Aiken & Associates
578 McNaughton Ave. West
Chatham, Ontario, N7L 4J6

Phone: (519) 351-8624
Fax: (519) 351-4331
Cell: (519) 365-1078
E-mail: raiken@xcelco.on.ca

June 25, 2007

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli,

RE: EB-2006-0268 - London Property Management Association Comments on Comparison of Distributor Costs Consultation on Consultant's Report

Please find attached the comments on behalf of the London Property Management Association in the above noted consultation related to benchmarking.

Three paper copies have been provided to the Board. An electronic copy has been e-mailed to the Board Secretary and an electronic copy as been submitted to the Board through the Regulatory Electronic Submission System.

Sincerely,

Randy Aiken

Randy Aiken
Aiken & Associates

Encl.

COMPARISON OF DISTRIBUTOR COSTS CONSULTATION ON CONSULTANT'S REPORT

COMMENTS OF THE LONDON PROPERTY MANAGEMENT ASSOCIATION

INTRODUCTION

The London Property Management Association ("LPMA") has reviewed the report entitled "BENCHMARKING THE COSTS OF ONTARIO POWER DISTRIBUTORS" dated April 25, 2007 from the Pacific Economics Group ("PEG"), as well as the written comments from a number of interested parties that have been posted on the Board's website.

In its April 27, 2007 letter to interested parties, the Board invited comments on the PEG report and comments on the following:

- the application and value of benchmarking in ratemaking;
- the relative merits of PEG's and Board Staff's proposed benchmarking methodologies; and
- any alternative methodologies that the Board should consider (including the rationale for the alternative and how it might be implemented).

The Board letter also asked interested parties to suggest alternatives for the timing and manner of collection of the additional data should the Board decide that collection of additional data is warranted.

GENERAL COMMENTS

LPMA believes that the objective of the development of a better understanding of electric utility costs and a better way to compare those costs across utilities would benefit the Board and ratepayers. Utilities would also benefit from this information, enabling them the opportunity to benchmark their costs as compared to the other utilities in the province.

Given the diversity of the utilities in Ontario, it is unclear to the LPMA that a detailed comparison of costs will be possible. Overall comparisons at the aggregate level of OM&A costs, such as that used in the PEG report, would appear to be of limited value to all parties involved in this process. Without knowing where the differentials exist within the OM&A costs, it is unclear how the Board, ratepayers or the utilities themselves would be able to use this information in any meaningful way.

This leads, of course, to the issue of balancing the need for accurate and consistent data with the costs of obtaining this information. This topic is discussed in more detail in the "Additional Comments Requested by the Board" section below.

LPMA is concerned that the potential uses of benchmarking, in whatever form that may ultimately be, do not appear to be clearly defined at this time. Further comments on this topic are also found in the "Additional Comments Requested by the Board" section below. If the objective is to only develop a screening tool for deciding which utilities come forward for rebasing, then the aggregate OM&A approach would be somewhat useful. It would only be somewhat useful because there would not be any information available to indicate which component or component of OM&A needs to be examined in greater detail. On the other hand, if the objective is the development of future distribution rates on the basis of some form of benchmarking, then a higher degree or level of detail and accuracy would be required.

COMMENTS ON THE PEG REPORT

The PEG Report, in the Executive Summary, states that "Regulators may still undertake more traditional prudence reviews but can rely in part on benchmarking results to set initial rates and the escalation terms of rate adjustment mechanisms". LPMA agrees with this statement, but with one change. Regulators **should** (rather than may) still undertake more traditional prudence reviews … would be more appropriate. Benchmarking can play a supporting role in the setting of initial rates, for example as a check on the reasonability of the requested increase in rates, but should not be used as the primary method to set these rates. The primary methodology for setting initial rates or rebasing following a period of an incentive rate mechanism should continue to be a cost of service filing. Benchmarking that reflected more recent historical results would provide all parties with a check on the reasonableness of the cost of service filing. For example, a utility that continues to under perform relative to its benchmark should expect the Board and intervenors to delve more deeply in a cost of service application to find the areas where improvements and cost reductions should be made. Similarly, if a utility has performed well relative to its benchmark, it could be expected to continue to perform at least at this level. A rebasing application that fell short of this expectation would generate additional scrutiny as well.

