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

RÉPONSES DE L'AQCIE/CIFQ DEMANDE DE RENSEIGNEMENTS NO 1 DE LA RÉGIE DE L'ÉNERGIE (LA RÉGIE) À AQCIE CIFQ RELATIVE À LA DEMANDE D'ÉTABLISSEMENT D'UN MÉCANISME DE RÉGLEMENTATION INCITATIVE ASSURANT LA RÉALISATION DE GAINS D'EFFICIENCE PAR LE DISTRIBUTEUR D'ÉLECTRICITÉ ET LE TRANSPORTEUR D'ÉLECTRICITÉ

1. Références : (i) Pièce C-HQT-HQD-0023, p. 15;
(ii) Pièce C-AQCIE-CIFQ-0025, p. 100.

Préambule :

(i) « Thus, the HQT depreciation and amortization expense (the recovery of capital invested), its return on rate base (the return on capital invested) and applicable taxes comprise 78.9 % of the company's revenue requirements. This represents a challenge for an MRI program because capital is typically the most difficult expense to accommodate under these programs. CAPEX are often "lumpy", and influenced by large projects over many years and are often dictated by *system requirements beyond management's direct control, such as the integration of new generation. These challenges are documented in the Elenchus report, and are present for distribution utilities as well, but even more so for transmission companies, such as HQT, where capital represents the vast majority of its revenue requirements. Concentric is not aware of any North American jurisdiction that has adopted an MRI program for a transmission specific entity. Where capital expenditures are large and uneven, a typical I-X program would be a poor fit. This suggests that the Régie should give very careful consideration to HQT's specific characteristics in choosing an MRI. »*

(ii) *« 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. We believe that an index based ARM should be "Plan A" for HQT given its advantages. » [nous soulignons]*

Demandes :

1.1 Veuillez discuter des positions en apparence contradictoires exprimées en vous référant aux passages soulignés en (i) et (ii).

1.1) Réponse de l'AQCIE/CIFQ :

Dr. Lowry notes that the suitability of an index-based attrition relief mechanism for HQT depends on the trajectory of its efficient *total* cost. This trajectory can be very different from those of its capital expenditure ("capex") or amortization, which Messrs. Coyne and Yardley highlight in their testimony. To illustrate the point, suppose that HQT's capex were $100 in 2018, $1000 in 2019, and $3 in 2020. Capex would be quite volatile but would nevertheless have a trivial impact on HQT's total cost of service. While the actual capex of HQT is, in reality, high enough to materially influence its total cost trajectory, it is still the total cost trajectory that matters.

The impact of HQT's capex on its total cost trajectory is muted, for a number of reasons.

- The size of HQT's transmission system is enormous.
- The system was built out gradually, so the replacement of individual assets typically does not produce the kind of major bump in total cost that might result if, say, a small municipal power distributor in Ontario needed to replace its sole substation.
- The capex projects expected in the foreseeable future are not extraordinarily large. The Québec grid lies at the "end of the line," and there is no need for major new projects to send power flows across it. Growth in native load is not growing rapidly, as in Alberta, and can be further suppressed by conservation and demand management. Québec does have some potential to increase exports from local generation, but the low-cost hydro resources have already been developed and low natural gas prices depress power prices in the United States.
- A sizable portion of the transmission cost of connecting to remote generating stations is, in any event, born by power producers rather than by HQT.

Surges in capital cost that do occur can be addressed by a variety of mechanisms that Dr. Lowry discusses in his testimony.

- Use of a scale index that includes Québec generation.
- Cumulative revenue escalation rights.
- Limited use of cost trackers, especially for projects that the Régie has already approved.

Table and Figure Régie-AQCIE 1 (a) plot the growth in the rate base, amortization, expenses, and revenue requirement of HQT since 2002, including the forecasted values for 2015 and 2016 from HQT's latest rate case. It can be seen that growth in HQT's revenue requirement has been fairly gradual. The trend in amortization that Messrs. Coyne and Yardley highlight in their testimony is very different.

Table and Figure Régie-AQCIE 1 (b) consider how a revenue cap index might have tracked the revenue requirement of HQT from 2006 to 2016. In this exercise, which is strictly preliminary, we consider a revenue cap index of general form

$$\textit{Growth Allowed Revenue}^{HQT} = \textit{Inflation} - X + \textit{growth Scale}^{HQT}.$$

We assume that the inflation measure is the indice implicite des prix du produit interieur brut. The growth in the scale index is a weighted average of three variables representing growth in the scale of HQT's operations.

- kilometers of HQT's transmission line
- Québec generation capacity
- Number of HQD's retail accounts (a driver of peak demand)

The weights for the index are based on econometric estimates of the impact of these variables on total power transmission cost, which we prepared for AQCIE using a large sample of US transmission utility operating data. This work is discussed in our response to question HQTD-PEG 31.

We chose the value for the X factor that would track HQT's revenue requirement from 2006 to 2016. Results of this simple "Kahn method" exercise, which produced a value of 0.63 for X, can be found in Table Régie-ACQIE 1 (c).[1]

Inspecting the results, it can be seen that the revenue requirement index tracks the growth in HQT's revenue requirement fairly well. Allowed revenue falls short of the revenue requirement in 2010 but is higher in other years.

1.2 Veuillez discuter également de la problématique que présente l'application du modèle de type « building block » au revenu requis du Transporteur, étant donné son contexte d'affaires.

<u>1.2) Réponse de l'AQCIE/CIFQ :</u>

Dr. Lowry provides an extensive discussion of the limitations of the building block approach in his direct testimony. He notes that the detailed cost forecasts required for this approach are complex and often controversial. It is difficult to ascertain the efficiency gains in utility cost forecasts unless these forecasts are based explicitly on productivity-based budgeting. Chronic exaggeration of cost growth by utilities in Britain has prompted Ofgem to develop a complex information quality incentive and make extensive use of benchmarking and independent engineering studies to develop an independent view of cost requirements. Regulators in Ontario and Australia also make extensive use of benchmarking and productivity studies in the appraisal of utility cost forecasts for multiyear rate plans.

Challenges in the building blocks approach can also be found in a review of the Australian Energy Regulator's ("AER") efforts to regulate power distributors. Australian regulation features multiyear rate plans based on forecasts of O&M expenses and capital costs. Utilities submit their proposed forecasts for review by the AER. The rules by which the AER regulates utilities are set by the Australian Energy Market Commission.

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[1] The Kahn method for calculating X was popularized by the American regulatory economist Alfred Kahn, and is used by the Federal Energy Regulatory Commission to set X factors in multiyear rate plans for US oil pipelines.

