EB-2008-0230

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 Greater Sudbury 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, 2009.

FINAL ARGUMENT
ON BEHALF OF THE
SCHOOL ENERGY COALITION

September 11, 2009

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1 GENERAL COMMENTS

1.1 *Introduction*

1.1.1 On December 22, 2008 Greater Sudbury Hydro Inc. filed an application for new distribution rates commencing May 1, 2009. The application identifies a deficiency of $2,645,783, and seeks approval for rates to recover a base revenue requirement of $28,818,357. It also seeks adjustments to revenue to cost ratios and harmonization of rates over two years between its Sudbury and West Nippissing rate areas. This represents an overall increase of about 10.1%, exclusive of the proposed increase in the smart meter rate adder.

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 September 10, 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 a draft of the submissions of the Vulnerable Energy Consumers' Coalition relating to the load forecast, and have noted our agreement or disagreement with their positions under that heading.

2 LOAD FORECASTING AND METHODOLOGY

2.1 *Methodology and Resulting Basic Load Forecast*

2.1.1 The Applicant has used a load forecasting methodology that has been used by many other Ontario LDCs for the 2009 test year, and has been accepted by the Board in a number of them. However, it does not appear to have been applied in accordance with its own underlying rules, or consistent with normal principles of statistical analysis. Mr. Bacon acknowledged that the science of electricity distribution load forecasting in Ontario is "evolving" [Tr2:142], but he was unable to come up with a clear or convincing explanation as to why the model was not used properly in this case.

2.1.2 VECC, in their final argument, have provided a thorough and careful summary of the Applicant's methodology, and the problems with it. While we ultimately do not agree 100% with their recommended course of action for the Board (we have a similar result, but different approach), we adopt their analysis of the problem subject to these additional comments.

2.1.3 The main problem that concerns us here is the negative GDP coefficient. Under the methodology employed by this Applicant and many other utilities, the model can produce the result that as GDP increases, load drops, and vice versa. Mr. Bacon noted that this happened this year in two cases, Sudbury and Lakeland [Tr2:138]. In all other cases, when the model is specified for the particular utility, that coefficient is positive.

2.1.4 It does appear to be counterintuitive that in a time of increasing GDP, load would go down. While the Applicant tried to give a real world explanation for why that relationship might actually be true [in Sudbury, people stay home more and use more electricity in an economic downturn – Tr2:139], that explanation is not even close to being convincing, and the Applicant admits that they have no data or research of any sort to back that up.

2.1.5 The real explanation for this may be that the models were developed during a period in which GDP was rising rapidly, so a model that showed load going down in those circumstances would benefit the utilities. It was also plausible, because of natural CDM and other impacts that could explain the unusual trend. It is only when the economy softens, and the falling GDP produces a higher load forecast, that the true extent of the anomaly becomes obvious.

2.1.6 It is surprising to us that, given this impact, the Applicant still continued to rely on what would appear to us to be a model of questionable value. But, they did, and if that was the end of the matter, we might shake our heads but leave it alone.

2.1.7 The problem was compounded, however, by a decision of the Applicant not to use up to date data in developing the actual load forecast for this rate application. As Board Staff have described this well in their Final Argument at pp.3-5, we will not reiterate it here. It is sufficient to say that the Applicant knew it had outdated data, and despite interrogatories asking for updated information [Staff #12, and Staff Supplemental #2] the Applicant, while giving the new results, continued to stick with its prior load forecast.

2.1.8 This question was the subject of a patient cross-examination by Mr. Buonaguro [Tr2:133-143], under the theme "*You like the model, but when the model works to increase the load forecast, it doesn't make sense [so] you're not applying the model*" [Tr8:136]. Mr. Bacon went back and forth with Mr. Buonaguro, but the nub of his explanation is that there were a number of problems with the result, yet since they appeared to balance each other out, no adjustments were made to get the load forecast right [Tr2:141]. In other words, they didn't try to be rigorous. They just let it go.

2.1.9 Subject to the CDM adjustment, discussed below, Staff appear to have concluded that, while there are obvious problems here, the resulting load forecast is intuitively fairly accurate, so it should be allowed to stand. That is, in our view, a legitimate and reasonable position, but we do not believe it is the optimum response of the Board in this case.

2.1.10 The load forecast forms the guts of any cost of service rate application, and the deficiency is driven directly from those values. The Applicant at all times had the onus to present a proper load forecast which the Board could use as a basis for calculating just and reasonable rates.

2.1.11 It would be one thing if this doubtful load forecast had been filed, but once the problems were raised the Applicant responded with the appropriate adjustments, so that the final forecast the Board had before it was solid evidence. In this case, the Applicant instead resisted the correction of obvious flaws, and even as late as its Argument in Chief is still arguing that its forecast is sound. It is not. The evidence is clear on that point.

2.1.12 In the face of this, we believe that the Board should not accede to the wishes of the Applicant that the Board accept a load forecast that it knows is not supportable. If the Board does so, it is lowering the standard for evidence, and other LDCs will see that as a signal that rigour in key aspects of their applications is no longer required. In our view, the methodology proferred and vigorously defended by the Applicant, and accepted by the Board in many other cases, should be applied properly and the Applicant should live with the results.

2.1.13 In Staff #12, use of proper historical information produced a 1.8% greater load forecast, and in Staff Supplementary #2 use of even more up to date information results in a 2.9% higher load forecast.

2.1.14 In our submission, the historical data in Staff #12 are those that should have been included in the load forecast in the first place. It is at least arguable that the more recent data in Staff Supplementary #2 are after the fact. We therefore recommend that the Board adopt a base load forecast (before CDM adjustment) of the numbers set out in Staff #12, totaling 991.0 Gwh vs. 973.5 Gwh as filed, and totaling 1,055.4 MW vs. 1038.2 MW as filed.

2.1.15 We note that, in addition to the adjustments we have proposed above, there is a further and offsetting adjustment that the Applicant has admitted is an error, relating to a mistake in the application of heating and cooling degree days. This is set out in detail in Staff #9, and would reduce weather sensitive load by 0.4%. We believe that this adjustment should also be made.

2.2 ***CDM Adjustments***

2.2.1 The Applicant proposes to reduce the load forecast by 4.045 Gwh to reflect the impact of CDM in the test year that is not included in the historical data**.** There are two components to this. First, how much of the test year CDM impact is already in the historical data? Second, is the CDM impact calculated appropriately?

2.2.2 We believe that the adjustment proposed by VECC to deal with these problems – reducing the CDM adjustment from 4.045 Gwh to 1.557 Gwh – is the appropriate response, for the reasons they have set out in their submissions.

2.3 ***Future Applications***

2.3.1 It is clear from the evidence in this proceeding that the model being used by this LDC, and many others, needs a thorough review to ensure that it properly reflects the correlation between the general economy and electricity use. In our view, the Applicant should be directed that, when they next come in for rebasing, they must demonstrate that the model they are using for their load forecast – whether an update of this one, or something else – is more robust.

2.4 ***Total Loss Factor***

No submissions.

3 RATE BASE AND CAPITAL SPENDING

3.1 *Introduction*

3.1.1 The Applicant is seeking approval of a capital budget of $10,868,524, all of which is proposed to close to rate base in the test year. In subsequent evidence, and confirmed at p. 6 of their Argument in Chief, the Applicant has reduced that amount to $10,549,192. The Applicant "acknowledges that this represents a sizeable increase over historical capital spending" [AIC, p.6].

3.1.2 In this area of the Application, there are several fundamental problems:

(a) The capital budget requested was net of $959,585 of contributions. The gross amount was $11,828,109 [J1.6]. The new budget figure of $10,549,192, is not net of contributions [J1.5].

(b) The capital spending program for which Board approval was originally sought is approximately $1.8 million higher than the capital spending this Applicant plans, and has approval from its own Board of Directors, to incur in the test year.

(c) The Applicant includes in opening rate base projects that were not used and useful at the end of 2008.

