March 5, 2010

BY EMAIL & COURIER

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge St, Suite 2701
Toronto ON M4P 1E4

Dear Ms. Walli:

Board File No. EB-2009-0143
Essex Powerlines Corporation – 2010 Cost of Service Application
Energy Probe Argument

Pursuant to the Decision on Partial Settlement and Procedural Order No. 3, issued by the Board on March 3, 2010, please find attached two hard copies of the Argument of Energy Probe Research Foundation (Energy Probe) in the EB-2009-0143 proceeding for the consideration of the Board. An electronic version of this communication will be forwarded in PDF format.

Should you require additional information, please do not hesitate to contact me.

Yours truly,

David S. MacIntosh
Case Manager

cc: Richard Dimmel, Essex Powerlines Corporation (By email)
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EB-2009-0143

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Essex Powerlines Corporation for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2010.

ENERGY PROBE RESEARCH FOUNDATION
("ENERGY PROBE")

ARGUMENT

March 5, 2010

ESSEX POWERLINES CORPORATION
2010 RATES

EB-2009-0143

ARGUMENT OF ENERGY PROBE RESEARCH FOUNDATION

A - INTRODUCTION

This is the Argument of the Energy Probe Research Foundation ("Energy Probe") related to the setting of 2010 rates for Essex Powerlines Corporation ("Essex") effective May 1, 2010.

This Argument is limited to the unsettled issues as identified at page 13 of the Settlement Agreement dated February 3, 2010 and filed on February 24, 2010. Where possible, Energy Probe has used the Settlement Agreement and the appendices to the Agreement as references to figures as they currently stand as a result of the settled issues.

B – REQUIREMENT FOR A LEAD/LAG STUDY

Essex has forecasted its working cash allowance using the "15% of specific OM&A accounts formula approach" included in the Board's Updated Filing Requirements dated May 27, 2009 (Exhibit 2, Tab 5, Schedule 1, page 1).

Energy Probe has concerns with the appropriateness of the standard 15% formulaic approach used to calculate the working capital allowance. This approach dates back to the prior regulation of municipal distributors by the former Ontario Hydro. The electricity industry has undergone significant restructuring since that time. Rates have been unbundled, distributors have been incorporated into for profit businesses and competition has been introduced in generation, to mention just a few. Customers can now pay their electricity bills on-line. In the near future further changes are expected including smart metering and time-of-use pricing. All of these changes have had or will have impacts on the cash working capital requirements for all distributors.

Energy Probe submits that the Board should direct Essex to undertake a lead/lag study in time for its next rates rebasing cost of service application. As shown in Appendix A to the Settlement Agreement, the 2010 test year working capital allowance is $8,119,276 and represents approximately 19.7% of the total rate base. This means that a one percentage point change in the 15% factor currently used to estimate the working capital component of rate base is equivalent to more than $541,000 in rate base and represents more than 1.3% of total rate base.

In other words, even a relatively small change in the level of the working capital allowance has a significant impact on rate base and the resulting revenue requirement. Ignoring the gross up for PILS, at the proposed weighted average cost of capital of 6.98% (shown in Appendix A of the Settlement Agreement), a one percentage point change in the 15% factor currently used to estimate the working capital allowance is equal to $37,800 in the revenue requirement. Over the four year cost of service and IRM period, this amounts to more than $151,000. The gross up for PILS would increase these amounts even further.

Energy Probe notes that the Board has expressed concerns about the potential costs to prepare a lead/lag study for distributors with a small working capital requirement and that the cost of an individual study may exceed any adjustment that might result.

As noted above, the revenue requirement impact of the current working capital allowance will factor into rates not only in the current cost of service year of 2010, but also in the subsequent 3 years under IRM. As a result, the Board should consider the potential cost of a lead/lag study in relation to the impact on the revenue requirement, multiplied by a factor of 4.

Energy Probe submits that the costs of a lead/lag study should not be significant. Most of the information required to prepare a lead/lag study is based on invoice dates for payments made by the distributor and when payment is received from customers relative to when their meter was read. As a result, this information can be obtained using internal resources.

Energy Probe further submits that the Board may want to hold a workshop and/or publish a generic methodology on how a distributor can complete their own lead/lag study with minimal external costs. Lead/lag studies are unique to a distributor since they will collect revenue from its customers with varying time lines. Different distributors will also pay their employees and invoices to third parties with different effective lags. However, the methodology used to calculate these leads and lags is generic. Once the distributors understand how to do a lead/lag study, much, if not all, of the work can be done using internal resources.

