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BY RESS and EMAIL

June 15, 2011
Our File No. 20100131

Ontario Energy Board
2300 Yonge Street
27th Floor
Toronto, Ontario
M4P 1E4

Attn: Kirsten Walli, Board Secretary

Dear Ms. Walli:

Re: EB-2010-0131 – Horizon 2011 Rates

We are counsel for the School Energy Coalition. Pursuant to the Board's letter of June 10th in this proceeding, we are enclosing a redacted version of the SEC final argument.

The redactions in the attached document have been prepared by Horizon at our request, as the confidential nature of the information is theirs and they should have the right to claim protection of that information. Horizon has, quite correctly in our submission, not redacted all references to confidential documents or in camera transcripts, but only those references that in their view actually contain material that should be treated as confidential. The Board will be aware that most of any confidential document or in camera transcript is made up of public information, and Horizon has taken the approach, with which we fully agree, that where information is otherwise public it should not be treated as confidential because it is also in confidential materials.

Notwithstanding our agreement with their approach, the filing of this document should not be taken as SEC's agreement that the specific redactions proposed by Horizon are correct. The Board will be aware that, at the time SEC filed its confidential final argument and provided a copy to Horizon for confidentiality review, SEC expressed the view that no redactions were required. Horizon has in fact proposed a number of redactions.

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The Board will, we assume, wish to assess whether it agrees with all of those redactions, as they will affect the extent to which the Board can refer to the SEC final argument in the public version of the Board's Decision with Reasons in this matter. However, we do not believe it would be productive, or helpful to the Board, for SEC to engage at this stage of the process in a debate over what parts of our final argument should be treated as confidential. If the Board feels otherwise, and would like our input before making its determination, we would certainly provide submissions, but we are not doing so at this time.

All of which is respectfully submitted.

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Yours very truly,
JAY SHEPHERD P. C.

Jay Shepherd

cc: Wayne McNally, SEC (email)
James Sidlofsky, BLG (email)
Maureen Helt, OEB (email)
Interested parties (email)

EB-2010-0131

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

~~UN~~REDACTED ~~CONFIDENTIAL~~ FINAL ARGUMENT ON BEHALF OF THE SCHOOL ENERGY COALITION

May 6 , 2011

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0. GENERAL COMMENTS

0.1 *Introduction*

0.1.1 On August 26, 2010 Horizon Utilities Corporation filed an Application for new distribution rates, effective January 1, 2011. The process included interrogatories, submissions, and a decision on the threshold issue, then further interrogatories, a technical conference, an unsuccessful ADR, an application update and questions on that, then an oral hearing.

0.1.2 The Application sought a rate increase to recover a deficiency of $19,560,006. After a significant number of changes during the course of the process, the revised deficiency is $20,721.655, and the rate increase thus requested is 25.3%. It is, by any standards, a very large increase, and particularly so in two cities that have been hard hit by the economic downturn.

0.1.3 This is the Final Argument of the School Energy Coalition.

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

0.1.5 As there is no Board-approved Issues List for this proceeding, we have organized our submissions under the general headings usual in a distribution rate case, consistent with the filing guidelines and the Application itself.

0.1.6 **This Final Argument is being filed in CONFIDENTIAL/UNREDACTED form only, and so has not yet been made public. SEC has been hampered in its attempts to limit this Final Argument to public information only, as the Board normally prefers, by the fact that the Applicant has not yet been able to review and redact the *in camera* sessions of the oral hearing. Therefore, we have assumed that everything said in those *in camera* sessions is confidential, even though we believe it is likely that all (or at least most) of the references to *in camera* evidence that we have included in this Final Argument do not need to be confidential. Concurrent with providing this Final Argument to the Board Secretary and Board Counsel in confidence, we have also provided a copy to the Applicant with a request to review it and propose redactions if they believe any references in this Final Argument should be treated as confidential.**

0.2 ***Special Circumstances of this Application***

0.2.1 ***Early Rebasing.*** This is an early rebasing application, and as such the Board carried out a preliminary process to determine whether there were substantial reasons why this Applicant should be granted permission to proceed on a cost of service basis. The Board, which by virtue of the provisions of the *Ontario Energy Board Act* has the authority to determine its own process and method of establishing rates, determined that the Applicant had met its criteria for early rebasing.

0.2.2 The essence of the rationale behind the early rebasing application was the Applicant's special circumstances, i.e. it was losing load from larger users, and was unable to handle the resulting drop in revenues.

0.2.3 While the Application also included claims that the Applicant desperately needed infrastructure renewal, and had to spend money to deal with an aging workforce, both of those rationales for early rebasing had already been rejected by the Board in previous decisions [EB-2010-0133 and EB-2010-0139]. Based solely on the "aging" argument (infrastructure and workforce), we believe it is unlikely that the Board would have allowed the Applicant to proceed with this early rebasing application.

0.2.4 As a practical matter, it is submitted that if there had not been load and thus revenue loss, the Applicant would not have been in a position to seek rates for 2011 based on cost of service. These are the "special circumstances" of the Applicant.

0.2.5 ***The Real Facts Emerge.*** As the evidence came out bit by bit during the proceeding, finally in the oral hearing it became clear that the loss of load in the large use class, which had been emphasized by the Applicant (a "material decline in load" – Tr.1:29), was not nearly as much as first appeared.

0.2.6 As we note in our discussion of the large use forecast in Section 1.3 below, the actual reduction in revenue from the large user class has to be adjusted for various items that the Applicant admits are necessary. When those adjustments are made, the maximum erosion of large user revenues from 2008 Board approved to actuals (2009 and 2010, which are equal), is about $2.1 million, or about 2.4% of the Applicant's revenues.

0.2.7 SEC agrees that $2.1 million in revenues is not insignificant, but it is actually only about 10% of pre-tax income. Most businesses are run so that they have that level of flexibility, given that the marketplace is not always very predictable.

0.2.8 Further, no evidence was provided in this proceeding that the reduction, seen during one of the worst economic downturns in recent history, will continue into the future. The fact that it had taken place, mainly in 2009, and continuing into 2010, is undisputed, but there is no evidence that it represents a fundamental shift in the customer makeup in the Hamilton and St. Catharines areas.

0.2.9 Further, what we also found out is that Horizon is less – not more – vulnerable to variations in revenues from large users than many of its peers. SEC was able to show that, if the percentage of large use revenues of Horizon is compared to the four other members of the CLD – Powerstream, Ottawa, Toronto, and Enersource – Horizon has the lowest percentage of its revenues from this class [Ex. K1.6]. Conversely, among this group of large distributors, Horizon has the highest percentage of revenues from the residential class.

0.2.10 Presented with this information, the Applicant said first that their risk is a “lack of diversity” risk [Tr.1:79]. After some discussion about that, the Applicant then said that the real problem is not just with the Large Use class, but with both Large Use and GS>50 [Tr. 1:82].

0.2.11 SEC pursued this in cross-examination. As shown in Ex.3/2/2, page 17, the total kW billing determinants for GS>50 and Large Use classes dropped from 2008 Board approved to 2010 by 14.5%. The Applicant accepted that it was around 15% [Tr.1:83]. The Applicant also agreed that about half the revenues from those two classes comes from the volumetric charge, i.e. the kW figures [Tr. 1:84].

0.2.12 The reason this is important is that those two classes make up, together, about 21% of the total revenues of the Applicant [Ex.3/1/2, page 4, Update]. Mathematically, this means that the drop in billing determinants for those two classes resulted in a revenue erosion from 2008 Board approved Total Operating Revenue of about 1.5%. This is consistent with the actual drop in revenues for those two classes over that period, $1.3 million [Ex. 3/2/1/, page 4, Update], which is 1.4% of the 2008 Board-approved Total Operating Revenue.

0.2.13 While the total drop in all revenues from 2008 Board approved to 2010 Actuals for all revenue sources is shown to be $4.0 million, in fact the loss has the following main drivers:

- ***(a)*** GS>50 and Large Users - $1.3 million;
- ***(b)*** Residential - $2.2 million;
- ***(c)*** Other Operating Revenue - $1.2 million

0.2.14 The problem is therefore not a drop in “larger user” revenues at all, nor “volatility” in those revenues. Indeed, given the existence of an economic downturn, it would appear that the real problem is one that a lot of utilities faced – broad-based short term revenue loss due to the economy.

0.2.15 We note that, if the Board accepts SEC’s proposals on the load and revenue forecasts in Section 1 of this Final Argument, much of this revenue loss will be treated –

correctly – as having been temporary. Appropriate load forecasts recognize that much of it will rebound as the economy does.

0.2.16 SEC believes it would have been of assistance to the Board if the Applicant had presented the true causes of their short-term revenue losses in a realistic and comprehensive way, with the type of analysis that we have now had to do after the fact. Much of this hearing would have been a lot simpler if everyone had not been caught up in the mantra of large industrial users closing up shop.

0.2.17 In our submission, Horizon does have a problem with load, but it is not the problem they described to the Board.

0.2.18 What is clear from the data is that Horizon is not seeing growth in revenue, and its mature franchise area does not appear to have a lot of room for the kind of growth that is seen, for example, in utilities like Powerstream or Enersource. Thus, the problem does not appear to be "a material decline in load", particularly one driven by large industrial and commercial customers. Setting aside the short-term impact of the economic downturn, the problem – one that a number of other LDCs share – appears to be lack of overall growth. Load is not declining over the long term, but it is stagnant.

0.2.19 ***Implications for this Application***. SEC is not really concerned, at this point, with whether the revenue challenges Horizon has been claiming are as serious as they first appeared, or are even correctly characterized in the evidence of the utility. What concerns us more is how management of the utility is responding to what is clearly a long-term issue with lack of revenue growth.

0.2.20 Running a business is a deceptively simple task, in which the key is to ensure that the revenues exceed the costs at all times. This is reflected in the famous Micawber Principle from Charles Dickens' David Copperfield:

> *"Annual income twenty pounds, annual expenditure nineteen pounds nineteen and six. Result happiness. Annual income twenty pounds, annual expenditure twenty pounds ought and six. Result misery."*

0.2.21 Of course, as simple as the task may be, it is very challenging in practice. But at its root, a business that has a mismatch between revenues and costs has to either increase revenues or decrease costs. The measure of management is their ability to do one or the other, or both, and exercise judgment and wisdom in how they do it. A key part of the Board's role as regulator is to supervise that exercise.

0.2.22 In this proceeding, we have a utility that faces a stagnant or even declining market for their products. They don't have the option, as a private sector business does, of simply exiting the business. Their entire raison d'etre is that business, and they have an obligation to serve. They also have only a very limited ability to grow their customer base, as a private sector business sometimes can. Their franchise area is fixed, and promoting greater throughput, in this era of conservation first, is generally contrary to public policy.

0.2.23 In reality, a utility in this situation has only three choices:

- ***(a)*** Increase revenue by raising rates; or
- ***(b)*** Decrease costs, either by:
  - ***(i)*** Merging with other utilities to gain economies of scale, or
  - ***(ii)*** Operating more efficiently and achieving higher levels of productivity.

0.2.24 This Applicant has already successfully used the merger option once, and sought to do it again recently with Guelph. These were strategically good responses, but in the latter case, it was unsuccessful. The Board will be aware that, at least for now, there is a lull in M&A activity, and Horizon themselves admit that they are less active than they once were [Tr. 2:17].

