EB-2009-0152

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF the Board Staff Discussion Paper on the Regulatory Treatment of Infrastructure Investment for Ontario's Electricity Transmitters and Distributors

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SUBMISSIONS OF THE SCHOOL ENERGY COALITION

July 7, 2009

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1 GENERAL COMMENTS

1.1 *Introduction*

1.1.1 On June 10, 2009 the Board released a report (the "Staff Paper") entitled "*Staff Discussion Paper on the Regulatory Treatment of Infrastructure Investment for Ontario's Electricity Transmitters and Distributors*". These are the comments of the School Energy Coalition on the Staff Paper.

1.1.2 During the course of reviewing these issues, we have also considered the Proposed Amendments to the Distribution System Code relating to connection cost responsibility, on which we have made separate submissions under EB-2009-0077. We have also considered the relevance of the Guidelines released by the Board June 16, 2009 under EB-2009-0087, and the Review of Asset Management Practices of the Ontario Electricity Distributors by KPMG, released by the Board on March 18, 2009. It has been unnecessary for us to refer to them directly in our Submissions, but they have informed our analysis.

1.1.3 As is usual in matters of this type, ratepayer groups have shared thoughts and analysis, and in particular we have had the opportunity to review the thoughtful submissions in this proceeding from LPMA, filed yesterday. Those submissions have been most useful, although in several cases our views on the issues are different from those of LPMA.

1.2 *Summary of SEC Comments*

1.2.1 In essence, SEC has concluded that the Staff Paper seeks to solve problems that it has not defined or even identified, and probably do not exist in Ontario. As a result, the mechanisms proposed in the Staff Paper are unnecessary in almost all cases.

1.2.2 In Section 2.2, we review a number of potential problems that the Staff Paper could be seeking to address, and conclude that, to the extent any of them exist in Ontario, they are well handled by existing regulatory principles and practices.

1.2.3 In Sections 2.3 and 2.4, we consider FERC Order 679 and the Hempling/Strauss paper, which form the basis for the proposals in the Staff Paper**.** We conclude that neither is applicable in the Ontario context, and if they are applied by analogy, they in fact lead to the conclusion that the mechanisms proposed by Board Staff are <u>not</u> required in Ontario.

1.2.4 The need for utilities to have reasonable certainty with respect to this new infrastructure spending is considered in Section 2.5, and we conclude that the Board should reassure the distributors and transmitters that a) utilities will have pre-approval of their infrastructure capital plans in a timely and thorough process, and b) the existing regulatory paradigm for cost recovery will be applied consistently to that capital spending. With those statements, in our view the Board removes almost all incremental risk associated with this wave of capital spending.

1.2.5 With respect to infrastructure spending during IRM years, we conclude in Section 2.6 that the incremental capital module already deals well with this concern, and no further action is needed by the Board in this regard.

1.2.6 Section 3 of these Submissions answers the questions posed by Board Staff. It largely flows from the discussions of the principles at play in Section 2. One area in which we covers new ground is the answer to Question 11, relating to accelerated depreciation. We show that matching depreciation to either contract term or renewable generation asset service lives reflects a fundamental misunderstanding of the difference between renewable and non-renewable generation.

1.2.7 Our overall conclusion, therefore, is that there will be very few cases in which special treatment of infrastructure spending may be required, and when they arise individual Board panels should be charged with the responsibility to fashion remedies appropriate to the specific problems those applicants are facing. With that exception, the additional mechanisms proposed in the Staff Paper do not solve any identified Ontario problems, and appear instead to import U.S. "solutions" to U.S. problems, which solutions are inapplicable in the Ontario context.

2 NATURE OF THE "PROBLEM" BEING ADDRESSED

2.1 *Basic Issue*

2.1.1 The basic problem with the Staff Paper is that it seeks to solve a problem or problems that are not defined or even identified, and in all likelihood do not in fact exist. Turning the current capital recovery system on its head needs to start with a good reason to do so – i.e. some goal that the Board wishes to achieve. No such goal is apparent in the Staff Paper.

2.1.2 The Ontario Energy Board has a sophisticated, often very subtle, system of principles, rules and guidelines for the assessment of capital spending needs and costs, and the recovery of those costs in rates. This system did not spring up overnight as a result of a dream by some crazed regulator or politician years ago. It, instead, evolved through individual cases, testing of issues and evidence, detailed analysis, and deep understanding by regulators over many decades. It is a system that works, not just in Ontario, but in many other jurisdictions, because it recognizes the many issues associated with recovery of capital spending, and balances them carefully. It does not just look at ease of obtaining financing. It does not just look at intergenerational equity. It does not just look at market equity returns. These and many other considerations have been looked at, over many years, not only as individual issues, but also in the context of each other, and in the context of many different types of utility situations and plans.

2.1.3 That is not to say that "thinking outside of the box" is bad, or should be stifled by the weight of convention. The Board needs to embrace new ideas, and never more so than when the electricity distribution and transmission system is clearly going to undergo fundamental change.

2.1.4 But new ideas do not have value for their own sake; they have value as ways of meeting new or more difficult challenges. Therefore, to test any new idea, the first step is to identify the problem, challenge or barrier that the new idea is intending to address.

2.1.5 Since the Staff Paper does not say what it is trying to accomplish, in the section below we will identify possible problems arising out of the new reality, to determine if any of them are not appropriately dealt with by the existing, sophisticated system of capital cost recovery.

2.2 *Barriers to Infrastructure Investment*

2.2.1 ***Possibilities.*** There is no question that the Green Energy Act and associated changes will result in fundamental changes to Ontario transmission and distribution infrastructure. Those changes will come at an initial capital cost, and it will not be insignificant. This changes is estimated to cost be between $10 and $50 billion over the next decade, and we would not be surprised if more were needed.

2.2.2 The question that needs to be addressed is whether that additional infrastructure spending is sufficiently large or sufficiently unique that the current capital spending approval and recovery process does not handle it well. We have identified six possible concerns, set forth below.

