EB-2009-0259

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an Application by Burlington Hydro Inc. pursuant to the *Ontario Energy Board Act* for an Order or Orders approving just and reasonable rates for the delivery and distribution of electricity effective May 1, 2010.

FINAL ARGUMENT
ON BEHALF OF THE
SCHOOL ENERGY COALITION

January 19, 2010

JAY SHEPHERD P.C.
120 Eglinton Avenue East, Suite 500
Toronto, Ontario M1P 3E5

Jay Shepherd
Tel: 416-804-2767
Email: jay.shepherd@canadianenergylawyers.com

Counsel for the School Energy Coalition

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1 GENERAL COMMENTS

1.1 *Introduction*

1.1.1 On August 28, 2009 Burlington Hydro Inc. filed an application for new distribution rates commencing May 1, 2010. The Application, after a number of adjustments outlined in response to Staff Supplementary IR #8 identifies a deficiency of $4,172,323, and seeks approval for rates to recover a service revenue requirement of $32,410,162 and a base revenue requirement of $30,651,843. This represents an overall distribution rate increase averaging about 15.8%. For a typical school in the GS>50KW class, the proposed distribution rate increase works out to about 19.2% over current rates.

1.1.2 This is the Final Argument in this matter on behalf of the School Energy Coalition.

1.1.3 In preparing this Final Argument, we have benefited from a review of the Staff Submission dated January 11, 2010. That was most helpful, and the fact that we had it before finalizing our own submissions has simplified this argument. We have also been able to review the very thorough submissions of Energy Probe, filed on January 17, 2010. In addition, because we are filing a day late, we have had an opportunity to see the submissions of VECC, filed yesterday. Where the submissions of Energy Probe, VECC or Staff fully canvass an issue, and we are in agreement, we have not repeated the arguments, but simply indicated our agreement.

2 LOAD FORECASTING AND METHODOLOGY

2.1 *Methodology and Resulting Basic Load Forecast*

2.1.1 The Applicant has responded to past Board guidance by moving from the NAC methodology used five or six years ago to econometric modeling for load forecasting purposes. In doing so they cannot be faulted, but a pattern has emerged in 2009 and 2010 rate cases of problems arising from the nascent nature of the econometric approach in electricity forecasting, particularly in this period of rapid change in Ontario electricity policy and therefore energy use.

2.1.2 As Energy Probe and Staff have both pointed out, the econometric model being proposed by Burlington does not pass the reasonableness test. A full analysis of the problem and why it cannot be accepted by the Board is found at pages 11-15 of the Energy Probe Submissions, and page 5-8 of the Staff Submissions. We adopt their analysis, although, as we discuss below, not their conclusions.

2.1.3 The problem is that the model proposed has a negative coefficient for number of customers, clearly not realistic. Staff's proposed solution is to revert to the NAC methodology, producing a total load forecast (billed energy) of 1,762.4 Gwhr. Energy Probe's proposed solution is to remove the offending coefficient from the equation, producing a total load forecast of 1,703.3 Gwhr.

2.1.4 In our submission, neither of these solutions is correct. Load forecasting is a critical step in setting just and reasonable rates, and the Board should generally insist that the forecasting methodology be rigorous and replicable. It is, in our submission, long past the time that electricity distributors should be presenting load forecasts with obvious and major flaws.

2.1.5 That having been said, the Board has a problem, because however bad the load forecast may be, the Board can't set rates without a forecast. In our view, the Board should expressly acknowledge the lack of a rigorous forecast in this case, and adopt a load forecast for this proceeding that averages the Staff solution (NAC) and the Energy Probe solution (modified BHI formula). By acknowledging the lack of acceptability of the options, the Board then makes clear that the solution used is not a precedent for other utilities in other rate cases, but a "lesser of evils" approach to this rate case.

2.1.6 We therefore suggest that the Board adopt a total load forecast of 1,732.9 Gwhr.

2.2 *Weather Adjustment*

2.2.1 With respect to weather normalization, we adopt the reasoning and conclusion of Energy Probe.

2.3 *Future Applications*

2.3.1 It is submitted that the Board should be concerned about the number of 2010 applications in which the load forecast is insufficiently rigorous. It is undoubtedly true, as was stated in another case, that the science of electricity forecasting is still developing in Ontario, and it is also true that the rapidly evolving policy environment, including the current process of shifting to time of use rates, adds substantial complexity.

