EB-2008-0226

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 COLLUS Power Corp. pursuant to the *Ontario Energy Board Act* for an Order or Orders approving just and reasonable rates for the delivery and distribution of electricity.

FINAL ARGUMENT
ON BEHALF OF THE
SCHOOL ENERGY COALITION

February 16, 2009

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1 GENERAL COMMENTS

1.1 ***Introduction***

1.1.1 On August 18, 2008 COLLUS Power Corp. filed an application for new distribution rates commencing May 1, 2009. The application identifies a deficiency of $976,701, and seeks approval for rates to recover a base revenue requirement of $6,134,984. It also seeks significant adjustments to revenue to cost ratios. The deficiency was subsequently reduced in an updated filing to $877,252. This represents an overall rate increase of about 18.2%, and for some customer groups, including schools, the rate increase proposed is as much as 166.5%.

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 February 6, 2009. 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 certain submissions of Energy Probe and the Vulnerable Energy Consumers' Coalition, and have noted our agreement or disagreement with their positions in a number of places in these submissions. Where we are in agreement with their positions, and how they have supported them, we have for the most part not duplicated their arguments.

2 LOAD FORECASTING AND METHODOLOGY

2.1 *Methodology*

2.1.1 In our view the load forecasting methodology used for Residential, GS<50, and GS>50 is insufficiently robust for a cost of service application in 2009. The use of 2004 normalized average uses is the key weakness. As noted by VECC in its submissions, this methodology is based on the assumption that 2004 normalized average uses are predictive of average uses in 2009 and beyond. There would appear to be no evidence that this is true.

2.1.2 On the other hand, in the absence of any alternative method of estimating the Test Year load for these rate classes, it is our submission that the Board should accept for the purposes of setting 2009 rates the normalized average use forecasts proferred by the Applicant.

2.1.3 We have reviewed the submissions of Energy Probe with respect to residential customer numbers, in which they propose an increase of 178 customers for the Test Year. We agree with those submissions.

2.2 *Future Applications*

2.2.1 Given the weakness of the load forecast, we believe that the Board should require the Applicant to develop, either alone or in conjunction with other distributors, a more robust load forecasting methodology to be used in its next rebasing application.

2.3 *Total Loss Factor*

2.3.1 It is submitted that the Applicant's proposed total loss factor of 1.0750, and the components of that calculation, should be accepted as filed**.**

3 RATE BASE AND CAPITAL SPENDING

3.1 *Capital Spending Plan*

3.1.1 The Applicant has proposed a capital spending program for the Test Year that is 61% higher than the Bridge Year. From the evidence filed, it would appear that the Bridge Year is typical of the normal capital spending for this utility, ie. $1.3 to $1.9 million. The Test Year program, at $3.0 million, appears to be an anomaly.

3.1.2 The main driver of the high Test Year capital budget is the proposed substation MS#9, with a cost of $1.9 million plus related costs. It would appear that the Applicant has reduced normal year to year spending in other areas by $300,000 or more [Ex. 2/3/1] to help make room for that large individual project, which we believe is the appropriate approach for a utility to take.

3.1.3 Based on the evidence filed by the Applicant, it is submitted that the capital budget should be accepted as filed. In our view, the Applicant has provided suitable support for the capital spending plan proposed.

3.2 *Rate Base*

3.2.1 ***Fixed Assets.*** The capital spending in the Test Year, and other items closing to rate base in that year, result in an increase in rate base in 2009 of $1.7 million [Ex. 2/1/2, p.2], or about 11.9%. Of that, about $1.4 million is an increase in rate base related to fixed assets. Given the nature of the capital spending plan for 2009, that increase would appear to be reasonable.

3.2.2 The increase in rate base from 2006 actual to 2009 Test Year is 22.9% [Ex.2/1/2, Table 1]. We have reviewed the additions to fixed assets in the intervening years, and the evidence supports the Applicant's submissions that these additions were prudently incurred.

3.2.3 It is therefore submitted that the fixed asset component of 2009 rate base, being $11,713,250, should be accepted as filed.

3.2.4 ***Working Capital.*** We note the submissions of VECC with respect to the calculation of the cost of power component of working capital, and in particular the inappropriate use of the RPP without some adjustment. We also note the submission of Energy Probe in this regard. In our view, the cost of power component of working capital should be adjusted to ensure that it represents the estimated actual cost of power that will flow through the books of the Applicant during the Test Year.

