RÉPONSES À LA DEMANDE DE RENSEIGNEMENTS N° 2 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-0028, p. 25;
(ii) Pièce C-AQCIE-CIFQ-0044, p. 90.

Préambule :

(i) « *De plus, la prépondérance des coûts liés aux investissements dans la structure de coûts du Transporteur et leurs variations dans le temps, ainsi que la nécessité de maintenir l'évolution du risque de défaillance partielle des équipements sous contrôle, sont autant d'éléments qui militent en faveur de l'établissement des revenus requis selon une évaluation des besoins budgétaires envisagés sur la période du MRI résultant de l'application du MGA. Le MRI retenu doit donc permettre l'exercice d'un jugement informé pour l'établissement de projections intégrant ces besoins. Dans ce contexte, le Transporteur estime ne pas pouvoir recourir à une formule prédéfinie pour l'établissement de ses revenus requis.* »

(ii) « *The OEB must decide whether the proposed Custom formula proposed by Toronto Hydro is appropriate. Toronto Hydro has proposed that distribution rates in Year 2 through 5 be adjusted annually by using a custom Price Cap Index (PCI) :*

$$PCI = I - X + C$$

Where,

- *"I" is the OEB's inflation factor, determined annually*
- *"X" is the sum of :*
  - *The OEB productivity factor;*
  - *Toronto Hydro's custom stretch factor.*
- *"C" provides incremental funds that are necessary to fund capital needs* ».

La Régie comprend que, dans le cadre du modèle « building block » qu'il propose, le Transporteur sera en mesure de formuler une projection pluriannuelle tant de ses dépenses de maintenance aux charges que de ses dépenses en investissement sur la durée du MRI proposé. Cette projection reflètera les besoins de son modèle de gestion des actifs tels que soulevé en référence (i).

Demande :

1.1 Veuillez élaborer sur la possibilité de définir un modèle de règlementation incitative du type de celui décrit en (ii) dans le cadre spécifique du Transporteur qui tiendrait compte de l'impact de son modèle de gestion des actifs. En d'autres termes, veuillez discuter de la possibilité de définir un MRI qui, tout en s'inscrivant dans une formulation de type I-X, prendrait en considération les particularités découlant du modèle de gestion du Transporteur par l'intégration d'un facteur « C » relatifs aux des dépenses d'investissement.

1.1 Réponse de l'AQCIE/CIFQ :

The multiyear rate plan of Toronto Hydro was approved under Ontario Energy Board ("OEB" or "the Board") guidelines for a Custom Incentive Regulation ("IR") plan. The basic idea of a C factor is to increase the likelihood that the utility recovers the cost of its capital. Suppose, for example, that a utility is otherwise subject to a revenue cap index with the escalation formula

$$growth\ RCI = I - X + G$$

where

RCI = revenue cap index,

I = growth in the inflation measure,

X = X factor, and

G = growth in the scale escalator.

Growth in total revenue can be shown to be a revenue-weighted average of the growth in revenue for O&M expenses ("ROM") and the growth in capital revenue ("RK"). Suppose that revenue for the first plan period is set equal to the utility's cost. Revenue in the first plan period subject to the escalation mechanism is then likely to recover expected capital cost ["$E(CK_1)$"] if

$$\begin{aligned} R_1 &= R_0 \cdot [1 + (ROM_0/R_0) \cdot (I - X + G) + (RK_0/R_0) \cdot growth\ E(CK_1)] \\ &= R_0 \cdot \{1 + (ROM_0/R_0) \cdot (I - X + G) \\ &\qquad + (RK_0/R_0) \cdot [(I - X + G) + growth\ E(CK_1) - (I - X + G)]\} \\ &= R_0 \cdot \{1 + [(ROM_0 + RK_0)/R_0] \cdot (I - X + G) + (RK_0/R_0) \cdot [growth\ E(CK_1) - (I - X + G)]\} \\ &= R_0 \cdot [1 + (I - X + G + C)]. \end{aligned}$$

where C, the C factor, can be defined as

$$\begin{aligned} C &= (RK_0/R_0) \cdot [growth\ E(CK_1) - (I - X + G)] \\ &= (1/R_0) \cdot [RK_0 \cdot growth\ E(CK_1) - RK_0 \cdot (I - X + G)] \end{aligned}$$

and, effectively,

$$R_1 = \mathrm{ROM}_0 \cdot [1 + (I - X + G)] + E(CK_1).$$

This is, essentially, a hybrid approach to the design of a revenue cap escalator in which escalation of the revenue that compensates a utility for its O&M expenses is driven by an index whereas escalation of revenue for capital cost is based on cost forecasts.

Several variations are possible on the C factor theme:

- C can reflect cost forecasts at the start of the plan or forecasts that are updated during the plan.
- If C reflects cost forecasts at the start of the plan, it can vary from year to year or be fixed at a value that is expected to recover the costs over a multiyear period.
- Revenue based on cost projections may be fully, partially, or not trued up to actual costs.
- C may be permitted to assume only positive values or permitted to assume positive and negative values.

This approach to the design of a revenue cap escalator has several advantages:

- Capital revenue can more closely track capital cost trajectories that deviate substantially from the gradual trajectory provided by I-X+G, where such trajectories are required. This can materially reduce the risk to some utilities of operating under a multiyear rate plan and thereby make such plans, with their various benefits, possible.
- To the extent that capital revenue is based on a multiyear cost forecast with no true ups to actual costs, incentives to contain capex are fairly strong.
- Revenue escalation based on multiyear cost forecasts has been extensively used by regulators in Australia, California, Britain, and New York.[1]
- Indexation of O&M expenses reduces regulatory cost relative to "all-forecast" approaches to escalating the revenue requirement like those used in Australia, Britain, and New York State.
- In addition to the Toronto Hydro plan, hybrid revenue caps with index-based escalation of O&M expenses and forecast-based escalation of capital cost have been used in multiyear rate plans of California energy utilities on numerous occasions beginning in the 1980s.

The hybrid approach also has several disadvantages.

- To the extent that C is based on cost projections and not trued up to actuals, the utility has an incentive to exaggerate its capex requirements. Exaggerated cost forecasts by utilities have been a chronic problem in British PBR. The British regulator Ofgem ultimately responded with large expenditures on benchmarking and engineering studies to develop an independent view on utility revenue requirements and by implementing a complex Information Quality Incentive to encourage more accurate cost forecasts. Revenue requirements in Britain are now primarily based on the regulator's cost forecasts. The Australian Energy Regulator also uses benchmarking extensively.

  EPCOR, an Alberta power distributor, has acknowledged in the Alberta Utilities Commission's currently open incentive regulation proceeding that utilities have an

[1] Please note, however, that in California and New York the terms of multiyear rate plans have typically been only three to four years.

incentive to engage in overforecasting when revenue escalation is based on forecasts with no true ups. Its multiyear rate plan proposal features an I-X mechanism with supplemental funding for capex provided by an "F factor" for predictable capex. The F factor would reflect an estimate of plant addition requirements based on a recent average of historical plant additions. EPCOR defended this provision in part because it could prevent exaggerated cost forecasts.