2.3.2 Nevertheless, we are concerned on two counts. First, the Board is having to address many different, and often unacceptable, load forecasting methodologies in rate cases. Second, eighty utilities are actively trying to find an acceptable approach, with the inevitable duplication and wasted effort that implies.

2.3.3 In our submission, load forecasting is a common element to all applications, and one in which the Board ultimately has to select a preferred approach. With that in mind, we believe that it would assist the industry, and all parties to the rate-making process, if the Board established a process – whether consultation, generic hearing, or otherwise - to review the various models in a disciplined way, and reach conclusions on which approach or approaches are acceptable in electricity distribution rate applications.

2.3.4 While the past few years of rate applications have produced a number of candidate methodologies, so a foundation of work has been done, we believe it is now time to establish standards. This will improve the overall quality of rate applications, provide consistency across distributors, and save substantial amounts of time and money that the distributors would probably prefer to use in other ways.

2.4 *Total Loss Factor*

2.4.1 SEC normally does not comment on loss factors. There are acceptable methods of forecasting the loss factor, and most utilities use similar approaches.

2.4.2 In this case, however, VECC has pointed out a specific factor – the purchase of the Palermo feeder in 2007 - that should reasonably be expected to reduce losses going forward. We therefore agree with their conclusion that the three year average of 1.0338 is more predictive of the Test Year and beyond.

3 RATE BASE AND CAPITAL SPENDING

3.1 *Introduction*

3.1.1 There is some confusion with respect to the capital expenditures budget being proposed in this Application. The Staff Submission, for example, assumes at page 16 that the proposal is for $8,836,100 of capital additions in 2010, net of contributions and grants. However, as Energy Probe correctly points out at page 8, projects deferred from 2009 to 2010 do not appear to be included in that figure, which means that the 2010 capital expenditures budget may actually be $9,680,100.

3.1.2 One might argue, as Energy Probe has, that the Applicant should simply clarify what they are seeking in their Reply Submissions. In our submission, this is inappropriate and contrary to proper regulatory practice. At this point in the process, the Applicant's evidence should be in, and it is what it is. If additional information is offered in the Reply Submissions, that is not subject to review, nor do the intervenors have an opportunity to make submissions on it. In our view, the Reply Submissions on this point should be limited to pointing out in the existing evidence where the actual capital expenditures budget is described, and its impacts on rate base are calculated.

3.1.3 In the absence of existing evidence, we believe it is appropriate to assume that the capital spending proposed is $9,680,100, as calculated by Energy Probe, and that the net 2009 spending should be adjusted by a similar amount, to $7,602,500 (reflecting the deduction of the net deferred projects – see SEC IR #28, page 2, which has an updated 2009 capital spending of $7,603K shown).

3.1.4 The Applicant has proposed an adjusted rate base of $104,578,009 [Staff Supp. #8]. It would appear to us that this has not been adjusted for the deferral of projects. We will discuss the implications of this further, below.

3.2 *Capital Spending Expected in 2010*

3.2.1 ***Overall Spending Level.*** As noted above, the capital expenditures budget appears to be $9,680,100. This represents an increase of 27.3% - $2,077,600 – over 2009 spending, an unusually high level. This is particularly surprising for a utility that was not able to deliver their entire, lower, capital program the previous year.

3.2.2 In our submission, it is appropriate for the Board to consider the overall capital spending budget, and how it relates to past spending and the utility's historical resources. There are from time to time situations in which a major change in budget from past spending to current needs is justified. Usually those result from a single large expenditure that doesn't happen often, like the purchase of a new CIS, or supply and construction of a transformer station. When that happens, the need for a budget that breaks from the past is easy to spot.

3.2.3 In this case, it is submitted that the evidence does not support a 27.3% increase in capital spending year over year. There is evidence showing the projects that the Applicant seeks to undertake in 2010, but that is no different from the evidence it provided to its own board of directors prior to 2009, supporting a capital budget of $8,447,000. It was unable to deliver on that budget, and it is reasonable to expect that the capital budget of $9,680,100 proposed for 2010 will also prove to be too high.

3.2.4 We therefore propose that the Board allow a capital budget equal to the average of the last three years' net capital spending. The 2007-2009 average is $8,169,540, which as a 2010 capital budget would represent an increase of $567,040 or 7.5% over 2009 actual spending. In our submission, this is a sufficient budget to cover the ongoing needs of the utility, and respond to growth in that community.

