RÉGIE DE L'ÉNERGIE
DOSSIER R-3897-2014, PHASE 1

RÉPONSES DE PEG À LA DEMANDE DE RENSEIGNEMENT NO.1 DU DISTRIBUTEUR ET DU TRANSPORTEUR D'ÉLECTRICITÉ À PEG

Demande de renseignements HQTD

1. **Préambule : C-AQCIE-CIFQ-0025**
   Rapport d'expert, p. 82, lignes 7-8.

   "Some features of current regulation may be worth keeping because they work well or do not work badly enough to merit change."

   a. **Quels sont les caractéristiques du régime actuel méritant d'être conservées dans le futur MRI du Transporteur et du Distributeur?**

1A) Réponse de PEG :

Dr. Lowry has not undertaken a meticulous review of regulation by the Régie that would permit him to provide an itemized list of desirable features. He notes, however, that general rate cases with forward test years would likely play a continuing role in the regulatory system. Additionally, marketing flexibility provisions of current regulation, which he discusses on pp. 90-91 of his testimony, would continue in some form. Some costs would continue to be accorded tracker treatment.

2. **Préambule : C-AQCIE-CIFQ-0025**
   Rapport d'expert, p. 100, lignes 6-9.

   "As for HQT, the Company's revenue requirement history does not provide pronounced evidence of a "stairstep" cost trajectory that might be better addressed by a hybrid ARM. The HQT system may be too large and diverse for particular capex projects to have a large impact. This is an argument favoring an index-based escalator."

   a. **Sur quelles bases PEG s'appuie-t-il pour tirer une telle conclusion? Veuillez préciser les documents consultés au soutien de celle-ci.**

2A) Réponse de PEG :

Please see our response to Régie -AQCIE 1.

3. Préambule :
C-AQCIE-CIFQ-0025
i) Rapport d'expert, p. 98, lignes 6-8.

"If the Régie instead prefers the all-forecast approach, extensive use should be made of statistical benchmarking and productivity research to reduce regulatory cost and ensure value for customers, as in Australia and Ontario." (nous soulignons)

ii) Rapport d'expert, p. 100, ligne 29 et p. 101, lignes 1-7.

"The Phase 2 study should, if HQT's data permits, consider the division's productivity trends as well as the trends for a large sample of investor-owned US power transmission utilities. The suitability of HQT's data for such an exercise is uncertain and should be clarified in Phase 1 data requests. The Phase 2 study should also consider appropriate inflation measures for an index-based ARM for Québec transmission. Finally, the study should survey transmission productivity studies from respected sources in the academic literature and regulatory proceedings. We also encourage the Régie to commission an independent statistical cost benchmarking study of HQT that can be useful in setting its stretch factor. Econometric research required for index development reduces the incremental cost of a benchmarking study." (nous soulignons)

a. Dans ces deux extraits, PEG fait-il référence aux mêmes types d'études?

3A) Réponse de PEG :

The underlying benchmarking and productivity research would be the same. However, additional work (i.e., productivity-based budgeting) might be needed to integrate the research into cost forecasts in a transparent manner.

b. Ces études présentent-elles toutes le même degré de difficulté de réalisation? Sinon, veuillez expliquer.

3B) Réponse de PEG :

Dr. Lowry notes that it is difficult to rank the studies in advance by degree of difficulty. One large area of uncertainty is the suitability of HQT's data for a benchmarking study or a study of its own productivity trend.

4. Préambule :
C-AQCIE-CIFQ-0025
Rapport d'expert, p. 108, lignes 3-4.

"If service to large load customers is subject to price caps, there is no need to recover load retention discounts from other customers between rate cases."

a. Veuillez expliquer ce que l'intervenant entend par : « there is no need to recover load retention discounts from other customers between rate cases ».

4A) Réponse de PEG :

Dr. Lowry clarifies that whereas the utility might wish to promptly recover revenues lost, due to discounts to one customer, from other customers the ability to do so is usually limited under a price cap system of regulation. This has traditionally been part of the appeal to regulators of price caps for utilities grappling with price-elastic customers. Price caps afford price inelastic (aka "core") customers some protection from adverse consequences of marketing flexibility. To the extent that discounts are not readily recovered from other customers, they are more likely to be a prudent response to demand elasticity.

5. Préambule :
C-AQCIE-CIFQ-0027
RevisedTable 4 - Summary of Incentive Regulation Recommendations

HQD : Revenue cap for most customers and Price cap for industrial customers

Le 3 novembre 2015, l'AQCIE-CIFQ soumet une version amendée du tableau 4 de la preuve d'expertise de PEG, à sa page 110 (C-AQCIE-CIFQ – 0025).
Dans ce tableau révisé, PEG recommande un mécanisme hybride pour le Distributeur (HQD) et non plus pour le Transporteur (HQT) comprenant entre autres, l'application d'un prix plafond pour les clients industriels.

a. Veuillez confirmer qu'aucune autre modification au reste de la preuve de l'expert n'est requise à la suite de la modification apportée au Tableau 4.

5A) Réponse de PEG:

Dr. Lowry's direct testimony contains several small errors and some unclear passages that unfortunately were not recognized prior to its submission. Attachment HQTD-PEG 5 is an updated version of his testimony that amends the passages that are especially likely to discourage reader comprehension.

b. Veuillez définir les catégories tarifaires visées par l'application d'un mécanisme hybride aux clients industriels.

5B) Réponse de PEG :

Revenue decoupling would not apply to large industrial customers. However, incentives for conservation and demand management programs to these customers could be strengthened by other means.

Questions de Concentric Energy Advisors

6. **Préambule:**
C-AQCIE-CIFQ-0025
Rapport d'expert, p. 3, lignes 9-13.

"Regulators use cost trackers to expedite recovery of some costs. Large, volatile costs like those for fuel and purchased power have traditionally been tracked. Tracking is further discussed in Section 5. The components of rates that address the less volatile costs of non-energy inputs like labor, materials, and capital are sometimes called "base rates," and are not typically tracked."

a. **Please confirm whether PEG is aware of numerous examples of cost trackers implemented in North America that do cover "non-energy inputs like labor, materials, and capital".**

6A) Réponse de PEG :

PEG confirms that there are numerous precedents for trackers of costs of non-energy inputs in the regulation of North American utilities. These costs are nonetheless tracked much less frequently in North America than those of fuel and purchased power. Furthermore, in the United States these trackers are generally approved in the context of regulatory systems that lack other pro-utility features.

b. **Please provide the report authored by PEG for EEI: Alternative Regulation for Evolving Utility Challenges: An Updated Survey, Mark Lowry, et al., January 2013.**

6B) Réponse de PEG :

Please see Attachment HQTD-PEG 6.

7. **Préambule :**
C-AQCIE-CIFQ-0025
Rapport d'expert, p. 3, lignes 14-21.

"To establish rates, the revenue requirement must be allocated across the utility's services. For each service, rates are then set to recover the assigned revenue

requirement given assumed quantities of "billing determinants." Most base rate revenue is typically drawn from usage charges which vary with a customer's use of the system. For commercial and industrial customers, demand charges collect most base rate revenue. For residential customers, who often lack advanced metering infrastructure, base rate revenue is typically drawn chiefly from volumetric charges. The balance of residential revenue is typically drawn from fixed customer charges."

a. Please indicate which of the above comments apply to distribution utilities, transmission utilities, or both.

