EB-2010-0136

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 Kingston Hydro Corporation pursuant to the *Ontario Energy Board Act* for an Order or Orders approving just and reasonable rates for the distribution of electricity commencing May 1, 2011

FINAL ARGUMENT
ON BEHALF OF THE
SCHOOL ENERGY COALITION

April 1 , 2011

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1 GENERAL COMMENTS

1.1 Introduction

1.1.1 On August 24, 2010 Kingston Hydro Corporation filed an Application for new distribution rates, effective May 1, 2011. The process included extensive interrogatories, a technical conference, an ADR, and a short oral hearing. While many issues were settled, some of the major financial issues were considered in the hearing, and remain to be decided by the Board.

1.1.2 This is the Final Argument of the School Energy Coalition on the seven issues not settled by the parties.

1.1.3 The ratepayer groups who intervened in this proceeding have worked together throughout the hearing to avoid duplication, including exchanging drafts or partial drafts of their final arguments. We have been greatly assisted in preparing this Final Argument by that co-operation amongst parties. Where we are in agreement with the submissions of other parties, we have not repeated their arguments here, but have adopted their reasoning where applicable.

1.1.4 We have also benefited from the early filing of the Final Argument of Board Staff, and in certain parts of this argument we have simply agreed with their analysis, rather than repeat it.

1.2 Summary of Submissions

1.2.1 This Final Argument contains an analysis of some of the issues arising in this proceeding. The following are the main recommendations resulting from that analysis.

1.2.2 ***Application of Half-Year Rule in 2010.*** Since the Applicant admits that they did not obtain an accounting order or any other Board approval to change their depreciation method in 2010, their previous approved accounting method – the full year rule – continued to apply.

1.2.3 To the best of our knowledge, there is no regulatory rule or principle that allows a utility to go back in time and retroactively restate rate base.

1.2.4 ***Cost of Power in Working Capital.*** We agree with other parties that the best available information should be used for forecasts. However, all of the Applicant's costs are based on the calendar year 2011, and therefore in our view working capital should also be calculated on that basis.

1.2.5 ***2011 Capital Expenditures.*** The top-down budgeting approach of the Applicant is a good one, and other utilities would benefit from adopting a similar approach. However, where capital spending is less than budget in a year due to lower costs, it is not good budgeting to increase the next year's budget to "catch up". There may be circumstances in which a project that had to be deferred should be done in the next year, but that is not the case here. The work that had to be done in 2010 was done, but it cost much less than planned.

1.2.6 We therefore agree with VECC that a capital expenditure budget equal to the originally filed level, adjusted for the impact of the Settlement Agreement, i.e. $4,465,000, is appropriate.

1.2.7 ***Interest Rate on Affiliate Debt.*** It is submitted that the market interest rate for long term debt for this utility is clear, as it regularly borrows from TD Bank for capital spending. The most recent debt is 4.78%, representative of 2011 interest rates. The Applicant could repay the City of Kingston debt, and borrow at that rate. Therefore, any interest rate higher than that is, by definition, imprudent. By our calculation, this will reduce the deficiency by about $250,000 but, as noted below, that need not actually reduce the monies available to the utility for operations.

1.2.8 ***Interest Income.*** We have proposed on the issue of the long term debt rate that the amount recoverable from ratepayers be reduced by about $250,000. However, we demonstrate in the body of this final argument that, with proper cash management, the Applicant can increase its annual operational benefit from its surplus funds by paying down the City of Kingston debt.

1.2.9 The net effect of including the proposed $96,000 interest income as a revenue offset, but then the Applicant actually using surplus funds to pay down the City debt, is to increase net interest benefit to the utility by $265,000, more than offsetting the lower recovery for long term debt. The ratepayers do not benefit from this operational choice, but the utility does.

1.2.10 ***OM&A.*** SEC approaches this from a somewhat different perspective than other parties. In our view, the Applicant has chosen a corporate structure that prevents the Board from seeing a transparent picture of utility operations. None of the FTE, OM&A or other figures presented as being those of the Applicant actually are those of the Applicant at all.