If the Board remains concerned with the potential costs associated with a full lead/lag study, then Energy Probe submits that a lead/lag study should be undertaken for the cost of power component of the working capital calculation. As shown in Exhibit 3, Tab 1, Schedule 1, Attachment 1 the total cost of power for 2010 was originally forecast to be $48,056,490. The response to Energy Probe Interrogatory #67 (c) reduces this amount by $239,894 related to the agreed upon methodology to reflect the difference in the RPP and non-RPP commodity costs, resulting in a total power supply expenses (including commodity costs, transmission costs, rural rate assistance and wholesale market service costs) of $47,816,596. Using the 15% factor, these costs translate into an amount of $7,172,489 or approximately 88.3% of the total working capital allowance shown in Appendix A of the Settlement Agreement. A review of these expenses, at a minimum, should be undertaken because of their significant impact on rates.

C - COST OF CAPITAL

The EB-2009-0084 Report of the Board on the Cost of Capital for Ontario's Regulated Utilities dated December 11, 2009 indicates that the result of the Report is Board policy and that the process was not a hearing process that did not, and indeed could not, set rates. The Report goes on to state that the refreshed cost of capital policies will be considered through rate hearings for the individual utilities, at which it is possible that specific evidence may be proffered and tested before the Board. Specifically, the Report states:

> *"Board panels assigned to these cases will look to the report for guidance in how the cost of capital should be determined. Board panels considering individual rate applications, however, are not bound by the Board's policy, and where justified by specific circumstances, may choose not to apply the policy (or a part of the policy)."* (Page 13)

Energy Probe submits that based on the December, 2009 Report of the Board and the evidence on the record in this proceeding there are two adjustments that Board should make to the cost of capital for the distributor. The first of these adjustments relates to the deemed capital structure and the second relates to the allowed return on equity.

a) Deemed Capital Structure

Short-term debt was not factored into electricity distribution and transmission rate-setting prior to 2008. As part of the December 20, 2006 Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors, the Board adopted a deemed short-term debt component of 4% of the capital structure. As part of that Board Report, the Board stated:

> *"As a general principle for ratemaking purposes, the Board believes that the term of the debt should be assumed to be similar to the life of the assets that are to be acquired with that debt. This suggests that, in theory, for an industry with long-lived assets, the majority of debt should be long-term. However, in reality, some short-term debt is a suitable tool to help meet fluctuations in working capital levels."* (Page 10)

As noted in the December, 2009 Report of the Board, capital structure was not a primary focus of the consultation. The Board determined that the split of 60% debt and 40% equity is appropriate for all electricity distributors (page 50). The Board did not explicitly state that the 60% debt component of the capital structure should remain at 56% long term debt and 4% short term debt, although Table 2 provided in the Summary section of the Board Report reflects the continuation of these figures.

Energy Probe submits that the evidence in this proceeding indicates that the 4% deemed level of short-term debt is not reasonable and that the incremental costs imposed on ratepayers by this are neither just nor reasonable.

Energy Probe agrees with the Board's comments provided in the December, 2006 Report of the Board that the term of the debt should mirror the life of the assets that the debt is used to finance. By its very nature, equity is long-term financing. This leaves the mix of long-term and short-term debt to be used to provide an appropriate balance within the capital structure to reflect the actual mix of assets being financed.

As noted by the Board in the December, 2006 Report, short-term debt is a suitable tool to help meet the fluctuations in working capital levels. As explained at Exhibit 2, Tab 5, Schedule 1, the working capital allowance has been calculated using the 15% factor. This effectively represents an average lag of 54.75 days between when a distributor pays its expenses and when they collect revenue from the customers. This reflects the short-term nature of the working capital.

As illustrated in Appendix A of the Settlement Agreement the working capital allowance component of rate base in 2010 is $8,119,276. This represents 19.7% of the total rate base of $41,128,526. The table in Exhibit 2, Tab 1, Schedule 1, Attachment 1 illustrates that the level of the working capital allowance has ranged from $7.2 million to $8.0 million over the 2006 through 2009 period.

At the same time, using the 4% deemed shot-term debt component to finance total rate base, the deemed amount of short-term debt is only $1,645,141 in 2010 (calculated as 4% of the total rate base of $41,128,526 shown in Appendix A of the Settlement Agreement). The resulting shortfall in deemed short-term debt in 2010 as compared to the working capital level is $6,474,135.

