EB-2010-0060

ONTARIO ENERGY BOARD

IN THE MATTER of the *Ontario Energy Board Act*, 1998, S.O. 198, c.15, Schedule B, as amended;

AND IN THE MATTER OF the review by the Board of issues relating to decoupling of distributor revenue from volumetric criteria

SUBMISSIONS OF THE SCHOOL ENERGY COALITION

May 17, 2010

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1 GENERAL COMMENTS

1.1 *Introduction*

1.1.1 On March 22, 2010 the Board published a report from Pacific Economics Group entitled "Review of Distribution Revenue Decoupling Mechanisms" (the "PEG Report") and sought input from stakeholders prior to the preparation of a Staff discussion paper outlining proposals for revenue decoupling. The PEG Report was followed by a stakeholder meeting on April 19, 2010 at which PEG provided further information on its report and analysis, and engaged in dialogue with stakeholders.

1.1.2 These are the submissions of the School Energy Coalition (SEC).

1.2 *Interest of Schools*

1.2.1 Part of the initial impetus to look at revenue decoupling comes from attrition, and in particular the loss of revenue by distributors due to conservation activities of customers. Schools, as early adopters and active participants in conservation measures, have a fundamental concern with any factor that could be a barrier to successful conservation in Ontario. Thus, if decoupling would facilitate increased conservation, schools are in principle in favour of that option.

1.2.2 But revenue decoupling is not, in our view, primarily about conservation. Rather, it is, or has the potential to be, a much more fundamental change in how the costs of electricity distribution are met, how risks are assigned, and the public's expectations of utility managers.

1.2.3 In this broader context, the interest of schools in revenue decoupling is governed by three imperatives:

(a) ***Strong Distributors.*** It is in the interest of schools, as well as all customers, to promote the establishment and maintenance of stable, well-run distributors of both electricity and gas. Where distributors already meet those standards, regulatory changes should not undermine their efforts. Where distributors still have a ways to go, regulatory changes should make it easier, not more difficult, to get there.

(b) ***Low Energy Costs.*** Schools want their electricity and natural gas bills to be as low as possible consistent with the safety, reliability and quality of service that are needed and expected. Whether upward increases in the cost of these services are the result of spending increases, government policy initiatives, cost allocation, or rate classification/design, those upward bill pressures must be limited to what is absolutely necessary and is fair to all ratepayers.

(c) ***Long Term Horizon.*** All regulatory initiatives must be considered within a long term context. "Short term gain followed by long term pain" is not in the interests

of most ratepayers, and that is particularly true of institutional ratepayers such as schools.

1.3 *Summary of Submissions*

1.3.1 ***Assignment of Risk and Responsibility.*** The main issue in revenue decoupling is the policy issue of assigning specific risks either to the utility (i.e. the shareholder) or the ratepayers. In part this is about who can most easily bear those risks, but it is also about the responsibilities of utility management, and how risk assignment affects their management focus.

1.3.2 In our submissions we review the various volume-related risks, and conclude that:

(a) It would be beneficial to ensure utilities are protected from revenue attrition from their own conservation programs, the program-induced conservation generated by others, and natural conservation including that arising from price elasticity.

(b) It would also be beneficial to re-assign weather risk from the utilities to the ratepayers, as long as the method of collection limits bill impact volatility.

(c) Utilities should not be protected from revenue impacts of economic cycles or customer growth/decline, except through their periodic rebasing applications. Central to the role of utility management is to operate their companies as commercial businesses, which involves planning for, and responding to, economic impacts both at the general level and locally.

1.3.3 For each of these risk re-assignments, we believe that there are adjustments to other ratemaking factors that may be required, such as ROE and IRM X factor.

1.3.4 On the other hand, if the Board can re-assign these risks in an effective way, the primary effect should be to free up utility management to increase their focus on operational excellence, and reduce the amount of time, effort and resources expended on less productive activities, including regulatory compliance**.**

1.3.5 ***LRAM.*** We believe that LRAMs have played a useful role over the last decades in Ontario, but they are no longer adding value to the system. Not only is their scope too narrow, but the time and effort expended to get to the LRAM numbers is wasteful, and the results are in any case doubtful at best.

1.3.6 ***SFV Pricing.*** Ontario already has some SFV pricing, because we have such high fixed monthly charges. To go further is not warranted, and in fact a reduction in the fixed component of rates would send a stronger conservation signal.

1.3.7 SFV pricing in its pure form is unfair to lower volume customers, and unfair to customers at the margin of a rate class. This specifically includes schools.

1.3.8 Underneath that conclusion is a more fundamental one, i.e. SFV pricing is a rejection of cost causality as the basis for ratemaking. Injection of cost causality back into the equation would require many more rate classes, and those would be based on some variation of demand or another volume measure. The increasing problem of class migration that would be created would more than offset any benefit achieved.

1.3.9 To really implement SFV pricing in Ontario, without producing a system rife with unfairness, would require a complete rethinking of the basis of rate classification and rate design. Once a few years of smart meter data is available, that is probably possible to achieve, but it would still be a major undertaking.

1.3.10 ***True-Up Methods.*** A decoupling true-up has many advantages in Ontario, particularly given our already extensive use of deferral and various accounts to manage and re-assign risks, and our strong experience with various methods of IRM. With that solid foundation, a true-up represents a conceptually sound approach that shifts risks in a simple and understandable way, with low regulatory churn in the process.

1.3.11 True-up mechanisms do come with their share of problems, which increase as the plan covers a more comprehensive set of risks. One major concern, for example, is that in protecting utility revenues, we do not create cost volatility amongst customers. Another concern is the muting of the conservation signal that might arise, particularly in smaller utilities where the same customers that implement conservation measures would be bearing the cost of the resulting revenue losses. .

