RP-2007-0673

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 Board Staff of 3rd Generation Incentive Regulation for Electricity Distributors.

SUBMISSIONS ON THE STAFF PROPOSAL BY THE SCHOOL ENERGY COALITION

May 16, 2008

SHIBLEY RIGHTON LLP
250 University Avenue, Suite 700
Toronto, Ontario M5H 3E5

Jay Shepherd
Tel: 416.214.5224
Fax: 416.214.5424
Email: jay.shepherd@shibleyrighton.com

Counsel for the School Energy Coalition

TABLE OF CONTENTS

1 GENERAL COMMENTS

1.1 *Introduction*

1.1.1 These are the submissions of the School Energy Coalition on the Staff Proposal dated May 6, 2008 and modified on May 15, 2008 for 3rd Generation incentive regulation (the "Staff Proposal"). They also include comments on the various submissions of other parties, and the work of the experts, including Dr. Kaufman, Dr. Lowry (on benchmarking), Dr. Cronin, and Dr. Yatchew.

1.1.2 This process has already included a number of submissions from parties, including SEC. We have not repeated our prior submissions in detail. However, we have tried to cover all issues, to ensure that this final submission in the process is complete. Where appropriate, we have referred to previous submissions by ourselves or others for fuller analysis of particular points.

1.1.3 This section of the submissions will provide a chart summarizing where we propose that the Board end up on each component of the plan, which we hope will be useful for ease of reference. In the Section 2, we will discuss a number of general issues that cross multiple aspects of the plan, some philosophical, some practical. In Section 3, we will discuss the particular plan components, and the evidence now before the Board that should help it reach a conclusion on these items. Finally, in the last section we will deal briefly with some process matters.

1.2 *Summary of Key Principles*

1.2.1 In our opinion, the following general principles should be apparent in the final plan approved by the Board:

(a) ***Overall Impact.*** The Board should have a target average rate increase during the plan term, for all LDCs, roughly equal to inflation, less TFP, less stretch factor. To the extent that plan components introduce potential assymmetrical adjustments to the core plan, the core plan should account for that expectation. We propose an "E-factor" to explicitly calculate and implement this adjustment.

(b) ***Status of Core Plan*** The proposal of EnWin Utilities to treat the core plan as a default, with LDCs and ratepayers having the option of seeking different parameter values at the time of rebasing, is a good one. We propose a slight variation of that in these submissions.

(c) ***Optional vs. Mandatory.*** While we recognize that the Board cannot prohibit LDCs from applying for special treatment, we believe that the Board should signal that this plan is intended to apply to everyone, with modifications as required. Further, in each rate order on rebasing, we recommend that the Board panel structure the

order so that annual adjustments, consistent with the plan as amended for that particular LDC, are included right in the order.

(d) ***Consumer Benefits.*** The plan should be structured to ensure that, on average, ratepayers benefit from incentive regulation, both during the plan period, and on rebasing.

(e) ***Yardstick Competition.*** As Dr. Cronin suggested in the Technical Conference, a well-designed plan should promote yardstick competition amongst LDCs.

(f) ***Relative Efficiencies.*** The Board, having taken the first step of having a significant amount of rigorous benchmarking work done, should now take the second step and, through plan elements, expect more productivity gains from the least efficient utilities than from the most efficient utilities. Because of data constraints in this first go-round, those differences can be fairly small, but they should still be meaningful to the utilities affected.

(g) ***Data Quality.*** The Board should accept that the data available to it for IRM will never be perfect, and should approve a plan based on the best information currently available.

(h) ***Data Improvements*** The time to start improving the quality of the data going forward is right now, and we recommend that the Board initiate an intensive project to expand the publicly available base data on all LDCs, so that future formula-based ratemaking can be even better.

(i) ***Ultimate Goal.*** The theoretical endpoint of this process should be LDCs moving towards frontier efficiencies. While never achieved, this goal is based on a paradigm of ongoing incremental improvement in the electricity distribution business in Ontario. The Board should accept, even welcome, the fact that the management of some utilities will feel pain as a result of this direction, just as is the case in the competitive markets. Conversely, the management of other utilities will be rewarded for a job well done. That, too, is exactly the way it should be.

1.3 ***Plan Components Recommended by SEC***

1.3.1 The Staff Proposal includes a number of specific components. The following chart is basd on page 6 of the May 6, 2008 Staff presentation, with some modifications to improve clarity in light of what we are proposing.

Plan Element	Staff Proposal	SEC Recommendation
Form	Comprehensive price cap index	Comprehensive price cap index
Term	Base year plus 4 years	Default of base year plus 4 years, subject to variation in rebasing

Inflation	GDP IPI FDD (updated annually in March)	GDP IPI FDD (updated annually in March)
X Factor – TFP	As calculated by PEG (0.88% on current data), fixed for term of plan	As calculated by PEG (0.88% on current data), fixed for term of plan
X Factor – IPD	Zero	Half of PEG "estimate" of 1.3%, ie. 0.65%
X Factor – stretch	Three groupings, minimum 0%, most 0.25%, maximum 0.5%	Same three groupings, minimum 0.25%, most 0.5%, maximum 0.75%
X Factor – annual update	None	E-factor adjustment each year to reflect actual rate increase experience in Ontario
K Factor	Continued migration to common capital structure	Continued migration to common capital structure
Reporting	RRR Annual Requirements (unstated modifications)	RRR Annual Requirements to be made public as filed; Further detailed data gathering for future IRM quality
Earnings Sharing	Asymmetrical +2% non-normalized earnings above approved ROE, shared 50/50 on rebasing	Same except: a) LDC can choose normalized in rebasing if they show adequate weather normalization model, and b) sharing annually
Incremental Capital	Capex in excess of 150% of depreciation; Proof outside of management control and prudent; Rate rider treatment until rebasing; Annual tracking of actual spend	Should be very rare. Capex in excess of 120% of IRM depreciation formula (i.e. for steady state, 152% of depreciation); Proof outside of management control and prudent; Rate rider treatment until rebasing; Annual tracking of actual spend;
Off-Ramps	Review initiated by LDC or stakeholders if earnings or service quality strongly inconsistent with expectations	Review initiated by LDC or stakeholders if earnings or service quality strongly inconsistent with expectations
Z Factor – General	On application; Materiality threshold 0.5% of approved RR in rebasing year	On application by LDC or stakeholders; Materiality threshold 1.0% of approved RR in current year, minimum $100,000 and maximum $2,000,000
Z Factor - Taxes	To be determined by the Board Panel hearing the Gas IR case	Board to establish policy based on all evidence, including Gas IR decision; If expert evidence in Gas IR not sufficiently thorough, Board should order a new independent study of the issue; If Z factor, normal materiality threshold not applicable
CDM	Existing LRAM – on application	Existing LRAM – on application

1.3.2 In our discussion in Section 3, we will review each of these elements in more detail, with the specific reasons for the proposals we are recommending.

2 KEY PRINCIPLES

2.1 *Overall Impact of the 3rd Generation IRM – What's the Number?*

2.1.1 We have discussed at some length in other submissions the philosophical goals of incentive regulation, and we believe that we are in general agreement with both the Board and Board Staff on the direction IRM should take the industry.

2.1.2 But that is about concepts, and rates are, for both the LDCs and the ratepayers, about dollars. In this particular case, the rubber meets the road when the Board, or any party, asks the question: "What's the number?" It is the submission of the School Energy Coalition that, before you determine the individual components of the plan, you should assess what the overall numeric result should be. If the plan doesn't achieve that result, something is wrong that needs correction.

2.1.3 The report of the Pacific Economics Group team, led by Dr. Kaufmann, has reviewed in some detail the expected increases in costs for utilities over the long term. The essence of that research is to establish an average for the industry as a whole that is achievable without extra effort by utility management. This is empirical data. It is not guesswork, or judgment, or estimation. There are no built-in excuses or rationales. PEG has looked in detail and using well-accepted, rigorous methodologies, at the electricity distribution industry, in both Canada and the US, and has let the raw data reveal a reasonable long-term level of cost increases for electricity distributors, given certain readily determinable variables. That long term level includes COS years and IRM years, many different types of regulatory models, and all special needs and exceptions to the rules. While there tends to be an ebb and flow of cost levels, in general the PEG data shows a very predictable long term rate of change relative to economy-wide inflation and customer volumes.

2.1.4 The "PEG number", depending on how you look at it, is probably something close to a freeze over time. Assuming inflation of about 2.1%, Dr. Kaufmann tells us [Tr.102-3] that the implied X factor from the data, before stretch, is about 2.18% (TFP of 0.88%, plus estimated IPD of about 1.3%). Because this uses limited IPD data (basically, basing it on an IPI calculated with too little information), the inflation component is suspect, as we discuss in more detail later. However, even if it is adjusted to reduce the IPD, the effect is still something in the order, after stretch, of 0.3% to 0.6% cost increases annually. Historically, this is the level of cost increases that LDCs can expect to experience at a 2% economy-wide inflation rate.

2.1.5 Later in these submissions, we will discuss in more detail the specific numbers being proposed, and recommend a resulting formula. However, whatever number can reasonably be inferred from the data, in our submission that number should be the industry average rate increase <u>in fact</u> during 3rd Generation IRM.

2.1.6 We are making this point first in these submissions because, while all the details are important, in the end this process is about dollars. As the process has evolved, there have been numerous debates about the "core plan" and its components, and about the potential exceptions (off-ramps, exits, Z factors, capital increments, and the like) that should be considered.