Energy Probe submits that this mismatch between the levels of deemed short-term debt and working capital included in rate base is not appropriate. The distributor is effectively financing short term assets through long-term debt. This means that ratepayers are being asked to pay long-term interest rates to finance short-term assets.

The impact on the revenue requirement of this unjustified mismatch can be calculated based on the difference between the long-term interest rate as shown in Appendix A of the Settlement Agreement and the deemed short-term interest rate as provided in the Board's February 24, 2010 letter related to the Cost of Capital Parameter Updates for 2010 Cost of Service Applications. In particular, the following table utilizes the long-term debt rate of 5.40% and the short-term debt rate of 2.07%.

	2010
Long-term Debt Rate	5.40%
Short-term Debt Rate	2.07%
Difference	3.33%
Deemed Shortfall	$6,474,135
Interest Cost Impact	$215,589

This amount represents a significant proportion (approximately 1.9%) of the total base revenue requirement of just over $11.4 million (Appendix A of the Settlement Agreement). This additional cost needs to be considered not only in the current test year, but also in the three subsequent IRM rate years. Over the four year period, ratepayers will be required to pay more than $862,000 more than they should.

As noted above, the distributor is effectively financing a significant portion of short-term assets with long-term financing at a higher rate. The distributor has a significantly different level of short term working capital levels in relation to rate base than a deemed short-term debt component of 4% would imply.

Energy Probe submits that it is neither just nor reasonable for the Board to expect ratepayers to pay long-term interest costs to finance short-term assets. This is not a good business practice and it is not a good regulatory practice. This is no more appropriate than if the distributor applied a high depreciation rate associated with computer software to a long lived asset such as poles that should have a low depreciation rate. In both cases the resulting revenue requirement is artificially inflated.

As noted earlier, the Board, in its December, 2009 Report indicated that panels assigned to individual utility rate cases are not bound by the Board's policy where justified by specific circumstances. Energy Probe submits that the evidence is clear. A 4% deemed short-term debt component is not appropriate when the distributor has a short-term asset component of rate base of nearly 20%.

It should be noted that the distributor has actual and forecasted long-term debt of $20,718,080 as identified in Exhibit 5, Tab 1, Schedule 2, Attachment 1, while the deemed long term debt is $23,031,975 (calculated as 56% of the total rate base of $41,128,526 shown in Appendix A of the Settlement Agreement). The difference between the deemed long-term debt and the level of actual long-term debt is $2,313,895. If only this amount of deemed long-term debt that is in excess to the actual amount of long-term debt forecast to be in place in the test year (i.e. unfunded long-term debt) was simply classified as short-term debt, the short-term debt component of rate base would increase to 9.6% (based on the addition of $2,313,895 to the deemed short-term debt of $1,645,141). This is a movement in the direction that is more in line with the level of short term assets in rate base.

Based on the 3.33% differential in rates calculated above, this would reduce the revenue requirement by more than $77,000 and reduce rates by this amount in the following three years. This represents more than 0.67% of the total base revenue requirement.

Equally important, it should also be noted that moving the difference between the deemed long-term debt and the actual level of long-term debt to short-term debt has no negative impact on the distributor since it does not have an actual cost associated with the unfunded long-term debt to recover.

Finally, Energy Probe notes the Board's comments at page 52 of its December, 2009 Report:

> *"The Board wishes to emphasize that the long-term debt guidelines relating to electricity distribution utilities are expected to evolve over time and are expected to converge with the process used by the Board to determine the amount and cost of long-term debt for natural gas distributors."*

Energy Probe submits it is time for the evolution to begin.

b) Allowed Return on Equity

The Board has determined a methodology to determine the return on equity as part of the December, 2009 Board Report. Based on this methodology and based on the September, 2009 information the return on equity would be 9.75%. This figure has been updated by the Board based on January, 2010 information to 9.85%.

The Board determined the 9.75% figure based on a long term Government of Canada bond yield of 4.25% and an initial equity risk premium of 550 basis points. This equity risk premium includes an implicit 50 basis point for transactional costs (page 37 of the December, 2009 Report). This is the same amount included in the equity risk premium as determined in the Boards December, 2006 Report. In that Report the Board noted that it would continue to include an implicit premium of 50 basis points for floatation and transaction costs. The Board further noted that this inclusion had been the case ever since the Board first introduced the premium in the early 1990s.