0.2.25 Faced with a perhaps more limited ability to respond to stagnant revenues with M&A solutions, what this Applicant does not appear to want to do is pursue the efficiency/productivity option. Instead, in this Application it seeks to use the first option, raising rates. When asked about that, and after a discussion about attempts to cut costs, Mr. Basilio engaged in the following exchange [Tr.1:127]:

> *"MR. BASILIO: Again, in any given year, I think we would do our best to manage the utility, but over the course of a number of years – and this was the point of advancing our application. It is becoming more and more uncomfortable. So as we move through 2011 and 2012, under these circumstances, it is certainly becoming very uncomfortable. Our only opportunity to address that level of comfort is to address revenue, which is – of which this process is very important to, obviously.*
> *MR. SHEPHERD: Because your billing determinants aren't going up, the only way to increase your revenue is to get higher rates, right?*
> *MR. BASILIO: Exactly."*

0.2.26 In our submission, a utility in the position of the Applicant should be free to come to this Board seeking a rate increase to cover cost pressures amidst stagnant revenues. But, it should be a precondition of the Board accepting any such rate increase that the Applicant demonstrate it has first done everything it possibly can to decrease costs.

0.2.27 This was, it appears to us, what Ms. Taylor was getting at when she asked the question [Tr.1:106]:

> *"What steps are you taking to adjust your structural costs to reflect the capabilities of your customer base to pay?"*

0.2.28 That is, it is submitted, the central question in this proceeding. And the answer?

0.2.29 The answer, on pages 107 and 108 of the transcript on Day 1, was that the Applicant is proposing to adjust cost allocation and rate design to change <u>how</u> they collect money from their customers. None of the answer, in fact, had anything to do with controlling the total <u>amount</u> they are asking their customers to pay.

0.2.30 It will be a theme throughout this Final Argument that the Applicant, faced with a cap on its resources due to static revenue, is proposing to spend as if its resources are unlimited. This is inappropriate. A more careful approach, emphasizing fiscal responsibility over growth in the enterprise, is needed. The approach should always, of course, seek a balance, but in this case the "balance" proposed by the Applicant lacks a sufficient dose of "living within our means".

0.2.31 ***Is this Achievable?*** The Applicant will argue that they have done all they can to control costs, and the costs that remain are all justified in the evidence. Later in this Final Argument SEC will test some of those claims.

0.2.32 At this stage, though, it is possible to look at the Applicant's situation generally to see whether more cost control is possible. Since this Applicant has a Board of Directors that appears to insist on cost containment in non-COS years, the evidence of available cost control is readily available.

0.2.33 As the Board will see from the discussions of Operating Costs and Capital Costs below, the Applicant has shown a distinct spending pattern, in which costs are tightly controlled when no rate increase is available, but are allowed to increase at high rates when being presented to this Board for a rate increase. Section 3.3.2 below, for example, shows a pattern of capital spending with clear jumps in the cost of service years. Sections 2.2.4 and [redacted] below show a similar pattern for operating costs.

0.2.34 SEC explored this problem in cross-examination, resulting in Mr. Basilio saying "I don't differentiate between spending shareholder dollars and ratepayer dollars." [Tr.1:139].

0.2.35 Sadly, that is exactly what the Applicant does, [redacted]

0.2.36 [redacted]

[redacted]

0.2.37 [redacted]

0.2.38 Further, they freely admit that they are using this Application as a "catch-up" [Tr.1:141]. And why is that? The reason is that during IRM years they cut back on their spending, hoping to be able to catch up the next time they come in for rebasing. Their spending control consists, they say, of "deferrals" and the like [Tr.1:141], not a tough look at how to reduce spending in more structurally sustainable ways.

0.2.39 This is the wrong way to approach IRM.

0.2.40 The Applicant has demonstrated that it has the will to operate the utility safely and effectively at a much lower cost than is claimed in this Application, as they have done so in their IRM years. They should now be seeking to consolidate and sustain that cost containment so that they don't feel compelled to keep coming back to the Board asking for higher and higher prices.

0.2.41 In our submission, the Board should allow them spending levels that are sufficient to operate the utility in the manner they have done so in the past, on the assumption that they will continue to be successful in containing costs on an ongoing basis. Any increases in excess of those they allowed themselves during the IRM years should be allowed only for truly exceptional reasons.

0.3 ***Summary of Submissions***

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

0.3.2 ***Load and Revenue Forecasts.*** SEC agrees with Energy Probe and VECC that the appropriate load forecast for non-Large Use is 4,267.5 Gwh for the Test Year.

0.3.3 For Large Use, SEC proposes that, once the actual Large Use revenues for 2008, 2009 and 2010 are normalized as proposed by the Applicant, they show a greater stability than first appeared. As a result, a Large Use forecast for the Test Year based on the average of those last three years is appropriate.

0.3.4 On Other Revenues, SEC notes that 2010 Other Revenues were higher than forecast. With that adjustment, we believe that the three year average of Other Revenues, excluding Management Fees to affiliates, should be used as the Test Year Forecast, i.e. $5,506,530. As noted by other parties, Management Fees to affiliates should in fact be treated as an OM&A offset, and not included in Other Revenues.

0.3.5 ***OM&A.*** SEC is concerned that the detailed information on OM&A from 2008 to 2011 is not available on a comparable basis, so with few exceptions it is impossible to drill down into the data to determine the root causes of the large proposed OM&A increase.

0.3.6 Therefore, SEC has looked at patterns of Total OM&A from 2007 to 2011, and OM&A per customer (actual and projected) from 2002 through 2013. Based on trending this data, SEC proposes that the overall OM&A budget be set at $41.1 million for the Test Year.

0.3.7 SEC has also looked at the composition of the Applicant's actual and proposed OM&A spending, and expresses its concerns over whether the Applicant is getting its priorities right.

0.3.8 ***Rate Base.*** SEC presents an analysis of the capital spending patterns of the utility over the past several years, and concludes that it has already ramped up its capital spending on its distribution system, starting in 2009, by more than 70%. The increase was, in our view, needed, but was also more than sufficient given the state of the Applicant's distribution infrastructure. A further jump in spending is not required. As a result, SEC proposes a Test Year capital budget of $38,980,051, which is a 12.69%

increase over 2010 Actual, and reflects primarily a shift of some 2010 spending to 2011.

0.3.9 In addition to an adjustment to opening rate base to reflect 2010 actual closing rate base, SEC adopts the changes to the working capital calculation proposed by Energy Probe, which would decrease rate base by a total of about $4.5 million.

0.3.10 ***Long Term Debt.*** In EB-2007-0697 the Board determined that on the $116 million of affiliate debt then in place, the Board's deemed rate for demand debt should be used. That rate was, at that time, 6.1%. That debt is still in place, and the Applicant proposes to retain the 6.1% rate.

0.3.11 SEC, on the other hand, proposes that this Board should decide, consistent with EB-2007-0697, that the Board's deemed rate should continue to apply to this debt. Today that rate is 5.32%.

0.3.12 ***Cost Allocation and Rate Design.*** SEC believes that revenue to cost ratios should be established in a principled manner, and consistent from one utility to the next. We therefore oppose the Applicant's proposal to reduce residential rates at the expense of the other classes, in exactly the same way as we have opposed Toronto Hydro reducing rates for schools and other larger customers at the expense of residential consumers..

0.3.13 We also express our concern with the substantial increase in the Large Use monthly fixed charge. Since the Applicant admits that they do not know the economic impact of this large change on these customers, in our view it should not be approved until that investigation has taken place.

0.3.14 ***Effective Date.*** We believe that the Applicant should be allowed to align their rate year with their fiscal year. However, because this Application was filed late, and the process was then extended in part due to actions of the Applicant, it is inappropriate to make that alignment effective on January 1, 2011. For 2011, rates should be effective after the rate order in this proceeding. SEC recommends that the rate year and fiscal year be aligned commencing with the Applicant's 2012 IRM rate adjustment.

0.3.15 ***IRM Period***. The Applicant was allowed by the Board to come in for cost of service one year early. In our view, this should not change the schedule for future cost of service applications by this utility. That permanent acceleration would be an additional benefit of early rebasing, one not connected with the original reason for the early application.

0.3.16 Thus, it is submitted that the Applicant's next scheduled rebasing year should remain unchanged, at 2016. They would, of course, continue to be eligible to seek early rebasing where they meet the Board's applicable criteria.

1 LOAD AND REVENUE FORECASTS

1.1 *Customer Forecast*

No submissions.

1.2 *Volume Forecast – Non-Large Users*

1.2.1 We have reviewed in draft the submissions of VECC and Energy Probe relating to the volume forecast for all customers other than the Large Use class. We agree with their analysis of the problems with the Applicant's evidence on their volume forecast.

1.2.2 Simply put, that evidence has many problems, and as the process unfolded it was clear that the problems were compounding. The cross-examinations on this issue, particularly on the final day of the hearing, when Mr. Bacon didn't even know the meaning of multicollinearity [e.g. Tr.4:32], a common statistical term, show that as the Applicant kept trying to respond to new information, or new thinking about old information, the reliability of the volume forecast kept dropping. The last thing the Board needed at that point was a further run of the model, as proposed by the Applicant right at the end of the proceeding [Tr.4:56], which could easily have created further problems.

1.2.3 At some point, it probably would have been worthwhile for the Applicant to press the reset button on the 2011 forecast, and start again with a better plan. That didn't happen, and simply re-running the same model again and again with new data and new assumptions, then trying out new explanations for apparently counterintuitive results with no empirical basis [e.g. Tr.4:58], was not helping.

1.2.4 The Board is now faced with a difficult situation, in which the evidence is poor, but rates cannot be set without the Board approving <u>some</u> volume forecast. We therefore agree with the pragmatic approach proposed by Energy Probe and VECC. The resulting non-large user volume forecast for 2011 – 4,267.5 GWh – appears to us to be reasonable based on past data and the likely impact of CDM.

1.3 *Volume Forecast – Large Users*

1.3.1 SEC has struggled with the claims of the Applicant that the large use forecast must be reduced because of large user volume volatility.

1.3.2 First, it now appears quite clear that the "volatility" that the Applicant has been talking about all along is not the normal meaning – unpredictable variations around a mean or baseline [Tr. 4:45]. What they really mean when they talk about volatility is that the actual large user loads have been lower than the 2008 Board-approved. In fact, Mr. Basilio said [Tr.1:141]: "We view this application as an opportunity to correct issues with respect to our 2008 application…"[emphasis added].

1.3.3 There is no question that the volume-based revenues for large users in each of 2008, 2009 and 2010 have been lower than the Board-approved level of $5,459,659 [Ex. 3/1/2, p. 4, Updated March 14, 2011].

1.3.4 However, when we look at the variance analysis contained in Undertaking J1.1, we see that the actual "apples to apples" revenues from large users in each of 2008, 2009, and 2010 were as follows:

(a) 2008 - $4.9 million
(b) 2009 - $3.3 million
(c) 2010 - $3.3 million

1.3.5 These figures are calculated as follows:

(a) 2008: The actual revenue from large users for 2008 was $2.1 million, but that is after deducting a transformer allowance of $1.9 million, and a foregone revenue of $0.9 million, both related to the implementation of 2008 rates only as of December, 2008. On a normalized basis, the revenue was the $5.5 million approved by the Board, less an actual load loss of $0.6 million [J1.1, p.3], for a net of $4.9 million.

(b) 2009: The actual revenue from large users for 2009 was $4.5 million, but it included $1.2 million of revenue from a rate rider related to the late implementation of 2008 rates, leaving a net of $3.3 million. The Applicant reports that actual load loss was only $0.9 million below 2008 Board-approved, but we are unable to reconcile this figure with the actuals for 2009 [J1.1, pp 3-4].