LPMA generally agrees that the direct econometric approach to benchmarking is more sophisticated and complex than cost indexing. However, the greater accuracy and the availability of statistical tests to test efficiency hypotheses associated with the direct econometric approach outweigh the advantages of simplicity associated with cost indexing. LPMA, therefore, supports a direct econometric approach to benchmarking.

LPMA generally accepts the methodology employed in the PEG Report. The remainder of this section is divided into comments related to Chapters 2 through 6 of the PEG Report.

a) Chapter 2 – An Introduction to Benchmarking

The measurement of capital inputs is identified as a complication that is often encountered in benchmarking. The characteristics of the capital stock, such as the age of the system, can influence OM&A expenses. The Report then talks about possibly employing an indicator of the age of a system such as the number of customers added in the last ten years. It is unclear to the LPMA that the equations presented later in the report indicate that this potential measure of system age was used as an explanatory variable and found not be significant, or whether there was insufficient data to include the variable in the equation in the first place.

It is also unclear why, or if, other potential measures of the system age were not investigated for inclusion in the equations. One such potential would be the ratio of accumulated amortization to the gross asset value. Older systems would presumably have a higher value and newer systems (or rapidly growing systems) would have a lower value. Such a ratio could be calculated based on all distribution related infrastructure, or could be further refined into specific categories, such as poles &fixtures, station equipment and/or overhead conductors & devices. LPMA suggests that this information should be readily available from all utilities over the period used for estimating the equations and should be gathered and used by PEG to add an additional explanatory variable to determine whether such an explanatory variable is significant in explaining OM&A costs.

The Report states that the error term in an econometric model is the difference between the actual value and that predicted by the model and that this error term reflects imperfections in the development of the model, such as misspecification. It is unclear whether the estimated equations were tested for any misspecification error using, for example, Ramsey's RESET test. It would be useful to provide the results of any such tests if they were performed. If no such tests were done, an explanation as to why they were not done should be provided, or such test should be undertaken. This would provide parties with a greater level of confidence in the results, assuming no specification error is found.

The report indicates that the econometric benchmarks can be made for historical years or for a hypothetical test year. The Report, however, fails to mention that in order to benchmark a future test year, predicted values of the explanatory variables would be required. The forecast of key explanatory variables such as customers and wage rate, as used in the example on page 9 of the Report, would likely be contentious because the result of the benchmark forecast could vary significantly based on the input values of the explanatory variables.

b) Chapter 3 – Precedents for Benchmarking in Regulation

As the PEG Report states, benchmarking may be of interest in the Ontario regulatory environment because the Ontario Energy Board has jurisdiction over a large number of electricity distributors. As indicated, most regulators in North America typically have jurisdiction over five or fewer utilities in each energy industry. These other North American regulators have extensive cost of service regulation experience, as does the OEB. It would seem to the LPMA that the use of benchmarking is appropriate for the electricity industry in Ontario given the large number of distributors. In the future, if mergers and acquisitions ultimately lead to a significant consolidation in the number of regulated utilities, the move to cost of service regulation for these consolidated distributors should be kept in mind. As the PEG Report states, econometric benchmarking is, in general, more accurate to the extent that is based on a large sample of good operating data. If the number of utilities drops from more than eighty to less than twenty, the amount of data would drop by more than 75%. As the PEG Report states, it is difficult to identify all of the relevant cost drivers and the appropriate functional form when the sample is small. In essence, the consolidation of the industry may reduce the viability and accuracy of benchmarking for regulatory purposes in the future.