Flotation costs of capital are applicable in cases where a particular distributor releases some new stocks in the market or if it issues debt. These costs generally consist of charges for underwriters, commissions to be paid to brokers, legal fees and cost of administration.

Based on a rate base of $41,128,526 as shown in Appendix A of the Settlement Agreement and the deemed equity component of 40%, the common equity forecast for 2010 is $16,451,410. Based on this figure, the 50 basis point allowance for the floatation and transactional costs represent a significant amount of the revenue requirement. This cost amounts to $82,257 and when grossed up for taxes using the marginal rate of 31.00% is nearly $120,000. Over the four year IRM horizon, this amounts to an increase in costs to ratepayers of nearly $500,000.

Energy Probe submits that inclusion of the implicit 50 basis points for transactional costs is not appropriate for this distributor. There is no evidence to support that the distributor expects to incur any floatation or transaction costs in the test year. There simply is no evidence to suggest that this distributor will incur any of these costs.

As noted above, the inclusion of some provision for floatation or transactional costs in the equity risk premium component of the return on equity has been long standing at the Board, and indeed, at other regulators across North America. Energy Probe submits that distributors that have such costs should be able to recover them. Energy Probe makes no comments as to whether an allowance of 50 basis points is appropriate, is too high, or is too low. In any case, that is irrelevant in the current situation.

The evidence in this proceeding is that the cost for this distributor is $0.

As noted earlier in the submissions on the capital structure, the Board panel assigned to individual utility rate cases are not bound by the Board's policy where justified by specific circumstances.

Energy Probe submits that the evidence is clear. The specific circumstance in this case is that there are no floatation or transaction costs associated with equity that needs to be recovered from ratepayers.

The Board should not, indeed cannot, allow a distributor to recover costs that the Board knows do not exist. To do so would not result in just and reasonable rates.

The Board would not allow a distributor to include a capital expenditure that it knew would not take place in the test year to be added to rate base. The Board would not allow a depreciation expense to be included in the revenue requirement if that depreciation expense was calculated on an asset that did not exist. The Board would not allow an OM&A expense to be included in the revenue requirement if the evidence indicated that the money would not be spent or the addition to staff was not going to take place. The Board would not allow a cost of debt of 6% if the evidence indicates that the forecasted cost of debt for the test year is 5.50%. Why would the Board allow recovery of any cost that the evidence clearly indicates does not exist?

Energy Probe submits that it would be grossly unfair to ratepayers to expect them to pay for equity-related costs that clearly do not exist.

Energy Probe also submits that this would be unfair to other distributors that do have floatation and transaction costs. In the case of such a distributor, it would earn 9.85% on its deemed equity and some portion of that would be related to costs that were actually incurred. If the 50 basis points is an appropriate and accurate allowance, then the shareholder effectively earns an after cost return on equity of 9.35%. The shareholder of the distributor that has no such costs, however, is allowed to earn an after cost return on equity of 9.85%.

Energy Probe submits that the Board should not discriminate on this basis. Shareholders of all distributors should be allowed the opportunity to earn the same after cost return on equity.

D – PROVINCIAL SMALL BUSINESS DEDUCTION

The provincial small business deduction provides a lower provincial corporate income tax rate of 5.5% on the first $500,000 of business income. The benefit of this reduction is gradually phased out on taxable income between $500,000 and $1.5 million. This is achieved through the application of 4.25% surtax on taxable income between $500,000 and $1.5 million. If the taxable income is in excess of $1.5 million, there is no tax savings for a corporation.

Effective July 1, 2010, the small business tax rate has been reduced from 5.5% to 4.5% on the first $500,000 of taxable income. The effective rate for 2010 is the average of these figures, or 5.0%. Also effective July 1, 2010, the surtax of 4.25% has been eliminated. For 2010, this means that the effective surtax rate applicable to taxable income between $500,000 and $1.5 million is 2.125%.

Energy Probe has estimated that these changes in the small business tax rates results in a reduction in PILs payable for a distributor with taxable income in excess of $1.5 million to be $18,750 in 2010. For a distributor with taxable income less than $1.5 million, the reduction in PILs is greater than $18,750

The $18,750 reduction in taxes is the difference between the small business reduction and the claw back associated with the surtax, as explained below.