3.2.5 ***Capital Contributions.*** In SEC IR #33, the Applicant disclosed for the first time that, unlike almost every distributor in the province, it provides indirect benefits to the shareholder, the City of Burlington, through the provision of free services. One of those free services is found in section 7.4 (g) and (h) of the Shareholder Direction, relocations and other work "free of charge" and "at no cost" to the City where the Applicant is responding to City roadwork and other priorities.

3.2.6 In our submission, this is not an acceptable practice. When utilities have to expend ratepayer funds because of road widening and other such activities by third parties, the normal expectation is that the third party will pick up some of the tab, typically about 50%. This reflects a fair division of responsibility, since the proximate cause of the spending is the third party's needs, but the ratepayers end up getting updated assets (albeit before they needed to).

3.2.7 Further, we note that the City, as shareholder, already is fully compensated for their ownership of the utility through ROE. Additional financial benefits would result in an effective ROE that is substantially higher than the level determined by the Board to meet the "fair return standard". In this particular case, it is clear that the only reason the City gets this free service is that it is the shareholder. That is seen by the fact that the free service is mandated in the Shareholder Direction, an OBCA document equivalent to a unanimous shareholders agreement. It is also seen by the fact that other third parties who need similar services, like MOT, do have to pay contributions.

3.2.8 It is therefore submitted that the net capital budget should be further reduced by the amount of contributions that the utility should be receiving from the City. Estimating the amount of the reduction is difficult, but in our view necessary. The total of the City-driven relocation projects in 2010 is $740,000. Based on the typical percentage of 50%, we believe the Board should deem capital contributions from the City of $370,000 in the Test Year. This would reduce the net capital spending for the year further.

3.2.9 We note that, while this reduces the net below the level outlined earlier, a proper practice would have reduced the previous years' capital spending as well, making the current year increase in net spending actually higher than the 7.5% we have proposed above.

3.2.10 ***Introduction of HST.*** Effective July 1, 2010 the Applicant will no longer pay PST on capital spending. The forecast of PST in the current capital budget (before the deferrals from 2009) appears to be $344,929 [EP IR #1], so in our submission half of that amount should be deducted from the capital additions in the year to reflect reduced cost for the projects.

3.2.11 It would appear to us to be fair that, if the net capital budget for 2010 is reduced as we have proposed, the Applicant should, in the preparation of the draft rate order, recalculate the PST for the year, and half of the revised amount should be applied as a reduction to capital additions.

3.2.12 ***Conclusion***. Based on the foregoing, it is our submission that the base capital budget for the test year that should be approved by this Board for addition to rate base, subject to adjustments for PST changes, should be $7,627,076, reflecting the $370,000 reduction for deemed contributions, and a $172,464 reduction for PST saved.

3.3 ***Rate Base***

3.3.1 ***Implications of Capital Additions.*** The Applicant has, in Staff Supp. #8, made an adjustment to the rate base to reflect the addition of $350,000 to 2010 capital spending. We are unable to find any further adjustments reflecting new capital additions numbers.

3.3.2 It is submitted that, when the Board has made a final determination of the capital additions for 2010, the rate base (as well as depreciation and CCA) should be recalculated as part of the draft rate order process. If the Board accepts our submissions above, it is our estimate that the revised capital additions would reduce rate base by about $1 million.

3.3.3 ***Opening Rate Base.*** It is not clear to us that the deferrals of capital spending from 2009 have been reflected in the opening capital assets, which of course would reduce the rate base for the year by a like amount.

3.3.4 In our submission, SEC #28 makes clear that 2009 capital spending was reduced by at least $844,000. If that is the final figure, then 2010 rate base should have a concomitant reduction.

3.3.5 ***Past Capital Contributions.*** We have raised above the fact that the City does not pay capital contributions for work done by the utility at their request. This is a material amount, and we have proposed an adjustment for 2010 to fix this problem.

3.3.6 If the problem arising out of the Shareholder Direction affected operating costs, that would in our view be the end of it. However, in this case the impact is on capital costs, and the lack of appropriate contributions has been going on since at least December 7, 1999, the date of the Shareholder Direction. Necessarily that means that the capital assets included in rate base have been consistently overstated, year after year, for more than ten years, and thus the opening rate base for 2010 has been overstated by some undefined amount.