7A) Réponse de PEG :

The last three sentences apply to utilities that serve retail customers.

8. Préambule :
C-AQCIE-CIFQ-0025
Rapport d'expert, p. 7, lignes 10-21.

"MRPs are the most common approach to incentive regulation around the world. These plans are designed to compensate a utility for its services for several years with revenue that does not closely track the utility's own cost of service. Two components of MRPs are most commonly used to accomplish this.

- *A moratorium is imposed on general rate cases that typically lasts four to five years.*
- *Between rate cases, an attrition relief mechanism ("ARM") automatically adjusts rates to reflect changing business conditions without linking the relief to the utility's own cost growth."*

The combination of a rate case moratorium and the ARM approach to rate escalation can strengthen cost containment incentives and permit an efficient utility to realize its target rate of return on equity ("ROE") despite a material reduction in regulatory cost. This constitutes a remarkable advance in the "technology" of regulation."

a. Please indicate the number of countries researched to determine "MRPs are the most common approach to incentive regulation around the world".

8A) Réponse de PEG :

Dr. Lowry's statement is based on his decades of experience in the incentive regulation field. This work has included projects in several countries and participation in international meetings and conferences on PBR. PEG has not systematically gathered reliable and up-to-date data on this topic. However, the surveys provided in Attachments HQDT-PEG 8A-1, 8A-2, and 8A-3 (by EY; REF-E, AF-Mercados EMI, and Indra; and the Agency for the Cooperation of Energy Regulators) show that MRPs are numerous in Europe. PEG can confirm, furthermore, that MRPs are used to regulate energy utilities in Australia and New Zealand. MRPs are also widely used in Latin America, as illustrated by the following quote.

> Most if not all reforming countries in the [Latin American] region implemented incentive-based regulation for setting multiyear tariffs and monitoring the compliance of distribution companies with service quality standards. This mechanism was very effective in Argentina, Chile, El Salvador, and Peru and is largely responsible for the improvements in the operating efficiency of the region's electricity systems.
>
> Kessides, I.N. (2012). Electricity reforms: What some counties did right and others can do better (Note No. 332), *Viewpoint: Public Policy for the Private Sector,* World Bank Group, pg. 3.

Countries that use MRPs to regulate power transmission utilities include Australia, Finland, Germany, Great Britain, Ireland, Lithuania, Luxembourg, the Netherlands, New Zealand, Nigeria, Norway, Romania, Slovakia, and Slovenia. Countries that use MRPs to regulate power distribution utilities include Australia, Austria, Finland, Germany, Great Britain, Hungary, Ireland, Luxembourg, the Netherlands, Nigeria, Romania, Slovakia, and Sweden.

In Canada, multiyear rate plans have on several occasions addressed the transmission services of vertically integrated electric utilities. Plans for FortisBC Energy and Enmax have featured index-based ARMs but transmission productivity trends were not considered. The Ontario Energy Board directed Ontario Hydro Services Company (OHSC) to develop a performance-based regulation plan for its transmission business. This lead to extensive work on transmission PBR by OHSC and Hydro One Networks. One product of this work was a thoughtful OHSC white paper entitled *Transmission PBR* which considered the design of a multiyear rate plan and index-based ARMS in some detail.

b. Please cite Canadian or U.S. legal standards or precedents indicating a utility must meet these standards to be permitted to "realize its target rate of return on equity".

<u>8B) Réponse de PEG :</u>

Dr. Lowry has reviewed a number of statutes and court rulings about the issue of fair returns in the US and Canada and has the following comments.

1. It is generally agreed that regulation must provide a *reasonable opportunity* to earn a market rate of return and not the *certainty* of such a return. Regulation need not protect the utility from all of fluctuations in business conditions that might cause actual earnings to deviate from their expectation. The US Supreme Court declared in its 1942 decision in the case *Federal Power Commission v. Natural Gas Pipeline Co.* that

> [T]he utility gets its return not from capitalizing the maintenance cost, but from current earnings by rates sufficient, having in view the character of the business, to secure a fair return upon the rate base, provided the business is capable of earning it. But regulation does not insure that the business shall produce net revenues, nor does the Constitution require that the losses of the business in one year shall be restored from future earnings by the device of capitalizing the losses and adding them to the rate

> base on which a fair return and depreciation allowance is to be earned. *Galveston Electric Co*. v. *Galveston*, 258 U.S. 388; *San Diego Land & Town Co*. v. *Jasper*, 189 U.S. 439, 44647. The deficiency may not be thus added to the rate base, for the obvious reason that the hazard that the property will not earn a profit remains on the company in the case of a regulated, as well as an unregulated, business.[1]

2. Several statutes and rulings state that revenue should be sufficient to recover the *efficient* cost of service, including a market rate of return on capital that is *prudently invested*. This was recently discussed in the Supreme Court of Canada's 2015 decision in the case *ATCO Gas & Pipelines v. Alberta (Utilities Commission)*.

> A key principle in Canadian regulatory law is that a regulated utility must have the opportunity to recover its operating and capital costs through rates. This requirement is reflected in the *Electric Utilities Act* and the *Gas Utilities Act* of Alberta, as these statutes refer to a reasonable opportunity to recover costs and expenses **so long as they are prudent** (emphasis added). The Commission must therefore determine whether a utility's costs warrant recovery on the basis of their reasonableness — or, under the *Electric Utilities Act* and the *Gas Utilities Act*, their "prudence". Where costs are determined to be prudent, the Commission must allow the opportunity to recover them through rates.[2]

The legislature in Québec has required that the Régie approve incentive regulation that will "ensure efficiency gains by the electric power distributor and the electric power carrier."[3]

3. Incremental costs of base rate inputs that are incurred after the start of a multiyear rate plan are usually not subject to final prudence determinations during the plan.

4. Since multiyear rate plans are a relatively new phenomenon in North American regulation, it is not entirely clear whether they are required by law to provide a reasonable chance to recover the prudent cost of service *in each and every year.*

5. If an MRP is required to provide a reasonable opportunity for a utility to recover its efficient cost in each and every year it can lead to chronic overearning as utilities are compensated for every cost "bump" but permitted to overearn when business conditions are favorable. This would run counter to the view of Canadian courts that rates must be just and reasonable not just from the perspective of the utility, but also from the perspective of the customer. [Northwestern Utilities vs. City of Edmonton and the Board of Public Utility Commissioners of Alberta]

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[1] US Supreme Court (1942), *Federal Power Commission v. Natural Gas Pipeline Co.,* 1942 U.S. LEXIS 1062, p. 15

[2] Supreme Court of Canada (2015), *ATCO Gas & Pipelines v. Alberta (Utilities Commission)*. 2015 SCC 45.p. 3.

[3] An Act Respecting the Regie de l'Energie, Section 48.1.

9. Préambule:
C-AQCIE-CIFQ-0025
Rapport d'expert, p. 9, ligne 25.

"Provinces, where MRPs are used in Canada, are depicted in Figure 1."

a. Does PEG consider the electric rate plans in effect for Yukon Electrical Company Limited and Northwest Territories Power Corporation to be models or templates appropriate for HQD or HQT? Please explain why or why not.