The reduction associated with the first $500,000 in taxable income reflects the difference between the 13.0% general provincial tax rate and the small business tax rate of 5.0%. This 8.0% differential in the tax rate, when multiplied by the $500,000, results in a reduction of $40,000. The surtax claws back a portion of this reduction. Application of the 2.125% surtax rate to the $1.0 million difference between the $500,000 and $1.5 million of taxable income results in a claw back of $21,250. The net difference between the reduction and the claw back is $18,750. If the taxable income is less than $1.5 million the claw back is less and the overall reduction in PILs is correspondingly higher than $18,750.

Essex has indicated that it does not qualify for the small business deduction (Board Staff Interrogatory #18 (a)). This belief if based on two things: its association with its affiliates and the total capital employed exceeding $15 million. In support of its position, Essex attached Section 2368.05 to the response.

The first rationale provided by Essex for not qualifying for the provincial small business deduction is that it is part of a group of companies. Energy Probe submits that being part of a group of companies is not relevant. The Board has a long standing policy that taxes for a regulated distributor are calculated on a stand alone basis.

Essex has, in fact, recognized this in the response to Energy Probe Interrogatory #38 where it corrected the Ontario capital tax exemption to the full $15 million amount. It did not allocate any of the $15 million exemption to any of the associated companies.

Energy Probe therefore submits that being part of a group of companies does not eliminate use of the provincial small business deduction for the calculation of PILs for regulatory purposes.

The second reason given by Essex to support its belief that the provincial small business deduction does apply to them is that it has taxable capital in excess of $15 million. However, there is no taxable capital limit associated with the eligibility for the provincial small business deduction. The $15 million referred to by Essex is the taxable capital limit associated with the federal small business deduction. Essex is not eligible for the federal small business deduction but this does not affect its eligibility for the provincial small business deduction.

Finally, Essex may believe that the small business deduction does apply to them because their taxable income is too high. This is not the case. Attached to this argument as Appendix A are the relevant pages (117-120) from the 2009 Ontario Budget – Confronting the Challenge – Building Our Economic Future.

Under the heading "Eliminating the Small Business Deduction Surtax", it is clearly stated that:

> *"If passed by the legislature, CCPCs would be taxed at the proposed new small business rate of 4.5 per cent, effective July 1, 2010, on the first $500,000 of active business income,* ***regardless of income level****. The proposed elimination of the small business deduction surtax and the general CIT rate cut* ***to 10 per cent****, in 2013, would provide all CCPCs with an average* ***CIT rate on active business income of below 10 per cent****." (emphasis added)*

This legislation has since been passed by the legislature. It is clearly stated that regardless of income level, the new small business rate will apply to CCPCs (Canadian Controlled Private Corporations). It also clear that the reduction in the tax rate on the first $500,000 remains in place, given the statement that when the general corporate income tax rate is cut to 10% in 2013, the tax rate on business income will be below 10%. The tax rate can only be lower than general corporate income tax rate if the reduced taxes payable on the first $500,000 of taxable income remain in place. The graph on page 119 of the budget documents reflects this.

In conclusion, Energy Probe submits that Essex is eligible for the provincial small business deduction. The Board should direct Essex to reduce its PILs by the full amount of the available reduction.

E – MANAGER, REGULATORY AFFAIRS

Essex is proposing to add the new position of Manager, Regulatory Affairs. The need for this new position is detailed at pages 6 and 7 of Exhibit 4, Tab 4, Schedule 1. The salary range for this position is shown as a range of $75,000 to $82,600. However, the all in costs associated with this position, including benefits, is $108,000 as stated in the response to Energy Probe Interrogatory #26.

Energy Probe submits that the Board should reject the need for this new position for a number of reasons.

First, Energy Probe submits that Essex has not provided sufficient evidence to support the inclusion of a new operations regulatory affairs manager position. The justification provided is that there is a need for this position due to the increasing regulatory burden related to the cost of service filing guidelines, the level of ongoing analysis including the collection of data and year to year comparisons. Energy Probe submits that since the 2010 rate rebasing has taken place, there will be a decrease in the regulatory burden associated with rate applications for the next three years. The only regulatory duties identified for this position are collecting data and ensuring the accuracy. Energy Probe submits that Essex has the onus to justify the need for a position that accounts for $108,000 of the increase in OM&A costs. Energy Probe submits that it should not require the creation of a management position in an organization that already has five management positions (Exhibit 1, Tab 2, Schedule 3, Attachment 2), plus a proposed management addition for special customer accounts, along with an existing position of finance & operations analyst to collect accurate data.