c) Chapter 4 – Application: Power Distribution

The PEG Report discusses the potential for sizable short run cost growth associated with the introduction of retail competition. In addition to the sizable capital outlays, the OM&A costs associated with dealing with the changes (training, travel, etc) could be significant. LPMA is concerned that the period of data used could have significant OM&A cost factors related to billing system changes dictated by the OEB and the Provincial policy related to retail competition. Similarly, LPMA is concerned that the data used in the study covers a period of significant transition for the utilities. Distributors with a large administrative workforce may have been able to absorb much of the additional requirements, without adding to staff levels or contracting out. Smaller utilities, on the other hand, may not have the workface size to be able to absorb any of the additional regulatory burden imposed on them. As such, the impact of the transition period may be significantly different among utilities. As the regulatory environment and provincial policy environment stabilize, this transitional impact may abate and change the relative performance of the distributors. In short, some distributors may be more adept than others at making course corrections to respond to new events, while others may be more adept at maintaining the course. The period used to calculate the econometric models may then influence the results toward the particular environment in place over that period that could well be different from the results in a subsequent period.

This chapter of the PEG Report lists a number of network characteristics and cost drivers such as the shape of the distribution system, reliability of the distribution services, age of the system, the number of languages spoken in the service territory and level of customer migration, among others. However, these drivers are not reflected in the final equations shown in Chapter 6. Were these variables found to be statistically insignificant, or were they not included in the analysis because of measurement problems?

Three key areas of concern related to the data used are identified in Chapter 4. These problems include different capitalization practices and policies, missing data, and the scale of demand-side management activities. LPMA is concerned with the impact of capitalization. High levels of capitalization reduce the OM&A costs, but ultimately increase the capital related costs through return on capital, depreciation and taxes. Low levels of capitalization have the opposite effect. However, it is unclear what the net impact on costs is of either approach when OM&A and capital costs are both taken into account. It does not appear that any attempt to remove the impact of inconsistencies in capitalization was made. Could the data have been adjusted to add back capitalized OM&A costs, so that these costs would be on a comparable gross basis for all utilities, rather than on a net basis? Was any analysis done that might suggest, for example, that large utilities tend to capitalize a greater proportion of their expenses than smaller utilities, thus accounting for some of the difference in the level of costs?

LPMA is also concerned with the impact that demand-side management (or conservation and demand management) has on the OM&A costs. LPMA notes that these costs were removed from the analysis, similar to the removal of bad debt expenses. Over the period for which the data was collected, some utilities may have been more advanced in their delivery of CDM programs. This could create a tilt in the analysis of the OM&A costs that has not been explicitly identified. The PEG Report does not address how these costs that were removed from total OM&A would or would not be used to potentially set initial rates or escalation terms of a rate adjustment mechanism.

d) Chapter 5 – Ontario Data

The PEG Report indicates that data for 2006 have become available since the study's completion. It would be a useful exercise to rerun the estimated equations under two different scenarios to test the stability of the models and the utility rankings that fall out of them. The first useful exercise would be to add the 2006 data to the 2002 through 2005 data used by PEG. The second useful exercise would be to add the 2006 data and drop the 2002 data and rerun the analysis. If the results of these two scenarios provide results that are relatively stable as compared to the original analysis, the results may be more credible to parties. However, if the results are significantly different, the benchmarking results may be viewed more critically, especially if the results are somehow used to set initial rates and/or determine the escalation terms of rate adjustment mechanisms.

The PEG Report states that a large and diverse set of data is highly desirable for statistically benchmarking. However, the number of Ontario distributors is likely to fall in the coming years due to mergers and acquisitions. The report is silent on the level of statistical benchmarking that would be available if there were a limited (for example, ten) distribution utilities in the province. The report is also silent on how statistical benchmarking would take into account changes in costs associated with mergers and acquisitions. It would not seem realistic, for example, to simply add the historical costs for a number of utilities that merge and assume that history reflects the going forward costs of the merged entity.

LPMA shares the concern that is expressed in the report related to the reporting of labour expenses. LPMA urges the Board to amend the US of A accounts so that labour expenses are segregated from other expenses for each of the major power distributor activity groups. Benefits costs should also be separately identified by major cost categories (for example, Canada Pension, employment insurance, health plants, etc). The rationale for this is that the labour related expenses of wages, salaries and benefits comprise a substantial portion of OM&A costs and the greater level of detail available for these costs would allow for a better analysis and comparison.

