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VIA MAIL AND EMAIL

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
26th Floor
2300 Yonge Street
Toronto, ON
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Dear Ms. Walli:

Re: Consultation on Distribution Revenue Decoupling
Board File Number: EB-2010-0060

Comments on behalf of the Vulnerable Energy Consumers Coalition

As Counsel to the Vulnerable Energy Consumers Coalition (VECC), I am writing, per the Board's Letter of March 22nd to provide VECC's comments regarding the above consultation. The comments are presented in two sections. The first section comments on the PEG Report while the second section responds to the specific questions identified by Board Staff in the March 22nd letter.

Comments on the PEG Report

Revenue Decoupling (Section 2.2)

The PEG Report (the "Report") identifies three approaches to revenue decoupling: lost revenue adjustment mechanisms (LRAMs), decoupling true-ups, and straight fixed variable (SFV) pricing. In VECC's view, the first two approaches are very similar in principle and only really vary in terms of degree. As noted in the Report (page 5), some decoupling true-up mechanisms are "partial" in that they exclude from decoupling the revenue impact of certain types of demand fluctuations. In this regard LRAMs can be viewed as very limited forms of decoupling as they exclude all sources of demand fluctuation except that associated with conservation and demand management programs. In contrast, the “partial decoupling” approach outlined in the Report includes all sources of demand fluctuation except weather; whereas the full decoupling approach also includes weather.

Approaches involving revenue decoupling true-ups inherently give rise to the same types of issues, namely i) the calculation of the true-up required and ii) the refund or recovery of the true-up. The Report (pages 4-6) discusses these issues but, in VECC’s view, implementation of a “true-up” approach would require them to be worked through in greater detail before a decision can be made as to which approach is preferred. For example, the calculation of true-up required involves identifying both the revenues deemed by the regulator to be warranted and the “normalized” actual revenue to be used in the true-up calculation. Even where the test year’s rates were set using a revenue requirement established on a cost of service basis or a revenue “cap” basis, the question will arise as to whether any adjustments are required to account for costs (such as working capital requirements) that vary with volumes. In cases where the rates were set using a price cap approach (as is currently done for the electricity distributors’ IR mechanism), the issue is even more complex as there is no “approved” revenue requirement or volume forecast.

Similarly, any partial true-up requires the calculation of the load variances that will be included versus those that will be excluded from the calculation. The Report mentions weather variations as been a factor that is frequently excluded from partial decoupling mechanisms. While gas distributors in Ontario have fairly well developed and generally accepted methodologies for weather normalization, the same cannot be said for most of Ontario’s electricity distributors. In VECC’s view, any adoption of a partial decoupling approach (based on weather normalized use) is premature for Ontario’s electricity distribution sector.

The Report mentions several issues associated with the refund/recovery of the true up, including frequency, the need to develop billing determinants in order to calculate the associated rate riders and the determination of how the refund/recovery will be allocated to customer classes. In VECC’s view this last issue will require considerable attention as it involves working through issues of both fairness and practicality. As noted in the Report (page 6), from a fairness perspective the question is when should customers in one class be insulated from fluctuations in demand of another customer class. However, at the same time, there are a number of Ontario electricity distributors where some customer classes contain only a few customers and variations in one customer’s load could result in a significant refund/recovery being required from the other customers in the class. Furthermore, in extreme circumstances such as plant shut down, events may unfold such that there are no remaining customers in the class.

The Report acknowledges the issues related to the frequency of rate adjustments (page 5) and the need to synchronize rate adjustments for purposes of decoupling with adjustments made for other reasons. The Report also notes the potential issues associated with the size of the true-up adjustment that may be required. In VECC's view a related issue is the impact the true-up will have on bill stability (e.g., a true-up refund in one period followed by a true-up recovery in the next would be viewed as contributing to bill instability). The approach to be taken will depend, to some extent, on the nature of the decoupling true-up. If the true-up addresses factors such as weather impacts that are expect to fluctuate around some normalized value, then it may be appropriate to take a longer term perspective on the refund/recovery with the expectation that the values will average out over time. In contrast, if the decoupling involves a full true-up mechanism it may be more appropriate to design the level of refund/recovery so as to ensure "full" clearance of the variance account over a specified period of time. VECC notes that the approach adopted by the BCUC for the clearance of similar variance accounts maintained by BC Hydro's is to set the level of refund/recovery so as to clear the account over 3-5 years[1].