> **the Commission and interested parties can be assured that no strategic behaviour or over forecasting is built into the … F factor amount.** Further, the use of average capital additions from 2013 to 2017 to set the F factor eliminates the possibility of the F factor being set too high by smoothing out the capital additions over the period, and precluding the F factor from being set based on a single year of unusually high capital additions. Finally, this method of establishing the F factor results in far less regulatory burden when compared to capital tracker applications or cost of service applications, due to the elimination of the need to file annual capital tracker applications. [Emphasis added][2]

- Since C factors afford utility supplemental revenue, they have an incentive to "bunch" their capex so that they qualify. They might, for example, accelerate replacement investments that might be postponed until the following plan period at no cost to system reliability.
- If C is based on a multiyear capital cost forecast, the regulator is compelled to sign off on a multiyear business plan. It is difficult for stakeholders and regulators to assess the reasonableness of plan proposals. For example, it is difficult to ascertain whether plans embody appropriate improvements in efficiency. The regulator relinquishes some of its opportunity to disallow costs if the business plan subsequently proves to have been unwise. Getting advance approval of a capex forecast is therefore very appealing to utilities.

[2] See EPCOR Distribution & Transmission Inc. Next Generation Performance-based Regulation Plan Submission, Exhibit 20414-X0074 in Alberta Utilities Commission Proceeding ID 20414, March 23, 2016, p. 64-65.

- It is difficult for the regulator even to identify the need for a C factor. The OEB noted in approving the cited plan for Toronto Hydro that "the OEB does not decide whether the option chosen by the applicant is the most appropriate."[3]
- Business plans are often inadequately substantiated. This has been an ongoing complaint of the OEB in proceedings for Custom IR applications. In its Toronto Hydro decision, for instance, the Board complained that Toronto Hydro's proposal was "largely supported by an asset condition analysis rather than the impact of the proposed work on the reliability of the system... The approach used by Toronto Hydro does not give a clear indication of how the overall spending is related to customer experience such as reliability... Continuous improvement measures are lacking... There does not appear to be any measurement of units of activity and their costs that would allow for year over year assessment of improvement in Toronto Hydro's proposed metrics."[5] Similar frustration over a previous Custom IR filing by Hydro One Networks prompted the Board to deny approval of a Custom IR plan with a five-year term. The Board instead treated the filing as a conventional rate proceeding with three forward test years.
- The regulatory cost of approving multiyear business plans can be substantial. The OEB noted in approving the Toronto Hydro plan that "the record in this case is one of the largest that the OEB has ever seen."[6] In Britain, proceedings to approve the revenue requirements of energy utilities can take as long as three years.[7]
- One manifestation of the daunting challenge to regulators is that in 2013 the Public Utilities Commission in the neighboring state of Maine was so opposed to the idea of a hybrid revenue cap escalator proposed by the state's largest utility, Central Maine Power ("CMP"), that it took the unusual step of rejecting it at an early stage of the proceeding. The Commission stated that:

[3] Ontario Energy Board, Decision and Order EB-2014-0116, December 2015, p. 4.

[5] Ibid, p. 6.

[6] Ibid, p. 2.

[7] However, multiyear rate plans in Britain now have eight year terms.

> We are also not persuaded by CMP's arguments that its 6-year capital distribution plan should be fully vetted and blessed by the Commission in this proceeding. Detailed long-term capital planning is an activity that, at least in detail, should be left to management subject to prudency review. In addition, as a practical matter, by requiring that the parties and the Commission pre-approved specific capital programs years in advance, whenever CMP acknowledges that there is uncertainty relating to the timing, cost and even the ultimate need for the projects, the CRM [Capital Expenditure Recovery Mechanism] introduces a level of predictive uncertainty into the ratemaking process that we find to be unacceptable.[8]

- It is highly unlikely under the C factor approach that customers will receive the benefits of industry productivity growth in the short run or the long run, even when it is achievable. If capex requirements are high, the utility will ambitiously detail reasons why supplemental revenue is needed. When capex requirements are low, however, the utility has no incentive to report the achievability of a negative C factor, and it is hard for other parties to make this case. In approving a C factor like that approved for Toronto Hydro, the Régie would therefore effectively concede that the achievement of an industry (or peer group) productivity growth standard is unattainable, even though there may be little evidence to support this notion.

  This is unfortunate, since the kinds of capex for which utilities might request C factor treatment are often routinely incurred by utilities in the samples used to estimate industry productivity trends. If capital productivity growth can plunge because of a sizable replacement investment, it can just as easily soar when the investment is completed.

- While the utility is incentivized to keep its actual capital cost below the forecasted level, it is nonetheless not subject to the pressure of achieving industry productivity growth norms. As the OEB notes in its Toronto Hydro decision, the plan "does not automatically trigger a financial incentive for distributors to strive for continuous improvement."[9]

[8] Maine PUC, Order of Partial Dismissal, Docket No. 2013-00168, August 2013, p. 7.

[9] Ibid, p. 5.

Further, "the OEB is concerned that the Application does not contain enough productivity incentives."[10]

- Since the utility can expect to recover its capital cost while O&M expenses are addressed by the revenue cap index, there are imbalanced incentives for O&M and capital cost containment.
- If the utility alternates between "pure" I-X+G escalation when capex is normal or low, and I-X+G+C escalation when capex is high, it is likely to be overcompensated since between rate cases I-X+G escalates the revenue requirement associated with the cost of older plant whereas the cost of this plant is likely to decline due to depreciation.

The following provisions can be added to a plan with a C factor to address these problems.

- A positive value for the C factor implies that the utility cannot achieve the MFP growth of the industry. If industry productivity growth should be achievable in the long run, the X factor can be adjusted to ensure that revenue growth reflects the productivity growth of the industry in the long run. If, for example, C is triggered by routine capex with a 40-year service life, X can be raised for 40 years by the small amount required to ensure the long run compliance of revenue growth with the industry productivity growth trend.
- The need for a C factor can be reduced by a sophisticated G factor formula that considers several possible reasons why capex might be needed. As one example, Dr. Lowry has discussed in his evidence a G factor applicable to HQT that would provide automatic revenue escalation if generation capacity or transmission line miles in Québec is increased.
- Minimum filing requirements for C factor applications can make it easier for the regulator to identify a good business plan. The regulator can require discussion of alternative plans involving less capex, and an explanation of why the proposed plan is required to maintain or improve reliability. For example, the utility can be asked what it would do if its revenue growth were limited to I-X+G and what the reliability consequences would be.

---

[10] Ibid, p. 16

- Use an I-X+G escalator that lacks a stretch factor in determining the capital revenue shortfall. This is tantamount to assuming that the capital cost forecast does not integrate sufficient productivity gains.

