2010 May 17

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge St., Suite 2700
Toronto, ON, M4P 1E4

via RESS and courier

RE: EB-2010-0060 Distribution Revenue Decoupling Consultation

CLD Submissions re P.E.G. Report

Dear Ms. Walli:

By way of a letter dated 2010 March 22, the Board commenced a consultation process concerning the possible adoption of Distribution Revenue Decoupling. The first stage of the consultation involved issuing a report commissioned by the Board and prepared by Pacific Economics Group Research (P.E.G.), and calling for stakeholder comments on that report (the Report). That stage is to be followed by the issuance of a Board Staff discussion paper, which itself is to be informed by both the Report and stakeholder comments.

The Coalition of Large Distributors (CLD), consisting of Enersource Hydro Mississauga, Horizon Utilities, Hydro Ottawa, PowerStream, Toronto Hydro, and Veridian Connections, has attached its comments on the Report.

Yours truly,

(Original signed on behalf of the CLD by)

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Comments of the CLD regarding the P.E.G. Report on Decoupling

Introduction

By way of a letter dated 2010 March 22, the Board commenced a consultation process concerning the possible adoption of Distribution Revenue Decoupling. The first stage of the consultation involved issuing a report commissioned by the Board and prepared by Pacific Economics Group Research (P.E.G.), and calling for stakeholder comments on that report (the Report). That stage is to be followed by the issuance of a Board Staff discussion paper, which itself is to be informed by both the Report and stakeholder comments.

The Coalition of Large Distributors (CLD), consisting of Enersource Hydro Mississauga, Horizon Utilities, Hydro Ottawa, PowerStream, Toronto Hydro, and Veridian Connections, provides its comments on the Report below. The CLD's general comments on the issues are presented first followed by its responses to the seven questions posed by Board Staff in the introductory letter.

General Comments on the Report

Scope – Inclusion of Revenue Adjustment Mechanisms

The Report contains much discussion of revenue adjustment mechanisms (RAMs), interwoven with the discussion of distribution revenue decoupling (decoupling) mechanisms. Although both are related to the general topic of ratemaking, they are separable and independent; decoupling may be effected regardless of the manner in which the subject revenue requirement was determined, and no manner of determining the revenue requirement demands that decoupling be instituted. In fact, the author of the report, Dr. Lowry, indicated during the stakeholder consultation meeting of April 19, 2010 that the original commission did not involve RAMs and that the discussion of RAMs was included on the initiative of P.E.G.

The Board, utilities, and other stakeholders have already gone through processes to develop the existing rate setting plan, i.e., 3GIRM. The methodologies and mechanisms for determining revenue requirements, explicitly through cost of service rebasing applications or implicitly through IRM adjustments, are already in place.

Serious concerns remain around the 3GIRM revenue requirement determination process and therefore the CLD remains strongly supportive of the continued evolution of those mechanisms, but urges the Board not to re-open the matter of revenue requirement determination *within the context of a decoupling inquiry*. To do so would detract substantially from the focus on the *unsettled* matter of decoupling and quite possibly embroil all parties in an ultimately unproductive process around an issue that is for now a settled matter. Since there is no interdependence between decoupling and revenue requirement determination, a better approach and the one that the CLD understands was originally intended by the Board would be to address these matters separately, each within its own focused proceeding. In that regard, the CLD looks forward to participating constructively in consultation processes concerning the development of '4GIRM'.

The Degree of Decoupling

The term 'Degree' is used here to denote the degree to which revenue recovery is independent (immediately or eventually) of volumetric system usage.

The CLD observes that the underlying cause for concern and motivation for decoupling is variability and/or downward bias of revenue recovered through usage based charges. This variability may be random (e.g., induced by weather), partially systematic and predictable (e.g., induced by economic changes), or systematically uni-directional (e.g., CDM and DSM). To the extent that strengthened conservation activities are not fully reflected in load forecasts, a downward bias in revenue may develop such that revenue fluctuations from forecast may on average be negative. In turn, this presents a strong counter-conservation incentive to utilities which are increasingly intended to be the agents of conservation in the province.

In any event the Report acknowledges and the CLD concurs that the issue of decoupling is not a matter of revenue recovery necessarily being completely variable or fixed; but rather that different decoupling mechanisms can produce smoothly adjustable degrees of dampening with respect to the variability of revenue recovery, or conversely, smoothly adjustable degrees of stability in revenues.

The Extent of Decoupling

The term 'Extent' is used here to denote the range of underlying causes of volumetric fluctuation addressed by any decoupling mechanism.