VECC submits that it would be unproductive to further explore the preferred approach to the above issues until the Board determines further investigation of revenue decoupling is warranted and that true-ups are the appropriate approach to be taken and established the degree of true up to be pursued. Until then the possible permutations are too great to permit a proper assessment within the time allotted.

In contrast, SFV is a fundamentally different approach to revenue decoupling that involves utility rate design. The Bonbright principles underlying proper utility rate design are well established and generally accepted by all regulators. Bonbright's attributes of a sound rate structure include "revenue stability and predictability, with minimum unexpected changes seriously adverse to utility companies" which aligns with the objectives of revenue decoupling. However, his attributes also include fairness in the apportionment of costs (i.e., cost causality); the promotion of efficient use and public acceptability. The adoption of a strict fixed rate would seriously compromise one or more of these other objectives. As a result, there would need to be a compelling case for revenue decoupling before SFV was adopted. In VECC's view such a case has not been made.

<u>Rationale for Revenue Decoupling (Section 2.3)</u>

Earnings Attrition Relief

The Report suggests (page 12) that in the short-term an energy distributor's costs are only sensitive to the number of customers served. This is incorrect. The delivered volumes affect the cost of purchased power and related transmission charges, both of which are key components of an electricity distributor's working capital requirements and can represent a significant portion of the distributor's overall rate base.

[1] It should be noted that in its current (F2011) Rate Application BC Hydro is seeking to deviate from the established formula in order to reduce the overall bill impacts for the test year.

The Report suggests that the potential for revenue erosion is a disincentive to energy distributors promoting CDM/DSM goals and that revenue decoupling can address this issue. VECC generally agrees but notes that this issue is muted for electricity distributors in Ontario by virtue of the Minister's Directive to the OEB to set CDM targets for all electricity distributors in Province and make meeting such targets a condition of the distributors' licences. As a result, electricity distributor will have an obligation to deliver CDM/DSM programs, lessening the need for incentives.

VECC does acknowledge that the introduction of programs to meet prescribed targets could increase energy distributors' earnings attrition between rate cases as discussed on page 17 of the Report. However, such risks have existed for a number of years and, therefore, can be considered to be reflected (to some degree) in the Board's current ROE formula. If the Board were to adopt a more aggressive form of revenue decoupling than the LRAM-adjustment currently available to electricity distributors, then there would need to be a reconsideration of the allowed ROE premium. The Report notes (page 17) that in five cases known to PEG regulators have made an explicit reduction in the target rate of return to account for this and that the average reduction was fifteen basis points. VECC notes that there are no references or documentation provided to support this statement.

In the case of electric utilities, the distributors effectively have the option of applying for a cost of service based application whenever they want and the option of applying for Z-factor adjustment to address the cost of events that are beyond management's control. Given this context, VECC considers revenue/volume risk to be one of the major risks facing electricity distributors. Given that the spread between the 2010 allowed ROE (9.85%) and the forecast long Canada Bond Rate (4.46%) is 539 basis points, it is VECC's view that revenue decoupling (particularly full decoupling) is worth considerably more than 15 basis points. VECC submits that any move to revenue decoupling beyond the current LRAM and rate design approach used by energy distributors <u>must</u> be accompanied by a significant reduction in the ROE premium. Furthermore, one might expect that adoption of such approaches and the commensurate reduction in risk could also affect (reduce) utility borrowing rates.