9A) Réponse de PEG :

PEG does not consider the MRPs of Yukon Electrical Company or Northwest Territories Power Corporation to be models appropriate for HQD or HQT. These MRPs have ARMs that are based on a multiyear forecast of the cost of service. Because there does not appear to be benchmarking or productivity analyses undertaken to support these MRPs, it is difficult to ascertain whether appropriate efficiency gains are factored into these forecasts. These plans also lack performance incentive mechanisms to reduce incentives for the companies to achieve efficiencies through service quality and reliability degradation or to improve performance in areas deemed important by stakeholders.

10. Préambule:
C-AQCIE-CIFQ-0025
Rapport d'expert, p. 9, ligne 28 - p. 10, ligne 6.

"Overseas, the privatization of many energy utilities in the last 20 years has forced governments to reconsider their approach to regulation. The majority have chosen MRPs over the traditional North American approach to regulation for power transmission and distribution alike. Regulators in Australia, Britain, Germany, the Netherlands, New Zealand, and Norway are MRP leaders."

a. Explain what is meant by "The majority have chosen MRPs".

10A) Réponse de PEG :

Dr. Lowry clarifies that the majority *of governments* have chosen multiyear rate plans for privatized energy utilities.

b. Please provide supporting data including the countries, utilities, type of utility (electric transmission, electric distribution, gas transmission, gas distribution, etc.), and type of MRP program adopted.

10B) Réponse de PEG :

Please see our response to HQTD-PEG-8A.

11. Préambule :
C-AQCIE-CIFQ-0025
Rapport d'expert, p. 10, ligne 13 - p. 11, ligne 2.

"The use of MRPs in the United States has recently spread to vertically integrated utilities in a diverse collection of other states that includes Colorado, Florida, Georgia, and Washington."

a. **Please indicate whether PEG's research shows that the use of MRPs in the United States has increased or decreased over the past two decades, and provide supporting data (including references, tables, lists, etc.).**

11A) Réponse de PEG :

A recent uptick in the use of MRPs by vertically integrated electric utilities in the United States is documented in Mark Newton Lowry, Matthew Makos, and Gretchen Waschbusch, *Alternative Regulation for Emerging Utility Challenges: 2015 Update.* A copy is provided in Attachment HQTD-PEG 11. There are probably more *formal* MRPs operational today than there were in 1995. However, several US electric utilities operated under rate freezes in that era under the terms of power market restructuring initiatives.

12. Préambule :
C-AQCIE-CIFQ-0025
Rapport d'expert, pp. 11 (lignes 5-11) et 12 (note en bas de page)

"An indication of the potential incentive impact of MRPs can be found in the experience of Central Maine Power ("CMP"), which operated under four successive MRPs from 1995 to 2014 […][13].

[13] In 2013, CMP made a request for an MRP that would have significantly increased its revenue to allow for new capital expenditures. The CMP rate case was eventually settled, with a stipulation to terminate PBR in Maine and return to a system more akin to COSR. Maine Public Utilities Commission, Order Approving Stipulation, Docket No. 2013-00168, August 25, 2014."

a. **Why, in PEG's opinion, did the MPUC approve a return to cost of service regulation, despite the productivity gains cited in Figure 3 on p. 12?**

<u>12A) Réponse de PEG :</u>

In its filings for a fourth generation MRP in 2013, CMP asserted a need for high capital spending due in part to an aging system. Its initial proposal involved a hybrid attrition relief mechanism that indexed revenue for O&M expenses and also featured a capital expenditure reconciliation mechanism that based capital cost revenue on a multiyear forecast subject to a partial true up to actuals. This proposal was rejected by the MPUC in the middle of the proceeding. The Commission commented that

> [T]he CRM is also inconsistent with the price cap principles set forth above. By tying CMP's profits to the level of investments, the CRM removes one of the core objectives of an ARP, the elimination of the incentive to over-capitalize. As part of the CRM, CMP has proposed that it would retain the first 10% of savings associated with capital spending and then flow the remainder of savings to ratepayers. This particular mechanism does little to reduce the incentive for CMP to overestimate both the need for capital improvements and the costs of such improvements.
>
> In addition, since capital spending can and often does result in O&M savings, by subjecting O&M costs to the inflation minus X formula while capital costs are subject to CRM process, the CRM would create a mismatch of cost and savings that is contrary to general regulatory ratemaking principles. In effect, customers would be subject to increased capital costs while depriving them of the corresponding benefits of O&M savings.[4]

CMP then proposed a comprehensive revenue per customer index with an X factor that reflected the average historical productivity trends of northeast utilities with aging distribution systems. The resultant X factor was negative. Other parties, including Commission Staff, opposed this proposal. Ultimately, parties agreed to a settlement of the case that abandoned MRPs. The MPUC approved this settlement.

b. Is PEG aware of other commissions that have returned to cost of service regulation in the U.S. or Canada for electric utilities? If so, please cite these examples.

<u>12B) Réponse de PEG :</u>

PEG is aware that commissions in Massachusetts and Oregon have also returned to cost of service regulation for electric utilities at the conclusion of multiyear rate plans with index-based ARMs. Additionally, an electric utility in British Columbia operated under MRPs with index-based ARMs followed by a switch to cost of service regulation. That company, currently called FortisBC, has resumed operation under an MRP with an index-based ARM.

c. Please confirm PEG was involved in the CMP case, and if so, provide PEG's written testimony and the MPUC's decision.

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[4] Maine Public Utilities Commission Docket 2013-00168, Central Maine Power Company Request for New Alternative Rate Plan ("ARP 2014"), Order of Partial Dismissal, August 2, 2013, page 7.

12C) Réponse de PEG :

PEG filed direct, supplemental direct, and rebuttal testimony on behalf of CMP in this proceeding. These filings and the MPUC's decision in this case are included as Attachments HQTD-PEG 12 A-D, respectively.

13. Préambule:
C-AQCIE-CIFQ-0025
Rapport d'expert, p. 13, lignes 1-4.

- *"Cost containment incentives 1 are strengthened by longer plan terms and well designed efficiency carryover mechanisms.*
- *The incremental incentive impact of lengthening the plan term diminishes.*
- *Incentives are modestly weakened by earnings sharing mechanisms."*

a. Please indicate when in years, in PEG's opinion, the "incremental incentive impact of lengthening the plan term diminishes."

13A) Réponse de PEG :

PEG believes that the incremental impact of lengthening the plan term diminishes continually.

b. Please show precedents and evidence that supports this opinion (provide the basis).

13B) Réponse de PEG :

This opinion is based on Dr. Lowry's incentive power research, which is detailed in Appendix A.2 of his testimony. In Table A1, for example, the "relative incentive power" of regulatory systems considered rises from 0% under cost plus regulation to 29% for "2 year cost of service", 39% for "a three year plan, 57% for a five-year plan, 62% for a six year plan, and 72% for a ten year plan.