(c) 2010: The actual revenue from large users for 2010 was $3.3 million. There was an increase in load of $0.4 million, offset by adjustments of a similar amount. The adjustments have not been explained that we can determine [J1.1, p. 4].

1.3.6 We note that the Applicant's evidence is that there was an actual load loss of $0.6 million in 2008 from Board-approved, an additional $0.3 million in 2009, and then a gain in load of $0.4 million to 2010 [J1.1]. However, those figures do not account for the 2010 total, so we have used the figures in para. 1.3.4 above, which are more favourable to the Applicant's position**.** We note that we attempted to get to correct figures in the oral hearing [Tr.4:42-45], but we were unable to get a clear picture of the apples to apples comparisons.

1.3.7 Why is this important? The Applicant has based much of their Application on the notion that their large user revenues are low and volatile. In fact, their own detailed evidence is that variations in large user volume-driven revenues have been miniscule – less than 1% of total revenue each year, not all in the same direction – for the last three years. Even if their net figures from J1.1 are used, as set out in paras. 1.3.4/5 above, at the very most the loss of revenue so far has been $2.2 million a year, or about 2.46% of revenue.

1.3.8 Now, however, the Applicant proposes that the large user forecast should drop even further. At 2010 rates, the forecast would result in a reduction at current rates of about $441,466 [i.e. a drop of 436,102 kW from Ex.3/2/2, Table 3-24, Updated, @ the 2010 volumetric rate of $1.0123 per kW] from the adjusted 2010 actual figure.

1.3.9 In our submission, what the Board can see is relatively stable revenues, and it would be unusual to use an estimate of less than $3.3 million for the Test Year given that it is the lowest of the last several years. This is especially true since the Applicant has admitted that they have reduced the revenue assumed from one of the large users to zero, despite the revenue currently being at 15% of previous levels [Tr.3:117 and VECC IR #39(b)].

1.3.10 Of course, the Applicant may argue that they are seeing a change in the composition of their customer base. If that is the case, the Board has not seen any evidence of that. The Board has seen anecdotal evidence of specific customers shutting down, locking out employees, or making other business changes. The Board has seen no evidence that the industrial nature of Hamilton and St. Catherines, and the load that flows from it, are trending downward or have experienced some sort of intrinsic drop.

1.3.11 It is therefore submitted that the large user load forecast that is appropriate is the average of the last three years, as adjusted to take account of the anomalies described in J1.1. That last three years includes a severe economic downturn, so it is still likely to be conservative, but the average will still be in the reasonable range. As the Board can see from past years, the actuals will be somewhat up and somewhat down year over year, but as a forecast the average is probably if anything on the low side.

1.4 ***Other Revenues***

1.4.1 We have reviewed the draft submissions of VECC with respect to Miscellaneous Revenues, and in general we think that their approach is a reasonable one. WE particularly note that the fact that 2010 actual was $461,221 higher than forecast [EP TC #5] was key to their approach, and we agree.

1.4.2 However, SEC also believes that an alternative approach should be considered, given the revised actual results for 2008 through 2010. In our view, Other Revenue should be normalized to remove two amounts: the rent paid to the City of Hamilton, which is ending in 2010, and the Management Fees paid to the affiliate, which should be treated as an OM&A offset. If those two adjustments are made, it is submitted that the normalized revenues for the past three years are the following:

Other Revenues	***2008***	***2009***	***2010***
Gross Other Revenue	$7,344,652	$6,083,647	$6,062,880
Less: City of Hamilton Rent	$184,082	$200,704	$162,971
Less: Management Fees	$908,446	$763,411	$751,976
Net Revenue	$6,252,124	$5,119,532	$5,147,933

1.4.3 The average of the last three years is $5,506,530, exclusive of management fees. This compares to the figure determined by VECC of $5,941,969, less Management Fees in the Test Year of $784,515, for a net total of $5,157,454.

1.4.4 In our submission, either approach can be justified, but the three year average is a more usual approach, and one that generally will produce more reliable forecasts.

2 OPERATING COSTS

2.1 ***Problems with the Empirical Data***

2.1.1 What we know for sure is that the Applicant is proposing an increase in the overall OM&A budget from $39.5 million in 2010 to $47.5 million in 2011, an $8.0 million increase, or 20.3%. The Applicant agrees with that figure [Tr. 1:147].

2.1.2 But there the simplicity ends. For a number of reasons, it is difficult to place the OM&A proposals of the Applicant for the Test Year in any reasonable context.

2.1.3 ***The Applicant's Description.*** A good starting point is the simplified description of the OM&A line set out by Mr. Basilio. After being asked in interrogatories and the Technical Conference to provide details of productivity gains by the utility since 2008, Mr. Basilio described the proposed increase in OM&A in the Test Year as follows [Tr. 1:147]:

> *"If we assume inflation at 3%, which is conservative, in my view, given wage and price inflation over the last three years, that is about $3.7 million on our OM&A base for 2008 of approximately $40 million. It think it was $39.8 million.*
>
> *We have provided for an increase of 60 headcount since that approved in our 2008 rate base. That aggregates five ½ million since 2008, of which 2.8 million is allocated to operating.*
>
> *In this 2011 financial plan, we've provided for initiatives that we think are very important to bring the utility forward, some of those initiatives being hiring skilled trades, some being enterprise data warehouse, that aggregate 3.9 million.*
>
> *When you sum those three items, that aggregates 10.4 million, $10.4 million. We're asking for eight.*
>
> *We've taken 2.4 out of the system."*

2.1.4 Of course, there are obvious problems with this summary: a 3% inflation assumption, when inflation overall has in fact been well below 2%; the fact that 2008 actual was $38.7 million, not $39.8 million; and, double counting of skilled trades in the final $3.9 million and the second $2.8 million.

2.1.5 However, leaving those aside, what the Applicant is saying that, but for $2.4 million in productivity improvements, their actual upward cost pressures over three years have been $10.4 million, or more than 26% (even assuming their erroneous 2008 figure). This would be an annual increase of more than 8.5%, sustained over three years, in a utility that is not increasing its customer base and not adding load.

2.1.6 This is then exacerbated by the fact that the increase is not in fact a regular annual increase. It is, instead, one very large increase proposed after a few years of very small ones.

2.1.7 It is obviously difficult for the Board to grapple with the OM&A increase with this description, and this context, as the starting point.

2.1.8 ***"Remapping".*** One tried and true method of looking at spending in a stable business such as this is to consider, category by category, the changes in spending over time. Since the business is not undergoing radical changes, many aspects of the business should also be relatively constant. By identifying those areas that are not, it is possible to get explanations for those anomalies, or challenge them.

2.1.9 The problem with this is that, in implementing its ERP system in 2008, the Applicant "remapped" many expenses to other categories [Tr. 2:88, 106, and other references], so that 2007 and 2008 Actual and 2008 Board-approved numbers are not comparable in many instances to 2011 Test Year Budget [Tr. 2:101].

2.1.10 By way of example, the category 5620 – Office Supplies and Expenses, which seems straightforward enough, included just those things. On remapping, all of the costs of the IT department became included in that category [Tr.2:88], resulting in it increasing seven-fold. The increase was not, as Mr. Warren posited "an awful lot of extra pencils". It was an accounting decision that made the old data and the new data no longer comparable.

2.1.11 This also impacts differences between 2008 Actual and 2008 Board-approved. As we learned only through cross-examination [Tr.2:103], four months of 2008 actuals were on a remapped basis, whereas 2008 Board-approved was all on the old basis. In fact, the differences were sufficiently confusing that the utility itself was limited in their explanations [Tr.2:103]:

> *"I think where we certainly tried in our evidence to provide year-over-year, we did have to do it at a much higher level, in looking at our O, like, our operations category, our distribution categories, our G&A categories in total."*

2.1.12 There were a number of other examples of movement. Supervisors, for example, were moved from G&A to their specific operational categories [Tr. 2:103]. All of the meter staff were moved to the meter expense line [Tr.2:108], although the record is not clear on where they were moved from. There are a number of others.

2.1.13 In the end, the result is that on a line by line basis, the numbers from 2008 are not comparable to the numbers from 2011 in many cases. It is therefore not possible for the Board to identify from the empirical data where the changes in spending are in fact occurring.

2.1.14 ***Personnel Data***. While we will discuss Human Resource costs and levels below, there are two aspects that add to the problem of quality of information.

2.1.15 First, it became clear during the hearing that there was much confusion between two quite different concepts – FTEs and headcount. As a result, much of the personnel data was set out on bases that were not comparable.

2.1.16 SEC understands the difference between FTE and headcount to be similar to the difference between an income statement and a balance sheet. The former is something that has transpired over a time period, while the latter is a snapshot at a point in time. An FTE is conceptually one person actually doing a job every day for a year (a "full-time equivalent" being the equivalent of one full-time person). It does not have to be either the same person or the same job. If 12 part-time employees each work for one month, they are essentially one FTE. Conversely, headcount is the actual number of employees of the company at a specific point in time. Those employees could all have worked for only one day at that point, and it would be irrelevant to headcount.

2.1.17 FTEs and headcount are often quite different. We heard, in the most recent Hydro One rate hearing, for example, that because they have large numbers of seasonal outside employees, headcount as of year end can be significantly lower than FTEs for the year. At year end, there is not much work for seasonal employees, so there are not many of them. The same is true for students.

2.1.18 The differences between the two concepts came up as a problem again and again [e.g. Tr.2:26, 31, 32, 151; Tr.4:9, 46, and many other references]. It makes the personnel related data – which in the explanation by Mr. Basilio is by far the bulk of the OM&A increases – very difficult to assess.

2.1.19 Just one example will help the Board understand why this is problematic. VECC asked how the average compensation numbers on the 2K were calculated [Tr.4:11-12]. What they found is that they were calculated as the compensation figures, divided by the year end headcount. Since the compensation is calculated on a period basis, it should be divided by the FTEs to get the averages per person. It is incorrect to divide by headcount, as Ms. Hughes essentially admitted [Tr. 4:12].

2.1.20 We note that this issue was further complicated by the fact that students are not included in the table at all [Tr.2:152], despite the fact that the Applicant proposes to hire quite a lot of them in the Test Year. Since students typically work in the summer, they would not be in headcount, but they would be in FTEs, much like normal seasonal workers. Luckily, the impact of this item is expected to be small [Tr.2:152], but it is an added complication.

2.1.21 The second area of problems in the personnel data relates to the Applicant's Executive category. As we note below, the Applicant does appear to have a lot of Vice-Presidents, but what was striking is that they had 18 people in the Executive category, as compared to 11, for example, at Toronto Hydro. The reason was that Horizon, unlike other utilities, includes in its Executive category all personnel down to a director level [Tr. 2:24-5], which increases their numbers and reduces their average compensation in that category. It will have converse effects on the Management category, the next level down.

2.1.22 This problem with comparability to other utilities (which is the reason why the Board has a standardized reporting requirement in the first place), was partially solved by an undertaking, J2.3, but it was too late to be of much use.

2.1.23 ***Presentation Changes.*** Another area of difficulty was changes in the presentation of information. Some of this should not have happened, such as the unheralded addition of "Distribution System Communications" [redacted] as a new category of distribution infrastructure spending, added for 2011 and beyond. Similar to remapping, this is a category of expense that would normally be part of General Plant, but for the purposes of this Application was added to Distribution Capital. There are a number of minor examples like this.

2.1.24 Of more difficulty is that some of the most useful information should have been the information in the business plans approved by the Board of Directors. However, as is often the case, the presentation of information to the directors is done for quite good reasons on a different basis than the presentation of information in a rate application.

