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July 6, 2009

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
Suite 2700
Toronto, Ontario, M4P 1E4

Dear Ms. Walli:

Re: EB-2009-0152 – Comments of the London Property Management Association on Staff Discussion Paper

These are the written comments of the London Property Management Association ("LPMA") on the Staff Discussion Paper on the Regulatory Treatment of Infrastructure Investment for Ontario's Electricity Transmitters and Distributors dated June 5, 2009.

Comments have been provided in general and in reply to the specific issues presented in the Discussion Paper.

GENERAL COMMENTS

LPMA has a number of general comments related to the Staff Discussion Paper. LPMA submits that the Discussion Paper is flawed in two major areas. First, the Discussion Paper assumes that new regulatory mechanisms are needed to address specific problems. There is no support in the Discussion Paper to even hint that the current regulatory mechanisms will not adequately address any problems or issues that may arise with specific utilities and their specific investment requirements. The Discussion Paper does not even clearly identify what has to be fixed. In the absence of knowing what needs to be fixed, it is hard to come up with solutions that will work. Suggesting that a higher return on equity on specific projects is required, in conjunction with cost recovery certainty, may be getting it backwards. Perhaps a lower return on equity is justified given the other mechanisms that may be available to a utility to mitigate the risk of non recovery of costs.

There has been no evidence that utilities will not be able to finance the investments that are required of them under the Green Energy and Green Economy Act. The Board is well aware that the Government of Ontario has made significant amounts of money available to local distribution companies through Infrastructure Ontario (http://www.infrastructureontario.ca/en/loan/rates/sectors/local_distribution_rates.asp). The amount of funding available to Infrastructure Ontario totals $30 billion.

The Government of Ontario can be reasonably expected to ensure that Infrastructure Ontario, or some other organization, will be able to provide financing to the utilities to assist them to in carrying out Government policy.

The second major flaw of the Discussion Paper is that the alternative regulatory mechanisms provided and discussed are for the most part based on the Federal Energy Regulatory Commission's July 20, 2006 Final Rule *Promoting Transmission Investment through Pricing Reform* (Order No. 679). The situation addressed by FERC is not comparable to the situation in Ontario. The FERC situation and response was to encourage privately owned transmission companies to invest in infrastructure. These privately owned companies were not and are not subject to government direction to invest more capital. FERC designed a number of incentives that it thought it would get these companies to take on incremental investment.

LPMA submits that no incentive is needed in Ontario to get distributors and transmitters to invest in the infrastructure that the Province has decided is required. These companies are required to make these investments. The Discussion Paper is clear.

"*...electricity distributors and transmitters will, as required by the Board, need to file plans and invest in their systems to be able to accommodate renewable generation. They will, also as required by the Board, need to file plans and make investments related to the development of the smart grid.* (page 9)

LPMA submits that the incentives listed in the Discussion Paper are not necessary. You do not need a carrot if the stick is working. The carrot is nothing more than an unnecessary cost.

LPMA further submits that any approach used by the Board should be geared towards providing certainty rather than providing incentives.

LPMA has reviewed the Board's Decision With Reasons dated August 16, 2007 in EB-2006-0501 which as an application by Hydro One Networks Inc. for 2007 and 2008 electricity transmission revenue requirements. In that case, the Board dealt directly with FERC Order No. 679. Hydro One proposed special regulatory treatments consistent with the FERC approach for a number of its projects.

In its Decision, the Board quoted FERC Commissioner Suedeen Kelly and the framework she provided for evaluating incentive proposals. She stated:

> *I deem it important to identify and assess the following six characteristics of any transmission project in order to make reasoned and consistent decisions on requests for incentives for the project: (1) the public interest benefits of the project; (2) the cost of the project in absolute terms; (3) the cost of the project in proportion to the current transmission rate base of the applicant; (4) the difficulty of completing it due to the number of jurisdictions traversed and whether they are jurisdictions the applicant regularly deals with; (5) the difficulty of relying on normal rate recovery methods due to the length of time it will take to complete; and (6) whether the applicant would otherwise be required to build the project even without an incentive.*
>
> *The comments submitted in connection with Order Nos. 679 and 679-A, and the experience gained in working on individual incentive cases over the past year lead me to conclude that these particular characteristics are most relevant to deciding whether to award incentives.*

LPMA notes, in particular, characteristic number 6. In Ontario, distributors and transmitters will be required to build the project even without an incentive.