3.2.5 We remain very concerned that this and other LDCs are using a 15% working capital

calculation in the face of evidence from other utilities (Toronto, Hydro One, Horizon) that the 15% level significantly overstates the actual working capital requirements of a distributor. However, we have made this submission in a number of rate cases, and the Board panels have consistently taken the view that, in the absence of more reliable information on working capital requirements, the Board's 15% guideline figure should be used. It now appears to be no longer feasible to argue for a lesser amount, since that would make the working capital of this utility inconsistent with the levels approved for many others.

3.2.6 The only solution, it would appear to us, is for the Board to have before it more reliable information on working capital requirements. We therefore ask that the Board order the Applicant to undertake a lead-lag study and file it with their next rebasing application.

3.2.7 ***Overall Rate Base.*** Subject to our comments above, it is submitted that the Board should accept the Applicant's rate base for the Test Year, as filed subject to any consequential updates required.

4 OPERATING EXPENSES

4.1 *2009 OM&A Budget*

4.1.1 ***Benchmarking.*** We note that the PEG Benchmarking Study lists COLLUS at an OM&A per customer of $225 in 2007, the last year for which there is data available. The average for the cohort for 2007 is $214, making COLLUS slightly above average in cost. This is consistent with the additional data provided by COLLUS in response to Board Staff IR#1.10, at page 19 of 71, using EDA numbers.

4.1.2 The proposed OM&A in this application would, by our calculations, increase OM&A per customer for COLLUS to $253 in 2009. Because we do not have forecast OM&A or customer counts for the other members of the same cohort, it is not possible to do a comparison. However, it is clear that COLLUS is proposing a 12.4% increase in OM&A per customer from 2007 to 2009. There does not appear to us to be sufficient justification for an increase of this size in the Application.

4.1.3 The benchmarking information is not probative in and of itself. As we know from the submissions of many LDCs, there are many variables in how OM&A is calculated, and how different LDCs account for the same activities, that affect the PEG data. That having been said, it is the best data available, and in our view the Board should expect from utilities that have above-average costs relative to similar LDCs a more stringent justification for further increases in excess of inflation.

4.1.4 In the case of this utility, we will below suggest some changes to the OM&A for the Test Year, which in the result would mean an increase in OM&A since 2007 of 7.33%, and an increase in the OM&A per customer of about 6% in the same two year period. This would appear to us to be a more reasonable level.

4.1.5 ***Personnel Costs.*** Of greatest concern is the proposed increase in the Wages and Benefits category of expenses, expected to increase over the period 2006 to 2009 by 34.7% [Ex. 4/2/3/Table 2]. In response to Board Staff #1.2 (b) and (c), the Applicant has provided a number of charts that show the reason for this large increase. In essence, the bulk of the change is an increase in FTEs from 17.9 in 2006 to 21.6 in 2009, an 18.4% increase. The balance of the change is average wage increases in excess of inflation for each of the three years.

4.1.6 With respect to the increase in FTEs, the Applicant notes [Board Staff IR #1.10, page 19 of 71] that COLLUS has for a long time been a leader in customers per employee. They do not provide original source data to support this, instead quoting a study that is not in evidence. We note that they do provide data to support a favourable distribution revenue per customer as well, but in that case they have also filed an excerpt from the source data that they used, so that the Board can understand the claim made. In the

case of customers per employee, no backup material was provided, and it is submitted that it is not possible for the Board to assess, on the information provided, whether there is any substance to the claim. Further, even if it is correct, lacking the context the Board is not in a position to assess how, if at all, the claimed leadership should be taken into account in reviewing the OM&A budget for 2009.

4.1.7 The FTE increase is stated [Ex. 4/2/3/ page 5] to be primarily driven by the addition of two new linepersons for "succession planning". No details are provided on the rationale for having two additional, and presumably excess, linepersons at a cost of $90,000 for the 2008 half year, and more than that for the Test Year.

4.1.8 The wage increases are said to average about 4% per year, but that would appear to be understated. Because the Applicant is adding new FTEs at the lower end of the pay scale, the average compensation per employee will be driven down by that change. Thus, the basic wage increases of the other nine union staff will be higher than the 16.7% from Schedule OEB IR#1.2(c)–2 [$61,250 in 2006 to $71,500 in 2009], probably something closer to 19%.