1.2.11 As a result, SEC believes that the only fair way to establish the OM&A budget for this utility is through the OM&A per customer metric. Based on the average of their cohort for 2009, and escalated for inflation for two years, the OM&A per customer for Kingston should not exceed $230. This translates to an OM&A budget for the Test Year of $6,273,000, a $655,000 reduction from the amount requested. This is still an 18.9% increase in OM&A over the two years 2009-2011.

1.2.12 ***PILs Schedule 1 Adjustment.*** It is submitted that Board policy on expenses of affiliates is clear. Where an affiliate employs personnel, the affiliate is responsible for the ups and downs of their costs, and any collateral tax impacts. In this respect we agree with the submissions of Board Staff and Energy Probe on this issue.

1.2.13 ***Intervenor Costs.*** SEC estimates its final cost claim to be under $30,000, despite the complications presented by a virtual utility, the last-minute evidence update, and the oral hearing.

1.2.14 We do not believe that the intervenor costs are material to the revenue requirement, and thus it would appear that there is no regulatory value in an additional inquiry into intervenor costs at the final argument phase (over and above the Board's normal supervision of cost claims). Rather, raising this issue appears to be no more than an adversarial tactic on the part of the Applicant, and not particularly helpful to the Board.

1.2.15 ***Effective Date.*** We believe that, while the parties clearly did not put their minds to the effective date of new rates in the Settlement Agreement, the wording of that agreement is only consistent with rates that are effective May 1, 2011. If rates cannot be implemented at that time, we believe that recovery of any shortfall is implied by the terms of the agreement.

2 HALF YEAR RULE FOR 2010

2.1.1 We agree with and adopt the submissions of Board Staff and Energy Probe to the effect that it is inappropriate to apply the half-year rule to 2010 depreciation.

2.1.2 We note that it is the Board's longstanding requirement that utilities obtain Board approval, either in a rate case or by way of accounting order, for any change in their regulatory accounting methods or policies. The Applicant did not obtain an accounting order or other approval in this case.

2.1.3 Lacking any approval from the Board, we know of no principle of regulation or practice of this Board that would allow a utility to change its historical data on a retroactive basis to increase current rate recovery of past costs. Aside from the fact that this would probably be retroactive ratemaking, it invites a kind of free-for-all in which utilities could maintain their accounts on one basis, then "optimize" their books of account when they are making a rate application. This would, in our view, undermine the regulatory process.

3 COST OF POWER IN WORKING CAPITAL

3.1.1 In our submission, the cost of power, like any other cost that affects rates, should be forecast for the Test Period. In this proceeding, the Test Period is the calendar year 2011, and therefore the cost of power for that calendar year is the appropriate figure to be used.

3.1.2 We note that some parties propose using the cost of power for the rate period, i.e. May 1, 2011 to April 30, 2012. With respect, we disagree. The rate period only has relevance for the rates themselves. It has no relevance for revenue requirement or the costs that make it up. The whole concept of a Test Period is that it is the period over which costs are tested. This is a cost, and so should be tested over that same period.

3.1.3 If it is not possible to get a cost of power for that exact period, it is in our view best to use the period that has the most complete overlap with the Test Period.

4 CAPITAL EXPENDITURES

4.1 *Background*

4.1.1 The Applicant's actual capital expenditures for 2010 are significantly lower than planned, because a large expenditure turns out not to be required. It should be noted that this underspending is not an amount that will have to be spent in the future. It is a real and permanent reduction in capital spending.

4.1.2 The Applicant's response to that 2010 underspending, filed in an Update in February, was to move a project previously scheduled for 2012 or 2013 to 2011, increasing the 2011 budget to $5,433,500, substantially in excess of the company's normal capital spending pattern. The justification for moving this project was that the underspending in 2010 created budget room in 2011, which they sought to utilize.

4.2 *Top-Down Budgeting*

4.2.1 This Applicant is relatively unique amongst Ontario utilities in its use of top-down budgeting for its capital spending plan. This approach keeps its spending stable and predictable, and allows them to manage their resources effectively.

4.2.2 For a business with stable revenues and stable customer numbers, a plan for capital spending that starts with a target level, and then fits the highest priority projects into it, is a sensible approach. It is SEC's general view that more Ontario LDCs should adopt the approach used by Kingston.