(d) The Applicant includes in closing rate base projects that are not expected to be used and useful at the end of the test year.

(e) The Applicant's primary justification for a significant increase in capital spending in the test year is underinvestment in plant renewal in past years, apparently due to prioritizing interest payments to the shareholder instead of needed capital spending on their system.

(f) The capital spending plan is predicated on their expectation of imminent reliability issues if plant renewal is not increased, but the data appears to suggest that SQIs in this area are improving.

(g) The $2.1 million of planned spending on a new CIS is not allocated between the affiliates who are expected to benefit from it.

3.1.3 We propose to deal with the first five of the above issues in turn, below. The last issue is considered as part of the discussion of Shared Services (Water Billing) later in this Final Argument**.**

3.2 *Capital Spending Expected in 2009*

3.2.1 ***What is the Applicant's Proposal?*** The Applicant has told this Board that it plans to spend $10,868,524 in capital expenditures in the test year. This amount is net of contributions of $959, 585 [J1.6].

3.2.2 In J1.5, the Applicant has now, after the end of the hearing, proposed a new capital budget, $10,540,192, but does not disclose in that budget, or deduct from the total, the amount of the contributions. It is clear from the presentation in J1.5 that the new budget is a $1,278,917 reduction from the budget as filed ($11,828,109 less $10,549,192), but the net budget requested is not set out. Further, the Argument in Chief, at page 6, appears to treat the $10,868,524 original request (which is net of contributions) as if it is comparable to $10,549,192 (which is before contributions are deducted). This is not correct, and the implication that they are proposing a capex reduction of $319,332 is misleading.

3.2.3 However, if we review J1.6, we see that the contributions are all in the "N" category of projects, and each of those projects is continued in the new budget in J1.5 (although some with different project costs). In the Board of Directors approved budget in J1.6, the contributions for those projects total $940,098. The new projects, listed in J1.5 near the bottom (without numbering) do not appear to be of the nature that would normally have contributions. We would ask that the Applicant, in their Reply Submissions.

(a) Confirm that none of the new projects include contributions, or, if they do, the amount of those contributions, and

(b) Advise if the contributions expected for any of the Board of Directors approved projects have changed in this new budget.

3.2.4 Assuming that there are no adjustments to contributions as a result of the questions above, it would appear to us that the capital budget currently being requested by the Applicant is now $9,609,094, being the gross budget of $10,549,192 less contributions of $940,098.

3.2.5 ***Board of Directors Approval.*** In SEC IR Response Appendix 9 (c), the Applicant reveals that in fact its planned capital spending for the test year, as approved by their own Board of Directors, and also net of contributions, is actually $9,068,549. In response to an undertaking requested by SEC [J1.6], the Applicant has provided a side-by-side comparison of their OEB Application and Board of Directors approved budgets, so that the Board can easily see where there are differences.

3.2.6 We note that the witnesses for the Applicant were very clear that the capital budget that their Board of Directors has approved is a "fixed envelope" [Tr1:45], and management has no discretion to spend beyond that without going back to their Board for a further approval. They have not done so.

3.2.7 A side by side comparison of the "new" $9,609,094 capital budget, compared to the Board of Directors approved budget of $9,068,549, reveals that there are a number of projects in the new budget that have not been approved by the Applicant's Board of Directors, and some of the approved projects are currently expected to be over budget. In the former category are the following projects that do not appear in the budget Approved by the Board of Directors:

AM/FM GIS Software Carryover	$160,610
Barrydowne 44 kV Reconductor Carryover	$150,000
Vehicle Carryover	$208,888
Building Carryover	$149,913
Substation Security Carryover	$4,985
Major Repairs to Substation Carryover	$11,691
Webbwood Drive	$50,000
Tilton Lake Road	$47,818
Gary Street Carryover	$305,801
Web Page Design	$21,658
TOTAL	$1,111,364

3.2.8 The "new" budget also includes the following projects that have material over budget conditions relative to the Board of Directors approval, a total of $1,316,693 over the budget amounts approved by the Board of Directors:

Project	*Approved*	*Expected Cost*
N6 System Betterment	$434,150	$938,020
A1 28M6 Montague to Whissell	$235,797	$525,000
A4 Sparks Street restricted conductor rebuild	$204,169	$365,000
Southlane Road	$174,814	$275,000
Pole Replacement 9M1 to 9M6	$187,826	$450,409
TOTAL	$1,236,756	$2,553,429

3.2.9 Three projects that were included in the OEB budget but not approved by the Applicant's Board of Directors have been removed from the "new" budget. In each case, the Applicant did not expect the projects to be used and useful by year end:

Bell Park OH to UG conversion	$62,011
Hillsdale Lakeview Rebuild	$610,298
44 kV tie between 28M4 and 9M4	$725,000
TOTAL	$1,397,309

3.2.10 Two Board of Directors approved projects that are not expected to be completed by the end of the year have been removed from the "new budget":

Shaughnessy OH to UG conversion	$237,614
Enterprise Resource Planning Software	$540,000
TOTAL	$777,614

3.2.11 It appears that the reason for much of this confusion is twofold:

(a) The Applicant filed a capital spending budget with this Board that included spending that, on their own admission, they did not expect to complete in the test year [Tr1:64], apparently because they believed that they could include capital spending right up until April 30, 2010; and

(b) The Applicant "moved projects forward" from 2010 and 2011 [Tr1:27] because this is their rebasing year and this is their opportunity to get approval for spending [Tr1:28-29], something they referred to as "levelizing" their spending.

3.2.12 We want to be clear that we are in no way suggesting that the Applicant intentionally tried to file false evidence, or mislead the Board. It appears to us, in fact, that the Applicant and their management, new to this process, believed that this is the way the "regulatory game" is supposed to be played.

3.2.13 ***What to Do?*** The difficulty the Board faces is that it now has a brand new budget, with many material changes from the original one, and neither of the budgets presented to the Board reflect what the company's management actually has approval to do this year.

3.2.14 Normally, this Board considers both the overall amount of an applicant's capital program, and, particularly when it departs markedly from past spending, the composition of that program. That program is subject to interrogatories and other discovery, and then tested in a hearing context.

3.2.15 Here the Board has a budget that bears very little resemblance to the one we have spent so much time talking about, and it has not been the subject of a discovery process or a hearing. It is untested evidence, provided after the oral hearing has been completed.

3.2.16 Of course, the Board could order that the Applicant answer written questions on this new budget, and/or come back for a further day of oral hearing. However, given the late date for this Application, and the time the process has taken, a further delay is to be avoided if possible.

3.2.17 In any case, even if this new budget undergoes the normal review process, there will still remain the disjunct between what the Applicant's management is actually authorized to spend by its Board of Directors, and what it is asking this Board to assume they will spend this year.

3.2.18 It is submitted that the Applicant cannot seek approval for a capital budget that has not been approved by their Board of Directors. Their clear evidence is that they have a "fixed envelope" from their Board of Directors of $9,068,949, and they are not allowed to spend more than that without a change to that approval. In our submission, then, subject to our further comments below, the maximum capital spending budget that this Board should approve in this Application is $9,068,949.

3.2.19 Once a maximum is determined, there is still a question of whether some lesser amount should be treated as their "real" capital budget for the year. It would appear to us that this Board could approach this question two possible ways:

(a) Assume that the Board of Directors approval is a completely discretionary envelope, and therefore the maximum of $9,068,949 should not be adjusted to reflect the components of the approval. This proceeds on the basis that management is free, with no restrictions, to make any changes they want to their capital budget, without consulting their Board of Directors, as long as the total is not exceeded.

(b) Assume that, while <u>within</u> certain categories management would have freedom to reprioritize (road work or pole replacements, for example), funding for major projects could not be unilaterally redirected by management to other priorities without Board of Directors approval. In this case, a major project not proceeded with this year would be treated as a reduction in the budget approved by the Board of Directors.

