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ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF a consultation by the Board with respect to a Renewed Regulatory Framework for Electricity.

SUBMISSIONS ON THE GENERAL ISSUES AND THE DISCUSSION PAPERS FROM THE SCHOOL ENERGY COALITION

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1 OVERVIEW

1.1 *Background*

1.1.1 On October 27, 2010, the Board initiated a significant consultation called the Renewed Regulatory Framework for Electricity, designed to focus mostly on distribution infrastructure investment. The stated emphasis was on network investment driven by new generation, but it was not limited to that scope. In the Board's words, there was a need for:

> "***a focus on long-term outcomes that ensure that the Province's electricity system provides value for money for consumers" [emphasis added]***

The consultation included three distinct initiatives: Network Investment Planning (377), Rate Mitigation (378), and Ratemaking, Efficiency Standards, and Incentives (379).

1.1.2 As a result of these new initiatives, the Board announced at the same time that it was extending 3rd Generation IRM, and it was deferring consideration of Revenue Decoupling.

1.1.3 On December 17, 2010 the Board provided more detail on its plans in these three areas, once more emphasizing the central role issues of cost effectiveness and economic efficiency would play in the analysis. This Board letter was followed by a February 2011 Stakeholder Conference that looked at what work needed to be done to deal with each of the three areas.

1.1.4 After receiving input at the stakeholder conference, Board Staff retained consultants to provide detailed background information and research. Staff also developed Staff Discussion Papers in each of the areas. In addition, the Board added two more initiatives to the co-ordinated consultation: Smart Grid (004), and Regional Planning (043). Research work and Discussion Papers for those were also developed by Staff.

1.1.5 On November 8, 2011 the Board released the Staff Discussion Papers and supporting consultants reports for all five initiatives, and announced a second stakeholder conference for December 2011. Participants were urged to send questions in advance, and a number of parties, including School Energy Coalition, did so.

1.1.6 After the December 2011 stakeholder conference, the Board in February 2012 released a straw man proposal prepared by Board Staff, and announced a series of meetings between the Board Chair and the CEOs of stakeholder organizations, including distributors, ratepayer groups, and others. Minutes of those meetings were produced by Board Staff and published.

1.1.7 Once those meetings were completed, a third stakeholder conference was held March 28-30, 2012, with presentations and discussions on each of the five initiatives. Some Board members were present for each of the sessions, and many Board Staff also attended and participated.

1.1.8 On April 5, 2012, the Board published a letter providing further details on the input it is seeking with respect to the overall Renewed Regulatory Framework for Electricity. It also noted that it was still seeking stakeholder input on each of the five staff discussion papers.

1.1.9 These are the submissions of the School Energy Coalition. They are organized as follows:

(a) ***Part 2.*** Commentary on the general issues raised by the Board in its April 5th letter, including particularly the "vision" question central to the entire consultation. This commentary includes analysis of the Board's straw man, and a detailed regulatory proposal from SEC. Many comments related to the individual consultations are integrated into these latter two steps.

(b) ***Parts 3-6.*** Comments and discussion on each of the Distribution Network Planning, Rate-setting and Rate Mitigation, Performance and Incentives, and Regional Planning staff discussion papers and the issues contained within them. For the most part, our comments on these areas are included in Part 2, and we have simply cross-referenced that analysis, but on a few points additional commentary is appropriate. (SEC is not participating in EB-2011-0004 on Smart Grid, as it is able to rely on other parties to canvass the issues in that area.)

(c) ***Part 7.*** Analysis and suggestions with respect to the appropriate process going forward, so that the Board can build from this consultation a set of implementable policies that deal properly with the issues of concern to both utilities and ratepayers.

1.1.10 SEC has already provided input to the Board on a number of occasions throughout this process, including the following:

(a) Active participation in the February 2011 Stakeholder Conference.

(b) Detailed questions and underlying analysis of issues, provided to the Board by way of letter in December 2011 as preparation for the December Stakeholder Conference, and then active participation in that meeting.

(c) Letter of February 16, 2012 dealing with some of the key issues affecting distributor rate-setting mechanisms.

(d) Presentation on March 30, 2012 at the Stakeholder Conference, plus questions and other participation in that proceeding throughout.

We have also provided submissions on many of these issues in other Board processes, dating back to the Natural Gas Forum. Our submissions in this document are generally consistent with our previous submissions. Except where in the context it is necessary, we have tried not to repeat those earlier comments in any detail.

1.1.11 As is virtually always the case, the ratepayer groups involved in this process have worked together closely on the issues, both to avoid duplication and to ensure that our individual submissions are as comprehensive and helpful to the Board as possible. In some cases, this has included circulating drafts of documents. This has been of enormous assistance to SEC in developing these submissions. While these submissions are the position of SEC, and do not purport to represent the positions of other ratepayer groups, open communications with other ratepayer groups have improved the result.

1.1.12 Unlike many other consultations, however, in this one there have also been a number of offline communications between utilities and ratepayer groups, some initiated by the utilities and some initiated by the ratepayers, starting as early as February. These have included exchanges of proposals, direct discussions of concerns and issues, and frank analysis of the potential for consensus. We note that, perhaps unsurprisingly, utilities and ratepayers have many common goals, and that commonality of interest is usually enhanced by dialogue. Again, we do not in any way suggest that SEC's proposals are supported by any of those utilities. However, the discussions have allowed us to include better consideration of their concerns. Our proposals are therefore modified from what we had originally planned.

1.1.13 Finally, RRFE is sufficiently important to schools that it was a specific agenda item at the recent annual meeting of SEC's parent organization. The discussion involved the active participation of the heads of some of our seven member organizations. They emphasized more than anything SEC's longstanding view that collaborative solutions to major issues between utilities and their customers are far preferable to adjudicated or imposed solutions. Our comments and proposals below reflect that belief.

1.1.14 SEC's submissions deal only with electricity distributors. While the original scope of RRFE included electricity transmitters in some of the initiatives, and there certainly are issues to be addressed on the transmission side, in our view there has been insufficient information provided in the course of this consultation for the Board and parties to make useful proposals relating to transmitters. Therefore, we have generally not considered transmission issues.

1.2 *Summary of Submissions on Vision and General Issues*

1.2.1 ***3rd Generation IRM – Concerns Expressed.*** Utilities have expressed a number of concerns relating to the current regulatory mechanism, of which four stand out:

(a) ***Funding For Capital Spending.*** Our submissions prove in detail that the arguments by some LDCs relating to CEEDs and the half year rule are entirely wrong. As long as the inputs are correctly calculated, the structure of IRM fully compensates for normal capital funding needs. In the areas in which capital funding may be a legitimate concern – capital spending due to government requirements, cost of increased functionality, and others – SEC continues to be of the view that the Board cannot solve these problems until they have been identified and quantified with some precision. This work has not yet been done.

(b) ***Cost of Being Regulated***. For the utilities that are concerned that regulation – even if perfectly efficient – is still too expensive for them, we have little sympathy. They are in a regulated business, and that entails certain natural and necessary obligations. Answering to the regulator is one of them. On the second aspect of regulatory cost, the question of whether the Board's processes can be more efficient, we agree with the Board's recent response to the Auditor General. Regulatory efficiency is and should be an ongoing, continuing, and important goal of the Board, but it has to be achieved without compromising the Board's standards and mandate.

(c) ***Distributor Diversity***. Distributors are diverse. Some of those differences – those that are truly external to the business, like local topography – should be reflected in rates. Others that are within the control of the utility – such as the choice of utility size, or the cost of past mismanagement – should generally not be reflected in rates. The owner makes those choices, and should bear the consequences. The SEC regulatory proposals seek to recognize diversity while still keeping the ratepayers protected.

(d) ***Other Cost Pressures.*** SEC has seen no evidence that LDCs have many common cost pressures in excess of inflation that are not being experienced outside of the sector as well. Cost pressures being experienced by other businesses are either included in the rate of general inflation, or are being managed by competitive businesses and so should be managed by regulated businesses as well. For the few special cost pressures that are left, they are specific to individual utilities, so a general rule to capture their impact is neither required nor appropriate.

1.2.2 ***3rd Generation IRM – Experience to Date.*** In the absence of empirical analysis by the Board or others, SEC has reviewed the Yearbook data with respect to capital spending and return on equity. What the data shows is:

(a) On average distributors are not underinvesting in capital. In 2010, they invested 224% of their depreciation in new capital assets.

(b) There is no significant difference in ROE between those who invest heavily in capital renewal, and those who do not.

(c) There is no significant difference in capital renewal levels between those on COS and those on IRM (once Hydro One and Toronto Hydro are excluded from the averages).

(d) On average distributors are earning more than their allowed ROE on a financial statement basis. In 2010, 30 out of 77 earned more than 8%, and of those 14 earned more than 10%.

(e) On average, there is no significant difference in actual ROE between those in a COS year and those in an IRM year. Further, of the 14 who earned more than 10%, only 3 were on COS.

These facts lead us to conclude that, at a high level, 3rd Generation IRM is working as it was supposed to work.

1.2.3 ***The Board's Straw Man.*** SEC has serious concerns about the origins and history of the straw man, and recommends that the Board revert to its traditional, more open practices when future proposals of this nature are being considered. However, whatever its genesis, it is still appropriate to respond to the proposal on its merits.

1.2.4 The Board's straw man has four key components on which we have comments:

(a) ***Shift from Comprehensive Price Cap to Targeted PBR.*** The regulation of OM&A and capital using separate methodologies has several serious problems, including the following:

(i) The effect is to incent capital spending and disincent OM&A.

(ii) The proposal requires a more resource-intensive process at the Board, which already has limited resources.

(iii) Some LDCs are not in a position to prepare the kind of multi-year capital plan necessary for this mechanism to work.

(iv) The formula rate increase applicable to OM&A may be more difficult to calculate than is apparent.

(v) The proposal does not properly reflect distributor diversity. Based on some

analysis SEC has carried out, it may in fact exhibit an unintended bias in favour of larger utilities.

(b) ***Change the Inflation and Productivity Factors.*** SEC sees merit in a review of these factors, and in particular including capital data in a total factor productivity analysis.

(c) ***Distributor Choice for Plan Term.*** We do not believe it is appropriate to allow distributors full discretion to choose the term of their IRM plan. On the other hand, if the flexibility is that they can propose a term subject to Board approval, and the term is a minimum of rebasing plus three years, then we believe this is a useful added flexibility.

(d) ***Expedited Process.*** The EDA/straw man proposal to have less than full scrutiny of some cost of service applications is contrary to law and inconsistent with the Board's statutory mandate.

1.2.5 Because the move to Targeted PBR appears not to be supportable, the overall proposal is in our view not worth pursuing. It did, however, have the positive effect of generating discussion and analysis of the issues. Some of the ideas have been incorporated into the SEC proposal.

1.2.6 ***SEC Proposal.*** SEC proposes that distributors be allowed to choose between three mechanisms to set their rates, each mechanism being inherently designed to protect ratepayers with respect to prices:

(a) ***Multi-Year Cost of Service.*** LDCs would be able to seek rates based on a cost of service application for a period of at least four years. The application would have to forecast costs of all types for each of the four years, and would also have to include a ten year strategic plan so that the rate increases requested could be seen in the long term context. Benchmarking would be used to assess the reasonableness of cost increases proposed. This choice would be most suitable for LDCs with special problems to address. Ratepayer protection relies on the Board's history of being able to drive cost effectiveness and economic efficiency in the utilities it regulates.