2.1.25 As a result, using the business plan information turned out to be somewhat confusing [redacted]. This is not intended to be critical. It is just a reality. Sometimes a Board of Directors wants to see things presented in a different way [redacted], and that makes otherwise useful information less useful.

2.1.26 ***Conclusion***. These are highlights of what we found to be problems with the quality of the information provided by the Applicant. In general, we found that the Applicant provided a lot of information, and it was particularly useful to have the individual Departmental Budgets provided as part of the pre-filed evidence. The problem was not with quantity, and the Applicant is to be commended for being thorough in their information flow.

2.1.27 The problem was, in fact, with the usability of the information. Information that is not consistent over time, that is not consistent with other sources of information within the organization, and is not prepared on a consistent basis with other utilities, is less useful to the Board and to other parties.

2.1.28 As a result of these concerns about the detailed information, SEC is not looking at the OM&A budget on a line by line basis. While we will attempt to raise some issues related to the human resources increases, and we will look at the Maintenance line specifically, our focus must because of the data limitations be instead on higher level comparisons.

2.2 ***Overall Level of OM&A – the Envelope Approach***

2.2.1 ***General.*** SEC has always been of the view that a good starting point for OM&A analysis is a top-down budgeting approach. This approach, which has started to be used more and more by Ontario utilities (OPG and Kingston have been using it, for example), starts from the premise that there is a reasonable pool of money available, and the budgeting exercise is to figure out how to operate the utility within that constraint. The initiating question is "How much do we have available to spend?"

2.2.2 Horizon has not approached their Application in that way. They have instead used a bottom-up approach, which starts by asking the question "What do we need to spend?", then seeing how it can be presented so that it will be approved. We believe top-down is the better approach to sound budgeting, and more consistent with the Board's role as a proxy for market forces. Further, in light of the difficulties with looking at the details of their bottom-up budget, we believe that the Board will be limited in its ability to deal with it. It is more appropriate, in our view, to test the overall budget being requested by the Applicant, using higher level metrics.

2.2.3 We believe there are two fairly straightforward ways of looking at the OM&A budget: total OM&A spend year over year, and OM&A per customer year over year.

2.2.4 ***Total OM&A Budget.*** The Applicant has provided historical and forecast information on total OM&A, which SEC has formatted into the following table:

Total OM&A by Year		
Year	***Dollars***	***% Inc.***
2006	$32,346,647	
2007	$37,004,870	14.40%
2008	$38,748,181	4.71%
2009	$38,804,636	0.15%
2010	$39,500,000	1.79%
2011	$47,457,439	20.15%

[Sources: 2006 – EB-2007-0697 p. 14 of Decision; 2007-2009 – Ex. 4/2/1, p. 2; 2010 – EP TC #7; 2011 – April 15, 2011 Revenue Requirement Work Form]

2.2.5 What this tells us is that after a jump from 2006 to 2007, the Applicant's OM&A has been quite stable until the Test Year, when it is proposed to increase by more than 20%.

2.2.6 There are two ways to approach this. One way is to look at all the years, and propose an annual increase that should be sufficient for a utility with little growth. For example, if an annual increase of 3% is used (which is the number used by Mr. Basilio to describe gross inflation for OM&A), the 2006 figure would calculate to $37,498,626 for 2011.

2.2.7 The problem with this approach is that it effectively claws back the OM&A increase approved by the Board in the EB-2007-0697 proceeding. An alternative would be to work from the 2008 actual, which at 3% increase would result in $42,341,183. If, instead the base year used is 2007 (to reflect the increases already made at that time), the 2011 result would be $41,649,306.

2.2.8 The problem with this is that the Applicant in fact has been increasing OM&A at a slower pace. A better approach, in our opinion, would be to use the data from the Applicant to calculate the increase. In the two years 2009 and 2010, when any increases were effectively borne by the shareholder, the average increase was about 1%. This would translate to a 2011 figure of $39,922,289. [redacted]

2.2.9 There is no magic in any of these numbers. They create a reasonable range for 2011 OM&A of $39.9 million to $42.3 million. Given that the Applicant should be tightening its belt, and given that the spend in 2010 was lower than forecast, we believe that an increase of 3% over 2010 actual is a reasonable result using this type of forecasting, i.e. $40.7 million. While that increase is higher than either of the last two years, it is within the reasonable range based on past data, exceeds inflation, and is significantly higher than the Applicant experienced [redacted] for any year except the Test Year (see below).

2.2.10 ***OM&A per Customer.*** There was considerable discussion in this proceeding with respect to the anomaly of a utility with a stable customer base and no growth having substantial jumps in OM&A per customer.

2.2.11 [redacted]

[redacted]

2.2.12 [redacted]

[redacted]

2.2.13 [redacted]

2.2.14 [redacted] SEC has reviewed JT1.5, which is the Applicant's comparative database of Ontario LDCs, and includes OM&A per customer numbers for 2005 through 2009, and the Report by Pacific Economics Group in EB-2006-0268, as updated in 2008, which sets out the OM&A per customer of all Ontario LDCs for the period 2002 to 2007. While it is clear that the Applicant's database and the PEG Report are not identical, they are close, and directionally match each year. [redacted]

2.2.15 [redacted]

2.2.16 [redacted] we do know that in the 2008 cost of service proceeding EB-2007-0697, the Applicant requested an OM&A increase of 27.2% (over the two year period 2006 to 2008, $32.3 million to $41.1 million, net of smart meters) [Decision with Reasons, p. 14, 20], and the Board ultimately approved an increase of 23.8% ($32.3

million to $40.0 million) [Decision with Reasons, p. 20]. Although it is true that the Applicant actually spent less in 2008, 2009 and 2010 than the Board-approved amount, it is still clear that a significant jump in spending took place.

2.2.17 We note that the Applicant was asked whether, in light of the past pattern of jumps in OM&A in cost of service years, that pattern could be expected to continue in the next rebasing year, and Mr. Basilio said it would be "more limited in scope" [Tr.1:114].

2.2.18 In SEC's view, the OM&A per customer data shows a utility that is able to manage within reasonable levels of increase each year, except for cost of service years, when it seeks very substantial increases.

2.2.19 [redacted]

2.3 ***Human Resource Costs and Levels***

2.3.1 ***General.*** A lot of time was spent in this proceeding, including considerable time at the oral hearing, exploring the reasons why a utility with little or no growth would need to add 60 people over three years, from 2008 to 2011, to a base of 368 employees. This 16.3% increase in personnel has not, in our view, been properly explained by the Applicant.

2.3.2 SEC is aware that other parties will be commenting in some detail on the increase in personnel proposed by the Applicant, so we will limit our comments in this area to three, two in this section and one in the next dealing with prioritization.

2.3.3 ***Timing of the Increase.*** The Applicant's proposal to increase its positions by 27 from 2010 to 2011 is actually a headcount increase of 42 people in the Test Year. In fact, as of the end of 2010, the actual headcount was 384, the same number as at the end of 2009, and 18 more than 2008 [J2.4]. What the Applicant is proposing is not, in fact, to increase its personnel by 16.3% over three years. It is proposing to increase its personnel by 10.9% in one year.

2.3.4 This raises three concerns.

2.3.5 First, this information was not clear until the oral hearing. The Applicant continued, even during the oral hearing, to talk about the number of additions in 2011 as being 27, when they were aware that the real figure was 42. This is not helpful to the

Board's understanding of the evidence.

2.3.6 Second, the Test Year budget includes 32 of the 42 positions as if they started in January 2011 (15 because they were assumed to be hired in 2010, and 17 listed as hired in January 2011), but in fact it appears that only three of them had been hired by the date of the hearing [Table 4-26]. While this latter figure is not 100% clear after various discussions about it in the hearing, what is clear is that the vast majority of the additions have not yet been hired, yet the budget includes most of them as full FTEs with full costs.

2.3.7 Third, the size of the one year increase far exceeds what even a growth utility would normally require, and for a utility like Horizon that is not growing, appears to be an order of magnitude above what would be reasonable.

2.3.8 ***Failure to Assess Existing Positions.*** The other comment we would make on human resources relates specifically to the Business Development Group. Although housed in the holding company, 80% of the salaries of this group are paid by the utility [Tr. 2:18].

2.3.9 This group was originally formed to work on M&A activity, and for that reason in EB-2007-0697 the Board determined that the cost was not recoverable from ratepayers [VECC TC 9(b)]. When M&A activity dried up, the group was refocused on strategic planning support. Previously, this work had been done by the Executive Management Team [Tr.2:19].

2.3.10 This is a group made up of a Vice-President and two supporting staff. What SEC does not understand is why, with the purpose of the group thwarted by the marketplace, and with the utility under serious cost pressures, the company did not simply make the tough choice and cut the positions.

2.3.11 The point here is not in fact whether Business Development is useful to the company or not. The point is more subtle. This is a utility faced with pressure to cut costs. In the only example on which the Board has any solid evidence, it appears that the company was not even willing to consider cutting where it was easy and perhaps even obvious.

2.3.12 Given that the evidence of the Applicant is only about <u>adding</u> positions, and nowhere talks about <u>cutting</u> or <u>consolidating</u> positions so that less people are required, we are concerned that this utility may be showing itself unwilling to make the hard choices necessary to contain costs in an ongoing and sustainable way. The Business Development Group may be an example of that problem.

2.4 *Spending Priorities*

2.4.1 SEC is concerned that the Applicant, which says it has a serious problem with its aging system, does not appear to be targeting its OM&A spending appropriately to deal with that priority.

2.4.2 We have commented earlier that the detailed comparison of spending is not really possible for this utility, because the historical data is not comparable to the Test Year budget. Within this limitation, we have identified two areas in which prioritization of spending appears to be an issue.

2.4.3 ***Maintenance Costs***. SEC took the Applicant's witnesses to Exhibit 4/2/1. Page 1, which has the spending on Maintenance [Tr. 2:109-112]. SEC was concerned that the spending on Maintenance is not increasing, even in the Test Year budget, at the same rate as the other categories. From 2010 to 2011, the increase proposed was 4.1%, and even at that Maintenance would still be down 21.4% from 2008 Board approved. Given the Applicant's evidence, this seemed counter-intuitive.

2.4.4 The witnesses pointed out that the cost of Tree Trimming has gone down from 2008 Board-approved [Tr.2:110], which accounted for all of the drop in spending from 2008. However, the end result is that net Maintenance spending (exclusive of Tree Trimming) did not increase from 2008 through 2011.

2.4.5 Ms. Lerette was in fact surprised at this, saying: "I think overall, our maintenance costs have gone up, with the exception of tree trimming, which has gone down." [Tr. 2:111]. However, that of course was not the case when looking at the actual numbers, so after a conference between Ms. Lerette and Ms. Hughes, the latter admitted: "The maintenance programs and the activities that we are doing have not changed significantly".

2.4.6 In our submission, this is not an appropriate situation. If the utility has a problem with aging infrastructure, the focus of new OM&A spending should be on better maintenance of what they have. They have substantially ramped up their distribution capital spending already, as we note in our discussion in Section 3, but on the operating side, despite their substantial increase in proposed spending, they cannot spare additional dollars for Maintenance. This is not, to us, good prioritization of scarce dollars.

2.4.7 ***Hiring Choices.*** The other glaring example of what appears to be poor prioritization is found in the descriptions of the newly created positions at the company.

2.4.8 SEC took the Applicant's witnesses to Table 4-26 [Ex. 4/2/10], which lists all of the new positions from 2008 through to the end of the Test Year. The Applicant was asked to identify those that were "tool-in-hand", i.e. the ones that represent people who actually work on the distribution infrastructure on a day to day basis [Tr.2:140].