- Economies are possible in the plant addition forecasting process. One idea is to focus the proceeding on the required value of plant additions in the first indexing year of the next PBR plan and then escalate this sum formulaically in later plan years. This *general* approach has some advantages. Regulatory cost can be considerably reduced. The Régie would not need to approve a complicated multiyear business plan and could retain the right to challenge the prudence of the expenditures addressed by the mechanism at a later date. A downside is that the additions to plant in the first plan year may be unrepresentative of those in later plan years.

  There is precedent for this *general* approach to establishing capital revenue requirements in California. Utilities there are required to operate under multiyear rate plans. Consumer advocates there have often resisted consideration of multiyear plant addition forecasts. In practice, plant addition budgets in the out years of the plans are often based on the carefully-considered budget for the (forward) test year. These budgets are, in turn, sometimes based on average plant additions in recent years.

- Indexing can be used for some kinds of capex to reduce the role of forecasts in establishing the capital revenue budget. In British Columbia, for example, capex rather than capital cost is indexed. For example, two formulas are used to set capital additions budgets in the current PBR plan of FortisBC Energy, the largest provincial gas distributor. One formula is for growth capital additions and the other for sustainment and other capital additions.

$$GC_t = \frac{GC_{t-1}}{SLA_{t-1}} \times [1 + (I - X)] \times SLA_t$$

Where: *GC = Growth Capital*
SLA = Service Line Additions
t = Upcoming year
I = Inflation Factor
X = Productivity Factor

$$RC_t = RC_{t-1} \times [1 + (I - X)] \times \left(\frac{AC_t}{AC_{t-1}}\right)$$

Where: *RC=Remaining Capital: Total of Sustainment & Other Capital*
AC=Average Customers
t = Upcoming year
I = Inflation Factor
X = Productivity Factor

The cost of older plant is essentially Y factored in the plan. This passes the benefits of depreciation on to customers.

- The utility's incentive to exaggerate its capex requirements can be reduced with a partial true up of capital revenue to actuals.

2. Références :(i) Pièce C-HQT-HQD-0045, p. 14;
(ii) Pièce C-FCEI-0031, p. 8;
(iii) Pièce C-FCEI-0031, p. 11;
(iv) Pièce C-AQCIE-CIFQ-0025, p. 108.

Préambule :

(i) « *At the conclusion of the first generation MRI, Concentric would expect HQD to file for a rebasing of rates* ***based on standard cost of service principles****. Assuming the plan has worked reasonably well for HQD and its customers, HQD would file for the next MRI plan.* » [nous soulignons]

(ii) « *L'intérêt de l'entreprise à opérer efficacement serait grandement réduit si elle ne croit pas que le mécanisme sera en place pour une longue période de temps ou qu'il risque de faire l'objet d'un recalibrage sur la base de ses coûts historiques ou prévus à intervalles réguliers.*

Cette crédibilité requiert un engagement clair du régulateur envers le mécanisme. La FCEI estime qu'il doit y avoir une attente légitime de toutes les parties que le mécanisme sera prolongé sans période de transition ou recalibrage à moins que son évaluation périodique ne révèle un *problème significatif ou que la clause de sortie ne soit déclenchée. Cela n'exclut pas que des ajustements puissent être apportés pour refléter des changements dans les attentes envers l'entreprise.*

La prévisibilité requiert que les règles de transition entre les termes successifs d'un mécanisme soient établies dès le départ. » [nous soulignons]

(iii) « *L'expérience d'autres mécanismes incitatifs montre que les entreprises ont tendance à adopter des pratiques d'affaires non soutenables durant la période d'application d'un mécanisme incitatif et à demander des ajustements du revenu requis lorsqu'une opportunité se présente de le faire.*[5] *L'expérience des dossiers du Distributeur et du Transporteur montre également que les reports de projets et d'activités sont choses fréquentes pour différentes raisons.* »

[5] « *Par exemple, à la fin de son mécanisme incitatif, Gaz Métro avait accumulé un important retard en développement informatique et a demandé une hausse budgétaire pour rattraper ce retard.* »

(iv) « *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*. »

Demandes :

2.1 Veuillez préciser comment le « *mid-term review* » proposé par l'AQCIE-CIFQ au préambule (iv) pourrait éviter un retour au coût de service pour le dossier tarifaire suivant la terminaison du MRI de première génération, tel que suggéré au préambule (i), et ainsi prévenir des situations telles que celles évoquées au préambule (iii). Veuillez préciser en quoi pourrait consister cette revue et sur quelle base elle serait effectuée.

2.2 Veuillez indiquer si l'AQCIE-CIFQ est d'accord pour que les règles de transition entre les termes successifs du mécanisme soient établies dès le départ, tel que suggéré au préambule (ii). Si oui, veuillez en exposer les grands principes. Si non, veuillez justifier.

2.1 Réponse de l'AQCIE/CIFQ :

The multiyear rate plan approach to PBR for energy utilities has traditionally involved the periodic rebasing of rates to reflect the utility's actual cost. This substantially reduces the tendency of revenue to deviate from cost. Such conventional rebasings have several advantages:

- Utility operating risk is substantially reduced, especially when there is a material risk that revenue could be uncompensatory due, for example, to a revenue cap escalator that is based on industry productivity trends. This makes it more feasible for utilities to operate under multiyear rate plans.

- The need for supplemental revenue from Y, Z, or C (dedicated capital cost) factors, which can weaken performance incentives and raise regulatory cost, is reduced.

- Customers have more protection from revenue that greatly exceeds the utility's cost due, for example, to a poorly chosen initial revenue requirement or a poorly designed revenue cap escalator.

- Benefits of the natural depreciation of older plant and of long-lived performance gains that the utility realizes are passed through to customers.

Disadvantages of conventional rebasings in multiyear rate plans have also been recognized:

- Utility performance incentives are weakened, especially in the later years of the sample period (e.g., years four and five of a five-year plan), for several reasons.

    - The full annual value of any long-term performance gains achieved under a plan is passed through to customers in a conventional rebasing. This reduces the cost/benefit balance of efforts to achieve such gains which involve material up front costs, particularly in the later years of the sample period.

    - Low cost in any historical reference year that is used in rebasing can lower rates in the first year of the next rate plan. In a five-year plan, the fourth year is typically the historical reference year.

- For costs that are ineligible for tracker treatment, there is an incentive to defer expenses from earlier years of the plan to the historical reference year and the first year of the next plan since expenditures in these years are more likely to raise rates in the next plan.

- With a future test year there is, additionally, an incentive to exaggerate the need for cost growth between the historical reference year and the test year.

- The regulatory cost of conventional rebasings is, for these and other reasons, high.

Several tools are available to address these problems:

- The frequency of rate cases can be reduced. Alternatively, the terms of the MRP can be drafted to preclude rebasing unless parties have reason to suspect that the plan is not functioning properly or the utility's earnings are unusually high or low.

- An efficiency carryover mechanism ("ECM") can reward the utility for offering customers good value in the initial rates of the next plan.