In its Decision on the Hydro One proposal, the Board noted the arguments of many of the rate payer groups as follows (page 60 of the Decision):

- *There is no reason why Hydro One should be compensated now for risks that may not materialize.*

- *The proposal is a significant departure from conventional regulatory treatment for capital projects. The Board should permit departures only under very exceptional circumstances and Hydro One has failed to establish that such exceptional circumstances exist. To allow Hydro One the relief it is seeking would set a precedent that may prompt other Ontario utilities to seek similar relief. Before setting such a precedent, the Board must be satisfied that conventional regulatory treatment is inadequate to meet needs such as those associated with the designated projects.*

- *If construction is delayed or if there are abandonment issues, Hydro One would be free to come to the Board for relief.*

- *Hydro One has not established that it is now subject to an increased risk with respect to the recovery of the costs associated with these projects.*

- *Hydro One has not established the need for "incentives" to undertake or complete those projects.*

- *FERC precedents arise out of a different regulatory regime and are not applicable in the Ontario context.*

- *The benefits to ratepayers as articulated by Hydro One have been overstated.*

The Board indicated in its Decision that it shared these concerns and found that a departure from conventional regulatory treatment had not been justified. The Board then went on to say (pages 61 – 62):

> *There is no evidence in this case that any regulator other than FERC has approved a package of special regulatory treatments like those advocated by Hydro One. FERC regulatory initiatives can be important guidance in some cases and the Board will continue to monitor FERC's actions to incent new transmission. However, the Board is not convinced that FERC's approach to incentives for transmission investments justifies the special treatment that Hydro One has requested. The cost of the designated projects, while large in absolute terms, is not particularly significant in relation to Hydro One's rate base, and there is no evidence that Hydro One will have difficulty financing the projects under conventional regulatory treatment.*
>
> *The Board is not persuaded that ratepayers would benefit from the proposed special regulatory treatment. Specifically, the Board does not accept Hydro One's argument that the treatment would result in revenue neutrality and rate smoothing. The evidence from Hydro One on this point was in conflict and lacked substance.*

The Board acknowledges Hydro One's concerns about the magnitude of its capital expansion program. At the same time, based on the evidence from the credit rating agencies, the Board is not convinced that Hydro One will be unable to finance the capital program under the conventional approach.

The Board is of the view that conventional regulatory treatment for the three designated projects provides the appropriate balance between the interests of ratepayers and utilities. The Board agrees with the consensus position of the intervenors that the mitigation of losses that have not, and might not, occur is unnecessary and not appropriate. There is nothing in the record that would justify the burdening of ratepayers with such losses. In addition, Hydro One is reminded that it can come forward with applications for relief, if a special circumstance arises which puts it clearly at risk. The Board has promptly responded to such requests from other applicants in the past. There is no reason to expect that the Board would not deal fairly and promptly with Hydro One on these projects should significant issues arise in the future.

Hydro One's request for special regulatory treatment for these designated projects is denied. In reaching this decision, the Board is not ruling out providing incentives for future projects where there is a compelling case.

The Board Decision noted above for Hydro One coincides with the submissions of LPMA. Where a compelling case is made by an applicant, the Board should consider if and what alternative regulatory mechanisms are needed. The applicant will need to provide a compelling case for the need. As a result, the Board should deal with any such applications on a case-by-case basis. The investments required to be made by a number of distributors may be spread out over a number of years and the rebasing and IRM filings, with the ICM, may well be more than enough to deal with this.

Note that LPMA does not believe that any alternative regulatory treatment should be confused with an incentive. An incentive is defined as something that arouses to effort or action; a stimulus. No incentives are required in the Ontario context as the investment must be made as required by the Board.

What **may be required**, are alternative regulatory mechanisms that **will facilitate** investment. This facilitation could take many forms, from educating the distributors (mainly the smaller ones) on how to apply for and receive loans from Infrastructure

Ontario, to encouraging utilities to seek third party partners to provide additional equity funding if the current shareholders are unwilling or unable to provide it themselves.

Rate payers should not be expected to pay more just because the current shareholder is unwilling or unable to invest additional capital unless they can get a premium return on equity. In the competitive business place if a company has significant expansion plans and needs to raise additional equity it can issue more common shares, merge with another company, or seek a third party than can invest the required amounts through partial ownership. LPMA sees no reason why a distributor should not be required to do the same thing. In today's economic environment, LPMA would suggest that there are many pension fund managers that would jump at the opportunity to invest in a relatively safe regulated industry and walk away with an after tax return on its investment of 8%.