4.2.3 We note that this approach also echoes the opinion of the Board in the EB-2005-0437 proceeding. In that case, Enbridge sought a large increase in its capital spending, and the Board reiterated its long-held view that stable capital spending in line with historical norms is the basic standard that the Board expects. Numerous other Board decisions, before and since, express similar views.

4.2.4 Therefore, SEC supports the overall budgeting approach of the Applicant. While of course using asset condition assessments and other techniques to prioritize spending, in our view the Applicant should continue to use top-down budgeting as the starting point for setting the annual capital plan.

4.2.5 Where we disagree with the Applicant is on what happens if the amount actually spent in a year is less than expected. In our view, there are two scenarios. In the first, the underspending is because work is delayed, but it will still be done in a subsequent year. In the second, the work plan simply costs less to deliver. What was expected to cost $1.00 only cost $0.90. To achieve the work plan doesn't require further spending later. Money has been saved.

4.2.6 In our submission, the delay of a project can sometimes be a legitimate reason to increase a future year's budget beyond the historical norms. The spending is as originally planned, but some of the spending in one year is shifted to the next year. Aside from that shift, the underlying capital budget remains stable and consistent. Subject to resource constraints in the later year, this is often a reasonable response to timing issues.

4.2.7 However, where money is actually saved, it is saved, period. The appropriate response is not to look for ways to spend the savings as soon as possible. Instead, the appropriate response is to continue with the plan for the next year, and treat the reduced spending in the previous year as a lucky economy.

4.2.8 In this regard, we note that the notion of "using up the budget" is a peculiarly government department approach to budgeting. As March 31st has just past, many of us have witnessed, for example, the scramble in provincial government departments to use up budget by year end.

4.2.9 In our view, this is not an appropriate approach for a utility, which is supposed to operate using a business model rather than a government department model.

4.3 ***Appropriate Budget Level***

4.3.1 It is therefore submitted that the increase in budget of $968,000 (for the Substation #3 project) included in the Update is not appropriate, and should not be approved. We agree with VECC that the result of removing that project is a capital budget of $4,465,000.

5 INTEREST ON LONG TERM DEBT

5.1 *The Issue*

5.1.1 Included in the long term debt of the Applicant is an amount of $10,880,619 payable on demand to the shareholder, the City of Kingston, bearing interest at a rate of 7.25%. As a result of the inclusion of this amount at this interest rate, the weighted average cost of debt is 5.60%, calculated as follows:

Creditor	Principal	Rate	Interest
City of Kingston	$10,880,619	7.25%	$788,845
TD Bank Capital Loan	$2,452,652	3.25%	$79,711
TD Bank Smart Meters	$6,000,000	4.50%	$270,000
TD Bank 2009 Capital Loan	$2,213,216	4.64%	$102,693
TD Bank 2010 Capital Loan	$2,557,493	4.64%	$118,668
TD Bank 2011 Capital Loan	$1,098,621	4.78%	$52,514
	$25,202,601	5.60%	$1,412,431

5.1.2 The Applicant takes the position that the City has, by resolution, determined that it will not call this loan prior to 2012. In the Applicant's view, this makes this term debt, so they rely on the Board's policy to allow interest on term debt at the rate in place at the time the debt was incurred, up to the Board's deemed maximum at that time.

5.1.3 We agree with the submissions of Energy Probe that passing a resolution voluntarily deferring the right to call the loan does not convert this into term debt. It remains callable on demand, and the City can at any time decide it wants the money, and get it. Therefore, at best the rate that would be applicable to this debt would be the Board's deemed rate for demand borrowings, which is 5.32%. If that rate is used, the weighted average cost of debt is 4.77%, calculated as follows:

Creditor	Principal	Rate	Interest
City of Kingston	$10,880,619	5.32%	$578,849
TD Bank Capital Loan	$2,452,652	3.25%	$79,711
TD Bank Smart Meters	$6,000,000	4.50%	$270,000
TD Bank 2009 Capital Loan	$2,213,216	4.64%	$102,693
TD Bank 2010 Capital Loan	$2,557,493	4.64%	$118,668
TD Bank 2011 Capital Loan	$1,098,621	4.78%	$52,514
	$25,202,601	4.77%	$1,202,435

5.1.4 We note that, even if the Applicant's argument that this is term debt were to be accepted by the Board, the effective date of that debt can only be the date of the resolution that converted it from demand to term. Under the Board's policy, the maximum rate to be applied to that debt would be the deemed rate at the time the term debt was created, which would appear to be 5.87%. Although we don't agree this is the appropriate result, this would be the highest number the Applicant could seek.