1.3.12 ***A Rolling, Pooled True-Up System.*** While it is too early in the process to suggest a conclusion, we have suggested that Staff consider in their upcoming discussion paper a true-up mechanism for electricity distributors in which the revenue variances of all distributors for a given class are accumulated each year in a common, province-wide pool, and a single common charge to recover the net is paid by all customers in that class throughout the province. This has the effect of socializing the cost of conservation revenue loss province-wide, much like the cost of renewable energy system changes.

1.3.13 Further, under our suggestion the recovery would be on a five year rolling average basis. The effect of this, plus the previous factor, should be to drastically reduce the volatility of the adjustment for ratepayers without in any way reducing the revenue and volatility protection for utilities.

1.3.14 We also note that a pooled true-up may create less accounting problems for utilities under International Financial Reporting Standards. A standard true-up, which relies on deferral and variance accounts, may be more problematic than an external pool against which the utility has a receivable or a payable.

1.3.15 ***Ratepayer Protection.*** The shifting of risks from the utility to the ratepayers implies a reduction in the appropriate ROE, and we are not in a position to suggest the quantum of that reduction on the information available. The removal of revenue attrition from the major sources could mean that the X factor for IRM should be altered, and in addition there is probably further scope to increase the stretch factor due to the greater stability of utility revenues over longer periods.

1.3.16 ***Mandatory vs. Voluntary.*** Because the implementation of comprehensive decoupling would involve both costs and benefits to utilities, we propose that the new system when finalized be made the default, but with utilities having the option to opt out with with Board's consent. Not only does this provide the utilities with a choice, but it may assist the Board in identifying when the ROE and X factor adjustments are too high, too low, or just right relative to the value of the re-assigned risk to the utilities.

2 FUNDAMENTAL POLICY ISSUE – ALLOCATION OF RISK

2.1 *Issue of Risk and Responsibility*

2.1.1 ***Nature of the Issue.*** The current regulatory compact under which distribution rates are set implicitly assigns risks as between the distributors (i.e. their shareholders) and the ratepayers. This is done in part by the way revenue is collected, with a substantial component based on volumes, and in part by express adjustment mechanisms such as deferral and variance accounts, forward test year rate-setting, and other means. In our view, revenue decoupling is first and foremost about deciding which of those risks, if any, should be re-assigned, and on what terms.

2.1.2 As the PEG Report correctly points out, there is already a substantial amount of decoupling in Ontario, perhaps 30-50%, just due to the relatively high fixed monthly charges that are imposed on Ontario ratepayers in both electricity and gas. While these charges are not uniform, particularly in electricity distribution, for many distributors volume adjustments are less of a problem due to the fixed monthly revenues.

2.1.3 Of course, on the other side the use of high fixed charges means that as customers reduce their usage, their average unit price increases. This undermines some of their motivation to implement aggressive conservation, but that effect is muted because distribution charges are a minority of the bill. Conservation signals are already strong through the commodity cost. While maximizing the bill savings for a customer implementing conservation measures is undoubtedly important, it does not have to be achieved at the expense of other policy imperatives.

2.1.4 The use of deferral and variance accounts, particularly in gas distribution, is also a significant feature reducing risks for the utilities.

2.1.5 Despite the factors already minimizing risks, it is still fair to say that Ontario distributors have significant volume risk from various sources, including both risks of volume volatility, and risks of generally downward trends. However, we note that those risks are in all cases short term risks. Because distributors have periodic cost of service proceedings, in which actual volumes are forecast for a test year, ultimately the cost of attrition is borne by the ratepayers. It is only the attrition, and the volatility, between cost of service rebasings, that is a risk for the utility.

2.1.6 Given these facts, we believe it is useful to identify the main volume-related risks that are currently borne by either the distributors or the ratepayers, and determine whether any of those risks should be re-assigned.

2.1.7 ***Connection of Risk and Responsibility.*** Part of assigning risks is sending the appropriate message to management of the distributor. People will naturally try to produce the result that they believe is good for them.

2.1.8 In the simplest case, if you ask distributors to promote conservation, and then allow attrition of their revenues unchecked by any protective mechanisms, it is not reasonable to expect the distributors to be whole-hearted in their conservation programs. Utility managers, like other individuals in Ontario today, will want to achieve social goals such as conservation. They have the same altruistic motivations in that regard as any of the rest of us, plus the ability to achieve a beneficial result. But also like anyone else, they will resist those same goals if we make them personally costly. In short, if you are going to punish anything, it should be failure, not success.

2.1.9 The other side of this is that risk assignment can only influence behaviour if utility management has some ability to respond to the risk. Identifying the ways in which distributors can and will respond to a particular risk, and how they will respond differently if they no longer bear that risk, is an important part of the risk allocation exercise.

2.1.10 At a more general level, selection of the risks that are assigned to the utility (and hence effectively to management) is in essence a decision about what the Board, as regulator, wants management's focus to be. As we will note in more detail below, utility managers may respond to some risks by operational or strategic excellence, while they may respond to other risks by concentrating on regulatory issues. Incenting them to focus on the former issues more than the latter is generally in the public interest.

2.1.11 ***Other Implications.*** As risks are shifted from the utility to the ratepayers, several other factors have to be considered. The one that is most discussed is cost of capital, and in particular equity thickness and ROE. Clearly those items are set to compensate for a given risk, and if that risk is reduced the cost of capital should go down.

2.1.12 However, there are other important implications that cannot be ignored. One good example of this is the pattern of costs that arises out of management mitigation efforts.

2.1.13 When revenues are down, management of utilities will generally try to put a tighter lid on costs as a response to the lower revenues. This, commonly called "mitigation", often leads to higher budgets in a subsequent cost of service year as work that was deferred still has to be done. In most cases not all of the mitigated costs are ultimately recovered from ratepayers, so revenue volatility may in some cases lead to an overall reduction in utility costs.