LPMA also shares the concern over the lack of consistency and the lack of detail associated with “billed” retail delivery volumes and peak demand. As the Board is aware, there is a tremendous range across Ontario distributors in terms of the mix of services provided by these utilities. In order to accurately account for these differences, LPMA recommends that more complete and detailed retail delivery volumes and peak demand information be collected in the future. LPMA notes that the movement to smart meters in the province should facilitate the collection of this data. This data would also provide better information for cost allocation and rate design purposes. It could also lead to more efficient system design.

e) Chapter 6 – Empirical Research

LPMA sees no valid or compelling reason to remove the costs of pensions and other benefits from the total OM&A costs. The PEG Reports notes in a footnote that these expenses are volatile and reflect commitments to former employees. Neither is sufficient justification to remove these costs from OM&A. The analysis should be redone with the costs related to pensions and other benefits included in the OM&A costs. These costs can be a significant portion of OM&A costs. Their exclusion may be part of the reason that the larger utilities appear to have lower costs. Larger utilities may have more generous pension and/or other benefit costs than smaller utilities. In addition, the removal of these costs may not provide an accurate comparison between utilities that have out-sourced a significant amount of work and those that maintain their own employees to do the work. Pension and other benefit costs are a legitimate part of maintaining a workforce. Their removal provides a bias against out-sourcing in terms of a comparison of the costs. If there is a significant difference in the analysis and the comparative performance rankings of including these costs as compared to removing them, then this suggests that utilities have different levels of commitments that should be recognized in the analysis.

The PEG Report states that the expense figures for Hydro One provided by Board staff exclude the costs that have been allocated to the power transmission services of Hydro One, and that no other company in the sample has a comparable operating advantage. It should be noted that Great Lakes Power ("GLP") has a similar operating characteristic in that it also has distribution and transmission components. It would be useful if Board Staff could confirm that the expenses provided to PEG for GLP also exclude expenses that have been allocated to the power transmission services by GLP. It would also be useful for Board Staff to provide the details of how this allocation between distribution and transmission for Hydro One and, if applicable, to GLP was done. Both of these utilities should be asked to confirm the appropriateness of their particular allocation.

A number of questions arise related to the cost drivers used. The output quantities of the number of retail customers, the total retail delivery volumes, and the total circuit km of distribution line were used. There is no explanation as to why the relative mix of customers was not used. For example, the number of residential customers and the number of non-residential customers may have shed some light on the impact of diverse mix of customers on costs. It is unclear whether the use of total retail delivery volumes includes the volume of deliveries to other distributors. It is assumed that it does not include these volumes. The delivery to other distributors appears to be a relatively common practice in Ontario. However, it is unclear that this practice is more or less prevalent by region, by urban vs. rural, by large vs. small, etc. The analysis should be redone to determine the impact on the equations and the performance rankings when good data is obtained for 2002 through 2005 for all utilities (immediately and retrospectively, as recommended by PEG).

More details on how the input price index that was developed should be provided to parties. The weights assigned to this index (0.35 for labour and 0.65 for material and supplies) may reflects PEG's knowledge of the cost shares in the States. However, that may not reflect the cost shares in Ontario. More importantly, it may not reflect changes in these shares that may be taking place over time as utility out-sourcing takes place to a greater or lesser extent than in the past.

The methodology and all information used to construct the labour subindex should be provided to all parties. This is obviously a key driver variable.

The labour price subindex was calculated based on data from the 2001 census. This should be updated to reflect the 2006 census information when that information becomes available, possibly in the early part of 2008.

It does not appear that the prices for materials and services is a significant cost driver, as the equations shown in tables 2 and 3 do not include such a variable. This may be due to the assumption that these prices were the same in a given year across Ontario. Given that much of the services acquired would be related to replacing labour, it could be the case that the services cost is different in different regions, similar to the difference in labour costs. Similarly material and some service costs may include a component related to transportation costs. These costs may be higher in the northern and rural areas of the province that those in the GTA or southern Ontario regions.