2.2.3 ***Willingness to Spend.*** In at least some cases the capital spending needed to incorporate renewable generation, and implement the smart grid, will be outside of the normal comfort zone for utility planners and operations managers. There may be some inertia, or resistance to the higher infrastructure spending required, particularly if one implication is that resources (such as experienced utility personnel) available for more routine spending are temporarily constrained. This raises the question of whether incentives for this additional spending are required in order to get the capital work done at all.

2.2.4 In our submission, this is not a problem that needs to be addressed by the Board. The government has already determined that LDCs now have a legal obligation to spend money on infrastructure to accommodate renewable generation and implement the smart grid. The government could have left it to the Board to "persuade" utilities to increase capital spending. They did not. While they gave the Board the incentive tool, in case it is needed, they did not mandate its use. Instead, they made utility infrastructure spending in this area an obligation, every bit as central to their mandate as the obligation to serve their load customers.

2.2.5 Thus, incentives from the Board are not required (unless the Board identifies a specific need, as discussed below). It is not good regulation to incent people to do what they are legally obligated to do. This would imply that LDCs should also be incented to keep their systems in good repair, and to connect new customers, and to make timely regulatory filings. The Board's normal approach to LDC obligations has been to require LDCs to meet those obligations. The LDCs have a public monopoly franchise, and it comes with obligations. The quid pro quo for meeting those obligations is the profit arising out of the return on rate base. Nothing more should be required.

2.2.6 Frankly, we think it unlikely that LDCs will in fact resist this incremental infrastructure spending. There will be inertia, but there will also be a realization that their local systems, and the transmission system, are being upgraded at ratepayer expense. Profits for utility owners will go up, because equity will go up. Where utility owners are also local municipalities, they will also see the secondary benefits in local economic activity, both from the infrastructure spending by LDCs, and from the spending by generators on their new projects. As a side benefit, unionized utilities will find that the problem of balancing cost efficiencies with union job security requirements will, at least for a few years, be alleviated, since the additional work will ensure jobs for people who, in a status quo world, might become redundant.

2.2.7 In addition, we note that LDCs have to respond to new spending requirements, due to public policy and other external factors, all the time. At least in Ontario, it is clear that LDCs respond by meeting their obligations, and doing so in a timely way. While the GEA-driven spending might be relatively large compared to most other government initiatives in the past, the LDCs have a good track record for embracing new requirements and meeting their obligations.

2.2.8 It is therefore submitted that utilities do not need to be incented to spend money on infrastructure. If, in the future, the Board starts to see resistance to infrastructure capital spending, then the appropriate step in our view is to identify the reasons for that resistance, and then identify the tools available to the Board to overcoming that resistance. It is not, however, a good idea to solve the problem unless it actually exists, and we do not believe it does now, nor will in the future.

2.2.9 ***Ability to Obtain Debt Financing.*** The second possible concern is that LDCs will have difficulty obtaining sufficient debt financing to finance the substantial increase in capital spending and rate base that may be required. There are several reasons why this is not a realistic fear.

2.2.10 First, the government has already taken the first step in dealing with this, making many billions of dollars available to LDCs and others through Infrastructure Ontario. This money is available to LDCs at reasonable rates for long term infrastructure renewal and enhancement. While there is some question whether the money available will cover all of the infrastructure costs in all areas, some or all LDC needs can be met this way.

2.2.11 Second, evidence from the 2008 and 2009 LDC cost of service rate cases has shown numerous instances where LDCs have had banks and other commercial lenders make substantial amounts of debt financing available to them on favourable terms. In some cases, the new credit availability reported by LDCs was just for contingencies, while in others the plan was to use new funds for capital spending. In still others, the LDCs reported that they had quotes from their bankers, but had not actually arranged for the financing because it was not needed in light of financing in place from municipal shareholders.

2.2.12 Third, as we have noted in our comments on Cost of Capital in another proceeding, there appears to be a flight to quality in the capital markets, and regulated utilities generally constitute quality debt issuers. By way of example, Manulife recently offered $75 million of 7.4% quasi-debt, and had to increase it to $100 million because of high market demand. At the other extreme of the low risk scale, the Ontario government's recent Ontario savings bond campaign, with 5 year bonds at only 3%, raised over $1 billion in three weeks in June. Ontario LDCs fall somewhere in the middle between those two risk levels, and it is clear that there is ample money available at low rates for quality debt.

2.2.13 In short, in our submission there is no reason to believe that Ontario LDCs or transmission companies will in general have any difficulty raising debt financing. On the contrary, it may be that they are in particularly good shape in this regard, because of the combination of very risk averse capital markets, and substantial government funding available.

2.2.14 There will, indeed, be exceptions. A few LDCs will have problems getting sufficient new debt finance. However, it is submitted that the only circumstance in which this could be true is where a utility with unusually high infrastructure capital needs has underlying financial weaknesses that make the financial markets perceive the risk to be very high. Where this is the case, in our submission there is a problem, but the problem is with the financial weakness of the regulated entity. That is the problem that the Board should address. It is not a new problem, and there are existing tools at the Board's disposal to deal with an LDC having financial difficulty. A new system of mechanisms is not required.

2.2.15 ***Ability to Obtain Equity Financing.*** The flip side of an inability to finance through debt is the potential inability to get sufficient equity financing to support needed new spending. This is particularly problematic since many distributors and transmitters are owned by government, and some government bodies are, or consider themselves to be, capital constrained. What may be easy for a publicly listed company with solid financials – raising additional equity from private sector shareholders – may be more difficult for an LDC owned by a local municipality with its own financial challenges.

2.2.16 It is important to keep this particular challenge in perspective. A typical LDC recovers from ratepayers, in ROE and PILs, approximately 12% of rate base. Thus, given that new spending typically provides a tax shelter, this means that annual earnings of an LDC should normally be sufficient to provide equity support for capital spending equal to 30% of rate base (at 60% debt financing). With compounding, this means a utility that doubles its rate base every three years still has sufficient equity in retained earnings to support that capital program.