Essex also indicates that the need for this position is driven by the GEGEA. Energy Probe submits Essex does not need the Regulatory Manager position to deal with the impacts of the GEGEA. This is because it already has two other new positions included in the 2010 revenue requirement to deal with the impacts of the GEGEA. These positions are the Distribution Engineer and the Special Customer Accounts Manager. The need for these positions is described on pages 7 through 13 of Exhibit 4, Tab 4, Schedule 1. The need for each position is significantly driven by the GEGEA. Energy Probe submits that with these two positions, Essex should be able effectively participate and provide input into the GEGEA related processes before the Board, should its positions differ significantly from that of the Electricity Distribution Association.

In conclusion, Energy Probe submits that Essex has failed to justify the need for this additional position and the Board should find that the additional costs have not been justified.

F – NON-UTILITY REVENUES AND COSTS

a) Inclusion of Non-Utility Revenues and Costs in Revenue Offsets

Essex has included the revenues in account 4375 and the associated costs in account 4380 in the forecast of Other Operating Revenues as shown in Exhibit 3, Tab 3, Schedule 1, Attachments 1 & 2. The detailed breakdown of these revenues and costs shown in Attachment 2 indicates that these revenues and costs are associated with three main activities: the provision of CDM services, services to affiliates and work done for others.

The total net margin originally forecast by Essex for accounts 4375 and 4380 totaled $100,000 and this amount was included in the total of $779,884 for Other Operation Revenue for 2010 as shown in Attachment 1 of Exhibit 3, Tab 3, Schedule 1. However, in Attachment 1 of Exhibit 6, Tab 1, Schedule 2, the Revenues Offsets used to reduce the service revenue requirement to the base revenue requirement totaled only $679,883. Essex did not include the $100,000 net margin associated with accounts 4375 and 4380 as part of the revenue offsets used to determine the base revenue requirements. Essex confirmed this in the response to VECC Interrogatory #13 (a).

In the response to the VECC interrogatory, Essex indicated that the amounts included in accounts 4375 and 4380 were excluded from calculating the base revenue requirement and that this exclusion was consistent with the OEB's 2006 EDR model, where those accounts were not included in the revenue offsets calculated on sheet 5-5. Essex also stated that there has been no change or guidance to the contrary from the OEB since that model was issued.

Energy Probe submits that the amounts included in accounts 4375 and 4380 should be included in the determination of the base revenue requirement. In other words, the revenue offsets should include the net margin generated by these accounts.

A review of Chapter 8 of the May 11, 2005 RP-2004-0188 Report of the Board 2006 Electricity Distribution Rate Handbook reveals that there is no discussion or ruling related to the removal of the amounts in accounts 4375 and 4380 from the revenues offsets to calculate the base revenue requirement. Indeed, the only relevant part of the Report is where the Board defines revenue offsets as:

> *"revenues derived by the distributor from other Board approved charges and from sources other than Board-approved charges."* (Page 63)

Energy Probe submits that revenues and expenses associated with non-utility operations should be included as revenues from "sources other than Board-approved charges".

Essex contends that the 2006 EDR model did not include amounts from accounts 4375 and 4380 in the calculation of the revenue offsets. Energy Probe submits that this may have been the case and if it was, it was an error in the model. The intent of the 2006 EDR Handbook is clear. Amounts from these accounts were to be included in the revenue offsets. This can be seen from Appendix A.1 and A.4 to the Handbook. In particular, Appendix A.4 defines revenue offsets to include Specific Service Charges, Late Payment Charges, Other Distribution Revenue, and Other Income and Deductions. For this latter category, other income and deductions, Appendix A.4 refers the reader to Appendix A.1 for Definitions of Minimum Groupings. Turning to Appendix A.1 of the Handbook, the Minimum Group for Other Income and Deductions includes a number of accounts **including** accounts 4375 and 4380. Clearly the intent of the Handbook was to include accounts 4375 and 4380 in the calculation of revenue offsets.

Regardless of whether or not the 2006 EDR model should have included the net revenues from accounts 4375 and 4380 as revenue offsets, the May 27, 2009 Chapter 2 of the Filing Requirements for Transmission and Distribution Applications is crystal clear. The filing requirements state that the applicant must provide the breakdown of each of the other distribution revenue accounts as shown in Appendix 2-D. The notes at the bottom of Appendix 2-D clearly state that Other Income and Expenses include, among others, accounts 4375 and 4380.