14. Préambule :
C-AQCIE-CIFQ-0025
Rapport d'expert, p. 20, lignes 17-23.

"Broad regional or national peer groups are commonly used to establish the base productivity trend. It is generally necessary for the regulator to develop an independent view of the appropriate index formula by commissioning an independent productivity study. These studies can be managed by the Commission or intervenors. The former approach has been used in Alberta and Ontario whereas the latter approach has been used in British Columbia. While controversy is common concerning peer groups or productivity measurement methods, the base productivity

trends chosen by North American regulators have tended to be around 1 percent."

a. Please indicate if the regulated electric or gas companies in Ontario also submitted independent productivity analysis.

<u>14A) Réponse de PEG :</u>

Productivity studies have been provided by consultants retained by utilities and/or their trade associations in several Ontario proceedings to approve multiyear rate plans with index-based ARMs. For example, CEA prepared a study, filed in testimony, several years ago on behalf of Enbridge Gas Distribution.

b. Please indicate in addition to the AUC's commissioned productivity study, how many additional productivity analyses were submitted by the utilities, and the range of submitted productivity estimates.

<u>14B) Réponse de PEG :</u>

The AUC's consultant prepared a study of the multifactor productivity trend of US power distributors and reported a 0.96% annual average trend (as revised). Each of the five participating utilities commissioned productivity analyses. A study prepared for FortisAlberta calculated a range of multifactor productivity trends for Ontario power distributors. This range was -0.4% to -1.5%.

Consultants for the other utilities did not perform original productivity work, instead drawing conclusions from the AUC-sponsored multifactor productivity study that differed from those of the study's author. These recommendations were typically based on using a shorter and more recent sample period than that relied on by the AUC's consultant. Reducing the sample period had the effect of lowering the productivity trend due to peculiarities of the methodology employed by the AUC's consultant such as the use of a volumetric index to measure output growth.

One of these analyses, sponsored by EPCOR, made a recommendation on O&M partial factor productivity rather than total factor productivity for the most recent 11 year period. This analysis led to a recommended O&M partial factor productivity trend of -4.6%.

The analysis for the ATCO companies relied on the AUC consultant's multifactor productivity study for only the most recent 15 and 10 year periods, resulting in multifactor productivity trend estimates of -0.3 to -1.1%. The analysis for Altagas shortened the sample period to one starting in 2000 and resulted in a multifactor productivity trend estimate of -1.4%.

c. Please indicate the range of productivity factors adopted by the OEB for the utilities considered the "most" and "least" efficient.

<u>14C) Réponse de PEG :</u>

The X factor for each distributor in Ontario participating in the fourth generation Incentive Regulation Mechanism is the sum of a productivity factor that is common to all distributors and a stretch factor that is assigned on a company by company basis. The OEB decided that an appropriate value for the common productivity factor was 0%. The values for the stretch factors assigned to distributors range from 0.0% to 0.6%. The stretch factors are reconsidered annually based upon the latest results of an ongoing econometric total cost benchmarking study.

d. Please indicate if the OEB excluded the two largest utilities from the data set supporting these analyses.

<u>14D) Réponse de PEG :</u>

The two largest Ontario distributors, Hydro One Networks and Toronto Hydro-Electric, were excluded from the industry productivity trend study used to inform the Board's decision to adopt a 0% common productivity factor. However, these distributors are included in the sample used to estimate the econometric benchmarking model that is the basis for the assignment of stretch factors.

e. Show detailed support of the specific base productivity trends chosen by North American regulators tending to be around 1 percent.

<u>14E) Réponse de PEG :</u>

Please see Attachment HQTD-PEG 14 for a summary of base productivity trends chosen by regulators in North America. It can be seen that the average of the trends for electric utilities is 0.85%. The table also shows that the average values of stretch factors and X factors for electric utilities are 0.32% and 1.19%, respectively.

15. Préambule :
C-AQCIE-CIFQ-0025
Rapport d'expert, p. 20, ligne 25 - p. 21, ligne 6.

"The indexing approach to the design of attrition relief mechanisms originated in the United States. Development was facilitated there by the availability of standardized high-quality data for numerous companies in several utility industries. First applied in the railroad industry, index-based ARMs have subsequently been used to regulate telecom, gas, electric, and oil pipeline utilities. California, Maine, and Massachusetts were early adopters in retail energy utility regulation. U.S. energy utilities that have operated under index-based ARMs include Bay State Gas, Boston Gas, Central Maine Power, San Diego Gas & Electric, Southern California Gas, and NSTAR Electric. Indexed based price caps are currently used by the Federal Energy Regulation Commission to regulate U.S. oil pipelines."

a. Please indicate how many electric distribution utilities in the U.S. are currently regulated under index-based ARMs. Please identify these companies.

15A) Réponse de PEG :

Index-based ARMs are currently used in the multiyear rate plans of two California electric utilities. However, indexing studies do not seem to have been used in the design of these ARMs. Green Mountain Power has an index-based ARM for O&M expenses that is informed by productivity research.

b. Please indicate how many electric transmission companies in the U.S. are currently regulated under index-based ARMs. Please identify these companies.

15B) Réponse de PEG :

No electric transmission utilities in the United States currently operate under MRPs with index-based ARMs. Formula rate plans are favored by the FERC in power transmission ratemaking. However, FortisBC operates under an index-based ARM that applies to all of its services, including transmission.

16. Préambule :
C-AQCIE-CIFQ-0025
Rapport d'expert, p. 21, lignes 14-21.

"Index-based ARMs compensate utilities automatically for key external cost drivers such as inflation and demand growth. This reduces operating risk without weakening performance incentives. Customers can be guaranteed the benefit of productivity growth that is superior to the industry norm.

Index-based ARMs do not fully compensate utilities for cost surges. Necessary cost surges can be addressed by cost trackers, but trackers involve their own complications as we discuss further below. The design of index-based ARMs can involve statistical cost research that is complex and sometimes controversial."

a. How are customers guaranteed the benefit of productivity growth that is superior to the industry norm with an index-based ARM?

16A) Réponse de PEG :

This guarantee is achieved by adding a stretch factor to the base productivity trend. This increases the X factor, thereby slowing the pace of revenue growth.

b. If an index-based ARM does not allow a utility a reasonable opportunity to earn its authorized return, in PEG's opinion, would the resulting return on equity meet the definition of a fair return in Canada?

16B) Réponse de PEG :

Dr. Lowry is not a legal scholar but notes that discussions of fair returns 1) are often confined to the target rate of return on plant that is used in the computation of the revenue requirement 2) often pertain to recovery of the *efficient* cost of service 3) do not necessarily apply to each individual year of a multiyear rate plan. A utility operating under a plan that guaranteed a utility a reasonable chance to earn its authorized return in each and every year would produce an expectation of overearning since typically the utility would experience favorable cost conditions in some years.

17. Préambule :
C-AQCIE-CIFQ-0025
Rapport d'expert, p. 22, lignes 13-18.

"The hybrid approach has been found to be adaptable to the diverse cost trajectories of California's gas and electric utilities and has been used from time to time before and after the restructuring of the electric power industry. The hybrid approach has recently been used in the ARMs of Southern California Edison and the three Hawaiian Electric utilities."

a. Please provide an overview of the hybrid ARMs used by Southern California Edison and the three Hawaiian electric utilities, and the dates adopted.