2.1.14 In general, it is our view that whether mitigation should be encouraged may depend on the reason for the revenue decline. Mitigation in a bad weather year generally seems to us to be counterproductive, assuming that weather impacts will average themselves out over time. The effect of this type of mitigation is to reduce costs in the bad weather year, without a symmetrical increase in costs in the good weather year. In the latter year, the primary impact is that profits are increased. Thus, mitigation due to weather may be counterproductive. Our experience with Ontario utilities, particularly the gas utilities, is that weather generally results in a long-term average ROE exceeding the Board approved level.

2.1.15 On the other hand, if the economy is going through a down cycle, and utility management responds by belt-tightening, this should in our view be encouraged. This is especially true of electricity distributors, for whom a response mirroring that of the other businesses in their local communities makes common sense. Since the ups and downs of the economy are not viewed as random (as with weather), we generally see that as the economy recovers utility spending recovers with it.

2.1.16 Another implication of risk assignment is the impact on regulatory costs and activity, including the reduction of "regulatory churn". Certain types of risks, of which weather is the most obvious, produce a high level of regulatory activity due to the combination of their contentious nature and complexity. A revenue decoupling solution to those risks could reduce regulatory costs, which is in the long term a benefit to the ratepayers.

2.1.17 In our submissions on the specific decoupling options, we will suggest specific responses to these other implications that should be considered.

2.2 *Specific Risks*

2.2.1 ***General.*** There are generally three categories of volume-related risks applicable to electricity and gas distributors:

(a) Conservation;

(b) Weather;

(c) Economy.

2.2.2 For the purposes of this analysis, we have further subdivided the conservation component into a utility's own programs, programs from other players in the marketplace, and natural conservation. We have also added an additional "volume" risk, demographics, which may be a result of economic factors, or may be separate, but still has to be considered.

2.2.3 ***Utility DSM/CDM Programs.*** It seems generally agreed that, if a utility-sponsored DSM or CDM program results in reduced volumes for that utility, those lost revenues should be recovered by some means. Typically in Ontario we have used a lost revenue adjustment mechanism (LRAM), although in the longer term it is the periodic rebasing applications that permanently assign the cost of those reduced volumes to the ratepayers. As the PEG Report points out, the existence of an SSM for most utilities also overcomes the negative incentive associated with lost revenues from utility conservation programs

2.2.4 We agree that risks associated with this component of attrition should be borne, both immediately and in the long term, by the ratepayers. As noted earlier, the last thing we want to do is punish conservation success.

2.2.5 The argument has been made by some that promoting conservation is an obligation imposed on the distributors by government policy, and therefore mechanisms such as an LRAM should not be necessary. Just as safety imposes costs on the utility, so does conservation, and they are just normal costs of doing business.

2.2.6 While we would agree that the obligation – a condition of being granted a public monopoly – is an important consideration, we think that is more relevant to the SSM than to LRAM. The case can legitimately be made that a positive incentive to do what you are obliged to do anyway is wasted funds. But, as we have said more than once, it is not so easy to make the case that we should allow the revenues of the utility to be eroded by their conservation success. This is especially true since the erosion is only temporary, with the ratepayers picking up the longer term costs 1-3 years later on rebasing. If it is right that the ratepayers pay long term, why would that not start immediately?

2.2.7 As we note later, the other problem with this risk is that it is tied to causation. The identification of the causal connection between utility activities and revenue loss has resulted in substantial regulatory costs. If this risk can be assigned to ratepayers without having to go through this causation exercise, that would be a substantial improvement.

2.2.8 ***Other Sources of Program-Related DSM/CDM.*** There is less consensus on whether distributors should be protected from revenue loss from government, OPA, and other conservation programs. In our view, they should be protected, for the same reason as justifies their existing LRAMs: sending the right signal to utility management.

2.2.9 The general thinking is that utilities are essentially passive when it comes to external impacts, including programs from others. As the PEG Report correctly points out, this is not true. Where utilities are being hurt by conservation programs, they will resist, whether in their dealings with government, their co-operation with OPA and others, or their dealings with their own customers. Instead of being a positive influence supporting those programs, they can represent a drag on public acceptance and political support for those programs.

2.2.10 As with their own programs, their natural inclination will be to support them, because they see – often better than those outside of the industry – the long term benefit to society that can be achieved. But, like their own programs, we can't expect them to be whole-hearted supporters if they are experiencing negative effects of the programs' success.

2.2.11 In addition, broadening the scope of the risk protection for conservation programs to include all such programs would reduce the regulatory time and effort involved in the causation question. Issues such as attribution are removed if revenue losses from all program-driven conservation programs are recoverable.

2.2.12 ***Natural Conservation including Price Elasticity.*** One more step removed from utility control is the natural conservation that arises because of changing public opinion, and because of the effect of higher prices.

2.2.13 There are many ways that a utility can directly or indirectly influence natural conservation. We saw such a reaction by gas utilities when, while their DSM groups were pushing out programs, senior management was still fixated on increasing throughput to increase profits. As long as volumes are the primary driver of profits in distributors, this will be the case, so utility management's focus will not be aligned to conservation.

2.2.14 In our view, as with program-driven conservation, utility revenues should be protected from erosion based on natural conservation. As a general principle, conservation of all types should not be a negative for utilities. If it is, they will resist as best they can. If it isn't, we would expect them to be strong supporters of the full range of conservation options.

2.2.15 ***Weather.*** Once we turn outside of conservation, the protection of utilities from other types of revenue attrition is undoubtedly more controversial. Weather is perhaps the biggest example of this, particularly with gas distributors.

2.2.16 There would appear to us to be three main components of this issue.

2.2.17 First, the issue with weather is primarily revenue volatility. At least in theory, it should be possible to forecast weather on a long term basis sufficiently well to prevent any permanent impact on either utility or ratepayers.

2.2.18 Of course, the simplest solution to volatility is averaging. Much of utility operations is based on averaging, since most spending is not identical year after year. Many aspects of utility operations go in cycles, and the regulatory process attempts to ensure that over a period of years the average amounts are collected from ratepayers in rates.