In its first efforts, the AER was severely constrained in its ability to encourage utilities to operate at efficient cost levels due to rules requiring the AER to accept proposals that "'reasonably reflect' efficient, prudent and realistic expenditure."[2] The language of the rules recognized that multiple cost forecasts may satisfy those criteria. The AER was further constrained in its efforts to ensure efficient expenditures by rules placing the burden of proof on the AER to prove that utility forecasts did not reasonably reflect prudent and efficient costs.[3] Even if it could provide that evidence, the AER could only reduce proposed amounts to the upper bound of what it considered reasonable. This created a system that encouraged distributors to overstate their cost forecasts, which could then only be reduced to the highest level the AER considered reasonable.[4]

The methods by which distributors justified their costs and the itemized nature of the building blocks approach limited the AER further. Most proposals submitted during this period were based on "bottom-up" calculations of expenditures and supported by a large amount of engineering detail.[5] This caused several related problems. The AER's rules that led to their approval of MRPs for distributors allowed the AER only to amend the distributors' forecasts "on the basis" of their current proposals.[6] Since distributors' proposals were based on bottom up analyses listing many individual expenditure items, the AER had to perform a line item analysis in order to reduce forecasts. This process was extremely resource intensive to the point that it could prevent third party stakeholders from becoming meaningfully involved in the proceedings.[7] It also prevented the AER from thoroughly examining all of the distributor's cost forecasts, particularly in smaller cost categories, much less adjust those forecasts to bring their total cost forecast in line with what the AER considered reasonable.[8] This also served to make effective benchmarking of cost forecasts impracticable. The total amounts proposed were generally higher than what would have been produced by "top-down" methods, such as statistical benchmarking, as the sum of reasonable line item expenditure estimates can be significantly higher than a reasonable estimate of aggregate expenditures.[9] The AER's efforts were further stymied by its inability to reduce cost forecasts to reflect the interplay between capital expenditures and O&M expenses.

The result of these rules was that

> On average across all networks, proposed forecasts of capex from NSPs [distribution and transmission companies] were 84% higher (in real terms) than actual expenditure in the previous regulatory period. While the AER reduced these forecasts in its final determinations, the approved forecasts were still considerably higher than previous actual expenditure.[10]

While some of these increases were certainly legitimate, their magnitude caused concerns that forecasts were being systematically overestimated.

> There are legitimate reasons for some increases in capex from previous levels. However, the sharp

[2] AER, Proposal to Amend the National Electricity Rules – Parts A & B, 2011, 13.
[3] AER, 2011, 13.
[4] AER, 2011, 29.
[5] AER, 2011, 13.
[6] AER, 2011, 27.
[7] AER, 2011, 29.
[8] AER, 2011, 29-30.
[9] AER, 2011, 29.
[10] AER, 2011, 7.

> and significant step change in expenditure forecasts draws into question whether the current framework is meeting the NEO [National Electricity Objectives] in 'promoting efficient investment' or whether it is stimulating investment above efficient levels.[11]

Ultimately, the AER came to the conclusion that

> The experience from the last five years has exemplified the restrictions on the AER's regulatory discretion and in turn suggests that concerns about inflated forecasts were well founded.[12]

These problems were exacerbated by the automatic roll in of capital expenditures into a distributor's rate base, which was responsible for a significant portion of price increases faced by consumers. This encouraged significant overspending of capex and led further increases of customer rates.

> Capex in excess of forecast has contributed to the step change in the regulated asset base at the start of the new regulatory period and electricity price rises. The AER estimates that up to 25 percent of increased distribution network charge arising in [New South Wales] and Queensland were attributable to capex in excess of that forecast during the previous round of regulatory resets.[13]

To address these problems, the AER proposed in 2011 to change their rules so that, in the next round of distribution determinations, they could consider top down analyses, including statistical benchmarking, in their evaluation of distributor cost forecast submissions.[14] The AER also proposed a rule change that would allow it to appropriately reduce individual project forecasts to better reflect cost estimates below the upper bound of what it considered efficient.[15] The proposed rule changes also included a proposal that only 60% of any capital expenditure overspend be allowed to be rolled into the rate base, with the remainder funded by shareholders and earning no return.[16] These changes were approved by the AEMC, with modifications, in 2012 and first applied in the most recent round of determinations for distributors.

The new rules allowed the AER to use a much wider variety of information in its decisions on reasonable distributor O&M expense and capital expenditures. Specifically, the AER commissioned annual benchmarking studies featuring multiple techniques for use in distributor determinations. Several distributors saw significant reductions from their proposed levels. The AER based O&M reductions in part off of estimates of efficient cost produced by its consultant's econometric benchmarking model. For example, Ausgrid saw its O&M expenses reduced by 26% and its capex by 15% for the next generation MRP.[17] Essential Energy saw its O&M expenses reduced by 30%[18] and its capex by 7%.[19] Both of these distributors were owned by the government of Australia's most populous state, New South Wales.

[11] AER, 2011, 8.
[12] AER, 2011, 14.
[13] AER, 2011, 10.
[14] AER, 2011, 29.
[15] AER, 2011, 29.
[16] AER, 2011, 19.
[17] AER, Final Decision, Ausgrid Distribution Determination, 2015-16 to 2018-19, 2015, 14 and 34.
[18] Calculation by PEG Research.
[19] AER, Final Decision, Essential Energy Distribution Determination, 2015-16 to 2018-19, 2015, 34 and 37.

1.3 Veuillez préciser comment un tel modèle pourrait prendre en compte la problématique de l'investissement.

1.3) Réponse de l'AQCIE/CIFQ :

Please see our response to part 2 of this question.

2. Références : (i) Pièce C-AQCIE-CIFQ-0025, p. 13;
(ii) Pièce C-AQCIE-CIFQ-0027, tableau 4;
(iii) Pièce C-AQCIE-CIFQ-0025, p. 96.

Préambule :

(i.) *« ARMs can escalate rates or allowed revenue. Limitations on rate growth are sometimes called price caps. In a typical price cap plan, allowed price escalation is typically applied separately to multiple service "baskets". There might, for example, be separate baskets for small volume customers, large industrial customers, and customers at risk of bypass. The utility is typically entitled to raise the average prices of the services in each basket by the same percentage permitted by the ARM, Y factor, Z factor, and any earnings sharing adjustments. »*

(ii.) *Au tableau 4, l'expert de PEG propose un MRI de type hybride comportant un plafonnement de revenu pour la plupart de la clientèle, à l'exclusion des consommateurs industriels dont le mécanisme reposerait sur un plafonnement de prix.*

(iii.) *« 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. »*

Demandes:

2.1 Veuillez élaborer sur les avantages, les inconvénients ainsi que les risques associés à l'implantation du modèle décrit en (i) et identifié en (ii) dans le contexte d'affaires du Distributeur.

2.1) Réponse de l'AQCIE/CIFQ :

Advantages of price caps include the following.

- Provided that a material portion of a utility's base revenue is gathered through usage charges, utilities have more incentive under price caps to maintain existing loads and seek new loads.

