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April 20, 2012

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

Dear Ms. Walli:

Re: EB-2010-0377/EB-2010-0378/EB-2010-0379/EB-2011-0049/EB-2011-0043 – Renewed Regulatory Framework for Electricity - Comments of the London Property Management Association

These are the written comments of the London Property Management Association ("LPMA") with respect to the Renewed Regulatory Framework for Electricity ("RRFE").

LPMA first provides its suggestions for a 4th Generation Rate Setting Mechanism that builds upon the success of the 3rd Generation IRM model that that has now been used for a number of years and has resulted in outcomes that are beneficial to both customers in terms of moderate rate increases and to electricity utilities in that they have been provided the opportunity to earn a reasonable return on their investments and to keep any excess earnings during the term of the IRM, and on the standard cost of service application.

LPMA then provides comments that have been organized around the questions for stakeholder written comment provided in Attachment A to the Board's April 5, 2012 letter. LPMA notes that these comments should not be read in isolation, but in combination with the comments provided to the questions in the Staff Discussion Papers in each of EB-2010-0377, EB-2010-0378, EB-2010-0379, EB-2011-0004 and EB-2011-0043.

LPMA PROPOSAL - 4th GENERATION RATE SETTING MECHANISM

Introduction

LPMA believes that the current 3rd Generation IRM model has been working well. Most distributors have been through the four year cycle of rebasing and price cap increases at least once and some have been through it partially for the second time.

The major complaints that distributors appear to have with process are related to capital expenditures, and the slow growth in rates due to the price cap (inflation and/or productivity measures). LPMA believes that these issues can be dealt with through minor adjustments to the current IRM model and by offering a menu of approaches for distributors and transmitters to select from for setting rates. Three possible approaches are provided below which LPMA believe would deal with most of the issues raised by utilities, while continuing to ensure that ratepayers pay just and reasonable rates.

A Menu Approach

LPMA suggests that a menu approach, in which a utility selects an option up front at the beginning of a multi-year rate setting period would provide flexibility for the utility to select the option that best suits their situation over the coming years. A utility with growing infrastructure replacements and little customer growth is likely to chose a different rate setting mechanism than would a utility where the predominant issue is fast customer growth in a relatively new system. These utilities face different levels of cost pressures and revenue growth. Trying to fit them into one regulatory system is not ideal.

Instead, LPMA proposes that a number of options be available to all distributors. At the time of rebasing from the current 3rd Generation IRM model, the utility would select its preferred alternative from a list of Board approved options. The utility would then be required to stay on that option for the life of that option, with certain exceptions that are discussed below in each of the proposed Options.

a) Option 1

Option 1 is a continuation of the current 3rd Generation IRM with the addition of an second capital module, a choice for distributors on the length of the plan and some potential review and adjustment to the plan parameters.

LPMA proposes that an additional incremental capital module be made available for those utilities that select this option to deal with additional capital and OM&A expenditures related to fulfilling government directives. Expenditures related to smart meters, the smart grid and the connection of renewable generation would be the type of expenditures that would be accommodated through this second incremental capital module. Exclusion of these types of capital expenditures would relieve the pressure for many utilities on dealing with increased capital expenditures under IRM.

This second incremental capital module would be used exclusively for expenditures related to new requirements and would not be eligible for capital expenditures related to the replacement of aging infrastructure.

LPMA does not believe that any special allowance should be made to the existing IRM approach for costs that are part of the normal course of business over the life of the assets. LPMA would, however, be open to the creation of a working group with utilities to discuss the problems and potential solutions involved in asset replacement if it can be shown that comprehensive IRM does not work in certain circumstances. The original incremental capital module would continue to be available and used for the purpose for which it was developed.

This second incremental capital module could be used at any time in the IRM period as is the original incremental capital module. This would eliminate the need to forecast these type of expenditures in the original rebasing year, which would likely be difficult to do especially if the associated projects are scheduled for several years in the future.

The second incremental capital module would be used to determine a rate adder that would be used to collect the revenue requirement impacts of the required investments. It would be trued up at a point in time when the utility comes in to rebase and the actual costs are known and included in rate base in the rebasing applicaiton.

In addition to the second incremental capital module, LPMA believes that the length of the IRM period should be extended beyond the current 3 years. In particular, LPMA proposes that utilities have the option to select a rebasing year followed by 3, 4 or 5 years under IRM. Once this selection has been made, the utility would then be obligated to stay on IRM for the selected period, subject to the offramp provisions noted below. LPMA would not object to a longer IRM period, but believes that a movement to 5 years, which is currently the standard for Union Gas and Enbridge Gas Distribution would be a good next step. It would provide the utilities with a longer term planning horizon, that would more fit with their longer term capital planning horizon, allowing them to implement productivity measures that take a longer time to pay off. Selecting a longer IRM horizon would lessen the regulatory burden on all participants including the utilities, intervenors and the Board and would like result in cost savings which would ultimately be passed along to ratepayers.