Another issue that is absent from the discussion in the Discussion Paper is whether the incremental costs that may arise out of the increment investment expenditures are distribution expenses, or expenses that reduce the transmission and/or generation costs that are passed on to rate payers. Distributed generation should lower the transmission costs incurred by a distributor since less power will be sourced from the transmission system. Should the costs incurred on the distribution system to enable this then be treated like transmission costs and allocated to rate classes on the same basis? Will distributed generation result in lower generation costs?

A related issue is the impact on different distributors. Will distributors that have no or little distributed generation located within their boundaries ultimately end up paying higher transmission costs for the same power? This could well be the result of higher transmission rates because the transmitters will now have a lower kW forecast over which to recover their costs. There is not likely to be any significant reduction in their costs as a result of distributed generation and/or the smart grid. The assets will still be in place and require maintenance. Such a distributor, and their rate payers, would be at a disadvantage relative to other distributors that have a high proportion of renewable generation connected to their systems. How will this potential cost issue be socialized?

COMMENTS ON SPECIFIC ISSUES

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?

LPMA submits that the answer to this question is no, without further information. It may well be that the framework and mechanisms identified in the Discussion Paper may have some limited applicability to other rate-regulated entities in specific circumstances, but on a generic industry wide basis, the answer is clearly no.

The framework and mechanisms identified in the Discussion Paper are in response to specific requirements. They should not be considered for generally applicability. If any other rate-regulated entity wishes to bring forward the use of such a framework or mechanism, the onus should remain on them to justify the need.

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

LPMA does not believe that the broad classifications as provided in the Discussion Paper are practical, useful or necessary. However, should the Board accept these broad classifications, LPMA submits that there should not be any other classifications for investment that should be considered. The reason for this is that as the number of "broad" classifications increases the more difficult it may become to classify a capital project, or components of the capital project.

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?

LPMA submits that this question is too general in scope. As Staff state in the Discussion Paper, they are recommending adopting a case-by-case approach to the review and approval of applications for one or more of the mechanisms. In light of this recommendation, which LPMA supports, it is clear that the application of the mechanisms to the recovery of costs related to all investments to accommodate renewable generation and/or to develop the smart grid by each distributor and transmitter may not be necessary.

Investments by some distributors related to the accommodation of renewable generation may be quite small in relation to their normal capital expenditures and/or level of rate base while for others it may represent a substantial portion of either or both. While there may be a need for special mechanisms in the latter case, there is not likely any need in the former case.

LPMA submits that if a distributor or transmitter believes that it needs to use a non-traditional mechanism to enable it to accommodate investment in the smart grid and/or the connection of renewable generation, it should bring forward an application requesting whatever special treatment it is requesting, and showing why other mechanisms would not work, including the status quo regulatory treatment.

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?

LPMA believes it is premature to answer this question. It is unknown how any province wide cost recovery mechanism would be structured or how it would work.

A province wide cost recovery mechanism may have significant impacts on the mechanisms proposed in the Discussion Paper. For example, the required return on equity could be substantially for individual distributors if there is greater certainty of recovery of the costs through a provide wide charge that would provide more stable revenue streams to the distributor than its own customer base may.

Details of how and what costs would be recovered through the province wide cot recovery mechanism would have to be known before it could be determined if the mechanisms set out in the Discussion Paper are required, are duplicative or are double counting costs.

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?

No. The costs of infrastructure investment in smart grid technology while it is at an early stage of development and where governing standard are not yet developed should not be recovered through the mechanisms set out in the Discussion Paper.

These costs should be "socialized" and recovered through the province wide cost recovery mechanism. The reasons for this are two-fold. First, this would not saddle distributors and their rate payers with costs for being early adopters or pioneers with technologies that ultimately are rejected. Second, it may foster greater competition between different systems and approaches so that, ultimately, the province adopts the most cost effective and practical systems and approaches as the governing standard. This would provide benefits to all rate payers across the province.

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?