2.2.19 Second, volatility includes responses, and in the case of weather that can result in the impact on utility profits not tracking the impact on utility revenues. As we have noted elsewhere in these Submissions, in our experience gas distributors have experienced average returns in excess of the Board-approved levels in part because they cut back on expenses in warm weather years, but don't add back to expenses the same amount in cold weather years. Expense increases have been driven by the regulatory cycle for the most part, not the weather. The effect of this asymmetry is that shareholder returns are at approved levels (or slightly below) during warm weather years, but are well above approved levels during cold weather years. Average returns have consistently exceeded approved levels over the last twenty or more years.

2.2.20 We would anticipate that, as electricity distributors develop the same level of regulatory and operational sophistication as the gas distributors, weather volatility could prove to be an ROE-enhancer for them as well.

2.2.21 If there is any upward pressure on experienced ROE as a result of weather volatility, ratepayers would be better off with some sort of true-up mechanism, as long as the volatility can be smoothed from a rate point of view. A true-up would stabilize utility revenues and reduce the need to mitigate expenses.

2.2.22 Third, weather forecasting and normalization has been the source of a great deal of regulatory activity, and that is not likely to reduce over time. While there is currently a lull in this activity due to the IRM periods of the gas distributors, that will come to an end soon. There is little doubt that weather with be a key issue in the next gas rebasing (particularly given the higher non-normalized returns of the distributors than normalized returns). Of more concern, weather has not yet been seriously engaged on the electricity side. It certainly will start to be an issue, with multiple weather forecasting systems currently in use by electricity distributors.

2.2.23 What is striking is that weather forecasting and normalization is simply a way of melding the forward test year concept with averaging of weather impacts over time. The goal is to ensure that the overall actual volumes of the distributor match the forecast volumes over the long term.

2.2.24 We thus conclude that, with the appropriate structure and adjustments, it may be in the best interests of all parties to shift the weather risk from the utility to the ratepayers, accomplishing the same averaging over the years, but more reliably.

2.2.25 ***Economy.*** There is an argument to be made that the risks of economic ups and downs are really no different from weather, and so utility revenues should be protected from those variations as well. We do not agree.

2.2.26 The fundamental shift in our electricity sector more than ten years ago was to require the government-owned component of the sector to operate like commercial businesses. Prior to that, for the most part they operated like government departments, which is an entirely different mindset. Sector restructuring – whether you love it or hate it – forced that to change. In the longer term, one would expect the electricity distributors to have approaches to their business much like the gas distributors, who already operate like commercial businesses.

2.2.27 Central to the idea of being a commercial business is that your management decisions reflect how your economic activity fits into the broader activity of all other businesses you deal with. If the economy is soft, you would be expected to respond, as other businesses do, by belt-tightening and other proactive measures. If the economy is strong, you would be expected to respond with new initiatives that expand or improve your business.

2.2.28 In our view, if the commercial paradigm has value, part of that value is the ability of utility operations to adjust to the ongoing economic reality. That reality promotes operational and fiscal discipline, and has utility management thinking in the same terms as their business customers.

2.2.29 There is nothing wrong with being a government department, and operating your enterprise based on public need and long-term, stable budgets. Schools do it. Utilities could too, and in fact did at one time. However, in our view this would involve a radical shift in the policy imperative under which utilities operate. That change, it is submitted, is one that the government should make, not this Board. The government mandated a change to a commercial model, and until it changes that policy, the Board should support that commercial model.

2.2.30 For this reason, we believe that the risk of changes in the economy should not be re-assigned, but should remain the responsibility of utility management to manage.

2.2.31 ***Demographics.*** We have included the risk of changing demographics for completeness. Especially in the electricity sector, a major source of changes to revenues, including sometimes attrition, is the changes in the demographics of the utility's service area. In our view, this risk should remain with the utility.

2.2.32 The rationale here is much the same as changes in the economy, but perhaps the connection with utility management decisions is even stronger. One of the most important roles of utility management is to anticipate how their service area will grow and change, and build an appropriate infrastructure to serve it. Anything that weakens that responsibility would, in our view, be counter-productive.

2.2.33 ***Other Volume Risks.*** There are, of course, other factors that can influence distribution throughput, such as availability of supply, force majeure, etc. None of these other factors appear to be ones that warrant a general decoupling rule, so we have not considered them in these comments.

3 DECOUPLING METHODS

3.1 *General Comments*

3.1.1 The PEG Report provides a good overview of the options available to the Board in revenue decoupling. What is most striking, it appears to us, is two things:

(a) The extent to which the solution for any given jurisdiction is specific to the needs and particular distribution sector in that jurisdiction; and

(b) The number of times that regulators have tried one technique, then rejected it in favour of another.

3.1.2 In our view, it is critical that the Board adopt a decoupling solution in Ontario that reflects the ways in which Ontario is different from other jurisdictions, such as:

(a) Ontario has adopted a very aggressive conservation and renewable energy agenda, showing leadership on many aspects of that endeavour.

(b) The large number of electricity distributors of varying sizes and approaches to the business means that conservation and other impacts on the sector may continue to vary widely from one location within the province to the next.

(c) Ontario is more vulnerable than some other jurisdictions to the economic impacts of energy pricing, so rate design changes that hurt particular customer groups could have a material effect on the economy.

(d) The Board has been a leader in introducing IRM regulation in both gas and electricity, developing an expertise that can be built on in decoupling.

(e) Ontario's gas distributors have used LRAM for many years, and so the Board has considerable experience with that model.

(f) Monthly fixed charges in both gas and electricity are already high relative to other jurisdictions.

3.1.3 Based on our review below, we have reached the preliminary conclusion, subject to considering the analysis in the Staff discussion paper, that a variation on the true-up approach is a solution worth considering for Ontario decoupling.