With respect to the plan parameters, LPMA believes that the working group should review the inflation index currently used, the productivity factor currently used, the levels and number of stretch factors currently used and the appropriateness of the offramps currently in place. In addition LPMA believes that the Board, through the working group, should re-evaluate the use of an earnings sharing mechanism.

As the Board is aware, the use of an earnings sharing mechanism has provided significant benefits to ratepayers of both Union Gas and Enbridge Gas Distribution. In particular, LPMA proposes an asymmetric earnings sharing, similar to that in place for Union and Enbridge. There would be no sharing of earnings above the allowed return on equity based on a dead band of perhaps 100 basis points. Sharing between 100 and 200 basis points above the allowed return would be 50/50 between the ratepayers and shareholder and any earnings over 300 basis points would be shared 75/25 in favour of ratepayers. In return for this sharing, LPMA would be inclined to review the inflation and productivity factors used in the calculation of the price cap index.

b) Option 2

Option 2 is the same as Option 1 with the exception that it would have an open ended IRM term. In other words, following a cost of service rebasing application, the utility would remain on IRM indefinitely. It could come in for rebasing any time after the fifth year under IRM.

The comments related to the second incremental capital module and to the parameters of the plan, including earnings sharing and the offramp, are applicable to this option in the same way that they would be applicable to Option 1.

Within this option the Board may wish to include a review provision such that if the utility over earns or under earns for 3 or 4 years in a row, the utility would be required to explain why rates should not be reset based on a cost of service application to get the utility (and ratepayers) back on track of earning the allowed rate of return.

c) Option 3

Option 3 is a multi-year cost of service application option. LPMA would suggest that the time frame should be flexible as it is under Option 1 for the length of the IRM period. To keep it consistent with the timelines in Option 1 (including the original cost of service rebasing year) , LPMA proposes that the number of years in a multi-year cost of service application be set between 4 and 6 years. Again this time frame would tie in with the expected length of capital plans for most utilities. Again, the utility would be able to chose the length of time it is willing to commit to.

Unlike Option 1, however, LPMA proposes that the utility also be given the choice of earnings sharing or not starting the second year of the multi-year period and extending to the last year. If the utility selects the earnings sharing option, they are also provided with an offramp provision that would allow to seek early rebasing. If the utility decides it does not want to offer earnings sharing to its customers, then there would be no offramp provision and the utility would have to live with the results over the life of the multi-year agreement.

In order to reduce the level of forecast risk for a 4 to 6 year period, LPMA would suggest that the second incremental capital module described in Option 1 be available for utilities under this option as well. This is because of the unpredictability of expenditures driven by political forces. The original incremental capital module would not be available since the long term capital plan should identify any such expenditures contemplated in the horizon for the multi-year cost of service rate setting option.

LPMA also submits that the cost of capital parameters should be set for the entire multi-year cost of service period based on the first test year. This would be required to ensure that utilities do not select this option simply because they believe interest rates are going to rise over the period and they want to take advantage of the higher costs for debt and the higher return on equity that may be available. LPMA notes that in times of declining interest rates, utilities may be biased toward using Option 1 rather than Option 3 in order to lock in at the higher rates, if the lower cost of capital parameters would be used in the multi-year cost of service approach. In either case, by locking in the cost of capital parameters for the entire period based on the first year, the incentive to pick one option or the other for cost of capital purposes is eliminated.

Under this option, the onus would be on the utility to provide long term outlooks (4 to 6 years) for not only capital expenditures, but also OM&A expenses, cost of debt and load forecasts and then to live with the consequences of those forecasts.

<u>Need for a Stakeholder Working Group</u>

LPMA proposes that a stakeholder working group be established with the goal of identifying and developing options that should be available to utilities upon rebasing for 2014 rates. It is obvious that it is too late to make any substantial changes for those utilities who are schedule to file applications for 2013 rates.

While all of the options and details may not be available when utilities begin their preparations for 2014 rate filings, LPMA believes that the Board could make interim determinations on such matters as an additional capital module or a multi-year cost of service applications that would enable the 2014 filers to proceed with their filings.

<u>Customer Involvement and Education</u>

LPMA noted that throughout the Stakeholder Conference, many people discussed the role of the consumer in the rate setting process and in the other components of associated with the RRFE. There was also discussion of how best to get the consumer perspective on issues and to increase consumer involvement and awareness.

LPMA submits that the best way to increase customer awareness and get them involved, and increase their level of understanding is to get them involved in the process. While the role of customer representatives and experts (intervenors) in the process, LPMA believes that all stakeholders - the Board, utilities and intervenors - would benefit from the direct involvement of customers.