3.3.7 On the one hand, it could be argued that the past is the past, and no action should be taken to address this. If the Applicant recovered too much from ratepayers in past years because of an inappropriate policy of providing benefits to the City, that horse has already left the barn. Nothing more should be done.

3.3.8 On the other hand, while the past rates may have had a problem, there is still a lingering impact going forward. If past foregone capital contributions are anything like the $370,000 this year, even with intervening depreciation there may be as much as a $3 million overstatement of current rate base. The impact on ratepayers of depreciation, cost of capital and PILs of that much overstatement could be $400,000 or more per year, for multiple years into the future. This suggests that the Board should make an immediate adjustment to remedy the problem.

3.3.9 As much as we would like to propose the latter, in our view that is not the right answer. It is submitted that the Board should first find out how much is actually involved, before making a decision on how to deal with it.

3.3.10 Therefore, we ask that the Board order the Applicant to calculate the amount of contributions that should have been received from the City in each year since the date of the Shareholder Direction, and the impact on both gross assets and accumulated depreciation up to December 31, 2010. The Applicant should be required to file that report with their rate application for 2011 (whether COS or IRM). At that time the Board can determine based on solid information whether an adjustment to rate base going forward should be ordered, and if so how much.

3.3.11 ***Working Capital Allowance.*** We agree with the submissions of Energy Probe with respect to the calculation of working capital.

4 OPERATING EXPENSES

4.1 *Introduction*

4.1.1 The Applicant is now proposing [Staff Supp. #8, p. 8] an OM&A budget of $14,789,994 plus capital and property taxes. Energy Probe and VECC have both provided quite thorough analyses of the proposed OM&A budget for 2010, so our submissions in this area will not be extensive.

4.2 *Overall Rate of Increase*

4.2.1 At Ex.4, Tab 2, Sched. 2, the Applicant notes that its OM&A spending increased 7.53% from 2008 to 2009, and it is proposing in this Application a smaller increase of 5.42% from 2009 to 2010.

4.2.2 That situation has now changed. In SEC IR #28, the Applicant shows that the actual 2009 spending has been changed, and is expected to be $13,355,482, not the $14,036.568 originally planned. In fairness, the revised 2009 figure should be adjusted for $108,348 because of smart meter OM&A that is not included in the total, leaving an actual 2009 OM&A of $13,463,830.

4.2.3 Using the revised number, the increase in spending from 2008 to 2009 is 3.21%, but the proposed increase from 2009 to 2010 is now 9.85%. It is submitted that this increase is not reasonable, and should be reduced.

4.2.4 In order to calculate a target level of OM&A, we have averaged the OM&A increases for the previous three years, getting a result of 3.66%. This is a substantial level, but is probably justified due to the customer growth in the City of Burlington. We also note that it is much greater than inflation, and greater even than the recent wage settlement for most of the Applicant's employees.

4.2.5 In our submission there is no reason to believe that an OM&A increase greater than the overage for the last three years is required in this case. Therefore, it is submitted that an appropriate target OM&A budget for the 2010 year is 2009 actual plus 3.66%, resulting in a budget of $13,956,606. The increase of $492,776 is more reasonable, in our submission, than the $1,326,164 proposed by the Applicant.

4.3 *Specific Elements of the Planned OM&A Budget*

4.3.1 ***Smart Meter Bank Fees.*** We adopt the submissions of Energy Probe.

4.3.2 ***Board of Directors Cost.*** We adopt the submissions of Energy Probe. We also wish to point out Section 4.2 of the Shareholder Direction [SEC IR #33], which requires that the utility be managed by its own separate Board of Directors, not the Board of Directors of the holding company.

4.3.3 ***Regulatory Costs.*** We adopt the submissions of VECC.

4.3.4 ***Tree Trimming Costs.*** Energy Probe, VECC and Staff have all proposed that tree trimming costs be "normalized" over the next four years. We disagree with that recommendation.

4.3.5 It is a peculiarity of IRM generally that cost of service is done in one "representative" year, while many costs have an ebb and flow that means any given year will not be totally representative for that cost category.

4.3.6 The Board could adopt a practice of normalizing all costs over four years, but that would create two problems. First, it moves toward multiple year cost of service, a model the Board has rejected. Second, under the 3rd Generation IRM model, there is no guarantee that a utility will be on a four year cycle, and we have already seen some utilities that routinely ignore that cycle. Therefore, any proper normalization is impossible.