- Companies can be offered a menu of optional regulatory provisions that include a bypass of rebasing.

- The rebasing process can be reformed to mitigate some of its undesirable properties.

    - Indexing can be used to escalate costs from the historical reference year to the test year. For example, the O&M expenses ("C_{OM}") of HQD can be escalated by the formula

$$growth\ C_{OM} = Inflation - (trend\ Productivity_{OM}^{Industry} + Stretch)$$
$$+\ growth\ Customers.$$

    - Multiple historical reference years can be used to establish cost in the future test year.

Dr. Lowry's incentive power research was detailed in Appendix Section 2 of his direct testimony for AQCIE. He showed that the use of multiple historical reference years in a rebasing can materially strengthen utility performance incentives. The intuition for this result is that it would be much more costly for the utility to raise costs in multiple years of one plan in order to raise revenue in the next plan. Compared with a five-year rate case cycle with no earnings sharing, average annual productivity growth is expected to increase by around 20 basis points in the long run.

Dr. Lowry also detailed in Appendix Section 2 stylized "rate option" mechanisms in which the utility is given the option of foregoing a conventional rebasing provided that it is willing to reset its rates for the first year of the next plan formulaically. The incentive power of these mechanisms was found to be quite substantial.

A mid-term review can be convened by the regulator or included as part of an annual PBR filing and involves an in-depth look at how the plan is working. Mid-term reviews vary in scope and may consider whether the initial revenue requirement and revenue escalation mechanism were set reasonably; trends in the utility's cost efficiency (with special attention to deferrable costs), earnings, service quality, conservation and demand management, and other metrics; marketing flexibility; the degree to which customers shared in the benefits of the plan; and the regulatory cost savings achieved. The regulatory community is then in a better position to ascertain whether plan adjustments are warranted, either immediately or in the following plan. The value of such reviews is especially great in first generation plans, since design flaws are more likely in these plans.

A good example of a mid-term review is one PEG undertook for the Ontario Energy Board in 2011 of the gas utility multiyear rate plans.[11] This included assessments of the trends in rates, revenue, productivity, cost performance, service quality, investment, and earnings of the utilities under PBR; regulatory efficiency; sources of cost efficiency; and the sharing of benefits between the utilities and their customers. Plans in British Columbia, California, Maine, Massachusetts, and Great Britain have also included mid-term review provisions.

---

[11] Kaufmann, L., Hovde, D., Kalfayan, J., and Makos, M. (2011), *Assessment of Union Gas Ltd. and Enbridge Gas Distribution Inc. Incentive Regulation Plans,* Report prepared for the Ontario Energy Board and filed in OEB Case No. EB-2011-0152.

In year 4 of multiyear rate plans that apply to several large energy distributors, the Alberta Utilities Commission is currently undertaking a review of select issues that have arisen in the first plan. Key issues that the AUC is considering in this proceeding include the provisions concerning rebasing, the X factor, and capital cost trackers.

Mid-term reviews provide an opportunity to extend the current plan if it is working well. Berkshire Gas, a Massachusetts gas utility, had a multiyear rate plan that featured a mid-term review to determine if the plan should be continued after 5 years. Extensions are often proposed in settlements between the parties. In principle, a menu approach that includes an option to skip rebasing may alternatively be offered at the conclusion of a review. There are several precedents for extensions of multiyear rate plans in the US and Canada. Several previous plans for the FortisBC utilities were extended as part of a mid-term review.

Many plan extensions have been approved outside of mid-term reviews. Some examples include the current and two previous plans of PacifiCorp in California, the previous plan for Sierra Pacific Power (now California Pacific Electric) in California, a previous plan for Southern California Edison, the recently concluded plan for Bangor Gas, an earlier plan for British transmission utilities, and an earlier plan for British gas utilities.

One advantage of striking a deal in the mid-term review is that additional information is available to the parties. For example, parties may have more confidence that the current plan is working. A disadvantage of relying on the mid-term review for this purpose is that certain desirable alternatives to rebasing are better implemented at the outset of the plan, such as Dr. Lowry's menu approach. For example, a menu approach implemented before the start of the plan gives the utility more time to prepare a plan of cost reductions that would avoid the need for a rate case or could allow parties to address other issues of importance.

2.2 Réponse de l'AQCIE/CIFQ :

Please see our response to 2.1 above.

3. Références : (i) Pièce C-HQT-HQD-0028, p. 17 et 18;
(ii) Pièce C-AQCIE-CIFQ-0040, p. 14;
(iii) Pièce C-FCEI-0031, p. 11.

Préambule :

(i) « *Une fois les indicateurs choisis, leur intégration au MRI et au MTÉR pourrait suivre les étapes suivantes :*

- *Définition d'une cible pour chaque indicateur basée, notamment, sur l'historique des résultats de cet indicateur. Ces cibles devront tenir compte de l'arbitrage nécessaire entre les résultats de chaque indicateur et les coûts requis pour les atteindre;*
- *Pondération attribuée à chaque indicateur;*
- *Calcul d'un indice composite de performance global (reflétant la moyenne pondérée des résultats de l'ensemble des indicateurs);*
- *Partage des écarts de rendement selon l'atteinte d'un certain pourcentage de réalisation de cet indice composite.* »

« *Le Distributeur envisage partager avec ses clients les écarts de rendement selon les résultats de l'indicateur composite. Préalablement, il importe de revoir les modalités du MTÉR afin de l'arrimer au nouveau cadre réglementaire du Distributeur, tel que le recommande CEA. Ceci permettra d'éviter que le MTÉR ne vienne réduire les incitatifs à l'efficience suite à la mise en place d'un MRI.* » [nous soulignons]

(ii) « *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.* »

(iii) « [La FCEI recommande] *l'inclusion de mécanismes visant à éviter de récompenser les gains à court terme et non soutenables* [par]:

- « *Le dépôt d'un rapport faisant état des retards dans l'avancement des activités de base ou les reports de projets et l'ajustement des excédents de rendement en conséquence.*

- *La mise de côté d'une portion des excédents de rendement dans un compte de frais reportés à être versé au début du terme subséquent si les gains d'efficience du terme en cour se révèlent soutenables au terme subséquent.* »

Demande :

3.1 Considérant le terme relativement court des MRI proposés, veuillez élaborer sur la possibilité d'inclure au mécanisme de partage des écarts de rendement, selon les résultats de l'indicateur composite tel que proposé au préambule (i), un mécanisme visant à s'assurer de la pérennité des gains d'efficience distribués, tel que suggéré au préambule (iii), afin de prévenir des situations telles que celles évoquées au préambule (ii).

3.1 Réponse de l'AQCIE/CIFQ:

The rationale for ECMs is to counteract some of the adverse incentives that result under PBR plans from a periodic rebasing of revenue to cost. These incentive problems were detailed in our response to question 2.1 above.

To counteract such incentives, ECMs can reward utilities for offering customers good value in later PBR plans, and can penalize them for offering customers poor value.