(b) ***IRM.*** The second choice, with a lower level of regulatory cost, and scrutiny, would be based on 3rd Generation IRM. After a review of the unit cost inflation, productivity, and stretch factors, the Board would make whatever changes are required to make those factors fairer, e.g. by including capital inputs. The ICM would be removed, because LDCs would have the option of multi-year COS. Government-mandated capital spending would be treated as a Y factor, on a case by case basis. Many utilities are thriving on 3rd Generation IRM, so we would expect this to be the most popular option. Ratepayer protection in this mechanism relies, as it does now, in part on the LDC's commitment to accept formula increases three years out of four, and in part on the Board's ability to require evidence of cost effectiveness in the rebasing year.

(c) ***Long Term Rate Commitment.*** The third choice, with minimal regulatory overhead, is a long term commitment by the LDC to have their rates set based on a percentage of inflation. The LDC would propose any percentage between 50% and 95% of inflation, and any term of ten years or more, and the Board would assess the appropriateness of the formula and term based on the current rate levels and operating efficiencies. This choice would allow smaller utilities, for example, who wish to remain independent, to reduce their regulatory costs almost to nothing, in return for a commitment to contain their other costs and protect their ratepayers. As utilities increase their internal focus on long term operational goals, this may become an increasingly attractive option. Ratepayer protection is based on the LDC guaranteeing to meet this price control responsibility.

1.2.7 The SEC proposal has a number of specific ideas embedded within it, described in more detail in the body of these Submissions. However, it is also important to note that there are still many details to work out. These Submissions provide a concept that, in our view, can be made to work, but as with most regulatory constructs, we recognize that the devil will still be in the details.

1.3 ***Other Submissions on the Issues***

1.3.1 Because most of our comments on the issues in the individual consultations are folded into the main analysis in Part 2, the additional sections are brief.

1.3.2 We do, however, want to emphasize our comment on Revenue Decoupling. This is an important issue, but the review has been suspended during this Renewed Regulatory Framework process. SEC believes restarting this review should be made a priority by the Board.

1.4 ***Summary of Submissions on Process***

1.4.1 The Board will get hundreds or thousands of pages of submissions on the issues in this initiative. As we indicated in our letter of February 16, 2012 to the Board, we agree with the DRRTF that it is important to keep this process moving. Therefore, a process to deal with the ideas in those submissions, and the areas of agreement and disagreement, is critical.

1.4.2 To this end, we propose three process steps following the receipt of this round of submissions:

(a) The Board should make provision allowing anyone who made submissions to reply to the submissions of any other party. SEC would like to have the opportunity to respond to the submissions of others. We also believe that these initial Submissions will be more useful to the Board if other parties have had a chance to challenge them, or agree with them. Not only will this complete the picture for the Board, but it creates an opportunity for full or partial consensus to emerge on some points.

(b) After receiving the reply submissions, the Board should provide some guidance on direction. This could include taking some options off the table, and narrowing the scope of other aspects of the debate. This is a method that has been used by the Board on many occasions in the past to provide momentum towards the final result, while recognizing that there is still considerable work to be done.

(c) The Board should establish a Working Group of utilities, ratepayers, and other stakeholders experienced in distributor regulation. Under the supervision of Board Staff, that Working Group should prepare detailed and <u>implementable</u> proposals based on the Board's guidance and representing, if possible, consensus amongst parties.

2 VISION

2.1 *Introduction*

2.1.1 The Board already has a detailed mechanism for setting rates for electricity distributors, established as a result of a rigorous and thorough process and based on empirical analysis. In our view, changes to the existing process should only be implemented to deal with situations in which:

(a) Stakeholders such as utilities or ratepayers, who are affected by the ratemaking process, are unhappy with its results in definable situations; and

(b) There is verifiable independent evidence that parties' concerns with those situations are well-founded.

2.1.2 Put in the vernacular, it is important for the Board to focus its attention on solving real problems. In situations where the stakeholders are satisfied with the balance in the result, or in situations where stakeholder concerns are not supported by facts, the Board should not try to "fix" anything. That will inevitably only make things worse.

2.1.3 This probably all seems trite, perhaps even not worth raising. We have done so because in our view the simple analysis above should drive the Board and parties to a specific way of approaching the issues. That is, first determine what stakeholders actually don't like about the current system. Second, test each of those concerns against empirical data.

2.1.4 In the analysis below, SEC identifies what it believes to be the major concerns of both distributors and their customers. We then look at the available data to see which of those concerns may have validity, and in what circumstances. Informed by that analysis, we first consider the Board straw man, and then make a detailed proposal of our own for the regulation of electricity distributors going forward.

2.2 *Issues Raised by Stakeholders*

2.2.1 ***Utility Concerns.*** The materials in this consultation, including the minutes of the meetings with the Chair, and the volumes of materials in rate cases over the last couple of years, reveal a number of concerns by utilities at various levels of granularity. Keeping to a relatively high level, it appears to us that the major utility concerns are the following (not in any particular order):

(a) ***Capital Spending Under IRM.*** A number of utilities have expressed the need for additional funding under IRM to cover the cost of infrastructure spending, and have suggested that the IRM framework is structurally deficient in the capital funding it provides.

(b) ***Resources Needed for Regulatory Requirements.*** A concern expressed by the EDA and some distributors, although not all, is that the regulatory process demands more of their resources than is reasonable.

(c) ***Distributor Diversity.*** Most LDCs would agree that distributors face quite different business realities depending on their geographic location, history and other factors, and therefore regulatory approaches based on a "one-size-fits-all" paradigm are problematic.

(d) ***Other Cost Pressures.*** Some LDCs have, in rate cases and other documents, expressed the view that the price escalator in IRM doesn't reflect the actual increases in their costs from year to year.

2.2.2 ***Capital Funding.*** The problem of capital funding under IRM is a difficult one. At a simplistic level, utilities argue that the only funding in rates for new capital is the depreciation on the existing assets, but new assets cost more than old ones because of inflation. The term Capital Expenditures in Excess of Depreciation (CEEDs) has been coined to express this. Those same utilities argue that the half year rule in the rebasing years builds in a further shortfall that is not recoverable under IRM.

2.2.3 This basic argument is simply wrong. On the CEEDs issue, the argument fails to reflect the fact that while new assets do indeed cost more than old assets, the annual cost of old assets (when depreciation, cost of capital, and related PILs is totaled) is going down every year because the undepreciated capital cost is dropping, and the depreciation provision is going up annually as new assets are included.

2.2.4 The easiest way to see this is to assume a situation in which there is no inflation, and assets all have a 30 year life. The replacement obligation this year will be $1/30^{th}$ of the original cost of the existing assets. The depreciation this year will also be $1/30^{th}$ of the original cost of the existing assets.

2.2.5 But there is inflation. How does that change this equation? The answer is a net of zero. The depreciation provision is no longer $1/30^{th}$ of the cost of the assets being replaced. It is $1/30^{th}$ of the cost of the existing assets, which have vintages from 1 year to 30 years. The depreciation provision will (ignoring compounding for simplicity) reflect, on average, assets that are 15 years old.

2.2.6 Further, the remaining costs associated with the capital being replaced have been going down year by year, as rate base is shifted from the balance sheet to the income statement through depreciation. This means that each year, while new capital assets are more expensive, and therefore the carrying cost increases, the old capital assets are less expensive, and therefore the carrying cost decreases.

2.2.7 It has been demonstrated algebraically, financially, and in a full model that, if the annual increase in the cost of capital assets due to inflationary forces is exactly equal to the net increase in the X factor, the IRM formula includes in rates exactly the amount necessary to replace the assets being retired (including the impact of compounding).

2.2.8 Take a simple example. Assume $100,000 of capital assets added each year, with a life of 10 years, and annual cost increases of 2%. What does the math show?

(a) When it comes time to replace the first assets in year 11, the 2% cost increase compounded annually will increase the cost from $100,000 to $121,899. That is the replacement cost.

(b) Depreciation on the pool of assets, which will include assets from 1 to 10 years old, will be $110,592 in the year the replacement of the first assets has to take place. The reason for this is that while the depreciation on the oldest assets is lower ($10,000), the depreciation on the most recent assets is higher because their original cost is higher. Not surprisingly, the increase in annual depreciation is roughly equal to the rate of cost increases, compounded for half the period.

(c) A 2% annual rate increase results in rates available to cover capital costs equal to 110.22% of depreciation.

(d) Multiplying the current depreciation by 110.22% gives you exactly $121,899, the cost of the new assets to replace the 10 year old ones.

(e) If the assets have a 20 year life, the cost of the replacement assets at 2% a year is $148,590, the depreciation in the current (replacement) year is $122,702, the rate increases provide funding for 121.10% of depreciation, and that nets a funding amount of – you guessed it - $148,590.

2.2.9 The above calculation works on any assumption as to cost increases, and any assumption as to the life of the assets.

2.2.10 It is also true that the same results follow if the half year rule is included in the calculations of first year depreciation. (In fact, the above numbers were initially derived using the full model, including the half year rule, and later checked removing the impact of the half year rule.)

2.2.11 Why doesn't the half year rule have an impact? The simple answer is that those promoting that argument are forgetting that in the last year of an asset's life, the remaining half a year of depreciation is charged. That impact offsets the impact in the first year. In any given year, some assets are depreciated at 50% because they are new, and some at 50% because they are old, and these are offsetting effects.

2.2.12 There are numerous objections that can be made to this simple analysis, including:

(a) 3rd Generation doesn't fund at inflation levels, but at much lower levels. That is true, but as long as the IRM escalator fairly reflects annual increases in utility unit costs, the conclusions above remain valid. The conclusions will only be invalid if the escalator does not correctly reflect the long-term annual escalation in the cost to LDCs of capital assets. That, then, would not be a problem with the structure of the capital funding, but rather a problem with the cost escalator used. We talk about this question further, later in these submissions.

(b) Replacement of assets is often not like for like. The new assets may have increased capabilities or functionality. Those come at an incremental cost. That is likely true, although offset in whole or in part by greater efficiencies in new assets and the resulting downward impact on other costs. In any case, this is again not a problem with the structure of the capital funding. It reflects instead either productivity investments or a higher level of service to customers. These have to be quantified if they are to be reflected separately in rates.

(c) There are many additional capital costs associated with government directives and other external forces. Again, this is not a problem with the structure of the capital funding, but is a separate issue. We discuss this further below.

2.2.13 SEC has been saying for some time that if there is a problem with capital funding, it must be identified with more precision. The erroneous arguments based on CEEDs and the half year rule are complicating the Board's review unnecessarily. It appears to us that those making those arguments either have to step up and demonstrate their arguments mathematically (they can't), or drop them and allow the Board to focus on the real issues.

2.2.14 There may well be real issues associated with capital funding: government and other external requirements increasing capital requirements, higher levels of service or reliability, etc. On the other side, some capital assets should be dropping in cost relative to the functionality being delivered, since this is a common cost pattern in categories like new technologies.

2.2.15 If the Board is going to make changes to address capital funding in IRM, then SEC believes the Board has to identify and quantify the problem being solved, before trying to solve it. Is the problem the cost escalator? Let's look at that. Is it the impact of government directives? That would have a different solution. And so on.

2.2.16 In the materials below we will make some specific proposals for how to reflect capital spending needs while still meeting the Board's mandate with respect to protecting consumers.

2.2.17 ***Regulatory Costs.*** The problem of the cost of regulation decomposes into two parts:

(a) Some LDCs are concerned that regulation, no matter how efficient, still takes up an inappropriately large percentage of their resources.