17A) Réponse de PEG :

A hybrid ARM was adopted in 2012 for Southern California Edison's multiyear rate plan. It applied to the 2013-2014 period. A new multiyear rate plan was adopted for SCE in 2015 featuring a hybrid ARM for the 2016-2017 period. In setting the revenue for capital, plant additions for 2016 and 2017 are calculated by applying a 2% annual escalation to the test year 2015 additions level. Revenue that addresses most labor and non-labor O&M expenses is escalated each year based on collective bargaining agreements and updated forecasts of O&M input price inflation from IHS Global Insight's Power Planner service. Medical program expenses, including post-employment benefits other than pensions, are escalated by 8% annually. Forecast errors by IHS Global Insight are not corrected.

Hybrid ARMs were adopted in 2010 for Hawaiian Electric and in 2012 for Hawaii Electric Light and Maui Electric. These ARMs have escalators for four cost categories: labor O&M expenses, non-labor O&M expenses, baseline capital projects, and major capital projects. Labor O&M for unionized employees is escalated by the amount agreed to in labor agreements less a productivity offset of 0.76% that reflects productivity research performed by Dr. Lowry for HECO. Labor costs for non-unionized employees are frozen between rate cases. Non-labor O&M costs are escalated by the forecasted growth in the Gross Domestic Product Price Index.

The value of plant additions added to rates for baseline capital projects is the average amount for baseline capital projects that were placed in service during the preceding five years. Major plant additions are included in rates only when a project is expected to be placed in service by

September 30 of the year. The value of major plant additions to be added to rates is the lesser of the Commission-approved value of plant additions as determined in a separate proceeding and the value of actual plant additions.

In 2015, an inflation cap was placed on the ARM based on the growth in the Gross Domestic Product Price Index.

18. Préambule :
C-AQCIE-CIFQ-0025
Rapport d'expert, p. 24, lignes 15-17.

"The menu developed for the 2010-2015 plan and presented in Ofgem (2009) is given in the matrix below. The first line of the matrix is a ratio between the utility's cost forecast and the regulator's cost forecast."

a. Please indicate if this methodology still applies in the Ofgem's most recent RIIO version of incentive regulation for electric distributors. If not, please describe how it has changed.

<u>18A) Réponse de PEG :</u>

There have not been any major changes to the IQI methodology from the fifth generation of price controls for power distribution network operators ("DNOs") to the first generation of RIIO for these companies. Minor changes have been made in the calibration and implementation of the IQI. For example, the old regime only adjusted revenues for the IQI at the end of the price control period whereas in RIIO revenues are adjusted on an annual basis. The updated menu and a matrix illustrating possible outcomes appears below.

DNO:Ofgem Ratio	90	95	100	105	110	115	120	125	130
Efficiency Incentive	65%	63%	60%	58%	55%	53%	50%	48%	45%
Additional income (£/100m)	3.1	2.4	1.7	0.9	0.1	-0.8	-1.8	-2.8	-3.9
Rewards & Penalties									
Allowed expenditure	97.50	98.75	100.00	101.25	102.50	103.75	105.00	106.25	107.50
Actual Exp									
90	7.95	7.9	7.7	7.4	7.0	6.4	5.7	4.9	4.0
95	4.7	4.76	4.7	4.5	4.2	3.8	3.2	2.5	1.7
100	1.5	1.6	1.7	1.6	1.5	1.1	0.7	0.1	-0.6
105	-1.8	-1.5	-1.3	-1.2	-1.3	-1.5	-1.8	-2.2	-2.8
110	-5.1	-4.6	-4.3	-4.1	-4.1	-4.1	-4.3	-4.6	-5.1
115	-8.3	-7.7	-7.3	-7.0	-6.8	-6.7	-6.8	-7.0	-7.3
120	-11.6	-10.9	-10.3	-9.9	-9.6	-9.4	-9.3	-9.4	-9.6
125	-14.8	-14.0	-13.3	-12.7	-12.3	-12.0	-11.8	-11.7	-11.8
130	-18.1	-17.1	-16.3	-15.6	-15.1	-14.6	-14.3	-14.1	-14.1
135	-21.3	-20.2	-19.3	-18.5	-17.8	-17.2	-16.8	-16.5	-16.3
140	-24.6	-23.4	-22.3	-21.4	-20.6	-19.9	-19.3	-18.9	-18.6
145	-27.8	-26.5	-25.3	-24.2	-23.3	-22.5	-21.8	-21.2	-20.8
150	-31.1	-29.6	-28.3	-27.1	-26.1	-25.1	-24.3	-23.6	-23.1

19. Préambule :
C-AQCIE-CIFQ-0025
Rapport d'expert, p. 26, lignes 14-15.

"We have noted benchmarking and productivity research are used extensively by

regulators that use forecasted ARMs."

a. Please describe for each regulatory agency, the estimated number of staff and utilities regulated:

i) Ofgem

ii) Australian Energy Regulator

iii) Ontario Energy Board

iv) Régie de l'énergie

19A) Réponse de PEG :

Dr. Lowry believes that Ofgem regulates approximately 14 power distributors, 3 power transmission utilities, 1 gas transmission utility, and 8 gas distributors. The AER regulates approximately 13 power distributors, 6 power transmission utilities, and an unknown number of gas utilities. The OEB regulates one power transmission utility, more than 70 power distributors, and two large gas utilities. The Régie regulates one power transmission utility, one power distributor, and two gas utilities.

Dr. Lowry does not know the number of staff employed by each commission and is not clear why this question is relevant. Benchmarking and productivity studies undertaken by regulators are frequently outsourced to independent consultants.

20. Préambule :
C-AQCIE-CIFQ-0025
Rapport d'expert, p. 32, lignes 14-15.

"Appropriate weights can be obtained from econometric research on the drivers of power transmission cost."

a. Please provide any studies PEG is aware of that provided econometric research on the drivers of power transmission costs and appropriate weights.

20A) Réponse de PEG :

Attachment HQTD-PEG 20 provides summaries of econometric studies of power transmission costs in the public domain which we have gathered. They include a study prepared by Dr. Lowry several years ago and included in the *International Handbook on the Economics of Energy.* These studies were undertaken for various purposes including statistical benchmarking and the estimation of scale economies. None were intended to produce weights for a multidimensional index of transmission operating scale, and none have results that would be satisfactory for this purpose. The papers nonetheless demonstrate that econometric models of power transmission cost have been developed on numerous occasions and published in respected venues. Dr. Lowry has also performed an econometric study of transmission cost drivers for a large Canadian transmission utility. This study is not in the public domain.

21. Préambule :
C-AQCIE-CIFQ-0025
Rapport d'expert, p. 33, lignes 23-24.

"Three practical methods that have been developed for calculating capital costs in indexing studies merit note."

a. Is there a consensus among practitioners as to the best approach for measuring capital costs for utilities?

21A) Réponse de PEG :

Dr. Lowry believes that the geometric decay approach to capital costing is the most widely used in studies of macroeconomic productivity growth. All three of the approaches to capital cost measurement that he mentions have been used in productivity studies prepared for X factor calibration.

b. Is data availability a constraint for each approach?

21B) Réponse de PEG :

All three approaches work best with plant value data for a lengthy period. The requisite data are available for numerous US utilities but few Canadian utilities.

c. Do these methods produce results that can vary considerably?