Efficient Regulation

The Report suggests that there are regulatory efficiencies to be gained through the introduction of revenue decoupling. One reason offered (page 18) is that it will address an important source of financial attrition and reduce the required frequency for rate cases. VECC acknowledges that it will remove one of the drivers underlying an energy distributor's need to file for rate rebasing. However, VECC notes that for the two electricity distributors in province (Hydro One Networks and Toronto Hydro) who continue to rely on cost of service applications, it is cost increases as opposed to revenue erosion that is the main reason for not relying on IRM. Similarly, many of the electricity distributors' rebasing applications have included significant cost increases such that revenue decoupling would not obviate the need for a rate case. As a result, VECC submits that the benefit attributable to revenue decoupling due to reduced rate cases is likely overstated.

The Report also suggests that revenue decoupling can increase regulatory efficiency by reducing the importance of load forecasts in rate cases. This point was raised in the Board's EB-2009-0260 Decision (page 15) regarding Cambridge & North Dumfries Hydro. While revenue decoupling will reduce the importance of load forecasting, it is VECC's view that it will not eliminate load forecasts as an issue in cost of service applications. There will still be a need for the forecasts to be reasonably accurate since they are a key input to the determination of the working capital component of rate base. Also, if a true-up approach is adopted for revenue decoupling, an inaccurate load forecast will likely lead to a larger variance account balance and future refund/recovery. Finally, since the proposed rates (and the resulting bill impacts) are based on the proposed load forecast, there will be continued interest on the part of ratepayer representatives to ensure that the forecast does not understate the likely sales volumes for the test year. The Board should not expect the implementation of revenue decoupling to eliminate the importance of and the controversy regarding electric utility load forecasts and load forecasting practices.

Potential Disadvantages to Decoupling

The Report comments on, with a view to dispelling, a number of criticisms regarding revenue decoupling. The first criticism cited is whether true-up plans cause customers in one rate class to absorb the impact of demand turndowns in another class. The Report suggests (page 19) that this issue can be readily overcome by using multiple revenue requirement baskets in the decoupling true-up plans. In VECC's view the solution is not that simple. The use of revenue requirement baskets means that the individual customer class load forecasts become particularly important – even more so that they are now. For example, if the impact of changes in industrial load due to economic conditions is to be deemed the responsibility of the industrial customer class, then industrial users will want to ensure that the load forecast for their "class" is not overly optimistic. In contrast, representatives of low volume consumer classes will want to ensure that the forecast does not understate likely industrial loads. The reason for this is that the test year's rates will be set based on the load forecast and higher forecast loads (in any rate class) will tend to reduce the average rate increase required.

Finally, as noted earlier, the "basket" approach may be untenable or even impractical for customer classes with only a few customers, in that a significant load variation may lead to a variance that is too large to be reasonably recovered from the remaining customer(s) or, in the extreme, there may be no customers left in the class.

The Report also notes (page 19) that true-up plans and SFV pricing erode incentives to offer services on market-responsive terms. The Report suggests that, since these issues tend to arise more with large use customers, this can be overcome by applying decoupling selectively to residential and small business customers. VECC notes that selectively apply decoupling mechanisms raises the question about whether the same cost of equity should be used in determining the rates for all customer classes as the revenue risk associated with those classes with no revenue decoupling scheme will be substantially higher.

Criteria for Decoupling Plan Selection (Section 2.4)

Other Criteria

This section of the Report starts (page 20) with the assumption that "some form of decoupling is deemed a useful addition to the regulatory system" and then proceeds to propose criteria for assessing which of the three described approaches is more appropriate. In VECC's view this assumption skips the first important question which is whether a decoupling mechanism is needed in the first place. VECC notes that the discussion in Sections 5.2.3 and 5.3.3 partially addresses this question by looking at trends in per customer use.