No. There is no evidence that "routine" investments made by transmitters or distributors require any of the alternative treatments identified in the Discussion Paper. The current regulatory approach, which is a combination of cost of service rebasing followed by a relatively short period of three years of IRM adjusted rates, works well for the vast majority of distributors and transmitters. These distributors and transmitters also have the capital module option available to them under IRM and always have the option to file a cost of service application.

If the Board were to allow "routine" investments to be eligible for one or more of the alternative treatments identified in the Discussion Paper it would be encouraging an unwieldy regulatory system that could, potentially, see a different regulatory model used by every electric distributor and transmitter in the province.

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, to which investments?

LPMA believes that the mechanisms identified in the Discussion Paper should **NOT** be presumed to apply to certain types of investments. As noted earlier, LPMA believes that adopting a case-by-case approach to the review and approval of applications for one or more of the alternative mechanisms would be the most effective way of balancing the needs of a distributor with the public interest.

If any of the mechanisms is presumed to apply to certain types of investments, there is a corresponding presumption that the distributor needs the mechanisms for those investments. This is not likely to be the case in many if not most of the cases. That is why a case-by-case approach is needed. Is a mechanism needed, and if so, which one or ones is the most appropriate to use?

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?

LPMA believes that the Board should be more prescriptive. This will add certainty for all parties and should make applications for use of the alternative mechanisms easier to deal with.

It is extremely important that the Board indicate which investments are not eligible for alternative mechanism treatment. It is equally important that the Board clearly indicate the type of investment that may qualify and indicate that there is a difference between "may" and "shall".

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?

In general LPMA agrees that prudently incurred costs associated with abandoned projects should be recoverable in rates if the abandonment is outside the control of management, subject to the qualifications below.

First, the utility should be required to provide evidence that the abandonment was outside of management control. Second, the utility should also be required to show that it had sufficient rationale for engaging in the project to begin with. It would not be appropriate, in the view of LPMA, for a utility to recover costs of an abandoned project if there was not a good business case for the project to be developed in the first place.

LPMA also believes that utility management should demonstrate that at the first sign that a project may be abandoned that it did as much as possible within its control to limit further costs associated with the project. In other words, the project should proceed in discrete steps, and only when certain benchmarks have been met.

The costs recoverable in rates should reflect the write-off for income tax purposes of the asset value of the abandoned project.

The utility should be required to show that they have done everything possible within their control to redeploy the assets associated with any abandoned project and/or otherwise minimize the costs to be recovered in rates. This would include, for example, trying to find another generator to site a facility to utilize the assets if the initial generator withdraws its proposal for some reason.

LPMA further submits that if the abandonment of a project is beyond the control of management, then these costs should be recovered through the province wide cost recovery mechanism rather than from the specific distributor or transmitter. Some distributors are likely to have a large number of potential projects to deal with because of their geographic location, especially when it comes to wind power. This could well result in a larger number of abandoned projects than for a distributor that has limited wind potential. It would not be just and reasonable for the rate payers to bear this risk alone.

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?

If the Board believes that allowing full or partial CWIP to be placed into rate base during the construction of facilities, then LPMA agrees with Staff that this should be limited to electricity transmitters. Further LPMA submits that this inclusion should only be allowed in specific circumstances.

Some projects may be able to be divided into smaller discrete projects where, for example, part of a line extension could be tied into the existing system. This portion of the larger project would, therefore, be used and useful and would be included in rate base as a normal course of business. The advantage to this approach, where possible, is that it also enable the transmitter to start claiming the Capital Cost Allowance ("CCA") for income tax purposes at the same time. The CCA deduction is available when an asset is "available for use". In general this concept is equivalent to "used and useful" for rate base purposes.

In situations where portions of the project cannot be used until the entire project is complete, LPMA suggest that some time line should be approved by the Board. For example, if the project has an expected completion date of one year or less, no special treatment should be accorded and CWIP should not be included in rate base. This would likely eliminate the need for many distributors to include CWIP in rate base as most of their projects would be completed within a year.

If CWIP is included in rate base it should be included in the same manner as other gross asset additions. That is, rate base would be the average of the opening and closing balances, including the CWIP balances associated with the specific projects.

LPMA also recommends that the Board should approach both the federal and provincial governments to obtain higher CCA rates than that currently available for investment costs associated with the connection of renewable generation and the smart grid. This would help mitigate the expected increase in rates in the short term associated with most of the alternative mechanisms described in the Discussion Paper.