The major impediment to customer involvement in the current process is that other than a few facility hearings, all of the oral components to a hearing (specifically the technical conference and the hearing) take place at the Board's offices in Toronto. LPMA notes that the Board has held some hearings outside of Toronto (Bruce to Milton in Orangeville and Natural Resource Gas Limited in Aylmer) in recent years but these hearings were not primarily related to getting customer feedback on the setting of rates.

LPMA proposes that the oral components of a process (technical conference and hearings, for example) should take place in the communities served by the distributor. While this may raise some issues for some utilities such as Hydro One or Veridian Connections or Entegrus that serve multiple geographic areas that are not necessarily contiguous, the vast majority of electricity distributors serve a small number of communities that are in close proximity to one another. By having the oral components of a rates proceeding take place in the community that the rates are going to impact, the impediment of having to take the time and incur the expense to travel to Toronto and stay overnight would be removed. This would not only encourage more individuals to actively participate, but it would like assist businesses and institutions that wished to participate but cannot afford the time and effort to go to Toronto while they are trying to run a business or a hospital.

Many customers, whether they be individuals or businesses, feel intimidated by the regulatory process that involves intervening in a process, filing interrogatories and many other words that the average person is not likely to understand with the help of a lawyer or consultant versed in the terminology. There is also an intimidation factor for individuals to go to a hearing room and appear in front of a Board members and lawyers and energy consultants. Moving the hearing to their own community would reduce the level of intimidation. In a local situation they are also more likely to bring some friends (more customers) with them for moral support.

There is also a feeling among customers that the decision will be made in Toronto and Toronto does not listen to anyone outside of the city. By becoming more accessible to customers, the hearing process may change this view, which LPMA believes would be a desirable outcome.

In summary, moving the hearing to the customer, rather than expecting the customer to come to the hearing, would encourage customer input and participation and increase the level of awareness and education for customers. Customers talk to one another, whether it be over the fence or over lunch at an association meeting. If a customer talks about what he saw, experienced and learned at a rates proceeding that took place at the local community center and passes that information and knowledge onto other customers, all stakeholders benefit from the multiplier factor. Spreading knowledge at little or no cost should be a goal of the Board in the RRFE.

COMMENTS on RRFE

What is your vision for a sustainable and long-term regulatory regime?

Please see the comments and proposal for a 4th Generation Rate Setting Mechanism provided above.

What changes would be needed to evolve planning, mitigation, and performance policies towards your vision?

The changes would be minimal since the 4th Generation Rate Setting Mechanism is based to a large extent on the current model. LPMA believes that planning has and will continue to evolve to meet the changing requirements regardless of how rates are set. The need for mitigation measures and what the appropriate form of those measure should be should continue to be reviewed on case by case basis.

With the continued and elongated IRM period envisioned under the LPMA proposal, there will be more emphasis placed on distributors to increase productivity and efficiency over the longer term horizon of the IRM plan, especially given the fact that the plan could continue indefinitely or be reviewed by the Board and intervenors at any time.

One change that the LPMA proposal would require would be the establishment of a second and distinct capital module for those parties that choose to enter the IRM framework.

As a means of representing the Board's vision for the regulatory framework, Board staff prepared a strawman that summarized the key elements of the regulatory framework. In providing their comments on the issues the Board would be assisted if stakeholders also provided comments in relation to this vision.

LPMA has no significant issues with respect to the Staff strawman, other than the components that deal with the setting and approval of rates. On this topic, LPMA provides the following comments related to this vision.

The strawman appears to treat capital expenditures as a pass through and OM&A under a partial PBR mechanism. LPMA does not believe this approach is appropriate since it fails to recognize the link between capital expenditures and OM&A expenses. In addition to the direct link between the two based on capitalization, it also fails to recognize that OM&A expenses should be reduced when aging infrastructure that costs a lot to maintain and operate is replaced with new assets that are like to have lower operating costs and minimal maintenance costs, especially in the first few years of operation. Ratepayers would have to pay for the capital additions and not get any of the expected OM&A savings.

Similarly, new infrastructure resulting from the replacement of old assets and that related to regional plans and smart grids are likely to result in a reduction in distribution losses. The strawman approach makes no reference as to how this would be reflected in rates to customers.

The strawman approach does not provide any comprehensive incentives for the utilities to beat their expectations and ultimately pass on at least a part of this savings to consumers.

As noted elsewhere in these comments, LPMA does not believe that benchmarking should be used as a tool to directly set rates. If the Board does believe that benchmarking is an effective tool then it should consider setting one set of distribution rates that would apply to the entire province, similar to what it does when it sets the uniform transmission rates for Ontario.