- The maintenance and growth of certain loads is desirable provided that they are efficient. These include the loads of large industrial customers that play a key role in the economies of some Quebec regions.

- Fluctuations in revenues from certain customers, due for example to special discounts and load fluctuations, have less effect under price caps on the revenues of other customers.

- It is easier for the regulator to sanction marketing flexibility.

Advantages of revenue decoupling include the following.

- The "throughput disincentive" that utilities have between rate cases to promote conservation and demand management can be eliminated. There will, for example, be less risk of utilizing advanced metering infrastructure to implement time-sensitive pricing. This disincentive to promote CDM would be much stronger under a multiyear rate plan than it is under the current system of annual rate cases.

- Controversy over future load growth, which has been a feature of HQD's rate cases, would be reduced.

- <u>Operating risk is reduced, thereby reducing concern that a </u>conventional <u>multiyear rate plan </u>for HQD <u>will be</u> <u>too risky</u> or require an increase in its target rate of return.

Dr. Lowry is proposing the "best of both worlds", where revenue decoupling applies to most customers but not to large industrial customers. The disincentive to develop strong CDM programs for large industrial customers can be addressed by other means such as a lost revenue adjustment mechanism or a performance incentive mechanism for demand management.

2.2 Veuillez préciser les motifs pour lesquels le traitement proposé pour les clientèles résidentielles et de petites entreprises ne serait pas applicable également pour la clientèle de grandes industries.

<u>2.2) Réponse de l'AQCIE/CIFQ :</u>

Please see our response to part 2.1 of this question. Note additionally that the demand of small-volume customers is generally less sensitive to the terms of service offered by HQD than is the demand of large industrial customers.

2.3 Veuillez élaborer sur les avantages, les inconvénients ainsi que les risques associés à l'implantation du dégroupement tel que décrit à (iii) dans le contexte d'affaires du Distributeur.

<u>2.3) Réponse de l'AQCIE/CIFQ :</u>

With one big basket, residential and commercial customers would immediately be called upon to make up for lost revenues resulting from discounts to large industrial customers or falling industrial loads. The Régie would be less inclined to afford HQD flexibility in marketing to large load customers. Residential and commercial customers will likely prefer to be insulated from the consequences of marketing flexibility and demand fluctuations in the large industrial sector. It is common for revenue decoupling not to extend to large-load customers of electric and natural gas utilities.

3. Références : (i) Pièce C-AQCIE-CIFQ-0025, p. 98;
(ii) Pièce C-AQCIE-CIFQ-0025, p. 99;
(iii) Pièce C-AQCIE-CIFQ-0025, p. 99;
(iv) Pièce C-AQCIE-CIFQ-0025, p. 99.

Préambule :

(i) *« 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. For example, sensible productivity-based formulas for forecasting O&M expense revenue could be required. Portions of the capex forecast can be based on test year capex or historical norms with an adjustment for inflation. »*

(ii) *« Independent productivity trend research should be commissioned in Phase 2 to inform the design of the ARM. Trends in the productivity of O&M and capital inputs should be calculated as well as the trend in multifactor productivity. In addition to its usefulness in an index-based ARM, O&M productivity results can be used to design the O&M escalator in a hybrid revenue cap and/or a productivity-based formula for forecasting O&M expenses that is useful in an all- forecast ARM. »*

(iii) *« 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. »*

(iv) *« US data are the best for an econometric benchmarking study of HQD because they are standardized and available for many years for a large number of power distributors facing diverse operating conditions. Advantages of US capital cost data were noted in Section 4.5.2 above. The Ontario Energy Board recently commissioned an independent transnational cost benchmark study using US data in a recent custom MRP proceeding for Toronto Hydro. »*
[nous soulignons]

Demandes:

3.1 Afin de compléter les parties soulignées en (i), (ii), veuillez déposer la liste des

études statistiques et de recherches sur la productivité (études de productivité multifactorielle) récentes en distribution et transport réalisées au Canada et aux États-Unis que la Régie pourrait utiliser dans le présent dossier en lieu et place d'une nouvelle étude.

3.1) Réponse de l'AQCIE/CIFQ :

Attachment Régie-AQCIE-3.1 is a table that summarizes results of recent US and Canadian studies of the multifactor productivity trends of energy utilities. It can be seen that the estimated productivity trend for Ontario is well below recent estimates of trends for the United States. The OEB ruled that its X factor must be based on the Ontario productivity trend, but Ontario data have numerous problems that complicate accurate productivity measurement.

3.2 Veuillez élaborer sur les avantages et les inconvénients, pour la Régie, de s'appuyer sur une revue d'études récentes de productivité et de balisage provenant d'autres juridictions pour l'élaboration d'un MRI de première génération pour le Distributeur et le Transporteur (c'est-à-dire de ne pas réaliser une étude de productivité propre à HQDT).

3.2) Réponse de l'AQCIE/CIFQ :

Dr. Lowry notes that benchmarking studies from other jurisdictions typically address the performance of utilities in other jurisdictions and would not shed light on the performance of Hydro-Québec. Productivity studies from other jurisdictions are more pertinent. A major advantage of reliance on other productivity studies is the savings on the cost of the studies. Additionally, a few regulators such as the Alberta Utility Commission and the Ontario Energy Board have taken the time to thoughtfully consider some of the issues in productivity measurement before choosing a productivity growth target.

The key disadvantage of not performing a custom productivity study, and instead relying on other studies, is that the adopted base productivity trend may result in windfall gains or losses for Hydro-Québec. This may result from one or more of several inconsistencies between the methods used in the studies and the application of the research to Hydro-Québec.

- The definition of cost used in the other studies may differ from the costs to which the attrition relief mechanism ("ARM") would apply. Our experience is that exclusions of certain cost categories, particularly uncollectible bills, pensions, and conservation and demand management costs can significantly increase the multifactor productivity trend. These cost categories are often tracked in multiyear rate plans and not addressed by the ARM. Uncollectible bills tend to spike during recessionary periods. Utilities in the U.S. often record their expenditures for conservation and demand management programs as customer service and information costs. Pension costs are also commonly tracked. Both CDM and pension costs have been rising in the United States in recent years.

- The output quantity indexes used in the other studies may be inconsistent with the manner in which the productivity results will be used. For example, an output index appropriate for a *price* cap index is generally inappropriate when the productivity results are being used to design a *revenue* cap index. The weights on the output trends matter. Multifactor productivity studies that rely primarily or solely on volumes delivered in the output index tend to understate the cost efficiency trend that is pertinent for a revenue cap, as volumes have slowed or even declined in recent years for various reasons.

- Special business conditions may influence the productivity trend in the other studies that would not be present for Hydro-Québec. For example, productivity growth may have been slowed by the installation of advanced metering infrastructure but this infrastructure will have been installed in Quebec before the multiyear rate plan begins.