2.4.9 After some confusion, since the witnesses were not familiar with the concept of "tool-in-hand", and since the table itself had an error, the witnesses admitted that only 15 of the 64 positions on the list were "tool-in-hand" positions. Of those, as of August 26th of last year, none of them had been hired, and as of the date of the hearing, only seven of them had been hired [Tr.2:147]. The Applicant's defence was that many other trades had been hired, but they had all been to replace people who had left. Only a small number of very recent hires have been new positions for people who actually work on the distribution infrastructure.

2.4.10 What we do see on the list, however, are three new executives, including two new Vice-President positions created in 2009. We also see 17 new Management level positions. In fact, as of today the utility has filled more new Executive and Management positions than it has "tool-in-hand" positions.

2.4.11 When we look at the rest of the positions, they are almost all in finance, IT, or regulatory (at least 20 of the remainder). The exceptions appear to be an Executive Assistant, an Administrative Assistant, two Engineering Interns, and a Specialist in Environmental Management.

2.4.12 These numbers are confirmed in other parts of the evidence. For example, under cross-examination by Mr. Warren, Ms. Hughes described the 13 new positions in the IT department [Tr.2:90-1]. In Regulatory, 5 new people were added from 2009 to 2010, and the Application contains a proposal for another two more in 2011 [Tr.2:83-4].

2.4.13 We have elsewhere commented that we believe the substantial increases in budget in this Application go far beyond the what is reasonable for a utility such as Horizon with no growth in its business. What the human resources evidence suggests is that the increases are almost all in support positions of various types, and represent increases in activities that are, in many cases, outside the core needs of the utility.

2.5 ***SEC Recommendation on OM&A***

2.5.1 SEC has concluded that only a top-down analysis can produce a reasonable OM&A budget for the Applicant in the Test Year. We looked at it several different ways, and in the end have three reasonable results:

(a) An increase of 3% from 2010 Actual, i.e. $40.7 million.

(b) The midpoint of the reasonable range based on escalation from 2008, i.e. $41.1 million.

(c) [redacted]

2.5.2 In the absence of any detailed evidence available to show which one of these is most supportable, and keeping in mind that all of them are within a very narrow range, we propose that the Board adopt the highest of the three, i.e. $41.1 million**.** This represents a 4.1% increase over 2010 actual, and would be the Applicant's highest OM&A budget in its history.

2.5.3 We also recommend that the Board provide its comments on how the Applicant is prioritizing its spending, with a view to focusing more closely on the items that require the most attention, particularly in the face of the necessity for cost containment.

2.6 ***Income and Other Taxes***

2.6.1 We have had the opportunity to review the submissions of Energy Probe and Board Staff with respect to taxes, and we adopt both the analysis and the conclusions in those submissions.

2.7 ***Depreciation Expense***

No additional submissions.

3 CAPITAL EXPENDITURES and RATE BASE

3.1 *Introduction*

3.1.1 This section of SEC's Final Argument deals with the rate base to be included for the purposes of determining rates in the Test Year, and by implication the capital spending plans of the Applicant for the Test Year.

3.1.2 In our view, this issue decomposes into four sub-issues, as follows:

(a) What is the appropriate opening rate base for the Test Year?

(b) Is the Applicant's claimed need for substantially increased capital spending supported by the evidence?

(c) What is the appropriate composition of the Test Year capital budget?

(d) What is the correct calculation of the working capital allowance in rate base?

3.1.3 We will deal with each of those sub-issues in turn. Based on our analysis, we will then propose to the Board a rate base and capital budget that reflect the unusual situation of this utility.

3.2 *Opening Rate Base*

3.2.1 In cross-examination by Mr. Aiken on the first day of the hearing, Ms. Hughes described how the Applicant's forecast of capital spending incorporates CWIP [Tr.1:38-41]. In essence, the Applicant assumes a constant amount of CWIP each year for forecasting purposes, although in practice the amount of spending that has not been put into service by year end varies from year to year.

3.2.2 The Applicant admits that the opening rate base for the Test Year as proposed in the Application is higher than the actual opening rate base. The CWIP at the end of 2010 was not the constant amount assumed in the forecast, $6.3 million, but actually something closer to $9 million [Tr. 1:40], and thus the closing rate base is that much lower.

3.2.3 However, asked whether the Application would be amended to reflect the actual opening rate base for the Test Year, Ms. Hughes responded that it would not [Tr.1:40], because they assume that the additional amount will be spent in 2011, and the CWIP at the end of 2011 will be back to the normal level.

3.2.4 This, in our submission, overstates Test Year rate base. Pressed by Mr. Aiken, the Applicant admitted that the "fair" approach would be to reduce the opening rate base, but reflect the additional spending in 2011 as new capex closing to rate base in that year [Tr.1:41]. Since the actual amount of the increased CWIP was $2,841,193 [EP TC #1], the result would be to reduce the rate base by about $1.42 million.

3.2.5 Despite this admission, we did not see this amendment in the Argument in Chief. It is submitted that adjusting the rate base as proposed by Mr. Aiken, and agreed by Ms. Hughes, is the correct and fair approach.

3.3 ***Capital Needs of the Utility***

3.3.1 At the centre of the proposed capital budget is the Applicant's position, stated in their opening direct evidence [Tr.1:30]:

> *"Our evidence shows our urgent need for increased renewal and maintenance of the electricity distribution system, and related underlying enabling systems and processes that are beyond their productive life or no longer suitable for business purposes that have evolved or must evolve."*

3.3.2 This is reflected in the capital budget. Actuals and forecast capital spending are as follows:

Year	Capital Additions (less smart meters)	Percent Increase
2007	$26,408,461	
2008	$34,449,049	30.45%
2009	$37,687,224	9.40%
2010	$34,590,491	-8.22%
2011	$46,833,292	35.39%

[Source: Ex 2/2/2, except 2010, which is EP TC #1, and 2011, increased by amount of extra CWIP in 2010 as per para. 3.2.4 above. 2007-2010 all actuals.]

3.3.3 The second sub-issue, therefore, is whether this substantial jump in capital spending in the Test Year, from an average of $33,283,806 over the last four years, to $46,833,292, an increase of almost 41%, is justified by the evidence.

3.3.4 What the Board has before it is an Asset Management Plan done by the Applicant internally in 2009 [Tr.1:159], with a report dated June 2010 [Ex. 2/3/2, App. 2-1], and a report from a respected independent asset assessment firm, Kinectrics, done in 2004 at the time of the Hamilton/St. Catharines merger [JX1.3]. Because those two reports produce inconsistent estimates of capital spending needs, the Board must determine the weight it will give to important but conflicting pieces of evidence.

3.3.5 ***Kinectrics Report.*** The Applicant admits that Kinectrics are recognized experts in the field of asset assessment and, in particular, due diligence analysis on assets, and were hired jointly by the two merging parties to do a "full study" of "assets on the ground" [Tr.1:151].

3.3.6 [redacted]

3.3.7 [redacted]

3.3.8 There are any number of problems with this testimony, but five are the most striking:

(a) Mr. Basilio is not an engineer, and he has no expertise that would allow him to form an opinion on the quality of an expert report of this nature. His passing reference to opinions of individual members of his Board of Directors [Tr.1:177] is heresay and inadmissible in all respects, and in any case does not cite any specific opinions, just makes a broad generalization. (This is akin to saying "Lots of people who do know what they're talking about agree with me".)

(b) Kinectrics are recognized experts in the field, as even the Applicant admits. The Applicant provided no evidence that any of the Horizon employees who worked on the Asset Management Plan have a similar level of specialized knowledge and expertise.

(c) The Applicant hired Kinectrics again to do a similar due diligence review when the merger with Guelph was contemplated, which would appear to be somewhat incongruous if Kinectrics had already screwed up one due diligence assignment for them.

(d) The Applicant's own Vice-President of Operations, responsible for the capital plan, Ms. Lerette, when asked whether the Kinectrics Report was "wrong", refused to say that. Instead, she claimed that their subsequent analysis was based on "better information" [Tr.1:158]. Thus, the testimony of Mr. Basilio, who is an accountant, and Ms. Lerette, who although not an engineer does have training as a Certified Engineering Technologist, is inconsistent.

(e) The 2004 Kinectrics Report formed part of the basis for a major merger transaction, and so a lot was riding on it being accurate. Conversely, the internal analysis that resulted in the Asset Management Plan was prepared with a knowledge that it would be used to support a request in the regulatory process for increased capital spending, and so a lot was riding on it showing the "hockey stick trend" [Tr.1:152] that it ultimately did.

3.3.9 We note that, when asked about the "better information" that formed the basis of the Asset Management Plan, the only thing the Applicant could offer is that they found out the age of all of their assets [Tr.1:158]. This is a sharp contrast to Kinectrics, which [redacted].

3.3.10 Taking all of this information into account, SEC would, but for our Yearbook data analysis below, be forced to conclude that the only thing the Asset Management Plan has going for it is that it is more recent. In all other respects, the independent analysis by recognized experts, in the context of due diligence for a major transaction, [redacted], would have to be preferred.

3.3.11 In these circumstances, and subject to our comments below, we believe that the Applicant had a heavy burden to show that the Kinectrics study was [redacted] and filing an updated report that is not independent, and not prepared by proved experts, falls far short of that burden. Whether or not Ms. Lerette and her team actually did a better job on this analysis than Kinectrics, which of course is indeed possible, is certainly not a conclusion the Board could reach based on the evidence in this proceeding.

3.3.12 Therefore, in our submission the Asset Management Plan, because it is inconsistent with the Kinectrics Report, does not provide sufficient evidentiary support for the capital spending budget proposed by the Applicant.

3.3.13 ***Comparison to Other LDCs.*** The Board's recent move to start publishing full Yearbook data in spreadsheet format has been useful for intervenors and utilities alike. As a result of the availability of this information, SEC was able to prepare Exhibit K1.6, which in its bottom chart shows the net Property, Plant and Equipment for the ten LDCs with the highest PP&E, and then compares that figure to number of customers to get a figure "PPE/Customer". All figures are for 2009 data.

3.3.14 SEC acknowledges that the Yearbook data, because it is based on financial statement information and is not fully adjusted to match the normal regulatory models, must be approached with caution. We would not propose that the Board simply rely on it by itself, as if it were completely valid and comparable.

3.3.15 However, sometimes even imperfect data can still be used to make higher level comparisons, and as a diagnostic tool.

3.3.16 In this case, SEC believes that the PPE/customer data, which shows the Applicant having the lowest level (essentially tied with London and Veridian) of their peer group, is an indicator that the distribution system in Hamilton and St. Catharines is relatively older than, for example, those of Powerstream, EnWin, Enersource, and Toronto Hydro, and the Applicant agrees [Tr.1:149]. In addition, SEC believes that this data suggests that the Applicant may have higher capital renewal requirements than some of these peers, and the Applicant agrees with that as well [Tr.1:149].

3.3.17 We have gone back to the 2009 Yearbook data, and it appears that forty-four LDCs have PPE/Customer that is lower than the Applicant's, which suggests that the situation at Horizon is not extreme. Further, we note from that same data that the average PPE/Customer in 2009 of all LDCs was $1410, only 2.6% above that of Horizon. All of this is information in the Board's public files. This again suggests that, while relative to the other large LDCs the Applicant is very low, relative to all LDCs the Applicant is pretty close to average.