4.3.7 What the Board has done, instead, is identify a few exceptional cost categories that are "one-time costs", often, like Regulatory Costs, ones that are high precisely because it is a cost of service year.

4.3.8 In our submission, if the Board goes beyond that, and starts normalizing other costs, it runs the risk of being unfair to either utility or ratepayers unless all costs are normalized. In this particular case, tree trimming should not, in our view, be adjusted simply because 2010 is a year when more is done than average. Clearly if this budgeting were intentional to take advantage of rebasing, the Board should step in and prevent that, but there is no evidence of that here. In this case, it appears to be simply the way the dates work out. If the Board reduces the budget for this category in the test year, without adjusting other categories which will be low in 2010 but higher in other years, it will be unfair to the Applicant.

4.3.9 Further, in our submission if the Board starts to go down this normalization road, rebasing applications will become more complex and more contentious, with little long term benefit.

4.3.10 ***Bad Debt Expense.*** We adopt the submissions of Energy Probe.

4.3.11 ***One Time Costs.*** We adopt the submissions of Energy Probe and VECC.

4.3.12 ***Provincial Sales Tax.*** We adopt the submissions of Energy Probe.

4.3.13 ***LEAP Funding.*** We adopt the submissions of Energy Probe.

4.3.14 ***Regulatory Accountant.*** We adopt the submissions of Energy Probe.

4.3.15 ***Wage Increases.*** We adopt the submissions of Energy Probe.

4.3.16 ***Incentive Pay.*** Both Energy Probe and VECC provide useful analyses of the appropriateness of allowing recovery of the payments under the Incentive Plan. We adopt their reasoning in part, although in the end we come to a different conclusion.

4.3.17 Our point of departure is the provision in the Incentive Plan [see SEC #17] that no incentive compensation arises unless the ROE, EBIT and Free Cash Flow targets are met. Thus, while some of the criteria for calculating the final amount are based on criteria that benefit ratepayers, there is no incentive compensation at all unless the shareholder's needs are met.

4.3.18 In these circumstances, it would appear to us that this Incentive Plan is designed to benefit the shareholder, and any ratepayer benefits are incidental. For this reason, it is submitted that payments related to incentive compensation, forecast at $204,000 for 2010, should be disallowed in full.

4.4 ***Recommended OM&A Approval***

4.4.1 Like Energy Probe, we have sought to reach an appropriate OM&A budget figure by both a top down and a bottom up approach.

4.4.2 If the specific reductions in Section 4.3 above are added up, the total is $698,314, which would imply an overall OM&A budget of $14,098,680. This would represent a 4.72% increase over 2009 actual.

4.4.3 Our calculation in Section 4.2 above, using a top down approach, yielded an overall OM&A budget target of $13,956,606.

4.4.4 As the difference of approximately 1% between the two is not substantial, SEC recommends that the Board approve a 2010 OM&A budget of $14,098.680.

4.5 ***Depreciation Expense.***

4.5.1 We have no substantial submissions on this issue. However, we note that if our submissions on capital spending and rate base are accepted, including the adjustments to opening capital assets, there should be a material change in depreciation expense..

5 COST OF CAPITAL INCLUDING PILS

5.1 *Long Term Debt*

5.1.1 The Applicant has proposed a long term debt rate of 7.62%, producing an interest cost of $4,462,553 on the proposed rate base. The Applicant acknowledges that the deemed rate will change when the Board recalculates it as part of the annual update.

5.1.2 VECC has raised the fact that $11 million, or about 22%, of the long term debt of the Applicant in 2010 will actually be Infrastructure Ontario debt at 4.55%. VECC is correct that, under the Board's rules, a weighted average interest cost for actual debt and deemed debt should be calculated. This would reduce interest cost for the Test Year by about $350,000.