Dr. Lowry noted in his response to question 7 of the Régie's first round of data requests that the ECMs used in Alberta multiyear rate plans are driven by earnings surpluses in the expiring plan. Utilities are permitted to keep a portion of the average value of earnings surpluses in a few years of the next plan period (if positive). This approach is suboptimal, for several reasons.

- Net earnings can be a poor measure of lasting performance gains. They may, for example, reflect performance gains that are *not* lasting, as well as miscellaneous favorable external business conditions such as severe winter weather or an unrealistically high initial revenue requirement.
- This approach does not effectively discourage strategic deferrals. A utility can, for example, bolster earnings by deferring expenditures and then requesting extra funding for them in the next plan despite being eligible for an ECM bonus. A strategy of this kind is facilitated in jurisdictions like Québec's which use forward test years in rate cases.

Dr. Lowry discussed a different approach to ECM design in Appendix Section 2 of his direct testimony. This involves a comparison of the revenue requirement ("RR") (or underlying cost) in the first year of the next plan period to a benchmark. The ECM could take the form of a targeted performance incentive mechanism linked to the provisions of an earnings sharing mechanism. Alternatively, the outcome of the comparison can adjust revenue directly. The revenue requirement in the first year of the next plan could, for example, correspond to the following formula.

$$RR_{t+1} = Cost_{t+1} + \alpha \cdot [Benchmark_{j,t+1} - E(Cost_{j,t+1})]$$

Here $E(Cost_{j,t+1})$ is the forecasted cost and α is a share of the value implied by benchmarking in the interval [0,1]. Note that the formula allows for the possibility that only a subset j of the total cost is benchmarked. This could be a subset that is easier to benchmark. Note also that the variance between the benchmark and actual cost can alternatively be used to adjust the X factor. This would typically take the form of a stretch factor adjustment.

This ECM clearly strengthens the utility's incentive to contain the forecasted cost of service in the forward test year. The utility would, for example, receive some reward for incurring up-front costs in years 4 and 5 to reduce cost in year one of the next plan. Moreover, by making the forward *test* year the focus of the appraisal rather than the years of the prior plan period, this ECM also guards against strategic deferrals and promotes a fair share of plan benefits for customers.

The choice of a benchmark is an important consideration in the design of this kind of ECM. Dr. Lowry discussed two methods for calculating the benchmark in his direct testimony. One was to escalate the cost established in the last forward test year by a suitable escalation index. This could be the I-X+G formula used in the prior plan.

Many variations on this theme are possible. For example, instead of benchmarking *cost*, the *productivity* growth that is implicit in the test year cost since the level approved in the last rate case can be compared to the productivity growth of the peer group. This guards against any failure of the inflation measure in the I-X+G mechanism to accurately track input price inflation.

Forecasted cost may, alternatively, be compared to a benchmark based on statistical cost research that is completely independent of the Company's cost. Econometric methods can, for example, be used to establish a cost benchmark.

Statistical benchmarking is used by the Ontario Energy Board to update stretch factors annually. Benchmarking is also used extensively in PBR by the Australian Energy Regulator and by Ofgem in Britain. Benchmarking studies have occasionally been filed by US utilities in support of proposed stretch factors or their test year cost proposals. Public Service of Colorado, for example, has filed benchmarking studies of its forward test year proposals for the cost of its gas utility and its vertically integrated electric utility.

Please note the following with respect to both of these options:

- The ECM should ideally apply to *total* cost, including the capital cost that has been tracked. However, the Régie may wish to apply it only to *O&M* expenses. In that event, it may be desirable to base any benchmark index on the *O&M* productivity trend of the industry (or other peer group) if this differs from the multifactor productivity trend.
- When costs of deferred capex can be recovered through a tracker, the utility may be incentivized to request recovery of deferred capex after the rebasing. This is an argument for annual benchmarking.

Both of these options have been considered by Dr. Lowry in his incentive power research. Assuming an *historical* test year, PEG Research considered a revenue requirement at the start of a new plan that is based α% on the benchmark and (1-α)% on the cost in the test year. This effectively permits the company to share α% of any deviation between its cost and the benchmark. PEG Research considered alternative values of α, ranging from 10% to 50%.

The incentive impacts of these ECMs were calculated for utilities with average, superior, and inferior initial operating inefficiency. Results for utilities with average operating efficiency were shown in Appendix Section 2 of Dr. Lowry's direct evidence.

Consider first the impact of the ECMs that use the predetermined revenue requirement from the previous plan as the benchmark. It can be seen that, in the context of a five-year rate plan with no earnings sharing, assigning α a fairly low value of 0.10 increases the average annual performance gains by a fairly modest 14 basis points in the long run [from 1.41% to 1.55%].[15]

[15] Plans for the Hydro-Quebec utilities might, however, have an earnings sharing mechanism. In this event, the incentive impact of the ECMs could be considerably higher.

Assigning α a weight of 0.25 increases the average annual performance gains by 35 basis points in the long run [from 1.41% to 1.76%].

Let's turn now to the alternative ECM in which cost in the historical reference year is compared to a fully external benchmark such as might be developed with statistical cost research. It can be seen that assigning α a value of 0.10 increases average annual performance gains by 39 basis points in the long run [from 1.41% to 1.80%]. Assigning α a value of 0.25 raises average annual performance gains by 90 basis points in the longer run [from 1.41% to 2.31%]. The greater incentive power of this alternative results from the fact the benchmark is completely external. Thus, the utility will not consider that its efforts to improve cost management will reduce future rate increases.

Benchmarking exercises might alter the provisions of the earnings sharing mechanism but might alternatively be used to adjust revenue directly via the stretch factor or the revenue requirement in the initial year of the next plan. The ECM can still be linked to the outcome of other performance appraisals using metrics. Dr. Lowry discussed in his direct testimony a number of metrics that might be used in a performance incentive mechanism. These include metrics for service quality and conservation and demand management.

4. Références : (i) Pièce C-FCEI-0040, p. 1;
(ii) Décision D-2014-034, p. 102.

Préambule :

(i) « *Demandes :*
1.1 Veuillez préciser sur ce que la FCEI entend par « fermeture des livres ».

Réponse :
La FCEI réfère à l'exercice qui consiste à se pencher rétrospectivement sur les résultats réels des entreprises. Différents forums sont envisageables pour cet exercice. On peut penser au rapport annuel, au dossier tarifaire subséquent à la fin d'une année réglementaire ou à tout autre forum pertinent.