In addition to the observations above regarding the degree of decoupling, the CLD also notes that distribution revenue recovery is a function of several variables including those noted above and therefore concurs with the Report's observation that the extent of decoupling may range from limited or partial (i.e., decoupling is conducted only with respect to variations one or a few variables) to complete or full (i.e., decoupling is conducted with respect to all causes of revenue variation). The CLD therefore submits that the extent of decoupling is a matter for determination by the Board in consultation with industry stakeholders, and that through such consultation, the Board may find that any extent of decoupling, partial through full, may be appropriate.

The CLD stresses however that its positions on issues related to decoupling assume that any decoupling mechanism would operate only with respect to revenue fluctuations arising from volumetric fluctuations and not with respect to variances from forecast in customer numbers. As noted below, the CLD shares the widely held view that distribution costs do vary in the short term with customer numbers, but not with marginal changes in throughput (i.e., energy delivered), and the exclusion of variances related to customer numbers is in accordance with that fact.

Decoupling Through True-up Mechanisms

Among the mechanisms for (partial or full) decoupling is the after-the-fact true-up mechanism. Generally, under such a mechanism actual revenue subject to decoupling would be determined for the subject year and any variance between that and the corresponding allowed revenue would be computed and recorded in a variance account, together with carrying charges, for later disposition.

The CLD has concerns around such an approach. First, in principle true-up decoupling amounts to retroactive ratemaking, which fact was expressly acknowledged by Dr. Lowry during the stakeholder consultation; at a minimum, true-up decoupling makes rates at any time effectively interim. In contrast to a case in which costs incurred prior to the test year are allowed for prospective recovery under final rates in a subsequent test year, true-up decoupling intrinsically goes to the rates charged during the rate year and makes no reference to costs. Instead, true-up decoupling means that consumers cannot be sure what rate will apply to their consumption during the rate year. For example, assume that costs are exactly on budget and no cost variance clouds the picture at all, and further assume that due to a combination of CDM, economic recession, and mild weather, residential class volumes in kWh are below budget by 12%. In the next available rate year after that initial year, a debit amount representing the revenue deficit plus carrying charges would be collected from the residential class. Some might construe the revenue deficit as a 'cost' in the subsequent rate year, but in fact it is a revenue variance from a prior period that is strictly a function of volume variances and associated carrying costs. In the result, misleading price signals may be sent to consumers, which in itself would at any time be unhelpful.

It is unclear how the revenue deficit would be recovered in a subsequent period, whether by variable charges, fixed charges, or some combination of the two. Dr. Lowry indicated that common practice is to use variable charges. In any event, the method used to prospectively recover a revenue deficit is independent of the issue of the retroactive character of the decoupling true-up that it is collected from customers in a subsequent period; unlike the case of a (non-extraordinary) cost variance which would be borne by the utility, customers collectively are effectively charged a second time for prior period consumption, expressly to 'correct' the rate to the one that should have applied given actual consumption in the initial rate year. Stated simply, under true-up decoupling, rates in a given year are conditional on actual consumption in that year equaling the forecast consumption underpinning the determination of rates. This condition is very unlikely to be met in reality.

Second, from a practical perspective it would appear that substantial and ultimately unjustifiable lags in the true-up would occur, given current conditions and established practice. For example, a utility whose cost year is calendar 2011 could have a corresponding rate year commencing May 1 2011. If in that rate year there is a consumption deficit, that information would not be available even on an unaudited basis until approximately July 2012. Audited information, which is generally required by the Board for purposes of deferral and variance account clearance, would not be available until approximately March of 2013 or even later. Such a schedule would make it very difficult if not impossible to settle the amount of the true-up, and the rate rider to be included in rates, for implementation May 1 2013, especially given that there would be as many as 80 cases to process at the same time as new rates are being determined – the strong likelihood is that clearance of the account could not take place until the 2014 rate year. On that basis both the Board and utilities would be in the position of having to explain to customers why a substantial surcharge was being added to their bill to cover a shortfall in revenue that occurred three years prior. Even apart from intergenerational inequities, ongoing customers would rightly and strongly object to such a protracted lag in billing. Furthermore, added complexity would be created if the 2014 rate rider for 2011 consumption was itself under- or over-recovered due to consumption fluctuations.

For these reasons the Board should discard true-up decoupling as an approach to be further pursued and instead direct efforts to decoupling accomplished through rate design such as those described below.