21C) Réponse de PEG :

Results do vary, and this can be demonstrated in a Phase 2 productivity study if the Régie desires. However, some methods measure capital cost in ways that are very different from the general method used in North American regulation. Also, some studies have used crude approximations for key aspects of the theoretically correct capital costing method. For example, some studies have used a "physical asset" approach to measuring the capital quantity (e.g. line lengths, number of distribution poles) as an approximation for a one hoss shay capital quantity index. The physical asset approach was expressly rejected by the Ontario Energy Board in its decision on its third generation incentive regulation mechanism (IRM3).

22. Préambule :
C-AQCIE-CIFQ-0025
Rapport d'expert, p. 36, lignes 3-7.

"Unfortunately, the number of utilities, for which good data are available, which face productivity growth drivers similar to those facing the subject utility is sometimes limited. This is a chronic problem in Canada, where standardized data that could be used to accurately measure the productivity trends of numerous utilities are not readily available and there are few potential peers for HQD and HQT in any event."

a. If PEG was asked to develop productivity studies for HQD and HQT, what specific peer groups would PEG recommend and why?

22A) Réponse de PEG :

In each productivity study, PEG recommends starting with the largest sample of US investor-owned electric utilities for which standardized data of good quality are available for the requisite variables. Each sampled company must have filed a FERC Form 1 since 1964. Issues that may compromise the quality of data include mergers and divestitures, changes in the classification of transmission vs. distribution assets, and the impact on reported costs of participation in a regional transmission organization.

Deciding whether a subgroup of this sample is more appropriate than the full sample for producing a base productivity trend is a Phase 2 issue, and would require an inquiry about special operating conditions facing the two divisions that might alter their productivity growth. It is important to note that many business conditions that cause cost *levels* to vary between utilities have much less impact on productivity *trends*. Generally speaking, productivity growth is sensitive to *changes* in business conditions such as the pace of customer growth, a key determinant of scale economies. Utilities located close to Québec are not necessarily preferable.

b. What does PEG consider to be the potential pool of transmission providers from which a peer group would be selected?

22B) Réponse de PEG :

Please see our response to Part A of this question.

23. Préambule :
C-AQCIE-CIFQ-0025
Rapport d'expert, p. 42, lignes 24-29.
"Our analysis suggests that for a distributor that does not have unusual CapEx needs,

a well-designed index-based ARM should be sufficient to finance normal CapEx requirements on average over many years. The budgets yielded by the ARM may be too small in some years but will be too large in others. This mirrors the outcome of competitive markets where, for example, an aluminum smelter cannot count on higher aluminum prices in the years immediately following an increase in its capacity."

a. What recourse would a utility have if the indexed ARM is insufficient to finance its capital requirements?

23A) Réponse de PEG :

A utility facing revenue growth insufficient to finance its forecasted capital cost has several options.

1. Reconsider its capital spending plan, looking for economies and postponements that do not reduce service quality. New technologies, such as peak load management using AMI for small-load customers, which can help to economize on capex should be considered.

2. Try harder to reduce operation and maintenance expenses.

3. Remember that, under an ARM that doesn't closely track a utility's own capital costs, investments made today slow future cost growth, creating future earnings opportunities.

4. Invoke provisions of the plan designed to address cost bumps, such as cost trackers, earnings sharing, and cumulative revenue escalation provisions that permit the utility to “borrow” revenue growth from the future.

24. Préambule :
C-AQCIE-CIFQ-0025
Rapport d’expert, p. 47, lignes 19-20.

“The popularity of capital trackers in US utility regulation reflects in part the generally more conservative approach to regulation in US jurisdictions.”

a. Please explain what is meant by “conservative” in this context.

24A) Réponse de PEG :

By conservative, Dr. Lowry means less favorable to utilities. For example, most utilities don’t operate under multiyear rate plans that provide automatic rate escalation. Less than half of the American retail rate jurisdictions permit the use of fully forecasted test years in rate cases. Most American utilities have high volumetric charges that expose them to the financial repercussions of volume fluctuations or declining trends in average use.

b. Does PEG believe that any of these trackers is not appropriate?

24B) Réponse de PEG :

Dr. Lowry has not undertaken a detailed review of the propriety of American capital cost trackers.

c. Does PEG believe that regulation in the U.S. is more “conservative” than in Canada?

24C) Réponse de PEG :

Dr. Lowry believes that regulation of retail rates is less favorable to utilities in many American states than in Canada.

25. Préambule :
C-AQCIE-CIFQ-0025
Rapport d'expert, p. 69, lignes 28-29.

"National Grid has secured efficiency carryover mechanisms for several power distribution utilities in the Northeast US."

a. Please indicate if the rate plans described for the National Grid utilities have been terminated, and if so, in what year.

25A) Réponse de PEG :

ECMs were approved for Massachusetts Electric, Narragansett Electric, and Niagara Mohawk as provisions of multiyear rate plans. These plans ended in 2009 for Massachusetts Electric and Narragansett Electric and in 2011 for Niagara Mohawk.

While Massachusetts Electric and Niagara Mohawk did not use the ECM provisions in their later rate case filings, Narragansett Electric received approval in 2010 to use the ECM to share in the savings resulting from measured efficiency gains. The Rhode Island Commission required the company to provide proof of continuing efficiency savings to continue sharing in the savings in any rate case filed four years after the 2009 rate case filing.

26. Préambule :
C-AQCIE-CIFQ-0025
Rapport d'expert, p. 76, lignes 8-9.

"Indications of operating inefficiency imply the need for slower revenue growth going forward. Unusual cost conditions complicate benchmarking."

a. Please provide support for operating inefficiencies if this statement is referring to HQD or HQT.

26A) Réponse de PEG :

Dr. Lowry is here providing a general statement that if, hypothetically, there were indications of operating inefficiency then revenue growth should be slower going forward.

b. Please describe how PEG would propose to account for HQD's and HQT's unusual cost conditions in a benchmarking study.

26B) Réponse de PEG :

Please see our response to HQTD-PEG question 37.

27. Préambule :
C-AQCIE-CIFQ-0025
Rapport d'expert, p. 94, lignes 10-15.

"A transition to MRPs may require a change in the culture of Hydro-Québec and other participants in Québec regulation. There is no practical way for MRPs to simultaneously strengthen performance incentives materially and ensure that rates of return are always close to allowed levels. A culture of cost recovery entitlement is less suited to operation under MRPs than an attitude, more typical of Québec businesses, that a competitive rate of return is, with sound management and a little luck, attainable in the long run."

a. **In PEG's opinion, how much difference between an allowed and earned return would indicate the fair return standard was no longer being met?**

27A) Réponse de PEG :

Dr. Lowry is not aware of a hard and fast rule on this issue and has not formed his own opinion on the precise amount by which the actual return must vary from the allowed level before the fair return standard is no longer being met. Dr. Lowry believes that if a MRP is resulting consistently in rates being unjust and unreasonable that the plan should be reviewed.