Under such a scenario, some distributors would be set up to earn in excess of the Board allowed return, while others would be set up to earn less than the Board approved return. This result, which LPMA believes would be the same as if revenue requirements were set based on benchmark amounts, would offer the same incentive for utilities to try and improve their returns. Distribution rates would be changed on an annual basis, based in part on a inflation less productivity factor as is currently done under 3rd GIRM, while some portion of distributors have their revenue requirements and load forecasts approved on a cost of service basis, again similar to what is now done under 3rd GIRM. The only difference is that the provincial distribution rate changes would be more gradual over all distributors, as compared to the changes that occur when a distributor files for changes in only its own rates under a cost of service application. This, of course, means that there would be an implicit cross subsidy taking place.

This would be the same cross subsidy that would take place if rates are based on benchmarking studies. Customers of low cost distributors would be paying more than would under a cost based system. Customers of high cost distributors would be paying less than under a cost based system. Customers in Chatham-Kent may wonder why they are paying more even though they are served by a low cost utility just so customers in Toronto, who have a high cost utility, can pay less than they otherwise would.

Finally, on total cost benchmarking and total factor productivity, LPMA does not believe that the data necessary for these estimates is available over a sufficient period of time so as to be relied upon. LPMA further notes that this type of analysis is best used in a steady state. Not only is Ontario not in a steady state, but the difference between distributors across the province is substantial. Other than the requirements imposed by the government (smart meters, smart grid, renewable connections, etc.) the difference in distributors in terms of their point in the life cycle of their assets and the multitude of varying factors that affect them (urban vs. rural, north vs. south, customer growth, summer peaking vs. winter peaking etc.) is anything but consistent.

LPMA believes that the 4th Generation Rate Setting Mechanism described above is a superior approach to setting rates in that it allows for diversity of distributors and their current situations while ensuring consumer protection in rates.

Planning (EB-2010-0377)

How do we optimize planning across the sector to ensure that investment decisions achieve the level of reliability and quality of supply that consumers demand and are paying for?

The Board needs to ensure that the appropriate parties are brought together in the planning process, whether this is a regional plan, or a small area plan that involves two parties.

The Board needs to ensure that there are checks and balances on the outcome of the planning to ensure that customers are getting the level of reliability and the quality of supply that they demand - nothing less and nothing more. In other words, customers demand that they get what they pay for and they are not required to pay for more than what they want.

Planning horizons should be a minimum of 5 years, and longer for large distributors and distributors in fast growing areas of the province. These distributor forecasts should be made available to transmitters on an ongoing basis so they are able to adjust or update their own forecasted requirements on an ongoing basis. LPMA does not believe that planning is a discrete process. Rather, it is an ongoing responsibility that needs to adapt to the changes in the requirements.

How might coordinated regional planning between utilities and third parties (e.g., municipalities) promote the efficient and cost-effective development of infrastructure and enhanced regulatory predictability, while maintaining reliability and system integrity? What are the implications, if any, for distribution network investment planning?

LPMA notes that in many cases, municipalities are not third parties since they are shareholders of the distributors.

LPMA supports the need for coordinated regional planning between utilities and between utilities and municipalities. However, LPMA cautions that long term planning is full of assumptions that can change and that even small changes in assumption can result in significantly different forecasts. LPMA submits that the long term planning assumptions and forecasts should be the subject of robust sensitivity analysis.

Coordinated regional planning should result in a cost-effective plan up front, rather than having a plan and part way through it, someone comes to the table with a need that had not been identified by others. All parties need to be at the table from the beginning, so there are no surprises. Surprises can result in additional costs and sub-optimal planning.

LPMA believes that distribution network investment planning should be fully incorporated into regional planning exercises.

How might the Board facilitate regional planning and the effective execution of the resultant plans as appropriate?

The Board should hold regional planning hearings at which it would ultimately approve a regional plan, including any distribution network investment plans that are part of the regional plan. This would be similar to facilities hearings for the expansion of Union's Dawn-Trafalgar transmission system on the natural gas side. Once the distributor & transmitter have an approved regional plan, these expenditures would be included in rates proceedings without the need to justify the need for the expenditure.

If we revise cost responsibility under section the Transmission System Code in respect of transmission line connection facilities to pool the costs, should the pooling

be on a province-wide basis, a regional basis, or some combination? Should the cost responsibility rules for industrial customers and distributor customers be the same? Why or why not?

LPMA believes that if transmission line connection facilities are to be pooled in some circumstances, then they should be pooled on a regional basis. The reason for this is to ensure that the ratepayers of distributors that do not and cannot benefit from the line connection asset should not be paying for it. For example, a transmission line connection facility that is required in the eastern area of Ontario that is needed for distributors in the Ottawa region will not provide any benefits to the customers of London Hydro and vice versa. Pooling these costs on a regional basis would result in a subsidization from one or more regions to other regions and would not be based on cost causality or the allocation of costs based on benefits. Moreover, this approach may lead to over building of transmission line connection facilities if the costs can be spread over a larger customer base than if the costs are recovered on a regional basis from the distributors and ratepayers that will benefit from the facilities. In other words, there is likely to be more emphasis on cost control by the proposing parties if they are also the paying parties.