5.2 *Evidence of Market Rate*

5.2.1 This case, though, is unusual in that it presents to the Board a utility that has been borrowing actively from a commercial bank on a long term basis. The Board has excellent evidence as to the cost of long term debt for this utility. It is between 3.25% and 4.78%, the rates a commercial lender has already given them for material debt transactions.

5.2.2 These rates are supported by the Infrastructure Ontario rates, which are 3.98% for 10 years and 4.72% for 20 years, the same range as the rates from the bank.

5.2.3 It is also clear to the Board that the Applicant can repay the debt to the City at any time.

5.3 *SEC Recommendation*

5.3.1 In our submission, the Board's Cost of Capital policy requires utilities to obtain financing on the best terms available. The Board's words were:

> *"Electricity distribution utilities should be motivated to make rational decisions for commercial "arms-length" debt arrangements, even with shareholders or affiliates."*

5.3.2 The evidence in this case makes clear that the Applicant is able to borrow at no more than 4.78% from a commercial bank in 2011, and is able to repay its 7.25% debt whenever it chooses to do so. A prudent utility faced with that situation would do one of two things:

(a) Renegotiate the debt rate on the City debt to 4.78%, and get a commitment to that rate for a reasonable term, or

(b) Borrow $10,880,619 from a commercial lender at 4.78%, and use the proceeds to pay out the City debt.

5.3.3 It is therefore submitted that the weighted average cost of debt for the Applicant should be 4.54%, calculated as follows:

Creditor	***Principal***	***Rate***	***Interest***
City of Kingston	$10,880,619	4.78%	$520,094
TD Bank Capital Loan	$2,452,652	3.25%	$79,711
TD Bank Smart Meters	$6,000,000	4.50%	$270,000
TD Bank 2009 Capital Loan	$2,213,216	4.64%	$102,693
TD Bank 2010 Capital Loan	$2,557,493	4.64%	$118,668
TD Bank 2011 Capital Loan	$1,098,621	4.78%	$52,514
	$25,202,601	4.54%	$1,143,680

5.3.4 We note, in addition, that our proposed resolution of the cost of long term debt does not explore whether the utility – acting prudently - should have replaced this debt earlier. It is clear, for example, that if management had acted prudently in the interests of the utility in 2010, the utility could have borrowed at 4.64% or even 4.50%, bringing the weighted average cost of debt down to 4.48% or 4.42%, respectively. While we are not advocating that further step, we do note that the result we propose produces a higher debt cost than this alternative.

5.3.5 By our calculation, and subject to any changes to rate base arising out of the Board's decision, the effect of applying market rates to the affiliate debt, as we propose, is a reduction in the cost of long term debt of $252,281.

6 INTEREST INCOME

6.1 ***Background***

6.1.1 The Board will note that we have dealt with the interest on long term debt out of order, because our proposed resolution of that issue has a significant impact on the resolution of the interest income offset.

6.1.2 The issue here is that, in the twelve months immediately prior to the hearing, the utility had a "bank account" with an average daily balance of $5,353,000 [calculated from J1.9]. The problem is that this "bank account" is not really a bank account at all. The money is held by the shareholder, the City, as part of their own funds, and a small amount of interest is paid on it [1.35%, according to Tr1:41].

6.1.3 The difficulty here is that at the same time as the City has the use of the utility's funds at a low interest rate, it is lending $10,880,619 to the utility at 7.25%. In simple terms, the utility is losing 5.9% on that money, or a total of $316,000 per year. This does not seem to be sensible.