- The other studies will typically not include the latest available data. This is germane because the period to which the X factor would apply is typically well into the future (*e.g.* 2018-21). Witnesses for Canadian utilities often claim that there has been a recent productivity slowdown.

3.3 Veuillez déposer la liste des études de balisage dont il est question en (iii). Veuillez préciser lesquelles parmi celles-ci sont le plus susceptibles de contribuer aux travaux de la Régie dans la définition d'un MRI de première génération pour le Distributeur et le Transporteur.

3.3) Réponse de l'AQCIE/CIFQ :

The table in Attachment Régie-AQCIE 3.3 summarizes an assortment of recent statistical benchmarking studies in the public domain. Dr. Lowry recommends use of an econometric benchmarking methodology for Hydro-Québec.

3.4 Veuillez déposer l'étude de balisage dont il est question en (iv).

3.4) Réponse de l'AQCIE/CIFQ :

This study, which was prepared by PEG Research, is provided in Attachment Régie-AQCIE 3.4, along with the Ontario Energy Board's ruling on Toronto Hydro-Electric's custom incentive regulation proposal. It can be seen that the Board's ruling on the stretch factor for Toronto Hydro is consistent with PEG's benchmarking evidence.

4. Référence : Pièce C-AQCIE-CIFQ-0025, p. 100.

Préambule:

« 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. » [nous soulignons]

Demande:

4.1 4.1 Veuillez indiquer si, à votre connaissance, de telles études ont été réalisées pour un ou des Transporteur d'électricité au Canada ou aux États-Unis. Dans l'affirmative, veuillez fournir les références en ce sens. Dans la négative, veuillez préciser les raisons pour lesquelles, selon vous, de telles études n'ont pas encore été réalisées en Amérique du Nord.

4.1) Réponse de l'AQCIE/CIFQ :

Dr. Lowry prepared a study of the productivity trends of US power transmission utilities for Hydro One Networks in 2002. The company was considering its use in a multiyear rate plan. This study is not in the public domain. Kansas City Power and Light Company commissioned a transmission productivity study in 2006.

Power transmission productivity studies are not common in North America for several reasons. One is that transmission services of utilities here have rarely been singled out for multiyear rate plans with index-based ARMs. Transmission services in the United States are commonly regulated by the FERC using formula rate plans (which feature a broad-scope cost tracker) or cost of service ratemaking. There has been greater interest in MRPs for power transmission in Canada. Please see our response to HQTD-PEG 8A for more discussion of Canadian experience.

5. Références : (i) Pièce C-HQT-HQD-0023, p. 26;
(ii) Pièce C-AQCIE-CIFQ-0025, p. 105.

Préambule:

(i) *« The current scorecard indicators measure customer satisfaction, service reliability, quality of service, safety, and environmental performance. HQD currently tracks eight measures across five categories (customer satisfaction, reliability, electric supply, customer service and public and employee safety), while HQT currently tracks several measures across four categories (customer satisfaction, reliability, costs evolution, environmental indicators). »*

(ii) *« 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 short list of the more important metrics should be featured in a scorecard that is posted electronically by the Régie or Hydro-Québec for the public to see. PIM calculations should be externally audited. Reliability goals should be carefully considered, since high reliability is costly. »*

Demandes:

5.1 Veuillez préciser quelles catégories d'indicateurs présentent la plus grande importance dans le cadre d'un suivi de la performance du Distributeur et du Transporteur.

5.1) Réponse de l'AQCIE/CIFQ :

Dr. Lowry identifies these categories in Section 6.2.7 of his testimony.

5.2 En regard de l'amélioration de la performance du Transporteur et du Distributeur relativement aux coûts et à la qualité de service, veuillez discuter de vos anticipations quant à l'ampleur et la manière d'en mesurer l'atteinte.

<u>5.2) Réponse de l'AQCIE/CIFQ :</u>

Key indicators of service quality are discussed in Section 6.2.7 of Dr. Lowry's testimony. Improvements in the cost performances of HQD and HQT can be measured using statistical benchmarking and productivity indexing. Distribution reliability can also be appraised using benchmarking methods, as standardized US reliability data are now in the public domain.

6. Référence : Pièce C-AQCIE-CIFQ-0025, p. 108.

<u>Préambule:</u>

« 6.2.8 Marketing Flexibility

Marketing flexibility provisions should permit a continuation of the economic development and load retention rates. 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.

<u>Both divisions should, additionally, be permitted to gradually redesign tariffs during the term of the plan to achieve any Régie-approved goals.</u> An example for HQD might be the phase in of time-sensitive usage charges, in standard tariffs for residential and commercial customers, which discourage system use in peak hours.

<u>Both divisions should also be permitted to provide certain optional tariffs to customers who retain recourse to service under standard tariffs.</u> One eligible optional tariff for HQD might feature time-sensitive pricing for residential and commercial customers. Another might encourage commercial customers to use electricity off-peak for space heating. Time-sensitive pricing should be required for electric vehicle customers. » [nous soulignons]

<u>Demandes:</u>

6.1 Veuillez élaborer sur les avantages, les inconvénients ainsi que les risques associés à l'implantation de la flexibilité commerciale tel que décrit en préambule dans le contexte d'affaires du Distributeur. Veuillez préciser les motifs appuyant un tel développement dans le cadre de l'implantation du mécanisme proposé pour le Distributeur.

<u>6.1) Réponse de l'AQCIE/CIFQ :</u>

HQD can use marketing flexibility to reduce its costs (eg costs of load-related assets), maintain desirable loads, encourage desirable new loads, and offer value-added services that make use of advanced metering infrastructure and other new technologies.

On the downside, marketing flexibility complicates the occasional rate cases under MRPs since costs must be allocated across a more complex array of rates and services. Marketing flexibility in services subject to decoupling must be carefully monitored since resultant revenue shortfalls are promptly recovered from other customers. Furthermore, marketing flexibility can affect other customers indirectly via the earnings sharing mechanism and off ramp provisions. For this reason, multiyear rate plans in which marketing flexibility played a central role have often not included earnings sharing mechanisms.

6.2 Veuillez élaborer sur les avantages, les inconvénients ainsi que les risques associés à l'implantation de la flexibilité commerciale tel que décrit en préambule dans le contexte d'affaires du Transporteur. Veuillez préciser les motifs appuyant un tel développement dans le cadre de l'implantation du mécanisme proposé pour le Transporteur.

6.2) Réponse de l'AQCIE/CIFQ :

Dr. Lowry explains in his testimony that marketing flexibility can potentially help HQT manage its costs (e.g. by discouraging system use in peak demand periods) and meet the complex and changing needs of its point to point customers. Since HQT effectively operates under a revenue cap, however, its rate and service offerings will need to be carefully monitored by the Régie.