4.1.9 We also note that the impact of increasing personnel costs is further masked by an almost doubling of the amount of capitalized union labour from 2006 to 2009. If one looks at the total union labour bill from 2006 to 2009 in Schedule OEB IR#1.2(c)–2, the increase over three years is $371,765, or 51.6%. If the cost of the new 2.5 unionized FTEs is about $180,000 all in for the Test Year, the total increase in compensation for the 8.5 FTEs still in the budget since 2006 is more than $22,000 per person, a three year increase in compensation averaging more than 25%.

4.1.10 Finally, we note below the problems we have with the Shared Services approach of this LDC. Many of the employees actually work for an affiliate, and there is limited transparency between affiliate and LDC. For example, a total of 1/10 of one FTE has been added at the executive and management levels over the period. It is not clear why this would be required, but the additional cost is about $18,000 of additional allocation to the LDC. The same is true throughout the organization. Thus, wage increases, or increases in FTEs, are not traceable to a logical LDC need.

4.1.11 The increases in personnel costs are more difficult to justify in light of concurrent increases in costs for external contractors, a further $125,000 in those three years. With a larger staff, the Applicant nonetheless forecasts continued increases in reliance on outside contractors. This is not intuitive.

4.1.12 It is difficult to assess the best way to handle the personnel costs problem. Clearly the increases in personnel costs are excessive, and the Board should not approve an OM&A budget based on these increases, but there is insufficient evidence to calculate with precision what the appropriate amount for personnel costs should be using a bottom-up approach.

4.1.13 In our view the best approach the Board could take in this situation is to allow reasonable percentage increases in personnel costs from 2006 to the Test Year. If the personnel costs from 2006, $1,613,096 [Ex. 4/2/3 Table 2], are escalated by 6% per year, the personnel costs for 2009 would be $1,921,223, which is a 19.1% increase. However, capitalized labour has also increased by $117,000, meaning that overall the increase in compensation is actually higher. This should be more than sufficient to allow for reasonable wage increases, plus increased staffing if required.

4.1.14 It is therefore submitted that the Board should reduce the OM&A component of revenue requirement by $250,939 to reflect this adjustment to the Wages and Benefits component of the budget.

4.1.15 ***Regulatory Costs.*** We have reviewed the submissions of VECC and Energy Probe with respect to the regulatory costs budget, and agree with them that a decrease in OM&A of $20,000 is warranted to reflect a less expensive rebasing process than expected.

4.1.16 ***Shared Services.*** It is submitted that the evidence provided by the Applicant relative to Shared Services, even after being supplemented through interrogatories, is unsatisfactory.

4.1.17 The allocations of Shared Services costs for the Applicant for each of 2006 through 2009 are set out in Schedule OEB IR#1.9-1 (the "Breakdown Schedules"). They show that in 2006 the utility bore about 50.9% of the costs of COLLUS Solutions Corp. the service providing affiliate, but in each of 2007 through 2009 that percentage has increased to more than 58%. They also show that approximately 48% of the OM&A of this Applicant is in fact payments to affiliates.

4.1.18 The Breakdown Schedules do not provide sufficient information, in our view, for the Board to determine whether the costs incurred (out of which a percentage is being allocated to the regulated utility) are prudent and reasonable, nor to determine whether the allocation methodology is appropriate. It is the proverbial black box.

4.1.19 Further, the figures in the Breakdown Schedules do not appear to align with the figures in Schedule SEC IR#1(d)-1, the Financial Statements of COLLUS Solutions Inc. For example:

(a) In the Breakdown Schedules, the amount paid by COLLUS Power Corp. to

Solutions in 2007 totals $1,437,785, but in the Financial Statements the amount for 2007 [Note 3] is $1,045,937.

(b) In the Breakdown Schedules, the amount paid by COLLUS Power Corp. to Solutions in 2006 totals $1,360,632, but in the Financial Statements the amount for 2006 [Note 3] is $967,635.

(c) In the Breakdown Schedules, the total of all costs incurred by Solutions in 2007 is $2,463,498, but in the Financial Statements Solutions has total expenses of only $1,816,605.

(d) In the Breakdown Schedules, the total of all costs incurred by Solutions in 2006 is $2,672,862, but in the Financial Statements Solutions has total expenses of only $1,708,649.