6.1.4 The Applicant's response is that it needs to have money in its account to pay its bills as they come in. It considers this sort of cash float as normal [EP IR #53].

6.2 ***Appropriate Cash Management***

6.2.1 We have had the opportunity to read the draft submissions of Energy Probe on this point, and in general we agree that there is an amount of the bank account that can be used to pay off the City debt. Energy Probe's number is $2.7 million. We believe the number is considerably higher.

6.2.2 In our submission, cash management is a normal function in companies with substantial daily receipts and disbursements. Managing that cash flow is about optimizing the net cost. If too much is left in the bank account at a low interest rate, the true value of that cash is lost to the utility, and instead benefits the banker (in this case, the City). If too little is left in the bank account, on those days when cash needs are high there will be higher borrowing costs for the resulting overdrafts.

6.2.3 SEC has taken the data from J1.9 and inserted it into a standard cash management model to determine the amount of the "bank" balance that can be removed on an optimal basis. The full Excel model is being filed with this argument and provided to all parties.

6.2.4 What the model shows is that, if $5 million from the account is instead used to pay down the City debt, the impact is as follows:

Kingston Cash Optimization Analysis
(all $ '000)

Amount to Invest	$5,000		
Interest on Invested Amount	7.25%		$362.500
Interest on Casual Deposits	1.73%		$15.675
Total Interest Earned			$378.175
Interest on Line of Credit	3.38%		$18.746
Net Interest			$359.429
Days of Credit Balances	235	average	$908.693
Days of Debit Balances	130	average	$555.436

6.2.5 In this scenario, the paydown of the 7.25% debt reduces interest cost by $362,500 per annum. The remaining amount in the account leaves an average credit balance of $908,693 on 235 days (64.4%), and an average overdraft of $555,436 on 130 days (35.6%). The interest received on the credit balances and the interest payable on the overdrafts is almost the same.

6.2.6 It is submitted this modeling of the Applicant's actual data demonstrates that retaining this excess $5 million in the City "bank account" is not prudent cash management.

6.3 ***Interaction of Deemed Capital and Interest Income***

6.3.1 In a business context, that analysis should be the end of the matter. However, the Board's method of calculating interest costs does not have any way to reflect the paydown of a debt such as we propose, above. Because the "amount borrowed" for regulatory purposes is calculated by formula based on rate base rather than actual borrowings, repaying high interest debt does not flow through. The only impact is a reduction in the weighted average interest rate.

6.3.2 Given our proposal above on long term debt, the calculated result of reducing the principal amount of the City debt by $5 million is to reduce the weighted average cost of debt from 4.54% to 4.48%, thus reducing the interest cost by $14,230. This would be more than offset by a reduction in interest income of $96,243 (as calculated by Energy Probe in their Final Argument), so the ratepayers would actually be worse off because the utility was saving money.

6.4 ***Recommended Solution***

6.4.1 SEC therefore proposes that the Applicant's proposal – treating the money in the City "bank account" as generating interest at a low rate (prime less 1.65%) – should be accepted by the Board.

6.4.2 We note that both Energy Probe and Board Staff have recalculated the amount this generates, and the corrected amount is $96,243. We agree with that number.

6.4.3 However, although we are proposing acceptance of the Applicant's proposal as modified to get the correct calculation, we note that it does not need to cost the Applicant anything.

6.4.4 Under the Applicant's proposal, $96,243 will accrue to the benefit of the ratepayers as interest earned. Under the SEC proposal as to the rate of interest on the City debt, the amount recovered for long term debt would decrease by $252,281. In total, these two proposals lower the deficiency by $348,524. Absent any other circumstances, this would be that much less money available to the Applicant to fund its costs.

6.4.5 The Applicant now knows that, independent of this Application, it can repay $5 million on the City debt, saving a net of $359,429 after all impacts are taken into account. Not only does this bring them back to the same cash position as they proposed (and more), but it even allows them to pay 7.25% on the remainder of the City debt, without eroding their cash position.

6.4.6 It is therefore submitted that the Board can order the interest offset of $96,243, and the reduction in the cost of debt of $252,281, not just because they are the right answer on those issues, but also in the knowledge that there is no net cost to the Applicant of those changes in revenue requirement.