(b) Some LDCs are concerned that there are inefficiencies in the regulatory process that increase costs unnecessarily.

2.2.18 On the first of these problems, it is difficult to have sympathy for the LDCs who are expressing it. They are in a regulated business. A natural and essential aspect of their monopoly business is that their rates will be subject to third party scrutiny, and their ratepayers will be interested and involved in that process.

2.2.19 In most cases in which this problem is expressed, the utilities are small ones. While there are benefits associated with small utilities, one of the drawbacks is the lack of economies of scale. Many functions in a utility do not scale in cost in lock step with the size of the enterprise. Regulation is one example of that.

2.2.20 When those utilities and their owners choose to remain independent, rather than merge or consolidate within a larger entity, that is a local decision that must be respected. At the same time, the owners must accept the consequences of that local decision. One of the consequences is that some economies of scale will be foregone.

2.2.21 SEC has consistently taken the position that ratepayers throughout the Province are entitled to a full level of regulatory protection, regardless of the size of the local utility. In the most extreme case, a school in a small town cannot be told "Your rates will not be scrutinized properly, because your LDC is too small. You just have to trust the utility not to raise your rates too much." That school is entitled to the same protection as a school in Toronto or Hamilton or Ottawa.

2.2.22 This does not mean that the overall cost of regulation should be ignored. In our proposals, later in these submissions, SEC sets out three types of regulation that could be available to LDCs: very streamlined, very thorough, and somewhere in the middle. Our proposals, however, seek to ensure that ratepayers are fully protected no matter which choice is made.

2.2.23 The second "cost of regulation" problem is inefficiencies in the process. There are, in fact, improvements that can be made in the regulatory process, and that is and should be an ongoing goal of the Board. The ratepayers pay these costs. We don't want waste. Waste comes directly out of our pockets.

2.2.24 For example, things like increased standardization of filing requirements help cut costs and improve the quality of information. This has been a Board focus, and should continue.

2.2.25 A number of other examples could be provided, and we support continued efforts to improve efficiency. However, we agree with the Board's caveat, in responding to the recent comments of the Auditor-General relating to the cost of regulation:

> *"The rate-setting process requires appropriate information on the public record to support sound and responsible decision-making." [page 77 of the Report]*

2.2.26 ***Distributor Diversity.*** It is undoubtedly true that distributors are not all the same, and the businesses they operate are not all the same. Those differences can affect their costs and their rates. For some – but only some – of those differences, it is just and reasonable for the Board to take them into account account in the rate-setting process.

2.2.27 The trick is knowing which differences get which Board response. A distributor faced with long distances or Canadian Shield topography may have higher costs, and those higher costs must be reflected in rates. Anyone supplying distribution services in those areas is going to have those higher costs.

2.2.28 Contrast that with the distributor who has elected to stay small, as discussed above. Where that decision by the local owner has been made, some economies of scale may not be available. These cost pressures are not the result of an external reality; they are the result of a choice made by the distributor and its owners. That choice has consequences, and it is likely unfair to visit those consequences on the ratepayers.

2.2.29 Similarly, if a distributor has suffered for some past years from bad management, and as a result costs are higher today, should the ratepayers pay for that? It is at least arguable that the shareholder should bear all or part of that consequence.

2.2.30 SEC's view is that diversity should in fact be recognized, but as exceptions rather than as the norm. The businesses of LDCs are, for the most part, very similar. Even where they are different, most of those differences come within a reasonable range of operating flexibility. There are some attributes that are truly external and drive costs in ways difference from the sector average. Where that can be demonstrated, the Board's regulatory processes should be sufficiently flexible to identify and reflect those cost differences.

2.2.31 ***Other Cost Pressures.*** Some LDCs have expressed a concern that their other costs – unionized wages, for example – are going up faster than inflation less productivity, and they can't manage within the IRM formula. An example of this sort of argument is the "aging workforce".

2.2.32 In general, SEC does not believe that there are significant general cost pressures within the sector that are not reflected in the IRM formula already. A case in point is the aging workforce. Yes, employees are getting older, and if the average employee works for 35 years, then at any given time 60% of the workforce will retire in the next 21 years. Further, if employees on average are eligible to retire after 30 years, so they work on average 5 years past their retirement date, then at any given time 60% of the workforce will be eligible to retire in the next 16 years.

2.2.33 The actual numbers don't matter in this context. The principle is clear. Employers have to be concerned about their most experienced people leaving, and have to manage in a way that minimizes the cost and disruption of that reality.

2.2.34 The first key point, though, is that this is not new. It is a natural result of having employees that they will be one year older each year.

2.2.35 Further, if the problem has been exacerbated by the baby boom, as some have suggested, then this is a problem common to all businesses in Canada. If they were increasing their prices for this additional cost, that would be reflected in the rate of general inflation. If they are not increasing their prices to cover this, why can't utilities manage these costs without increasing prices as well?

2.2.36 In our view, a cost pressure – even if real – that is common to many businesses in Canada is either reflected in the rate of general inflation or it is one that can be managed by the company, as others do.

2.2.37 We have not seen any examples of material cost pressures that are common to most LDCs, but are not also common outside of the sector. The one exception to that may be government directives. To the extent that LDCs have more costs due to new government requirements than unregulated companies, that would be a sector-specific common cause. These additional cost pressures, however, have generally been reflected in rates separately (smart meters, GEA plans, CDM), so do not appear to be the heart of the problem.

2.2.38 There are exceptional cases where utilities have cost pressures that are not covered by IRM, but they are unusual and not common to other LDCs. In our view those costs have to be dealt with through a review specific to those LDCs. Establishing a general rule to capture them is a) unlikely to capture them fully, and b) likely to allow incremental increases for unaffected utilities as well.

2.2.39 ***Ratepayer Concerns.*** Ratepayer groups have not expressed as many concerns with the status quo, but they do have some, including:

(a) ***Rate Levels.*** There is a wide variation in the cost of distribution service from one

LDC to the next, and there are not always good reasons for those differences.

(b) ***Pattern of Rate Increases.*** The initial pattern that has emerged for many LDCs under IRM is three years of controlled rate increases, followed by a spike on rebasing.

(c) ***Underinvestment and "Harvesting the Assets".*** The large differences in capital in the ground and capital spending levels between LDCs raise a question of whether some distributors are not investing sufficient dollars in infrastructure renewal.

2.2.40 Our comments on these ratepayer concerns are included in our analysis and proposal below.

2.3 ***The Results from 3rd Generation IRM***

2.3.1 Before looking at the straw man proposal, it is appropriate to consider whether and, if so, to what extent, is 3rd Generation IRM "broken" and therefore in need of fixing.

2.3.2 With respect to some of the detailed aspects, we will consider those in the context of our review of the straw man, and our own proposals for regulatory change. In this section, we will deal only with the higher level empirical data. We will consider two areas:

(a) Capital spending levels; and

(b) Profitability.

Our data is drawn from the Yearbook for 2010, the most recent year information is available.

2.3.3 ***Capital Spending.*** The Yearbook contains the actual annual depreciation amount, and the actual capital spending for the year. The ratio of actual capital spending to actual depreciation can easily be determined.

2.3.4 What the data discloses is that, on average, Ontario LDCs had new capital spending in 2010 equal to 224% of depreciation. The range is from 24% to 412%, including outliers, but in fact with only seven exceptions all are between 100% and 299%, i.e. spent more on capital than their depreciation provision for the year.

2.3.5 Both Hydro One and Toronto Hydro had high capital budgets, so it is appropriate to test the results without them. Excluding those two, the average is 191%.

2.3.6 Those are weighted averages. The simple average including all utilities was 183%, suggesting that larger utilities spent a higher percentage of depreciation on new capital.

The weighted average of 224% is much higher than the unweighted. However, when Hydro One and Toronto Hydro are again removed, the simple average is 178% compared to a weighted average of 191%. These are much closer, suggesting that any correlation between size and spending level is mostly the result of Hydro One and Toronto Hydro.

2.3.7 There also does not appear to be a significant difference between utilities on IRM, and those on COS. Again excluding Hydro One and Toronto Hydro, those on IRM spent 188% of depreciation, and those on COS spent 204% of depreciation. An 8% differential between IRM and COS is not indicative of a big problem in the IRM years.

2.3.8 Finally, there does not appear to be any correlation between the capital spending ratio of an LDC and its actual ROE for the year. As is apparent from our comments below, the actual ROEs were healthy in many cases, and the high ones did not correlate to either high or low capital spend.

2.3.9 SEC concludes from this capital spending analysis that 3rd Generation IRM is not on average, or as a general, common or pervasive factor, causing LDCs to underinvest in capital.

2.3.10 ***Return on Equity.*** The next piece of information that is useful is return on equity, because if capital spending remains high but overall profits are low, that implies that utility management is doing the right thing at the expense of their shareholders instead of their ratepayers. That does not appear to be the case.

2.3.11 Our analysis looked at the data two different ways.

2.3.12 First, we looked at the overall actual ROE of the sector in 2010. That figure – net after-tax income divided by shareholders' equity – was 8.64% in 2010, well above the average ROE built into rates.

2.3.13 Second, we looked at the data from the point of view of the principle that an LDC has to have "an opportunity" to earn their allowed rate of return. Of the 77 distributors whose results are reported in the Yearbook, 30 had an actual ROE in 2010 of more than 8%, including 14 with an ROE in excess of 10%.

2.3.14 We note that using actual ROE has some difficulties, particularly where financial statement data may include revenues and/or expenses that are not included for regulatory purposes. We know of some examples both ways. A more rigorous review would look at only regulatory data, but that data is not publicly available, so we have made the simplifying assumption that financial statement adjustments will affect the data equally upward and downward. There is no evidence on which to base that assumption, but we are using the best data available.

2.3.15 Assuming the ROE data is indicative, it is worth noting that the actual ROE for the utilities on COS in 2010 was 8.84%, pretty close to the total for the industry, and the actual ROE for the utilities on IRM in 2010 was 8.52%. (Hydro One and Toronto Hydro are included in all of the ROE totals, but removing them does not have a significant impact.)

2.3.16 It may also be worthwhile noting that, of the 14 LDCs that earned more than 10% actual ROE, only three were 2010 cost of service filers.

2.3.17 We have three conclusions from the ROE data. Clearly whether on IRM or COS, the 3rd Generation IRM is providing distributors overall with an opportunity to earn their allowed return. Clearly, as well, some distributors have been able to earn far more, which is one of the goals of IRM.

2.3.18 The third conclusion is that, if there is a problem with 3rd Generation IRM, it is not a problem that affects most LDCs. The overall averages appear to be quite acceptable. If there are problems, it is important to look into the specific cases to see who is affected, and why.

2.4 ***The Board's Straw Man***

2.4.1 ***Genesis.*** The straw man provided by the Board bears striking similarities to a proposal by the Electricity Distributors Association in July of 2011.

2.4.2 This has an unfortunate history. The EDA proposal was provided to the Board somewhere around the time it was finalized in late July 2011, but it was not made public by the EDA or the Board for a considerable period of time (apparently about three months) while it was being reviewed by the Board. Requests from stakeholders to the Board to have it made public were rebuffed.