4.1.20 We note that we are not in any way suggesting that anything untoward has caused these discrepancies. What is clear, however, is that on the evidence filed it is not possible for the Board to get a clear and comprehensible view of the shared costs, and how they have been allocated to the regulated utility.

4.1.21 It is therefore submitted that the Board should order the Applicant to file, with its next rebasing, a comprehensive analysis of the allocation of costs between the Applicant and its affiliates, to include detailed historical, bridge and test year costs of each affiliate, and details on the cost drivers used to allocate them within the corporate group.

4.2 ***Depreciation Expense***

4.2.1 We have reviewed the submissions of Energy Probe with respect to the calculation of amortization (depreciation) expense. We support those submissions, and the reduction of $49,847 in the depreciation expense in the Test Year that would flow from the corrections proposed.

4.3 ***Capital and Property Taxes***

No submissions.

5 COST OF CAPITAL INCLUDING PILS

5.1 *Long Term Debt*

5.1.1 We note that the Applicant has two components to their long term debt, a commercial demand loan with an arm's length third party for $1,100,000, and a promissory note due to an affiliate, payable on demand, with a stated interest rate of 7.25% and a principal amount of $1,700,000.

5.1.2 With respect to the commercial demand loan, COLLUS originally proposed a rate based on the five year Infrastructure Ontario rate, 5.08%, but has subsequently proposed to change to a much higher 25 year rate. In fact, in January the Infrastructure Ontario five year rate was significantly lower still.

5.1.3 On this rate, we have read the submissions of Energy Probe, and agree with them that, if the loan was obtained in January, it is the January five year rate that should apply. If it has not yet been obtained, it is the current five year rate that should be used. In either case, it would be significantly lower than the 5.08% originally proposed. There would appear to us to be no credible argument in favour of the last minute change by the Applicant to propose the higher 25 year rate.

5.1.4 With respect to the affiliate debt, we agree with Board Staff that under the Board's policy the callable affiliate debt should be at the Board's deemed rate, which is currently 6.10%.

5.1.5 We note the incongruity of the Board's deemed rate in this context. Market rates are clearly signalled by the government through the Infrastructure Ontario term rates, yet LDCs continue to be allowed to recover from ratepayers interest rates far in excess of market rates for affiliate long term debt. We believe that interest on affiliate debt that is in excess of market rates as shown in evidence before the Board should not be recoverable from ratepayers.

5.1.6 In this regard, it is submitted that the Applicant has provided evidence that it can borrow at levels that are much cheaper than the affiliate debt, likely 5% or less for five years. Since the affiliate debt is repayable by the utility at any time without notice or bonus [Schedule OEB IR#2.1-1], it is submitted that the utility should, if it is acting prudently, repay this $1.7 million promissory note forthwith and replace it with less expensive debt. This Board should allow in revenue requirement a weighted long term interest rate that reflects the assumption that management will act prudently to keep costs as low as possible. That long term interest rate, it is submitted, will be 5% or less.

5.2 ***Short Term Debt***

5.2.1 Prior to the final rate order, it is submitted that the short term debt rate should be recalculated using the new Board-approved rate for 2009, and all revenue requirement and rate calculations in the rate application should be adjusted accordingly

5.3 ***Return on Equity***

5.3.1 Prior to the final rate order, it is submitted that the return on equity should be recalculated using the new Board-approved rate for 2009, and PILs and all revenue requirement and rate calculations in the rate application should be adjusted accordingly**.**

5.4 ***Payments in Lieu of Taxes***

5.4.1 The Applicant appears to agree that it must update its PILs calculation to take account of corrected calculations, as set forth in Board Staff 5.1 and Energy Probe 19. We agree with the submissions of Board Staff and Energy Probe on this point.

5.4.2 We also agree that the Applicant must recalculated PILs to reflect

(a) Changes to taxable income resulting from changes to ROE, debt rates, OM&A, rate base, etc.

(b) Changes to the tax rates and rules flowing from the January 27, 2009 Federal Budget.

5.4.3 In the case of the budget-based changes, it is not clear to us that the taxable capital of the Applicant will exceed $15 million in the Test Year. It is not self-evident that the taxable capital will equal rate base in this case, and we think it likely that the amount will actually be somewhat lower. We therefore ask the Applicant, in their Reply Argument, to include an updated calculation of taxable capital for federal purposes so that eligibility for lower rates can be assessed by the Board. If the taxable capital is below $15 million, the PILs calculation should be recalculated as well.