The Report suggests that the relevant criteria are efficient regulation, attrition relief, and the removal of financial disincentives for CDM/DSM. In VECC's view this list is far from complete and the following criteria should be added:

- Year to Year Bill/Rate Stability. VECC notes that "stability" should not be interpreted as meaning no change in rates but rather that the year over year pattern in rate changes is smooth and predictable. Consideration of this criteria is particularly important with regard to the true-up approaches to revenue decoupling. Rate and revenue stability is discussed in the Report under "Other Repercussions of Decoupling" (page 27). However, in VECC's view bill/rate stability is important from the perspective of consumers. Given that protection of the interests of consumers with respect to price is one of the statutory objectives of the OEB, VECC submits that it should be a criterion in assessing the various decoupling approaches
- Fairness in Cost Recovery. In the case of true-up mechanisms this involves both issues of inter-generation equity as well at inter-customer class cost recovery issues. In the case of SFV pricing, it involves the fair apportionment and recovery of costs from customers within the same rate class.
- Fairness in Risk Apportionment Between Customers and Utility Shareholders. True-up mechanisms involve a transfer of risk between utility shareholders and consumers. SFV pricing involves a reduction in risk to shareholders. In both cases, the question arises as to if/how the revenue decoupling scheme recognizes this change in risk to utilities.
- Efficient Pricing. The Report includes, as one of its criteria, the removal of CDM/DSM disincentives. As noted in the Report (page 22), this criterion has two dimensions to it. The first is the concern that the reduced loads that result from CDM/DSM will discourage utilities from actively pursuing/supporting related initiatives to full extent they could. The second dimension is that rate design can have an important impact on customer incentives for CDM/DSM. In VECC's view it is worthwhile clearly distinguishing between these two different dimensions,

particularly as true-up mechanisms and SFV pricing have significantly different implications when it comes to efficient pricing.

Efficient Regulation

The Report states that (page 20) it is "challenging to estimate the impact of conventional CDM/DSM programs in a world in which demand is affected by numerous other business conditions". The existence of this challenge is one of the factors underlying the support for a broader form of decoupling than LRAM. However, the Report also notes (page 21) that "the impracticality of LRAMs is a less material consideration when CDM/DSM incentive mechanisms are operative". In Ontario, gas distributors are eligible for (and regularly request) shared savings incentives based on their CDM/DSM achievements. As long as savings estimates are required for this purpose, the regulatory efficiency gains of eliminating the LRAM and adopting a broader decoupling mechanism are likely to be minimal.

In the case of electricity distributors, only a minority of them have (to-date) applied for a shared savings incentive. However, the Minister's recent Directive to the OEB not only requires that CDM/DSM targets be set and made a licence condition but directs that a tiered performance incentive mechanism be made available and that the verified results of each distributor's programs be published annually. Based on these requirements, VECC submits that the introduction of a decoupling mechanism based on anything other than an LRAM (which solely considers utility program savings) is likely to increase regulatory burden on the electricity side.

Earnings Attrition Relief

The Report suggests that since attrition relief is an important reason for adopting decoupling, the interest should be in the approach that provides the most relief. The Report goes on to suggest (page 22) that LRAMs are deficient to the extent that there are declines in average use for reasons other than CDM/DSM. In VECC's view it is important to distinguish between earnings variability and earnings attrition. Earnings variability can arise from factors such a weather, where earnings may be more or less in a given year but should average out over the longer term. Earnings attrition arises to a consistent trend to lower use per customer due to factors such as DSM/CDM. If the objective is to provide earnings attrition relief then it is important to determine, first, if there is an downward trend in average use and, second, if the trend is due to more than just CDM/DSM. This distinction is noted later in the Report (page 78).

Conclusions

It should be noted that LRAMs are also comparatively advantageous in situations where the load impact of DSM/CDM initiatives needs to calculated, in any event, for other purposes (e.g. to demonstrate performance or to qualify for performance incentives).

The conclusions fail to note that SFV pricing will be less favoured by regulators who put a premium on cost causality and the fair apportionment of costs between customers.

Application to Ontario – Gas Sector (Section5.2)

Average Use Trends

Section 5.1 of the Report notes that a key consideration in the analysis is whether the average use is declining for reasons other than CDM/DSM programs. Section 5.2.5 (page 92) claims that declines in average use are due to external trends in business conditions as well as to DSM programs. However, the claim is not substantiated in the Report. Having noted this, the matter is relatively moot since in the case of Union Gas the current IRM plan includes an adjustment for trends in averages use for the four main customer classes and a partial true-up based on weather normalized use per customer. Similarly, in the case of Enbridge, the IRM plan is based on a revenue cap and an updated load forecast is produced each year that captures the expected impact of the company's DSM programs. Furthermore, for Enbridge, an Average Use Variance Account has been established for the residential (Rate 1) and general service (Rate 6) customer classes. As a result, the current regulatory schemes for both companies include revenue decoupling true-up mechanisms that go well beyond a simple LRAM true-up.