LPMA sees no need for the cost responsibility rules for industrial and distribution customers to be the same. Industrial customers, in most cases, have an option of where they wish to locate, whereas distributors do not. Industrial customers are usually the only customer that can benefit from a transmission line connection facility to their facility. There should be no subsidization to an industrial customer from distribution customers or other industrial customers.

LPMA also believes that transmission line connection facilities that are required for only one distributor should be pooled either on a regional or province-wide basis. These costs should continue to be paid for by the distributor that requires the use of the asset. To do so otherwise would result in the subsidization of some customers that require use of the asset by those that do not and cannot benefit from these assets.

How can the Board satisfy itself that multi-year investment plans are appropriate?

LPMA believes that the Board and intervenors should follow the same approach that the Board uses to satisfy itself that any distribution or transmission expansion is appropriate. In particular, the Board has several decades dealing with the on-going expansion of the Dawn-Trafalgar transmission system on the gas side. The Board and intervenors review the evidence that includes a long-term forecast for the demand that drives the need for the expansion, as well as reviewing routing alternatives and other alternatives to meet the demand. The costs are also scrutinized through the regulatory process. LPMA submits that this process has worked well and there is no reason to expect that it cannot be successfully adapted to deal with regional electricity plans. Both the Board, through Staff, and intervenors have many years of expertise in dealing with this type of regulatory review and approval.

How should smart grid investments be treated (i.e., as part of rate base, or based on type of activity/asset)?

LPMA believes that smart grid investments should ultimately be treated as part of rate base and should be included in a cost of service rebasing application. In the interim period, the Board may wish to consider treating smart grid investments based on the type of rate setting methodology that the distributor or transmitter has opted to used, based on the 4th Generation Rate Setting Mechanism described by LPMA earlier in these comments.

In particular, if a utility has opted for a rebasing approach followed by a fixed number of IRM years, LPMA believes that a separate capital module should be used for the IRM years to determine the revenue requirement impact and a rate adder to be used until the assets are included in rate base under the subsequent cost of service rebasing application. There would be a true up of the revenues recovered through the rate adder with the actual revenue requirement over the IRM period. In a situation where the revenue collected was in excess of the actual requirement, the excess could be rebated to customers or used as reduction in the amount included in rate base, similar to a contribution or grant (similar to that described on page 25 of the Navigant report titled "Transmission and Distribution Rate Mitigation Measures for Ontario dated May 3, 2011), or a combination of approaches.

If a utility has opted for the open-ended IRM option, then a process would be needed to include the expenditures in rate base at the point in time when the project has been completed and all costs have been finalized. A methodology to adjust rates under the IRM process would be required, similar to adjustments that have been used to adjust revenue to cost ratios or changes in tax rates or capitalization rates in the past. There would also be a true up as described in the previous paragraph.

If a utility has opted for the multi-year cost of service application, LPMA would submit that because of the uncertainty in the level and timing of costs associated with smart grid investments, the investment should only be included in rate base when a project has been completed and costs are known. The evidence would include the forecasted cost and timing of the smart grid project on a standalone basis (i.e. it would not be included in rate base). In the meantime, a rate adder approach could be used, similar to that under IRM, again with a true up at the time the costs are included in rate base as described above.

The circumstances described above have a number of common themes. In particular, a rate adder would be established prior to the actual expenditures taking place, allowing distributors and transmitters to mitigate the impact on cash flow and the need for financing. It essentially allows ratepayers to pre-pay part of the investment costs, similar to a contribution or grant. It ensures that ratepayers only pay the actual costs associated with the project.

The approach allows the utility to file evidence either as part of a multi-year cost of service application or a rebasing year under IRM. It also allowed a utility to file a separate application part way through an IRM period or a multi-year COS period if information is not available at the time of the main filing, or when new projects materialize.

In all scenarios, the investments are included in rate base at the first opportunity after the project is completed and actuals costs are known.

What empirical and qualitative tools and methods might be used to inform: (a) utility planning processes; (b) utility applications to the Board; and/or (c) the Board's review of utilities' plans?

LPMA believes the Board should follow the same process as has been successfully utilized in the applications and approval of the Dawn-Trafalgar transmission system for Union Gas. LPMA that reviewing the process used by Union Gas, intervenors and the Board in those applications will provide guidance to the utilities in their planning processes, in the preparation of their applications to the Board and in the Board's review of these plans. LPMA believes that a working group consultation consisting of intervenors, Board Staff, the distributors and transmitters, and Union Gas would be of great assistance to all parties involved.