3.1.4 As we have noted above, we propose that distributors be protected from all conservation impacts on revenue, and from weather effects, but that they retain the responsibility to manage the effects of changes in the economy and changes in their local demographics. Our analysis of the decoupling choices reflects that conclusion.

3.2 *LRAM (Bottom Up) Approaches*

3.2.1 We are not big fans of the LRAM, for three reasons.

3.2.2 First, the LRAM is a resource-intensive method of protecting utilities from revenue erosion, in which there are often substantial debates over who has caused what, and whether the "assumptions" forming the foundation of the calculation are reasonable ones. The expenditure of those resources might be useful if they produced reliable and valuable information, but it appears what they produce is conflict between utilities and their ratepayers.

3.2.3 Second, even after the LRAM is finalized there is a lingering doubt about whether the results are even close to being correct. In the end, there is no empirical evidence available to show that the LRAM results are reasonable, and the recent report by PEG on measurement of DSM impacts (filed in EB-2008-0346) suggests that no such evidence may even be possible in the near term. Indeed, one way of looking at that PEG DSM measurement report is that there may actually be no material impact on consumption from DSM programs. While that radical inference from the PEG data still needs further review, many stakeholders believe, as we do, that LRAM calculations are at best of doubtful validity, and at worst just wrong.

3.2.4 Third, LRAM is specifically designed to recover revenues lost to a utility's program-driven conservation. As you get further from a direct cause and effect, LRAM is less and less suitable. Since we believe that decoupling should not be limited to utility-run programs, LRAM is unlikely to be a suitable decoupling choice.

3.2.5 For these reasons, we believe that LRAM has run its course in Ontario. Although the sector and the Board have undoubtedly learned from it, in our submission it does not deliver the sort of solution that Ontario needs today. We note that while LRAMs are still in use in a number of jurisdictions, as the PEG Report makes clear they are not the decoupling method of choice in most places that have reviewed this issue comprehensively.

3.3 *Straight Fixed Variable Pricing*

3.3.1 There are a number of jurisdictions experimenting with SFV pricing, in which the revenue mix between customer-driven and volume-driven revenues is skewed more in favour of the former. In fact, as the PEG Report notes, Ontario with its high fixed charges already has some of the impact of SFV pricing.

3.3.2 In our view, SFV pricing is not appropriate for Ontario, because it is unfair to lower volume ratepayers and those at the margin, because it mutes the conservation price signal, and because it rejects the cost causality basis on which rates have traditionally been set.

3.3.3 The last point in the most important, and subsumes the other two. Because SFV pricing structures rates not to cover costs caused, but to produce a revenue result, the Board in implementing any form of SFV would have to rethink the very structure of rates for both electricity and gas distribution. In this rethinking, it will not have the cost causality principle to fall back on to the same extent.

3.3.4 An example of this problem is customer classifications. The current small number of classes for electricity distribution has the advantage of simplicity, but makes broad and often incorrect assumptions about cost causality within the class. A school with 100 KW of typical monthly demand causes costs on the system that bear no relationship to the costs caused by a factory with 3 MW of typical monthly demand. They can be placed in the same class only if the adjustments to cost causality within the class can be accomplished through rate design. Imperfect though it is, the use of a fixed charge plus a demand variable reflects different cost causality within the class. If all had the same fixed charge, the school would pay far too much, and the factory would pay far too little.

3.3.5 A similar effect occurs if you look at residential neighbourhoods. At one extreme, you have a neighbourhood of large houses set well back on large lots, each with 200 amp. service or more. At the other extreme, you have a neighbourhood of semi-detached or row houses on small lots with 60 amp or 120 amp service. In the former case, for a given geographic area the utility serves 200 residential customers, while in the latter case for the same geographic area the utility serves 1000 residential customers. Their cost to serve those customers is not five times the cost to serve the first group, yet under SFV pricing the revenues would reflect a 5X differential.

3.3.6 To avoid either the GS>50 problem, or the residential problem, it is possible to establish many more classes, so that cost causality is tracked more through rate classification than today, and less through rate design. This is a substantial exercise, and one that does not appear to us to be justified by the potential benefits of SFV pricing.

3.3.7 Further, adding many more classes does not, in our view, reduce the problem of revenue attrition. Since classes would presumably be still based on demand or other volumetric measures, it simply replaces variability within the class with more class migration. The problem of decreasing volumes still affects revenues, but an additional administrative cost is added. Further, the number of customers erroneously left in more expensive classes after volume changes would increase, leading to additional customer complaints.

3.3.8 We also note that the price signal being given to customers is not neutral, but in fact counter-intuitive. If a customer is at the margin in a rate class, SFV pricing gives a strong price signal to conserve, so that the customer can migrate downward to a lower cost class. Once a customer is out of range of possible migration, however, the price signal is that additional usage is, from a distribution point of view, free, and conservation saves nothing in distribution costs.

3.3.9 Of course, SFV pricing does not need to be absolute. As noted above, we already have a moderate SFV effect in Ontario due to our high fixed charges. It is also possible to implement a variation on SFV that includes high fixed charges, and attempts to adjust for cost causality unfairness at the margin through volume-based adjustments. The latter are not popular in practice, but they have been tried on occasion.

3.3.10 In our view, full SFV pricing coupled with "back-door" adjustments to reflect cost differentials is just an indirect way of getting to the balanced revenues we have in Ontario today. It would be better to achieve that in a direct way, but that would imply no material change in our current structure.

3.3.11 Partial SFV pricing also seems to us to be inappropriate. We already have a form of this today, but it is at least in theory based on cost causality. The implementation of higher fixed charges to extend the SFV impact could be done, but the Board would have to determine on what basis it should assess the change required. The Board has no data on what impact any given change in the fixed/variable split would have on the utilities, nor does it have data on cost causality impacts of such a change. It would be just guessing on all counts. The only fact it would know for sure is that it was moving away from a structure that it believed was good ratemaking, and the direction was toward less reliance on classic ratemaking principles. This does not appear to be a good policy approach.