5.4.4 We also note – contrary to the submissions of Energy Probe - that Ex 4/3/2, page 3 does contain, in the continuity schedule, net additions to CCA classes that may benefit from budget changes. We would therefore ask the Applicant, in their Reply Argument, to include a calculation of the impact of these changes on the PILs calculation, or provide an explanation as to why there is no impact.

6 REVENUE REQUIREMENT

6.1 *Revenue RequirementCalculation*

No submissions.

6.2 *Other Revenues*

6.2.1 The Applicant has, in its updated material, proposed to add $46,000 to Other Revenues representing interest on cash balances during the Test year. This is a reduction from their previous calculation of $68,856, flowing from decreases in deposit interest rates. We agree with the inclusion of this revised amount in Other Revenues.

7 REGULATORY ASSETS

7.1 *Disposition of Existing Deferral and Variance Accounts*

7.1.1 It is our understanding that the Applicant is not seeking to dispose of any deferral or variance accounts in this Application.

7.2 *New Deferral and Variance Accounts*

7.2.1 ***Large Customer Variance Account*** COLLUS has proposed a variance account to record loss of revenue if they lose their remaining large customer. We oppose that variance account, for two reasons:

(a) The 3rd Generation IRM structure includes an off-ramp and Z factors, and in addition any utility can at any time come to the Board on a cost of service basis instead of IRM. Thus, this variance account is not required.

(b) The proposed variance account would only cover lost revenues, and would thus assume that cost of service is unchanged. This is inappropriate. Utilities are compensated through their ROE to accept and manage normal business risks, including the loss of revenues through economic conditions or other factors. If the loss of this large customer would be so serious that it is not part of the normal business risks for the utility, it must have far-reaching impacts on the utility's operations. In those circumstances, the Board can only determine the resulting just and reasonable rates through a cost of service application.

7.2.2 Although it is not necessary for the purposes of the above rationale, we note that the Applicant believes its franchise area will buck the economic trends in other areas of the province, due to unique population and load growth conditions. If that is the case, then in the event of loss of a large user, the Board would have to take into account other load growth, to determine whether there is an offseting impact. Since this could only be done in the context of a cost of service proceeding, the proposed variance account would serve no useful purpose.

7.2.3 ***IFRS Expenses Deferral Account*** The Board has a proceeding underway to determine how IFRS will be handled, and included in that process is consideration of responsibility for IFRS transition costs, and the methodology for recovery of any part the Board determines should be paid by the ratepayers. In these circumstances, in our view the establishment of this account is premature. If the Board determines in the IFRS process that deferral accounts are the appropriate way to deal with these transition costs, the Applicant will have the benefit of that decision. If the Board determines otherwise, the Applicant should have the solution that applies to all.

7.2.4 ***Capital Spending Variance Account (Energy Probe)*** In their submissions, Energy Probe has proposed a variance account to record the revenue requirement impact if major capital spending is delayed beyond the end of the Test Year. While we understand that Energy Probe is proposing this in the context of exceptional circumstances, we disagree with that proposal.

7.2.5 In our submission, the forward test year methodology is based on the implicit assumption that the Board establishes a reasonable amount to be recovered in rates, and thereafter the utility is free to spend as it wishes. It can spend more or less, and it can reallocate between categories, as its operational needs unfold. It is not required to spend in the same manner as the budget on which the Board based its approved rates.

7.2.6 Clearly there is always the potential for a disjunct between the revenue requirement calculation, and what actually occurs. However, utilities are unlikely to depart markedly from the budget they put before the Board unless circumstances change. If spending is inconsistent with the budget, and there is no change, then the utility runs the risk of undermining its credibility, and having greater difficulty getting subsequent budgets approved. Therefore, we are not concerned that the Applicant will, for example, delay major capital projects in a crass attempt to improve ROE.

7.2.7 On the other hand, if there is a material change, and the appropriate response is to delay a major capital project, the utility will have to justify that response as prudent the next time they rebase. If there is a good justification, then in retrospect we <u>want</u> them to have delayed the project, and we <u>don't want</u> to incent them to go ahead regardless for fear of having to pay some revenues back to the ratepayers.