<u>Performance & Incentives (EB-2010-0379)</u>

What outcomes for customer service and company cost performance should be established?

LPMA believes that before the Board determines what outcomes for customer service and company cost performance should be established, it needs to consult with intervenors and design a comprehensive customer survey to find out what is important to customers and what is not important to them. LPMA believes that the responses are likely to vary by the type of customer (residential, commercial, industrial) and by region (north vs. south, urban vs. rural, etc.). The parties involved would then have to determine how the weighting of customer values could be achieved in the establishment of customer service and company cost performance measures. For example, different performance measures may be needed for each of residential, commercial and industrial customers. Moreover, there may be a need for different performance measures within each of the customer groups. Low income residential customers may have different requirements or demand than do other residential customers. Institutional commercial customers may have a different view of what is important than do landlords and property managers. Industrial customer views may vary by industry or use of electricity.

LPMA submits that the Board should establish a working group consisting of ratepayer representatives, distributors, transmitters and Board Staff to come up with a methodology and weighting factors to accurate reflect the views of customers.

What standards and metrics for customer service and company cost performance should be established in regard to these outcomes? How do the performance benchmarks that are in place today relate to your proposed metrics?

LPMA submits that this question cannot be properly answered until the views of all customer types have been received and reviewed.

What are the characteristics of a "high-performing regulated entity" (i.e., what specific metrics can be used to evaluate the level of performance of the regulated entity)?

LPMA submits that a "high-performing regulated entity" is a utility that consistently meets or exceeds all of its customer service and company cost performance targets, while ensuring employee and customer safety, at rates that are affordable for all customers.

What incentives, if any, are appropriate to reward utilities for cost-effective and efficient performance, including appropriate rewards for exceeding standards for customer service, and company cost performance? What incentives, if any, are appropriate for the purposes of rewarding performance with regard to multi-year capital programs?

LPMA does not believe that incentives that are targeted at any one area of performance are justified or warranted.

LPMA cautions the Board in the provision of rewards for exceeding standards. Customers have little tolerance in this age of austerity for bonuses paid to entities for doing what they are already being well paid to do. It should be noted that customers are the key group that the Board should use to set standards. In a regulated environment, where distributors and transmitters are provided with the privilege of providing a service with no competition, it is submitted that customers should not pay the cost of any incentive for exceeding what customers want. In a competitive market, customers generally are not willing to pay for more than what they want. They can choose an option that provides them with what they want with no added costs.

LPMA further submits that any incentives for exceeding customer service standards or company cost performance could result in distributors and transmitters focusing their efforts on obtaining these bonuses to the detriment of other parts of their business. Not only does this result in immediate cost increases to customers who would be paying for the bonus, but it could well result in longer term cost increases to customers because the utility has not been focused on the big picture. If the utility is not focused on the big picture in the short term, how can they see the big picture in the longer term? In short, targeted incentives are a distraction that customers cannot support and should not be asked to pay for.

With respect to incentives to reward performance with respect to multi-year capital programs, LPMA submits that the same comments provided above are applicable. Why should customers pay to have the utility do a good job? They are already being paid to do exactly that, unless of course, the Board believes that a utility should be allowed to earn its approved rate of return regardless of how well it does its job. LPMA does not believe this is the case, but allowing incentives for a good job implies that utilities are not earning enough money. Under the fair return standard this, of course, is not the case.

LPMA believes that utilities already have an incentive to cut costs and improve capital expenditure efficiency through the current regulatory environment of the 3rd Generation IRM model. As Board Member Sommerville put it:

> *"The whole purpose behind the IRM system is to allow the utility -- after having gone through the cost-of-service exercise -- to maximize its return throughout that period.*
>
> *The cost-of-service that follows that period is intended to be the catch-up for ratepayers. That's the architecture of the IRM cost-of-service architecture. That is what it is intended to do."* (Stakeholder Conference Transcript Volume 3, page 58)

Under the 4th Generation Rate Setting Mechanism proposed by LPMA above, utilities will still have a substantial incentive to operate effectively and efficiently. In order to earn more than the Board approved return on equity, utilities will need to do well in all areas of their business, not just a few. This approach will ensure that utilities keep their eye on the big picture and not be distracted by the allure of quick profits to the detriment of long term efficiency and to customers.

How might the Board enhance the alignment of customer and company interests through the use of incentive mechanisms?

See the LPMA proposal above with regard to the 4th Generation Rate Setting Mechanism.

<u>Rate-setting & Mitigation (EB-2010-0378)</u>

How might the Board align rate-setting with multi-year investment plans? Do you have a preferred approach, and what are its benefits and disadvantages?