2.1.7 Those exceptions are, in general, not symmetrical. They are on average more likely to push rates upward than downward. So here is the problem. The empirical data says that an appropriate industry average annual rate increase is X%. If the core plan builds in a rate increase of X%, but there are many exceptions that increase that average rate increase to X+Y%, Ontario LDCs will be getting rate increases that are in general higher than the data says they should be. Individual LDCs may in each case have a legitimate case for their particular exception to the rules, but ratepayers overall will end up with higher rate increases than are "just and reasonable" on the data before the Board. This is not the right answer, and if it were the result, the ratepayers would be harmed by IRM.

2.1.8 There are, in our submission, only two real ways to deal with this problem of asymmetrical adjustments.

2.1.9 First, the Board could explicitly recognize in the values of the base plan the expectation of assymmetrical exceptions, and thus use lower rate increases than would otherwise be appropriate given the PEG research. This would have the effect of producing an appropriate average. The problems with this are both practical and normative. On the practical side, estimating the level of average exceptions over the course of the plan would be a difficult task, and at this late point in the process maybe too difficult to accomplish with any degree of reasonableness. On the normative side, we have to recognize, as was pointed out more than once at the Technical Conference [e.g. Tr.153-4], the vast majority of Ontario LDCs (60 to 70 was the estimate, which we believe is probably low) will have no choice but to accept the core plan, largely or fully unmodified. A basic adjustment such as this would be inherently unfair to those LDCs.

2.1.10 Second, the Board could ensure as it considers applications for exceptions that they are balanced, overall not favouring higher or lower rates. This is great in theory, but not very realistic in practice. While the Board can and should be conscious of the fact that various exception applications will be pushing up average rate increases, it is hard to imagine how that can be applied in fact to deal with an individual application. On the evidence before it, the Board is obligated to make a fair and reasonable decision. It can be hesitant to make exceptions, but if the evidence is there, the Board should not refuse. Further, we already know that the likely pressure to move rates in exceptions will be mainly upward, not downward, so seeking a balance may be a losing battle.

2.1.11 We therefore wish to propose a third alternative: The Board, after being cautious in granting exceptions throughout the year, as it normally is, should, in the following year, adjust the X factor for all utilities by the amount of any difference between the industry average rate increase and the appropriate industry average as determined by the long term historical data. We call this an "E-Factor" (for "experience factor"). The E-factor adjustment would include the impacts of COS, off-ramp, capital modules, non-standard IRM, and standard IRM, but would expressly include generic cost increases or decreases from exogenous factors (like smart meters, or tax decreases).

2.1.12 We propose that this should work in a simple and straightforward way. The Board should, once, say, 95% of all rate orders for a given year have been issued (there are always a few stragglers), calculate the weighted average rate increase (ie. increase in the distribution component of the bill) implied by all of those rate orders. Increases or decreases resulting from government actions such as smart meters and tax changes would be excluded. The Board should then calculate the long-term industry standard rate increase (ie. net inflation less TFP less stretch), and compare the two. If the actual average rate increases are higher than the long-term industry standard, the core/default X factor for the following year should be increased by that amount (a positive E-factor). Conversely, if the actual average rate increases are lower than the long-term industry standard, the core/default X factor for the following year should be reduced by that amount (a negative E-factor).

2.1.13 In effect, what this E-factor proposal does is emphasize that the pot of money LDCs should collect from the ratepayers should increase at a predictable rate. If the result of the plan as implemented is higher or lower, a subsequent adjustment should try to get it back to that rate. Another way of looking at this is that, as was pointed out at the Technical Conference [e.g. Tr. 126], and discussed at the Working Group, for every LDC that has greater than average needs, there should be another that has less than average needs.

2.1.14 The utilities, by seeking high levels of exceptions and flexibility in 3rd Generation IRM, have effectively made this kind of adjustment necessary. If, as it turns out, there are few exceptions in practice and they are implemented within tight parameters, then the impact of the E-factor on the X factor would be negligble. Conversely, if some (particularly large) LDCs are lining up for more money on a regular basis, and getting it, then the ratepayers would be protected by an overall E-factor adjustment. The extra some LDCs get would come from the rate increases for the other LDCs.

2.1.15 We therefore recommend that the Board implement an annual E-factor adjustment during the term of the 3rd Generation Incentive Ratemaking Mechanism.

2.2 ***Status of Core Plan***

2.2.1 Andrew Sasso, speaking on behalf of EnWin Utilities, proposed at the Technical Conference an approach to the core plan's status that we believe may be worth consideration by the Board. His proposal [Tr. 151 et seq] is that the values in the core plan be treated as defaults, and those defaults should then be considered at the time of initial rebasing on an LDC by LDC basis.

2.2.2 While Ms. Hare has indicated that the EnWin proposal is inherently consistent with the Staff Proposal [Tr. 167], in fact the EnWin idea is a new twist on the flexibility issue.

2.2.3 As Staff had originally proposed the core plan, it would apply to everyone unless they applied on a cost of service basis. The exceptions would be quite limited. As a practical matter, this is a "mutually assured destruction" approach to gaining compliance with the IRM plan. Anyone who does not accept the core plan has to endure the pain and suffering of COS. As Mr. Sasso correctly pointed out, this is only an option for a relatively few utilities.

2.2.4 Under the EnWin proposal, as we understand it, an LDC at the time of their rebasing has the option (as would their ratepayers) to ask the Board to change one or more of the default parameters in the plan: term, TFP, stretch, Y, ESM, etc.

2.2.5 For example, a small stable utility can come to the Board and say: "The expense of a COS application is very high relative to our revenue requirement. We are happy to accept the core plan, and even to increase the stretch by 0.2% annually, in return for being able to come back for COS every 10 years instead of every 5." This might be good for the LDC, good for the ratepayers, and good for the Board.

2.2.6 Similarly, another utility might say: "Our community's biggest employer will be permanently reducing its operations next year. We can forecast the specific impacts on our costs and revenues, including all of our mitigation efforts, and can express that in an adjustment factor that reduces our X factor." While there are some COS elements to this, it may be a situation in which it is possible to fix the existing budget, and not necessary to build a completely new one (as COS requires).

2.2.7 This is, we think, a welcome middle ground between the taking the core plan as a "package deal", and having to go through a full COS proceeding. It is a type of flexibility that, used carefully, could be suitable for some LDCs who are close to fitting the core plan, but not exactly.

2.2.8 We add some notes of caution here, in the interests of ensuring that this flexibility doesn't just extend the current debate over the defaults to every individual rebasing application:

(a) ***Not COS Lite.*** Having the flexibility to propose alternations to core plan parameters should not be a type of "COS lite". If the essence of a utility's case is that their actual forecast costs in the future will be different than the core plan, that utility should be filing under COS. It is only where the specific factors affecting that utility differently can be isolated and costed fairly that this option makes sense. Utilities should be encouraged to speak to the Rates group, and intervenor groups,

before filing on this basis, so that if it appears that COS information will be necessary, that need is identified early on.

(b) ***Co-operation and Consensus.*** As Mr. Sasso points out, this approach is inherently ADR-friendly, and the ability to apply on this basis may encourage utilities to work out appropriate compromises with intervenor groups, either during the rebasing proceeding or, preferably, before the rebasing application is even filed.

(c) ***Symmetry.*** Just as the LDC can in its application seek a modification to one of the core parameters, so too any intervenor group should be entitled to argue for a modification, whether or not the utility asks for it.

(d) ***Onus***. The party seeking to change the default value should have a substantial onus of showing that it should not apply to the particular LDC. An intervenor, for example, should not be able to argue that the utility's stretch factor should be 1% instead of 0.5%, because in general higher stretch factors are better. That intervenor should be required to demonstrate, in the hearing or in argument, that on the evidence before the Board the individual LDC is sufficiently unusual that the default in the core plan is not fairly applicable to that LDC.

(e) ***Variable Elements*** We believe that, in implementing this, the Board should specifically list the elements that it will consider as variable if parties want to propose values different from the defaults. For example, the Board may well say that the inflation factor (either the source – GDP IPI FDD – or the actual number) is not variable, but fixed. This would avoid ongoing debates on which inflation factor is the best. Similarly, if the Board accepts that an IPD should be included, that may be fixed. However, we believe that the TFP figure, the stretch factor, the term, the ESM parameters, and Y and Z factor parameters, can all be considered defaults from which parties can depart through agreement or evidence.

(f) ***Issues List.*** To facilitate the use of this approach, each rebasing application should include on the Board-approved issues list all of the variable parameters in the core plan. Utilities should not be in a position to argue that an intervenor cannot raise an issue of, say, term, because the utility is willing to accept the default. (We think that, in general, a standardized basic Issues List for all LDC rebasing applications should be prepared by Board Staff, in consultation with utilities and intervenors, so that the parties don't have to reinvent the wheel with each new application. This would promote consistency. Such a common list should include a section on default IRM values.) We note Mr. Fogwill's comments at the Technical Conference [Tr. 170] that, if one parameter is put in play, all others would be in play as well. We disagree. We think the essence of the EnWin proposal is that all parameters are in play in any proceeding if any party wants to put them in play. This is not initiated by the LDC. It is initiated by any party. While in most cases all parties would accept the defaults, any party can question any of them in the rebasing application.