As noted above, LPMA does not believe that the inclusion of CWIP in rate base would be necessary for most distributors. However, in special circumstances, if required, the Board could review this request on a case-by-case basis.

LPMA is also concerned with the potential double counting that could result from the inclusion of a project in rate base through CWIP and the subsequent recovery of an abandoned project. In such a case, the cost associated with the abandoned project from rate payers should be reduced by any return on equity that the distributor or transmitter has earned as a result of including the project in rate base (through CWIP) for a number of years. It would not be appropriate for the utility to earn a return on a project and then expect rate payers to pay for this when the project is abandoned. Similarly, any depreciation included in rates should also be removed from the costs to be recovered from rate payers since they will already effectively have paid for this through their rates.

Finally, if CWIP is allowed in rate base, then LPMA submits that this CWIP should also be depreciated beginning at the date that it is included in rate base. This would provide a declining rate base impact on the cost of capital (debt and equity) for rate payers. Rate payers ultimately pay for the cost of the asset through depreciation. They also pay for the cost of capital on the declining net asset value of the asset over its lifetime. If no depreciation is calculated on the CWIP, then rate payers will end up paying the same amount of depreciation over the life of the assets, but will also have paid more for the overall higher cost of capital on the asset since the rate base amount would not start to decline until it was moved out of CWIP and reclassified as a gross asset addition.

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?

It is not clear to LPMA how much of an impact this would have on intergenerational cost recovery. It is also not clear to LPMA whether the depreciation adjustment would be done a case-by-case basis or if a shorter asset life would be mandated for all distributors and transmitters across the province.

In general, LPMA supports shorter depreciation periods where appropriate, as the result is an accelerated decline in rate base, and a lower aggregate cost of capital over the life of the assets.

Matching the depreciation period to the contract term is appealing in that it matches the economic life of the asset with the expected contract term for which the assets will be used. However, this approach means that within a utility, it might have different asset lives for depreciation purposes for assets that are virtually identical to one another. It also means that different utilities may have different asset lives for the same assets. This would result in higher rates for rate payers where the asset life is lowest.

Offsetting these issues is the increase in cash flow that is the result of the higher depreciation. This increase in cash flow could and should be used to finance the capital expenditures resulted to the incremental investment requirements, resulting in a reduction in borrowing requirements. If the availability of capital is perceived to be an issue, then this would be a way to mitigate that issue.

The Board may want to consider a hybrid approach to depreciation. Under this hybrid approach, an accelerated depreciation rate could be used for some pre-determined period and then after this period, the depreciation rate would revert to the lower rate determined by the expected life of the asset. The pre-determined period could be the period during which the asset is included in CWIP and also included in rate base. This would provide some of the cash flow required for the initial investment in the asset. After the initial investment has been made, the depreciation rate would then decline to a rate more in line with that used for other similar assets.

LPMA submits that the Board may want to consider a fixed period for accelerated depreciation, such as three years, after which the lower normal depreciation rates would apply. It is likely that expenditures related to the smart grid and/or the connection of renewable generators will be spread over a number of years. It is also likely that there will be on-going expenditures to reflect new technologies and/or new generators.

A fixed period of accelerated depreciation for each project could help smooth out the rate impact on customers while providing increased cash flow to help finance the projects to the utilities. After the initial three year period in the example provided, the depreciation expense on the first year projects would decline, either providing rate relief to customers, or providing room for higher depreciation costs of new investment requirements in the fourth and subsequent years.

Finally, LPMA submits that the Board should take into consideration any impacts of moving to International Financial Reporting Standards ("IFRS") when determining what to do with depreciation. Under IFRS the depreciation rate may need to be adjusted annually.

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

LPMA believes that under the legislative context in which the Board may mandate infrastructure investments, incentives are neither necessary nor appropriate. Such incentives are not necessary because the utilities have an obligation to make the appropriate investments, just as they are now when it comes to safety or planning for the additions of new customers. Incentives are not appropriate because they add an additional level of costs for rate payers without any corresponding benefits. The investment will be made with or without the incentive of an increased return on equity or project specific capital structures.

If the Board believes it needs to incent a utility to do what it is required to do, then it should implement a penalty system. In such a system the utility would be penalized with a lower return on equity on its entire rate base if it fails to invest in infrastructure as mandated by the Board until it complies with the investment requirements.