5.1.3 However, in our submission the evidence of the Infrastructure Ontario agreement has wider implications for this utility. The Board's December 11, 2009 Report on Cost of Capital signals, at page 52-54, a new approach to long term debt rates. In the context of this Applicant, which has callable affiliate debt, we draw the Board's attention to the following in the Cost of Capital Report:

> *"The Board recognizes that there is still a need for the deemed long-term debt rate, however its usage should become more limited in application. The Board wishes to reiterate that the onus is on the distributor that is making an application for rates to document the actual amount and cost of embedded long term debt and, in a forward test year, forecast the amount and cost of new long-term debt to be obtained during the year to support the reasonableness of the respective debt rates and terms…*
>
> *The Board is of the view that electricity distribution utilities should be motivated to make rational decisions for commercial "arms-length" debt arrangements, even with shareholders or affiliates.*
>
> *In general, the Board is of the view that the onus is on the electricity distribution utility to forecast the amount and cost of new or renewed long-term debt. The electricity distribution utility also bears the burden of establishing the need for and prudence of the amount and cost of long-term debt, both embedded and new...*
>
> *The deemed long term debt rate will act as a proxy or ceiling for what would be considered to be a market-based rate by the Board in certain circumstances."*

The Report goes on to include callable affiliate debt as among those "circumstances".

5.1.4 In our submission, this Applicant has provided evidence with respect to the prudence cost of their long term debt. That evidence is not the 7.25% originally set up by the shareholder, since the note is callable and so the rate is only retained at the discretion of the lender. Rather, that evidence is the rates available to the Applicant on the market, of which the clearest indication is the chart of available Infrastructure Ontario rates, attached to SEC IR #28. This shows a rate of 4.55% for 15 year debt, the term of the funding planned for 2010. It also shows a rate of 5.14% for 25 year debt, a typical term for most utility assets.

5.1.5 It is submitted that, on this evidence, it would be prudent for the Applicant to obtain third party financing at 5.14% to replace the City note, and thus save 248 basis points on the old 7.62% deemed rate, and 211 basis points on the 7.25% nominal rate on the note. If utility management acted prudently in this regard, in our submission the deficiency would be reduced by at least $1,187,000, which would be in addition to the $350,000 referred to above.

5.1.6 We anticipate the Applicant will argue, in response to this, that this amounts to "changing the rules", and even if it is correct, it should not be applied to them because they had no warning that management would have such an obligation. In our view, this position, if taken, would not be well founded, for two reasons.

5.1.7 First, management of a regulated utility is always under an obligation of prudence, and that obligation has always included an obligation to seek to keep all costs at their lowest reasonable level. The change signaled by the Board in the Cost of Capital Report, while perhaps reflective of the Board's assessment that the electricity distribution sector is maturing and able to handle more responsibility in some areas, is not a fundamental change in utility management responsibilities. Rather, it is a change in the level of expectations of the Board.

5.1.8 Second, the Cost of Capital Report also established a much higher level of ROE, also suddenly, and also something that management of the utility did not anticipate when it filed this Application. The Applicant is not proposing to defer the $1,086,000 ($728,991 plus grossed-up PILs) impact of the higher ROE. In our submission, the Cost of Capital Report should be implemented in full, or not at all, for this Applicant. The fact that the impact of the ROE increase, and the impact of a prudent level of long-term debt costs, are roughly offsetting, is in fact a reasonable result. To provide the utility with the benefit of one side of the equation, without the offset in favour of the ratepayers on the other side, is in our view inherently unfair.

5.1.9 It is therefore submitted that the cost of long term debt should be recalculated, with the cost of the City note being treated as 5.14%, reflecting the market rate for prudent debt issuances, and $11 million of long term debt at 4.55% being included to get a weighted average debt rate..

5.2 ***Short Term Debt.***

No submissions.

5.3 ***Return on Equity***

5.3.1 Energy Probe has raised an interesting argument with respect to the appropriateness of including 50 basis points for flotation costs in the 9.75% ROE being sought by the Applicant. We find that argument compelling, and we adopt those submissions.

5.4 ***Capital Structure***

5.4.1 Energy Probe has also raised an interesting argument with respect to the split between short term and long term debt.

5.4.2 It would seem to us incontrovertible that working capital is short term in nature, and therefore is appropriately matched to short-term debt. For a utility such as Burlington with a very high level of working capital in its rate base (more than 20%), we believe that maintaining an equivalent amount of short term debt, at the much lower rates available for those instruments, is simply good business practice.

5.4.3 We therefore support the Energy Probe submission, although we do recognize that this would involve a substantial change in the Board's approach to capital structure.

5.4.4 We note that, if our submissions on the prudent interest rate applicable to long term debt are accepted, the impact of increasing the short-term debt component of the capital structure would be considerably less. For example, if the adjustment as proposed by Energy Probe were accepted by the Board, the reduced rate differential would mean an impact on revenue requirement of $400,000 or less.