3.3.12 Finally, on this point, we note that within the next two or three years the Board will have available to it a significant body of data provided by smart meters. That body of data may allow for a fundamental restructuring of rate classes, rate design, and perhaps even cost allocation based on real information. A restructuring at that time could seek to balance the goals of making utility revenues more reliable, enhancing the conservation signal, and maintaining fairness as between customers and customer groups.

3.3.13 We note that a change in rate design, with a strong empirical foundation, can co-exist with a true-up system. SFV pricing today, on the other hand, could not achieve an appropriate balancing of interests.

3.4 ***True-Up Methods***

3.4.1 The other decoupling method employed by regulators in North America and elsewhere is true-up, in which variances from the volumes on which revenue requirement is based are recovered from, or paid to, the ratepayers in a subsequent period.

3.4.2 The true-up approach has a couple of key advantages in Ontario:

(a) ***D/V Account Experience.*** The Board has in the past used deferral and variance accounts quite extensively, and with increasing sophistication, to deal with the assignment of risks between utility and ratepayers. The commodity accounts in both gas and electricity are a good example of this. A true-up system is essentially the use of deferral and variance accounts to re-assign volume risk.

(b) ***IRM Experience.*** In addition, most true-up mechanisms in other jurisdictions have foundered, not on the true-up, but on the revenue adjustment mechanism (RAM) in between rebasing years. The Board has already spent considerable time and effort thinking about RAM options, and has four different revenue adjustment mechanisms (2^{nd} GIRM, 3^{rd} GIRM, Union, and Enbridge) currently in place providing real life information on what works and what doesn't work.

3.4.3 A true-up also allows for substantial flexibility, whether in terms of timing of collection, class differences, conservation signals, and other aspects of its design.

3.4.4 We prefer the true-up approach because it is a conceptually sound and well-understood approach to increasing the reliability of utility revenue. Applying this method to new risks – conservation and weather – is also a simpler, more manageable approach than a complete rethinking of how rates are delineated, or a bottom-up calculation of the revenue impacts of particular causes.

3.4.5 We do see three key problems with the true-up approach:

(a) ***Rate Volatility.*** Unless the collection of trued-up amounts is over a relatively long period of time, the true-up simply shifts the problem from revenue volatility suffered by the utility to expense volatility suffered by the ratepayer. While it is true that some ratepayers are relatively indifferent to volatility, most are not. This issue has to be addressed in the design of any true-up mechanism.

(b) ***Conservation Signal.*** Given the number of smaller utilities in Ontario, truing up revenues on a local scale means, in the case of conservation, that communities that adopt conservation more aggressively pay the cost of that lost revenue themselves, thus reducing their incentive to show leadership. This is less true in utilities with broader service areas, because in those areas there will likely be pockets of conservation intensity, with the remainder less so. In those utilities, the revenue losses caused by the conservation leaders are borne by a broader group of customers. The leaders win more, and the laggards lose more.

(c) ***IFRS.*** The Board has just gone through a substantial review of the impacts of IFRS on utility regulation, and one key impact is the potential that deferral and variance accounts will be less effective or cause more accounting problems. A true-up covering both conservation and weather would be substantial, and so the extent to which IFRS restricts its use has to be considered in its design.

3.4.6 Despite these issues, in our view the true-up approach shows the most promise as a decoupling solution in Ontario. In the next section, we explore a modified approach to true-up that may limit the negative impacts of the issues we have raised.

3.4.7 One component of true-up design that needs to be considered in any case is how it is divided between groups of ratepayers.

3.4.8 It is clear that, the broader the range of risks being re-assigned using true-up, the more likely it is that revenue variations will be different for different customer groups. In the simplest case, different customer groups have different levels of weather sensitivity. As well, different customer groups engage in different levels of conservation of all types. Lumping customer classes together for true-up purposes seems to us to create a likelihood of unfairness, and thus we believe that the optimum approach is a true-up by customer class.

3.4.9 We also note that for some classes true-up may be less appropriate. For example, large industrial customers are not materially affected in their energy use by the weather, and their conservation activities may be easier to pick up in forecasting. It thus may be less necessary to true-up revenues for the large user classes in electricity or natural gas than it would be for smaller general service customers.

3.5 ***Additional Alternative – Rolling, Pooled True-Up***

3.5.1 We believe that Staff, in preparing its discussion paper, should give consideration, at least for electricity distribution, to a more comprehensive approach to true-up, with two key components. First, true-ups would be on a rolling, five year term, so that expense volatility for ratepayers is minimized. Second, revenue differentials would be pooled between all electricity distributors using a common pooling fund.

3.5.2 Our proposal for consideration has the following components:

(a) ***Industry-Wide Pooling Accounts.*** The Board would require the establishment, either by the industry or by the Board on the industry's behalf, of province-wide true-up pooling accounts for each rate class.

(b) ***Utility True-Up Receivables and Payables.*** As each distributor experiences its actual results for a given year, it compares its volumes for each class to the volumes on which rates were set, adjusted for economic factors. The difference, translated into revenues for the year, would be either payable to, or receivable from, the

common, industry-wide pooling account for that class. For example, if Utility A had residential rates set on the basis of 10,000 Mwhrs and experienced 9.5 Mwhrs (adjusted to reflect a GDP forecast variance), it needs a true-up for that attrition. The attrition would be calculated as the 500 Mwhrs of lost volumes times the average province-wide distribution volume rate for that class, and would become a receivable from the industry-wide pooling account. As it was collected over the subsequent period, it would be paid to the utility.

(c) ***Five Year Rolling Rate Riders by Class.*** The assets and liabilities of the pooling account for each class would be aggregated for the year from all electricity distributors, and recovered over five years on the basis of a volumetric unit cost for that class (volumetric rates being the standard collection approach for true-ups). In effect, it would be a rate rider that is common across all utilities. Because the true-up would take place each year, the rate rider at any given point in time would be made up of the Ontario-wide true-ups for each of the previous five years.