Decoupling Through Rate Design

By way of preliminary remarks, the CLD concurs with the widely held view, expressed by Dr. Lowry during the stakeholder consultation, that short-run distribution costs are virtually unaffected by marginal changes in energy throughput: apart from incremental changes in losses, which are not part of distribution revenue requirement, costs on the distribution system do not change with an increase or decrease in kWh delivered. However, distribution costs exhibit a minor level of short run variability with the number of customers served or added during a particular period. Theoretically then, the pure Straight Fixed-Variable (SFV) approach to rate design reduces to a system of fixed charges matched to fixed costs for purposes of recovering the approved revenue requirement, since as a matter of fact, short-run distribution costs (the only costs ever recovered in rates) are essentially fixed with respect to system usage and there are no variable costs to be recovered through variable charges.

It is also arguably improper and unfair to distort distribution rates to a substantial degree in order for them to serve an external purpose unrelated to recovering the costs of distribution. For example, this would be the case if distribution cost recovery were done substantially through inverted block variable rates, for the purpose of discouraging ‘excessive’ energy consumption: in that instance distribution rates would be highly unreflective of the underlying distribution costs and would be used to further an unrelated item of social policy, instead of being directed to the proper purpose of recovering distribution costs.

In addition, where the variable component of distribution rates is based on energy throughput, consumers may be misled into thinking that distribution costs can be lowered by conserving energy. This is clearly untrue in the short-term, when energy conservation makes no difference to distribution costs, and is dubious even in the long-term. Since short-term distribution costs are fixed, the sharing of those costs is a zero-sum game, and the costs cannot be avoided by consumers as a group.

Despite these observations, the CLD acknowledges that as a holdover from the former regime under which utility rates were bundled and recovered distribution costs as well as upstream cost of power amounts, distribution costs have for the past decade been recovered on a combined fixed-variable basis, and that that practice has shaped consumer expectations. Furthermore, while the distribution revenue requirement consists only of short-run costs, it may be appropriate for distribution rates to convey some level of price signal to consumers regarding the long-run costs of placing demands on the capacity of the distribution system. Such a signal could be conveyed by partially recovering the distribution revenue requirement through charges based on system capacity usage.

The CLD observes that variability in revenue recovery stemming from system usage fluctuations can be dampened by one or both of two means; increasing the proportion of fixed recovery (mainly through monthly customer charges) or using a variable billing determinant that itself is more stable. In the case of small general service and residential classes, an alternate and more stable consumption-based billing determinant is kilowatts (kW), instead of kilowatt-hours.

Measurements of demand (kW) are inherently more stable than measurements of energy due to the intrinsic features of electricity-using equipment. Except under fault conditions, electrical devices are designed to consume electricity at a given maximum rate i.e., at a given level of demand. However, the work required to be done varies depending on conditions and will require more or less energy to be used accordingly. For example, a single residential air conditioner exerts a relatively fixed level of demand on the system when it is running and that level of demand does not vary according to the outside temperature; nevertheless the energy used will be relatively low when it is mild and the air conditioner does not have to run as long to achieve a set inside temperature, and relatively high when it is hot and the air conditioner has to run longer. In this example, the demand measure is a constant while the energy measure is highly variable depending on weather conditions.

The CLD submits that the use of demand measurements in the low-volume customer classes merits strong consideration by the Board as a means to simultaneously achieve two objectives: first, to reduce the variability of revenue as a function of system usage; and second, to provide a signal to customers to conserve on their use of the capacity of the distribution system. In the context of rates for distribution system usage, demand measurements are more appropriate than energy measurements since they are directly related to a key function of the distribution system: the provision of capacity. Demand measurements measure what is actually provided by the distribution system. A non-coincident measure of demand (kW or kVA), parallel to that used for larger classes, is also appropriate from the perspective of providing customers with definite and predictable information on the rates and costs of exerting demand on the distribution system.

The use of demand measurements is enabled by the rollout of smart metering across the province, and would provide a further use of those meters and the other parts of the Advanced Metering Infrastructure. Adoption of kW demand as a billing determinant for residential and small business consumers would, of course, have impacts on MDMR and distributor settlement systems. At this time the CLD is not able to identify the potential costs related to these impacts.

The CLD acknowledges that a change in billing determinants from energy to demand for low-volume customers will require an effort to educate those customers about the change and how they can modify their electricity usage in response to the change. However, the introduction of TOU rates has served to shift consumer awareness of and attitudes toward electricity pricing considerably and the CLD believes that with the proper background information, consumers would both understand and accept distribution pricing based on demand.