7. Référence : Pièce C-AQCIE-CIFQ-0025, p. 108.

Préambule:

« 6.2.9 Plan Termination Provisions

(i) *Given the lack of experience with MRPs in Québec, we recommend relatively short four year terms for both companies in the first plan. The incentive power of such plans should be considerably greater than annual rate cases. Mid-term review of each plan would be undertaken in the third year. This review would consider trends in the utility's cost efficiency (with special attention to deferrable costs), CDM, marketing flexibility, service quality, and earnings and the regulatory cost savings achieved. The midterm review should have the possible outcome of a plan update and extension.*

(ii) *Efficiency carryover mechanisms should be considered for each company. Existing ECMs in Alberta and Australia unfortunately do not provide good starting points for a Québec mechanism and fresh thinking is needed. Mechanisms should be designed to reward good value to customers in the rates of future MRPs rather than focusing on cost savings in the expiring MRP. » [nous soulignons]*

Demandes:

7.1 En vous référant à la partie soulignée en référence, veuillez discuter des

raisons pour lesquelles les exemples cités ne constitueraient pas de bons points de départ dans le cadre des MRI du Distributeur et du Transporteur.

<u>7.1) Réponse de l'AQCIE/CIFQ :</u>

Please see the response to Régie-AQCIE 7.2

7.2 Veuillez élaborer sur les caractéristiques que devrait comporter un mécanisme de report de l'efficience applicable aux situations du Distributeur et du Transporteur.

<u>7.2) Réponse de l'AQCIE/CIFQ :</u>

An efficiency carryover mechanism (« ECM ») permits a utility to keep some of the benefits of lasting efficiency gains that it achieves during a multiyear rate plan after the plan expires. Such mechanisms are intended to bolster incentives to achieve lasting efficiency gains. There are several reasons why the incentive to achieve lasting efficiency gains may need to be strengthened in an MRP.

- The performance incentives in multiyear rate plans are stronger than under annual rate cases, but are nonetheless weaker than they are in competitive markets due to provisions, such as earnings sharing and a four year rate case cycle, that are used to share plan benefits with customers.

- The incentive to undertake initiatives that create lasting efficiency gains attenuates in the later years of a multiyear rate plan because the up-front costs of such initiatives erode current earnings while an increasing share (and potentially all) of the benefits of the initiative will be passed through to customers in the next rate case.

- Utilities can sometimes benefit by deferring costs in one plan and then asking for extra revenue to fund these costs in the next plan, thereby being compensated more than once for the same costs.

Alberta Approach

The Alberta approach to ECM design calculates an average of surplus and deficit earnings achieved during an MRP and then permits the utility to keep a share of net gains during the next plan period. This approach is problematic for several reasons. Net earnings can be a poor measure of lasting performance gains. Moreover, this approach does not discourage strategic deferrals. A utility could bolster earnings by deferring replacement capex and then request extra funding in the next plan plus the ECM bonus.

Australian Approach

<u>Overview</u>

Australian regulation typically features an MRP with a five year term and an attrition relief mechanism based on forecasts of utility costs. Forecasts of O&M expenses are often based on an escalation using indexing of their actual cost during the penultimate year of the previous plan. This has led to a concern that a utility might increase its costs during the penultimate year. There has been a more general concern that utilities have reduced incentives to improve their efficiency in the later years of an MRP.

To help address these concerns, the Essential Services Commission of Victoria adopted efficiency carryover mechanisms ("ECMs") for power distributors during the years that it regulated them. These mechanisms reduced the incentive for utilities to make inefficient decisions in the later years of an MRP by extending the duration of the financial impacts of their choices, both efficient and inefficient, that were made during the course of an MRP. At the time of a rate rebasing, the amounts to be carried over through the ECM are added to the forecasts of the utility's costs.

The Australian Energy Regulator ("AER") now regulates most Australian energy utilities and uses MRPs that feature ECMs. The AER's first-generation ECMs applied only to operation and maintenance ("O&M") expenses. In 2013, the AER updated the ECM for O&M expenses and implemented one for capital expenditures. The ECM for O&M expenses in Australia is called the Efficiency Benefit Sharing Scheme ("EBSS"), while the mechanism for capital expenditures is called the Capital Expenditure Sharing Scheme ("CESS"). We discuss each of these mechanisms in turn.

O&M Expenses

The EBSS is designed to properly rebalance incentives for the timing of O&M efficiency improvements such that utilities benefit as much from efficiency gains made in the first years of a MRP as they do from those made in the later years of a MRP. It also includes a mechanism to penalize companies for attempting to game the system by allowing costs to run up during the base year used to forecast O&M expenses for the next regulatory period. The ECM accomplishes this by allowing utilities to benefit from incremental efficiency gains for a 5 year period following their occurrence, regardless of when during the regulatory period those gains were made. In each year of the following regulatory period, the applicable carryover gains for the preceding 5 year period are summed and added to the revenue requirement for the appropriate period (e.g., gains during the first year of one plan carry over only for the first year of the following MRP while gains made during the final year of an MRP carry over for the entirety of the next one).

There are three formulas used to calculate incremental changes in efficiency. The formula used for years 2-4 of Australia's 5 year regulatory period is

$$I_{i,n} = \left(F_{i,n} - A_{i,n}\right) - \left(F_{i-1,n} - A_{i-1,n}\right) .$$

For year *i* of regulatory period *n*, *I* is the incremental efficiency gain, *F* is the forecast O&M and *A* is the actual O&M. The formulas used for the first and last year of the regulatory period attempt to simulate the same thing, after adjusting for peculiarities arising from the timing of that year relative to the regulatory determinations. The formula used for the first year of the regulatory period is

$$I_{1,n} = \left(F_{1,n} - A_{1,n}\right) - \left[\left(F_{f,n-1} - A_{f,n-1}\right) - \left(F_{b,n-1} - A_{b,n-1}\right)\right] - \\ non\text{-}recurrent\ efficiency\ gains_{b,n-1}.$$

The subscript *f* refers to the final year of a regulatory period, the subscript *b* refers to the base year for a regulatory period (typically the fourth year of the previous regulatory period), and *non-*

recurrent efficiency gains refer to any adjustments made to base year O&M expenses to forecast O&M expenses in that regulatory period. The replacement of the previous year efficiency term, $(F_{i-1,n} - A_{i-1,n})$, with $(F_{f,n-1} - A_{f,n-1}) - (F_{b,n-1} - A_{b,n-1})$ penalizes the utility for any run up in O&M costs, relative to the forecast, during the base year of the previous period that was followed by a drop in the final year by expecting that drop to be replicated in the first year of the current period. In the final year of a regulatory period, the formula used is

$$I_{f,n} = (F_{f,n} - A^*_{f,n}) - (F_{f-1,n} - A_{f-1,n})$$

where A^* is estimated actual O&M expenses and is calculated as

$$A^*_{f,n} = F_{f,n} - (F_{b,n} - A_{b,n}) + \textit{non-recurrent efficiency gains}_{b,n}.$$

Essentially, this formula expects final year efficiency to be equal to base year efficiency during a regulatory period.