3.2.20 Our reading of the evidence before the Board in this proceeding has not disclosed a clear answer as to which of these two assumptions is correct. It was clear to us that management reprioritizes spending throughout the year without formal revisions to the budget, but the examples of this given by the Applicant were all items in which reprioritization was from one business-as-usual project to another. It was also clear from the evidence that the Board of Directors does a line by line review of the budget [Tr2:77]**.** That would imply that it is approved subject to its contents, and major changes to the composition of the program would require revised approvals.

3.2.21 Based on the evidence, we cannot discern whether (a) or (b) above is the correct assumption.

3.2.22 However, there is a further complication to this. The Board of Directors approval of $9,068, 949 included two projects, totaling $777,614, that will not be completed in calendar 2009. These are the Shaughnessy project, and ERP. The evidence is that the Applicant is still proceeding with these projects, but they have been removed from the budget before this Board because they will not be used and useful in 2009.

3.2.23 If it were reasonable to expect that these two projects are not going to go ahead, then it is at least arguable that the same budget amount remains available to management for other priorities. This resolves to the question in para. 3.2.19 above.

3.2.24 But if, as the evidence clearly indicates, these projects are proceeding as planned, then there is no room in the Board of Directors approved budget for additional work to replace them. The Board of Directors approved a budget that was $8,290,925 of spending expected to be used and useful in 2009, and $777,614 of spending not expected to be used and useful until 2010. Since those two projects are still proceeding, the Board of Directors approval is unchanged in that respect, and there is still only room in the approved budget for $8,290,925 of spending in addition to those projects.

3.2.25 In our submission, this result is inescapable, and as a result the capital spending that this Board should approve, to be added to rate base in 2009, should not exceed the amount approved by the Applicant's Board of Directors, $8,290,925.

3.2.26 We note that, with this conclusion, the issue raised in para. 3.2.19 above becomes largely moot. As long as changes to the budget for an approved project are treated as approved spending, the Board does not have to determine whether the $1,111,364 of new projects not yet approved by the Board of Directors are OK because of re-allocations from other planned projects. The current approval requested by the Applicant of this Board, $9,609,094, is $1,318,169 higher than the budget of $8,290,925 approved by the Applicant's Board of Directors, so there is no room in the Board of Directors approved budget for any of those projects anyway.

3.2.27 We also note that this conclusion renders the procedural issue in para. 3.2.15 and 3.2.16 moot. The new budget proposed by the Applicant does not need to go through a further procedural review, because the maximum that could reasonably be approved is made up mostly of projects that have already been reviewed.

3.2.28 ***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 outlined below, should be $8,290,925.

3.3 ***Used and Useful***

3.3.1 ***General Issue.*** The Applicant follows a policy of closing capital spending to rate base at the end of each year, even if projects are not completed and/or the capital asset in question is not used and useful as of the year end [Tr1:52]. This is, of course, contrary to the Board's policies and to standard regulatory accounting principles.

3.3.2 Two adjustments have to be made in this situation. First, amounts closed to rate base in 2008 that were not used and useful should be reversed, so that opening rate base for 2009 is reduced. Second, amounts proposed to be closed to rate base in 2009 that are not expected to be used and useful should be left as capital work in process, and closed to rate base in a subsequent year.

3.3.3 ***Opening Rate Base.*** Undertaking J1.2 shows capital spending in 2008 of $293,906 booked to rate base in 2008 but not used and useful at that time.

3.3.4 In our submission, that entry should be reversed for the purpose of calculating 2009 opening rate base. We note that the 2008 depreciation expense should also be reduced, which would reduce the accumulated depreciation in the 2009 opening rate base calculation. Assuming those expenditures are used and useful in 2009, they should be closed to rate base this, year, and the depreciation, cost of capital, and PILs calculations should be adjusted accordingly.

3.3.5 It is not clear to us, but we wonder if this $293,906 has been included in the revised capital budget set out in J1.5. If it has been, then in our view it should be backed out and closed to rate base as an incremental addition, since the capex are from a previous year. This would not change the capital budget we have recommended, since it is driven by the Board of Directors approval, not the revised budget, but it would have the effect of increasing rate base a further $293,906 less depreciation in 2009.

3.3.6 ***Closing Rate Base.*** The Applicant has listed in J1.3 $2,162,992 in 2009 capital projects that are not expected to close to rate base in this calendar year. These are the projects listed in para. 3.2.9 and 3.2.10 above. The first group were not in the Board of Directors approved budget, and so have been backed out of the current proposed budget in J1.5, and of course they are not in the capital budget we have proposed approving either (since they were not Board of Directors approved). The second group were in the Board of Directors approved budget, and will be proceeded with, but will not close to rate base this year. They are not in the J1.5 budget, or in the capital spending figure we have proposed in para. 3.2.28 above.

3.3.7 Therefore, with respect to the five projects listed in J1.3, no further adjustments are required, as they have already been backed out of both the J1.5 capital budget now proposed by the Applicant to this Board, and the net capital budget that we have proposed above, being the Board of Directors approved budget less projects in it that will not be used and useful this year.

3.3.8 There is one item in the Board of Directors approved capital budget that still remains in this category, a purchase of land at a cost of $200,000 for MS14 station. This item was included in the OEB Application at $400,000, and has been put back into the J1.5 budget at $200,000, the Board of Directors approved amount. The Applicant has admitted that this acquisition may not be completed by year end, and even if it is, the land will not be used and useful until next year some time [Tr1:41]. Therefore, it is submitted that this must be a further reduction to the capital expenditures that are closed to rate base in 2009.

3.3.9 In the result, we are proposing that this Board approve capital spending to close to rate base this year of $8,090,925, plus a further 2009 addition to rate base related to the $293,906 reduction in opening rate base described above. (A further reduction is proposed in our section on Shared Services, later in this Final Argument, relating to the SAP project.)

3.4 *Infrastructure Deficit Issue*

3.4.1 ***"Slow, steady rot".*** Much of the Applicant's evidence about capital spending is about their "infrastructure deficit" [e.g. Tr1:23], an ongoing shortfall in capital spending on plant renewal over many years that is finally catching up with them. Plant renewal in the past has been "significantly underfunded" [Tr1:45], witnesses said multiple times and in different ways. Mr. McMillan called it a "slow, steady rot" of the distribution system [Tr1:83], and was adamant that spending has to be ramped up to deal with this.

3.4.2 To this end, the Applicant filed a Capital Asset Management Plan, with an independent review of their planned spending. This is not the first capital plan they have had. They also had one from 2001 to 2005, but there are a number of projects in that plan that still have not been done [Tr1:25]. The impression that was left is that over the last ten years capital spending has been constrained by available funds.

3.4.3 We also note that the Applicant disclosed, in the oral hearing, the reason for the Capital Asset Management Plan: it was this rate case. This is not how capital asset management is normally done at Greater Sudbury Hydro. The spectre of a rate case caused them to implement a more rigorous review.

3.4.4 The other thing we note is that the independent review was not a broad look at the deficiencies of the Sudbury system. Rather, it was a check on whether the capital plan authored by Mr. McMillan was "on the right track" [Tr1:26]. Further, it did not offer an opinion on the timing of projects [Tr1:29-30], so it is not possible to discern any confirmation of urgency from METSCO.

3.4.5 This background raises two questions. First, is there really a serious infrastructure deficit that has to be addressed? Second, if there is, who should be responsible for the catchup?

3.4.6 ***Service Quality Indicators.*** The first step in assessing whether a distribution system is in trouble is to look at certain service quality indicators, of which in our view SAIFI is the one that will most quickly show growing breakdowns. As a system falls into disrepair, the first thing that happens is that reliability incidents start to happen more often. That is what SAIFI measures.

3.4.7 The evidence is that this Applicant's three main reliability indices show better than the North American average [Staff 37(c) and Tr1:88]. Even the draft METSCO report [TC Undertaking #4, at page 14], includes a chart that shows a declining trend for Sudbury's SAIFI. (In a rather strange logic, this is used by METSCO to justify increased O&M spending on maintenance.)