2.4.3 In our submission, this was completely inappropriate, and the Board should take immediate steps to ensure that this error is not repeated. When stakeholders make proposals to the Board for changes to the regulatory process, those proposals should be made and considered in an open and transparent way. For regulated entities – including associations representing them – to seek to influence the Board's thinking on an area of regulation in secrecy is, if not contrary to law, at the very least contrary to good practice, transparency, and the Board's historical approach. The Board's reputation and effectiveness are founded on its independence and impartiality. Policy dialogues between the Board and regulated entities should be held behind closed doors only in the most exceptional circumstances. Even then, the Board has an obligation to explain publicly why an exception was appropriate in any specific case.

2.4.4 We note that it is not a sufficient answer to say that, despite the secrecy, many in the industry had copies of the EDA document long before it was made public. It is the

Board's responsibility to ensure that its processes and policy engagements are transparent. Failure to do so is cause for alarm.

2.4.5 The background of the EDA proposal is doubly unfortunate because essentially all of the key elements found their way into the Board's straw man. In other circumstances, this could undermine the value of the straw man by making it look biased, and implying that it is not really a proposal from Board Staff at all.

2.4.6 SEC sees that direction as an unproductive one. Even if the originator of many aspects of the straw man is the EDA, it is still appropriate to deal with those proposals on their merits. In our view, the straw man is really no different from the other proposals made in the most recent stakeholder conference by various parties. It represents ideas – whatever their source – on how regulation of electricity distributors should be changed. We propose to respond to it on that basis.

2.4.7 ***Components.*** The straw man has four main components:

(a) ***Targeted PBR replaces Comprehensive Price Cap.*** The capital component is dealt with separately, on a cost of service basis, over the period of a multi-year capital plan.

(b) ***Change Inflation and Productivity Factors***. The productivity factor would be reduced, based on total factor productivity and taking into account more recent trends, and the inflation factor would be shifted to an industry-specific metric.

(c) ***Distributor Elects Term of IR Plan***. Each distributor would be free to choose how long their IR plan would last. At least on the face of it, a distributor that wishes cost of service every year would have that option.

(d) ***Limited Review of Some Capital Plans***. The Board's would offer an "expedited process" for review of capital plans that meet specific tests, which are as yet undefined. Those tests do not appear to be driven by comparative rates. The level of fast-tracking has not been described.

2.4.8 We will deal with each of these components in turn.

2.4.9 ***Targeted PBR.*** There are a number of reasons why splitting the regulatory structure into OM&A using IRM and capital spending using COS is problematic:

(a) It may incent capital spending at the expense of operational spending.

(b) The proposed regulatory regime requires significantly more Board resources, and also intervenor resources, and is likely to increase the cost of regulation.

(c) Many LDCs may not be at a point in their development that they can produce good quality multi-year capital plans, and/or the cost to do so may be prohibitive.

(d) The appropriate indexing factor for OM&A will be a difficult challenge, both because of the basic calculation (total factor productivity less partial factor productivity on capital, perhaps), and because of the interaction between increasing capital costs and declining OM&A costs.

(e) The proposal does not reflect the significant diversity between distributors in mix of spending, and may in fact benefit larger utilities much more than smaller utilities due to different levels of reliance on OM&A.

Each of those issues requires some explanation.

2.4.10 First, whenever you place tighter reins on one area of spending rather than another, you create an incentive to increase spending in the more loosely-regulated area. In this case, the perverse result of putting capital on COS and OM&A on IRM is that the Board incents increased capital spending and reduced OM&A spending.

2.4.11 Is this a bad thing? Clearly, sometimes it would not be bad. Some distributors do "harvest the assets", and encouraging them to renew their infrastructure is worthwhile. In recent settlement agreements, intervenors have in fact supported increased capital spending by utilities where it appeared that the utilities were underinvested relative to their customers' needs.

2.4.12 However, what is proposed here is that there be a systematic encouragement of increased capital spending by all LDCs, i.e. a shift in emphasis from day-to-day operations to capital planning and renewal. This is not likely to be correct in all or perhaps even most cases, and utilities that manage based on this spending signal from the Board would be less well managed.

2.4.13 Therefore, in our view splitting the regulation of OM&A and capital into two streams only works if the Board panels reviewing the multi-year capital plans are sufficiently tough on those plans that utilities do not perceive capital approvals to be "easier". While the Board has been increasingly willing to look forensically at utility proposals in recent years, in general the Board has been easier on capital spending than OM&A in cost of service applications. If this continued under this new proposal, the necessary result would be a shift in focus by the utilities, and overall increases in rates to cover the increased spending.

2.4.14 Second, the development and approval of multi-year capital plans, while in many respects a very good thing, will increase the demands on the resources of the Board and the parties.

2.4.15 Right now, the Board considers cost of service rate applications for less than twenty LDCs each year, and some of them have very simple capital plans. If each of those twenty is now required to do a multi-year capital plan, the Board and parties will have to spend more time considering it, not only because it is for four or five years instead of one, but also because as planning goes out in the future, uncertainty increases.

2.4.16 Third, it is not clear to us that all LDCs are currently ready to develop multi-year capital plans at the level that would be required to meet the legal obligation to set just and reasonable rates. The very utilities that feel that the regulatory burden today is more than they can handle would, in our view, be stretched further by the need to develop and defend multi-year plans. When they do file their capital plans, the resources of the Board and intervenors required to deal with them could also be greater, because of the information gaps that may arise.

2.4.17 We note that forcing LDCs to be more rigorous in their network planning is not altogether bad. On the other hand, pushing them past their reasonable limits will not produce good plans, yet at the same time their attention will be diverted from operational issues. Making multi-year capital plans mandatory appears to us to be an idea that is before its time, i.e. something that should be reconsidered in a few years when industry consolidation has had some further success.

2.4.18 Fourth, it appears clear that establishing the indexing factor for OM&A alone will be a very difficult task.

2.4.19 One cannot simply look at how much OM&A costs have risen in past years, in effect calculating inflation and productivity on OM&A alone. The more correct approach, it appears to us, would be to calculate overall inflation less total factor productivity, then separately calculate the inflation and productivity on the capital component of revenue requirement. The difference between the two would be the implicit X factor for OM&A, and even a cursory review suggests that the number may be far lower than LDCs would like.

2.4.20 Further, the indexing factor has to take into account the effect of increasing capital spending on future OM&A and on load. New infrastructure needs less maintenance and operational supervision, and many processes can be automated with more modern gear. Capital plans will include productivity-driven investments, which will also tend to reduce OM&A going forward. Capital plans will include growth-related investments, which growth will also have to be reflected in the price cap to maintain cost and revenue symmetry.

2.4.21 For the OM&A IRM formula to be fair, it will have to take those downward pressures into account. The quantum of the adjustment cannot be determined in advance, for all LDCs, as it will be driven by the size of the capital plan, and the nature of the spending. On the face of it, the COS proceeding will have to have as one of its issues the establishment of a reasonable IRM formula for OM&A for that LDC. This not only increases the cost, but decreases the certainty surrounding the process.

2.4.22 Fifth, this is all complicated by the fact that the percentage of revenue requirement driven by OM&A vs. capital varies substantially between Ontario LDCs, and the proposal does not take that diversity into account.

2.4.23 As part of our continuing analysis of Yearbook and other comparative data, SEC has reviewed the capital vs. operating cost split for Ontario LDCs in two ways.

2.4.24 The most obvious method, of course, is to take final COS rate orders for LDCs and determine the percentage of the revenue requirement that is OM&A and the percentage that is capital. There have been seventeen final COS rate orders for 2010 and 2011, shown in Appendix A to these Submissions. The range of capital component of revenue requirement is from a low of 35.9% to a high of 66.3%.

2.4.25 What is most striking is that there appears to be a correlation between distributor size and percentage of revenue requirement driven by rate base. This can be seen visually when the distributors are listed in order of operating/capital split. It can also be seen in the fact that the simple average capital percentage is 50.9%, while the weighted average capital percentage is 57.2%. Necessarily, those with larger revenue requirement must have a higher percentage driven by the capital side.

2.4.26 To ensure that this is not skewed by Toronto Hydro, we re-ran the numbers excluding that LDC. The effect remains, only very slightly reduced.

2.4.27 To test this further, we ran the same calculation on the actual OM&A spending by all LDCs in 2010, compared to total non-commodity revenues. That shows precisely the same effect. The range (even after ignoring anomalies and outliers) is wider - around 30% to 70% capital-driven revenue requirement - but the overall pattern is identical. That includes the higher weighted average than simple average, confirming the higher capital intensity of larger utilities.

2.4.28 SEC is not proposing that the Board can, with this limited analysis, reach conclusions on the nature and causes of this particular diversity.

2.4.29 What the Board can do, however, is recognize that this diversity exists, and that any regulatory mechanism that regulates capital spending differently from OM&A will affect LDCs in markedly different ways. The simplest example is size. Assuming that the percentage increase in the OM&A component of revenue requirement will be smaller than the capital component, the EDA proposal, and the straw man, would likely provide higher rate increases to larger utilities, and lower rate increases to smaller utilities. This appears to be the case whether or not the starting rates of the larger utilities are higher or lower than the smaller ones.

2.4.30 The above five reasons are, in our view, sufficient to take the bifurcation of the regulatory methodology between operating and capital costs off the table.

2.4.31 We note one other thing on this point. Targeted PBR has been used by the Board before, on the gas side. During the process that resulted in the gas utilities moving to their current mechanism, the Board and the parties rejected targeted PBR as the option to be used. Our analysis suggests that some of the reasons we have outlined above were in fact among the reasons for rejecting targeted PBR in the current gas IRM, including perverse incentives and increased regulatory resource requirements.

2.4.32 ***Inflation and Productivity Factors***. SEC believes that the inflation/unit cost and productivity factors should be reviewed and updated, and this is part of our own proposals below. However, our rationale is somewhat different than that of the EDA, or the assumptions in the straw man.

2.4.33 On inflation, there is an initial policy question whether the inflation measure should reflect prices to customers, or costs to distributors. In general incentive regulation structures apply the latter, in effect assuming full elasticity of demand and prices driven by the costs of the most efficient suppliers. The current IRM does that as well, although the input price differential is zero.

2.4.34 As we have said more than once in this process, the market proxy role of the Board suggests that there should be more of a customer focus, i.e. on prices rather than costs, with the LDCs directed and expected to manage within reasonable price/revenue levels. This is highlighted by the Board's central mandate – just and reasonable rates – and by the objectives the Legislature has directed the Board to consider.

2.4.35 This is further highlighted by the fact that many of the costs of LDCs are controllable in the broadest sense, in that LDCs have tools to control them to a greater or lesser extent. Collective bargaining is an example of the tools available to the LDCs to keep costs down. Using an industry-specific inflation measure necessarily assumes that LDCs have at all times in the past fully controlled all costs to the extent possible. Since there is no competition, this is a big assumption, and unlikely to be true.

2.4.36 On the other hand, in a competitive market the cost pressures on the suppliers in that market – to the extent common to all – will be part of the price-setting mechanism. Willingness of customers to pay will also play a role, but across-the-board cost pressures will not be irrelevant.

2.4.37 In our view, it is generally true that a broader-based inflation measure will reflect a normal balance of cost and price pressures in the competitive markets, and therefore without more should be the starting point for utilities as well. It will also build in at least some of the effect of competitive companies pushing toward the cost frontier.

However, it should only be the starting point, and any significant differences between input costs for utilities and competitive companies should be reflected at least in part in the inflation factor.

2.4.38 Whether GDP IPPI is the best general measure, or whether CPI or some other general inflation measure would be more appropriate, is something that we believe is best determined through a debate amongst experts. Similarly, the nature of any input price differential is a matter that would be informed by expert analysis, and that should be done. We have proposed a working group, later in these submissions, which would be able to take that expert input and seek consensus on a reasonable result.