3.3.18 Overall, SEC concludes that the Yearbook data is directionally similar to the Asset Management Plan, but is insufficiently robust to provide reliable support for the high levels of capital spending proposed by the Applicant. At best, in our view, it shows that some modest increase in capital spending may be appropriate, without being strong enough to justify the levels proposed by Horizon.

3.3.19 ***Conclusion.*** SEC believes that the evidence in this proceeding – whether the Asset Management Plan or the Yearbook data - does not support the high levels of capital spending proposed by the Applicant. The best quality data [Kinectrics] would suggest that a capital spend of about [redacted] may be appropriate, but that is to a certain extent out of date. Between the AMP and the Yearbook data, a limited increase appears to be justifiable.

3.3.20 The Board is always faced with a dilemma when an Applicant fails to file sufficient evidence to support a key element in their Application, or when the filed evidence is contradictory. Obviously the Board should not just reject the Application in those circumstances, but approving a very large capital budget is also not appropriate.

3.3.21 Therefore, after first looking at the nature of the proposed spending, SEC will propose that the Board take a different approach to establishing the capital budget, which while still providing a substantial increase, would be within a more reasonable range.

3.4 ***Prioritization***

3.4.1 We have noted in our earlier discussion of Operating Costs SEC's concern with how this Applicant is setting priorities. Faced with a system that they claim needs capital renewal and increased maintenance, the focus of most of their new spending appears not to be "tool in hand" personnel. We originally had the same concern about the capital spending proposals, although the information was much less clear.

3.4.2 [redacted]

3.4.3 [redacted]

3.4.4 However, SEC has reviewed the data further, and provides the following table of Distribution Capital spending from the Application (adjusted to remove the IT spending in 2011-13):

Year	Distribution Plant Capital Spending	Percent Increase
2007	$19,280,286	
2008	$17,841,422	-7.46%
2009	$31,142,411	74.55%
2010	$30,404,796	-2.37%
2011	$31,960,133	5.12%
2012	$33,983,926	6.33%
2013	$34,566,381	1.71%

[Source: Ex 2/3/1, Tables 2-16, 2-20, 2-22, 2-32. 2007-2009 all actuals. All net of capital contributions.]

3.4.5 What this data suggests is that the increase in on the ground spending is not something that is happening in the Test Year. It in fact started in 2009, and is being maintained at a fairly constant level thereafter.

3.4.6 To verify this data, we looked at the 18xx series of USofA accounts in the fixed asset continuity schedules. These are the accounts that deal with capital spending on distribution infrastructure. What we found is a slightly different, but directionally similar, pattern:

USofA	Capital Category	2007	2008	2009	2010	2011
1808	*Buildings-Substations*	$83,043	$9,964	$3,740	$15,175	
1820	*Substation Equipment*	$81,750	$17,446	$306,708	$968,939	
1830	*Poles, Towers & Fixtures*	$5,008,005	$5,694,015	$7,383,755	$7,038,049	$9,821,067
1835	*OH Conductors & Devices*	$2,880,569	$2,763,188	$3,219,768	$4,338,975	$5,295,003
1840	*UG Conduit*	$3,060,535	$2,821,545	$5,622,716	$4,791,624	$5,751,825
1845	*UG Conductors & Devices*	$4,984,166	$5,901,655	$8,756,746	$8,042,752	$7,087,848
1850	*Line Transformers*	$3,262,932	$4,234,437	$9,382,665	$6,188,044	$7,044,713
1855	*Services (OH & UG)*	$1,497,253	$1,789,580	$1,763,849	$1,987,036	$701,504
1860	*Meters (excl. Smart Meters)*	$1,178,884	$5,403,196	$1,479,356	$1,715,776	$1,125,434
Total Infrastructure Spending		$22,037,137	$28,635,026	$37,919,303	$35,086,370	$36,827,394
Percent Change From Previous Year			29.94%	32.42%	-7.47%	4.96%

[Source: Ex 2/2/2, except 2010, which is EP TC #1. 2007-2010 all actuals. These figures are all before deductions for capital contributions, so are higher than the previous set of data.]

3.4.7 What both of these tables demonstrate is that the Applicant did not ramp up their spending on their system in response to their Asset Management Plan at all. That increase in spending happened at the very least in 2009, and probably to some extent in 2008 as well. The Asset Management Plan was not published until June 2010, and the studies on which it was based took place in mid to late 2009. By that time this increased capital spending program was already in place.

3.4.8 It therefore appears to us from the evidence that the Applicant has already ramped up distribution infrastructure spending, in an appropriate way, commencing in 2008 and 2009, so the Historical and Bridge Year spending already includes that substantial increase. No significant part (actually, about 5%) of the large increase in capital spending from 2010 to 2011 is, it appears to us, driven by incremental spending on the distribution system itself. The bulk of the new spending appears to be on general plant (IT spending, facilities upgrades, etc.).

3.5 ***SEC Recommendation on Capital Budget***

3.5.1 The adjusted budget requested by the Applicant, after moving spending from 2010 to 2011 as discussed in detail earlier, is $46,833,292. The average of the last four years' actuals is $33,283,806, which leads to the 41% increase cited earlier.

3.5.2 However, this four year average turns out to be misleading, because the Applicant's capital spending on its infrastructure took a jump in 2009, apparently to catch up with respect to past underinvestment. An average of the last <u>four</u> years does not capture the full impact of that infrastructure ramp up.

3.5.3 SEC therefore recommends that the Board establish the capital budget at the average of the last <u>two</u> years of capital spending, so that the increase in infrastructure spending is fully captured in that average. The result of this is $36,138,858.

3.5.4 Further, in consideration of the high CWIP in 2010, and consistent with our submissions in Section 3.2 above, the amount of $2,841,193 should be added to the 2011 capital expenditures. This produces a final capital budget for the Test year of $38,980,051, which is an increase of 12.69% over 2010 actual. However, it is approximately $8 million less than the high levels proposed by the Applicant.

3.6 ***Working Capital***

3.6.1 SEC has reviewed a draft of the submissions of Energy Probe on the calculation of working capital, and believes that analysis correctly sets out how working capital should be recalculated consistent with Board policy and the facts established in this proceeding.

3.6.2 In summary, Energy Probe has proposed the following adjustments to the working capital allowance:

(a) Recalculate the service lag based on revenue weighting, the standard and mathematically correct approach. This reduces the service lag.

(b) Recalculate the collection lag, also based on revenue weighting throughout. This increases the collection lag.

(c) Reduce the cost of power by applying all updates including updates to the load forecast, and by correcting an error in its calculation. The resulting cost of power should be $378,810,503.

(d) Reduce the interest expense from 7% on the affiliate debt to 6.1%. We will in fact propose later in this argument that the rate on the affiliate debt be reduced to 5.32%, which should result in a further working capital reduction.

(e) Update the tables in the Lead/Lag study to reflect the revised load forecast.

(f) Update the OM&A to reflect the final OM&A approved by the Board in this proceeding. This would include adjustments already proposed by the Applicant in updates and IR responses, plus any further reductions decided by the Board.

(g) Remove from the final OM&A total the $784,515 of management fees paid to an affiliate.

(h) Adjust the revenue weightings to reflect the changes in billing determinants since 2009, the year on which the lead/lag study is based. This will reduce the service lag and the revenue lag.

3.6.3 It would appear to us that these various corrections, detailed in the Energy Probe submissions, will reduce the working capital component of rate base by at least $4.5 million.

4 CAPITAL STRUCTURE AND COST OF CAPITAL

4.1 *Capital Structure*

No additional submissions.

4.2 *Return on Equity and Short Term Debt*

4.2.1 ***Appropriate Rates.*** In keeping with our submissions, below, on Effective Date, it is SEC's submission that the ROE and short term debt rates should be those set out in the Board's letter of March 3, 2011 applicable to distributors with a May 1, 2011 effective date. Those figures would be 9.58% for ROE, and 2.46% for short term debt.

4.2.2 While it would perhaps be fair to recalculate those rates based on the actual effective date determined by the Board (as proposed by Board Staff in their Final Argument, and agreed by the Applicant at Tr. 3:135-6), in our submission that could have unfortunate consequences in other applications. Ontario LDCs have shown a tendency sometimes to file their rebasing applications too late for rates to be in place at the proposed date. The Board's tool for dealing with that has been an increasingly rigorous approach to the dates for new rates. Thus, if a utility does not file a timely application and pursue it at an appropriate pace, it may lose one or more months at their new, presumably higher, rates.

4.2.3 If the Board were to now start recalculating cost of capital based on a later effective date, sometimes those capital figures will be higher than those for the normal January or May dates. The unfortunate result could be that a late-filing utility could benefit from that late filing with a higher cost of capital, which would then continue for almost four years. In the worst cases, a utility could game the system by delaying an application to get the benefit of increasing capital markets.

4.2.4 It is therefore our submission that, in this case, the ROE and short term debt should be calculated on the basis that this is a May 1, 2011 rate year, even if in fact new rates are not effective until some later date.

4.2.5 ***Early Rebasing Windfall***. We are aware that at least one other intervenor, and perhaps others, may be arguing in favour of deferring the application of the new cost of capital parameters until 2012, the year in which the Applicant would otherwise have been able to file on a cost of service basis and have those new parameters applied.

4.2.6 There is a lot to be said for this position, from a regulatory policy point of view. Of particular note is that, in the current case, the increased ROE under the new cost of capital parameters is nothing other than a windfall, entirely unconnected to the reasons that the Applicant sought and was granted the privilege of rebasing early.

4.2.7 Notwithstanding this fairness conclusion, SEC does not believe that deferring the application of the new cost of capital parameters is consistent with the current state of the law on cost of capital. Simply put, the cost of capital is a <u>cost</u>, and the Board has already determined the appropriate way of establishing the fair return when calculating the cost of capital. We believe that, in this particular cost of service proceeding, the Board under current law is obligated to allow recovery of the cost of capital in accordance with its own policies, with one exception as noted below.

4.2.8 In this respect, we note that if the Applicant were still under IRM, they would not have their cost of capital recalculated. The reason for this is that, under IRM, the Board does not set rates based on costs. Therefore, whether the cost is OM&A, depreciation, or cost of capital, it is not relevant to the setting of rates in an IRM year.

4.2.9 By contrast, the current application sets rates based on costs. Once the Board accepted a rate application on that basis, it was under current law required to establish the reasonable and prudent costs for the test period, which costs include cost of capital.

4.2.10 We do not believe that the Board is completely prohibited from determining that the implementation of new cost of capital parameters should be delayed until the next normally scheduled rebasing year. It may well be that the cases that require the cost of capital to be set like any other cost are distinguishable from a legal point of view, since none of them contemplate the interaction of IRM and a discretionary early rebasing.

4.2.11 However, we note that, if the Board were to decide in this case to delay implementation of the new cost of capital parameters, it would not only have to explain the inconsistency with cases in 2010 in which the new parameters were applied to Toronto Hydro and Hydro One, but it would also in our view have to identify the precise reasons why the leading Supreme Court of Canada cases on cost of capital should not apply in these unique circumstances.

4.3 *<u>Long Term Debt</u>*

4.3.1 ***Weighted Average Cost of Long Term Debt.*** The Applicant proposes to continue the use of 6.1%, in the calculation of the cost of long term debt, as the rate applicable to the affiliate debt of the Applicant. The full calculation of the weighted average cost of long term debt is as follows [Ex.5/1/1, p. 3, as updated by SEC IR #34]:

Creditor	***Principal***	***Rate***	***Interest***
Hamilton Utilities Corp.	$116,000,000	6.10%	$7,076,000
Horizon Holdings Inc.	$40,000,000	4.89%	$1,956,000
	$156,000,000	5.79%	$9,032,000

4.3.2 Applying that weighted average rate to the proposed long-term debt amount of $210,123,630 [AIC p. 15] produces an interest cost for long term debt of $12,165,619.