3.4.8 Asked to explain these facts that are apparently inconsistent with the Applicant's evidence, Mr. McMillan had no data or information contrary [Tr1:90-1]. He was going on his gut feel as a professional engineer, that a problem was just around the corner with this system.

3.4.9 Faced with a lack of hard evidence of any problem, in our submission it would be difficult for the Board to approve a large jump in capital spending for this Applicant based on allegations of past underspending and poor system condition that are not supported by the evidence before the Board.

3.4.10 ***Shareholder Responsibility***. Where a utility knowingly underinvests year after year in plant renewal, and then comes to the Board and asks for more money to play catch up, the Board from time to time in the past has said that the shareholder of the utility has to bear some of the cost. For example, in the Toronto Hydro 2008 rate case, the Board said that the ratepayers are entitled to expect that the utility will invest needed capital each year, regardless of whether it is a cost of service or IRM year, or otherwise. In the end, only part of the proposed increase in capital spending was allowed.

3.4.11 In our view, this should be especially true where the shareholder finances the utility with a high ratio of debt, and management treats the interest payments on that debt (which is really a tax efficient way of structuring equity) as if they were the top priority payments, rather than dividends out of earnings.

3.4.12 Therefore, in our submission if the Board finds that there is a material infrastructure deficit in this utility, the responsibility for correcting it should be shared between the ratepayers and the shareholder, who by the Applicant's direct admission should have invested more over the past decade,.

3.4.13 ***Recommended Resolution.*** We have in para. 3.3.9 above proposed a capital spending budget closing to rate base in 2009 of $8,090,925, less adjustments for shared services. If the $1,525,000 spending in 2009 on the SAP billing program is taken out of that, the resulting budget for distribution system spending is $6,565,925. This is still an ample budget relative to that proposed in the Capital Asset Management Plan, and reviewed by METSCO. It is, in fact, fairly close to the budget that was originally in the capital plan, before the Applicant moved projects from 2010 and 2011, where they were scheduled in the plan, to 2009, the rate year [Tr1:27].

3.4.14 In our view, the capital budget that the Applicant's Board of Directors has approved, subject to some adjustments, and we have proposed, provides for a modest increase in plant renewal spending in the test year, but still along the general trend from previous spending levels. Due respect can be given to the professional instincts of Mr. McMillan, and some additional renewal can be funded, without the Board having to agree to a major budget increase with no hard evidence of need. Further, because the increase is manageable, the need to assess whether the shareholder should bear some of that cost is reduced.

3.5 ***Working Capital Allowance***

3.5.1 This utility uses the Board-standard 15% calculation for working capital. We have expressed our general concerns about this calculation elsewhere, and we will not reiterate them here.

3.5.2 This is a case, though, in which we believe the characteristics of the Applicant make a lead/lag study particularly appropriate. First, the Applicant has a complex set of affiliate relationships which mean that its flow of cash will not be comparable to most other utilities. Second, the Applicant will be required in the next year or two to carry out a transfer pricing study, and there is some overlap in the investigations (and perhaps the investigators) between the two studies. There may be some economies of scale thus available. Third, the impact of working capital on revenue requirement is substantial, and the dollar amounts are high.

3.5.3 For these reasons, we believe the Board should direct the Applicant to carry out a lead/lag study, and file it with their next rebasing application.

4 OPERATING EXPENSES

4.1 *Introduction*

4.1.1 There are four aspects to the operating budget that need to be addressed.

4.1.2 First, it is clear that the operating budget that has been presented to this Board is neither what the company plans to spend in 2009, nor what has been approved for spending in 2009. However, unlike the situation with the capital program, in which the Applicant in J1.5 has filed a revised budget trying to correct this problem (but also adding in new projects to bump the total back up as much as possible), in the case of OM&A the Applicant has filed a revised budget that discloses they spent $4.9 million on OM&A in the first six months of the year, and now plan to spend a further $6.8 million in the second six months in order to reach the original budget total of $11.7 million. The Board of Directors approved amount is $10.5 million.

4.1.3 Second, there are a number of specific expenditure items that appear to be unusually high, or include activities that are not appropriately charged to ratepayers.

4.1.4 Third, the Applicant has a complicated corporate structure, with charges going back and forth between affiliates, all of which has been the subject of several years of concern from the Compliance Office. It appears clear that action has to be taken to address the transfer pricing issues, and in the meantime the cost to the ratepayers of some services appears to be too high.

4.1.5 Fourth, the Applicant does not follow the Board's rules with respect to depreciation expense, with the result that revenue requirement is overstated by $405,558 [J1.4].

4.1.6 The balance of this section of our Final Argument will deal with each of these in turn. In considering Shared Services, this section will also cover the related capital costs issue, since the analysis is the same.

4.2 *2009 OM&A Budget*

4.2.1 ***Board of Directors Approval.*** The Applicant has calculated its revenue requirement based on an OM&A budget of $11,874,566 [Ex. 7/1/1, p. 2]. In fact, the Applicant's Board of Directors has only approved a budget for 2009 of $10,474,643 [SEC App. 9(e)], a difference of $1,399,923. Both of those figures include an amount of $187,236 for CDM which is offset by a revenue item of the same amount. The figures net of that amount (i.e. OM&A chargeable to ratepayers) would be $11,687,330 and $10,287,407, but the difference is, of course, the same.

4.2.2 As of June 30, 2009, the Applicant had spent $4,921,185 on OM&A [J1.10], which is

42.1% of the OEB requested budget, and 47.8% of the Board of Directors approved budget.

4.2.3 The Applicant has provide a breakdown of spending to June 30th, plus a forecast to December 31st (which is unchanged from the Application) [J1.10], and a side by side comparison of the Board of Directors approved budget with the OEB requested budget [J1.11]. We have combined and simplified those numbers in the following table:

Spending Category	*Six Month*	*OEB Budget*	*BofD approved*
General and Administrative	$1,208,040	$2,754,722	$2,528,456
Corporate Costs	$147,129	$428,581	$369,524
Billing and Collecting	$1,152,465	$2,769,547	$2,492,526
Distribution Expense – Operations	$1,800,589	$3,822,807	$3,346,050
Distribution Expense - Maintenance	$612,962	$1,916,669	$1,563,397
TOTALS	$4,921,185	$11,692,326	$10,299,953

4.2.4 We note that neither of these figures matches the previously cited ones exactly, but we have not identified the precise variances in the time available, and they are relatively small ($5,000 and $12,000 respectively).

4.2.5 ***Maximum Approval.*** It is our submission that, as a starting point, the Applicant should not be given an OM&A budget for rate purposes that exceeds what their Board of Directors says they are allowed to spend. This is in part a simple matter of principle. The Board has on many past occasions made clear that it expects management to get its internal approvals for spending before making its "pitch" to the Board. It is also a matter of logic. Absent an internal approval to spend the budget requested from the Board, the additional revenue simply drops to the bottom line, increasing the profit and thus ROE.

4.2.6 It is therefore our submission that, before looking at the components of the OM&A budget, it is appropriate for the Board to determine that the maximum OM&A budget that will be approved will be the budget approved by the Applicant's Board of Directions, which was $10,474,643, including the CDM budget.

4.2.7 ***Budget Components***. We also would like to point out that the line item differences between the Board of Directors approved budget and the OEB requested budget are, in many cases, the very same issues that have already arisen, at the level of prudency and reasonableness, in this proceeding. We have prepared the following summary of some of the major variances from J1.11:

Expense Category	*OEB Excess over BofD*	*Comments*
Legal/Consultants – IFRS Provisioning	$50,000	Should be deferral account
Increases in personnel complement	$400,459	Total of many items included in OEB budget but not in BofD budget
SAP/WIPRO Maintenance Fees	$125,596	Two amounts, will not be paid until 2010
Leases and Rentals (GSHPI)	$110,000	Unknown. Possibly 24/7 control room.
Legal/Cons. BLG re rate application	$65,000	Discussed below
Redistribution from Capital	$77,148	May self-adjust if capital budget is adjusted to match BofD approved
PCB Contamination Costs	$178,000	Total of three amounts
Contract Labour OH Tree Trimming	$213,696	$510,696 in OEB Budget vs. $297,000 approved by BofD
TOTAL	$1,219,899	

4.2.8 While the above summary does not capture all of the variances between the two budgets, it does show that most of the difference is reflected in major variances of which at least $900,000 would be items in dispute in this proceeding in any case. This appears to suggest that the Applicant's Board of Directors took a more prudent approach to budgeting than management did, and their approved budget is to be preferred over the budget management has requested from the OEB.