1.2 Veuillez indiquer si la fermeture des livres est souhaitable ou nécessaire au bon fonctionnement d'un MRI.

Réponse :
La FCEI estime qu'il est inévitable de devoir regarder de façon rétrospective les résultats réels des entreprises ne serait-ce que pour les fins du partage des excédents de rendement, si un tel mécanisme est mis en place, ou pour s'assurer de l'atteinte des indicateurs de performance retenus. » [nous soulignons]

(ii) Extrait de la décision D-2014-034 concernant le cadre réglementaire pour l'application du MTER :

« *[414] Conformément aux modalités autorisées par la Régie à la section 6.3 de la présente décision, le résultat du calcul de l'écart de rendement à remettre aux clients sera présenté dans le rapport annuel de l'année historique (à titre d'exemple, l'année historique 2014), déposé à la Régie en vertu de l'article 75 de la Loi. L'écart de rendement à partager sera comptabilisé dans un compte d'écarts. La prise en compte de l'écart à remettre aux clients sera traitée dans le dossier tarifaire de la deuxième année subséquente (année tarifaire 2016) à l'année historique (année historique 2014).*

[415] ***La Régie juge que le compte d'écarts relatif aux écarts de rendement devient un enjeu dans le dossier tarifaire de la deuxième année subséquente à l'année historique, et en tant que tel un sujet à y être examiné.***

[416] ***La Régie accueille la proposition des Demandeurs de présenter les écarts de rendement lors des rapports annuels du Transporteur et du Distributeur en vertu de l'article 75 de la Loi*** *».*

Demandes :

4.1 Advenant l'adoption d'un mécanisme de partage des gains d'efficience dans le cadre du MRI, veuillez élaborer sur la nécessité ainsi que sur les avantages et inconvénients d'avoir recours à une fermeture réglementaire, au rapport annuel ou à un examen lors des dossiers tarifaires, tel qu'évoqué au préambule (i), afin d'établir et attribuer les gains d'efficience éventuels.

4.2 Veuillez préciser ce qui pourrait justifier, s'il y a lieu, de modifier le cadre réglementaire établi dans la décision D-2014-034 et énoncé au préambule (ii) pour l'application du mécanisme de traitement des écarts de rendement dans le cadre du MRI.

4.1 Réponse de l'AQCIE/CIFQ :

Dr. Lowry explained in his responses to questions 2 and 3 above and in his earlier evidence in this proceeding that various provisions of multiyear rate plans can strengthen utility incentives to realize long-term performance gains and forego strategic deferrals that deprive customers of plan benefits. These provisions include efficiency carryover mechanisms. He reiterated in his response to question 3 that efficiency carryover mechanisms based on surplus earnings are used in Alberta but are not recommended because earnings are a poor indicator of lasting performance gains and these mechanisms do not effectively discourage strategic deferrals or encourage performance initiatives involving up-front costs in the last plan years.

In theory, surplus earnings can be adjusted to remove benefits of strategic deferrals and add benefits of late-period performance initiatives but this procedure is cumbersome. Dr. Lowry noted in response to the Régie's Round 1 information request 7.2 that adjustments for strategic deferrals are featured in the Australian Energy Regulator's efficiency carryover mechanisms.

Regulators must be alert to the problem of strategic deferrals, for various reasons. The ability of deferrals to skew the outcome of some efficiency carryover mechanisms is one example. In addition, deferrals are potentially an issue in conventional rebasings and capital cost trackers. In its decision approving a Custom IR plan for Toronto Hydro, for instance, the OEB noted the following:

> Toronto Hydro requested an OM&A budget of $269.5 million for 2015, with indexed adjustments over the 5 years of the plan.
>
> The 2015 request is an increase of 11.7% over the 2014 actual expenditures of $241.2 million.
>
> The OM&A expenses since the last rebasing in 2011 have been fairly flat as can be seen in the above table.
>
> The breakdown of spending on program areas was not available for 2014 actuals at the time of the hearing, so comparisons are with the 2013 actual expenses.
>
> The main drivers of the requested increase are preventative and predictive maintenance (57% over 2013), corrective maintenance (31% over 2013), customer care (16% over 2013), information technology and facilities management.[16]

The Board took account of the suspected deferrals in its rebasing decision.

> In the absence of compelling evidence as to the reasons for the spending levels in 2014, the inference drawn by the OEB is that this is the level of spending reasonably required by Toronto Hydro to maintain and operate its system.
>
> The OEB expects that the benefits of Toronto Hydro's IRM from 2011 to 2014 will persist for ratepayers into the next rate cycle. Toronto Hydro's request for an OM&A budget for 2015 of $269.5 million is an 11.7% increase over its actual

[16] OEB, op. cit. p. 8-9.

> spending in 2014. Given Toronto Hydro's evident ability to operate for the last 4 years with very modest increases, the OEB finds that a 2015 base OM&A increase should be 2.1%, approximately the rate of inflation over the 2014 actual spending.[17]

It follows that some means must be found for the Régie to monitor deferrable expenses in a multiyear rate plan. The annual reports are one possibility, but the current regulatory accounts do not have satisfactory detail concerning deferrable O&M expenses and capex. Hydro Québec should maintain detailed data on deferrable expenses and be prepared to report on these expenses in periodic reports or in response to information requests.

4.2 Réponse de l'AQCIE/CIFQ:

Dr. Lowry discussed the pros and cons of earnings sharing mechanisms [aka Mechanismes de Traitement des Ecarts de Rendement (« MTERs »)] on p. 104 of his direct testimony. In addition to the pros and cons discussed there, he notes here that an MTER is one means to share benefits of deferred expenses with customers during a rate plan and/or to mitigate the problem of exaggerated cost forecasts where these are used in ratemaking. Exaggerated cost forecasts were evidently a major concern of the Régie in approving MTERs for Hydro Québec. If a plan includes a capital cost tracker or « C-factor », however, these alternative mechanisms can share with customers the benefits of capex underspends. The OEB included an ESM in the Custom IR plan of Toronto Hydro.

An ESM is not needed to implement performance incentive mechanisms, as these mechanisms can adjust revenue directly.

[17] OEB, op cit. p. 10.

APPROVISIONNEMENTS

5. Références : (i) Pièce C-RNCREQ-0026, p. 5 à 7;
(ii) Pièce C-FCEI-0040, p. 4 et 5;
(iii) Pièce C-AHQ-ARQ-0023, p. 2;
(iv) Dossier R-3933-2015, pièce B-0023, p. 13;
(v) Dossier R-3568-2005, HQD-2, Doc-1, p. 6;
(vi) Dossier R-3726-2010, HQD-1, Doc-1, p. 27;
(vii) Dossier R-3891-2014, Pièce B-0004, p. 9.

Préambule :

(i) « *Dans le contexte réglementaire actuel, le Distributeur n'a aucun intérêt financier à réduire ses coûts d'approvisionnements puisque ceux-ci sont récupérés à 100 % dans les tarifs via les mécanismes de tarification et le compte de pass-on.*

Il est par ailleurs important de souligner qu'une importante part des coûts d'approvisionnement post-patrimoniaux du Distributeur sont engagés auprès d'HQP. Cela est vrai autant pour les achats à long terme (67 % d'HQP) que de court terme (en 2014, 57 % des achats bilatéraux du Distributeur, ou 42 % en incluant les achats auprès des bourses, ont été faits auprès d'HQP).