2.4.39 We note one additional concern. Past data used in the analysis of the IRM formula is based mainly on periods where inflation was more volatile than it is today. Going forward, due to government fiscal policy, it is more reasonable to expect sustained low levels of general inflation.

2.4.40 If inflation is low, the current formula results in little or no rate increases for many LDCs.

2.4.41 SEC is constantly asking other stakeholders to take a common sense approach to available data. That applies here as well. Does common sense tell us that cost pressures for LDCs have been such that rates should go down? Are their costs in fact going down? Some are, of course, but it is unreasonable to assume that overall distributor costs are – or, except in specific cases, should be - getting lower from one year to the next.

2.4.42 Yet, since the current formula is based on past actual experience, unless the data is wrong or the future is different from the past, the future expectations should be in line with that past data.

2.4.43 The one way in which we know that the future is different from the past is that the future will include sustained low inflation. This has been true for about ten years, but prior to that inflation was all over the place. If our past data includes that prior period, there is the possibility that it is not reflective of reasonable expectations today.

2.4.44 SEC does not have an answer for this. On the other hand, since we have not seen any analysis of whether this could have an impact on reasonable cost levels going forward, we believe that it should be considered before the revised IRM formula is finalized.

2.4.45 On productivity, we agree with the Board that it is time to use additional Ontario data. No-one doubts that we have better data today, and to the extent that it is still not quite enough, there is enough to test against US data and see whether there is a close similarly in trends.

2.4.46 SEC believes that the key is to set reasonable expectations for cost containment. If expectations are too high, management will not strive to achieve them, because they are simply impossible. This can create a pattern of rate spikes at rebasing, as LDCs need to catch up. If the expectations are too low, waste will occur, and rates will not be just and reasonable. Neither result is good for the ratepayers, the utilities, or the Board.

2.4.47 ***Distributor-Chosen IRM Term.*** The straw man proposes that individual distributors choose the term of their own IRM. In general some flexibility in terms is probably a good thing, but SEC sees two problems with this particular proposal: gaming, and resource requirements. In both cases, we believe they can be addressed by placing tight limits on the LDC's choice of term.

2.4.48 The gaming issue arises because, if you give a distributor options, you have to expect the distributor to optimize their choice. It would be unreasonable to expect otherwise. Unless we expect LDC management to act altruistically (which we believe would be unfair), optimizing the choice means selecting the option that will allow them the biggest budget over time, and therefore the biggest safety net if negative events occur.

2.4.49 For example, in the most generic case game analysis would suggest that two years of one-year cost of service applications, to bump up rates, and then a lengthy IRM period with a fulsome capital plan, may provide the highest overall revenue requirement during that period.

2.4.50 On the other side, a utility that is experiencing rapid customer growth may prefer a single COS and lengthy IRM, because ROE will be maximized with the growth.

2.4.51 You could also see examples of "timed" applications, in which the strategic plan identifies future years with high costs, and others with low costs, and the former are scheduled as rebasing years.

2.4.52 These are, of course, gross examples, and it may be that gaming is much more subtle, but it would be unrealistic to think that a timing choice such as this will never be used to produce higher revenues over time.

2.4.53 The resource issue will arise at least during transition, and maybe thereafter as well. Under the current model, the Board controls how many applications it receives each year, with limited variation. Under the distributor-choice model, the Board cedes that control to the utilities, and at least at the beginning it is certainly likely to mean considerably more COS applications, each with greater work than before. 2013 and 2014 could be very busy years.

2.4.54 This problem is not, in our view, fatal to the proposal. We believe the proposal can be adjusted to remove the problem, through two changes.

2.4.55 If distributor-choice is to be allowed, it is submitted that there should be a minimum IRM period, which should be rebasing plus three years. Utilities would be free to propose longer terms, but the test for shorter terms would be as it is today (as seen in the various early rebasing decisions).

2.4.56 The second change is that rebasing plus three years should be the default, and the distributor should be free only to propose a different term. The Board would still determine what the appropriate term should be, based on the nature of the evidence and the submissions of all of the parties. This would be done at the end of the COS rebasing proceeding, when the current situation of the utility is most clear to the Board panel.

2.4.57 By way of example, if a utility comes in for a six year cycle, but its capital plan is very aggressive, the Board may determine that it is necessary to take another look sooner than year seven.

2.4.58 In general, we would expect the Board to use this discretion to keep terms shorter where rate increases are higher, and allow longer terms when rate increases are lower. This is consistent with the SEC proposals below.

2.4.59 We note that, while this type of term flexibility can be made to work, this should not be taken as implying that a targeted PBR can work. For the reasons we have set out above, we do not believe that it can.

2.4.60 ***Expedited Process.*** The straw man appears to provide for some kind of fast-tracking of a cost of service application with a multi-year capital plan when the application and the plan prioritize and pace network investment effectively.

2.4.61 In our submission, the Board is not legally free to promise less than complete scrutiny of a cost of service rate application. This is not the same as IRM, where the Board's review is limited because rates are being set based on an empirically justifiable formula. This does not mean the Board gives those applications a less than complete review. Rather, the Board's review is complete within the context of the rate mechanism being employed.

2.4.62 By contrast, the straw man expects that the multi-year capital plan will be reviewed on a cost of service basis. The principle of audi alteram partem and the SPPA place strict requirements on the Board, which this proposal would not meet.

2.4.63 In addition, this would be contrary to the Board's longstanding practice and legislated mandate. In fact, the Board in these applications would have to determine a) that the network investment is required and reasonable, b) that the prioritization and pacing has been optimized, and c) that all other impacts have been properly taken into account, all in addition to the full cost of service review of the initial Test year. The Board is not entitled to assume any of these, in whole or in part.

2.4.64 There are, in fact, ways to provide for an expedited process, but that does not involve reducing the Board's scrutiny of costs in a cost of service application. In our proposals below we suggest an approach that may allow for significant regulatory streamlining, while staying within the Board's mandate and responsibilities.

2.4.65 ***How to Reflect Distributor Diversity.*** We have one other brief comment on the straw man. It would appear to us that the proposal (and the EDA proposal as well) continues to assume that one regulatory mechanism should be used for all LDCs.

2.4.66 SEC does not believe that attempting to require all distributors to fit within the same box – even if it is made more flexible – is necessarily the best answer. As we note in our proposals below, there may be room to provide a menu of regulatory options, as long as all roads lead to a reasonable result.

2.4.67 ***The Straw Man – Conclusion.*** SEC therefore reaches the following conclusions on the straw man:

(a) Targeted PBR has far too many serious problems to be implemented in Ontario.

(b) The promise of an "expedited" cost of service process is contrary to law and would fail to deliver on the Board's statutory mandate.

(c) It is fair and reasonable to review the inflation and productivity factors in the current IRM, and to consider whether a revised approach to the past data should be used.

(d) With some changes, the proposal to have different IRM terms for different LDCs can be made both fair and effective.

2.5 ***SEC Regulatory Framework Proposal***

2.5.1 Based on the above analysis, and our experience with many rate applications – both IRM and COS – over the last few years, SEC has developed some proposals for a modified form of distributor rate regulation. These proposals are set out below.

2.5.2 We note that these proposals have been circulated to other ratepayer groups, and to a number of utilities. Some of both groups have given us feedback, which has allowed us to refine the analysis. However, the proposals remain those of SEC, not of any other parties.

2.5.3 ***Overall Structure.*** The SEC proposal seeks to recognize distributor diversity, and provide for reduced regulatory costs, within a flexible structure that continues to protect ratepayers with respect to price, and continues to drive cost effective and economically efficient management of utilities.

2.5.4 To do this, SEC proposes that distributors be allowed – subject to Board oversight – to choose one of the following three regulatory mechanisms for their rates:

(a) ***IRM***. This mechanism would be based on the current 3rd Generation IRM, with some small but meaningful improvements. By its nature, it provides a moderate level of regulatory thoroughness.

(b) ***Multi-Year Cost of Service.*** For utilities who feel they have special issues that need to be addressed, they could opt for a full multi-year cost of service model, which has a much higher depth of scrutiny and regulatory thoroughness. This is necessary where special problems have to be reviewed. This review level would be offered within a framework in which fair and reasonable benchmarking would be a key aspect of the analysis.

(c) ***Long Term Rate Commitment.*** Utilities who seek a much more streamlined ("light-handed") approach could make a long-term commitment to limit their rate increases to a percentage of inflation, and through that guarantee avoid the cost of annual rate cases.

2.5.5 Giving distributors a choice of mechanisms only works if each choice, if selected, will still provide full protection to the ratepayers in respect of prices. In this proposal, the ratepayers are protected in different ways depending on the choice made:

(a) If a distributor makes a long-term rate commitment, it is saying that it is willing to take full responsibility for protecting its ratepayers as to price, from the outset, and for the long term. While some Board review at the beginning may be required, these utilities are essentially offering a guarantee of ratepayer protection in return for more light-handed regulation.

(b) At the other extreme, if the distributor opts for multi-year cost of service, the ratepayers are totally relying on the Board to ensure that rates are kept as low as reasonably possible. The success of this three-choice mechanism is dependent on the ability of Board panels reviewing individual COS cases to require cost effectiveness and economic efficiency in the cost of service of the utilities before them. The Board has a good record in that regard.

(c) In between the two, IRM relies in part on the Board's discretion in controlling utility spending requests, and in part on the choice of the utility to accept formula-based rate increases three years out of four. As is the case today, ratepayer protection is achieved by that combination of factors.

2.5.6 It is SEC's view that, if each of the three choices is structured appropriately, LDCs will not be incented to game the system, but will instead choose between the choices based on whether they need to undergo a more onerous process in order to deal with their special needs**.** Ratepayers should be satisfied, as in all cases utilities should be strongly motivated to keep rates as low as possible.

2.5.7 We describe below each of the three optional mechanisms in turn.

2.5.8 ***Existing IRM Option.*** As we have indicated earlier, there is only limited evidence of serious problems with 3rd Generation IRM, and strong evidence that 3rd Generation IRM is working well for many utilities. It therefore appears to us that LDCs should be given the option to continue on the current mechanism, with a few modifications to deal with the various legitimate issues that have been raised.

2.5.9 There are four areas in which some changes may be indicated: the inflation/unit cost escalator, the productivity factor, the stretch factor, and the incremental capital module.

2.5.10 As we have indicated in our earlier analysis, there is a serious debate about whether GDPIPPI without any input price differential is reflective of the full basket of utility cost increases. This would benefit from further study. In doing so, we believe that the Board should also look at whether the formula should vary depending on the level of general price inflation. If the future is sustained low inflation, and the past data is more volatile inflation, is this difference sufficient to require an adjustment to the formula?

2.5.11 Aside from making that general observation, SEC has no further proposals on what cost escalator should be used. This is something that should be analysed by the experts for the Board and others, and a reasonable conclusion reached.

2.5.12 Utilities have expressed a concern with the productivity factor, and certainly data quality issues influenced that aspect of the formula. We believe that now, with a few more years of better quality data, plus the improvements in older data as a result of the transition to IFRS, these deficiencies can be addressed.

2.5.13 The additional suggestion by the EDA and others that the productivity factor should be artificially reduced, because there are more demands on utilities today, is not a reasonable one. Lacking any empirical basis, those suggestions are merely an unjustified attempt to reduce the productivity expectations, at a time when goals of cost effectiveness and economic efficiency have deliberately been added to the Board's mandate in the electricity sector.