<u>Capex</u>

The Capital Expenditure Sharing Scheme functions similarly to the EBSS. It is somewhat more complicated due to the necessity of including financing benefits resulting from capex efficiency gains. The magnitude of capex efficiency gains is calculated as the end of period net present value ("NPV") of the difference between forecast capex and actual capex, adjusted for the financing effects of deviations between the two as well as any capex that is excluded from rate base. For a regulatory period, the total efficiency gain, *E*, is calculated as

$$E = \sum_{i=1}^{n} \left[\frac{1}{(1+WACC)^{i-n-0.5}} * (F_i - A_i)\right]$$

where *WACC* is the nominal weighted average cost of capital applied during the regulatory period, *F* is forecast capex, *A* is actual capex, and *i* is the year in the regulatory period of length *n*.[20] This total is then multiplied by the sharing factor, which is 30%, to determine the utility's share of the efficiency gains.

From this share, the net financing benefit that the company has already received due to the deviation of actual capital expenditures from forecast capital expenditures is subtracted. For each year *t*, the financing benefit, B_t, is calculated as

$$B_t = [(1+WACC)^{0.5} - 1] * (F_t - A_t) + \sum_{i=1}^{t-1} WACC * (F_i - A_i).$$

The full period net financing benefit, *N*, is calculated as

$$N = \sum_{i=1}^{n} \left(\frac{1}{(1+WACC)^{i-n}} * B_i\right).$$

The carryover amount, *C*, can then be calculated as

$$C = E - N.$$

[20] Because this determination is done before the end of the regulatory period, estimates of actual capex are relied upon for the final year.

After adjustments for capex excluded from rate base and capex underspend due to deferrals, *C* is added to the company's revenue requirement in the following regulatory period. To adjust the carryover amount for underspend due to deferrals, the NPV of forecast capex increases in the following regulatory period that are due to deferrals in the current regulatory period is calculated and subtracted from *E* before *C* is calculated.

Appraisal

The Australian approach to ECM design is based on the building block approach to ARM design, which Dr. Lowry (and AQCIE) opposes. It is clearly quite complicated and does not discourage all strategic deferrals.

7.3 À l'échéance de la période d'application du MRI de première génération, veuillez discuter de la possibilité d'intégrer à ce dernier un mécanisme prévoyant sa transition vers un nouveau mécanisme de réglementation incitative. Veuillez élaborer sur la pertinence et les modalités d'un tel mécanisme de transition.

7.3) Réponse de l'AQCIE/CIFQ :

Dr. Lowry recommends that the Régie consider use of an ECM in the first plan period. The focus of an ECM should be on encouraging lasting efficiency gains. This is best achieved by mechanisms that reward the utility for offering customers demonstrably good value in the next plan period. Statistical benchmarking is useful for appraising the value to customers of the revenue requirement in the next plan period. The design of ECMs for HQT is a Phase 3 issue.

8. Références : (i) Pièce C-HQT-HQD-0023, p. 5;
(ii) Pièce C-HQT-HQD-0023, p. 30.

Préambule:

(i) « The term of an MRI is a key design element as a longer period provides the utility with a greater incentive and opportunity to make investments or modify business processes to produce efficiency gains. Longer terms also create greater risk for the utility and consumers that rates will deviate substantially from costs and potentially impact the financial risk of the company with a resulting impact on ROE. »

(ii) « Concentric proposes a rebasing of rates, followed by a two-year MRI term for both HQD and HQT. »

Demande:

8.1 Veuillez discuter de la position de HQDT en (i) et (ii) relativement au risque associé à la durée dans le cadre d'un MRI de première génération dans les propositions du Distributeur et du Transporteur.

8.1) Réponse de l'AQCIE/CIFQ :

A three year plan plainly undoubtedly reduces the risk of MRIs for HQD and HQT. The real issue is whether the marginal benefits of this risk reduction outweigh the marginal costs.

9. Référence : Pièce C-HQT-HQD-0023, p. 24 et 25.

Préambule:

« SECTION 5: PRODUCTIVITY STUDY

[...]

The productivity studies objectively apply data to a valid theoretical model but face several challenges that are widely recognized:

- *selecting a valid comparison group ;*
- *determining the study period (beginning and end years) ;*
- *compiling a vast amount of data, potentially from multiple sources ;*
- *comparability of input and output data that is subject to varying accounting and regulatory accounting policies among jurisdictions ;*
- *difficulty of controlling for external factors ;*
- *need to specify numerous assumptions ; and*
- *the specific algorithms that are used to estimate productivity.*

Benchmarking studies face many of these same challenges. There is an important distinction, however. Benchmarking studies inform the determination of "X", along with other relevant information and the application of judgment ; productivity studies produce an estimate of "X" that frequently begins a lengthy, costly, and complicated discussion of all aspects of the study (or studies in many jurisdictions). Regulators are left in the position of sorting through and trying to make sense of a large and confusing record. This is not to suggest that productivity studies are necessarily better or worse than alternative methodologies, but this post-study engagement should be anticipated as part of the process.

The "Judgment" approach avoids many of the controversies over sample size, data sources, and quantitative methods while still providing an incentive to pursue efficiency gains. » [nous soulignons]

Demandes:

9.1 En regard des défis soulevés en préambule par l'expert du Transporteur et du Distributeur quant au recours à des études de productivité et de balisage, veuillez discuter de ceux qui se présentent dans le cadre de l'établissement du MRI pour le Distributeur et le Transporteur.

9.1) Réponse de l'AQCIE/CIFQ :

Productivity trend studies are often complex and involve methodologies with which the Régie has limited familiarity. Since substantial money is at stake in the choice of an X factor, extensive controversy can ensue. X factors have been vigorously debated in recent MRI proceedings in Alberta, British Columbia, Ontario, and Maine.

It is nevertheless common for regulators to choose X factors based on custom studies and not just use their "judgement" after reviewing other studies. There are several reasons for this.

- Windfall gains are likely to be reduced, as discussed in our answer to question Régie-AQCIE question 3.2.
- A "valid comparison group" is typically much less of an issue in a productivity trend study than it potentially is in a benchmarking study. That is because many of the business conditions that effect the *level* of cost (e.g. forestation of the service territory) have much less effect on the *trend* of cost.
- Productivity indexes that are appropriate for the design of *revenue* cap indexes are usually fairly insensitive to the choice of a sample period. The sample period issue matters more when the output index places a heavy weight on delivery *volume*, which might be appropriate with the design of a *price* cap index.
- Data sets are large, but most of the required data for a US productivity study are fairly easy to obtain. Experts on productivity have, in any event, already gathered most of these data.
- Variations in accounting and regulatory policy do complicate research on utility productivity in Canada. However, abundant standardized data are available in the United States because numerous electric utilities are required to submit detailed data on their operations to the US government.
- Relatively simple methods, such as the "Kahn method", are available to calculate X if simplicity is an important priority.