(g) ***Evidentiary Burden.*** At the Technical Conference, the question was fairly raised [Tr. 168] of whether small utilities could afford to muster sufficient evidence to challenge any of the defaults. In one sense, this is part of a larger problem the Board faces – whether small utilities can afford to be regulated entities at all. However, within the framework of that broader question, the Board has in the past been appropriately sensitive to this concern, and we agree with Mr. Sasso that the expectations of the Board for each individual LDC should be specific to that LDC.

2.2.9 Mr. Sasso suggested at the Technical Conference [Tr. 165] that this proposal may not be ready for 3rd Generation IRM. We disagree. We think that the flexibility inherent in this "limited adjustment" approach is worth trying out in 3rd Generation IRM. If it turns out to create problems, the Board can limit it. However, in the meantime it is a good idea that should in our view be tested in practice now.

2.3 ***Optional vs. Mandatory***

2.3.1 Whenever the Board deals with a policy process that will lead to rate-making activity (as is often the case), the issue arises as to whether utilities can legally be required to comply with the Board policy. As the Board will be aware, SEC believes that rates must be set in rate cases, based on the evidence before the Board, and no policy process – not even one as thorough as this one has undoubtedly been - can short circuit those legal requirements. One implication of this is that any LDC can, at any time, apply to have rates set on whatever basis it thinks is appropriate, and whether the Board likes the proposal or not, it must consider the application on its merits. Short of changing the law, there is no getting around this.

2.3.2 On the other hand, when a Board panel orders rates in a rebasing COS application, it does so with the expectation that the LDC will be subject to certain future rate adjustments based on a formula. That is a real factor in many rate cases today. For example, in the Toronto Hydro EB-2007-0680 decision, released today, the Board said, at page 7, commenting on the applicant's request for a three year COS rate order:

"Accordingly, the Board will approve rates for 2008, and 2009 based on its consideration of the evidence filed with respect to each of these years. We anticipate that the rates for the subsequent year will be determined through the application of a formulaic adjustment using the then Board-approved methodology."

2.3.3 In light of this background, we wish to propose a variation in the way the Board has approached rebasing rate orders in the past, which may enhance compliance with the Board's overall policy, while still complying with all legal requirements. Our proposal is that the Board, in making a rebasing order granting new rates, specifically include in that order the IRM formula for each subsequent year.

2.3.4 This proposal, if adopted, could accomplish two things. First, of course, to the extent that the Board had accepted different values for any of the defaults in the core plan, this would create a method by which that decision could be implemented.

2.3.5 Second, though, it would also mean that the rates for years two through five of the IRM cycle had been set in a proper hearing, with evidence considered by the Board. Any subsequent application by the utility to re-open any of those years would be a reconsideration of the existing order, not a fresh application. For example, a utility rebased for 2009 cannot come prior to its 2012 year and say: "We know you have made an order for our 2012 rates already, but we've changed our minds and now want you to order something different." Instead, the utility would have to say: "We have new evidence showing that the existing 2012 order is no longer appropriate for our utility, and we are seeking a variation on that order."

2.3.6 We therefore propose that the Board include the annual IRM formula, including values, in the rebasing orders for each utility.

2.4 ***Consumer Benefits***

2.4.1 At the Technical Conference, Dr. Yatchew reiterated an oft-stated "principle" of IRM [Tr. 203]:

"…consumers ultimately capture the benefits of efficiency gains upon re-basing…"

2.4.2 Sadly, this has so far not proved to be true in the Ontario electricity sector. We have, in our April submissions, expressed our concern that the rebasing applications of many utilities after 2nd Generation IRM appear to be seen as an opportunity to bump up the revenue requirement, not pass on efficiency gains to the ratepayers. This may be because of the public sector history of the electricity distribution sector (budget time is a time to ask for more, not less), or it may be a legacy of the sudden and unfortunate rate freeze imposed by government fiat. Whatever the reason, on the evidence before us there is no reason to believe that there will be efficiency gains to benefit the ratepayers on rebasing.

2.4.3 This leads us to two conclusions. First, as we will argue later in these submissions, a stretch factor should not be "conservative" ("very conservative", Dr. Kaufman says at page 146 of the Technical Conference), since that is likely to be the only benefit the ratepayers get from this plan. Second, exceptions should not be allowed to erode the very benefit that is the only one left. Therefore, an E-factor adjustment such as we have suggested in Section 2.1 of these submissions, or some other factor that protects against "exception erosion", is essential.

2.4.4 Mr. Sasso, in his submissions at the Technical Conference, used a slide that showed COS = slow and expensive, but good outputs; IRM = fast and cheap, but bad outputs. His point was obviously being made from the LDC perspective, but the same issue arises from the ratepayer perspective. It is submitted that the Board should, in considering the components and structure of 3rd Generation IRM, ensure that both during the plan, and on rebasing, ratepayers are likely to experience an actual net benefit. If that cannot be achieved, it is submitted that COS is the preferable answer for all LDCs.

2.4.5 We note that, in our April submissions, we proposed an end-of-term adjustment based on the efficiency gains delivered by the LDC to its ratepayers. In essence, we proposed that if a utility delivers an average rate decrease on rebasing, then in 4th Generation IRM it should be entitled to a lower stretch factor, based on a predetermined formula. Details of that proposal are included in our April submissions, and we ask that the Board consider implementing this as in integral part of the 3rd Generation IRM. By announcing it now, the Board would give LDCs a goal to shoot for, and a known reward for achieving it.

2.5 ***Yardstick Competition***

2.5.1 Dr. Cronin, in arguing in favour of an IPI over an economy-wide inflation measure, points out [Tr. 224] that by using an IPI, which is influenced by the actions of the utilities themselves, a "yardstick competition" is created between LDCs. For many reasons, the IPI is probably not a good idea at this juncture. However, the concept of yardstick competition permeates the Staff Proposal and the work of PEG, and should be specifically approved and adopted by the Board.

2.5.2 We recognize that "yardstick competition" is really all about having a reliable and acceptable yardstick, and there is currently a significant debate about whether the existing data and metrics fairly compare the actions of utilities one to another. That having been said, the principle is an important one. In 3rd Generation IRM, the Board should, as we submit below, take an initial step in the direction of comparisons between LDCs, and should signal its intention to keep moving down that path as better data and metrics become available.

2.6 ***Relative Efficiencies***

2.6.1 This leads, of course, to the issue of benchmarking. At the Technical Conference, there was an interesting exchange [Tr. 142 et seq], led by Mr. Fogwill, to see what people felt about differentiating between utilities based on efficiency levels or groupings. What transpired is that virtually all LDCs are opposed to being differentiated on the basis of relative efficiency, arguing for the most part that it is premature to do so. Dr. Cronin, in agreement with the utilities, in fact said that benchmarking is useful, but not "when money and rates are involved" [Tr. 209]. In effect, he agrees that it is useful as long as there are no real consequences. On the other side, the ratepayer groups all agree that real differentiation based on some form of benchmarking is a good idea, and not premature, and should be adopted by the Board right now.

2.6.2 In some respects, this is a little surprising. LDCs claim that the data is still poor quality, and so the results are unreliable, yet the work done by PEG is in fact much more thorough and high quality than most of the internal benchmarking studies that the utilities rely on already. That can't be the real reason. If you look at it from the point of view of the LDCs, some of them will benefit from their past efficiencies. Why would they want to give up those benefits to protect their peers who – when you talk privately to LDC personnel – are seen to be profligate, or gaming the system, or simply not very good at their jobs? Yes, of course, all agree that some have also been unlucky, or saddled with unfair past histories, or the victims of other exogenous factors, but there is little doubt that within the LDC community some are seen as doing a better job than others. Why would the best want to prop up the worst?

2.6.3 It is in a sense just as inexplicable on the ratepayer side. Any differentiation is or should be a zero-sum game. If Utility A gets a higher stretch factor, Utility B must get a lower stretch factor. Since the intervenor groups for the most part represent ratepayers across the province, there is not likely to be any net gain from differentiation. Why are ratepayer groups pressing for the use of benchmarking to differentiate between LDCs?

2.6.4 In our view, LDCs, will <u>never</u> believe that there is sufficiently good quality data to differentiate between them. The explanation, we believe, lies in human nature. Utility management often perceive that being labelled "substantially less efficient than the norm" is inherently more dangerous than the concomitant benefit of being labelled "substantially more efficient than the norm". The former can cause people to be fired or demoted, but it is not likely to result in a shareholder or board of directors lowering the bar for future performance. Conversely, the latter may in some cases result in bonuses and promotions (less likely than the downside, probably), but at the same time increases shareholder and director expectations on management for the future. Thus – and this is a problem for all businesses, regulated and unregulated – there is a basic asymmetry between downside risk and upside reward. Or, put in the vernacular, if you are one of the most efficient, you still look at the unfortunate few and think "There but for the grace of God go I."

2.6.5 The view of ratepayers is less defensive. Ratepayer groups believe that pervasive benchmarking will act as a type of yardstick competition, incenting utility management to work harder to achieve efficiencies, not wanting to be in the bottom tier (or, alternatively, preferring to be in the top tier). This is probably true, and in the long term should produce lower distribution bills overall. There is, likely, no immediate benefit from differentiating based on efficiency levels. The benefit comes as utilities – perhaps reluctantly – respond to the differentiation with increased efficiency levels. The essence of the expectation is that poor performers will respond by getting better, but good performers will not be any worse than they would have been without differentiation. On average, efficiencies will improve across the sector.