4.2.9 ***Benchmarking.*** We also note that the Board can get a perspective on the Applicant's OM&A costs by the PEG Benchmarking data, which was discussed with the witnesses during the oral hearing [Tr1:132]. The data, confirmed by the witnesses, shows that the OM&A cost per customer for GSHI was, and in the Application would be forecast to be:

2006	$204.13
2007	$215.75
2008	$218.97
2009	$252.07

4.2.10 We note the obvious anomaly in the proposed 2009 figure, a 15.1% increase from the prior year. In the 2006 through 2008 figures, we see a utility that is at or slightly below the average for its peer group. In 2009, we see a change.

4.2.11 On the other hand, if the same calculation is done using the Board of Directors approved budget, which is the budget under which management has operated in previous years, the result is $222.41 per customer, a 1.6% increase over the prior year, a 9.0% increase over the three years from 2006, and still at or slightly below the expected average for the peer group.

4.2.12 In our view, this somewhat unexpected use of the benchmarking data, to indicate that the Board of Directors of the Applicant was pretty close to getting the budget right, but the Application is not consistent with those results, should be given some weight in the Board's consideration.

4.2.13 ***Rationale/Timing***. In fact, the evidence appears clear that the management of the Applicant planned their Board of Directors approved budget on the basis of three assumptions: that this Board would not approve everything they asked for in rates, that rates would be effective July 1, 2009 because of their late-filed Application, and that their spending in calendar 2009 would be limited to the revenues actually received in calendar 2009. Thus, it was a budget of what they actually plan to spend in 2009.

4.2.14 The difficulty, it appears, is that they thought that what they presented to this Board did not have to be what they actually plan to spend in calendar 2009. The Applicant appears to have been under the impression that it could present to this Board a "normalized" budget, which would be the amount they would spend if the budget were announced prior to the year commencing, the new revenues were in place January 1, 2009, and they are allowed to do everything on their wish list (with a cushion in some cases). It was like a labour negotiation, in which you ask for everything you could possibly get, and settle for something less.

4.2.15 This is, of course, incorrect, and in some senses our comments here are thus critical of GSHI's management. On the other hand, as we have noted elsewhere in this Final Argument, this utility is one of a number that are new to the regulatory process, and many of the problems in this Application appear to be problems of understanding the utility's responsibilities to this Board and to its customers via the regulatory process.

4.2.16 What does surprise us is that, as the process unfolded, it became quite clear that the OM&A budget was not prepared in compliance with the Filing Guidelines (because it was not the real calendar 2009 budget), and was not consistent with standard regulatory practice before this Board. When that became obvious, the Applicant (albeit after the oral hearing was complete) at least made an attempt at revising the capital budget [in J1.5] to try to be compliant with the Board's practices. While it still fell short, as we have noted earlier, they did try.

4.2.17 However, given the opportunity to do the same thing for the OM&A budget, their response in J1.10 was to suggest that they plan (and are capable of) spending almost 40% more ($6.8 million vs. $4.9 million) in the second half of the year than the first half of the year. It is hard to maintain your credibility when you ask the Board to accept propositions like that. Instead, it taints the entire application with the attitude of "if you don't ask, you don't get".

4.2.18 In our submission the evidence is clear. The Applicant did not put to the Board an OM&A budget of what they actually plan to spend in 2009, but the Board does have that budget before it, because it is the budget that was presented to the Board of Directors. In our view the Board's proper course of action is to use the Board of

Directors approved budget as the starting point for the OM&A component of the test year revenue requirement, subject to the small number of adjustments we propose below.

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

4.3.1 ***Personnel Costs.*** Much was made in this proceeding, through interrogatories and in the oral hearings, of the Applicant's plans to ramp up their headcount and FTEs for succession planning, regulatory compliance, and other purposes. This has led to an increase in overall compensation of about 20% over three years [Staff #27 and Tr1:69], and there is in total an 11% increase in the number of personnel planned for the test year [Tr1:70].

4.3.2 This led to a number of discussions about the number of people, and much confusion about whether data is being presented as headcount or FTEs [Tr1:162-3, Tr:47-8, and a number of other places].

4.3.3 We also found out that a number of the people charts include some "people" that are really vacancies [Tr2:53], but are included in the 2009 OEB Budget. In J2.5, these vacancies are shown to total 5 positions, although that undertaking also suggests that all of those vacancies can be filled by year end. What it does not show is how much of the annual cost of those individuals will actually be incurred in 2009.

4.3.4 The Board's ability to sift through this human resources information is limited by the confusions in the data and the large amounts of conflicting information.

4.3.5 However, in our submission this is one of the cases in which the Board of Directors of the Applicant can be of assistance to this Board. As noted in para. 4.2.7 above, the variances between the OEB requested budget and the Board of Directors approved budget, as set out in J1.11, include about $400,000 representing personnel costs that have been requested from this Board but not approved by the Board of Directors. This would appear to us to be roughly the amount by which the human resources costs are too high in this Application, reflecting total numbers of people, vacancies, and overall cost levels.

4.3.6 It is therefore submitted that if the Board accepts our recommendation to use the Board of Directors approved budget as the OM&A starting point, no further adjustment is required.

4.3.7 ***Regulatory Costs.*** The Applicant has, in J2.8, set out a "levelized" breakdown of regulatory costs for the period 2009 through 2012. While we could comment on many of the line items, we will not, except to agree with the comments of Board Staff in their Final Argument, at p.19.

4.3.8 We do believe one adjustment is appropriate in this case. The Board of Directors approved budget did not include any amount for legal fees for the cost of service hearing this year. That was, presumably, an oversight. We would normally expect the cost to a utility like this of their legal representation in a contested oral hearing to be around $120,000, so we believe it is appropriate to add $30,000 to the OM&A budget approved by the Board of Directors, to reflect recovery of this cost over the four year IRM period.

4.3.9 ***Tree Trimming.*** The tree trimming budget has two aspects of concern.

4.3.10 First, the Applicant has gone from a seven year cycle to a four year cycle. There is no useful evidence supporting that change except the oral evidence of a witness that aggressive local tree planting in the 90s is now producing mature trees that cause problems on the lines. No support for this has been given.

4.3.11 Second, the City requires the utility to "shape" trees when they are being trimmed, for aesthetic reasons. While the evidence was unclear on this, there is certainly some additional cost associated with this aspect of the work. We agree with Staff at p.19 of their Final Argument that this is not an appropriate cost for ratepayers, but the evidence does not give the Board information on the differential.

4.3.12 In this, as with other parts of the OM&A budget, if the Board accepts our recommendation to use the Board of Directors approved budget, this is resolved. The Board of Directors approved $213,696 less for tree trimming than is included in the OEB application. That appears to us to be a suitable adjustment for the concerns expressed above.

4.3.13 ***Audit Expenses.*** This utility appears to have about $242,000 in its budget for audit and audit related activities, including $100,000 for the audit by three accounting firms, $50,000 for IFRS work, $50,000 for special audit work, and $42,000 paid to GSHPI for management fees that appears to be at least to some extent for audit and tax services. For a utility this size, these amounts are more than one would expect.

4.3.14 As noted earlier, the $50,000 for IFRS is not in the Board of Directors approved budget, and in any case should be charged to a deferral account.