4.3.3 In our submission, for the reasons set forth below, the appropriate rate to be applied to the Hamilton Utilities Corp. affiliate debt of $116,000,000 is not 6.1%, but the deemed rate of 5.32%. As the result, in our submission the weighted average cost of long term debt should be as follows:

Creditor	***Principal***	***Rate***	***Interest***
Hamilton Utilities Corp.	$116,000,000	5.32%	$6,171,200
Horizon Holdings Inc.	$40,000,000	4.89%	$1,956,000
	$156,000,000	5.21%	$8,127,200

4.3.4 Application of this revised 5.21% weighted average rate to the proposed long-term debt amount produces an interest cost for long term debt of $10,946,902, a reduction in the debt cost and therefore the deficiency of $1,218,717.

4.3.5 ***The $116 Million Affiliate Debt.*** On February 28, 2005 the Applicant executed a promissory note payable to its then parent, Hamilton Utilities Corp., for $116 million. This note represented a replacement for a note originally entered into in 2002, and, among other things, for the first time it fixed the interest rate for the financing - at 7%. There was evidence in the EB-2007-0697 proceeding that the market rate at the time the note was issued in 2005 was 5.21% to 5.26%. The note replaced one at a rate fixed at the Board's "permitted rate" from time to time.

4.3.6 The 2005 promissory note was the subject of considerable evidence and debate in the EB-2007-0697 proceeding, with the Applicant seeking to recover the new 7% rate on the note, while the intervenors took the position that if management had been acting prudently, they would have borrowed (whether from an affiliate or on the market) at the admitted market rate of 5.26%. The discussion by the Board is found at pages 20-25 of that Decision.

4.3.7 In the end, the Board rejected both the Applicant's and the intervenors' positions, instead determining that the appropriate rate to apply was the Board's deemed rate. We note that what was applied was not the deemed rate at the time the note was executed, but the deemed rate applicable to 2008, the rate year. It was, essentially, treated as demand or variable rate debt, just as the note it replaced.

4.3.8 The position of the Applicant in this proceeding [Ex. 5/1/1, p. 2] is that nothing has changed since the Board set the 6.1% rate in EB-2007-0697. We agree, but the correct conclusion that flows from that is not that the 6.1% rate should continue. That was the rate in 2008, based on the deemed rate at that time.

4.3.9 The correct conclusion, in our view, is that the rate should be set on the same basis this time around as it was set for this very promissory note in 2008, i.e. the deemed rate, currently 5.32%.

4.3.10 We note that we are actually in the unusual situation here in which there is evidence on the record as to the appropriate long term interest rate to be paid to the Applicant's affiliate in the Test Year. That rate is 4.89% [SEC IR #34], being the rate that the Applicant will pay to its affiliate Horizon Holdings Inc. for $40 million of new debt incurred July 21, 2010. It is therefore not necessary for the Board to use a deemed market rate, since the actual market rate, and its application to an affiliate of this particular LDC, is known. You can't really get better evidence than that.

4.3.11 It is therefore reasonable for the Board to expect that the Applicant's management would refinance this debt immediately, in order to lock in a significantly lower rate. This is especially true since the Applicant admits that in 2012, when the 2005 note expires, the Applicant's intention is to finance it through Horizon Holdings Inc. on the same basis as the existing $40 million debt (except for the interest rate, which would be as of July 2012).

4.3.12 Notwithstanding that in our view it would not be unreasonable to apply a 4.89% rate to this $116 million, this argument is similar to the one SEC made in the EB-2007-0697 proceeding. While in this case the evidence is tighter, the substance of our submission that known market rates should be applied is much the same. The Board did not accept that position in the EB-2007-0697 proceeding. It would therefore appear to us, consistent with our comments above, that this Board panel should adopt the same conclusion (on the same instrument) as the previous Board panel, and thus apply the current deemed rate.

4.3.13 ***Proposed Variance Account.*** In the Application, the Applicant asked the Board to allow them to adjust their long term debt rate as part of their 2013 IRM application [Ex. 5/1/1, p. 3]. When the unusual nature of that request was pointed out to them by SEC, the Applicant responded [SEC IR #33] with several alternatives that might have some regulatory basis, including #4, a variance account based on the actual interest rate on their 2012 refinancing. This option was reiterated by Mr. Basilio under cross examination by Mr. Aiken [Tr.3:84-5], and at that time Mr. Basilio admitted that the proposal was not just to protect the ratepayers, but also to protect the Applicant if interest rates are higher.

4.3.14 SEC is generally opposed to the plethora of new variance accounts proposed by parties seeking to reduce uncertainty about future events, and therefore reduce the normal business risks of running utilities. While variance accounts are sometimes useful tools, they are not appropriately used to remove the responsibility of management to manage prudently.

4.3.15 In this case, management could (and in our view should) refinance this debt now, when it is clear from the evidence that they can get an interest rate of less than 5%. If they choose not to do so (and continue to pay a higher than market rate to their affiliate), the last thing the Board should do, in our view, is protect their downside risk if the ultimate interest rate when they refinance in 2012 is higher.

4.3.16 [redacted]

4.3.17 [redacted]

4.3.18 [redacted]

4.3.19 [redacted]

4.3.20 [redacted]

4.3.21 [redacted]

4.3.22 In our submission it is not appropriate for the Board to place this risk on the ratepayers through this unusual mechanism. It is more appropriate, we believe, to apply the deemed rate for the 2005 note, and face the issue of the actual rate on the refinancing at the time of the next rebasing.

5 DEFERRAL AND VARIANCE ACCOUNTS

5.1 *Amounts, Disposition and Continuation of Existing Deferral and Variance Accounts*

No additional submissions.

5.2 *New Accounts*

5.2.1 ***LPP Settlement Account.*** As we understand this request has been withdrawn, we make no submissions.

5.2.2 ***MDM/R Costs Account***. As we understand this request has been withdrawn, we make no submissions.

5.2.3 ***Debt Refinancing Variance Account.*** Please see our submissions commencing at para. 4.3.12 above.

5.2.4 ***OMERS Variance Account***. SEC continues to believe that pension costs are one of the normal costs that should be forecast and managed, and in respect of which the utility is compensated for the risk of increases We therefore believe that the Board, consistent with its decisions in a number of other rate proceedings, should not approve this proposed new variance account.

5.2.5 ***Large Use Load Variance Account.*** In our submissions at Section 1.3 of this Final Argument, SEC has demonstrated that the claimed "volatility" of large use load, in the sense of unpredictable variance around a baseline, has not really been demonstrated in the last three years. When the revenues from the Large Use class are adjusted as the Applicant agrees they should be, there appears to be a drop in 2009, but otherwise they are relatively stable. Also, as we have previously noted in Section 0.2 of this Final Argument, the Applicant's primary vulnerability to volume declines has not been in the larger users in any case. It has been in the Residential class.

5.2.6 The Applicant has proposed a variance account around the loads for certain large users, which would be asymmetrical and split 50/50 between ratepayers and shareholder. They also acknowledge that, if they experience further load declines, they may come back to the Board seeking relief [Tr. 3:172].

5.2.7 In our submission, the ROE provided to utilities is intended to compensate the shareholder for normal business risks, including the risk of variations in revenue driven by customer volumes. While there may well be circumstances in which a particular volume risk is outside of the normal business risks, in our submission that case has not been made out here.

5.2.8 Therefore, it is submitted that once a fair and reasonable load forecast has been approved, the volume risks in this case should remain with the utility, and management should be expected to respond appropriately to changes in volumes. Some will go up; some will go down.

5.2.9 Cherry-picking one narrow category of volumes and shifting that risk – and benefit, or part of it - to the ratepayers through a variance account or any other means should only be allowed in the most unusual of cases, where a specific uncertainty is of such magnitude that no reasonable utility could manage the risk. That is not the case here.

6 COST ALLOCATION

6.1 *General*

6.1.1 We have had an opportunity to review a draft of the submissions of VECC on this issue. We agree with VECC that the cost allocation study has been done correctly.

6.1.2 We also agree that the table of revenue to cost ratios arising out of VECC 44 (d) and (g), cited in VECC's Final Argument, and once updated to take account of the revised load forecast in April, is the appropriate starting point for analysis of the revenue to cost ratios for the Test Year.

6.2 *Revenue to Cost Ratios*

6.2.1 Those first items do not appear to be controversial. However, the proposed revenue to cost ratios are a significant concern.

6.2.2 On this point, SEC has also reviewed the submissions of VECC in draft, and we agree with the principles and conclusions in those submissions.

6.2.3 The Board will be aware that SEC, VECC and others are parties to multiple LDC rate applications, and the question of adjusting revenue to cost ratios often comes up in those proceedings. In some cases, utility proposals to move closer to one would result in schools having reduced rates (e.g. Toronto, EB-2010-0142). In other cases, the opposite is true (e.g. Horizon).

6.2.4 We agree with VECC that it is important for the Board to make decisions on changes in rates for customer classes in a principled way. We therefore fully adopt the submissions of VECC on this point.

6.2.5 We also note that we have made consistent submissions in the EB-2010-0142 proceeding, where schools would benefit from the utility's proposals. Rather than rephrase those submissions, it is appropriate to simply quote them in full, as follows:

> ***"1.*** *SEC has always believed that the goal of each LDC should be to get all revenue to cost ratios to 100% of allocated costs. Since most schools are in the GS>50 class, and that class is the one that most often recovers more than 100% of allocated costs, over the entire province it would be beneficial for schools to speed up the move to unity.*
>
> ***2.*** *But, we fought that battle, and we lost. In 2008 and thereafter, in numerous cases, SEC argued that there should be movement toward unity.*

In general, the Board concluded in those cases that the cost allocation data is insufficiently rigorous to warrant a full move to unity. At this point, said the Board in those cases, the goal should be to get everyone within the ranges established by the Board. As the data becomes better, classes can then be moved closer to unity.

***3.** The Applicant's data is no better than the data they had in 2008. Therefore, in our view further movement towards unity is, on the Board's normal practice, premature.*

***4.** SEC would still like to see further movement towards unity. On average, rates for schools would go down.*

***5.** However, what we would not like to see – and what we believe the Board should avoid – is a situation in which the move to unity is left to the discretion of individual utilities. It is not up to the utilities, in our view, to decide what rates for each class are "just and reasonable". They can provide valuable input to the Board, but in the end the fair division of revenue responsibility between classes should be decided by the Board based on ratemaking principles and goals that are applied consistently by the Board to all distributors.*

***6.** The Applicant says that they have made a "policy decision" [AIC, para. 82] that residential should be at 92%. This is, in our submission, not a "policy" matter that should be within a utility's discretion. No benefit is gained by giving this discretion, and granting the discretion creates a scope for exercise in ways not consistent with good ratemaking. A utility should not, for example, be free to decide that GS<50 customers should pay a little less in order to stimulate the local economy. It should not, for example, be free to decide that residential customers should get a break on rates in a municipal election year. While no-one is suggesting that the Applicant is doing either of these things, the fact is that ratemaking "policies" should be established by the Board, based on a set of common principles, and the utilities should simply implement those policies.*

6.2.6 It is submitted that the same situation applies here, but with the residential being moved <u>down</u> (rather than up, as in Toronto) due to a utility "policy" decision, and despite the utility having no better cost allocation data than it did in 2006 [Tr.3:147]. Therefore, for the same reasons as in Toronto, SEC believes that the proposal by Horizon to move closer to unity should be rejected.