28. Préambule:
C-AQCIE-CIFQ-0025
Rapport d'expert, p. 96, lignes 10-14.

"If decoupling is instituted, several issues in the design of the revenue decoupling mechanism will require resolution. One is whether decoupling should apply to industrial customers. If the answer is "yes", an important further issue is whether baskets should be implemented that insulate residential and commercial customers and industrial customers from the revenue impact of fluctuations in each other's revenue."

a. **Please provide examples of where price and revenue caps have been mixed across customers' classes in the implementation of MRPs.**

28A) Réponse de PEG :

Few plans must be examined to answer this question due to the limited number of multiyear rate plans that feature revenue decoupling. In New York, MRPs commonly decouple revenues from volumes only for the smaller volume customer classes. A recent example of this type of plan is the current multiyear rate plan of Central Hudson Gas & Electric. This plan extends revenue decoupling only to the residential and general service customer classes. In Canada, the MRP of FortisBC Energy applies only to small-load customers. Consideration should also be paid to the many revenue decoupling mechanisms that apply only to residential and commercial customers and are not combined with an MRP.

29. Préambule:
C-AQCIE-CIFQ-0025
Rapport d'expert, p. 99, lignes 11-13.

"Research should ideally be conducted on the productivity trends of both HQD and a large sample of US power distributors. A study of US trends is the more essential of these two as those trends provide the essential external productivity growth standard."

a. What large sample of U.S. power distributors would PEG propose for such a study?

<u>29A) Réponse de PEG :</u>

Please see the response to HQTD-PEG 22A.

b. If such a study were conducted, how would PEG specifically propose to account for the substantial differences between HQD and the U.S. sample?

<u>29B) Réponse de PEG :</u>

Please see the response to HQTD-PEG 22A.

30. Préambule:
C-AQCIE-CIFQ-0025
Rapport d'expert, p. 99, lignes 19 à 25.

"We also encourage the Régie to commission an independent transnational statistical benchmarking study of HQD that can provide input on the appropriate stretch factor. Econometric research used to develop ARMs reduces the incremental cost of a cost benchmarking study. Econometric benchmarking studies are favored by regulators in a number of jurisdictions. We believe that independent benchmarking studies are much more effective at establishing the truth about a utility's operating performance than a critique by Régie staff and intervenors of utility-commissioned studies."

a. What countries would PEG propose to include in such a study?

30A) Réponse de PEG:

Dr. Lowry recommends that an econometric model used to benchmark HQD be based on US data. A large, standardized data set is available on the operations of investor-owned US power distributors.

b. What would be the estimated cost and timeframe for its completion?

30B) Réponse de PEG :

A study of this type would take 2-4 months to complete and would require cooperation by Hydro-Québec. PEG's proposed charge for such a study would be disclosed in its confidential bid.

c. How would the study account for the differences in the governmental, macroeconomic and operating circumstances of the sample?

30C) Réponse de PEG :

Please see our response to HQTD-AQCIE-37.

31. Préambule:
C-AQCIE-CIFQ-0025
Rapport d'expert, p. 100, lignes 20-23.

"Using data on the operations of US utilities, we have undertaken preliminary econometric research that suggests that we can obtain sensible and statistically significant weights for a transmission scale index that is serviceable for a revenue cap index for HQT."

a. Please provide the preliminary econometric research.

31A) Réponse de PEG :

Please see the Attachment HQTD-AQCIE 31, which contains the results of an econometric model prepared by PEG for AQCIE of the total cost of transmission services. The model, which has a translogarithmic functional form, was estimated with data on the operations of 37 vertically integrated investor-owned US electric utilities.

The model estimates the impact on transmission cost of several scale variables:

- The number of retail customers is correlated with peak load and the number of delivery points for the network

- The generating capacity variable measures the cost impact of connecting generating plants to the network

- The miles of transmission line provides a measure of the geographic expansiveness of the network

The model also includes other business condition variables:

- An input price index variable reflects the level and trend of the prices faced by each company relative to other sampled companies

- A trend variable is included that captures the cost impact of miscellaneous other developments over time.

This model shows that several scale variables have a statistically significant impact on transmission cost, and this supports the referenced statement. The introduction of additional scale variables such as MWh delivered, substation capacity, or system peak did not result in the included scale variables becoming statistically insignificant.

Although the attached model results are preliminary, PEG believes additional work in Phase II can confirm the statistical significance and relative importance of multiple scale-related cost drivers. Should additional work be commissioned in this area, PEG would:

- upgrade the line mile and consider other scale-related variables

- attempt to add additional companies to the sample

- investigate other relevant business condition variables

- further investigate transmission accounting issues to improve the comparability of cost for companies in the sample.

32. Préambule:
C-AQCIE-CIFQ-0025
Rapport d'expert, p. 100, lignes 24-30 - p. 101, ligne 1.

"Indexing research can provide the foundation for an index-based ARM for HQT. It is also useful in the design of index-based escalators for O&M revenue in hybrid ARMs and index-based forecasts of O&M expenses in all forecast ARMs. An independent productivity study is, therefore, desirable for power transmission in Phase 2 as well. Trends in the O&M, capital, and multifactor productivity of transmission utilities should be addressed in this study as well.

The Phase 2 study should, if HQT's data permits, consider the division's productivity trends as well as the trends for a large sample of investor-owned US power *transmission utilities."*

a. Please provide a list of companies PEG would include in such a study.

<u>32A) Réponse de PEG :</u>

Detailed data on transmission operations are available for a large sample of major US investor-owned electric utilities on FERC Form 1. Companies with data suitable for use in productivity trend research would be determined in the study. One key consideration is the quality of required data. Consideration of a peer group suitable for Hydro-Québec is a Phase 2 issue.

b. How would the transmission operations of these companies be isolated from other operations?

<u>32B) Réponse de PEG :</u>

FERC Form 1 data on utility costs and facilities are highly itemized, making it fairly straightforward to estimate transmission cost models.

c. Please list all transmission companies in North America PEG is aware of operating under index-based ARMs, or other forms of MRPs.

<u>32C) Réponse de PEG :</u>

FortisBC operates under an MRP with an index-based ARM that applies to transmission, as did Enmax for several years. Neither of these plans was expressly designed for an application to transmission. Some MRPs for vertically integrated electric utilities in North America may apply to transmission. These likely include the plans in the Northern Territories and the Yukon.

33. Préambule:
C-AQCIE-CIFQ-0025
i) Rapport d'expert, p. 102, lignes 3-6.
ii) Rapport d'expert, p. 106, lignes 5-7.

i) "While more effort in a traditional review of HQD's power supply costs should produce better results, steps should be taken to strengthen HQD's incentive to contain these costs. One possible approach is to incentivize the power supply cost tracker. Revenue/MWh could, for example, be based b% on HQD's actual cost and (1-b)% on its forecasted cost."

ii) "We discussed in Section 6.2.4 the option of an incentivized cost tracker for HQD's power supply expenses. An alternative means of strengthening the division's incentive to contain these expenses is to establish a PIM for power supply costs."

a. Please indicate any North American commission that has approved such a mechanism on power supply costs, and cite the decision.

33A) Réponse de PEG :

Please see our response to Régie – AQCIE 10.1.

34. Préambule :
C-AQCIE-CIFQ-0025
Rapport d'expert, p.102, lignes 23-26.

"We do not believe that HQD needs a capital cost tracker in the first plan period. HQT, in contrast, might need the option of requesting tracker treatment for some projects if an index-based ARM is developed. This proposed treatment would be similar to the Ontario Energy Board's Incremental Capital Module."

a. Is PEG aware of any concerns expressed by utilities regarding the allowance of capital projects under the OEB's Incremental Capital Module?