2.5.14 The stretch factor is more problematic. SEC has always been a strong advocate of differentiating between LDCs based on their current efficiency levels. Simply put, it is more difficult for an already low cost LDC to drive productivity improvements than it is for a utility with a higher level of waste built into its existing spending. It is important that this be reflected in the rate-making process.

2.5.15 On the other hand, we agree with LDCs that benchmarking their existing level of productivity based on OM&A alone, while perhaps necessary in 2007, is inherently unfair to some LDCs. Having now seen the wide variations in OM&A vs. capital in revenue requirement (as discussed earlier and seen in Appendix A), the unfairness is even clearer. While the current stretch factor system tries to adjust for some aspects of capital intensity (topography and undergrounding, for example), there is little doubt that a measure of current efficiency that includes both OM&A and capital components would be much better.

2.5.16 SEC has long been of the view that the best comparison between LDCs to test productivity is overall rates. That does not mean simply deeming those with higher rates to be less productive, and vice versa. Clearly no-one can expect Algoma Power to have rates as low as Entegrus, and comparing them head to head would be unfair. On the other hand, comparing the prices/rates of a utility to other similar LDCs is, if it can be done rigorously, the best way to assess comparative productivity. Indeed, in competitive businesses that is exactly how the market compares productivity, usually with blunt consequences for those businesses that compare unfavourably.

2.5.17 There are two issues associated with moving to a rate-centred comparison:

(a) What is the precise metric to be used?

(b) Do the existing cohorts have to be adjusted with a different metric?

2.5.18 On the first point, there are a number of different rates for each utility, and different LDCs have different mixes of customers and different levels of collection of revenue from different customers. Unless LDCs have a similar customer mix, and similar revenue to cost ratios and rate design, a straight up comparison of rates is difficult.

2.5.19 SEC has experimented with an average distribution bill comparison, for example in our filings in EB-2011-0144. In that case, we calculated the basic distribution bill (monthly charge plus volumetric charge) for typical customers in the four main rate classes. Comparing each bill to other LDCs, and then averaging the comparative levels, we were able to get a rough comparison of which utilities are more or less expensive.

2.5.20 We are not proposing that formula. It was a rough and ready formula that was only really useful because, in the particular case, the subject utility had similar comparison levels for all four rate classes. For some of the other utilities on the list, it is less clear that the composite "score" we used was sufficiently rigorous to be relied on. Variations due to rate design (e.g. utilities with unusually high monthly charges), and variations due to revenue to cost ratios (e.g. utilities with unusually high or low RTCs for particular classes) were not adjusted.

2.5.21 However, we see potential in the development of a metric that does normalize those rate comparisons. For example, actual rates could be adjusted – to facilitate productivity comparisons only - to reflect standardized fixed/variable splits and 100% revenue to cost ratios.

2.5.22 Therefore, SEC recommends that the Board, in offering the IRM option, change the stretch factors so that they are based on a broader productivity measure, including exploring the use of distribution bill comparisons as a basis for that metric.

2.5.23 The last area of change is simpler: the incremental capital module. In our view, once the option of multi-year cost of service is available, the ICM is largely unnecessary. It is significantly better from a rate-making point of view to review major capital spending plans in the context of overall cost of service, rather than in isolation from it. The Board has historically avoided "cherry-picking" elements of costs in setting rates, and rightly so. It leads to perverse results. The ICM was an exception, and created a lot of confusion as a result.

2.5.24 With the COS option available, in our view the best approach is to end the ICM altogether. Leaving aside government mandated incremental capital spending (see below), there is no longer a real need for it. At the very most, an ICM limited to extraordinary capital projects (a transformer station, for example) should be all that is left.

2.5.25 It is still necessary to deal with government-mandated incremental capital spending, like smart meters, renewable enabling improvements, etc. In our view, these are better handled as a Y factor than in an ICM. This allows the Board to identify those government mandates that are legitimately outside of the LDCs' normal course of business, and are sufficiently material to warrant special treatment. For each such spending requirement, a Y factor response can be fashioned that suits the situation. For example, should there be a funding adder in advance of the spending? Sometimes the answer will be yes, sometimes no. Making government-mandated incremental capital spending a separate track like this allows the Board the flexibility to deal with each government requirement in the best way possible.

2.5.26 In SEC's submission, therefore, one of the options available to the LDCs for ratemaking purposes should be the current IRM, with the following changes:

(a) Updating the inflation/unit cost and productivity factors in light of new data and further analysis, while maintaining their technical rigour.

(b) Retaining benchmarking to graduate the stretch factor, but using a broader (and fairer) metric such as a composite price levels relative to similar utilities.

(c) Removing the ICM, and treating government-mandated incremental capital spending as a Y factor, to be structured on a case-by-case basis based on the nature of the government mandate being addressed.

2.5.27 ***Multi-Year Cost of Service Option.*** There will still be LDCs that have legitimate issues that need to be considered. It is fundamental to distributor diversity that the actual needs of specific LDCs will be diverse, and the most flexible mechanism available to deal with diversity is cost of service.

2.5.28 For a cost of service option to be effective, in our view there should be a number of specific requirements.

2.5.29 First, the application should be for multiple years. This is for practical and policy reasons.

2.5.30 On the practical side, the Board is not in a position to consider cost of service applications annually for any number of LDCs. The resources required would be even worse than those required in the straw man. Since the Board's resources are now structured to handle cost of service applications (rebasing) every four years, that is probably a reasonable minimum period.

2.5.31 On the policy side, it is more effective to review spending plans over multiple years. Most utilities do their own planning in this way, and the Board should have the benefit of at least that same level of information.

2.5.32 Second, the application should include a Strategic Plan for the utility that runs out at least ten years. The purpose of this is to show the context within which the rate proposals are being made.

2.5.33 Since we assume that most LDCs will not seek multi-year cost of service unless their rate increases are well above those available with the other two options, the Board should have a long-term context before considering approval of high rate increases. In short, if the applicant wants high increases now, it should be able to show that in the longer term this will benefit the ratepayers.

2.5.34 A good example of this might be a high growth utility, like PowerStream. Suppose they project a growth spurt that will require a significant buildout of infrastructure in their franchise areas. It would be reasonable for them to come in for a four year cost of service, covering the period of the buildout and the incremental costs to do so. The inevitable result is likely price increases that are above average.

2.5.35 On the other hand, a Strategic Plan in this circumstance should demonstrate that after these initial increases, rates are expected to trend down as new customers come on stream and start taking up their share of the costs. Not only will the customer growth cover the capital spending, but OM&A per customer should go down due to economies of scale. Neither the Board nor ratepayers are likely to complain about short term spending that gives long term benefits.

2.5.36 The reason for requiring a Strategic Plan instead of a more narrow "business case" is that the ratepayer benefits of a current spending increase will usually be spread throughout revenue requirement for future years. By requiring a Strategic Plan, the Board would ensure that benefits are expected to be reflected in rates, not eaten up by increases in other areas. It would also facilitate the establishment by the Board of conditions related to shorter term rate increases.

2.5.37 Third, the application should include standard benchmarking data that allows the Board to determine a range of "normal" for a utility like the applicant. It should also include detailed analysis showing the special requirements of the applicant that are different from "normal".

2.5.38 The concern of ratepayers with multi-year cost of service is that it could easily devolve into large utilities, with lots of resources, using cost of service to get higher rates, while everyone else lives within more formulaic and controlled rate-setting mechanisms. In this respect, the ratepayers would be relying on Board panels to police the use of this option. One way to do that would be to require Board permission to file on a multi-year cost of service basis, a kind of "threshold" question. While we are not proposing that component, SEC agrees that it may be a reasonable addition to the proposal if predictable criteria for access to this choice can be determined.

2.5.39 This option, therefore, would allow an LDC to choose to file a multi-year cost of service application as long as the following conditions are met:

(a) The application is for a minimum of four years.

(b) Information benchmarking the applicant to its peers is provided, and a detailed explanation of variances from "normal" is included.

(c) A Strategic Plan of at least ten years demonstrates the longer term impacts of the current proposals.

2.5.40 ***Long Term Rate Commitment Option.*** Some utilities will prefer a rate-setting mechanism with even less regulatory cost and attention than IRM. That may be because the utility is small, and prefers to focus its resources elsewhere, or because the utility is growing rapidly, and is able to forecast increasing economies of scale, so is able to keep rates low more easily than others.

2.5.41 The problem with the "limited oversight" goal is that the Board cannot simply close its eyes and hope for the best. The Board must meet its statutory mandate, and that necessarily involves having a way of keeping rates just and reasonable.

2.5.42 SEC believes that the only circumstance in which an LDC should have highly streamlined ("limited" or "light-handed") regulation is if it can guarantee, at the outset, that its rates during the period will not exceed a just and reasonable level. Conversely, if an LDC is willing to give such a guarantee, SEC agrees that limited review during the "guaranteed" period is appropriate.

2.5.43 To that end, SEC proposes that a utility be entitled to choose a long term rate commitment at a percentage of inflation that is less than 100%. The LDC would propose both the term (minimum 10 years), and the percentage of inflation (50% to 95%), both of which would require Board approval. Future cost forecasts would not be required, but benchmarking of existing rates to those of the LDC's peers would be part of the initial application.

2.5.44 SEC believes that ratepayers will accept limited oversight of their LDC if rates are dropping in real terms. LDCs, on the other hand, will benefit from having rates with long-term predictability, and freedom to focus on operations without worrying about regulatory implications. It is, in effect, the purest form of incentive regulation. For these reasons, we would expect this option to increase in popularity over time as more LDCs try it and have good results.

2.5.45 There are four specifics of this option that should be addressed.

2.5.46 First, should this start with a "rebasing" year? We have not included that in the proposal, as it does not appear to us to be strictly necessary. We are proposing that an LDC can elect to move to this choice at any time, whether after a rebasing year, or after any subsequent year. From a ratepayer point of view, a long term guarantee of just and reasonable rates is valuable at any time. To the extent that rates are relatively high or relatively low at the beginning, that would be factored into the inflation percentage (see below).

2.5.47 Therefore, while a utility with reliability or asset condition issues may be considered by the Board to be ineligible for this option, in general we do not believe cost of service at the beginning should be a general requirement.

2.5.48 Second, the Board's discretion to determine the percentage of inflation used should have known parameters. We have suggested a range, but we also propose that the main factor in setting the percentage should be the comparative level of rates/productivity at the outset. LDCs with rates and costs that are high relative to their peers should have a percentage that is lower, and vice versa.

2.5.49 In practice, we would expect that LDCs choosing this option will discuss their desired inflation percentage with the Board and stakeholders prior to filing. This will allow a consensus to emerge, either on a number to be recommended to the Board, or at least a narrower range that all can support.

2.5.50 Third is the question of periodic information filings for the Board. In our view, the RRR filings should be augmented to include more information on a regulatory rather than a financial basis, all of which should be made public. Once that is done, we see little reason to require any LDC on this mechanism to file anything annually other than a rate order done in a completely mechanistic way.

2.5.51 Fourth, some LDCs and perhaps others will be concerned with the long time frames being proposed. To deal with this, we believe that any party to the initial application should be free to propose a review at the end of five years. This would be limited in scope, but would have the advantage of catching any problems before they get too big.