Appraisal and Suggested Refinements

The Report suggests (page 92) that there are two refinements to the established decoupling mechanisms that could be considered for the next "round" of incentive regulation. The first is that the LRAM calculation could be eliminated and the partial decoupling true-up mechanisms used to address lost margins from utility DSM plans and other sources. This suggestion has some merit. However, in VECC's view the overall workings of the current partial true-up mechanisms is something that will be subject to re-assessment in considering the next "round" of incentive regulation for both utilities and the suggestion must considered within that context. One issue associated with the Report's suggestion is the fact that the current decoupling mechanisms (i.e., adjustments for changes in average use) do not apply to all customer classes. Unless the other customer classes are included in the next round of incentive regulation there would be a continued need to apply the LRAM approach for the excluded customer classes.

The second suggestion is that revenue can be decoupled from weather fluctuations. The Report notes (page 93) that this would provide a further small simplification to regulation. The report also suggests that this would foster the ability of the gas distributors to experiment with alternate rate designs that more effectively promote DSM goals. As noted earlier, weather fluctuations give rise to earnings variability as opposed to earnings attrition. As a result, the major impact of adopting decoupling the impact of weather fluctuations would not be to avoid erosion of revenues during the IRM period but rather to shift risk away from utility shareholders. Furthermore, given the long established weather normalization practices of these utilities, VECC considers that the gains (in terms of regulatory efficiency) would be minor.

Set against these possibly minor gains would be the effort required to adjust the regulatory framework (e.g., allowed ROE formula) to reflect this shift in risk. Other regulatory considerations that have not been identified in the Report include the fact that decoupling weather variations is likely to increase the absolute dollar adjustment recorded each year in the related deferral account. This will increase the regulatory issues (e.g., rate stability, inter-generational equity, etc.) associated with managing the balances.

The second reason given for decoupling weather fluctuation is that it would allow gas distributors to experiment with rate design. As noted earlier, there are other considerations besides utility revenue stability and promoting DSM that must be considered in the design of a utility's rates. In VECC's view it is yet to be determined whether distribution rate design experimentation, such as the reduction of customer charges/raising of volumetric charges suggested in the Report, is warranted and appropriate. As a result, at this time, limited weight should be given to this perceived benefit from full revenue decoupling.

Application to Ontario – Power Distributors (Section 5.3)

Use Per Customer Trends

As the Report notes (pages 97-98) there is limited data, particularly properly weather normalized data, available on which to draw conclusions regarding trends in customer average use for electricity distributors. Furthermore, in the one cited case (Toronto Hydro) where weather normalized use is referenced, no effort has been made to separate the impact of CDM/DSM from other factors. Thus the Report is unable to answer the one of key analysis questions identified in Section 5.1 – "Is the average use declining for reasons other than utility CDM/DSM programs?".

Rate Rebasings

The Report discusses (pages 101-102) the Board's filing requirements for cost of service applications with regard to load forecasting and the general approaches used by electricity distributors. What the Report does not acknowledge is that in their applications many distributors have noted that there are significant data limitations which restrict their ability to develop robust forecasts at the customer class level. Also, the Board in a number of its Decisions regarding 2010 rates has expressed concerns regarding the models used by many distributors for purposes of forecasting total wholesale purchases.

This suggests that, in contrast to natural gas distributors, in the electricity sector current load forecasting and weather normalization methodologies are not sufficiently robust to provide a sound basis for either partial decoupling (i.e., based on weather normalized use) or for determining decoupling variances (partial or full) on a customer class basis. While the introduction of smart meters should help resolve the underlying data limitations and lead to more robust load forecasting and weather normalization methodologies, the resulting improvements are a number of years off.