2.6.6 SEC believes strongly that the Board should continue to show leadership in this area.

We accept that the data quality is not perfect (see below), but as the Board's own experts have said, it is sufficient to start along the benchmarking path. The Board should do so, and should make no bones about the fact that it will be improving the data, and then enhancing its use, in the future. We believe that once utility management accept the inevitability of benchmarking and efficiency ratings, they will show their true talents and abilities by competing aggressively with each other to each be seen as the most efficient utility. As the benchmarking data becomes more accepted, utilities will start including efficiency levels in management performance appraisals and compensation plans (just as they do with things like SAIDI today), and the Board will have created an organic structure improving LDC efficiency across the province.

2.6.7 Frankly, as the Board well knows, it is almost impossible in a COS application to assess whether the utility is being operated efficiently. Many Board panels have attempted this, some even with surprising success, but it is very difficult. Now is the time for the Board to push in the direction of a structure that, as it evolves, will create pressure for improved efficiency without the COS debate being required to get there.

2.7 ***Data Quality***

2.7.1 How much of the Technical Conference was consumed by debates over the quality of the data being used by the experts, how they were adjusting for data deficiencies, and whether better data is available?

2.7.2 Let us be the first to say that the perfect is the enemy of the good**.** Everyone must accept that there are flaws in the data, especially that relating to historic Ontario LDC capital stock. As we note below, this is an urgent problem, and the Board needs to take action to correct it.

2.7.3 But having said that, the data is what it is. The Board's experts – Dr. Kaufman in IRM and Dr. Lowry in Benchmarking – have accepted the reality of data deficiencies, and have used thoughtful workarounds based on the data that is reliable and available. The Board has ample experience making decisions based on incomplete or imperfect evidence. Every rate case has some component of that. This is not different. In our submission, the Board should make decisions on 3rd Generation IRM based on the data available to it.

2.7.4 This does not mean that the Board closes its eyes to deficiencies. Where the experts have said they have insufficient information to reach a conclusion they are willing to stand behind (the IPI, for example), that is one thing, and the Board should be loathe to rely on data that independent experts will not rely on. But, where the experts have said that the incomplete data is still enough for them to reach reasonable conclusions, and they have strong rationales for doing so, the Board should proceed to a decision on that basis.

2.8 *Data Improvements*

2.8.1 This does not mean that the data deficiencies should be ignored. The Board's experts have made some specific recommendations for further data collection, and Board Staff in various departments are considering how to deliver on those recommendations. In our submission, this should be considered a high priority for the Board, starting today, so that by the time 4th Generation IRM rolls around, there is a much stronger data set to work with.

2.9 *Ultimate Goal*

2.9.1 Underlying many of the comments of LDCs during this process, both at the open meetings and in the Working Group, is a fear that a "one size fits all" approach to LDC ratemaking could result in significant cost-cutting pressures. This is also the fear of the PWU. Frankly, any thoughtful ratepayer group should also be concerned with the potential adverse effects of that pressure.

2.9.2 The Board should recognize, we believe, that it has been handed a mandate from the government to oversee a transformation of the Ontario electricity distribution system. After some transitory but serious interference, the ball is now in the Board's court to engineer a transformation from public sector bodies delivering an essential service to private sector like businesses, that deliver that essential service in a manner similar to investor-owned utilities.

2.9.3 It is, of course, possible to debate the merits of that transformation as a public policy goal, but that is not the Board's prerogative. The Board has a mandate, and has been forthright in its long-term plan to deliver on that mandate.

2.9.4 The point of this is not "motherhood and apple pie". The point is, rather, that the mandate is a difficult one, not just for the LDCs that have to adjust, sometimes with difficulty, to a fundamentally different paradigm. It is a difficult one, not just for the ratepayers, forced to bear dramatically increased rates due to increased operating and regulatory costs and the addition of a shareholder rate of return. It is also a difficult one for the Board, which will face complaints from one side or the other, or both, no matter what it does.

2.9.5 This somewhat obtuse, perhaps, section of our submissions arises because of a comment at the Technical Conference by one of the utility reps, who said [Tr. 140]:

"If we pull out, through this "stretch factor," if you decrease the revenue that's being recovered by these LDCs, where are they going to get their dividend? And the risk is that they're dipping into capital, and they're not putting money into infrastructure."

2.9.6 The simple answer is that the shareholder dividend is last on the priority list. So many LDCs assume that their shareholder has a "right" to its ROE, just as the employees have a right to their salaries. That is not the case at all. The utility must be given the reasonable opportunity to earn the approved ROE, or more, but it is a performance based system, not an absolute entitlement. As part of the transformation to a private sector model, some members of utility management will experience pain as they come to grips with the nature of the performance demands that this model imposes. Some have gone through it already, and have now adopted (even enjoy, in some cases) the new business paradigm Others are still at the "pain" stage. That pain is not really any different from the pain that ratepayers experienced when they were required to increase their rates for ROE and PILs.

2.9.7 It is tempting to characterize the complaints of a few LDCs about IRM (and the demands of the regulatory process generally) as "whining", but it would be unfair in the extreme, just as it would have been unfair to call the ratepayers "whiners" when they complained about paying for ROE and PILs. Today, some LDCs are still adjusting to their new business model, and it is not always easy, but adjust they must, and this IRM plan is an important step along that path. In our submission, the Board should not mistake these inevitable pains of adjustment for deficiencies in the Board's long-term vision for the sector, or in the leadership it is providing to deliver on a difficult mandate.

3 COMPONENTS OF 3rd GENERATION IRM

3.1 *Price Cap Format*

3.1.1 We note that a consensus appears to have emerged around a comprehensive price cap structure for 3rd Generation IRM. We strongly support this approach, for the reasons we have set out in numerous past submissions.

3.2 *Term of Plan*

3.2.1 The Staff Proposal is for a base year, plus four IRM years, for a total cycle of five years for each utility.

3.2.2 In our April submissions, we have argued that LDCs and their ratepayers should be given flexibility to propose alternations to the term based on the particular circumstances of the utility. We continue to believe that this is a good idea, but if the Board adopts the EnWin proposal, which we have supported in Section 2.2 of these submissions, that flexibility would already be available, on a broader scale. If the Board does not adopt the EnWin proposal or some variation, then we believe that it should still allow proposals for modified plan terms, for the reasons set forth in our April submissions.

3.3 *Inflation Factor*

3.3.1 The changes in position of Board Staff and a number of other parties on the inflation factor reflect the difficulty that arises in dealing with this issue. It is a simple fact that the cost pressures of electricity distributors are not the same as the cost pressures in the economy as a whole [see for example the interesting discussion at Tr. 100]. Logically, the most effective approach should be to track with some precision the actual cost pressures inherent in the nature of the utility business. That would be an IPI, and in our April submissions we supported the work of PEG and Board Staff in proposing an IPI, although we did propose some modifications to handle the problem of volatility.

3.3.2 The new Staff Proposal reverts to the previous use of GDP IPI FDD, an economy-wide inflation metric that, if it is to be useful, must be adjusted to take into account the different cost profile of distributors relative to the economy at large.

3.3.3 The experts appear to agree (and we have also taken this position in past submissions) that whether the Board uses an economy-wide metric, then adjusts it using an IPD, or whether the Board uses an IPI, the end result should in theory be the same, since the two approaches are simply using different approaches to measuring the same parameter. To the extent that they are both accurate, they should theoretically produce identical results.

3.3.4 SEC has no problem supporting the use of the GDP IPI FDD. There is an ongoing tradeoff between using a macroeconomic indicator, and adjusting it (which has the advantage of a widely used and accepted inflation measure that has inherent stability in Canada), vs. using an industry specific measure alone (which has the advantage of precision, but the disadvantage of debates over volatility and the construction of the metric). We have, for example, in our April submissions, criticized the design of the IPI then proposed, because of its unacceptable volatility. While we believe that problem can be fixed through smoothing techniques, we also agree that moving back to a more stable metric is another acceptable approach.

3.3.5 We accept that there are advantages to using the macroeconomic indicator. However, as we note in our submissions later, in our view it is not appropriate to use that indicator without making some adjustment for input price differentials between the economy as a whole and the target industry, in this case electricity distribution. We discuss this further under the heading "X Factor – IPD" below.

3.4 ***X Factor - TFP***

3.4.1 We have commented in past submissions on the high quality of the PEG Report authored by Dr. Kaufmann and his team on 3rd Generation IRM. Central to that report is an estimate of TFP at 0.88% for Ontario LDCs in this round of IRM. We believe that is the best evidence available to the Board, based on thorough and comprehensive work and with transparent and well thought out judgments to deal with data deficiencies.

3.4.2 Inevitably, the independent analysis has been challenged by utilities on various grounds. The Technical Conference was rife with such debates. Interestingly, for the utilities it turned out those debates probably hurt their case more than helped it, but they served to give further examples of the quality of the PEG work on this project.

3.4.3 We just draw to the Board's attention one exchange in that Technical Conference, at pages 173 to 190, largely between Dr. Yatchew and Dr. Kaufmann. In our submission, on any fair reading of that discussion it is clear that Dr. Kaufmann's analysis is significantly more compelling. For example, in dealing with start date analysis, Dr. Yatchew appears to confuse the goal of controlling for periodicity with the goal of controlling for end point distortions. They are not even similar concepts, yet as Dr. Kaufmann points out at page 180, that is the key difference between them. Start date analysis would not in fact be a good way of controlling for periodicity, as Dr.