2.5.52 In our view, a mid-term review is not strictly necessary if annual RRR filings contain sufficient information to spot emerging problem areas. However, we think it is reasonable to offer that as an option in this scenario.

2.5.53 ***Open Issues.*** The above proposals provide a construct, with many of the details still to be determined. Some of those open issues include:

(a) At what point does the initial "choice" between plans arise? The simplest approach is to provide that the choice is made when each LDC comes up for rebasing in the current schedule. That may not be the best answer, however. In some cases, shifting from one plan to another may be reasonable. Of course, shifting from the long-term commitment to IRM or COS is not OK, since it is inconsistent with the long-term nature of the rate guarantee. Similarly, shifting to COS during IRM should generally not be allowed. On the other hand, shifting to the long-term rate guarantee at any time during an IRM or COS period may be less problematic. It is also worth considering whether an LDC seeking multi-year cost of service should be free, in that application, to commit to move to a long-term rate commitment at the end of the COS period. This may be a way of mitigating the short-term impacts of the COS spending requests.

(b) Should there be any type of earnings sharing or similar mechanism? SEC has long opposed ESMs on principle, but for more pragmatic reasons it may be that some kind of ESM would make these choices more palatable for utilities or ratepayers.

(c) What about off-ramps? The current IRM has an off-ramp, but it has not been used. An off-ramp may be more important for the long-term commitment, but may be covered through a mid-term review. An "underspending" off-ramp may also be worth considering in multi-year cost of service.

(d) How does the concept of a Z factor fit within each of these three choices? Should the IRM Z factor concept be available during the years of COS, or during the rate commitment years? If so, what changes have to be made, or restrictions imposed, to ensure that it is still fair?

2.5.54 The above, in addition to the issues we have already flagged earlier (detailed changes to the IRM, price benchmarking metrics, etc.), would have to be addressed prior to implementing a plan along the lines of the three choices we have proposed.

2.5.55 ***Conclusion.*** SEC believes that distributor diversity, and the desire of distributors to have lower regulatory requirements, can be achieved by giving LDCs choices of rate-setting mechanisms, as long as each choice available is structured to ensure that ratepayers are fully protected.

3 DISTRIBUTOR INVESTMENT PLANNING (EB-2010-0377)

3.1 *Introduction*

3.1.1 SEC's comments on the integration of distributor investment planning and the setting of rates are included in Part 2 of these submissions. In particular, SEC does not believe that separate consideration of multi-year capital plans, as proposed by the EDA, is an appropriate method of regulating rates, and has given detailed reasons in the analysis of the Board's straw man.

3.2 *Different Types of Capital Needs*

3.2.1 The presentation of the DRRTF at the stakeholder conference, and their detailed submissions on capital spending preceding that conference, provide a useful breakdown of the various types of capital spending. The DRRTF acknowledges that these different capital needs have different causes and impacts, and it is clear that not all distributors will face all types of capital needs. SEC agrees.

3.2.2 SEC has demonstrated, in Section 2.2 of these Submissions, that normal ratemaking structures, including in particular 3rd Generation IRM, provide sufficient funding in rates for the normal increase in cost of replacement assets over the assets they are replacing. The arguments of some utilities with respect to CEEDs, and the half year rule, in the context of IRM, are mathematically unsustainable, and divert the focus of the Board from the true capital spending issues.

3.2.3 SEC also notes, in Part 2, the need to identify government-mandated incremental spending and provide a custom solution for each material requirement. The Board has been doing that to date, and it should continue.

3.2.4 Aside from those two examples, SEC reiterates its often-stated view that, until there is empirical evidence of the size and extent of capital spending pressures of each category, it is inappropriate for the Board to try to establish a generic "solution" to a problem that has not yet been defined. The solution to a problem of past lumpy spending is different from the solution for capital unit costs increasing faster than inflation, which is in turn different from the solution for new assets providing higher reliability or other services, but at an incremental cost. It is, in our submission, unacceptable that no evidentiary foundation has been laid for proposed changes to the regulation of capital spending.

3.2.5 In this regard, the existence of Asset Condition Assessments showing that assets are in bad shape is not a useful category of evidence. The point of an ACA is to identify every single way in which assets are not perfect. That is useful management information, but it provides no useful input on how much money should be spent on capital renewal. Every large organization with significant capital assets has an ACA showing millions or billions of dollars of repair, renewal and replacement requirements. Every school board, for example, has such a requirements list, often much larger than that of their local LDCs. So, too, every university, every municipality, and every large, well-run business has such a list. (You can even do the same thing for your home.)

3.2.6 No-one actually proceeds with all of the spending that an ACA seems to require, because that would in almost every case be prohibitively expensive, and largely unnecessary.

3.2.7 The evidence that is required is, in our view, not an ACA. What is required is evidence of the causes of particular capital spending pressures. This is vintage data, reliability tracking data (compared to renewal spending), maintenance tracking data, before and after functionality comparisons, and things of that nature. Anecdotal evidence is not really useful if the problem is truly endemic. More detailed evidence is required. There is a lot of ratepayer money involved.

3.2.8 In setting rates, the Board has to identify what is a reasonable long-term trend for capital spending, before incremental cost pressures. That it has largely done in 3rd Generation IRM. The Board then has to identify the nature and quantum of those incremental cost pressures, using evidence, to establish how to reflect those pressures in individual rate applications. This has not yet been done.

4 RATE-SETTING AND MITIGATION (EB-2010-0378)

4.1 *General*

4.1.1 The Staff Paper on this subject focuses on rate mitigation rather than rate-setting. The consultant's report is about the calculation of total bill impact in a rigorous way.

4.1.2 As discussed briefly below, SEC is less concerned with both of those issues than it is with the issues of cost effectiveness and economic efficiency. It is those latter issues which are the focus of these Submissions, and our ratemaking proposals.

4.2 *Amount vs. Timing of Energy Costs*

4.2.1 Like any ratepayer, schools prefer not to pay an amount now if they don't have to. So, if rates can be "mitigated" through delayed payment, that is generally good. The problem is, "good" is a relative term, and delay in payment is a very small "good". Keeping costs down in the first place is so much more important that the issue of mitigation is rarely even considered.

4.2.2 Volatility is a different thing. Schools are on a fixed budget, so if costs go up and down too much that is very difficult to manage. Smoothing of costs over a period of time (a rolling average, for example) to reduce volatility is a valuable step.

4.2.3 Smoothing and delay are not the same. Telling a school board that the Board is going to allow a utility to collect an extra million dollars from them is not in any significant way mitigated by also saying the million dollars will be collected, with interest, over the next five years. To the school board, it is an extra million dollars they have to find, and some pedagogical initiative will have to suffer to achieve that result. (In fact, mitigation at WACC-based interest is a negative for school boards, since their cost of funds is much lower than WACC.)

4.2.4 For these reasons, schools focus their attention on keeping utility costs down, and driving cost effectiveness and economic efficiency in the management of LDCs. Rate mitigation techniques are of significantly less interest.

4.3 *Impact of Total Bill Analysis*

4.3.1 SEC has no additional submissions on the issues related to Total Bill Impacts.

4.4 *Revenue Decoupling*

4.4.1 In the EB-2010-0060 proceeding, the Board early in 2010 started consideration of ways to decouple distributor revenues from throughput volumes. A study of available decoupling methods was published, and submissions from many parties, including

SEC, were received. In October, 2010, the Board suspended that process, recognizing that the issues in the Renewed Regulatory Framework are in some cases logically prior to revenue decoupling issues. At the very least, they are intricately related.

4.4.2 SEC supports some forms of revenue decoupling. Where volume risks can be managed better by allocating them to ratepayers (with appropriate compensation), rather than to utilities, that is the logical step to take. The overall cost of the service goes down in those circumstances.

4.4.3 With the Renewed Regulatory Framework having proceeded further towards resolution, SEC believes it is time to restart the Revenue Decoupling analysis, and recommends that the Board do so no later than this fall.

5 PERFORMANCE AND INCENTIVES (EB-2010-0379)

5.1 *Introduction*

5.1.1 In April, 2011 Pacific Economics Group produced a report on benchmarking and performance measurement that is clear, thorough, and very helpful.

5.1.2 In November, 2011, a Staff Paper was produced on these issues. While it suffers from starting with the assumption the capital spending has to go up (which we have challenged elsewhere in these Submissions), it still provides some useful input.

5.1.3 We have proposed in these Submissions a working group, and one of the roles of that group should, in our view, be to develop detailed benchmarking metrics that are fair to the utilities and, so far as possible, measure top level results. We have also explored a number of issues relating to benchmarking in Part 2.

5.1.4 There are two more general issues relating to benchmarking. First, we have to be clear on what we want to measure, and why. Second, we have to recognize that no metric is perfect.

5.2 *What do we Want to Measure?*

5.2.1 What we want to measure should be entirely driven by what we want to use it for. Conversely, availability of the information to measure something should only be a factor in choosing that metric AFTER the options have been ranked based on suitability for use.

5.2.2 SEC has been vocal over the last five years in discussing the difference between "operative" metrics and "diagnostic" metrics:

(a) An operative metric has a predetermined consequence. The stretch factor in 3rd Generation IRM is based on operative metrics. Once they are determined, the result (a higher or lower rate increase), is automatic.

(b) A diagnostic metric is useful information, but is only relevant as an input to judgment, for example by the Board hearing a case. An example of that is the comparisons of rates, spending, and rate base provided by SEC in the EB-2011-0144 proceeding (and others). They may be indicative of certain possible facts, but do not lead to any conclusions on their own.

5.2.3 It is clear that operative metrics have to be more analytically correct and technically sound than diagnostic metrics, because there is no-one actually checking other evidence to see if the results make sense. For this reason, SEC has generally preferred to focus on using benchmarking metrics in a diagnostic context. In the proposals we have made in Part 2, for the most part all benchmarking is intended to be of the diagnostic variety.

5.3 *Benchmarking – "The Perfect is the Enemy of the Good"*

5.3.1 Using benchmarking to spot problems, or inform judgment, does not mean that one can be sloppy in developing the metrics used. The higher the precision, the more judgment is informed.

5.3.2 At the same time, it is submitted that the Board must accept a level of imprecision in any benchmarking metric. There will almost always be exceptions to the fair applicability of any metric, no matter how carefully it has been developed. Trying to get perfection is not the answer. That just means useful comparisons are foregone. In this, as in many aspects of the regulatory process, "the perfect is the enemy of the good".

5.3.3 SEC continues to support the use of multiple benchmarking comparisons, each as precise as possible, but together providing a more balanced picture of the performance of any given utility relative to its peers.

5.3.4 In our view the task the Board should give to the working group is to come up with benchmarking metrics that are as precise as possible, and come from different angles at the data so that the weaknesses of any one are counterbalanced by the strengths of another. This is the best way to provide useful input to the Board panel in exercising their independent judgment on the issues.

6 REGIONAL PLANNING (EB-2011-0043)

6.1 *General*

6.1.1 Consideration of regional issues in network investment planning is, of course, essential and should be a standard part of the planning process. The Staff Paper in this area dated November 8, 2011 identifies a number of functional barriers that limit regional planning initiatives, and potentially penalize distributors that initiate such discussions.

6.1.2 On the other hand, the Board also heard from LDCs that they regularly engage in regional planning discussions, because it is just sensible to do so. We have also had direct discussions with a number of distributors to the same effect. The general sense we get is that the LDCs are saying "We don't need to be told to do this. It is just common sense, so of course we do it."