2.2.17 Thus, for the vast majority of LDCs, the only thing could be stopping them from financing the equity component of their capital spending will be dividends required by the shareholder. It is submitted that the cash flow needs of the shareholder should not be allowed to be a barrier to the capital spending obligations of a regulated entity.

2.2.18 Another aspect of this is the fact that ROE includes compensation for the risk that the utility will require additional equity capital to fund its operations. The whole point of the ROE analysis is that the market tells the Board what the right number is. The market figures include capital requirements. In an even more fundamental sense, the current ROE formula is designed to ensure that utilities will, if required, be able to attract necessary capital.

2.2.19 As a practical matter, it is clear that this is in fact the case. The current level of ROE is sufficient to attract private sector investment interest, as seen by continuing M&A activity and premiums paid on acquisitions. The Board has seen M&A valuation analyses in recent proceedings that make clear the current 8% rate is sufficient to justify valuation premiums. Looked at from the point of view of the general markets, there is little doubt that risk-averse investors like pension funds and insurance companies are eager to invest in companies with regulated 8% after tax returns.

2.2.20 It would therefore appear to us that ample equity financing is readily available both internally and externally for utilities, so that if local municipal shareholders are unable or unwilling to meet their obligations to fund their utility properly, sufficient funding is still available.

2.2.21 In our submission, the only circumstance in which an LDC should be equity capital constrained is where the infrastructure capital spending is substantial, and the shareholder is both unwilling to give up its dividends and unwilling to have a private sector equity partner. In that situation, we believe it would be unfair to saddle ratepayers with additional costs because of the shareholder's position. Local municipalities have chosen to remain shareholders of their LDCs because they like the returns on both debt and equity, and they like their control over the utility's policies and operations. Those substantial returns, and those powers, come with responsibilities, and the Board should simply require them to meet those responsibilities.

2.2.22 It is, of course, possible that in the odd case an LDC will not be able to get sufficient equity from the shareholder, because of lack of funds, and will have too weak a financial condition to attract private equity. In the rare cases where that is true, in our submission the problem – as with the inability to access debt financing - is the basic financial weakness of the LDC. That is the problem that the Board should address. In those circumstances, the pressure for increased infrastructure spending merely stresses the utility and thus brings to a head a pre-existing problem.

2.2.23 ***Construction Lead Times.*** The discussion of rate base renewal, above, ignores the time frames involved in new infrastructure projects. Those projects can be as short as one construction season, or as long as several years. The longer they are, the more the utility has to finance the costs during the construction period. The concern is that LDCS will not have sufficient financial resources to cover these capital needs until projects go into rate base.

2.2.24 There are two components to this potential problem. First, there is the issue of whether the existing working capital formula is sufficient to provide the initial working capital for this additional capital spending. Second, there is the issue of whether the cost of capital embedded in CWIP is appropriate, or whether a cost of capital more akin to the weighted average cost of capital would be more appropriate.

2.2.25 On the first of these points, the intervenors and others have been calling for a review of the current working capital formula for some years, and there is some discussion that the Board will embark on this in 2010 or 2011. The hard evidence, in the form of real lead-lag studies, is that the current 15% number is too high, and something closer to 11.5% to 12.5% is more in keeping with actual working capital needs. Against this background, if there is a working capital shortfall due to increased infrastructure spending, the solution is to get the working capital formula right, not to layer further adjustments on top of the existing questionable formula.

2.2.26 On the second point, it is clear that the cost of capital embedded in CWIP is less than the cost of capital applied to rate base. Generally, CWIP can be financed with short or medium term debt at relatively low cost, and it is only when it goes into rate base that the equity plus debt capital structure is engaged. This is particularly true given the availability of Infrastructure Ontario and bank construction financing on favourable terms.

2.2.27 If, despite the availability of debt to finance this increased spending, there were evidence that additional equity is also required, the Board would have to consider the best way to address that. There is no evidence that we are aware of supporting that premise, and it seems counter-intuitive. Aside from the question of certainty of recovery (dealt with later), there is no logical reason to us why infrastructure projects cannot be funded with conventional construction debt at relatively low cost.

2.2.28 We therefore conclude that there does not appear to be a barrier to infrastructure spending based on the costs during construction. Whatever may have been the case for capital-constrained U.S. investor-owned utilities, there does not appear to be an Ontario parallel.

2.2.29 ***Abandoned Projects.*** A concern that is implied in the Staff Paper is whether utilities that start projects to connect generation or reinforce their system will be able to recover those costs if the generation or reinforcement is no longer required, so the projects have to be abandoned.

2.2.30 The key to dealing with this is to ask "What happens now?". That is, what does the current system do to deal with this eventuality? For example, if a distributor builds a line to connect a major new factory, but the factory never opens, or it opens but then closes before the useful life of the new infrastructure has run its course, how does the distributor recover those costs? Of course, some of that is typically covered by a capital contribution agreement, but the balance is not.

2.2.31 It would appear to us that, where capital spending is prudently incurred by a distributor, but changing circumstances mean that the spending was not needed, or not needed for its full life, the current system would generally allow its recovery from ratepayers in the normal course. Where a project is abandoned prior to completion, or in some other special cases, the distributor has to make a special application to the

Board, but we cannot recall a case in which recovery was denied for prudent spending, even where the assets were ultimately stranded.

2.2.32 When distributors are allowed to recover costs from ratepayers for which the ratepayers do not get a benefit, there is an inherent unfairness, but that is ameliorated by the possibility that the distributor would have to "eat" prudently incurred costs. The Board has generally been careful in balancing those considerations.

2.2.33 The key here is prudence. It is important that the utilities continue to have the obligation to manage risk and make good capital spending decisions. This is the primary protection for the ratepayers against wasteful or inappropriate utility capital projects. Utility managers generally do a good job assessing the need for, and cost of, proposed capital projects. While we don't always agree with their budget requests, for the most part their project decisions are sound, and this is in part because they have understood and internalized their responsibility to act prudently.