Kaufmann realizes, but the math makes clear that end point distortions can only really be controlled by that method. PEG has done this right; Dr. Yatchew is incorrect. In our view, this is but one of many examples where the PEG work is materially superior to the work of the other experts.

3.4.4 We also note that one of the biggest criticisms of the PEG work – the use of US data to supplement the limited Ontario data – actually works against the ratepayers, not the LDCs. As Dr. Kaufmann points out [Tr. 89], if the Ontario data were more complete and could be relied on without the assistance of the US data, it is likely that the TFP would be higher, not lower.

3.4.5 It is therefore submitted that the Board should adopt the best evidence available to it on TFP, the PEG Report, and use the TFP number PEG has calculated.

3.4.6 We wish to add one other comment on this point. In 2nd Generation IRM, after a debate on X Factors, the Board selected a compromise number. As a transitional step, this was a reasonable approach. In this case, however, we believe that the Board should signal the importance of having a more rigorous foundation for its X Factor by expressly adopting the best number available to it. This is not a case where compromise makes sense. If the Board is going to continue to move in the direction of empirically based rate-making formulae, which we agree is an appropriate goal, then it is time to take a further step in that direction by basing the productivity factor expressly on the evidence.

3.5 ***X Factor – IPD***

3.5.1 The main area where the PEG work is lacking is the input price differential. This is not really their fault, since they have been consistent in arguing throughout the process that an IPI is the better approach, with appropriate smoothing techniques. As a result, we do not see the kind of detailed IPD analysis that we would expect where a macroeconomic indicator is used as the inflation base.

3.5.2 The result of this, as everyone appears to accept, is that the Board currently has no solid basis on which to determine an IPD component for the X Factor. There appears to be consensus that an IPD is an appropriate part of the X Factor where a macroeconomic indicator is used, but no reliable number has been put forth.

3.5.3 During the course of a discussion at page 102/3 of the Technical Conference, Dr. Kaufmann did provide a thumbnail estimate of the likely IPD, based on the fact that the calculated IPI is significantly lower than average GDP IPI FDD**.** If the calculated IPI is correct, then implicitly the IPD would be 1.3% to 1.4%, and when you add that to the TFP number you get an X Factor, before stretch, of 2.18%. While Dr. Kaufmann was not advocating that approach, it does give a kind of soft indicator of the kind of IPD that would be likely.

3.5.4 The obvious problem with this, as Dr. Kaufmann recognizes, is that if the IPI number were right, then it could be used directly, and no IPD would be required. The reason the Staff Proposal is opting for GDP IPI FDD is that the IPI has its own data and volatility problems. It is no more valid to use it indirectly as directly.

3.5.5 The Board is thus left with a dilemna. It knows in fact that there is likely a material difference between utility input prices and the GDP IPI FDD, but it doesn't have sufficient evidence on which to select a "correct" number.

3.5.6 In our submission, the Staff Proposal, zero, is perhaps the only number that is clearly the wrong number. With the only (weak) evidence before the Board indicating that, directionally, utility input prices are rising more slowly than GDP IPI FDD, it is submitted that selecting zero is likely to be unfair to ratepayers.

3.5.7 Above, we have argued that the Board should, where possible, base the 3rd Generation IRM formula on empirical studies, not guesses or compromises. However, in the case of the IPD we already know that the figure (whether zero or something else) will be based on judgment rather than on empirical study. Therefore, in our view the Board has to exercise its judgment in this case, and zero would not be a good exercise of judgment.

3.5.8 There is no rigorous way to do this. It is the nature of the beast that the Board has to simply "pick a number". Given the limited IPI evidence, and in the interests of cushioning the impact on LDCs, SEC proposes that the Board use half of the implied IPI Dr. Kaufmann, discussed, ie. half of 1.3%, or 0.65%, as the IPD for this round of IRM.

3.5.9 We note that this is not a really good conclusion, and is only proposed because of the exigencies of the current situation. We believe that, assuming the Board continues its work on data quality and other empirical work, by the time 4th Generation IRM rolls around, it will no longer be necessary to "pick a number", whether for IPD or for IPI. The Board will, we hope, have sufficient data at that time to use a number with a firmer foundation.

3.6 ***X Factor – Stretch***

3.6.1 The stretch factor has been the subject of heavy debate at all stages in this process. The debate has two components. First, many LDCs believe that there should be no stretch factor at all. Second, if there is a stretch factor, most LDCs oppose differentiation based on relative efficiencies. We have discussed the second of these points in some detail in Section 2.6 above, and argued in favour of the Board's leadership in benchmarking with real consequences. This section of our submissions deals with the question of the average level of the stretch factor, whether it is a single number or a range.

3.6.2 Let us start with the question of whether there should be a stretch factor at all. Dr. Kaufmann pointed out several times at the Technical Conference, and Ms. Girvan from CCC agreed [e.g Tr 145], that stretch factors exist in virtually every IRM plan. We are not reinventing the wheel here. Many jurisdictions have reviewed the use of stretch factors, and concluded universally that a stretch factor is a necessary part of an IRM formula.

3.6.3 Dr. Yatchew points out, correctly [Tr. 204 and elsewhere], that just because there is precedent for something in other jurisdictions does not make it right. That is undoubtedly true. But, it is also common sense that if every other jurisdiction has concluded that their plan needs a stretch factor, including this Board on many occasions, the strength of the opposing arguments would have to be pretty compelling to displace the likelihood that everyone else has probably gotten it right.

3.6.4 In this case, it is submitted that those who argue against a stretch factor have not presented any compelling arguments. In most cases, they boil down to "Our rates will be lower than we need", without any further justification. A few have argued that, because of the rate freeze in the early part of this decade, they have already built in efficiencies, and further efficiencies from IRM are less likely. Given that all utilities are going into this round of IRM with at least two COS proceedings behind them, many with substantial rate increases, that argument is not persuasive.

3.6.5 Therefore, we believe that this Board should order a stretch factor, and the only question is the number or numbers used.

3.6.6 The Board Staff proposals and discussions at various stages of this process have been fairly consistent in suggesting that a low stretch factor is appropriate, but no real justification for the low levels has been provided. Dr.Kaufmann's evidence is that an average of 0.5% stretch factor would be the norm, and he characterizes the Staff Proposal of a 0.25% average as "very conservative" [Tr. 146]. In fact, the number is so low that it prompted one intervenor representative, Mr. Clark, to comment that the LDCs should not be concerned about the stretch factor, because it is so low as to be almost negligible [Tr. 144].

3.6.7 Throughout this discussion, it appears that the real rationale for the low stretch factor is a desire to "go easy" on the LDCs, who have expressed strong concern about the stretch factor.

3.6.8 With respect, "going easy" on the LDCs means asking the ratepayers to pay more. This is not happening in a vacuum. If more money is to go to the LDCs, it is coming from somewhere, so "going easy" on the LDCs is necessarily "coming down hard" on the ratepayers. If there is a justification for this, that is one thing. If there is no basis for the low number, it should not be allowed to stand.

3.6.9 We therefore strongly urge the Board to rely on the evidence before it, that a reasonable average stretch factor is 0.5%. Based on that, we propose that the stretch factor for the highly efficient LDCs be 0.25%, for the low efficiency LDCs be 0.75%, and for the bulk of the LDCs be 0.50%.

3.7 *X Factor – Other*

3.7.1 As we have noted in Section 2.1 of these submissions, in light of the asymmetry of exceptions likely to occur year by year, the Board should include an additional adjustment, which we have called an E (for "experience") Factor, to ensure that the average of rate increases across the province annually continues to track the historical norms. This would not apply in the first year, but would apply in each subsequent year of the IRM plan based on the overall weighted average rate increase for the previous year.

3.8 *K Factor*

3.8.1 The continued migration to the common capital structure appears to be non-contentious.

3.9 *Reporting*

3.9.1 The Staff Proposal does not discuss the level of transparency of annual reporting requirements, but only suggests that RRR filing will continue.

3.9.2 SEC strongly believes that the key to a successful IRM process lies in transparent and ongoing information flow. There are two parts to this.

3.9.3 First, the Board should continue the direction it has been going for some time of increasing the information available to the public on the financial status and results of LDCs. That should include, starting with 3rd Generation IRM, changing the RRR rules so that all RRR filings are made public as filed, by posting on the Board's web site. The objection we have heard from some utilities, ie. that some of this information is confidential, is in fact not a viable one. These are regulated entities with a local monopoly. They are not in a competitive business. Transparency should be an integral part of their business operations, and this Board should continue to move in that direction.

3.9.4 We note in passing that even some of the largest LDCs sometimes have difficult accepting the normal day to day implications of their regulated status. In the recent Toronto Hydro EB-2007-0680 decision, for example, the applicant was (gently, perhaps) chastised [Decision, page 6] for seeing the regulatory process as a problem it had to deal with. We agree with the Board panel in that case. Being regulated means certain things. One of them is the obligation to make many business decisions under the public eye.

3.9.5 Second, the Board should consider how ratepayers and other stakeholders will scrutinize the annual filings of the utilities. Those filings, which will have to include information on earnings sharing, deferral and variance accounts, and other material issues, should be considered by intervenors. We consider, for example, the Board's decision in 2008 to deny costs for intervenor review of IRM applications to be an unfortunate one, and we urge the Board in its 3rd Generation IRM plan to provide on an annual basis for appropriate funding so that stakeholders can review and comment on information reported by the LDCs.