Rate Design

The Report's discussion (page 106) on electricity distributor rate design does not include any reference to the November 2007 Report of the Board – Application of Cost Allocation for Electricity Distributors (EB-2007-0667). In this Board Report, a range is established for the monthly service charge for each customer class based on the results of the Board's Cost Allocation methodology. In the 2007 report, the Board notes (page 12) that the setting of the monthly service charge is an issue that will be examined within the scope of the Rate (Design) Review and will need to consider various objectives including conservation as well as cost allocation results. In VECC's view, this reinforces its earlier observations that the adoption of SFV pricing to resolve earnings attrition ignores other issues associated with rate design. Furthermore, a similar observation applies in those circumstances where rate design is being considered as tool for promoting CDM/DSM (i.e., there are other criteria and considerations that must be taken into account).

Appraisal and Suggested Refinements

On pages 111-112 the Report sets out some the current conditions in Ontario's electricity distribution sector that will affect the need for and the type of decoupling mechanism that could be applied. Set out below are some observations regarding both the points raised in the Report as well as some that have been missed:

- No evidence has been provided to support the contention that there is/will be a reduction in average use after allowing for the impact of distributor CDM programs. While admittedly there are other CDM programs out there that will decrease average use there are other factors that will tend to increase it (e.g., emerging technologies).
- The Report cites (page 96) the Green Energy Act as a driver for increased conservation and notes that it permits the Minister to set conservation targets for electricity distributors. It should also be noted that the recent Minister's Directive to OEB provides for the establishment of a tiered performance incentive mechanism based on verified electricity savings and requires the Board to annually review and publish the CDM/DSM results for each distributor. As a result, distributors will be required to determine CDM savings even if there is no specific LRAM calculation as part of the OEB's regulatory framework.
- The Report suggests that the Revenue Adjustment Mechanism (RAM) can be designed to provide sufficient relief from cost attrition to avoid frequent rebasing. VECC is not convinced that this is the case. As noted earlier, the main driver behind

both Hydro One Networks' and Toronto Hydro's continued use of annual/bi-annual cost of service applications is cost, not revenue attrition.

One of the suggestions in the Report (page 112) is that the Board should give strong consideration to moving from LRAMs to some form of decoupling true-up plan or SFV. The rationale is that both alternatives would further facilitate CDM/DSM, provide regulatory certainty/stability and achieve administrative simplicity. In VECC's view the case is nowhere near as compelling as the Report suggests.

The report claims that distributors would have diminished disincentives to encourage DSM in ways not credited, only partially credited and/or only credited with difficulty under current LRAMs. However, the recent Minister's Directive will lead to distributors focusing their CDM effort primarily on those initiatives for which they can measure the results and get credit. The reasons for this are three-fold. First, meeting their assigned CDM targets will be a condition of each distributor's licence. Second, distributors will be required to report annually and the Board is required to publish the savings attributable to their utility (OPA and Board approved) programs. Third, the Directive provides for an incentive mechanism for verified electricity savings up to 150% of the distributor's CDM target. In VECC's view, providing for a broader revenue decoupling mechanism will do little to broaden the focus of electricity distributors regarding CDM/DSM.

Admittedly, the provision for a broader decoupling mechanism may provide more complete relief from earnings attrition between rate rebasings and increase the time between such filings. However, as discussed earlier, the inability of the current IRM process to fully address cost increases is the main reason for utilities forgoing the IRM adjustment and seeking early rebasing. VECC is not convinced that there would be substantial gains on this front through the introduction of a broader decoupling mechanism.

The Report also suggests that a broader decoupling mechanism would also simplify the regulatory process as LRAMs could be eliminated and the importance of the load forecast in rebasing applications would be reduced. While the use of a broader decoupling mechanism would eliminate the need for an LRAM calculation, a distributor will still be required to calculate and verify the savings attributable to its CDM programs in accordance with the Minister's Directive. VECC notes that it is these "savings" estimates that are the most controversial and difficult part of any LRAM calculation. As result, VECC does not see much regulatory efficiency to be gained from the elimination of the LRAM.