2.2.34 In addition, the Green Energy Act has established a paradigm in which LDCs will prepare multi-year infrastructure capital budgets for advance approval by the Board. Particularly in the first couple of years, when connecting renewables is relatively new, and some LDCs are learning how to protect themselves in those situations, advance approval of plans by the Board will allow more supervision during the period of transition.

2.2.35 This all leads us to conclude that the risk of non-recovery where projects are abandoned is not a significant one. The existing system already deals with this in an analogous context, and the capital budgeting process under the GEA will provide for ample public review and Board approval in advance of significant spending.

2.2.36 ***Amount to be Recovered in Rates.*** The last possible concern is that the amount to be recovered in rates – the cost of capital component – will be insufficient for utilities because their risk in connecting renewable generation or altering their system architecture is greater than is the case with their current capital spending. We are sure some utilities will argue that they should have a premium ROE, for example, for their new infrastructure spending program.

2.2.37 The Board's approach to ROE is entirely driven by risk. For a given risk, the market discloses a fair return. Therefore, unless the Board seeks to go to a non-risk-based ROE model, the only reasonable way to justify a premium ROE, a different capital structure, or any other mechanism that will increase the net return to the shareholder through increased rates, is to identify higher risk for infrastructure projects or a component of them.

2.2.38 In the analysis in the previous sections, we have considered a number of potential risks, all of which appear to be deal with properly and fully by the current capital cost recovery system used by the Board for many years. In our submission, if there remains in particular cases any remaining increased risk, not dealt with by the current system (which we doubt), then it is appropriate for the Board to deal with that increased risk.

2.2.39 However, the first step in dealing with that risk is to reduce the risk, not increase the compensation for taking it. If even after that there is a situation in which an increased risk remains, the next step is still not to increase compensation, but to assess whether projects with that higher risk level are truly appropriate. That is, if a project is so high risk that a) the risk cannot be mitigated, and b) a higher return would be justified, the obvious question is why an LDC would be undertaking such a risky project in the first place. Surely these tests would be met in only a very few unusual cases, such that no general rule for how to deal with them is either required or appropriate.

2.3 *FERC Order 679*

2.3.1 We have reviewed in detail the FERC decision in Docket RM06-4-000, being Order No. 679. We have also reviewed the comments on this decision from LPMA, with which we concur.

2.3.2 Without repeating the submissions of LPMA, it is appropriate to bring to the Board's attention the following aspects of the FERC decision that are not like the Ontario situation:

(a) The decision is a response to the Energy Policy Act of 2005, in which Congress <u>required</u> FERC to provide incentives to investor-owned transmission companies to upgrade the bulk transmission system.

(b) Congress was in turn responding to a perceived urgent problem with underinvestment by those transmission companies in needed infrastructure (see, e.g. p. 25 of the decision).

(c) The transmission companies were not under an obligation to invest. Under the system in which they operate, it is presumed that the market will dictate when, where and how they make capital investments, i.e. in response to demand sufficient that revenues will cover the capital cost over a reasonable time. The system failed to produce adequate investment (p.7, 8 and many other places), and the legislated solution was to mandate incentives so that the market would in fact work. Throughout, the system was and still is market driven.

(d) As anyone who reads the decision can see, FERC was not comfortable with the need for incentives, and clearly elected to circumscribe them as much as it possibly could within its legislative imperative. Thus, it interpreted the mandate narrowly, so for example assumed that incentives would only be appropriate where the result would still be just and reasonable rates (p. 2).

(e) Even a cursory read of the decision demonstrates that most of the state regulatory

commissions who participated in the case opposed granting additional incentives. There seems to be a consistent theme that the incentives are not really needed. The FERC rejected those arguments almost entirely because they concluded that Congress had already made that call. It was no longer open to them to consider whether the incentives were needed.

(f) Some of the most expensive new facilities would not be the responsibility of any one utility, but could be undertaken by any one of a number of transmission companies (p.15), so it would be difficult to centre in on one entity to do what is needed. This is another reason that market levers were more appropriate than direct regulatory action.

(g) The FERC concluded that the "incentives" under consideration were not in fact incentives, because their role was to remove barriers to needed investment (p.17). Among the most important of those barriers was that many of the needed transmission upgrades were higher risk projects. Another that was critical was the problem that investor-owned utilities might not have adequate cash flow to support the financing of these large projects.

(h) Notwithstanding the requirement to offer incentives, the FERC determined that they would only be available on a case by case basis where the applicant demonstrates that they are necessary for a project to proceed, and the rates remain just and reasonable.

2.3.3 It is submitted that there is no reasonable nexus between the reasoning in FERC Order 679 and the situation in Ontario under the Green Energy Act, other than by exception. That is, the reasoning in the decision can be used to show why Ontario should <u>not</u> take the same steps as FERC was obligated to take, but does not form any foundation for the Board to adopt the FERC solutions. We don't have the same problem or problems, nor the same sector structure that limits capital spending.

2.3.4 We therefore conclude that the heavy reliance by Board Staff on the FERC decision in the Staff Paper was inappropriate and, ultimately, counterproductive.

2.4 ***Hempling/Strauss Paper***

2.4.1 Board Staff also relied on a paper by Scott Hempling, a lawyer and executive director of the National Regulatory Research Institute (NRRI), and Scott Strauss, a lawyer with Spiegel and McDiarmid LLP in Washington, D.C., entitled "*Pre-Approval Commitments: When and Under What Circumstances Should Regulators Commit Ratepayer Dollars to Utility-Proposed Capital Projects?*"

2.4.2 While the paper does not express the views of NRRI, Mr. Hempling is its executive director. NRRI operates in part under the auspices and supervision of NARUC, and is funded largely by donations from state utility commissions. The balance of its funding comes from investor-owned utilities. It is, however, considered in the U.S. to be independent in its research results.