4.3.15 Staff has proposed, at p. 19 of their Final Argument, that the $100,000 normal audit budget be reduced by two-thirds to reflect the lack of need for three audit firms. While we agree in principle, we think that a two-thirds reduction is too much. The evidence [TC Tr. 79-80] is that this is a legacy situation, in which one firm actually does the audit, and the other two do a more limited review of the first auditor's work. In our view, a more appropriate reduction would be 50%. The resulting audit fee of $50,000 is in line, in our experience, with audit fees for LDCs in Ontario of this size.

4.3.16 ***24/7 Control Room.*** The Applicant has given evidence that the control room was put on a 24/7 cycle, at an annual incremental cost of about $100,000, in order to pursue non-distribution revenue opportunities, and until the end of 2008 that incremental cost was borne by the unregulated affiliate. When that business venture was not successful, the incremental cost was moved to the regulated utility starting in 2009 [Tr2:34-5].

4.3.17 In our submission, the incremental cost of a 24/7 control room for this utility has not been justified, and the only evidence before this Board on this point makes clear that the purpose of the expenditure was to make unregulated profits. The utility should not be able to shift the incremental annual cost of a failed unregulated business to the ratepayers.

4.3.18 ***ERP Maintenance.*** The evidence of the Applicant is that the annual costs for maintenance of the new billing system ($65,000 for SAP and about $65,000 for WIPRO, as set out in J1.11) will not be incurred until calendar 2010 [cite]. In our submission, they should not be included in the OM&A budget for this year.

4.3.19 As these amounts are not in the Board of Directors approved budget, no adjustment for this is required if the Board accepts our submission that the Board of Directors approved budget is the starting point for approval by the OEB.

4.4 ***Shared Services***

4.4.1 ***Structure.*** The Applicant operates using the Serviceco model, in which most (in this case, all) of the employees running the distribution business actually act for an unregulated affiliate, GSHPI. In fact, in the Argument in Chief the Applicant makes clear that the Applicant and GSHPI are run as one entity. One has to ask how this protects the ratepayers, but that is the practical reality given how this Applicant uses this business structure.

4.4.2 It appears that the costs of GSHPI are ultimately borne by the various affiliates, including the Applicant and the City, on the basis of a particular cost allocation approach. That approach, established in 2000 and essentially unchanged since then [Tr2:87], allocates costs to the unregulated activities, largely based on management judgment [Tr2:59]. Whatever is left over after the charges to everyone else is paid by the Applicant [Tr2:83].

4.4.3 No analysis has been done to determine the proper cost allocation between the various users of these shared services.

4.4.4 In 2006, after an investigation and detailed discussions with the Applicant, the Board's Chief Compliance Officer advised the utility that it was in violation of the Affiliate Relationships Code on numerous counts. Some of those have now been resolved, but a key one, the need for a transfer pricing study, continues to be delayed. We discuss this question below.

4.4.5 ***Water Billing.*** Of particular concern in this regard is water billing. The total cost of billing and collection is about $3.6 million, of which the City, for whom the utility does water billing on their behalf (through GSHPI), pays only $729,000 [VECC #34]. This represents a fixed fee set in 2004, adjusted only for CPI and for increases in meter reading charges. The number of water bills and electric bills are approximately equal. Most bills are shared, but about 17,000 water-only bills and 17,000 electricity-only bills are also handled.

4.4.6 In addition to the issue of whether the current division of costs is reasonable and fair, the Applicant is implementing a new CIS, which will be used for both electricity and water billing. The Applicant has proposed that the utility bear 100% of the $2.1 million capital cost, and 100% of the $100,000 per year incremental operating cost [Tr2:31], on the basis that the cause of the new system is electric, not water, billing. They admit that the water billing side will benefit from it as well.

4.4.7 When faced with the decision of this Board in EB-2008-0246 [K2.1], in which the same issue was resolved by dividing the cost in the same manner as the operating costs, the Applicant in J2.7 has estimated that the portion of the CIS capital cost that would be allocated to the City on that basis would be $420,000, but continues to argue that is not a reasonable result.

4.4.8 There was extensive discussion of water billing in the oral hearing, and a number of the undertakings deal with related issues. It seems clear that a transfer pricing study is required to get these numbers right. Therefore, rather than discuss the water billing issue separately in detail, we propose to address the process for having a transfer pricing study done, and the interim treatment of water billing until that is completed and considered by the Board.

4.4.9 ***Transfer Pricing Study.*** The Applicant has had extensive transfer pricing in place since 2000, with no analysis of the correct formula or cost drivers. In 2006 the Board's Chief Compliance Officer pointed out this problem, and directed the utility to carry out such a study. Had the utility done what the Chief Compliance Officer directed at the time, this Board would today have evidence which, once tested, could form the basis for approving a budget that includes a lot of shared services.

4.4.10 The company's excuses for not complying include, initially, the fact that they disagreed with some of the other issues raised by the Chief Compliance Officer, and thereafter that the EDA was pursuing a motion for changes to ARC, and thereafter that the Board had a consultation on various aspects of ARC, and now the utility is awaiting clarification from the Board on certain interpretations of ARC. None of this, by the way, has anything to do with transfer pricing.

4.4.11 Now, the Applicant accepts that it has to do a transfer pricing study [Tr1:160], but wants this Board to wait another four years before it is considered for implementation in rates.

4.4.12 In our view, onus and responsibility have to count for something. This Applicant has the onus to show that their revenue requirement is appropriate, and they have known for some years that they would need a transfer pricing study, fully completed, by the time they had a cost of service proceeding before this Board. If the fact situation didn't make it clear, the Board's own Chief Compliance Office told them this very clearly.

4.4.13 All the way through this, all the Applicant has done on this front is delay, delay, delay. Now it is proposing a further delay. In our view, this is unacceptable, and the Applicant should be ordered to carry out a proper transfer pricing study forthwith.

4.4.14 ***Scope.*** The Board has asked for input on, among other things, the scope of the transfer pricing study. In our view, it should not be necessary for the Board to provide the Applicant with a detailed roadmap of how to do a transfer pricing study. If they retain experienced consultants, that should not be an issue.

4.4.15 Therefore, our comments on scope are limited to the following:

(a) The study should include all affiliates of the Applicant that provide services to, or receive services from, the Applicant or GSHPI, or whose operations affect the cost of the Applicant.

(b) The study should be carried out in accordance with industry standards, and should reflect the requirements of this Board as set out in numerous proceedings dealing with transfer pricing, notably those relating to Enbridge Gas Distribution's transfer pricing and corporate cost allocations issues.

(c) The utility should be encouraged, but not required, to work with stakeholders to develop and implement the study, much as Enbridge has done so successfully in their CIS, open bill and other consultative processes, and as Enwin is now doing today.

4.4.16 ***Cost.*** The Applicant has suggested that the cost of such a study is substantial, and has proposed that the cost be borne by the ratepayers. In our view, that is not appropriate. This study should have been done either in 2000, when the shareholder would have had to bear the cost, or in 2006 on the direction of the Chief Compliance Officer, when the shareholder would have also had to bear the cost. It is not reasonable to delay a necessary expenditure until a cost of service year, and then claim that the ratepayers have to pay for it.

4.4.17 In this regard, we note that management did proceed with the Hay study on management compensation, with resulting raises for management personnel [Tr2:40-1], during the same period, and was quite happy to have that come out of profits in a non cost of service year, rather than wait a couple of years until there was a cost of service year, and the cost could be included in a rate increase.

4.4.18 ***Interim Transfer Pricing Solution.*** Assuming that a transfer pricing study is required and ordered, the next question is how water billing services, at least, should be treated in the meantime. In our view, this interim solution should have two goals. First, it should ensure that the Applicant can no longer benefit from any further delay in this process. Second, it should ensure that the Board is able to review the study in a timely manner.

4.4.19 To that end, we propose that the Board establish a Transfer Pricing Variance Account, in which the Applicant should record the difference between

(a) the amounts that are included in revenue requirement for payments back and forth with affiliates and the City, and

(b) the amounts that, pursuant to the transfer pricing study, should have been included in revenue requirement each year relating to those same payments..