7 OM&A

7.1 *The Issue*

7.1.1 The Applicant has proposed a substantial increase in OM&A budget for 2011, up 15.2% over 2010. This comes on top of an increase of 14.0% from 2009 to 2010. In prior years, the annual OM&A increases have in virtually every case been much more modest.

7.1.2 Much of the budget increase proposed involves an increase in FTEs, and that in our view creates a significant problem. The Applicant does not actually have any employees. Rather, the people who carry out the work are all (except for a few who work for the City of Kingston), employees of Utilities Kingston, an affiliate. The lack of transparency of this arrangement made it difficult for the intervenors and the Board to get a clear picture of this substantial expansion of personnel.

7.1.3 It will be clear from the oral hearing that SEC has considerable concerns about the "virtual utility" structure employed by the Applicant. Whatever its purpose years ago, it is in our view inappropriate for a utility to have no employees, and to be headed up by the Public Works Manager for the shareholder, the City of Kingston.

7.1.4 On the other hand, this proceeding is not an ARC review, it is a rates case. We therefore recognize that only the impacts of this structure on the revenue requirement and rates in this proceeding are relevant to the issues before the Board.

7.1.5 In our view, the primary impact of this structure is that it is not possible, on the evidence before the Board, to have a complete picture of the costs of operating the utility. The deeply interrelated activities within Utilities Kingston mean that, absent a detailed review of all of the business activities of that entity, a clear view of the standalone electricity distribution business is not possible.

7.2 *Setting the OM&A Budget Through Benchmarking*

7.2.1 Given this problem with conventional review of the OM&A budget, SEC believes that the alternative is to establish at least the limits of the budget based on benchmarking.

7.2.2 We note that this approach is particularly appropriate in the case of Utilities Kingston. The essential argument of Mr. Keech in favour of the unique structure employed here is that they have been able to deliver electricity distribution services at low cost. On that, they are entirely right. Kingston has consistently outperformed its peers on the important OM&A per customer metric. In 2009, for example, its cohort averaged $221 per customer, and Kingston came it at $197, almost 11% better. This has been true in previous years as well.

7.2.3 Mr. Keech is probably correct in his evidence that this tight control over spending has come at a cost, and now some easing up on the pressure may be warranted. As much as ratepayers like the rate impacts of low spending levels, often sustained below average spending can mean that things are not getting done that should be done. In the long term, no-one benefits from such a situation.

7.2.4 On the other hand, easing up on that pressure does not mean abandoning all fiscal caution. In this case, the proposal is to increase the OM&A budget by 31.3% over two years. This massive increase would, if approved, not only take Kingston out of its leading position amongst its peers, but would put it well behind the average of its cohort.

7.2.5 In our submission, the Board should look at OM&A per customer as a useful starting point in the analysis of the proposed OM&A budget for the Test Period, and should not allow the OM&A budget of the Applicant to move past the average OM&A per customer of their cohort. That is, the status as a very low cost utility can be given up, but moving from low cost to high cost is not appropriate. Moving to the average should be the limit.

7.2.6 In practice, this involves reducing the proposed OM&A budget by $655,000. The $221 cohort average OM&A per customer, escalated for inflation to 2011, is $230 per customer. This translates to an OM&A budget for the Applicant of $6,273,000, which is an 18.9% increase over two years from 2009.

7.3 ***SEC Recommendation***

7.3.1 SEC therefore proposes that the OM&A budget for the Test Period be no greater than $6,273,000. Since the proposed reductions in OM&A budget based on line item reviews from other parties are less than this reduction, SEC proposes that this cap be used as the budget for the Test Period.

8 PILS ADJUSTMENT FOR FUTURE BENEFIT LIABILITIES

8.1.1 We have reviewed the submissions of Board Staff and Energy Probe on this issue, and we are entirely in agreement.

8.1.2 In our view the Applicant has no employees, so cannot have any accrued costs of future benefits, and cannot and does not have any tax impacts of such costs. This is consistent with many past Board decisions.