With respect to diminishing the importance of the load forecast in rebasing applications, VECC's earlier comments have identified a number of reasons why load forecasts will still be important. VECC also notes (for reasons also discussed earlier) that if the clearance of any resulting deferral account is done a class specific basis, then the <u>individual</u> customer class forecasts used in the rebasing application are likely to take on even <u>greater</u> importance than they have to date and become more contentious.

Pages 113-115 of the Report discuss the pros and cons of applying the various approaches to revenue decoupling to Ontario's electricity distributors. While no clear conclusion is presented the Report appears to favour the use of decoupling true-up plans over SFV pricing. VECC agrees that, should it be determined further revenue decoupling (i.e., beyond the current LRAM) is warranted, then true-up decoupling mechanisms are preferable to SFV pricing. However, as noted above, the case for decoupling is not as compelling as the Report suggests and warrants further justification.

The Report goes on to identify a number of issues that would need to be addressed as part of the decision to proceed with full versus partial revenue decoupling and implementation of the preferred approach. In VECC's view there are some key policy questions linked to these implementation issues. There are also timing issues, since smart meter data is just now becoming available and the ability of the industry to address many of the issues (e.g., weather normalization, adequate customer class load forecasts, etc.) will be greatly enhanced a few years from now. VECC submits that consideration of whether or not additional revenue decoupling is required should not be separated from the question of how it would implemented. Both matters must be considered together as the idea may be good in principle but prove to be bad in terms of the industry's capability to implement it at this time.

Response to OEB Staff Questions

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?

Gas Distributors

Both of the major gas distributors have just recently entered IRM mechanisms that include revenue decoupling mechanisms that go beyond a simple LRAM. In each case, it will necessary to wait and see how these mechanisms perform. The Report has made some minor suggestions for refinements and these should be considered along with the performance of the current mechanisms for the IRM plan that may follow the next rebasing.

Electricity Distributors

Major recent developments for electricity distributors include the fact that the province-side implementation of smart metering is nearing completion and the Minister's Directive to the OEB regarding the establishment of CDM targets for each distributor and the adoption of a performance incentive mechanism for verified electricity savings. With the smart meter installation just nearing completion it will be a few years before sufficient data is available to allow electricity distributors to improve their load forecasting/weather normalization methodologies. As a result, while longer term plans can be made to leverage off of such improvements in the future, there is no basis for any immediate changes "at this time" due to improved load forecasts using smart meter data.

Smart meters do provide a capability for distributors to implement alternative rate designs such as time of use and critical peak pricing. As noted in the Report, the adoption of such pricing schemes for distribution service could increase earnings uncertainty. However, such schemes are more likely to be applied first at the commodity level (e.g., TOU-based RPP pricing). Currently, there are limited study results available as to how the application of such pricing schemes to the commodity portion of the bill will impact total volumes and, therefore, utility distribution earnings.

As discussed earlier in these comments, the Minister's Directive regarding CDM targets for electricity distributors is likely to increase the focus of electricity distributors on the success and verification of their own (OPA and Board-approved) programs. Indeed, the Directive may well increase the focus on the LRAM and the determination of savings attributable to utility programs.

Overall, VECC does not see any of these recent developments as requiring the implementation of further or modified revenue decoupling mechanisms at this time.

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?

VECC has addressed this issue under its comments regarding Section 1.3 – Other Criteria.

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

Please see the response to Question #2.1. Eventually the wide deployment of smart meters will permit electric utilities to improve their load forecasting and weather normalization techniques. At that time, the industry will be in a position to adopt more extensive revenue decoupling approaches that rely on weather normalization and/or customer class specific load forecasts, if warranted.

The most immediate implication from the deployment of smart meters will be the widespread adoption of TOU pricing for RPP supply. However, as discussed earlier, it is not immediately clear what impact this will have on volume-based billing determinants currently used for distribution charges. Eventually, TOU or critical peak pricing may be adopted for distribution charges. Presumably, this will be one of the issues considered in the forthcoming Rate Design Review. In VECC's view, it would be premature to implement decoupling mechanisms at this time that prejudged the outcome of this review.