2.4.3 Speigel and McDiarmid is a small (28 lawyers) Washington law firm whose largest client base is suppliers, transmitters and distributors of energy. Scott Strauss is a senior partner of the firm whose primary client base is municipally owned and consumer owned regulated entities and generators, and labour unions in the energy field. Mr. Strauss has also on occasion acted for the Office of the Peoples' Counsel in Washington on behalf of ratepayers.

2.4.4 In this paper, Hempling and Strauss argue that the traditional U.S. regulatory model, in which regulated entities must complete a project before they get assurance of cost recovery, creates risks for utilities that lead to underinvestment. They propose instead that the regulator give an assurance of cost recovery earlier in the process, thus shifting risk from the utility shareholders to the ratepayers. The assumption that recoverability is not known until spending is complete is central to their thesis (p. 5 and elsewhere).

2.4.5 It is clear, we submit, that this paper does not really apply in the Ontario context, for one main reason: using a forward test year model, utilities know in advance that their capital spending plans are acceptable to the regulator. This will be enhanced when multi-year infrastructure plans are considered and approved. Even without that, the Board's history is that there is almost no risk of a utility failing to recover capital spending in rates once it has been made, unless it should have been considered by the Board previously, or the decision to proceed is manifestly inappropriate.

2.4.6 But even in the very different situation that they are describing in the U.S., Hempling and Strauss point out a considerable number of important caveats to their thesis, including for example:

(a) It is critical that the regulator identify with precision the conditions under which risks will be transferred from utility shareholders to ratepayers, and the benefits the ratepayers will be getting in return.

(b) Pre-approvals should be tightly limited, so that approving prudency is not considered to be acceptance of the actual capital costs in rates. A subsequent review of actual spending should still be undertaken to determine what is appropriate for inclusion in rates.

(c) The risk that pre-approval seeks to control is the potential that costs will not be recovered in the future from ratepayers. The result of this risk is that the cost of capital could be higher, since the capital markets overvalue such risks.

(d) Pre-approval increases the responsibility of the regulator to oversee the project's ongoing progress, and regulators should be careful to make sure that they do not take on responsibilities that are more appropriately left to management.

(e) Where pre-approval is granted, regulators should consider whether the reduced risk should result in a reduced ROE as well.

2.4.7 On pages 24-26 of the paper, the authors propose a series of criteria for determining whether and to what extent a regulator should provide comfort in advance that a project will be considered prudent and recoverable in rates. While we might quibble with some of the wording of the points, in general it is a useful list of considerations relevant to future capital spending. It could be a valuable resource, for example, when the Board is considering the infrastructure spending plans of the LDCs.

2.4.8 But the other side of this is that, compared to the Staff Paper, the Hempling/Strauss paper counsels considerably more caution and hesitance on the part of the regulator, even when applied to a U.S. situation which is far more problematic. Fairly read, the Hempling/Strauss position appears to us to lead to the conclusion that extraordinary measures are probably <u>not</u> required in most cases in Ontario, and in the few cases where they might prove useful, they should be applied with extreme caution.

2.5 ***<u>The "Certainty" Issue</u>***

2.5.1 In our analysis in section 2.2 above we did not include amongst the potential problems to be addressed the "certainty" of utility cost recovery. In light of the long period of uncertainty surrounding the recovery of transition costs at market opening, and the proceedings that followed under which some of those costs became recoverable, it is perhaps understandable that some utilities want special rules to ensure that the costs of this new industry transformation – which they expect to incur in good faith – will ultimately be recovered in full from the ratepayers**.**

2.5.2 In large part, the legislature in the Green Energy Act, and the Board in its plans to consider infrastructure spending plans, have solved the certainty issue. The concern of utilities that they will not recover the costs they incur is dramatically reduced when the regulator has already seen what they plan to do, those plans have been tested in a public review, and the regulator has approved the result. They still have to manage their projects prudently, and they still have to keep on top of the changing needs of their generator customers, but these are all things well within their core competencies. This kind of operational management risk is not new to them, and does not create any material uncertainty.

2.5.3 In our view, the biggest boost the Board can provide to utility certainty of recovery is to reinforce the existing Board policies of cost recovery, and confirm that they apply to this new wave of infrastructure spending. If utilities know that the rich system of fairness already in place will apply here as well, and that they retain their current ability to come in for cost of service or other rate reviews in their own discretion, then their certainty of recovery of costs under an approved plan is very high, and thus their risk is low.

2.5.4 This is in stark contrast to market transition costs. There was no opportunity for plan pre-approval, the rules that might be applied were completely unknown as the spending occurred, and the rules that ultimately applied were unique to the circumstances. Also, the utilities and the regulator operated for years under a regulatory moratorium that extended the uncertainty and exacerbated the difficulty in getting full recovery.

2.5.5 There may still be a limited number of cases in which uncertainty of cost recovery creates difficulties for individual utilities. In our view, it is unnecessary for the Board to establish a predetermined menu of alternative approaches to cover those cases. Those cases will, by their very nature, be unique. When utilities in those unique circumstances present their infrastructure capital plans, the Board should fashion specialized remedies for those utilities that reflect those unique circumstances. While they may include some of the techniques that the FERC used in Order 679, the Board has long shown its willingness to be creative when individual applicants need creative solutions.

2.5.6 We note that, in those limited cases in which, in considering plans, the Board is convinced that special treatment may be necessary, the analysis and the cautions in the Hempling/Strauss paper may be useful. In particular, it will be important for the Board to ensure that any shifting of risks to the ratepayers comes with concomitant benefits to them, and that the Board's response to the situation does not undermine the responsibility of utility management to manage prudently and keep risks under control.

2.6 ***The Special Case of IRM***

2.6.1 IRM creates a special problem, because the LDCs may have large and unexpected capital spending obligations under the Green Energy Act that are not accounted for in their base rates. It is clear that LDCs may be concerned that they will have to defer needed infrastructure spending until rebasing, or come in for rebasing early, or suffer non-recovery of significant amounts until their rebasing occurs.