There is no evidence that a higher return on equity or project specific capital structures are required to attract the new capital required. This is especially true in the economic reality of today. An after tax return on equity in the 8 to 9 percent range will attract significant interest from the investment community.

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?

LPMA does not believe that project specific ROE should be allowed by the Board. Such an approach could result in making some projects more attractive than others to the utility. This may result in a reduction in routine investments that could result in higher operation and/or maintenance costs being incurred now and/or in the future. This would not be a just and reasonable result. When projects compete for capital in the distribution and transmission capital planning process it should be based on requirements and needs, not on rewards.

The Board may want to establish a maximum value for the adder, but require a distributor or transmitter to make a specific application for a value. Given the variability in situations across the province, it is not likely that a specific adder would be appropriate. It should also be noted that the adder could be negative.

Any appropriate range or ROE adder would have to be done on a case-by-case basis. The situation of the specific distributor will need to be taken into account, as will what other alternative mechanisms are being proposed to be used by the utility. For example, if a utility proposes that it be able to recover costs associated with abandoned projects, use accelerated depreciation and include CWIP in rate base, it could be argued that the return on equity on this investment should actually be lower than that of its routine assets as significant risks have been shifted from the utility to rate payers.

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

LPMA submits that if the Board were to provide for incentives, the use of project specific capital structures would be preferable to a project specific ROE. However, this does not automatically mean a higher or lower equity component of the capital structure than for the remainder of the rate base. Again, the Board would have to review this on a case-by-case basis to review the specific circumstances of the utility making the application, what other alternative mechanisms the utility is applying for and the availability of debt financing for the investment. It may be that a substantially lower equity component is needed for some utilities because they have no problem finding debt financing while others may need a larger equity component because of a problem getting debt.

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

The Board should consider allowing and/or mandating 100% debt financing for the investment requirements. This debt financing would consist of a significant amount of short term debt in the initial years of the investment which could be gradually phased out and replaced with equity. This approach would have a number of benefits. First it would not require a utility tó obtain substantial amounts of equity all at once. This lumpy injection of equity would be replaced with a "laddering" of incremental equity over a number of years. The use of short term debt would result is a lower overall cost of capital in the first few years of the project's life, resulting in a lower rate impact on customers. This debt would also help reduce income taxes payable, again helping to mitigate the impact on rates. Even if a premium was required on the debt rates, it would likely be no higher than the return on equity. And again, all of the interest expense would be deductible for tax purposes.

As noted in the accelerated depreciation discussion above, this mechanism would provide a source of funding the increase in equity required. A matching of the years of accelerated depreciation (for example three years) with a three year phase exchange of short term debt for equity would smooth the rate impact on rate payers and provide for an orderly and less lumpy injection of equity into the capital structure.

Another option that the Board should investigate is a reverse capital module. The current capital module under IRM allows a distributor to increase rates if the capital expenditures are above a threshold determined by a formula that takes into account deprecation and the price cap.

On the other side, there may be instances when capital expenditures in an IRM year are less the replacement amount. This could be the case for distributors that have little if any customer growth and where the distribution systems are relatively new and do not require significant "routine" capital expenditures to replace existing assets. In such circumstances, which are primarily driven by where a distributor is in the investment cycle, the price cap mechanism may provide excess revenues that should be used to finance, at least in part, the new investment requirements related to the smart grid and the connection of renewable generation.

16. In addition to the potential considerations identified, are there any other matters that the Board might consider in making decisions on requests for alternative treatment?

The Board should consider the applicant's willingness to accept debt financing from affiliate and third party sources that would be over and above the deemed debt component associated with the investment requirement if it would result in a lower rate impact on rate payers. In other words, the applicant should be willing to forego a return on equity on the investment if sufficient debt financing is available in order to mitigate the impact on rate payers.

In particular, the Board may want to consider approving affiliate long term debt at a rate equivalent to the return on equity. This would provide the same return to the affiliate and provide lower rates to rate payers through the deductibility of the interest cost.

As noted in previous comments, the Board should also consider the phasing in of additional equity by replacing short term debt over a fixed period after the investment has been made.

The Board should consider whether any alternative treatment is required, and if so, is the treatment required immediately or is it something that can be implemented in future years if the utility finds itself in circumstances where additional revenues are required. In other words, the current regulatory construct should remain in place when the investment is made (i.e. no return on equity adder, no project specific capital structure, no accelerated depreciation, no CWIP in rate base, etc.), unless the utility provides evidence that it cannot finance the investment at a reasonable cost.