4.4.20 The purpose of this variance account is to ensure that, starting in 2010, the actual amount the ratepayers will ultimately pay in rates will reflect proper transfer pricing. The alternative is for the Board to leave the new rates that result from this Application as interim, until transfer pricing is finally resolved (for example in a mini-hearing), or to allow the Applicant to continue to benefit from any further delay.

4.4.21 Of course, in the event that a variance account is established, the Board must still determine the appropriate amount to include in rates in the meantime. The Applicant has proposed to retain the status quo.

4.4.22 There appear to us to be three options for setting the interim allocation of billing costs:

(a) Review the evidence and determine the likeliest appropriate allocation. In our view, there is insufficient evidence to do this, which is why a transfer pricing study is so necessary.

(b) Leave the status quo, and adjust later.

(c) Split all billing and collection costs 50/50 between electric and water, and adjust later.

4.4.23 In our submission, (a) above is impractical.

4.4.24 Our concern with (b) is this. The transfer pricing study will be done under the supervision of the Applicant, and will at some point be reviewed by this Board. There is a reasonable likelihood that the final cost allocation will be different from the transfer pricing study. If (b) is selected, it would appear to us that legally the Board can only order payment to the ratepayers of the lesser of the result in the transfer pricing study, or the result the Board determines is appropriate. This is because to do otherwise, assuming the Applicant's rates are final, would be retroactive ratemaking.

4.4.25 An example may help to explain this. Assume that the current split of costs, $2.9 million electric and $0.7 million water, is included in rates today. For 2010, the consultant doing the transfer pricing study says the split should be $2.7 million electric, and $0.9 million water. The Applicant credits the difference, $200,000, to the variance account. The Board reviews the study, and concludes that the appropriate allocation is $2.3 million electric, and $1.3 million water. The ratepayers are notionally entitled to a 2010 refund of $600,000, but the variance account only has $200,000 in it. The Board cannot order payment to the ratepayers of more than this amount, because that is all that is in the account. Anything more has to come from the Applicant, and to so order would be to engage in retroactive ratemaking.

4.4.26 For this reason, we believe that the appropriate solution is (c) above. The amount of $3.6 for billing and collections should be split $1.8. million to electric, and $1.8 million to water, and the capital and ongoing costs for the new CIS in the same way. When the transfer pricing study is completed, if the consultant thinks more should have been charged to electric, the utility can charge that to the variance account, and seek clearance through an application to this Board when the study can be reviewed.

4.4.27 We note that, with this starting point, and using the same numbers as above, retroactive ratemaking is not a problem. The initial amount charged to the variance account is $900,000, for which the utility seeks clearance. Upon review, the Board reduces that to $500,000, which is recovered from the ratepayers.

4.4.28 An additional benefit of the approach in (c) above is that the Applicant's timing of the transfer pricing study and the review by the Board can be left more to their discretion. Since the interim allocation is less favourable to the City, there will be pressure to complete and review the study as quickly as possible, and the delays we have seen in the past are less likely.

4.5 ***Depreciation Expense.***

4.5.1 The Applicant has calculated amortization of capital assets on the assumption that all capital assets are placed in service on January 1st of each year [Tr1:55-6]. This is contrary to the Board's standard practices.

4.5.2 In J1.4, the Applicant has calculated the difference between their depreciation approach for new assets, and the correct approach, at $405,558. However, if the capital spending program is reduced in this Board's decision, this adjustment will also be incorrect.

4.5.3 In our submission, the Applicant's depreciation expense should be reduced by an amount that is the difference between their depreciation methodology, and the Board-approved half year rule..

4.6 ***Capital and Property Taxes***

No submissions.

5 COST OF CAPITAL INCLUDING PILS

5.1 *Long Term Debt*

5.1.1 The Applicant has proposed a weighted average long term debt rate of 7.01%, comprised of

(a) a 7.26% promissory note of $48.6 million owing to an affiliate, which they propose to be treated as embedded debt at 7.25%; and

(b) a 6.10% term loan from the TD Bank which has not yet been borrowed.

5.1.2 The evidence is clear [Tr1:81] that the Applicant can borrow on a high ratio from the TD bank at commercial rates. The rate of 6.10% is the current estimated rate the Applicant thinks it would have to pay.

5.1.3 This raises the question, noted in the Board Staff Final Argument, whether if the company is able to borrow at less than 7.25%, it wouldn't be prudent management to do so. If that were the case, by implication paying interest at 7.25% is not prudent, and therefore not recoverable from ratepayers, if it is possible to get similar financing at a lower rate.

5.1.4 We have sympathy for the direction being taken on this point by Board Staff, and we do believe that utility management should be under an obligation to seek market financing if they can do so at a cheaper rate than affiliate debt. However, in this case we do not believe that principle can be applied to the Applicant.

5.1.5 In this case, the evidence the Board has before it is that the Applicant can raise all of its needed financing from a commercial bank, at much lower rates, "with the appropriate guarantees from the city" [Tr2:157]. While we believe that this Applicant might well be able to get some or all of its needed debt financing without such a guarantee, especially if it reduces its debt ratio from the current 80% [Tr1:80] to the Board's approved capital structure, we do not believe there is evidence before the Board on which the Board could reach that conclusion. Further, there is no evidence before the Board to show that, if such a guarantee was required, the overall cost of long term debt would be less than 7.01% when any guarantee and transaction fees are included.

5.1.6 Therefore, it is submitted that the long term debt rate of 7.01% should be accepted by the Board for this test year.

5.1.7 We also believe that the Board should direct the Applicant to seek alternate debt financing arrangements at market rates in time for its next rebasing, and bring that evidence forward at that time along with its new proposed cost of debt, having taken that information into account. This analysis should be done in conjunction with the analysis we are proposing relating to capital structure in para. 5.5.4 below.

5.2 ***Short Term Debt***

No submissions.

5.3 ***Return on Equity***

No submissions.

5.4 ***Capital Structure***

5.4.1 ***Debt Ratio***. We are concerned that this utility has financed its operations using 80% debt**.** This has three obvious impacts, the first two of which are well known to the Board, and the third of which may be somewhat novel.

5.4.2 First, the high debt ratio of utilities like this Applicant means that the utility collects funds for PILs from ratepayers that do not have to actually be paid out for that purpose. We have discussed this below, and calculated the impact on rates of $1,298,564 per annum. This represents about 4.5% of revenue requirement.

5.4.3 Second, a high debt ratio means that the cost of capital may be higher than would otherwise be the case, or the availability of additional capital as required for the business could be restricted. By way of example, if this Applicant did not have to replace $48.6 million of 7.25% affiliate debt with lower rate commercial debt, but $30.5 million, the healthier debt ratio may well mean that the company can get financing on commercial terms without the guarantee of the city. That would reduce the cost of capital charged to ratepayers by about $350,000 in 2009.

5.4.4 Third, this utility does not treat the return it pays the City on the promissory note as a type of quasi-equity, as you would expect. In fact, the former CEO was adamant that the interest payable on the affiliate debt is just like interest payable to the bank, and it has to be paid before any spending, whether on OM&A, capital, or anything else, can be considered [Tr1:78]. This is in stark contrast to utilities that have a normal equity component. For those LDCs, their shareholder may well be fairly insistent on their dividends, but those dividends can only be paid if the utility has a profit out of which to pay them. If there are urgent spending needs within the utility, and those needs use up the profit, dividends have to be suspended, as many LDCs have done.

5.4.5 We noted earlier that this utility has systematically underinvested in plant renewal over the last decade, by their own admission. While we understand the sometimes unfair pressures put on LDCs during the rate freeze, most utilities responded by cutting dividends to shareholders. On the evidence before the Board in this case, the only reasonable inference is that this utility deferred capital spending rather than reduce its payments to the City.