9.2 Veuillez discuter de l'approche fondée sur le « jugement » en précisant ses avantages et ses inconvénients dans le contexte d'un MRI de première génération pour le Transporteur et le Distributeur.

9.2) Réponse de l'AQCIE/CIFQ :

Please see our response to question 9.1.

9.3 Veuillez discuter de la possibilité, pour la Régie, de recourir à son expérience et à l'expertise d'autres juridictions en matière de réglementation incitative afin de déterminer le facteur X d'un MRI de première génération pour le Transporteur et le Distributeur.

9.3) Réponse de l'AQCIE/CIFQ :

Dr. Lowry discusses the pros and cons of relying on productivity studies from other jurisdictions in his response to the Regie's question 3.2. He provides here the following supplemental comments.

- The Ontario Energy Board used a judgement approach to setting X in its second generation incentive regulation mechanism for power distributors.
- No Commission has ruled on the appropriate productivity trend for a power transmission utility.
- A judgement approach delays development of expertise in Quebec's regulatory community on the methodological issues involved in X factor selection.
- There are three recent Canadian rulings on the productivity trends of power distributors. One of these is quite different than the others, because it is based on Ontario rather than US data. Consumers would object if the Ontario trend were chosen, whereas Hydro-Québec might well object if the average of the three were chosen.

10. Référence : Pièce C-AQCIE-CIFQ-0028, p. 5.

Préambule :

« De l'avis de l'AQCIE et du CIFQ, l'exclusion des coûts d'achats d'électricité et de transport de l'application du MRI équivaut au maintien du statu quo en mode coût de service, avec toutes les lacunes qu'on lui connaît, pour au moins 77,1 % de l'ensemble des postes de dépenses du Distributeur. Selon l'AQCIE et le CIFQ, l'application du MRI devrait bien plutôt porter sur un maximum de postes de dépenses, tout comme le font les forces du marché dans un environnement concurrentiel. Ainsi, par exemple, une grande industrie exposée à la concurrence doit non seulement optimiser ses dépenses d'exploitation mais également tous les autres postes de dépenses constituant les intrants de sa structure de coûts. Pour ce motif, l'AQCIE et le CIFQ recommandent plutôt à la Régie de s'en remettre à la recommandation suivante contenue dans l'expertise de PEG (à la page 102) :

> *"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. <u>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.</u>" [nous soulignons]*

Demandes:

10.1 Veuillez expliciter l'approche soulignée en préambule particulièrement dans le contexte spécifique au Distributeur et préciser sur quelle base et selon quel

critère pourrait être déterminée la variable « b » de la référence.

<u>10.1) Réponse de l'AQCIE/CIFQ :</u>

The Basic Idea

Suppose that the forecasted cost of power supply (fourniture) in a given year is denoted by $CE^{Forecasted}$ and that the actual cost is denoted by CE^{actual}. If the cost of power supply is tracked, the revenue (RE) that ultimately compensates a utility for supplying power might then conform to the following stylized formula:

$$RE = CE^{Forecasted} + (CE^{Actual} - CE^{Forecasted}) = CE^{Actual}.$$

Forecasts can be produced with methodologies that have varying degrees of sophistication.

One means of incentivizing the tracker is to true up for only the share "a" of the variance. Then

$$\begin{aligned} RE &= CE^{Forecasted} + a \cdot (CE^{Actual} - CE^{Forecasted}) \\ &= a \cdot CE^{Actual} + (1- a) \cdot CE^{Forecasted}. \end{aligned} \quad [1]$$

The energy revenue ultimately received by the utility is a weighted average of the utility's cost and an initial forecast of the cost.

It is also possible to recognize the effect of input prices on cost. We could, for example, use the following cost benchmark

$$CE^{Bench} = (CE_{t-1}{}^{Forecasted}/PE_{t-1}{}^{Forecasted}) * PE_t{}^{Actual}. \quad [2]$$

in a power supply performance incentive mechanism of general form

$$RE = CE^{Forecasted} + (CE^{Actual} - CE^{Forecasted}) + b \cdot (CE^{Bench} - CE^{Actual}) \quad [3]$$

Indexing the power cost benchmark for inflation using a price index (PE) is one means of accounting for the inflation in the price of power from the Heritage Pool and other sources.

Numerous additional adjustments are possible to make a power cost benchmark more realistic, and a benchmark formula can be quite complicated.

An alternative to mechanistic formulas like [1] and [3] is a *discretionary* financial incentive that is tied to power supply cost performance. HQD could, for example, be rewarded $X million if it managed to contain further purchases outside the Heritage Pool or if purchases outside the Heritage Pool were made through competitive tenders designed to solicit the power at lowest cost.

Precedents

While PEG has not undertaken a comprehensive study of incentive regulation of power procurement costs, they have obtained two surveys of approved incentivized cost trackers for fuel and purchased power in the US. The first, from the 1990s, included a table that identified 6 jurisdictions where incentivized trackers for energy procurement costs had been approved.[21] The second, a recent survey by Regulatory Research Associates on utility cost trackers, was filed with the Missouri Public Service Commission and shows that at least 10 regulators have approved incentivized trackers for energy procurement costs.

PEG has undertaken a more in-depth review of three of these incentivized cost trackers for the development of this response. These examples are for Portland General Electric, Consolidated Edison, and Avista Utilities.

The regulator in New York approved a "partial pass-through fuel adjustment clause" for Consolidated Edison in 1995 that reimbursed the utility for a set level of "fuel" costs plus an additional 30% of the variance between the actual and set level up to a maximum of $35 million per year. It is unclear if the mechanism covered only generation fuel costs or purchased power as well.

In Oregon, the regulator approved a "power cost adjustment" mechanism in 2001 for Portland General Electric that allowed the utility to collect a base amount for power plus an additional "adjustment amount" tied to the "power cost variance," defined as the variance between actual costs and the costs from which base revenue was computed. The magnitude of the adjustment amount changed with the size of the power cost variance and is given in the table below.

Power Cost Adjustment Amount for Portland General Electric	
Power Cost Variance (M)	**Adjustment Amount**
-$28 to $28	Zero
$28 to $38	50% of PCV between $28 million and $38 million
$38 to $100	$5 million plus 85% of PCV between $38 million and $100 million
$100 to $200	$57.7 million plus 90% of PCV between $100 million and $200 million
over $200	$147.7 million plus 95% of PCV in excess of $200 million
-$28 to -$38	50% of PCV between -$28 million and -$38 million
-$38 to -$100	-$5 million plus 85% of PCV between -$38 million and -$100 million
-$100 to -$200	-$57.7 million plus 90% of PCV between -$100 million and -$200 million
less than -$200	-$147.7 million plus 95% of PCV beyond -$200 million

It can be seen that there was a "dead band" in the mechanism for smaller variances.