Finally, the Board should consider whether a utility should be allowed or required to seek ownership partners that would be willing to inject equity into the utility at the current Board approved return on equity (i.e. no return on equity adder and no project specific capital structure). If there are investors, which could be other utilities, that are attracted to the Board approved after tax return on equity, these investors should be welcomed by the utility and the Board if the net result prevents an increase in rates to rate payers because of ROE adders or capital structure changes. It is a normal course of business that when a company is seeking to expand it may need to seek additional equity through a number of methods, including the issuance of additional shares, seeking a merger, or seeking partnerships with other corporations.

17. What performance conditions, if any, should be established?

LPMA believes that performance conditions should be determined on a case-by-case basis and are likely to depend to a large extent on the alternative mechanism(s) being requested by the utility.

LPMA agrees that for multi-year projects, the Board should require some type of milestone to be achieved before any of the applied for mechanisms take effect.

LPMA also submits that there should be a true up mechanism to ensure that rate payers only pay the actual costs incurred, rather than costs based on a forecast.

18. Are the reporting requirements suggested appropriate and adequate?

It is not clear to LPMA how the reporting requirements will help the Board monitor the success of the alternative treatments set out in the Discussion Paper in facilitating timely and appropriate investment. If projects are proceeding as planned, this does not necessarily mean that the alternative treatments have facilitated this outcome. The projects may have proceeded as planned in the same fashion had no alternative treatment been in place. Similarly, if a project is behind schedule, this does not necessarily mean that the alternative treatment is somehow inadequate. The alternative treatment may, in fact, be ineffective, and should be eliminated because it is not working as planned and many only result in increased rates to customers.

LPMA does, however, support the reporting requirements for other purposes. The detailed reporting, including the five year outlook, should provide all parties with information on the amount of money being spent across the province as well as by specific utilities. LPMA notes that the reported information should be publicly available to all parties.

19. Are there any other conditions that the Board might need to establish in relation to an approved alternative mechanism referred to in this Discussion Paper to protect ratepayer interests?

LPMA submits that any utility that is over earning for whatever reason (e.g. mergers, efficiency gains, poor forecasts, etc.) should not be allowed to use any of the alternative mechanisms identified in the Discussion Paper, or any other methodology, that would result in an increase in rates to customers. If such a utility is already over earning it would not be fair to rate payers to increase rates further to fund investments in the smart grid or to connect renewable generation.

The Board should indicate that the dividend payment policy of a utility may be reviewed if it claims it cannot obtain debt or equity financing at the prevailing rates, but continues to pay significant dividends to its shareholder. As the owner of a regulated monopoly, the shareholder should be expected to invest the money needed at the generous return on equity rates currently available to regulated distributors and transmitters in the current economic climate. Part of this investment can be achieved by leaving retained earnings in the utility to finance the growth in rate base.

If, after the mechanisms are put in place for a utility, the utility over earns in future years, the Board should consider two options. First, it should consider taking the over earnings and refunding it to customers as the alternative mechanisms were not needed to ensure the utility earns its regulated return. Second, the Board should discontinue some or all of the alternative mechanisms for future years as these mechanisms are providing the utility an excess return. In other words, if a utility does not need some or all of the alternatives to earn an appropriate return, remove those mechanisms and return to the default regulatory model.

20. Beyond those already reflected in the Board's existing filing guidelines (e.g., the Z-factor test of causation, materiality, and prudence) and in the Board's jurisprudence, is there a specific test that successful applicants should be required to meet in order to be granted an alternative treatment?

There are a number of tests, or hurdles, that successful applicants should be required to meet in order to be granted an alternative treatment. These include such hurdles as providing evidence that debt financing at current market rates cannot be obtained (such as correspondence between the utility and potential lenders indicating why those lenders have declined to lend), that additional debt cannot be obtained through public sources such as Infrastructure Ontario, all steps the utility has taken to raise equity, including, but not limited to an equity injection from the current shareholder and/or other parties.

LPMA believes it may be premature to specify any tests at the current time. It may well be that these "tests" will need to be determined on a case-by-case basis as the need for any of the alternative treatments are likely to be utility specific and situational specific.

21. Are the Board's existing filing guidelines for electricity transmitters and distributors sufficient to support the case-by-case approach discussed in this Discussion Paper? If not, what additional information should an applicant provide?