3.10 ***Earnings Sharing***

3.10.1 The School Energy Coalition is generally opposed to earnings sharing in IRM plans, because we believe that it mutes the incentive for utility management to drive efficiencies and improve productivity. We understand, however, that many other ratepayer groups disagree with this position, and the Staff Proposal includes an ESM.

3.10.2 In this transitional plan, an ESM makes sense as a consumer protection device. We therefore support the Staff Proposal, subject to two modifications.

3.10.3 The Staff Proposal contemplates that earnings to be shared would not be weather normalized. The rationale is that the weather normalization methods being used by the LDCs today are not sufficiently sophisticated, for the most part, to rely on them for earnings sharing. We agree that for most LDCs that is the case, and earnings should not be weather normalized.

3.10.4 We also note that, in the Gas IR case recently concluded, Union Gas insisted that their ESM would be non-weather normalized, on the basis that they did not want to find themselves in the position of sharing "earnings" that were not actually earned. This is a perfectly reasonable position.

3.10.5 Conversely, in the case of Enbridge they were equally adamant that their ESM should be weather normalized, on the basis that their long term protection from weather fluctuations requires that they keep the higher profits from cold years to offset the lower profits in warm years. If an ESM takes away some of the cold year profits, their protection is incomplete. This is also a perfectly reasonable position.

3.10.6 We agree with Board Staff that, if a utility does not have a sufficiently robust weather normalization system, the ESM should be based on actual earnings. However, we believe that a utility should be allowed to demonstrate, at the time of rebasing, that they do have a robust and reliable weather normalization system, and elect to apply it to have their ESM based on normalized earnings. Ratepayers should normally be indifferent to this choice, as long as the normalization technique is sound, and the LDC would be allowed to select the risk it wished to take: sharing phantom earnings, vs. losing some level of weather protection.

3.10.7 The second point on ESM has to do with when earnings should be shared. The Staff Proposal contemplates sharing at end of term. We believe this is inappropriate, for three reasons. First, it is simpler and easier to calculate sharing when the financial information is first prepared, rather than going back over potentially four years to determine the correct calculation in each year. Second, annual review will ensure that disagreements on how ESM is calculated are caught early and fixed. Third, and far more important, the utilities will need certainty as to their earnings to be shared for financial reporting purposes.

3.10.8 This latter point is a variation on an issue that has been raised many times by utilities relative to deferral and variance accounts. Where their judgment is that an amount is collectible from the ratepayers, or payable to the ratepayers, some amount must be reflected in their annual financials. However, these calculations are not without debate, and utilities will every year have to assess what, if any, earnings they will have to refund to ratepayers. In our view, the uncertainty this will create is unnecessary, and should be avoided. It is preferable if the Board makes a determination each year as to the earnings to be shared. Of course, once that decision is made, there is no reason for the LDC to keep the money. It should be refunded to ratepayers along with clearance of deferral and variance accounts, and other such adjustments.

3.10.9 We have one other comment on earnings sharing. At page 41-42 of the Technical Conference transcript, there is a discussion between Ms. Anderson of Hydro Ottawa and Mr. Fogwill of Board Staff about how earnings would be calculated for sharing purposes. Ms. Anderson assumed that ROE would be calculated based on actual equity, and so would be affected by dividend policy. Mr. Fogwill correctly points out that it would be deemed equity that would be used for the ROE calculation, as it always is in any regulatory accounting environment.

3.10.10 However, Ms. Anderson correctly notes that this would mean the denominator of the ROE calculation would be a historical number (40% of rebasing year rate base, in effect), while the numerator would be current year earnings. This raises a legitimate point of fairness, and we believe that the denominator should be 40% of current year average rate base (ie. average of monthly averages, the standard calculation), not historical rate base.

3.10.11 We recognize this would mean that a utility that dramatically overspends on capital would reduce its earnings available for sharing. We do not think this is likely to be a problem, but if it arises we believe that the Board will have the discretion to look at the underlying components of the ESM calculation and produce a fair result. The other option – basing it on the known historical equity – is not in our view fair to the utilities.

3.11 ***Incremental Capital Investment Module***

3.11.1 Both the Working Group and Board Staff have spent a good deal of time grappling which what is supposed to be a substantial problem: the inability of a price cap plan to provide adequate funding for capital spending requirements.

3.11.2 At the Technical Conference, this continued to be a recurring theme. For example, Mr. Poray, from Hydro One, said, at page 25:

"The minute your capital expenditures on an annual basis exceed your depreciation costs, there is is a net change in your rate base, and therefore you're incurring costs that you're not getting recovery of."

3.11.3 Later, Ms. Anderson from Hydro Ottawa echoed those concerns, when she said, at page 30:

"I'm saying just in keeping [capital spending] constant, I'm falling behind millions of dollars every year because I'm not being funded for my amortization. So I would have to curtail my capital budget hugely. I'd have to practically, you know, drive it into the ground in order to make my ROE base. And so this proposal doesn't work for us because it's only about incremental."

3.11.4 These are two variations on a theme we have heard throughout this process, ie. the only funding provided in a price cap plan for capital spending is essentially an amount equal to the annual depreciation provision approved on rebasing. With respect, this concept is mathematically incorrect, and has led some to a view of capital spending that is far from the true numbers.

3.11.5 There are three answers to this supposed problem. The first, and most technically correct, is that provided by Dr. Kaufmann in his response to Mr. Poray [Tr.26], where he says:

"Andy, that's an opinion that was expressed in various submissions, and <u>it's actually not true</u>. What's reflected in the X factor is, there is a pattern of capital expenditures for the industry, and what matters is not how your capital expenditures compare to depreciation, but the capital expenditures relative to the real capital expenditures that are reflected in the TFP trend, total factor productivity trend."[emphasis added]

3.11.6 Simply put, the analysis done by PEG already implicitly includes the relationship between existing rate base (and therefore depreciation) and new capital spending. It is inherent in the numbers. Unfortunately, the data quality issues then surface, and there is (and was at the Technical Conference) another of the many debates about whether you can rely on numbers from data that is not perfect.

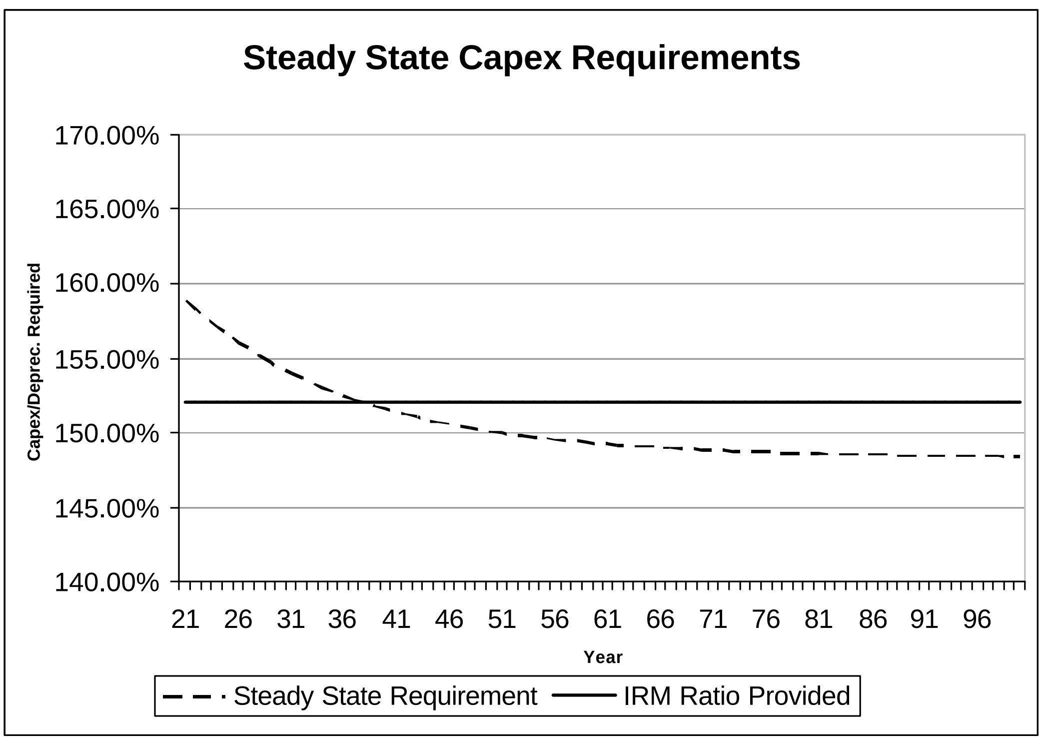
3.11.7 But the other two reasons why Mr. Poray, Ms. Anderson and others are simply incorrect do not rely on empirical data. They rely on straightforward mathematics.

3.11.8 The second reason for rejecting the "capex = depreciation" argument is the conceptual side of the math. As every regulator knows, the capital component of revenue requirement is composed of interest expense, ROE, taxes and depreciation. All of those are based on a rate base that is in turn almost entirely based on historical costs at prices from many years ago. The impact of current prices, and the impact of current capital spending, is actually quite small on revenue requirement each year.

3.11.9 The effect of historical cost accounting is to cause capital costs to go down each year on a real basis. Take a simple example. In 1988, a utility spends $100,000 on capex with a 25 year life. The annual revenue requirement for that is about $16,000, made up of interest, ROE, PILs, and depreciation. That annual revenue requirement is the same in 2008 as it was in 1989 in nominal dollars, but the difference is that inflation has eaten away the value of those dollars. The result? The cost in real 1988 dollars is actually about $8,000 in 2008.