5.4.6 To deal with the above concerns, we propose, in para. 5.5.4 below, a review of the Applicant's capital structure, including its costs, benefits, risks, and other implications, at the time of this utility's next rebasing.

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

5.5.1 As noted above, the high debt ratio means that the PILs calculation in this Application is overstated. We believe the amount of the overstatement is the grossed-up tax amount on the $18 million of debt that is treated as if it is equity for rate purposes. [See 7/1/1, p. 2, equity of $33,571,879 at 43.3% ratio equates to $15,506,639 at 20% ratio. The difference – equity for rate purposes and debt in the real world – is $18,065,240.] The grossed-up tax on that differential appears to be about $1,298,564 [See 7/1/1. p. 2, pretax income of $4,899.552 reduced to $2,263,073, plus adjustments of $1,229,061 is taxable income of $3,492,134, and net tax of $1,152,404, for a tax difference of $870.038. Grossed up for equivalent rates, that tax difference is $1,298,564].

5.5.2 We are concerned that overleveraging by this utility appears to result in a windfall profit to the shareholder of $870,038, and excess rates to the ratepayers of $1,298,564. Given that overleveraging does not appear to be in the best interests of the utility, at least in this case, we believe that this is inappropriate.

5.5.3 That having been said, the Board has not in the past stepped in to prevent LDCs from overleveraging to get tax benefits. It would therefore not really be fair to this utility, which has structured its affairs to comply with the Board's standard practice, if its excess rates were disallowed.

5.5.4 Therefore, we propose that this Board direct the utility to present evidence, at the time of its next rebasing, either showing that its capital structure complies with the Board's standard ratios, or justifying a departure from those ratios in the interests of the utility, and proposing a reasonable sharing of the resulting costs and benefits with the ratepayers. That analysis should include full evidence of the impact of the overleveraging on the interest rate and capital availability of the utility, and the impact on taxes payable, and should take those factors into account when proposing fair rate treatment.

6 REVENUE REQUIREMENT

6.1 ***Revenue Requirement Calculation***

No additional submissions.

6.2 ***Other Revenues***

6.2.1 Board Staff in their Final Argument at pp. 5-6 have suggested that certain components of Other Revenues have been underforecast for the test year. If those submissions were accepted, the result appears to us to be an increase in the Other Revenues amount of about $220,000.

6.2.2 For the reasons set out by Board Staff, we believe that these adjustments are appropriate.

7 REGULATORY ASSETS

7.1 *Disposition of Existing Deferral and Variance Accounts*

7.1.1 The Applicant has a net credit of about $3.1 million of regulatory assets and liabilities, i.e a net amount owing to its ratepayers. They have proposed that the accounts not be disposed of at this time.

7.1.2 Board Staff, in their Final Argument, have noted at pp. 28-31 that this is a substantial balance owing to the ratepayers, and action to start to clear it is probably a good idea. We agree.

7.1.3 In looking at the amounts, Board Staff propose to clear all totals excluding smart meters and CDM. In general, we agree, with one caveat. We have not been able to identify evidence supporting the $282,798 in accounts 1570 and 1571. We would invite the Applicant in their Reply submission to point the Board to that evidence. If it is not on the record, then in our view these accounts should not yet be cleared, but the rest should.

7.1.4 Board Staff has also done a thorough review of the three options for clearance. We agree with their proposal that the second option – a uniform rate rider for all Sudbury customers over two years – is the most appropriate.

7.2 *New Deferral and Variance Accounts*

7.2.1 ***Capital Interest Deferral Account.*** The Applicant has proposed a new deferral account, the Capital Interest Deferral Account, to record interest costs associated with capital spending. We believe that this category of expenditure is already dealt with in the Board's comprehensive policies relating to AFUDC and related rules, and there are deferral and variance accounts already available where that treatment is appropriate. We are unable to see any circumstances in which this proposed account would provide any further protection to the utility that is both material, and appropriate in an IRM environment.

7.2.2 ***Transfer Pricing Variance Account.*** We have proposed, in our submissions earlier relating to Shared Services, that the Applicant establish a new variance account, the Transfer Pricing Variance Account, to record variances between the amounts that it is paying to its affiliates for services, and the amounts ordered by this Board in this proceeding for recovery from ratepayers. Our submissions in support of this new account, which responds to the Board panel's request for proposals on how to deal with the proposed transfer pricing study, are set out earlier.

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, and that the approach taken by the Applicant in Ex. 9/1/1, allocating the transformer allowance solely to GS>50 customers, is appropriate.

8.1.2 Further, we submit that the response to VECC #23(c), which makes a further correction to the calculations for the purpose of proper allocation of revenue responsibility to classes, improves on the Applicant's original calculations, and thus should be preferred as the starting point by the Board..

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. We continue to urge the Board at every opportunity to move to the next step in the LDC cost allocation review, so that data accuracy can be increased and the endemic built-in subsidies, usually of residential customers by general service customers, can be reduced and ultimately removed over time.

8.2.2 ***Adjustments to Revenue to Cost Ratios.*** Subject to our general policy concern, we agree that the proposed revenue to cost ratios summarized by Board Staff on page 22 of their Final Argument [column 2 of Table 1] are appropriate for the Test Year.

8.3 *Fixed/Variable Splits*

8.3.1 ***Impact of Harmonization.*** The fixed charges proposed by the Applicant appear to comply, with one exception, with the policies set out by the Board. Where the Applicant has discretion under those policies, we might question whether they have exercised that discretion appropriately, but the Board has consistently allowed utilities leeway in setting these amounts.

8.3.2 The one exception in this case is the fixed charge for GS>50. For Sudbury customers, the fixed charge started at $178.96 per month [Ex. 9/1/9/A, p. 4], while the minimum system with PLCC (i.e. the cap in the range) is $78.87 per month [Ex.8/1/2, App.A]. Under the Board's current practice, and if there were nothing more to it, the utility is not obligated to bring the fixed charge within range.

8.3.3 The problem lies in the fact that the current fixed charge for WNES customers in this rate class is $30.34 [Ex.9/1/9/A, p. 9]. The Board's policy is that, while fixed charges that are already outside the range do not have to be brought into the range immediately, utilities should not move fixed charges from inside the range to outside of it. The Applicant proposes to increase the WNES fixed charge to a level outside of the range as part of harmonization.

8.3.4 In our submission, this should not be allowed. Instead, it is submitted that the preferred result would be for the fixed charge for all of the Applicant's GS>50 customers, in both the Sudbury and WNES rate areas, to be set at $78.87, the top of the range. While this would still be a substantial jump for WNES, it would comply with the policy, while still achieving the overall goal of rate harmonization.

9 OTHER MATTERS

9.1 *Effective Date of Rate Adjustment*

9.1.1 It is our submission that any rate increase that results from this Application should be effective from September 1, 2009, reflecting the fact that the Applicant was four months late in filing their Application.

9.1.2 For simplicity, we suggest that rates, which would likely not be able to be implemented until November or December, 2009, be set at the rates that would otherwise have been allowed had the Application been filed and approved, with the changes determined by the Board, in a timely manner. Then, the difference in rates by class should be multiplied by the actual billing determinants for each of September, October, and November (if applicable) to determine the revenue shortfall. Those amounts by class, once calculated, should be collected from ratepayers through volumetric rate riders commencing January 1, 2010.

9.1.3 However, if the Board accepts the submissions we have put forth with respect to revenue requirement, the result is likely to be a sufficiency for the test year. Where there is a delay within the control of the Applicant, and as a result a rate reduction cannot be implemented in a timely manner, it would be unfair to the ratepayers to penalize them for the tardiness of the Applicant. It is therefore submitted that any rate decrease that results from this Application should be effective from May 1, 2009, the date it would have been implemented had the Applicant filed in a timely manner.

9.1.4 In this situation, a rate rider calculated in the same manner as set forth in para. 9.1.2 above should be applied, covering the months from May until the date new rates can be implemented.

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.

All of which is respectfully submitted.

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Counsel for the School Energy Coalition