3.5.3 Based on our preliminary analysis, a true-up system such as this could have all or some of the following advantages:

(a) ***Conservation Cost Socialized.*** Just as the incremental cost of renewable energy on the distribution system is mainly being socialized, this approach would socialize a large part of the cost of conservation. This may be an appropriate policy result.

(b) ***Conservation Signal.*** Early and/or more aggressive adopters of conservation measures would have less of the benefit of that choice clawed back in higher unit prices. All customers would pay the same unit cost for conservation revenue loss, but those who implemented more conservation measures would be insulated more from that cost. In this respect, conservation revenue loss for electricity ratepayers would be much like conservation program costs are today for gas ratepayers. In gas, all ratepayers of a class, across a broad geographic area, pay the same unit price to cover the utility's conservation program costs. That is harder to implement for electricity, since the conservation effects for a small utility are a direct feedback into the rates of the same small group of customers. Pooling solves this.

(c) ***Conservation Competition.*** If utilities are not required to bear the main cost of conservation – revenue attrition – locally, this may encourage them to be more aggressive in their conservation programs to compete with each other for CDM success.

(d) ***Weather Averaging.*** This approach averages the impacts of weather over five years, which itself reduces volatility. As well, Ontario is a large and diverse geographic area. By pooling the revenue true-up, weather differences in different parts of the province have an offsetting effect. While for the most part a cold year will mean most parts of the province are colder than normal, and vice versa, it is likely that the level of overall provincial weather volatility year to year is less than

the annual volatility in smaller individual regions.

(e) ***Utility Management Focus.*** The main benefit of true-up approaches is to direct management attention more towards operational excellence and less towards regulatory or other activities. A pooled, rolling true-up that removes both conservation revenue attrition and weather volatility creates much more stable operating budgets for distributors. This allows management to develop their operating and capital plans more strategically, and thus could improve the operational focus of management.

(f) ***IFRS.*** Because the utility asset or liability would be a receivable or payable from a common external fund, the financial statement recognition of the asset or liability is less likely to be affected by IFRS changes.

(g) ***Bill Impacts***. The longer recovery/payment period that produces a rolling average effect, and the pooling across different distributors, both create a situation in which impacts on customer bills will be less volatile, and more predictable for the customers, than would be the case if the recovery period were a shorter term or the geographic area covered were more narrow.

(h) ***Local Economic Impacts***. One of the results of pooling may be that local impacts of conservation and/or weather are muted. For some towns whose local economies are unusually sensitive to energy price changes, this could be a further benefit.

3.5.4 SEC has not in this process done a sufficient review of this option to be confident that it is the optimum choice. Instead, it is proposing the option in these Submissions in the hopes that Staff, in its analysis, will consider this approach and these factors more completely and provide comments on its viability.

3.5.5 We note that while this approach appears to have some potential for electricity distributors, it is less apparent that it would have value for the two large gas distributors.

3.6 ***<u>Adjustments to Other Regulatory Components</u>***

3.6.1 ***Cost of Capital.*** In these Submissions we are proposing a major change in the business risk of Ontario distribution companies. It is likely that means the appropriate level of return on equity for those distribution companies should be reduced to reflect the reduced level of risk.

3.6.2 In the PEG Report Dr. Lowry notes that many regulators that have implemented decoupling have also reduced ROE, on average 15 basis points (page 17). On the other hand, PEG provides an example of the problem of attrition (page 13) showing that effective ROE is much less than real ROE without decoupling protection, in the example 267 basis points. While that number is not necessarily indicative, the math used shows that without decoupling the difference between effective ROE and forecast ROE is likely to be much more than 15 basis points.

3.6.3 In our view, Staff should get further information on those reductions, and review the decisions and the evidence considered in those cases.

3.6.4 Without seeing that detailed evidence, it is impossible to assess the appropriate level of ROE reduction for a decoupling as extensive as the one we propose in these Submissions. We would assume that it would be something more than 15 basis points, perhaps in the range of 100 to 200 basis points. This requires more analysis.

3.6.5 We note that the lower risk profile should also reduce the cost of debt. For most utilities, this should be reflected in the market interest rates they are paying. However, for those whose interest expense is based on a deemed rate, in our view some reduction appears to be appropriate.

3.6.6 ***IRM Framework including Calculation of X Factor.*** PEG also notes the fact that in an IRM period customer growth can improve earnings, but that it may only be offsetting attrition if there is no decoupling.

3.6.7 In our view, the converse is also true. If a decoupling solution that covers the main volume risks, conservation and weather, is implemented, then customer growth will tend to improve earnings above the allowed rate of return. This may be the reason why the net X factor in the two gas IRM models, which have a form of decoupling, is much higher than the electricity X factor, yet the gas utilities are still experiencing strong earnings levels during this IRM.

3.6.8 There does not appear to us to be an obvious answer as to what adjustment is appropriate to compensate for the effect of a true-up on the IRM structure. However, this issue should be accessible using econometric techniques. Before designing a decoupling solution, we believe that Staff should expand their 3rd G IRM and Gas IRM work to encompass this additional factor.

3.6.9 We note that many U.S. utilities with decoupling have as their IRM model some form of revenue per customer or revenue cap freeze.

3.6.10 Another potential impact of decoupling on IRM may be the ability to increase the stretch factor. Utility management, with much more stable revenue streams, should be in a position to convert that higher certainty into more cost and better efficiency initiatives. This may be particularly affected by the shift of weather risk, since the lower revenue volatility that results means operational spending can be planned more reliably, on a multi-year basis.

3.6.11 In the case of both of these effects, they are more likely to be true if conservation spending is outside of the IRM framework. If decoupling, coupled with increasingly pointed government policies, has the effect of increasing utility CDM activities, that should be a key growth area of utility operations, and the indexing of costs for other activities may in fact be lowered.