3.11.10 Conceptually, each year the utility spends money on capital, and each subsequent year that spending acts to put downward pressure on revenue requirement, until the useful life of the assets is reached. Then, new capital spending puts upward pressure on revenue requirement, counteracted by the downward pressure of the assets still in their useful lives.

3.11.11 This effect can be modelled quite simply, showing the relationship between annual capital spending (impacted by inflation) and the base depreciation levels built into rate base already. For a utility with zero growth (and therefore constant real dollar capital spending), at a 2% inflation rate and 3.9% average depreciation rate, as the utility matures its capital spending needs hit and maintain a level of around 148% of depreciation annually. That can be shown in the following simple chart:



3.11.12 In effect, and this holds true over most reasonable sets of assumptions applicable in Ontario, a utility that has no revenue growth and capital input prices increasing at the economy-wide rate of inflation needs to spend about 148% of its depreciation provision on new capital in order to continually replenish its capital assets.

3.11.13 Of course, it is a little more complicated than that, so that leads to the third reason why the assumptions of some of the utilities are mathematically incorrect: the detailed math itself.

3.11.14 To test the hypothesis that under a price cap a utility can only invest in new capital spending equal to the amount of its depreciation, we prepared a highly simplified model using one of the same utilities used by Board Staff. In that model, which is attached as Schedule A to these submissions, we assumed an inflation rate, increase in OM&A, and increase in capital costs of 2% (ie. the Bank of Canada target inflation rate), and an average depreciation rate of 3.9% (the current Ontario norm). That is, we have deliberately excluded the impact of productivity and other such factors. All we are trying to identify is the relationship between inflation, capital funding, and depreciation. Everything else is held constant.

3.11.15 What the model shows is that a utility with no growth at all (volumes and customers unchanged year to year: the "steady state" scenario) can spend 152% of depreciation on new capex while staying within a 2% price cap.

3.11.16 We then looked at what happens if that utility has organic growth in revenues (through increases in customers or volumes or both). Assuming 3% growth, and assuming that incremental OM&A is half the growth rate, but incremental capex is 100% of the growth rate (both quite conservative assumptions), we show that the utility can spend 288% of depreciation on new capex while staying within a 2% price cap.

3.11.17 Utilities, and perhaps others, will of course say that it is still more complicated than this, and indeed it is in the real world. LDCs and their experts are welcome to prepare variations on this mathematical relationship, including productivity assumptions, different classes of assets, lumpiness of spending, and any other complications they might want to throw at it.

3.11.18 But, what they will find is that, when all is said and done, our simple model is doing nothing more than describing a very fundamental mathematical relationship. Better mathematicians than we are can probably develop an algorithm that describes this with considerable precision, but it will not change either the underlying truth, or the general range of the numbers. You can play with the assumptions, and change the steady state 152% to 130%, or 180%, and you can change the 3% growth figure from 288% to 250%, or 350%. You cannot, on any assumptions, make either of those numbers anything close to 100%.

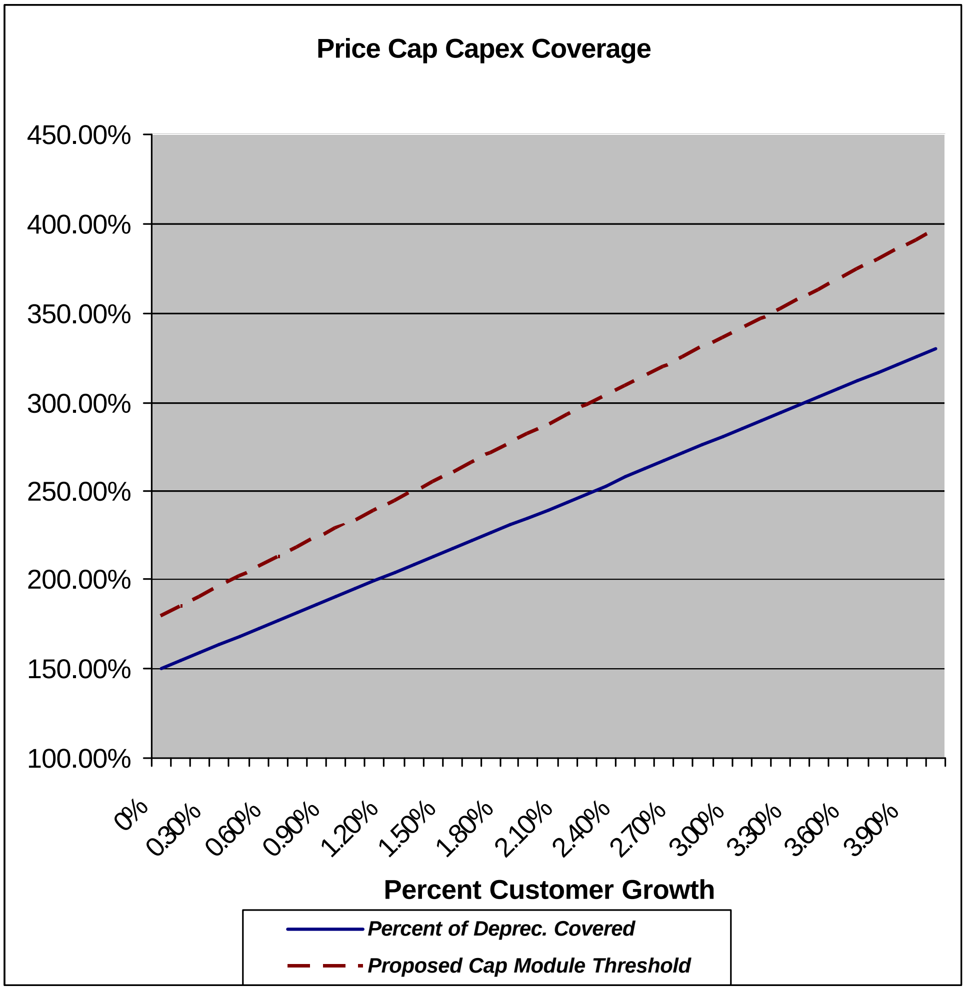
3.11.19 We believe that this, and any other mathematical analysis of the revenues available to utilities under a price cap regime, will show that a normal price cap will include a provision for capital spending far in excess of the amount of the depreciation provision.

3.11.20 This leads us to the new Staff Proposal on capital spending. Under the Proposal, utilities whose capex in an IRM year is expected to exceed 150% of approved base year depreciation would be allowed to apply for incremental rates to cover that cost. There are other criteria proposed as well.

3.11.21 In general, we believe that Board Staff are looking in the right direction for a capital spending "relief valve", but we believe that the numbers they are proposing are far from the correct ones. As our analysis above demonstrates, the price cap mechanism naturally provides for capital spending of 150% of depreciation or more for most Ontario LDCs. Where the utility has growth, they have available, without any special treatment, substantially more than the 150% level. The 150% figure proposed by Staff is therefore too low.

3.11.22 We believe that, for the Staff Proposal to work, the threshold has to be at least 20% higher than the capex spending provided for naturally by the price cap regime. Further, we believe it is possible to estimate the amount of capex generally allowed for by the price cap, tracked to growth rates, and thus to create a simple threshold formula that depends only on the approved depreciation level, and the utility's growth rate.

3.11.23 The following chart shows what we believe to be the appropriate thresholds for incremental capital spending relief, based on the utility's growth rate and the approved depreciation level. The chart shows the base line, which is the amount that the price cap would generally allow without any special treatment, and a proposed threshold, which is simply 20% above the base line. We recommend that the Board adopt this formula and this threshold line for the incremental capital spending module.



3.11.24 In calculating the proposed annual capital budget to test the threshold, in our submission government or Board-mandated incremental spending (such as smart meters) should be excluded. In our view the Board's existing approach to such spending – essentially treating the revenue requirement implications of new government mandates as a Y factor – is the most appropriate approach. It is not part of the normal flow of the utility's capital spending. It is an add-on, and should be treated as such.

3.11.25 Once the Y factor capex are excluded, a utility that needs to spend more than the threshold on capex might face that need for one of two reasons:

(a) ***Lumpiness.*** As a number of utilities have correctly pointed out, major spending programs in the 60s, for example, may entail major replacement spending programs now. Where that is true, the utility should be required to show the past spending pattern that is producing the current need for lumpy spending.

(b) ***Productivity.*** Well run utilities should always be looking for capital investments

that will improve their long term productivity. Many utilities have implemented or are implementing GIS systems, or ERP systems, for that purpose. This should be encouraged, preferably within the normal budget, but outside of it if necessary. However, the Board should make clear that a proper business case must be filed, showing the long term productivity benefits that will accrue to the benefit of the ratepayers. Ratepayer groups can then be expected to hold utilities accountable in rebasing applications for the benefits they have said will accrue.

3.11.26 The Board will note that we have been more specific about the reasons the incremental capital module can be invoked than Board Staff. We do not believe that the Board should allow incremental rates where, for example, a utility seeks to capitalize more of the costs of its existing labour force, or where a utility says that its input costs for poles have gone up faster than inflation, or where a utility says that it wants to prepare for future growth patterns. These are all capital spending issues that should be handled within, and not outside of, the price cap budget provided.