Energy Probe submits that over and above the inclusion of the amounts in accounts 4375 and 4380 based on the 2006 EDR Handbook and EB-2004-0188 Report of the Board and the filing requirements for the 2010 cost of service applications, there is a compelling reason to have these amounts included in the revenue offset. This reason is that the services provided are all driven by, enabled by, and related to the distributor providing regulated services. The link between the regulated distributor and the provision of CDM related services is clear. The provision of street light service, traffic light service and sentinel light services to its affiliate (Exhibit 3, Tab 3, Schedule 1, Attachment 2) is directly related to the personnel and equipment used by the distributor for its regulated services. The provision of billing and collection services for water to its affiliates is related to the billing system used to bill for natural gas services. The work done for others is again enabled by the personnel and equipment used to provide regulated services. In summary, the provision of the services included under account 4375 is directly the result of being an electricity distributor. These services could not be provided without the assets and utility personnel in place at the regulated utility.

As a result, Energy Probe submits that it is reasonable to expect that any net margin generated by these services should be used to reduce the base revenue requirement by reflecting this margin as a component of the revenue offsets.

Energy Probe further notes that the Board has explicitly included the amounts included in accounts in 4375 and 4380 as part of the revenue offsets used to calculate the base revenue requirements in other cost of service rebasing applications. For example, in the EB-2008-0245 Decision and Order dated June 3, 2009 for Thunder Bay Hydro Electricity Distribution Inc. the Board found the following related to Non-Utility Operations:

> "*<u>Non-Utility Operations</u>*
>
> *Energy Probe submitted that Thunder Bay has under forecast the net revenues associated with non-utility operations. Thunder Bay proposed $7,000 as the 2009 net amount for accounts 4375 – Revenue from non-utility operations and 4380 – Expenses from non-utility operations. Energy Probe submitted that the Board should increase this amount to $25,000 given that the historical numbers were*

$24,000 for 2006, $29,000 for 2007 and $42,000 for 2008 to the month of November. Energy Probe noted that no explanation for the significant decrease was provided by the Company. Energy Probe further noted that the average of the above figures is $31,000.

In its reply submission, Thunder Bay stated that it did provide an explanation for the decrease in response to Energy Probe interrogatory #14 d). In that response, Thunder Bay noted that the significant decrease in the net income from accounts 4375 and 4380 is due to the sale of the Water Heater Rental assets by its affiliate, Thunder Bay Hydro Energy Services Inc., in 2008. Thunder Bay stated that the increase to $25,000 is not appropriate.

Board Findings

The Board finds that Thunder Bay's proposals with respect to Other Distribution Revenue, as revised during the course of the proceeding, are reasonable and should be reflected in the Draft Rate Order. The Board finds that a deferral account of the kind proposed by Energy Probe is unnecessary. By letter dated January 16, 2009, the Board has already indicated that any meter salvage value should be tracked in Account 1555 and used to offset the capital costs of the replacement smart meters. ***The Board is also satisfied with Thunder Bay's explanation of the decrease in revenues from non-utility operations****."* (Pages 37-38) (emphasis added)

The Board clearly approved the inclusion of the net revenues from non-utility operations as part of the revenue offsets. Energy Probe therefore submits that the amounts included in accounts 4375 and 4380 are properly included in the calculation of the revenue offsets used to calculate the base revenue requirement. The actual amount that should be included in the revenue offset is discussed below in part (b) of this section of the argument

In the event that the Board determines that the amounts in accounts 4375 and 4380 should not be used as revenues offsets in the calculation of the base revenue requirement, Energy Probe submits that the Board should direct Essex to file a fully allocated costing study as part of its next rates rebasing cost of service application. Such a study will be required to determine if the distributor is properly allocating costs between those assigned to the regulated utility and those to the unregulated services. If these amounts are included in the revenues offsets, the division of costs between the two functions does not impact on the base revenue requirement. However, this is not the case if the amounts are excluded from the determination of the base revenue requirement.

b) Level of Non-Utility Revenues

In the original evidence, Essex identified revenues in account 4375 of $1,787,240 and expenses in account 4380 of $1,687,240 (Exhibit 3, Tab 3, Schedule 1, Attachment 1) for a net margin of $100,000.