34A) Réponse de PEG :

Yes. PEG understands that some of these concerns pertained to the restrictions on eligibility that the OEB instituted when it first approved the Incentive Capital Module. These restrictions included the requirement that the Incremental Capital Module could only apply to discrete capital projects.

b. In which of the OEB's options under its latest incentive regulation framework for electric distributors is the Incremental Capital Module allowed, and how many utilities have applied under this option?

34B) Réponse de PEG :

Incremental capital modules have been available to Ontario power distributors under the third and fourth generation Incentive Regulation Mechanisms. Approximately 11 distributors out of the more than sixty in Ontario applied for Incremental Capital Modules under IRM3 and about 2 have thus far applied under IRM4.

35. Préambule :
C-AQCIE-CIFQ-0025
Rapport d'expert, p.105, lignes 10-12.

"Both plans should have extensive performance metric systems. In these systems, some metrics should have only targets whereas others should be used in performance incentive mechanisms."

a. What criteria would PEG apply to determine whether a metric would be used in a performance incentive mechanism vs. "have only targets"?

<u>35A) Réponse de PEG :</u>

Performance incentive mechanisms are desirable to the extent that the following conditions prevail.

1. There is concern about the strength of incentives in the targeted area. In the case of HQT, areas of concern about incentives include reliability, customer service quality, and safety. In the case of HQD, areas of concern include reliability, customer service quality, safety, and the cost of power supply expenses.

2. The utility must have some control over the performance metric.

3. The benchmark must reflect business conditions that are outside the utility's control.

4. Measurement of performance is not unduly complex and controversial.

36. Préambule :
C-AQCIE-CIFQ-0025
Rapport d'expert, p.105, ligne 28 - p. 106, ligne 4.

"HQD could be rewarded for documented success at reducing peak load. Its reward could be a share of documented distribution, transmission, and power supply savings. Distribution CapEx savings from particular local projects could be rewarded in the manner of the Brooklyn Queens Demand Management project. Market transformation is further encouraged if a PIM can be devised that encourages CDM from all sources."

a. Does the reference to a share of documented distribution and transmission savings refer to avoidance/deferral of future investments or savings from facilities that are already in service?

<u>36A) Réponse de PEG :</u>

The reference refers to avoidance/deferral of future investments.

b. Please describe how the BQDM project is relevant for purposes of this proceeding?

36B) Réponse de PEG :

This proceeding is intended to establish the broad outlines of new regulatory systems for HQD and HQT that encourages improved cost performance. Load-related assets account for a sizable share of the costs of HQD and HQT. Regulatory provisions that reward HQD for using peak load management to reduce load-related costs therefore merit consideration in such a proceeding. The Régie has expressed an interest in appropriate performance metrics for the new regulatory system. Measures of load peakedness are germane in this regard, but the cost savings from reducing load peakedness are often localized. The BQDM incentive mechanism incentivizes peak load reductions to realize cost savings in a targeted area.

c. **Does PEG understand that the current proceeding is addressing "market transformation" issues? If so, please explain how.**

36C) Réponse de lPEG :

This proceeding is intended to identify the broad outlines of new regulatory systems for HQD and HQT that encourages improved cost performance. Conservation and demand management programs can reduce cost and customer bills. Market transformation is one of the most cost-effective means of achieving load reductions since most of the costs are not incurred by the utility. Incentivizing the transformation of markets for conservation and demand services is an important challenge in the design of incentive regulation mechanisms today.

37. Préambule:
C-AQCIE-CIFQ-0025
Rapport d'expert, p. 109, lignes 11-15.

"In addition to independent productivity trend studies, there should be statistical benchmarking studies of each division's recent historical costs and the costs forecasted for the 2017 test year. The Régie should also consider hiring independent engineering consultants or developing additional in house expertise to develop better independent views of the capex requirements of the two divisions."

a. **Please describe precisely how the benchmarking studies would be used in the rate determination.**

37A) Réponse de PEG :

Dr. Lowry believes that these studies could be used to set the stretch factors in the X factor terms of attrition relief mechanisms. The mechanistic use of such studies to set X factors in Ontario is one approach that merits consideration. Distributors there are grouped into 5 performance groups. The poorest performing utilities have a stretch factor of 0.6% whereas the best performing utilities have a stretch factor of 0.0%.

The precise use of benchmarking studies to set X factors for HQD and HQD is an issue for Phase

3 of this proceeding.

b. How will these benchmarking studies take the specific characteristics of the Transmission and Distribution provider into account?

37B) Réponse de PEG :

1. Currency differences between Hydro-Québec and US utilities can be addressed using OECD purchasing power parities and other data on relative price levels between the US and Canada.

2. Certain costs incurred by Hydro-Québec that reduce comparability can be excluded. An example would be costs of the autonomous systems.

3. FERC Form 1 cost data are highly itemized, making it possible to add or exclude certain costs from the totals for US utilities which might not be relevant in an appraisal of HQT. These might include special costs of operating in regional transmission organizations with managed power markets.

4. Costs that are difficult to benchmark can be excluded from the data for all companies. These might include costs of pensions and other benefits, uncollectible bills, and conservation and demand programs.

5. The benchmarking studies would use econometric models capable of predicting the cost level associated with a given set of business conditions determined by the research to have a statistically significant impact on cost. For example, a very simple model of distribution cost can be stated as:

   $$Cost = a_0 + a_1 * Customers$$

   The research would take data on the cost and business conditions of a large group of utilities and estimate the impact on cost of each business condition variable. This results in a model that allows one to “plug in” the current or future conditions faced by HQ and produce a prediction of a cost level commensurate with those conditions.

   Data from all utilities could be used to determine the values of the parameters which will result in an equation that can predict cost for any given number of customers. A prediction for an individual utility like HQD can be obtained by using the actual number of customers and calculating the corresponding benchmark of cost. The use of econometric models avoids the need to find peer utilities to provide comparisons because the model produces a prediction for a hypothetical peer that has exactly the same business conditions faced by Hydro-Québec.

   The model could include variables to account for differences in price levels and trends, the scale of operations, and other relevant business conditions. Input price levels and trends would be constructed from publicly available sources such as Statistics Canada, the U.S. Bureau of Labor Statistics, and the OECD.

Relevant scale variables for power distribution benchmarking could include the number of customers served, miles of distribution line, and substation capacity. Other relevant business conditions could include the percent of assets that are underground, system age, the number of natural gas distribution customers served, the extent of ruralness in the service territory, and weather conditions such as precipitation and heating degree days.

Relevant scale variables for power transmission benchmarking could include the number of customers served, MW of generation capacity, and miles of transmission line. Other relevant business conditions could include the percent of assets that are underground, system age, and weather conditions.

Capital cost would be calculated using methods that standardize depreciation and adjust for differing vintages of plant in service. Such methods are standard practice in productivity research and are used by the U.S. Bureau of Economic Analysis when calculating the multifactor productivity trend of the U.S. Economy.

6. Companies that have markedly different circumstances could be excluded from the sample.