2.6.2 In our submission, the Board has already dealt with this problem thoroughly and after a full debate, by implementing the incremental capital module (ICM). No further special treatment of infrastructure spending is required given the availability of that remedy.

2.6.3 To the LDC, there is no rate-related difference between capital spending on a new ERP system, or capital spending to make renewable generation a reality. While they have to be managed differently, dollars are dollars. If they are spent, and they are recovered from ratepayers, the LDC is in good shape.

2.6.4 The ICM starts from two requirements: capital spending in excess of the amount already provided for in 3rd Generation IRM, and the special nature of the incremental spending that justifies an extraordinary tool like ICM.

2.6.5 Infrastructure spending that, together with the utility's normal capital spending, does not exceed the threshold, is by definition already provided for in rates. The utility does not need any special treatment for that spending because it is already collecting in rates enough to cover those costs.

2.6.6 If the spending does exceed the threshold in a given year, there are a number of specific criteria, of which the key for these purposes is that the capital needs be unusual and unexpected. It is difficult to argue that the substantial new obligations imposed by the Green Energy Act would not, in most circumstances, be sufficiently unusual to invoke the ICM. Therefore, in those situations in which LDCs have to ramp up spending in an IRM year, they have a solution that is straightforward and efficient, and seems perfectly designed for these circumstances.

2.6.7 There remain the few distributors that will have rebasing for 2011, and so are still under 2nd Generation IRM. If those distributors have significant new infrastructure spending in 2010 that will close to rate base in that year, they could potentially be disadvantaged. For that category, which we believe will be very small, in our view it would be appropriate for the Board to extend the availability of the ICM to them rather than forcing them to come in for rebasing a year earlier than planned, or delaying the in-service dates for infrastructure capital.

3 RESPONSES TO QUESTIONS POSED BY BOARD STAFF

3.1 *General*

3.1.1 Our general conclusion is that the Staff Paper is seeking to solve problems that are neither identified nor, in fact, likely to occur. As a result, we do not believe that most of the questions posed by Board Staff need to be answered at this time. The following section deals with each of those questions in turn, in that context.

3.1.2 In light of our general position, it was unnecessary for us to address Questions 17-22 inclusive.

3.2 *Specific Questions*

3.2.1 ***Question 1. Should the framework and mechanisms identified in this Discussion Paper apply to other rate-regulated entities? If so, why and for what types of projects?***

3.2.2 The framework and mechanisms should not apply at all. There is no reason to establish a menu of mechanisms of this sort for any rate-regulated entities. In the rare cases in which special treatment of infrastructure spending is necessary for a particular LDC, these and other mechanisms may need to be considered, or the Board panel may fashion a more creative remedy, but in either case the remedy should be specifically tailored to the LDC's needs.

3.2.3 ***Question 2. Are there other broad classifications for investment, beyond "routine", "non-routine incremental" and/or "GEGEA-related" that should be considered? Is so, what are they and what are the specific underlying drivers for such investment?***

3.2.4 There is no evidence that these investments have different risk profiles, so the classifications are largely irrelevant, except for application of the ICM, which already has its own classification structure.

3.2.5 The category of GEGEA-related also has a special relevance, because of the statutory requirement to file infrastructure spending plans. This puts this in a special "transition costs" type of category, but as noted earlier, no alternative rate-making mechanisms seem to be needed as a result of this categorization.

3.2.6 In our submission, large capital spending plans, whatever the reasons for them, present challenges and risks to utilities. The Board's role in each case is to ensure the financial well-being of the regulated entity while protecting the ratepayers. This does not change because some spending is to attach renewables, or to implement the smart grid. Those two regulatory goals – financial stability and ratepayer protection - are still primary, and the GEA does not purport to undermine either of them, or their importance.

3.2.7 ***Question 3. Should the mechanisms identified in this Discussion Paper apply to the recovery of costs incurred by electricity transmitters or distributors for investments to accommodate renewable generation or to develop the smart grid, or both. Why or why not?***

3.2.8 Neither. No problem has been identified for either category that is not already appropriately handled by a well-tested and robust regulatory cost recovery approach.

3.2.9 ***Question 4. Should the mechanisms set out in this Discussion Paper be applied to infrastructure investment if the cost of the investment is potentially recoverable through a Province-wide cost recovery mechanism? Why or why not?***

3.2.10 In our view, this menu of mechanisms is not required at all. Whether or not that position is accepted, how the cost of the investment is to be recovered, and from whom, is not relevant to whether any of these mechanisms are required. In any case, until the terms of such a socialized recovery system are known, it is premature to try to assess whether that system will impact the risks and challenges of the distributors and transmitters. There are too many variables in the potential design of that socialized recovery system, and it is not possible to predict what it might look like.

3.2.11 ***Question 5. Should the mechanisms set out in this Discussion Paper be applied to infrastructure investment in smart grid technology while it is at an early stage of development and where governing standards are yet to be developed? Why or why not?***

3.2.12 Consistent with our previous comments, the proposed mechanisms are not required at all.

3.2.13 On the other hand, there may well be an issue as to who pays for pilot projects carried out by individual LDCs for the benefit of the industry as a whole. This is not addressed in the Staff Paper, and has in the past not really been a problem in the industry. Different (usually large) utilities have regularly stepped up and been willing to try out new technologies at the expense of their local ratepayers, knowing that their leadership has an added cost and that other utilities will end up being, in essence, "free riders" relative to their initial investment. It has generally worked because the utilities have often worked together to help each other, and share the overall responsibilities for leadership. If that becomes less prevalent under the pressures of moving to a smart grid, the Board may have to address the issue, but in our view that is for the future. It is not yet a problem that the Board has to address.

