.R., Dean, D.A., "Integrated Resource Planning", Presented at the Annual Meeting of the Ontario Natural Gas Association, Toronto, September 1990
- Higgin, R.M.R., "Non Utility Generation In Ontario", Presented at CAMPUT Educational Conference, Lake Louise, Alberta, May 1990
- Higgin, R.M.R., "Regulation of the Crown Owned Electric Utility In Ontario", Presented at CAMPUT Educational Conference, Lake Louise, Alberta, May 1990
- Higgin, R.M.R., "Conversion of Refuse to Energy in Ontario Canada and the Provincial Energy from Waste Program", Conversion of Refuse to Energy Conference, Berlin, West Germany, October 1979
- Higgin, R,M.R., "Ontario Biomass/Energy from Waste Program", CSChE Conference, Halifax, 1978
- Orgill, J.F. and Higgin, R.M.R., "The Effect of Component Costs on Solar Systems Design", Renewable Alternatives Conference, Solar Energy Society of Canada, London, 1978
- Higgin, R.M.R., "Windpower Applications in Ontario", CSME Annual Meeting, Toronto, 1978
- Higgin, R.M.R., "Novel Energy Sources", 26th CSChE Conference, Toronto, 1976
- Higgin, R.M.R., "Solar Heating for Buildings in Ontario", Sharing the Sun, Joint ISES/SESCI Conference, Winnipeg, 1976

- Higgin, R.M.R. and Brown, C.K., "Preliminary Assessment of the Potential of Wind Generators as Fuel Savers in A.C. Community Diesel Power Systems in Ontario", Sharing the Sun, Joint ISES/SESCI Conference, Winnipeg, 1976
- Chisamore, G.C. and Higgin, R.M.R., "Ontario Resources Recovery Program", Conversion of Refuse to Energy Conference, Montreaux, Switzerland, 1975
- Higgin, R.M.R., Ogner, D.J. and Shenfeld, L., "Frequency and Particle Size Distribution of Lead in the Toronto Urban Aersol", 1975
- Higgin, R.M.R., "Shock Tube Studies of the Dissociation of Ammonia and Methane", Joint ACS/CSChE Conference, 1970
- Higgin, R.M.R. and Williams, A., "Ignition Delay of Methane/Oxygen Methane/Oxygen/Butane Mixtures in Shock Tubes", 12th International Symposium on Combustion, Poitiers, France, 1968

**Articles**

- Northern Miner, September 18, 1976; Renewable Energy Resources Merit Continuing Study"
- Conservationist, March 1977
- Ontario's Energy from Waste Program: Perspective March 1981
- Time for Reassessment of Alternatives: Oil Week July 1982