3.11.27 Three other issues arise in the context of the capital spending module. First, in our view, which we think is supported by Board Staff, the implementation vehicle should be a deferral account and a rate rider. In that way, the actual spending ends up being funded, not the forecast spending. This deals with the concern, expressed by Dr. Kaufmann [Tr. 199] and others, that recovery of incremental forecast capital could incent utilities to forecast high and spend low.

3.11.28 Second, the amount that should be collected in the rate rider should be the forecast revenue requirement impact, and the amount that should be charged to the deferral account and therefore trued up later should be the actual revenue requirement impact of the incremental capital spending. This would include things such as resulting reductions in OM&A, increases in revenue, etc.

3.11.29 Third, we believe it is important for the Board to affirm that past underspending on capital programs is not generally a good excuse for a catchup. In this respect, we draw to the Board's attention the words of the Board panel in the Toronto Hydro EB-2007-0680 case, at page 13, where the Board says in relation to the capital program proposed:

"In large part, the various studies referenced earlier establish the need for a substantial increase in sustaining capital spending. However, there are some other considerations: for example, ratepayers are entitled to expect that Utility management has an ongoing strategy to address equipment condition issues year over year. This is as true of years prior to rebasing as it is within rebasing years. In the years since amalgamation the present utility is expected to have been anticipating equipment condition issues in a manner calculated to smooth spending and ensure reliability of the system. Indeed, the present utility cannot point to the inadequacies of its constituent utilities, or the uncertain operating environment referred to above as a complete explanation for its inability to anticipate the equipment condition issues

highlighted by Kinectrics….

The Board also is concerned that the failure of the Company to adequately address this issue before now has created a situation where lumpy spending is needed. Wherever possible, utilities should act so as to avoid the kind of extensive catch-up program described in the Company's proposal."

In our view, this principle should apply with equal or perhaps even greater force to applications for special treatment of incremental capital spending.

3.11.30 We have elsewhere expressed our concerns that the inclusion of an incremental capital module may push average rates above the rate levels that the empiral research says are reasonable. In our view, there should be very few cases in which a utility outside of its own control requires capital spending rate assistance in excess of the thresholds the price cap regime already provides naturally. In those rare cases, we believe that Board should be very rigorous in its review and analysis of the reasons for the high capex, and the future impacts of approving the request.

3.12 ***Off Ramps***

3.12.1 The Staff Proposal does not really propose a formal off-ramp process. Rather, as we understand it, the Staff Proposal simply recognizes that, at any time, any stakeholder is entitled to apply to the Board to review an LDC's current rates on the basis that "this isn't working out properly". For example, if an LDC's service quality begins to deteriorate in a material way, ratepayers can ask the Board to take a look at the situation, and determine whether intervention is required. Similarly, if an LDC loses significant load, and as a result its ability to cover its costs is in jeopardy, the LDC can ask the Board to review the situation, again with a view to intervention.

3.12.2 We note that key to this approach is that the Board is asked to review, with no predetermination that it will take action. This is the approach that was taken in the two Gas IR settlements recently reached, although in that case there was a defined earnings level at which the review kicks in. We would urge the Board to adopt an approach to off-ramp applications in which there is a preliminary hearing, like a motion, to assess the nature of the problem, and the type of evidence that will be needed to address it, rather than treating every such application as a full COS proceeding.

3.12.3 We also note that, in Section 2.3 of these submissions, we have proposed to the Board that rebasing rate orders include the IRM formula for subsequent years, so that any party seeking to re-open the process before the IRM term ordered has run its course would have the onus and burden of demonstrating that something material has changed, and the original order is no longer a good basis for "just and reasonable rates".

3.13 *Z Factors*

3.13.1 The Staff Proposal provides for a standard set of causation and other rules relating to Z factors, none of which appear to be particularly controversial. As we have seen with the storm damage cases recently, Z factors are an area in which the devil is truly in the details, and we believe that the general rules proposed by Board Staff are reasonable.

3.13.2 There continues to be a concern about the materiality threshold, and we here propose a modification that we think will solve that.

3.13.3 The problem with the threshold, whether it is 0.5% or 3%, is not really in the middle of the range, but at the extremes. Whatever the formula used, the actual dollar value for each utility is not right if the utility is very small or very large. The solution, it appears to us, is a percentage with a top and bottom. We therefore propose that materiality for Z factor purposes be 1% of Board-approved revenue requirement, with a minimum of $100,000 and a maximum of $2,000,000. Only a few LDCs would be affected at the top and bottom, and for the bulk of LDCs the 1% figure would be a good one. If an LDC has a revenue requirement above $200 million, it would be fixed at $2 million materiality. If it has a revenue requirement below $10 million, it would be fixed at $100,000.

3.14 *Z Factors- Tax Changes*

3.14.1 During the course of the Technical Conference, Board Staff suggested [Tr. 20] that the possible Z factor treatment of tax changes will be determined by the Board panel hearing the Gas IR case on that subject. With respect, we disagree with this suggestion.

3.14.2 It is true, of course, that a Board panel has heard evidence on this point, and is now charged with making a decision as to the extent to which, in the Union Gas IRM period, rates should be adjusted to take into account reductions in tax rates and levels. Experts testified, and a decision will have to be made. However, that decision will not be a generic decision, and we believe that any fair reading of the transcript of that case must lead to the conclusion that it is specific to its individual facts. Indeed, much of the debate and argument centred around the actual tax savings forecast, and the changes in the GDP deflator that would have to take place to offset them, including the impact of lags, prior period tax changes, etc. It ended up, at least in the hearing and argument stage, being about the numbers, not really the principle.

3.14.3 It is also true that all parties to the proceeding appear to have agreed that there are disciplined ways of determining empirically the extent, if any, to which tax changes in a given period are captured in the GDP deflator in that period. That work has not been done. It should be.

3.14.4 We therefore believe that, unless the Board panel in that case concludes that it is able to make an overall decision on the principle, based on the evidence before it, this Board should separately determine whether tax changes should be Z factored for electricity distributors. That determination should not ignore the evidence and analysis in the Gas IR case, but should also look at other information and, optimally, include the empirical work necessary to get a more complete answer.

3.14.5 In the event that tax changes are considered to be an exogenous adjustment, we recommend that the Board continue its current practice of making a mechanical adjustment each year for all LDCs having IRM applications, rather than requiring each utility or the ratepayers to apply for Z factor treatment in the normal way. In effect, since these are known changes that will arise over the IRM period, they should be treated more like a tax Y factor than a Z factor, adjusted annually to the appropriate levels. In these circumstances, materiality is not an issue, and there should be no threshold. Taxes should simply be adjusted to reflect the new reality, whatever it is.

3.15 ***CDM***

3.15.1 The area of CDM is one that is still in a state of flux, with the respective roles of OPA and the OEB in approving CDM spending continuing to be in transition. We believe that a process to consider how this is working will be necessary at some point, including rethinking the current SSM and LRAM structures. However, for the purposes of 3rd Generation IRM, we do not think this is the appropriate time to be adjusting those rules without considerable further review.

4 OTHER MATTERS

4.1 *Process*

4.1.1 We believe that this has been a successful process, in which solid empirical work has been complemented by broadly-based and thorough stakeholder consultation, and supervised with a careful touch by Staff. We thank the Board for allowing us the opportunity to participate, and to make our views known both in the Working Group and in this formal submissions stage.

4.2 *Costs*

4.2.1 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.

Jay Shepherd, Shibley Righton LLP
Counsel for the School Energy Coalition

5 SCHEDULE A

Sample IRM Calculations (000 omitted)

No Growth Scenario

O&M Escalator	2.00%	Avg. Depreciation	3.90%
Capex Escalator	2.00%	Tax Rate	33.00%
Capex/Depreciation	152.00%	Interest Rate	6.00%

	Base Year	***1***	***2***	***3***	***4***
Rate Base	$1,713,000	$1,747,740	$1,783,155	$1,819,261	$1,856,072
Interest	$61,668	$62,919	$64,194	$65,493	$66,819
ROE	$58,722	$59,913	$61,127	$62,364	$63,626
PILs	$28,923	$29,509	$30,107	$30,717	$31,338
Depreciation	$66,807	$68,162	$69,543	$70,951	$72,387
Cost of Capital	$216,119	$220,502	$224,970	$229,526	$234,170
Capex	$101,547	$103,578	$105,649	$107,762	$109,917
O&M Expense	$308,881	$315,058	$321,360	$327,787	$334,342
Revenue Requirement	$525,000	$535,561	$546,330	$557,312	$568,512
Increase in RR		2.01%	2.01%	2.01%	2.01%

3% Annual Growth Scenario

O&M Escalator	3.50%
Capex Escalator	5.00%
Capex/Depreciation	288.00%

	Base Year	***1***	***2***	***3***	***4***
Rate Base	$1,713,000	$1,838,597	$1,968,916	$2,104,254	$2,244,920
Interest	$61,668	$66,189	$70,881	$75,753	$80,817
ROE	$58,722	$63,027	$67,494	$72,134	$76,956
PILs	$28,923	$31,043	$33,244	$35,529	$37,904
Depreciation	$66,807	$71,705	$76,788	$82,066	$87,552
Cost of Capital	$216,119	$231,965	$248,407	$265,481	$283,228
Capex	$192,404	$202,024	$212,126	$222,732	$233,868
O&M Expense	$308,881	$319,692	$330,881	$342,462	$354,448
Revenue Requirement	$525,000	$551,657	$579,287	$607,943	$637,676
Increase in RR		5.08%	5.01%	4.95%	4.89%