In summary, the CLD concludes that a balanced and smoothly adjustable approach to decoupling can be achieved through the combination of appropriate levels of fixed customer charges recovering a reasonable proportion of distribution costs together with the use of demand billing determinants and rates for the remainder. Demand billing determinants have the advantages of being

- inherently more stable than energy measurements;
- strongly related to the long-run costs of distribution system capacity; and
- conducive to reduction of system peak demand, an important energy goal of the Province.

For the electricity sector, the Board should reject true-up decoupling for the reasons set out above. Similarly, the Board should dismiss partial targeted approaches to true-up decoupling because of the additional concerns around controversy, administrative costs, and uncertainty of data involved.

Questions Posed by Board Staff

1. In light of developments in metering, CDM and demand side management ("DSM"), among possible others, is the implementation of further or modified revenue decoupling mechanisms for electricity and/or gas distributors warranted at this time and if so, why? For example, is the Board's current Lost Revenue Adjustment Mechanism adequate in light of the contemplated introduction of CDM targets for all electricity distributors in the Province?

a. The CLD does not consider the LRAM, in and of itself, an adequate mechanism for addressing counter-conservation financial incentives on the parts of utilities. The administrative cost of LRAM applications is significant and LRAMs may not fully address revenue loss due to conservation within LDC service territories. The CLD suggests that other mechanisms to address such losses should be explored.

   The implementation of some form of revenue variance stabilization may be warranted if that is achieved through appropriate means.

2. What factors should be considered when assessing the suitability of Ontario's current mechanisms and of alternative approaches? Are any of these factors more or less important than others? If so, why?

   a. Key factors for consideration include avoidance retroactive ratemaking; minimization of administrative costs relative to the benefits achieved; and timeliness and certainty of rates. These factors are all of approximately equal importance.

3. What, if any, are the implications of the wide-spread deployment of smart meters for the Board's approach to revenue decoupling?

   a. The most important implication is that smart meters and the AMI generally enable the use of demand measurements as billing determinants for residential and small general service customers, who are currently billed on a kWh billing determinant. Demand billing determinants are more stable than energy billing determinants, and therefore have an immediately stabilizing effect on revenues derived from system usage rates. In addition, demand billing determinants are directly related to long-run distribution system costs for incremental capacity and send an appropriate price signal to consumers to economize on their use of system capacity.

      Furthermore, demand billing determinants for small volume customers make additional use of the smart meter/AMI investment and produce greater benefits from it.

4. What scope for further or modified revenue decoupling might be appropriate? For example, should the impact of all variances from forecast in commodity demand be eliminated regardless of the cause (i.e., distributor-provided CDM/DSM programs, other CDM/DSM programs, the economy, weather, customer growth, etc.)? Why or why not?

a. The CLD does not favour targeted partial approaches to decoupling for electric utilities because they will create unsupportable administrative burdens for the Board, intervenors, and utilities. The rate design approach to (the appropriate degree of) decoupling is administratively practical and economical and is smoothly adjustable to balance competing considerations.

5. Are there any alternative approaches, beyond those identified in the P.E.G. Report, which better address revenue erosion due to changes in consumption? What are the costs, benefits and implications of implementing the alternative approach?

    a. The CLD is not aware of significant alternatives to the approaches set out in the P.E.G. report.

6. Is there a preferred approach (or elements of an approach) and if so, what are the important implementation matters that must be considered? What are the costs, benefits and implications of implementing the preferred approach or of refraining from doing so?

    a. As explained above, the CLD supports the rate design approach to decoupling. The favoured approach requires that smart meters be in place for all small volume customers of a given utility, and that the Board, in consultation with distributors, determines guidelines for the appropriate proportions of fixed versus usage based recovery of costs; with the ultimate determination based on a utility's specific circumstances through a re-basing application.

7. Can or should the preferred approach need to be the same in both the gas sector and the electricity sector? Why or why not? Would any other form of differentiation based, for example, on a specific distributor characteristic(s) be appropriate? If so, what might be the defining characteristic(s)?

    a. The CLD supports symmetry where appropriate in the regulation of the gas and electric sectors but acknowledges that at the level of practice different particular approaches may be desirable or necessary. The most significant difference between the sectors is the number of utilities and the consequential administrative costs of certain options like true-up decoupling. The gas sector also has a longer history with DSM programs and regulatory accommodations of those programs, so the need for change may be less pressing in that sector.