3.7 *Mandatory vs. Voluntary*

3.7.1 In much of the discussion to date there appears to be an assumption implicit in the statements of many that any decoupling mechanism will become the new regulatory standard, applied to all. It is not clear to us that mandatory imposition of a new system is required. In fact, there may be some advantages to making the decoupling mechanism voluntary, or at least the default coupled with opting out by utilities who wish to do so and are able to obtain the Board's consent.

3.7.2 Any new mechanism for decoupling will include benefits and costs to each individual utility. Risks will be reduced, and revenues will have higher certainty, but those benefits will be offset by costs. For example, the X factor may be reduced, or ROE may be lower. Utilities may understand that their annual spending will be expected to have increased stability, in keeping with their more stable revenues.

3.7.3 In our view consideration should be given to allowing individual utilities to decide that the lost ROE or indexing factor is too high relative to the benefits, and they would prefer to keep the conservation and weather risks, and manage within them, rather than to pay a price for offloading them. In general, we have no problem with utilities making this choice.

3.7.4 An additional advantage to allowing utilities the choice is that the fairness of the costs – principally ROE and X factor – will be readily apparent from the number of utilities opting for the status quo. If everyone wants the new system, it may be that the ROE and X factor adjustments are too low. On the other hand, if many utilities want the status quo, it may be that those adjustments are too high. In the long term we would expect that a fair system attracts most utilities, but a few with special situations would opt out in any given period.

3.7.5 The reason we have suggested Board consent to opting out is the government's upcoming conservation targets for utilities. Government policy will require each LDC to make a serious effort to pursue conservation. Some utilities may want to opt out of decoupling because they are not planning to pursue conservation vigorously, so don't face as big an attrition problem as most of their peers. The Board's consent to opting out would likely prevent this in most cases.

3.7.6 For these reasons, we propose that the decoupling mechanism the Board lands on should be the default for all distributors, with the right to opt out upon demonstrating to the Board that it is in the public interest for them to do so.

4 ANSWERS TO THE BOARD'S QUESTIONS

4.1 *Should Decoupling be Implemented?*

4.1.1 ***Question 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 distributed 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?***

4.1.2 We do not believe that the LRAM is sufficiently comprehensive to provide meaningful decoupling, and it is too resource intensive to be efficient.

4.1.3 As we have discussed earlier, a more comprehensive decoupling mechanism that includes all program and natural conservation, plus weather, can be implemented with the appropriate ratepayer protections.

4.2 *Relevant Factors?*

4.2.1 ***Question 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?***

4.2.2 The primary consideration is the Board's policy determination of which risks should be re-assigned from the utility to the ratepayers. Once that determination is made, issues of fairness, regulatory efficiency, and stability drive the selection and specific design of the decoupling mechanism.

4.3 *Implications of Smart Meters*

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

4.3.2 Smart meters do not affect the decoupling choices of the Board, but the mass of information available from smart meters could, when it comes, form the basis of an major redesign of rate and rate classes. Until that information is available, we do not see any SFV method that overcomes the problems associated with that choice. Once the smart meter data can be used, we think the Board has more options. However, we also think that rate redesign within a true-up mechanism will, even at that time, be a better solution.

4.4 *Scope of Decoupling*

4.4.1 ***Question 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, the economy, weather, customer growth, etc.)? Why or why not?***

4.4.2 We believe that protection from revenue attrition from all forms of conservation, natural and induced, as well as protection from weather volatility, could be beneficial. We do not believe that the responsibility of utility management to manage within the actual economic reality, general and local, from time to time should be diluted, so we do not feel that revenue protection related to economic factors should be provided.

4.5 *Alternative Approaches*

4.5.1 ***Question 5: 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?***

4.5.2 We have suggested that Staff, in their discussion paper, give consideration to a pooled true-up mechanism with a five year rolling recovery mechanism, so that ratepayers in each class would, on a province-wide basis, bear the same cost associated with revenue protection. Since weather should largely average out in the long term, the primary effect of this approach would be to socialize the revenue attrition resulting from creating a conservation culture in Ontario.

4.5.3 We have noted a number of possible implications of decoupling, including at least a reduction in allowed ROE, and two possible changes in how the X factor in IRM is calculated. On the positive side, the main implication appears to us to be freeing up utility management to focus more on operational excellence, and less on regulatory activities and other less productive work.

4.6 *Preferred Approach*

4.6.1 ***Question 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?***

4.6.2 We think it is premature to identify a preferred approach, although we have suggested an approach that Staff should consider, as noted above. Further investigation and analysis is required before a solid conclusion can be reached relating to a change this significant.

4.7 ***Different Systems for Different Distributors***

4.7.1 ***Question 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)?***

4.7.2 There are at least two key differences between gas and electricity that should be reflected in the Board's decoupling conclusions. First, the gas sector may not have the same need to socialize costs across the province as is evident for electricity. The two main gas distribution companies each cover a large enough territory that costs are effectively socialized. Second, the gas companies already have partial revenue decoupling in their IRM models, and X factors that reflect that. This suggests that the existing model should be allowed to play itself out, so that the Board can learn from the experience.

5 OTHER MATTERS

5.1 ***Process and Participation***

5.1.1 We thank the Board for inviting us to participate in this process. We hope these submissions are useful, and we would appreciate the opportunity to continue to be actively involved in all future consideration by the Board of issues relating to revenue decoupling**.**

5.2 ***Costs***

5.2.1 The School Energy Coalition hereby requests that the Board order payment of our reasonably incurred costs in connection with our participation in this process. It is submitted that the School Energy Coalition has participated responsibly in all aspects of the process, in a manner designed to assist the Board as efficiently as possible.

All of which is respectfully submitted.

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Jay Shepherd
Counsel for the School Energy Coalition