As noted above, in order to qualify for an alternative treatment, LPMA submits that a utility should have to justify and provide evidence for what they cannot do – such as they cannot attract debt financing at market rates and they cannot attract equity at current Board approved returns. This type of information would be different from what is normally provided through the existing filing guidelines.

The applicant should also be required to file detailed capital expenditure estimates and timelines associated with the individual projects that are driving the need for the alternative treatment(s) sought. This evidence should clearly show how the projects are consistent with the Board-approved plan for the utility.

22. Should the process for applying for the regulatory treatment of infrastructure investment discussed in this Discussion Paper be more prescriptive (e.g., the timing, sequencing, and/or combining of applications)? Should it be combined with the process for approving infrastructure investment plans? If so, why and in what way?

LPMA does not support the combining of an application for the regulatory treatment of infrastructure investment with the process for approving infrastructure investment plans. This approach would only slow down the approval of infrastructure investment plans.

The Board has a long history of dealing with transmission investment plans for natural gas distributors, most notable Dawn – Trafalgar expansions on the Union Gas system. The Board's practice has been to deal with the merits of those expansions and then in a subsequent rate case the impact on rates would be dealt with. LPMA believes this is the approach that should be taken here as well.

LPMA does not support specific or single issue rate applications as these type of applications are almost always biased in favor of the utility and against rate payers. LPMA submits that the best approach to dealing with the cost consequences of infrastructure investment is by dealing with the detailed expenditure plans as part of a cost of service application. This could be a rebasing application as part of the IRM process or it could be a cost of service application in place of an IRM filing.

LPMA also supports the filing of a multi year cost of service application to deal with infrastructure investment. If investments are expected to take place over a multi year period, it would seem appropriate to set rates on a multi year basis as well. A multi year rate application would also deal with the situations in which most if not all of the investments are made in one year with a corresponding decrease in capital expenditures in subsequent years that would normally be covered under the IRM filing guidelines.

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 treatment(s)? Why or why not?

Yes, the Board should allow **and require** applicants to seek approval prior to construction of the facilities to determine whether the facilities qualify for the requested alternative treatment(s). Such an application would include complete and comprehensive evidence on the costs associated with the facilities, any impact on OM&A costs associated with the existing system, the reasons for the need for alternative treatment, and the rationale for the selection of the alternative treatment(s) selected over those not selected. This is in line with LPMA discussion above about separate applications for Dawn – Trafalgar expansion applications by Union Gas.

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

LPMA submits that the use of a single-issue rate review process should be limited to situations where there is no impact whatsoever of the new investments on the existing system, such as extending the life of existing assets, reducing OM&A costs, or on revenues. Further if a utility has been earning at or near its allowed return on equity for any reason, including mergers, etc., then a single-issue rate review process should be denied and the applicant should be expected to file a full cost of service application.

As noted above, a single-issue rate application almost always favours the utility over rate payers. Utilities rarely, if ever, file a single-issue rate application that results in lower rates to rate payers. Even with mergers that are expected to result in cost savings, utilities are allowed to keep the savings for up to 5 years. LPMA is not aware of any utility volunteering to file early so those savings can be passed on to rate payers.

If single-issue rate applications are used, there must be significant scope involved in such filings for parties to determine what sub-issues are to be included in the single issue. These sub-issues could range from the impact on taxes (through the increased CCA and interest deductions), OM&A impacts, depreciation expenses, capital structure, return on equity, cost of debt and so on.

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?

LPMA supports the use of rate riders for implementing rate adjustments associated with the alternative treatments identified in the Discussion Paper. This would enhance the visibility of the allocation of these costs to the various customer classes. The Discussion Paper is silent on the allocation of costs, but in the view of LPMA this will be a significant issue.

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?

LPMA submits that if the Board allows the use of multi-year rate riders, it should limit the period for which these rate riders can be applied to the three years, the current length of the IRM period before rate rebasing is required. Even if the IRM period is lengthened, LPMA submits that the use of rate riders should be limited to three years. It is only through rebasing applications that rate payers can see how the utility has performed historically and how they expect to perform on a forecast basis. This allows for a check on all aspects of a utility operation, including the level and need for rate riders.

If you require any further information or clarification, please contact me.

Sincerely,

Randy Aiken

Randy Aiken
Aiken & Associates