The PEG Report identifies seven other business conditions that were found to be statistically significant cost drivers in one or more of the econometric models that they developed. However, not all of these drivers are included in the equations provided in the report. PEG should provide all the equations that it estimated.

It is unclear in the translog form of the equation shown in Table 3 why some of the variables that reflect the interactions between different variables are included and others are not. For example, the following variables are not included in the model: NV, NM and VM. It may be that these variables are not statistically significant at a 90% confidence level (with a s-statistic of 1,645). However, three of the variables shown in Table 3 are not significant at this level of confidence, but are nonetheless included. An explanation is required.

An explanation is also required why there are no variables included in the model to take into account the possible interaction between the additional business conditions and the other variables in the equation. Appendix A states that in order to preserve the degrees of freedom and to permit the recognition of additional business conditions, PEG did not translog these “Z” variables. It is unclear that the reduction in the degrees of freedom would be of sufficient magnitude to justify this approach. Further, with the addition of 2006 data, this point may be moot. If the equations are estimated using this expanded data set, the decline in the degrees of freedom may no longer be an issue.

The PEG Report indicates that cost theory suggests that economies of scale are available from further output growth if the sum of the cost elasticities of the scale variables is less than one. At the sample mean of the three output variables (number of retail customers, retail deliveries, distribution line circuit kilometers) is 0.938, indicating that modest incremental scale economies are available at the average level of operating scale. The report also indicates that incremental scale economies are not exhausted until a level of output has been reached that is somewhat above the Ontario mean. Given the wide variation in utilities in Ontario from the mean, does this mean that the larger utilities, which are more than somewhat above the Ontario mean, have exhausted their potential for scale economies?

It is not clear how the econometric benchmarking results found beginning at page 54 of the PEG Report are to be interpreted. In particular, the reports talks of a 90% confidence interval with p-values reported in Table 5. Table 5 does not have p-values, so it is assumed that this reference should be to Table 4. However, the report states that there were only 10 distributors that were found to be significantly superior (i.e. with a p-value between 0 and 0.10). However, a review of Table 4 appears to indicate a larger number of utilities with a p-value of between 0 and 0.10 and an actual/predicted value of less 1.00.

It would be useful if all of the data used by PEG in their research was available to all parties in a downloadable Excel file. Each utility should be asked to verify the information pertaining to it, including the constructed variables such as degree of forestation and percent of distribution plant that is underground for reasonableness.

ADDITIONAL COMMENTS REQUESTED BY THE BOARD

The Board requested additional comments on the following topics:

a) The application and value of benchmarking in ratemaking

LPMA believes that benchmarking has value in ratemaking when it comes to adjusting base rates as part of an incentive regulation term. Benchmarking would allow for the differentiation in productivity factors by utility. This would allow the Board to reward efficient utilities with a productivity factor less than their individual historical achievements, meaning that there would be a potential increase in return to the shareholder. At the same time, under performing utilities would have their historical productivity factors ratcheted up by the Board to force improvements.

In both cases LPMA believes that the use of these productivity factors should be limited to three years under an incentive regulation mechanism. Rebasing should take place based on cost of service filings to bring rates in line with actual and forecasted operating results. This would transfer any sustainable efficiency gains from the previous incentive regulation period from the utilities to the ratepayers. The following incentive regulation period could then be "rebased" as well, based on updated productivity information based on the most recent period. New X factors could then be assigned to each utility for the next round of rate changes.

b) The relative merits of PEG's and Board Staff's proposed benchmarking methodologies

LPMA generally agrees with the comments in the PEG Report at Section 6.9 related to the Board Staff methodology. In the short term the econometric cost models should be used as a supplement to the unit cost indexes, at a minimum. The Board may want to use the cost models in lie of the unit cost indexes. However, in the longer term, LPMA believes that the use of econometric cost models should be used in lieu of the unit cost indexes and not simply as a supplement to the unit cost indexes.