5.4.5 As an alternative to the result proposed by Energy Probe, the Board may wish to consider a partial adjustment, in which the short term debt component of capital structure for this utility is increased to, say, 10% reflecting its high level of working capital relative to other utilities. This would not only be an appropriate initial adjustment in rates for this distributor, but would also be a signal to other distributors that evidence on this issue might be appropriate in their applications.

5.4.6 We note in passing that Energy Probe has proposed a requirement that this utility undergo a lead-lag study. To the extent that the resulting level of working capital is lower, as is likely, the short-term debt component of capital might also be lower, but so would the overall rate base. In the meantime, decreasing the interest cost associated with working capital reflects not only the business realities, but also the likelihood that the working capital component of rate base is higher than is required.

5.5 ***Payments in Lieu of Taxes***

5.5.1 We adopt the thorough submissions of Energy Probe on this issue.

6 REVENUE REQUIREMENT

6.1 ***Revenue Requirement Calculation***

No additional submissions.

6.2 ***Other Revenues***

6.2.1 The current forecast of Other Revenues is $1,758,319 [Staff Supp. #8], reflecting adjustments during the IR process.

6.2.2 In our submission, a further adjustment is required.

6.2.3 Section 7.4 of the Shareholder Direction [SEC IR #33] sets out the rules for dealings between the City and the utility. We have earlier referred to the fact that no capital contributions are paid for City-initiated capital spending, such as road widening, and we have proposed an adjustment to capital additions, and other actions, to deal with that.

6.2.4 That Section also includes things for which the utility must pay the City, and things that utility does for the City, without payment. Chief among the latter is that the City is entitled to use utility poles for "street lighting, traffic signals, communication signals, and signs, free of charge".

6.2.5 In our submission, this is inappropriate, and the Board should require the utility to obtain normal payment by the City for this use. This is especially true since the City charges the utility full freight for the use of every City-owned asset.

6.2.6 The Board does not have direct evidence of the appropriate amount of these charges. However, the Board is aware that Toronto Hydro, also a largely urban utility, forecast $1.53 million of pole rentals in 2010 on a base revenue requirement (requested) of $528.7 million, representing a 0.29% ratio. If that same percentage is applied to the proposed base revenue requirement for this Applicant, the result would be about $89,000 of payments by the City to the Applicant.

6.2.7 In our submission, the Board should deem an additional "other revenue" amount of $89,000 for 2010 to reflect the amount the City should be paying for access to ratepayer-financed poles.

7 REGULATORY ASSETS

No submissions.

8 COST ALLOCATION AND RATE DESIGN

8.1 ***Cost Allocation***

No submissions.

8.2 ***Revenue to Cost Ratios***

8.2.1 Both Energy Probe and VECC have noted and opposed the proposed increase in the revenue to cost ratio for GS>50KW class from 80.3% to 85%, which would if allowed result in an incremental rate increase of 5.85% for customers in that class**.** We agree with their submissions on this issue.

8.2.2 We note that this is an issue that has arisen in a number of cases, and for a given rate class the impact can be positive in one case, and negative in the next. In this case, the impact would benefit residential customers at the expense of GS>50KW customers such as schools. In the next case, the opposite will be true.

8.2.3 VECC has taken the principled position that, although this departure from the Board's guidelines by the Applicant would benefit residential ratepayers, it should not be allowed. In other cases, SEC has been put in the same position, opposing a utility that wants to ignore the guidelines, even though schools would be benefited if they did.

8.2.4 We have argued in the past that revenue to cost ratios should move towards unity, and over the entire province that would generally benefit schools. The Board's policy is to move revenue to cost ratios to within the ranges, but not move them closer to unity at this time. This hurts schools overall, but we have accepted that it is the Board's policy at the current stage of utility cost allocation. However, if schools and other GS>50KW customers are to be denied the benefit of moving towards unity in the many utilities where that class is overcontributing, it would be unfair to allow this Applicant to increase the revenue to cost ratio for this class within the range. The Board's guidelines should, in our view, be applied consistently and symmetrically.

8.3 ***Fixed/Variable Splits***

8.3.1 We adopt the submissions of VECC on this issue.

9 OTHER MATTERS

9.1 *Costs*

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

All of which is respectfully submitted.

Jay Shepherd
Counsel for the School Energy Coalition