3.2.14 ***Question 6. Should "routine" investment made by a transmitter or distributor be eligible for one or more of the alternative treatments identified in this Discussion Paper? Why or why not?***

3.2.15 See our comments under Question 2.

3.2.16 ***Question 7. Should the mechanisms identified in this Discussion Paper be presumed to apply to certain types of investments (for example, to accommodate renewable generation)? Why or why not? If so, which investments?***

3.2.17 See our comments under Question 1.

3.2.18 ***Question 8. Should the Board be more prescriptive as to which type of investment may qualify and which will not? If so, what criteria might the Board use to make a determination on which type of investment would qualify?***

3.2.19 In the rare cases in which these or other mechanisms should be considered by the Board, it should only be on a case by case basis, and the criteria in the Hempling/Strauss paper, among others, should be considered by the relevant Board panel. Foremost, though, special treatment should only be considered in advance of a project's commencement, and then only if the applicant meets its onus to show that, but for the special treatment, it will be unable to proceed with a needed project despite management's (and the shareholder's) willingness to do so.

3.2.20 ***Question 9. Should the Board permit applicants to request confirmation from the Board that prudently incurred costs associated with any abandoned projects will be recoverable in rates if such abandonment is outside the control of management? Why or why not?***

3.2.21 The risk of recovery of costs of abandoned projects is not a new one, and the Board already has principles, rules and guidelines to balance the interests of shareholder and ratepayers in those situations. There is no reason for the Board to change its current approach, which in any case rarely requires utility shareholders to bear costs of abandoned projects.

3.2.22 ***Question 10. Should the Board allow for full or partial CWIP to be placed in rate base during the construction of transmission facilities to accommodate the connection of renewable generation and/or develop the smart grid? Why or why not? Should the Board allow this particular treatment for distribution investment? If so, on what basis?***

3.2.23 In the absence of any evidence that, in Ontario, LDCs are having difficulty financing CWIP outside of rate base, the only reason for this proposal would appear to be to increase the return to the utility during the construction period. There is no credible basis for this increase.

3.2.24 Further, this proposal represents a fundamental shift in the regulatory paradigm. Under the Board's current principles of ratemaking, this year's ratepayers pay the costs for the distribution and/or transmission system that serves them this year. This matching of cost responsibility with benefits is fundamental to the regulatory compact (i.e. the "used and useful" principle). If the Board starts requiring today's ratepayers to bear in today's rates the costs of the system to serve future ratepayers, the principle of intergenerational equity is undermined, and for no material benefit to anyone.

3.2.25 Hydro One has proposed this alternative treatment more than once, and the Board has never approved it. Why? Because Hydro One has never demonstrated that there is any need for it. The Staff Paper doesn't demonstrate any need either, and therefore in our submission this proposal is unwarranted.

3.2.26 ***Question 11. Should the Board allow depreciation to be adjusted to match a contract term or the useful life of the connecting renewable generation facility? Why or why not?***

3.2.27 This question proceeds from the incorrect premise that the reliable period of use of a distribution expansion serving a renewable generation facility is either the period under which it is contracted to supply power, or the useful life of the generation assets. This might, in fact, be appropriate for conventional (non-renewable) generation, but it is clearly inappropriate for renewables because of their unique nature.

3.2.28 Take a simple example. A utility builds infrastructure with an average useful life of, say, 40 years to facilitate the connection of a wind farm. The wind farm will operate under a 20 year power sales contract, and the turbines and towers have an estimated service life of 25 years. What is the reasonable expected service life of the distribution infrastructure? The simple answer is, 40 years.

3.2.29 The unique nature of renewable energy includes the fact that nature provides specific locations where it is efficient to harvest renewable resources. Those resources – wind, falling water, sunlight – did not start when generation commenced on the site. The location had the resource available, and humans subsequently build machinery and distribution infrastructure to harvest the resource. That resource does not go away. It is, in fact, "renewable", and doesn't have an end point in the foreseeable future. That is the key to understanding the service life.

3.2.30 What happens when the contract is up? The resource is still there, the harvesting equipment, in this example wind turbines, is still in place, and the infrastructure to bring the power to load is also still in place. It is unlikely that the provision of power from the site will cease. The incremental cost of that power at that point is very small, and the resource is still available to be harvested.

3.2.31 But, what then happens five years later when the turbines and towers reach the end of their service lives? Again, the answer lies in the fact that the resource is still there, and the infrastructure is still in place to bring the power generated to load as long as the resource continues to be harvested. Therefore, basic economics dictate that the turbines get replaced, the towers get refurbished or replaced, and the resource continues to be harvested.

3.2.32 Ontario has ample experience with this phenomenon on the context of hydroelectric power. Once a dam and station are built, and infrastructure is in place to take the electricity "to market", it is essentially a permanent source of generation with an infinite expected life. Turbines and electrical controls are replaced or upgraded or refurbished periodically, the station is rebuilt from time to time, and even the dam is rebuilt, restored, or otherwise improved over time. Even the distribution or transmission infrastructure serving the station is replaced periodically. What does not change is that the resource remains available, and so it continues to be exploited for renewable electricity. Ontario has numerous hydroelectric facilities that are more than 100 years old, and still going strong.

3.2.33 The only reasonable conclusion to reach is that, once infrastructure is built to connect a renewable generation facility, that infrastructure will almost certainly continue to be used to support renewable generation at that location until the end of its own useful life, and then it will likely have to be replaced to continue to harvest the renewable resource from that site.

3.2.34 In this respect, the expected useful life of infrastructure built to facilitate renewable energy is considerably more certain than the expected useful life of assets built to add new load. It is much more likely that a factory will close, or a new load centre will reduce its needs due to changes in the economy, than that a renewable energy resource, once harvested, will cease to be harvested at that location.

3.2.35 Some utilities may seek to justify accelerated depreciation, not because of contract terms or generation asset lives, but as a way of incenting them to spend on infrastructure. We have commented previously on the lack of any need for incentives. In addition, we note that accelerating depreciation creates the same sort of intergenerational equity issues that arise with including CWIP in rate base. Depreciation normally has the effect of ensuring that ratepayers each year pay their fair share of the costs of the assets that serve them. Accelerated depreciation rejects that principle, and in our view there is no significant benefit sufficient to justify undermining the principle.