Or, dans l'ensemble de ces transactions, y compris la négociation d'ententes qui les gouvernent, dont entre autres l'Entente globale cadre, l'incitatif financier de la société Hydro-Québec est clairement aligné avec celui de sa division HQP. Si le but de la réglementation incitative est d'aligner les intérêts de la compagnie réglementée, en l'occurrence le Distributeur, avec ceux de ses clients, le RNCREQ considère qu'il est essentiel de lui donner un incitatif financier réel à réduire ses coûts d'approvisionnements, notamment dans ses relations d'affaire avec sa contrepartie HQP.

En ce sens, la suggestion de PEG d'ajouter un incitatif au tracker est une bonne piste. Avec l'appui de Synapse, le RNCREQ a identifié plusieurs précédents d'une telle approche aux États-Unis :

[…]

Le RNCREQ considère que l'utilisation d'un tracker avec partage des coûts d'approvisionnement du Distributeur entre celui-ci et ses clients pourrait effectivement permettre de favoriser la conciliation des intérêts du Distributeur avec ceux de ses clients. Toutefois, étant donné les divers types d'interaction entre HQD et son principal fournisseur (associé), HQP, le pourcentage de partage ainsi que les autres modalités applicables requerront un examen soigné. »

(ii) « *La FCEI privilégie donc l'utilisation d'un indicateur pour inciter le Distributeur à optimiser le coût des achats d'électricité*

[…]

La FCEI présente à titre d'exemples les indicateurs potentiels suivants :

Gestion des besoins en puissance : Indicateur basé sur l'écart entre un besoin en puissance théorique et le besoin en puissance réel. Le besoin en puissance théorique pourrait être défini sur la base d'un besoin en puissance moyen par client par catégorie de clientèle qui tiendrait compte des tendances récentes.

[…]

Gestion des achats d'énergie : Indicateur basé sur l'écart entre le coût des achats d'énergie et un ou des indicateurs de marchés. »

(iii) *Pour les coûts dont une partie est sous le contrôle du Distributeur et qui feraient l'objet de facteurs Y comme principalement les coûts d'approvisionnement, de transport et de combustible : par le plafonnement du prix de l'intégration éolienne puis par la mise en place d'indicateurs ciblés pour s'assurer que les coûts demeurent justes et raisonnables en fonction des critères de fiabilité retenus comme, par exemple :*

a. L'utilisation et les coûts des achats de court terme en hiver versus la puissance et l'énergie patrimoniales inutilisées3;
b. La puissance de pointe planifiée mais non utilisée (en considérant des besoins normalisés).

À la référence (iv) le Distributeur fournit un tableau suivant :

TABLEAU 8 :
INDICATEUR DE PRIX DE MARCHÉ POUR L'ANNÉE 2014

Total pour les approvisionnements postpatrimoniaux		Indicateur de marché	Coûts réels
Coût total	***M$***	**1 239,9**	**1 709,9**
Besoins postpatrimoniaux	*TWh*	15,3	15,3
Coût moyen	*$/MWh*	81,1	111,9
Achats de long terme			
Coûts des approvisionnements	*M$*	761,2	1 151,6
Coût de la fermeture de TCE (1)	*M$*	37,4	37,4
Coût total	***M$***	**798,5**	**1 189,0**
Quantités acquises	*TWh*	12,5	12,5
Coût moyen	***$/MWh***	**63,6**	**94,8**
Achats de court terme			
NY HQ_GEN_IMPORT (2)(3)	$CA/MWh	143,9	
+ Frais de sortie de NY (2)(3)	$CA/MWh	5,4	
+ Frais de courtage (3)	$CA/MWh	0,8	
+ Frais de GES (4)	$CA/MWh	3,0	
= Prix d'achat	$CA/MWh	153,1	
Coût des achats bilatéraux et sur les marchés	*M$*	409,6	495,4
Coût de l'entente cadre	*M$*	0,1	0,1
Coût de l'énergie de l'électricité interruptible	*M$*	13,3	7,1
Coût de la puissance (UCAP & Electricité int.)	*M$*	18,4	18,4
Coût total	***M$***	**441,4**	**521,0**
Quantités acquises	*TWh*	2,7	2,7
Coût moyen	***$/MWh***	**161,4**	**190,5**

(1) Le coût de la fermeture de la centrale de TCE de 37,4 M$ exclut les coûts de puissance de remplacement (inclus sous la rubrique «Achats de court terme»).

(2) Moyenne annuelle pondérée sur les transactions réelles.

(3) Taux de change (moyenne annuelle) : 1,1045 $CA = 1 $US.

(4) Les frais des émissions de gaz à effet de serre sont ceux reliés à l'indicateur du marché de New York.

Les ententes des références (v) et (vi), soit l'Entente cadre et Les Conventions d'énergie différée, incluent des références à des indicateurs de marché incluant le Day-Ahead-Market (DAM) du NYISO et des ajustements.

(vii) Les crédits fixes et variables de l'électricité interruptible sont établis, respectivement, en fonction des produits UCAP et du DAM sur le marché de New-York.

Demandes :

5.1 Selon le contexte du Distributeur et l'expertise de PEG, veuillez élaborer sur les modalités possibles de mise en œuvre d'un indicateur couvrant le coût annuel d'achats d'énergie post-patrimoniale du Distributeur en tenant compte des références en préambule.

5.2 Selon le contexte du Distributeur et l'expertise de PEG, veuillez élaborer sur les modalités possibles de mise en œuvre d'un indicateur couvrant le coût annuel des approvisionnements post patrimoniaux du Distributeur pour répondre à ses besoins de puissance à la pointe, incluant entre autres, l'électricité interruptible, le contrat d'énergie cyclable, les contrats découlant des appels d'offres A/O 2014-01 et A/O 2015-01, la nouvelle entente avec TCE et les achats de court terme sous dispense, en tenant compte des références (i), (ii), (iii), (iv) et (vii).

5.3 Selon le contexte du Distributeur et l'expertise de PEG, veuillez élaborer sur les modalités possibles de mise en œuvre d'un indicateur global couvrant les coûts d'approvisionnement post-patrimoniaux du Distributeur en tenant compte par exemple de la référence (iv).

5.1-5.3 Réponse de l'AQCIE/CIFQ :

There are strong arguments for strengthening the incentive of HQD to contain its power supply expenses. Power supply cost is a large part of the bill that customers pay, particularly in the industrial sector. Unnecessarily high prices for power erode Quebec's competitive advantage as a place to do business. The current ratemaking treatment of power supply expenses weakens HQD's incentive to contain them. Most post-patrimonial supplies are obtained from HQP, an affiliated company. A MRI for power supply expenses can also reduce the cost of regulating HQD's power purchases because these purchases are more likely to be prudent.

As Dr. Lowry explained in his testimony, one way to strengthen power supply incentives is to incentivize the cost tracker by, for example, having HQD absorb a share of the variance between its forecasted and actual cost. Another is to develop a performance incentive mechanism that adjusts revenue (or the provisions of an MTER) automatically based on performance appraisals (e.g., a comparison of actual cost to a cost benchmark).