See the LPMA proposal above with regard to the 4th Generation Rate Setting Mechanism.

Should the Board amend the ICM rules as proposed by some participants to provide for an interim solution? If so, how? What are the implications of such an interim change in the context of the longer-term RRFE approach of incorporating multi-year capital plans in rates?

See the LPMA proposal above with regard to the 4th Generation Rate Setting Mechanism.

How might further benchmarking be used to: (a) help determine appropriate cost levels; (b) achieve further efficiencies; and/or (c) assist in managing cost increases?

LPMA believes that benchmarking between utilities should only be used as a guide to appropriate cost levels, to achieve further efficiencies and to assist in managing cost increases. Benchmarking should not be used to determine costs or set rates in a utility. T do so would, in the view of LPMA, results in rates that may not be just and reasonable.

A utility with higher costs than the benchmark would be penalized with rates that cannot sustain its level of costs. Benchmarking provides no information whatsoever of why the costs may, justifiably, be higher than the benchmark. Ultimately, this results in a lower return to the shareholder and could end up costing ratepayers through higher debt costs due to the weakened financial integrity of the company and/or through lower customer service standards.

Similarly a utility with lower costs than the benchmark would be rewarded with rates that cannot be justified on a cost of service basis. Benchmarking in this instance provides no information to explain why the costs are lower. What it does do, however, is reward the shareholder and penalize the ratepayers, who are now expected to pay more than they otherwise would. LPMA submits that there is no reason why customers should be penalized and expected to pay more than the reasonable costs (including a reasonable return) of providing a monopoly service.

How might the Board's approach to the application review process be proportionate to the characteristics of the application (including quality) and the performance of the applicant?

The obvious answer to this question is that the current process, by and large, already reflects an application review process that is proportionate to the characteristics of the application. The worse the application, the longer the review process; the better the application, the shorter (and less expensive) is the review process.

The regulatory consultant for the LPMA has been involved in dozens of applications over the last number of years on behalf of both a number of intervenors and utilities. The quality of the information and the clarity of the presentation of the material varies significantly from applicant to applicant. Over the last year or so, the general trend has been an improvement in both areas, but there are still, unfortunately, exceptions to this rule. LPMA would expect that the quality of the applications and the interrogatory answers would continue to improve as the distributors gain more experience and put that to good use in the process. LPMA reminds the Board that may distributors have only been through a complete cost of service application based on a forward test year once, or at most twice. The benefits of moving along the learning curve should now start to reveal themselves through better quality applications.

Applications that are internally inconsistent or leave out significant details take longer to process because more interrogatories and technical conference questions need to be asked and answered. Often the answers provided to these questions are vague, incorrect or lead to more follow up questions. The is more time for the Board, Board Staff and intervenors to determine what the real answer is when a complete response to the original question would have dealt with the issue.

In the absence of having the required information or have faith in the information provided, intervenors and utilities are less likely to be able to arrive at an agreement in the settlement process, resulting in some issues and the related impacts going to an oral hearing before the Board.

It should also be noted that in many applications, information is repeated in great detail in multiple sections of an application. This is especially true with respect to the capital expenditures detail. This adds time and costs to the regulatory review process because intervenors and Board Staff often end up spending additional time and effort going through the duplication of the evidence. This is necessary from a due diligence perspective because additional information may be provided in one repetition of the evidence and not in another, or one repetition may refer to another project and the link between the two that was not identified in the other, and in many cases, there are actually differences in the description of, need for, or cost of the same project provided in different sections of the evidence.

As noted above, the performance of the applicant in providing fulsome comprehensible evidence and in providing complete answers to interrogatories and technical conference questions goes a long way in determining the time and effort needed for the application review process. LPMA submits that this is appropriate. Quality is rewarded with quicker and less expensive reviews. Lack of quality is rewarded with longer and more expensive reviews.

A better question for the Board to ask, is what can be done to increase the quality of applications, the supporting evidence and responses to interrogatories and technical conference questions to ensure a quality and efficient process?

LPMA notes that the Board has, in the past, sponsored training for electricity distributors with the Society of Ontario Adjudicators and Regulators ("SOAR") and that other organizations may also be providing such training. LPMA believes the Board should continue to do this, but with more emphasis on practical aspects of the application process.

LPMA also believes that distributors should be encouraged to attend technical conferences and oral hearings prior to when they begin to prepare their applications. This will give them the opportunity to learn by observing. LPMA notes that in the past, some distributors have complained that intervenors ask the same questions from distributor to distributor. The obvious answer to this concern is for the distributor to include the answer in their own evidence in a clear and concise manner, thereby allowing the intervenors to not have to ask the question. By reviewing the interrogatories and responses in other cases related to similar issues, distributors would be able to increase the quality of their application process, to the benefit of all parties involved.