3.2.36 ***Question 12. In light of a legislative context in which the Board may mandate infrastructure investments, are incentives necessary or appropriate in Ontario?***

3.2.37 No. Incentives are not required. If legitimate barriers to infrastructure investment are identified that are not appropriately handled by existing cost recovery mechanisms, then techniques to remove those barriers should be considered. We have not been able to identify any such barriers, and the mechanisms proposed in the Discussion Paper do not appear to be directed at removing any known barriers to investment.

3.2.38 We note that even the FERC, which was legislatively obligated to implement incentives, and was in a very different environment, still characterized its own incentives as techniques for removing the specific investment barriers that had been identified in the U.S. FERC Order 679 is clear that incentives for their own sake are not appropriate. They are only appropriate in the context of identifiable barriers. None of those barriers appear to exist in Ontario.

3.2.39 ***Question 13. If the Board were to provide for incentives, should it allow project-specific ROE? If so, should the Board consider adopting a range rather than a specific adder? Further, how might the Board determine an appropriate range or ROE adder?***

3.2.40 ***Question 14. If the Board were to provide for incentives, should it allow project-specific capital structures?***

3.2.41 See our comments in para. 2.2.36 to 2.2.39 above.

3.2.42 ***Question 15. What other alternative mechanisms, if any, might the Board consider be made available to applicants? Why?***

3.2.43 In our view, in those rare cases in which an applicant meets their onus to show the need for special treatment, the Board panel charged with deciding the case should tailor a remedy – whether those described by Board Staff, or other existing techniques, or something completely new – that addresses the specific problems of the applicant.

3.2.44 ***Question 16. In addition to the potential consideration identified, are there any other matters that the Board might consider in making decisions on requests for alternate treatment?***

3.2.45 As has been noted by both Board Staff in the Staff Paper, and ourselves in para. 2.4.7, the Hempling/Strauss paper includes a good starting point for regulatory considerations. However, in addition we believe it is critical that the Board identify the precise problem that will demonstrably prevent a necessary project from proceeding, so that the solution can be structured to solve that problem directly, while doing as little violence as possible to the Board's fundamental regulatory principles.

3.2.46 ***Question 23. Should the Board permit applicants to seek approval prior to construction of the facilities to determine whether the facilities qualify for the requested alternative treatments? Why or why not?***

3.2.47 It is, in our view, central to the Board's regulation of this wave of infrastructure spending that comprehensive multi-year infrastructure capital plans be considered by the Board and approved in advance of most spending. This provides certainty to the applicants that they are marching in the right direction, and the transparency necessary for ratepayers to accept the rate increases that will inevitably result. Pre-approval through multi-year plans should be established as the norm, and the Board should signal its expectations consistent with this principle.

3.2.48 It is unlikely that more than a handful of utilities will need any special treatment for the capital spending in pre-approved plans. When they do, it will most likely be a symptom of a separate underlying financial problem, rather than a capital spending issue. In either case, the first opportunity the Board has to consider that problem is when the plan is being considered.

3.2.49 Plans should include not only the technical and operational proposals, and the costs and cost/benefit analyses associated with those proposals, but also a financing plan that shows the utility will remain financially strong throughout the capital program. If there are any weaknesses in that plan, whether identified in advance by the applicant or not, it is part of the Board's responsibility and mandate to resolve those weaknesses before approving the plan. The Board has numerous tools at its disposal to do this, and considering how utility plans hang together and work (or don't) is fundamental to what the Board does day to day. It will be seldom that it needs any special tools to deal with plans that have financing or other issues.

3.2.50 Utilities should be expected to consider financing and cost recovery issues in their plans, but they should still have the opportunity – as they do right now – to apply to the Board later if circumstances change and their plan is no longer working out well. This is the Board's second opportunity to consider whether some form of special treatment is required, but at the same time the Board should be asking why the utility didn't raise its concerns the first time around.

3.2.51 All of this makes sense only in the context of problems which otherwise would prevent needed infrastructure investments from being made by willing utilities. This means that the instances of this being applicable will be rare and specialized, and consideration must be in advance of the project proceeding for any special treatment to actually solve the problem.

3.2.52 ***Question 24. What are the implications, if any, of using the single issue rate review process?***

3.2.53 The School Energy Coalition is strongly opposed to single issue ratemaking, which as a matter of longstanding principle has not been part of the regulatory paradigm in Ontario. In our submission, no credible case has been made that it is necessary in the case of infrastructure spending. The only possible exception is the application of the ICM, which is sufficiently circumscribed that the dangers of single issue ratemaking (i.e. taking costs out of context) are partially ameliorated.

3.2.54 ***Question 25. Is the use of rate riders an appropriate approach for implementing rate adjustments associated with the alternate treatments identified in this Discussion Paper? Alternatively, should the adjustments be made directly to base rates?***

3.2.55 ***Question 26. Should the Board allow applicants to seek approval of multi-year rate riders or should the applicant be required to apply every year to adjust its rate riders to reflect any changes in project costs?***

3.2.56 Rate riders designed to recover from present ratepayers costs of assets for the benefit of future ratepayers are fundamentally unfair and breach the principle of intergenerational equity. As a matter of general principle, assets should be recovered from ratepayers when they are in use for the benefit of ratepayers, and not before.

3.2.57 There may be circumstances in which some assets have to be paid for on a "layaway plan", so to speak. As noted earlier, those circumstances should be rare and utility-specific. We have seen no evidence that this will be required for the upcoming wave of infrastructure investment to facilitate the smart grid and renewable generation.

4 OTHER MATTERS

4.1 *Process and Participation*

4.1.1 We thank the Board for inviting us to participate in this process. We hope these submissions are useful, and we would appreciate the opportunity to continue to be actively involved in all future consideration by the Board as the many issues relating to the transition to a new distribution and transmission infrastructure are considered**.**

4.2 *Costs*

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

All of which is respectfully submitted.

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