8.1.3 We note that it is always open to the Applicant to have an agreement with an affiliate to flow through actual costs incurred by the affiliate to provide services to the Applicant. There is no such agreement in this case. If there were, it would then be necessary to determine if the tax impacts of these future benefit costs are actual costs for the purposes of affiliate cost recovery. In this case, that inquiry is not required, because there is no evidence before the Board that the Applicant is contractually responsible for those tax impacts.

9 OTHER MATTERS

9.1 *Effective Date*

9.1.1 The Settlement Agreement does not specifically deal with the effective date for new rates, nor what would happen if the implementation date were to be later than the effective date, creating a period of revenue shortfall. The ADR took place in December, and at that point it was not in the reasonable contemplation of any of the parties that a rate order would not be in place by May 1, 2011.

9.1.2 With the filing of the Update, and the delay that caused, the Board is now faced with the likelihood that new rates may not be in place by May 1st. Originally, it was SEC's intention to make submissions on the appropriateness of recovery of any resulting revenue shortfall. However, it has been brought to our attention that the Settlement Agreement contains the following clause:

> *"For the purpose of settling all issues except the seven outstanding issues, the Parties agree that any issues not expressly dealt with in this Settlement Proposal are acceptable as proposed in the Application, pre-filed evidence, interrogatory responses, and other evidence in this proceeding. Appendix "B" to this Agreement is a Revenue Requirement Work Form that sets out the result of all issues expressly agreed in this Settlement Proposal, and all other issues on which the Parties have accepted the Applicant's evidence as filed."*

9.1.3 The Application includes a request to make rates interim as of May 1, 2011, and another to allow recovery of any shortfall if new rates are not in place until after that date. In our view, this clause in the Settlement Agreement is therefore determinative of the issue of effective date.

9.2 *Costs*

9.2.1 The School Energy Coalition hereby requests that the Board order payment of our reasonably incurred costs in connection with our participation in this 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.

9.2.2 The Board has asked parties in this proceeding to comment on the proposals of the Applicant with respect to intervenor cost estimates.

9.2.3 SEC estimates that its cost claim for this proceeding will be just under $30,000. This is higher than we would normally expect for a utility of this size, and arises from three factors. First, the matter went to an oral hearing with most of the major issues still unsettled, which always adds substantial costs. Second, the Applicant filed a change in their evidence after ADR, causing a further phase in the process. Third, the Applicant has structured itself in a non-transparent way through its affiliate, and real operating entity, Utilities Kingston, as well as some services from the shareholder, the City of Kingston. This structure substantially increased the difficulty in getting to the root of many issues. As well, many of the standard analytical approaches we use to review rate applications were not applicable, or had to be used in a modified way, because of the unusual operational structure.

9.2.4 The Applicant has proposed a new approach to intervenor costs. We find that somewhat strange. Intervenor costs are not a material part of their budget, so the proposals for estimates, and a special variance account, seem to be overkill. We can only conclude that the purpose of these proposals is not forecasting accuracy, but adversarial tactics. This does not appear to us to be helpful to the Board.

9.2.5 In general, we believe that like many aspects of regulation, the rules with respect to intervenor costs could be improved. The appropriate forum to do so, however, is not an individual rate case. The Board has an existing policy on intervenor costs, and procedures in place to deal with them. If the policy is to be changed, it is appropriate to change it through a policy consultation in which all affected stakeholders – regulated entities, intervenors, and others – can participate. This alternative of nibbling at the edges of the policy – in this case and in EB-2009-0274 – is not very productive.

9.2.6 The Applicant has forecast intervenor costs in the Application. It is submitted that unless they are wrong in some material way – which in most cases would be quite unlikely – this should not be handled differently than any other forecast cost.

9.2.7 We note in passing that, contrary to suggestions by the Applicant, intervenor costs are largely within the control of the Applicant. The Applicant decides the content of the Application, including how aggressive their budget requests will be, and the Applicant decides how they will engage the process. The more the utility is well-prepared, timely, open, and reasonable, the less the regulatory process costs. That applies not just to intervenor costs, but also to their own counsel and consultant fees, and the Board's costs.

All of which is respectfully submitted.

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Jay Shepherd
Counsel for the School Energy Coalition