To support the cost-effective and efficient implementation of Board-approved network investment plans by transmitters and distributors and to help mitigate the

effects of any unavoidable and significant bill impacts, what mechanisms might be appropriate?

Assuming that the unavoidable and significant bill impacts are the result of a robust regulatory process in which ratepayers are assured that their interests are being taken into account, the first question that LPMA believes should be asked is if unavoidable and significant bill impacts should be mitigated? Is the Board doing the correct thing by hiding, delaying or otherwise mitigating the price signals that result in the bill impacts? Price signals allow the consumer of the product in question to react appropriately. If the customer does not see the price signal, then they cannot be expected to react in an appropriate manner. By simply delaying the price signal, the Board may, in fact, be making the customer worse off. Customer choices made today in the absence of knowing that the price signals have delayed until tomorrow will result in less than optimal outcomes for customers.

In theory mitigation moves today's problem into tomorrow. If we knew with certainty what tomorrow would look like, this approach might be appropriate, assuming full consumer knowledge of what tomorrow holds as a result of today's mitigation.

In practice this is not likely to occur. We do not know if we are solve a problem today by making a bigger problem for tomorrow. Customers do not know that mitigation today is even taking place, never mind that they will have to pay these costs tomorrow and that there may be additional costs to be paid as well, such as carrying charges on the deferred revenue. In the current low interest environment, this may not be a concern, but in the future as short term interest rates rise, as they are likely to do, the additional costs of mitigation would grow significantly.

As part of a working group to determine what customers want and what they are willing to pay for, LPMA suggests that customers should be surveyed on their views related to mitigation as it relates to unavoidable and significant bill impacts.

A mechanism that the Board may want to investigate is to use a rate adder to collect money from customers before the network investment plans are placed into service and into rate base. This would provide a source of cash flow for utilities and replace part of the debt that they might need to finance the expenditures. Any excess revenues collected (in excess of the cost of debt needed to finance the project) could then be used as a contribution or grant to reduce the impact on rate base when the investment is closed to rate base. This way consumers are prepaying part of the investment, resulting in lower depreciation and capital return costs in the future. This preserves the concept of ratepayers not paying for an asset until it is used and used and placed into service, while at the same time providing a source of revenue for utilities to cover the carrying cost of the asset while it is in CWIP, and providing ratepayers with the ability to get a benefit out of prepaying for a portion of the investment through lower rates when the asset is placed into service.

Other

In light of what you heard at the March 28-30, 2012 Stakeholder Conference, what are your priorities for the Board's development of the RRFE and how might the Board manage the transition to the renewed regulatory framework in a manner consistent with your priorities?

LPMA believes that the priorities should be centered around a choice or menu of rate setting options like that of the 4th Generation Rate Setting Mechanism described earlier in these comments. What LPMA heard throughout the Stakeholder Conference is that not all utilities are the same and not all face the same problems. For some replacement of aging infrastructure is an issue, while it is not for others. Some utilities are facing pressures related to strong customer growth. Others have moderate or no customer growth related pressures. Some utilities are happy with the 3rd Generation IRM model, including the capital module, while others do not believe it works well for them. In short, the utilities cannot agree amongst themselves as to what works well. LPMA believes there is no reason for them to do so because the answer lies in diversity, not in conformity.

A priority for the Board is to set up a working group, similar to that used in the 3rd GIRM process, to set up a 4th Generation Rate Setting Mechanism that would be tasked with coming up with rate setting processes that would used to set rates for electricity distributors and transmitters for at least the next decade. This will provide all parties with regulatory certainty over a long term planning horizon.

Another priority for the Board is to set up a working group to find ways to get customer input on what service and performance are important to them and what their views are on the need for and benefits of mitigation measures if they are needed. As noted elsewhere in these comments, customer opinions are likely to vary by customer type, within customer type and by customer location. There may well be other distinctions among customers that are identified as the working group moves forward.

Are there other key issues that should be considered in the development of the RRFE?

One key issue that does not appear to have been addressed is whether some version of the RRFE should be applicable to the regulated natural gas distributors in Ontario. LPMA submits that it should not.

The current regulatory framework for natural gas distributors (in particular for Union Gas and Enbridge Gas Distribution) has resulted in benefits to the distributors, to the regulator and to ratepayers. The distributor benefits have included reduced regulatory costs, and the ability to achieve returns in excess of the allowed return on a sustainable basis. The benefit to the regulator has been a reduction in, complexity of and duration of regulatory proceedings. Ratepayers have benefitted through both the built in productivity offsets to inflation used in the price cap and in the sharing of earnings in excess of the dead bands. This has been a win win win situation. LPMA sees no valid or compelling reasons to deviate from this approach now.

Sincerely,

Randy Aiken

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