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?

In the case of gas distributors, the current IRM schemes include revenue decoupling mechanisms beyond just an LRAM (e.g., adjustments for changes in average use and deferral accounts to capture differences between actual and normalized average use). However, these additional revenue decoupling mechanisms do not apply to all customer classes. When the next "generation" IRM plans are developed in conjunction with the next rebasing review, consideration should be given to extending these decoupling mechanisms to all customer classes as well as to the suggestions put forward by PEG in its Report. However, the current IRM plans should be allowed to "run their course".

In the case of electricity distributors, as discussed earlier, most distributors' load forecasting/weather normalization methodologies are not sufficiently well developed to currently support partial decoupling based on weather normalized use. Indeed, they will likely not be robust enough to do so until a number of years of smart meter data has been accumulated and analyzed.

This leaves full decoupling as the only viable option in the short-term. Full decoupling involves a significant shift in risk from utility shareholders to rate payers and will necessitate an adjustment in the allowed ROE for distributors. It could also lead to significant year to year variances which means close attention must be paid to policies with respect to refund/recovery – both in terms of over what period and from what customer classes. As noted in the Report (page 115) these issues need more careful consideration before a decision is made as to whether or not full decoupling can and should be implemented. In VECC's view it would be premature to decide that full decoupling is warranted until further consideration is given to these issues.

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

The PEG Report identifies three basis approaches (LRAM. Decoupling True-ups and SFV Pricing) to revenue decoupling. However, it then goes on to identify a number of permutations to Decoupling True-ups based on:

- Full vs. Partial (weather-normalized) true-ups,
- Application to some versus all customer classes, and
- Choice of customer class "baskets" for purpose of any variance refund/recovery,

In VECC's view, the Report has done a reasonable job at identifying the alternatives. Indeed, each possible permutation represents a potential "alternative". However, the Report does not identify the costs, benefit and implications of implementing each but rather notes (page 115) that these are issues yet to be addressed.

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?

As discussed in response to Question #2.5, the Report does not provide sufficient information to determine a preferred approach. As noted in earlier comments, based on the information considered to-date, VECC's preference would be for a form of decoupling true-up as opposed to SFV pricing. However, the actual form of true-up and whether it should extend beyond what is currently available to electricity and natural gas distributors are matters that require further assessment.

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)?

VECC does not believe that the "preferred approach" needs to be the same for both the gas and electricity sectors. First, the evolution of the regulatory framework for the two sectors is at fundamentally different stages. The major gas distributors in the province both currently have decoupling mechanisms that extend well beyond an LRAM; while many electricity distributors have yet to even apply for an LRAM adjustment. Second, the load forecasting and weather normalization methodologies used by the gas distributors are well developed and more broadly accepted by all stakeholders, including the Board, than is the case for the electricity distribution sector.

In the case of the gas distribution sector the two distributors currently have different approaches to IRM and, thus, to revenue decoupling. If the distributors continue to use different IRM approaches then it is likely some variation in their revenue decoupling approach will be necessary. Given the limited number of gas distributors, VECC believes any differences can be managed effectively as part of the rate review process for each.

In the case of the electricity distributors, there may be some scope for allowing different approaches to be used. However the choice of approach should not be up to the distributor but rather reflect the distributor's characteristics in areas such as:

- Load Forecasting/Weather Normalization – i.e., is the methodology used considered sufficiently robust to support the revenue decoupling approach?
- Commitment to IRM – i.e., is the utility committed to IRM or does it continue to rely on cost of service based applications?

- Observed Trends in Average Customer Use – i.e., is there evidence that revenue decoupling beyond LRAM is required?

VECC would like to thank the Board for the opportunity to comment and if any clarification is needed please don't hesitate to contact either Bill Harper (416-348-0193) or myself (416-767-1666).

As VECC has noted in its comments, the case for revenue decoupling and, if warranted, the particular approach to be taken required more consideration. VECC looks forward to continuing its participation in the Board's review of revenue decoupling.

Yours truly,

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