8 COST ALLOCATION AND RATE DESIGN

8.1 *Cost Allocation*

8.1.1 ***Transformer Allowance*** We agree with VECC that the Board's cost allocation model does not deal with the transformer allowance correctly. However, we do not agree with the alternative methodology they propose.

8.1.2 Under the VECC methodology, the cost of the transformer allowance is excluded from costs and from revenues in calculating revenue to cost ratios. This is an improvement over the Board's cost allocation, but it has the weakness that it will tend to exaggerate the extent to which the revenue to cost ratios of affected classes vary from 100%.

8.1.3 In our view, the better approach is to start with the presumption that the LDC delivers transformed power. For most customers, the LDC owns transformers to do that. For a few customers, the customers own the transformers, and the LDC pays them for the use of those transformers through the transformer allowance. It can be looked at as "rent" of the customer-owned equipment. Thus, it should be treated as a cost of transforming power for the class in which those customers are situated, and should be collected from the customers of that class. The result is similar to the VECC method, but the revenue to cost ratios will be calculated more accurately.

8.1.4 ***Distribution Revenue Responsibility*** VECC has proposed a recalculation of distribution revenue responsibility because, in their view, the numerical values of the charge determinants have changed materially from 2006, when the cost allocation study was done, to 2009. With respect, we do not believe that argument is valid.

8.1.5 It is indeed true that the numbers of KW, kwhrs, and customer counts have changed since 2006. However, the method that VECC proposes to "fix" that problem is circular. They propose to "assume that revenues at current rates are consistent with the revenue to cost ratios determined via the cost allocation informational filing". Yet, in fact they know that assumption to be false, for the same reason that there is a problem in the first place: the numerical values of the charge determinants have changed. This assumption would only be true if 2008 were identical to 2006, which we know is not the case.

8.1.6 In fact, what VECC is proposing is a shortcut, with no basis to believe that the shortcut is correct. If the charge determinants have changed so dramatically that the distribution revenue responsibility numbers are no longer fair, the only solution is to re-do the cost allocation study with updated costs and charge determi nant values.

8.1.7 We note that this issue is not like the transformer allowance. The transformer

allowance is a unique cost that has been treated incorrectly in the model, and there is a simple fix to the model that will treat it correctly. In the case of the distribution cost responsibility, there is nothing wrong with the model. The problem is that time has marched on, and the cost allocation run for 2006 is no longer 100% accurate with respect to the different numbers of KW, kwhrs, customers, and costs in 2009. VECC proposes to use an untested shortcut to update part of the problem, but totally ignoring the biggest part, the changes in costs.

8.1.8 In our submission, there is indeed a problem with using an outdated cost allocation study as circumstances change, but there is no simple solution to that problem. An adjustment to the charge determinants component of the calculation, even if it could be done correctly (and the VECC solution does not accomplish that), will deal with only part of the problem. Because the components are interconnected, there is no assurance that the partial correction will even get the result closer to a correct answer. It could just as easily take it further away.

8.1.9 Therefore, it is submitted that the distribution revenue responsibility percentages by class should not be "corrected" as proposed by VECC.

8.2 ***Revenue to Cost Ratios***

8.2.1 ***General Position.*** The School Energy Coalition believes that LDCs should be moving to revenue to cost ratios of 100% Although there are undoubtedly weaknesses in the current cost allocation information, it is the best available information, and in our view the Board should use that information to require utilities to move towards 100% for each class.

8.2.2 However, SEC has been unsuccessful in making that argument. In most LDCs, the general service classes that include schools have been well above 100%, and are thus overcontributing relative to other classes. Streetlighting, on the other hand, is always always a small fraction of the 100% norm. We have on numerous occasions sought to alleviate the overcontribution of schools by increasing classes such as streetlighting, and in every case the Board has been unwilling to move further than the edge of the range. In this respect, the summary of past Board decision by VECC is correct and instructive.

8.2.3 COLLUS is one of the rare cases in which the general service classes are undercontributing rather than overcontributing. In our view, consistent with the many other decision of the Board, the policy should be followed and uncontributing classes should be moved, stepwise, towards the bottom of the range. Otherwise, the perverse situation would be created in which the general service classes do not get rate relief in the franchise areas in which they are overcontributing, but they are force to give up the benefit of inter-class subsidies in franchise areas in which they are undercontributing. This would not be fair.