The design of a performance incentive mechanism for power supply cost is complicated by several circumstances.

- The cost of post-patrimonial supplies is very sensitive to demand, which is inherently volatile due to volatile demand drivers that are beyond HQD's control such as weather and prices for Quebec's industrial products.
- Prices of many power products are also volatile, and tend to be highest when demand is strongest.
- Capacity, energy, and ancillary services must both be purchased.
- Numerous power supply options are available to HQD to meet its post-patrimonial requirements. These include long term contracts, bilateral contracts with shorter terms, interruptible rates, and purchases on Ontario and US managed power markets.
- Prices for standard products on the Ontario and US power markets are transparent. However, far less transparent data are available on prices in less standardized bilateral trades.
- HQD has entered into numerous long term contracts that limit its ability to reduce its power supply cost in the short and medium term. If the costs of these contracts are included in the benchmarking exercise, the outcome of the exercise may be unfavorable to HQD.
- Quebec's government has occasionally intervened to encourage certain power supply strategies that may raise cost.

The following considerations nonetheless suggest that a well-functioning incentive mechanism can be designed for HQD's power procurement.

- The benchmark can reflect prices of several kinds of power products.
- The benchmark can vary formulaically with the peak load and/or energy demanded. As one example, it can be based on supply management software that predicts a cost given these quantities and market prices. Containment of peak load and energy can be addressed by separate performance incentive mechanisms.
- The increasing sophistication of US and Ontario power markets now provides a proliferation of benchmark prices. For example, New York now has day ahead and capacity markets.

- HQD can design requests for tenders that create additional benchmarks.
- HQD can make sufficient purchases from neighboring markets to ensure that they are reasonably liquid.
- HQD could engage an independent marketer to supply a share of its post-patrimonial requirements and use its cost in benchmarking.
- Long term contracts can be built into benchmarks, and this actually reduces the risk of the mechanism.
- There are many other ways to contain the risk of the mechanism.
  - Place modest funds at risk, especially in the initial plan.
  - Provide awards for good performance but no penalties for bad performance, especially in the initial plan.
  - Levy awards and penalties based on measured performance over a multiyear period.
  - Create a deadband for small variances between benchmarks and actuals.
  - HQD can contain its risk by mimicking the power procurement strategy that is implicit in the benchmark.
- Market indicators have already been developed for HQD's power supply expenses, as detailed in the Regie's question.
- A benchmark doesn't have to represent the optimal procurement strategy to be useful in ratemaking.
- In addition to Dr. Lowry, there are several parties active in Regie proceedings that have the expertise to help design an appropriate MRI (e.g., FCEI and Brookfield).
- Many US natural gas distributors procure large quantities of gas for their customers. Despite volatile demand and gas prices and numerous gas supply options, many of these distributors have operated under gas supply incentive mechanisms. For example, the following statement appears in a recent financial document of San Diego-based Sempra Energy, which owns two of the largest US gas distributors.

> The current regulatory framework for SoCalGas and SDG&E permits the cost of natural gas purchased for core customers (primarily residential and small commercial and industrial customers) to be passed through to customers in rates substantially as incurred. However, SoCalGas' gas cost incentive mechanism provides SoCalGas the opportunity to share in the savings and/or costs from buying natural gas for its core customers at prices below or above monthly market-based benchmarks. This mechanism permits full recovery of costs incurred when average purchase costs are within a price range around the

benchmark price. Any higher costs incurred or savings realized outside this range are shared between the core customers and SoCalGas.[18]

6. Références : (i) Pièce C-AQCIE-CIFQ-0028, p. 4;
(ii) Pièce C-AQCIE-CIFQ-0028, p. 5.

Préambule :

(i) « *L'AQCIE et le CIFQ considèrent qu'il est inexact pour CEA de suggérer que le Distributeur n'exerce aucun contrôle sur ses coûts d'approvisionnement en électricité non plus que sur ses coûts de transport.* *<u>En effet, c'est le Distributeur lui-même qui prépare et propose à la Régie, pour approbation, sa stratégie d'approvisionnement en électricité et ce, tant au chapitre des quantités requises que des coûts. Il s'ensuit donc nécessairement que les coûts d'achat d'électricité et de transport qui sont facturés aux usagers du Québec sont largement tributaires de la justesse des projections du Distributeur dans son plan d'approvisionnement.</u>* » [nous soulignons]

(ii) « *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. 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" ».

Demandes :

---

[18] Sempra Energy, San Diego Gas & Electric Company, and Southern California Gas Company (2016), *Form 10-K 2015*, Sempra Energy Financial Report, p. 21. Retrieved from Sempra Energy's SEC Filing website: http://files.shareholder.com/downloads/SRE/2321322680x0xS86521-16-91/92108/filing.pdf.

6.1 Veuillez élaborer sur votre avis à l'effet qu'il soit préférable de traiter les coûts d'approvisionnement et de transport avec un *tracker* (facteur Y) plutôt que de les inclure dans le MRI (référence (ii)).

6.2 Concernant l'opinion de l'AQCIE et le CIFQ selon laquelle les coûts d'achat d'électricité et de transport sont largement tributaires de la justesse de la prévision des ventes du Distributeur (référence (i)), veuillez élaborer sur la pertinence d'inclure les coûts d'approvisionnement et de transport dans le MRI, ceci afin d'assurer un meilleur encadrement et diminuer les risques d'écarts prévisionnels.

6.3 Veuillez préciser en quoi les caractéristiques relatives aux différentes sources d'approvisionnement de court terme et de long terme en électricité empêchent le Distributeur de s'ajuster aux différents facteurs externes et d'exercer un contrôle sur la gestion optimale de chacune des sources d'approvisionnement afin de minimiser leurs coûts totaux annuels.

6.1 Réponse de l'AQCIE/CIFQ :

Dr. Lowry believes that tracker treatment is appropriate for HQD's power supply and transmission expenses because these expenses are very large and HQD's ability to control them is limited. To contain the risk of operation, the revenue for these services must be fairly similar to their cost. Dr. Lowry nonetheless endorses some kind of MRI for power purchase expenses, as well as a performance incentive mechanism for peak load management that can have a material impact on power supply and transmission expenses.

6.2 Réponse de l'AQCIE/CIFQ :

As noted in our response to question 5, the benchmark can in principle vary formulaically with the peak load and energy demanded, and even be based on supply management software that predicts a cost given these quantities. Containment of peak load and energy can instead be addressed by separate performance incentive mechanisms.

6.3 Réponse de l'AQCIE/CIFQ :

Dr. Lowry believes that the numerous power supply products available to HQD today facilitate development of sophisticated and sound power supply strategies given the right incentives. Since market conditions are volatile, the chosen strategy will never be optimal in a given year with the benefit of hindsight. However, over many years sound strategies will yield material benefits that can be shared with customers.