6.1.3 In light of the comments below, SEC therefore doesn't believe that the Board should be considering changes right now that formalize regional planning requirements. While the time may come when that is necessary, we do not consider it a high priority in light of the current reality.

6.1.4 The one area where there may be a problem is cost responsibility. The Staff Paper identifies circumstances in which co-operation between LDC and transmitter results in a requirement for a capital contribution, which otherwise would not be the case.

6.1.5 While the question is one of "cost causality", the various concepts of causation appear to be confused or equivocal in the current rule, with the result that only a triggering event ("proximate cause") can result in cost responsibility to a particular distributor. Distributors that also "cause" the cost, for example because their existing load is necessary in order that the cost be required ("causa sine qua non"), do not bear any of it. That is even true if the distributor's existing load is the main cause ("causa causans") of the additional cost being incurred.

6.1.6 This does not appear to be a sensible result. However, the question it raises for SEC is a broader one: which transmission-related costs should be borne locally, and which should be socialized across the province through transmission rates. This is particularly important now, as distributors' status as either a load or a source of generation is changing. This will have implications in transmitters' investment decisions, of course, and any consideration of a change in this area must ensure that it does not limit needed transmission investment.

6.1.7 While this appears to be an existing problem, SEC does not believe it should be resolved immediately. For the reasons set forth below, it appears to us that external events should be allowed to play out before problems such as this are dealt with by the Board.

6.2 ***Industry Consolidation and Organizational Changes***

6.2.1 Regional planning may be significantly affected by two recently-announced industry changes.

6.2.2 First, the Drummond Report recommended further consolidation of LDCs, and the government has responded by establishing a panel to consider how this can best be accomplished (among other things). Even before these two events, many distributors were actively looking at M&A opportunities, whether as buyers and sellers or anything in between.

6.2.3 Given this direction, and especially if the vision of a small number of regional distributors is pursued, regional planning issues will be changed significantly. This suggests that any major changes relating to regional planning may be premature. The Board may be solving a problem that will either naturally resolve, or change its nature materially.

6.2.4 Second, the government has announced the merger of OPA and IESO, both organizations that are actively involved in regional planning issues. Depending on how that merger shakes out in the coming months, distributors (and transmitters) could be dealing with a much changed oversight at the provincial level. Further, the Board's role in supervising this process may change.

6.2.5 Again, with this change imminent, changes by the Board to its rules related to regional planning may be premature.

6.2.6 For these reasons, it is submitted that the Board should suspend the Regional Planning initiative for a period of at least six months, to allow external developments to occur. Once that happens, the initiative could be restarted. Depending on the changes, that restart could perhaps be in conjunction with the combined OPA/IESO.

7 PROCESS OPTIONS

7.1 ***Introduction***

7.1.1 The many submissions the Board will receive at this phase of this initiative, even added to the preliminary work that has been done by consultants and Board Staff, and the three day stakeholder conference in March, are not in our view sufficient for the Board to establish an implementable system for the regulation of distributors going forward. A process is needed to move from the conceptual discussion now taking place, to a detailed plan that actually can work.

7.1.2 SEC believes that there are three steps required before the Board can finalize and implement such a plan:

(a) Reply submissions on the submissions made in this round.

(b) Board direction on the regulatory directions it will consider, and those it has rejected.

(c) A collaborative process – through a working group – to move from the Board's guidance to a detailed plan, optimally with consensus on all or most of the major points.

7.2 ***Reply Submissions***

7.2.1 The value of reply submissions is apparent, and does not need lengthy analysis.

7.2.2 Clearly SEC would like the opportunity to review the submissions of others, and provide its perspective on the suggestions and assertions made. We will disagree with some, and agree with others.

7.2.3 More important, from our point of view, SEC has made a number of proposals in these Submissions. While we have had dialogue with other ratepayers groups, and with a number of utilities, those discussions were more preliminary in nature. Now our detailed proposals, with supporting analysis, are on the table. It is important to us, and to the Board, to see what others have to say about these proposals. We believe some utilities, for example, will agree with them, likely with some proposed modifications.

7.2.4 Others will challenge our assumptions and assertions, and that is also as it should be. Those challenges, if successful, will require changes to our thinking. If unsuccessful, they strengthen the foundation on which our proposals are made. Both ways, our work in developing these Submissions is made more valuable by the way others respond to it.

7.2.5 Therefore, in our view the dialogue is improved substantially if all parties are given an opportunity to respond to the submissions of others.

7.3 ***Board Guidance***

7.3.1 Once the Board has reply submissions, so that it has heard all available perspectives on each of the issues, including on new proposals, the Board will be in a position to make some decisions at a conceptual level about direction.

7.3.2 For example, if as SEC believes, the straw man is not a realistic option, and our view on that survives the reply submissions of others, the Board will be in a position to determine – if it agrees - that it will not regulate capital and OM&A on different tracks. Similarly, if the Board agrees that regulatory streamlining should only be available where ratepayer price protections are locked in, it is also in a position to make that determination.

7.3.3 The Board has, in the past, used guidance documents to narrow the scope of a consultation by identifying options that will not be considered, and those that will. This leaves fewer questions to be addressed in the remaining discussion, and creates a focus on implementable solutions within a manageable range. This has been used to good effect last year in EB-2008-0346, for example, and in numerous rule and code-making proceedings.

7.3.4 SEC therefore proposes that, once the reply submissions are in, the Board should formally consider its policy options in the same manner as it would if it were issuing a policy document, then issue a letter providing guidance on the direction it is going with respect to regulation of distributors. This is not yet a Board policy, of course, because the details still have to be worked out, but it provides parties with direction going forward.

7.4 ***The Value of a Collaborative Process***

7.4.1 Once the Board has determined a direction, there is still a need to build an implementable Board policy consistent with that direction. The devil is, as they say, in the details, and there are many details to be determined. Some of them have been identified throughout these Submissions, and others will arise as an implementable policy is developed.

7.4.2 As we noted at the outset of these Submissions, one of the key views expressed by the heads of school organizations is their strong desire to have energy issues resolved collaboratively. They have seen the value of this approach in past Board processes, and they use a collaborative approach in their own business activities.

7.4.3 In our discussions with utilities, we also hear regularly the desire to work through issues and find consensus on as many as possible.

7.4.4 While this is in part philosophical (both for the schools and the utilities, organizations that often have similar philosophies and cultures), it is more than that. It is also very pragmatic.

7.4.5 One of the risks of any new regulatory mechanism is that rates will go up too fast. If that happens, the problem typically moves from the regulatory arena to the political one. No-one wants that.

7.4.6 For the utilities, their general experience is that when their rates become political issues, they face freezes and other major changes that can seriously limit their ability to run their businesses.

7.4.7 For the ratepayers, they have more confidence in an independent, specialized regulator, than in government, on the subject of utility rates. That is especially true where there is a minority government in place, so ratepayers don't even know who they would need to get to for rate relief.

7.4.8 For the Board, a key part of the Board's role is to ensure that rates are controlled independently, and do not enter the political arena. The OEB Act is set up to make rate-making independent of the political process, and when rates move back in that direction it could be seen as a failure of the Board to achieve its goals.

7.4.9 The simple solution, of course, is to ensure that distribution rates don't go up beyond inflation. This cannot always be achieved, and even if it is on average, there will always be some high profile utilities with higher rate increases.

7.4.10 The other solution is to seek consensus on ratemaking issues. If it is necessary to make available some higher rate increases in specific cases, it will be because ratepayers, utilities and the regulator reached a consensus that this was necessary and reasonable. While this is no guarantee that the public will support the result, it significantly changes the likely dynamics.

7.4.11 There are really two ways that the details of an implementable plan can be worked out. Board Staff can develop the detailed plan, and the Board can impose it on the industry and other stakeholders. Alternatively, the utilities, ratepayers and other stakeholders, working with Staff, can develop the detailed plan for consideration by the Board.

7.5 ***Electricity Distribution Working Group***

7.5.1 Clearly SEC believes the latter is the better approach, and for that reason we propose that the Board establish a working group of 10-15 representatives with experience in regulation of distributors.

7.5.2 The working group would be asked to take the Board's guidance and turn it into a proposal for a detailed rate regulation mechanism. As part of the process, the Board would likely develop a set of specific questions and issues it would like the working group to address, and some prioritization of those issues.

7.5.3 For example, if hypothetically the Board decided to implement the SEC proposal included in these Submissions (it is a hypothetical, after all), the Board could list things like the IRM inflation and productivity factors, comparative rates metrics, benchmarking tests, and similar issues as being ones that the working group should address. The Board could also identify some of them – the inflation factor, for example – as of immediate priority, and others as being for later consideration.

7.5.4 In SEC's submission a working group, properly constituted and given clear instructions, is the fastest and most effective way of moving from a debate about concepts to a regulatory system that works in practice. We also believe that many LDCs would support such an approach.

8 GENERAL ISSUES

8.1 *Conclusion*

8.1.1 SEC appreciates being allowed to provide input to the Board on these important issues. SEC proposes to continue to be involved, either in any subsequent steps in this process, or in any further processes relating to the framework within which electricity distributors are regulated.

8.2 *Costs*

8.2.1 SEC submits that it has participated responsibly in this process with a view to providing assistance to the Board, and requests that the Board order payment of its reasonably incurred costs for that participation.

All of which is respectfully submitted.

Jay Shepherd
Counsel for the School Energy Coalition

APPENDIX A

Revenue Requirement Breakdown for Distributors

Utility	Reference	Revenue Requirement	OM&A	Percent	Capital	Percent
Hydro One Brampton	EB-2010-0132	59,576,836	20,070,266	33.7%	39,506,570	66.3%
Waterloo North	EB-2010-0144	29,145,614	10,039,282	34.4%	19,106,332	65.6%
Horizon	EB-2010-0131	102,346,735	42,418,667	41.4%	59,928,068	58.6%
Toronto	EB-2010-0142	548,065,426	231,214,224	42.2%	316,851,202	57.8%
Milton	EB-2010-0137	14,464,579	6,300,000	43.6%	8,164,579	56.4%
Hydro Ottawa	EB-2011-0054	162,872,809	71,390,393	43.8%	91,482,416	56.2%
Niagara Peninsula	EB-2010-0138	30,975,767	13,854,208	44.7%	17,121,559	55.3%
Norfolk	EB-2011-0272	12,170,855	5,616,855	46.2%	6,554,000	53.8%
Woodstock	EB-2010-0145	8,198,345	3,910,054	47.7%	4,288,291	52.3%
St. Thomas	EB-2010-0141	6,992,482	3,449,938	49.3%	3,542,544	50.7%
Guelph	EB-2011-0123	27,972,312	14,326,000	51.2%	13,646,312	48.8%
Kingston	EB-2010-0136	12,662,924	6,850,907	54.1%	5,812,017	45.9%
Oshawa	EB-2011-0073	20,043,143	11,330,870	56.5%	8,712,273	43.5%
Grimsby	EB-2011-0273	4,232,036	2,407,163	56.9%	1,824,873	43.1%
Brant County	EB-2010-0125	6,173,189	3,815,249	61.8%	2,357,940	38.2%
Parry Sound	EB-2010-0140	2,434,786	1,525,589	62.7%	909,197	37.3%
Kenora	EB-2010-0135	3,077,201	1,971,057	64.1%	1,106,144	35.9%
Totals		**1,051,405,039**	**450,490,722**	**42.8%**	**600,914,317**	**57.2%**
Simple Averages				**49.1%**		**50.9%**
Weighted Averages				**42.8%**		**57.2%**