c) Alternative methodologies that the Board should consider (including the rationale for the alternative and how it might be implemented)

The Board may want to consider reducing the number of comparator groups. For example, as shown in Table 5 of the PEG Report, there is little difference between the group average productivity of 0.830 for the Small Northern LDCs and the group average of 0.832 for Large Northern LDCs. These two groups could be merged into the Northern LDCs group. Similarly, there is not a significant difference between the average of 1.291 for Large City Southern LDCs and the average of 1.210 for GTA Towns LDCs. These could be combined into one group. Similarly, with productivity averages of 1.050 and 1.070, respectively, the Southwestern Midsize Town LDCs and the Eastern LDCs could be combined into one group.

Alternatively, the Board could eliminate the groupings all together. With an estimate of the productivity for each utility, the Board could simply set a common X factor based on the straight average from all of the utilities and use this common figure for all utilities under an incentive regulation term for a Price – X price cap. Utilities that have a higher than average productivity factor would be reward during the incentive period with higher returns, while utilities with a lower than average productivity factor would be encouraged to improve their performance, or face lower returns. This would eliminate the potential problem associated with utilities requesting that they be moved from one group to another or the creation of another group in which their performance relative to the others in the group may appear better.

d) Alternatives for the timing and manner of collection of the additional data should the Board decide that collection of additional data is warranted

If the Board determines that the collection of additional data is warranted, then LPMA submits the following. First, the level of detail of data required should be the subject of a consultative process between the utilities, ratepayer representatives and Board Staff. Second, the Uniform System of Accounts should be amended to provide the level of detail required and to provide clarity on how costs are to be recorded. Third, the Board's Audit section of Market Operations should be charged with the task of educating utilities in the use of the US of A and ensuring that all utilities are using a consistent interpretation of the accounts. Fourth, the data should be gathered on a regular basis, probably quarterly through modified RRR filings (if necessary). Fifth, the data should be compiled by Board Staff and accumulated over time. This data, preferable in a downloadable spreadsheet form, should be made publicly available to parties on the Board's website.

CONCLUSIONS

The PEG Report highlights the main reason for using benchmarking for regulation. That is, a regulator that has jurisdiction over numerous distributors, such as Norway and Germany. In this regard, this is the situation that the Ontario Energy Board finds itself in.

The use of benchmarking, especially frontier benchmarking or a top quartile standard, and the employment of rate escalation mechanisms calibrated to move rates for all utilities to a level commensurate with frontier costs over a multi year period, such as done in the Netherlands and in other countries, will likely lead to the consolidation of the industry into a lower number of utilities.

The PEG Report states that companies in the top quartile were given revenue requirements in excess of their costs by European regulators. In the Ontario context, it is open to debate whether a revenue requirement in excess of the utilities all-in costs could result in just and reasonable rates. In any event, the goal is to force the poorer performing utilities to reduce their costs. LPMA supports this goal. However, this does not mean the utilities that perform well should be entitled to continuing profits in excess of a reasonable return on investment. It is the ratepayers, not the shareholder, which should benefit in the long run from improved efficiencies. Shareholders should only be rewarded on an interim basis for better than average efficiencies.

One way of improving the performance at utilities is to use benchmarking to determine a utility efficiency relative to others and to use this information as part of the process of setting the X-factor in a Price – X price cap rate mechanism. In particular, the more inefficient a utility is, the higher would be the X-factor assigned to that utility. This provides the utility with an incentive to close their efficiency gap with the other utilities.

However, in attempting to force poorer performing utilities to change their ways and become more efficient, the Board must be prepared to allow utilities to fail. Failure to do so would eliminate the incentive/need for efficiency gains and defeat the purpose of benchmarking. LPMA believes that this is one area where additional comments from Board Staff and other parties would be useful.

The use of a common X factor would achieve the same results as those above and would eliminate any problems with utilities lobbying to be placed in one grouping versus another that might be more advantageous to them.