In 2002, the state of Washington's regulator approved an "Energy Recovery Mechanism (ERM)" for Avista Utilities. Under the ERM, Avista was allowed to collect base power supply costs plus 90% of the difference between actual and base power supply costs outside of an annual $9 million dead band. Base power supply costs were determined using a dispatch model. The ERM was modified in 2008 to include asymmetric sharing when the difference between actual and

[21] Charles H. Stetson (1991), *Adjustment Clauses: A Survey of State Policies and Practices*, Published by the Edison Electric Institute's Rate Regulation Department.

base power supply costs was between $4 million and $10 million on an annual basis. The sharing level in this range was 75% to customer/ 25% to company when actual power supply costs were lower than base power supply costs and 50% to customer/ 50% to company when actual power supply costs were higher than base power supply costs. If the difference between actual and base power supply costs were outside of $10 million on an annual basis, the company recovered/ rebated 90% of the difference.

PEG is also aware that incentive regulation has been used extensively to regulate the procurement of natural gas by gas utilities. For example, plans have been approved for distributors in California, Idaho, Illinois, Oregon, and Washington. Costello (2006) provides a useful discussion of gas procurement incentive mechanisms in the United States. [22]

10.2 Veuillez expliquer comment pourrait être pris en compte l'indexation du prix de l'énergie patrimoniale, à l'exception de l'énergie allouée au tarif L et aux contrats spéciaux, ainsi que la part croissance des charges de fourniture postpatrimoniale, compte tenu de l'article 71.1 de la Loi sur la Régie de l'énergie.

10.2) Réponse de l'AQCIE/CIFQ :

It is straightforward to take account of the indexation of the price of patrimonial energy in the development of power cost benchmark. This can be addressed in the power cost forecast and subject to an index-based true up.

11. Référence : Pièce C-HQT-HQD-0028, p. 15.

Préambule:

« De plus, l'alternance de l'année de départ des MRI du Transporteur et du Distributeur peut constituer une source additionnelle d'allégement pour les partis impliqués en plus de permettre de profiter des leçons apprises. C'est d'ailleurs l'approche qu'a retenue l'Ontario Energy Board. »

Demande:

11.1 Veuillez indiquez dans quel ordre la Régie devrait procéder si elle devait retenir cette proposition. Veuillez motiver votre réponse.

11.1) Réponse de l'AQCIE/CIFQ :

Dr. Lowry believes that if the MRIs are developed sequentially it makes more sense to start with an MRI for power distribution. There is an extensive record of deliberation on the design of MRIs for power distribution in several jurisdictions, including Alberta, Australia, Britain, and Ontario. Expertise has accumulated on the measurement of power distributor input price and productivity trends.

[22] Costello, Ken and Wilson, James F. "A Hard Look at Incentive Mechanisms for Gas Procurement." The National Regulatory Research Institute. 2006.

12. Référence: Pièce A-0029, p. 7.

<u>Préambule:</u>

« [21] La Régie retient l'opinion des intervenants quant aux enjeux à inclure à la phase 1. Cette phase doit permettre d'identifier le type, <u>le nombre et les caractéristiques d'un MRI</u> pour les mises en cause, ainsi que les indicateurs permettant de mesurer l'atteinte de chacune des caractéristiques ou chacun des objectifs opérationnels. » [nous soulignons]

<u>Demande:</u>

12.1 Parmi les caractéristiques proposées par les participants, veuillez préciser les cinq caractéristiques qui, selon vous, doivent être retenues dans la définition du MRI de première génération :

12.1.1. pour le Distributeur;

<u>12.1.1) Réponse de l'AQCIE/CIFQ :</u>

Dr. Lowry believes that the following characteristics are most essential in a first generation incentive regulation mechanism for HQD that fulfills the objectives of the law.

1. **Basic Form**

The basic form of the MRI should be a multiyear rate plan. These plans involve a moratorium on general rate cases, an (external) attrition relief mechanism ("ARM"), and a performance metric system.

2. **Attrition Relief Mechanism**

The attrition-relief mechanism should be a revenue cap index. The X factor should ensure customers the benefit of industry productivity growth and include a stretch factor absent clear evidence of superior performance.

3. **Cost Trackers**

Costs of HQD's power, transmission, and conservation and demand programs should be scheduled for tracking (i.e. Y factored). A few costs additional costs may be Y factored, and a few hard to foresee developments that affect cost should be eligible for special revenue adjustments (ie Z factored). The incentive to contain power costs will be strengthened by an incentivized tracker or power cost incentive mechanism.

4. **Revenue Decoupling**

Revenues from most services classes should be subject to decoupling. This would reduce HQD's operating risk and eliminate the "throughput disincentive" to embrace conservation and demand management (CDM) , which is strengthened by a multiyear rate plan,

5. **Benefit Sharing**

A number of provisions will promote an equitable sharing of plan benefits between HQD and its customers. These include occasional rate cases, an earnings (or expenditure) sharing mechanism, and the addition of a stretch factor to the X factor if warranted. An efficiency carryover mechanism should be considered.

6. **Performance Metric System**

The key performance areas for HQD are reliability, customer service, CDM, and price (cost). A performance metric system will aid review of performance in these areas. Some metrics will be tied to performance incentive mechanisms. PIMs should address reliability, customer service, power procurement, and CDM. Cost efficiency may be appraised using productivity indexes and/or econometric benchmarking.

12.1.2. pour le Transporteur.

<u>12.1.2) Réponse de l'AQCIE/CIFQ :</u>

Dr. Lowry believes that the following characteristics are most essential in a first generation incentive regulation mechanism for HQT that fulfills the objectives of the law.

1. **Basic Form**

The basic form of the MRI should be multiyear rate plan.

2. **Attrition Relief Mechanism**

The attrition relief mechanism should be a revenue cap. An index-based approach to revenue cap design is preferable. The X factor should ensure customers the benefit of industry productivity growth and include a stretch factor absent clear evidence of superior performance.

3. **Cost Trackers**

A few costs may be Y factored. Eligible costs may include some capital costs as a last resort to address capital expenditure surges. A few hard to foresee developments that affect costs will be eligible for Z factoring.

4. **Benefit Sharing**

A number of provisions will promote an equitable sharing of plan benefits between HQD and its customers. These include occasional rate cases, an earnings (or expenditure) sharing mechanism, and the addition of a stretch factor to the X factor if warranted. An efficiency carryover mechanism should be considered.

5. **Performance Metric System**

The key performance areas for HQT are reliability, customer service, environmental impacts, and price (cost). A performance metric system will aid review of performance in all of these areas. Some metrics will be tied to performance incentive mechanisms. PIMs will address reliability, safety, and customer service. Cost efficiency may be appraised using productivity indexes and/or econometric benchmarking. Performance will be summarized in a publicly available scorecard.