8.2.4 ***Calculation of Revenue to Cost Ratios.*** There are at least four calculations of revenue to cost ratios before the Board in this proceeding. In the Staff Submissions, at page 15, are the original revenue to cost ratios from the cost allocation informational filing [Ex. 8/1/2, page 4], and the revenue to cost ratios from the updated model, with the loss of a major customer reflected [Ex. 8/1/2, page 5]. VECC correctly points out that the updated revenue to cost ratios do not total 100%, and has proposed, at page 12 of their submissions, to gross each one up in the manner done by the Board in the EB-2007-0761 Decision with Reasons. The fourth set of revenue to cost ratios is with a revised approach to transformer allowance, as found in VECC's submissions at page 14 [VECC IR #33(c) adjusted upwards in the same manner as above].

8.2.5 As we have noted above, the VECC approach to the transformer allowance is good, but it is not the most optimal, and we have suggested a more appropriate correction.

8.2.6 We do, however, agree that VECC's proposed gross-up method, which has previously been approved by the Board, is correct. Although it grosses up the percentage figures rather than the dollar figures, our modeling indicates that in every case it produces the correct answer in the dollar figures as well.

8.2.7 Therefore, subject to the small correction to the transformer allowance calculation we have proposed, we believe the beginning revenue to cost ratios are those found in the VECC submissions, at page 14.

8.2.8 ***Adjustments to Revenue to Cost Ratios.*** On the basis of the recalculated revenue to cost ratios, it appears that Residential is the only class outside of the range on the high side, at 124.4% compared to the top of the range of 115%. On the low side, Streetlighting is the furthest, at 17.5% compared to the bottom of the range of 70%. GS>50 is at 36.4% and Large User is at 59.3%, in each case compared with a bottom of the range of 80%. GS<50 and USL are within the range and, under the Board's standard approach, they should not be adjusted.

8.2.9 The Board's standard approach is to bring those below the range to the bottom of the range in either two or three steps. If each of GS>50, Large User and Streetlighting were to move halfway to the bottom of the range, we calculate that would increase their collective revenues by $404,951, and result in distribution rate increases in some cases in excess of 100%. If that amount is then re-allocated to the Residential class, since they are out of the range on the high side, their revenue to cost ratio would be reduced to 105.1%, almost exactly the same as GS<50, the only other overcontributing class.

8.2.10 In our view, this movement in one year is too drastic, particularly in difficult economic times where the classes most detrimentally impacted would be those with all of the business customers. That is in no-one's interests. Therefore, we propose that the

Board order each of GS>50, Large User, and Streetlighting to move one-third of the way to the bottom of the range, with the remaining movement to get to that stage being implemented in two equal steps in 2010 and 2011. If this proposal is adopted, , we calculate that $269,967 of revenues will be added to those classes in 2009, and Residential would be reduced accordingly. The resulting revenue to cost ratio for Residential in 2009 would be 112.9%, comfortably within the upper limit of the range.

8.2.11 We note that the Applicant has proposed that Streetlighting be moved stepwise to the 70% bottom of their range, while GS>50 be moved immediately to 80%. We find it incongruous and inappropriate that the class that contains the shareholder would face a limited increase, while the class that contains most of the major employers in the area, and most of the public buildings including schools, would be hit with a large jump without any transition. No evidence in support of this unusual result was given, and we agree with VECC that GS>50 should be moved in steps, not all at once.

8.2.12 We therefore propose that for 2009, and subject to the adjustments discussed earlier, the revenue to cost ratios be as follows:

Residential	112.9%
GS<50	105.3%
GS>50	50.9%
Large User	66.2%
Street Lighting	35.0%
USL	89.3%

8.2.13 We further propose that the Board order that GS>50 move to 65.5% in 2010 and 80% in 2011, that Large User move to 73.1% in 2010 and 80% in 2011, and that Streetlighting move to 52.5% in 2010 and 70% in 2011. We agree with VECC that the revenue shift in 2010 and 2011 should be re-allocated to Residential until its revenue to cost ratio is the same as GS<50, and thereafter it should be reallocated pro rata to those two over-contributing classes.

8.3 ***Fixed/Variable Splits***

No submissions.

8.4 ***Retail Transmission Service Rates***

No submissions.

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.

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