7 RATE DESIGN

7.1 *Monthly Fixed Charges*

7.1.1 It is not the normal practice of SEC to comment on rate design matters as they relate to other classes. Since those decisions typically impact only intra-class cross-subsidization, they have no impact on schools.

7.1.2 We are treating this case as an exception to that rule, because the proposal of the Applicant to increase the monthly charges in the Large Use class by 123% could have an impact on the overall revenues from the Large Use class, and therefore the revenues that have to be collected from other classes.

7.1.3 What is proposed is that the monthly fixed charge in the Large Use class increase from $11,151.32 to $24,900.49. This is an annual increase of approximately $165,000 per year per customer, and is one of the main reasons for increases in the delivery cost for this class ranging from 25-39%, and total bill impacts of 4-6% [Ex. J3.6].

7.1.4 The utility's agenda is fairly clear. Mr. Basilio, asked about the increased fixed charge for Large Use class, said the following [Tr. 3:111]:

> *"It would be my contention that where your costs are largely fixed, which is our contention with respect to distribution, the design of your revenues is going to be a largely fixed component.*
> *And that is our contention. I think this is an evolution. We've advanced before that 100% fixed distribution charges, something approaching 100%, probably makes sense given the underlying cost structure of the utility, particularly in the short to medium term. But we're not – we're not proposing that today. I think <u>that's probably a journey</u>."[emphasis added]*

7.1.5 What the utility has failed to look at, in our view, is the potential impact on the customers. In fact, despite their claim that they are unusually susceptible to load volatility from the large use classes (which we have challenged earlier in this Final Argument), and despite the fact that when directed to do so by the Board they have now proposed to hire a Key Accounts Representative for large users and others, they still don't know how their bill affects their large users. Asked about this, Mr. Basilio said [Tr. 1:114]

> *"How does electricity costs weigh into the overall cost structure of our large user class? I don't have an answer."*

7.1.6 In our submission, until the Applicant finds out how their big-dollar rate design proposals for the Large Use class are likely to impact the twelve large users they have, it is inappropriate for them to make those proposals.

7.1.7 This is part of a larger issue, which can be summarized as follows. Utilities and their policies have an impact on their customers. It is part of their responsibility, as providers of a public monopoly, and as important economic influences within the community, to understand those impacts. When they come to this Board saying "Let's make this change", they should have already done their homework, and they should be able to tell the Board what that proposed change will mean to their customers.

7.1.8 Simply put, if adding $165,000 per year to the bills of twelve large customers could mean that next year there will only be nine of them, this Board has to know that. It should not be open to the utility to say "I don't know" when asked that question. And, it should not be open to the utility to propose policies considering only their internal risks, and not the broader implications. Good ratemaking requires understanding what will happen if changes are made.

7.1.9 It may be, in the end, that the loss of some customers over rate increases is a necessary result. That is sometimes true. But, it is also true that it is only good ratemaking if the Board is aware of the result, and approves the rate change with that knowledge. Proposing or approving rate changes without knowing their impacts is not, in our submission, good ratemaking.

8 OTHER MATTERS

8.1 *Effective Date and Rate Year Alignment*

8.1.1 The Applicant is seeking an effective date of January 1, 2011. That raises two questions. First, should the Applicant be allowed to align their rate year with their fiscal year? Second, what should be the effective date of new rates arising out of the Board's decision, regardless of the ultimate rate year ordered?

8.1.2 ***Rate Year Alignment.*** On the question of alignment with the fiscal year, SEC is on record as saying that, in most cases, and subject to handling any transitional impacts, the fair result is to allow the LDCs to collect rates over the period to which they relate, i.e. their fiscal period. The existing legacy structure is, in our view, an anomaly that should be corrected if possible. That applies here as well.

8.1.3 ***Effective Date.*** On the question of the effective date for 2011, we have less sympathy for the Applicant. In our submission, the Applicant has not made a case that its new rate should be effective January 1, 2011.

8.1.4 The analysis starts with the undisputed fact that the Applicant did not file their Application early enough to expect rates in place by January 1, 2011. A more reasonable expectation would have been May 1, 2011, based on their filing on the deadline for rates effective that date.

8.1.5 However, even May 1, 2011 is probably too early, because the Applicant knew they were seeking an early rebasing, and therefore had forewarning that a preliminary process would likely be required to determine whether the Application would even be considered. That process did add considerable time to this proceeding.

8.1.6 The Applicant then has a further problem. Not only was their Application not early enough, but throughout the process they were not able to pursue it with enough speed to warrant an early effective date. The most obvious example of that is the filing of an evidence update and new deficiency request <u>after</u> the settlement conference was concluded, followed by further changes of many key figures in the Application before or at the oral hearing [see generally Tr.1:16-19 to get a sense of just some of the changes], further followed by a new load forecast and materially increased deficiency right at the very end [J3.3].

8.1.7 We note that the process was also bogged down by the many requests for confidential treatment of documents, and by the length of the oral hearing, the latter a result of a) no issues being settled, and b) the full factual basis of many key issues only becoming clear in the oral hearing, rather than in the interrogatories and technical conference as would normally be preferred.

8.1.8 The facts, therefore, suggest that the Board should follow its normal practice of making new rates effective after the date of the final rate order. This is the most straightforward way to do it, and it helps the Board enforce a process discipline on its many regulated entities. Missing a deadline matters before this Board, so the once somewhat casual way that some utilities approached the Board's processes in the past is now less evident, and the Board's processes are more efficient as a result. It also avoids unnecessary rate riders and adjustments, including the related customer confusion, and it simplifies the ratemaking process.

8.1.9 On the current schedule, we would therefore expect new rates to be effective August 1, 2011 or September 1, 2011, depending on when the Board's decision in this matter is released. Given the need for a preliminary process, and the subsequent delays in the process as a result of the Applicant's own actions, the resulting elapsed time of 11-12 months from application to new rates is a reasonable one.

8.1.10 We note that the Applicant has [AIC, p. 21] referred to the "precedent" of EB-2010-0132, the 2011 rates for Hydro One Brampton. This is not an appropriate precedent. Not only did H1 Brampton file on June 30, 2010, much earlier than the Applicant, and without any need for a preliminary process because they were filing on their normal schedule. Not only did H1 Brampton have a smooth process, without updates, and resulting in an oral hearing at the beginning of December. These facts, all true, would still not, in our view, have been enough for the Board to provide for a January 1, 2011 effective date for new rates in the H1 Brampton case.

8.1.11 The biggest difference between the Brampton case and the Horizon situation is that in Brampton there was a sufficiency, so the issue was whether the rate <u>decrease</u> should be effective from January 1, 2011, as requested by the utility, or whether it should be deferred.

8.1.12 In our submission, the Applicant is not in a similar situation to Brampton. That case does not, in our view, provide any support for their request to reach back and recover their deficiency for a period of seven or eight months that was the result of the Applicant's failure to file and pursue a timely process.

8.1.13 Utilities should accept responsibility for bringing applications early enough to get new rates when they propose. Filing an early rebasing application with four months left until you want new rates does not, in our submission, meet that test.

8.1.14 ***Integration of Effective Date and Rate Year Alignment.*** Given our submission that a January 1, 2011 effective date is not justified in this case, the rate year alignment cannot be accomplished at that time. However, SEC still believes that it is appropriate.

8.1.15 Therefore, it is submitted that, while the effective date should be after the date of the final rate order, as per the Board's usual practice in these cases, the Board should make clear that the Applicant's rate year is, on a going forward basis, the calendar year, meaning that their next IRM application will be effective January 1, 2012.

8.2 ***Next Rebasing Year***

8.2.1 The Applicant has confirmed that they expect to submit their next rebasing application for the 2015 rate year, also a year ahead of their current schedule, but allowing for a four year cycle 2011-2014, followed by another rebasing [Tr.1:115]. It is submitted that the Board should not allow the special circumstances of this early rebasing application to provide a permanent procedural benefit to the Applicant in the future. Instead, the Board should in our view advise the Applicant that their next rebasing should be on their existing schedule, i.e. for the 2016 rate year.

8.2.2 The policy issue that arises is whether, when a utility is allowed to rebase early, the current schedule (i.e. the current and future years each individual utility can expect to file for rebasing) or the standard four-year cycle should be the basis for a utility's next rebasing.

8.2.3 In favour of the "standard cycle" approach is the fact that the Board established the IRM cycle for 3rd Generation IRM on the basis that it felt four years was an appropriate time period. This is further supported by the fact that, while here rebasing is only one year early, in some cases it could be two or potentially even three years early (although the latter is highly improbable). This would create a six or seven year cycle if the original schedule were to be maintained. In those cases, one would expect that something closer to the standard four year cycle would be more appropriate.

8.2.4 In favour of the "current schedule" approach is the fact that the Board has provided this utility with the privilege of rebasing early because of a particular problem that needs to be addressed now. The availability of that privilege will be sought by utilities, as the Board has already seen for 201l, and not just because they have unusual problems to be addressed. A number of Board policies are implemented only in cost of service applications (e.g. cost of capital parameters, rate year alignment), and as well rebasing is sometimes, as we have seen in this case, a chance to bump up costs and seek approval for incremental spending. Each collateral benefit of early rebasing makes it more likely that utilities will apply to rebase early, not only for the reasons they should, but to achieve those additional benefits. If a further benefit is that the early rebasing is not just a one-time acceleration, but will result in early rebasing thereafter, that will make the privilege even more attractive. Conversely, if an early rebasing application only has a short term impact, accelerating only the current year, it is less attractive.

8.2.5 The other reason for supporting the "current schedule" approach is that the Board has gone to some effort to spread the difficult task of cost of service applications for eighty distributors over a period of years. Each shift in that balance, such as the Applicant's current request to move from 2016 to 2015, disrupts the Board's ability to handle all of the distributors in an orderly way.

8.2.6 We don't believe it is appropriate to have a hard and fast rule about changes to the future rebasing schedule. If a utility is allowed to rebase in year two of their cycle, or perhaps even year three, it may well be appropriate to schedule their subsequent rebasing for five or even four years later. That will depend on the circumstances of the distributor.

8.2.7 Conversely, in our view when a utility seeks early rebasing in the fourth year of the cycle, so that their first cycle is three years instead of four, it would appear to us that, absent special circumstances, it would usually be appropriate for their next cycle to be five years to get them back on track.

8.2.8 That is, in our view, the case here. Even if the load loss problem the Applicant put forward as its rationale for early rebasing has been demonstrated in this hearing (which we believe is somewhat in doubt), nothing in this proceeding suggests that Horizon cannot get back to its normal schedule, and come back as originally planned for a 2016 rebasing. There are no special circumstances, and the advantage to the Board's procedures of not providing another collateral benefit for early rebasing is clear.

8.2.9 Of course, if the Applicant does face problems in year three or four, they have already said they may seek relief from the Board [Tr.3:172], but there is no reason to assume that will happen. Further, if it does happen, the Board has established a set of criteria for determining whether an early rebasing is appropriate. Those criteria can be applied at that time based on the facts then known, just as in this case.

8.2.10 It is therefore submitted that the Board should confirm the Applicant's next rebasing year as unchanged, at 2016, subject to the Board's normal rules for early rebasing requests.

8.3 *Costs*

8.3.1 The School Energy Coalition hereby requests that the Board order payment by the Applicant 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 thoroughly and efficiently as possible.

All of which is respectfully submitted.

Jay Shepherd
Counsel for the School Energy Coalition