This net margin of $100,000 in 2010 and in 2009 is a reduction from a net margin of more than $200,000 recorded in 2008. Essex explained this reduction as a reduction in "anticipation that at least one of the towns will not be contracting from Essex" for billing services (VECC Interrogatory # 13 (c)). This would effectively reduce the net margin for accounts 4375 and 4380 to $0.

In response to Energy Probe Interrogatory #68, Essex indicated that the towns have expressed an interest in reducing their billing costs and may be seeking interest from other parties to provide these services. However, Essex did not have any correspondence from the towns, stating that this had been expressed verbally to them by the town treasurers. It was also indicated that there were no signed agreements to provide this service to the towns.

Energy Probe submits that Essex has not provided any evidence to substantiate the reduction of $100,000 in margin forecast for 2009 and 2010. If Essex had indeed lost this business as of the filing of responses to second round interrogatories on January 18, 2010, it would have indicated so. Energy Probe submits that the Board can only conclude that Essex did not lose this margin in 2009 and has not lost it in 2010.

Energy Probe notes that the materiality threshold for Essex is approximately $43,000 on OM&A expenses (Exhibit 1, Tab 4, Schedule 7). Should Essex lose any or all of the $100,000 margin while under IRM, it would be free to bring forward an application to reflect this loss of revenues.

In addition to the above, Essex has provided corrected expense figures for account 4380 associated with Work for Others (Energy Probe Interrogatory #19 (b)). In particular, the costs shown in account 4380 for Work for Others has been reduced from $263,142 to $222,158. The impact of this reduction in costs is a net increase in the margin associated with accounts 4375 and 4380 of $40,984. Energy Probe submits that this correction should be taken into account when determining the net margin associated with accounts 4375 and 4380.

In summary, Energy Probe submits that the net margin for accounts 4375 and 4380 should be increased from the $100,000 shown in Exhibit 3, Tab 3, Schedule 1, Attachment 2 to $240,984. This reflects the addition of $40,984 related to lower costs for Work for Others and the elimination of the $100,000 reduction forecast for billing services to the affiliates. The full amount of $240,984 should be added to the revenue offsets of $611,073 shown in Appendix A of the Settlement Agreement to calculate the base revenue requirement.

G – RSVA ACCOUNT 1588-GLOBAL ADJUSTMENT DISPOSITION

Energy Probe submits that the Board should adopt a separate rate rider for recovery of the Global Adjustment sub-account whenever the distributor is able to apply different rate riders to different customers within a rate class, as this follows the cost causality principle.

It is not clear to Energy Probe based on the evidence in this proceeding (including the responses to Board Staff Interrogatories #32 & #47) whether or not the Essex billing system is capable of creating distinctions among customers of the same rate class with respect to rate riders in order to clear the Global Adjustment balance only to non-RPP customers.

Energy Probe is concerned with the potential costs that may be incurred to have a separate rate rider for non-RPP customers and that these costs may outweigh the benefits in the test year.

At the same time, however, the Board is aware that the Global Adjustment is an adjustment sub-account that is likely to have significant balances that need to be cleared on an annual basis going forward. Over the long term, therefore, the expenditure may be justified.

Energy Probe submits that the Board should direct Essex to investigate the cost of being able to have different rate riders for different customers within a rate class.

The Board should initiate a consultative to review who can and who cannot dispose of the Global Adjustment to non-RPP customers only, and what are the likely costs and benefits for those distributors and their ratepayers that currently cannot follow the principled approach.

H - COSTS

Energy Probe requests that it be awarded 100% of its reasonably incurred costs. Recognizing the size of Essex Powerlines Corporation, Energy Probe has attempted to minimize its time on this application, while at the same time ensuring a thorough review.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

March 5, 2010

Randy Aiken

Consultant to Energy Probe

level. As a result of the proposed reductions in CIT rates, Ontario would adjust the tax credit rates for dividends from taxable Canadian corporations. The changes to the dividend tax credit rates would maintain the integration of Ontario's CIT and PIT systems by reflecting the reduction in CIT rates.

Competitive Business Taxes

The Budget is proposing business tax relief that would lower business costs, enhance Ontario's competitiveness and support growing small businesses. These measures would support the government's five-point economic plan and build on the tax relief already in place, such as the elimination of Capital Tax in 2010.

Cutting CIT Rates

Ontario's current general CIT rate is 14 per cent of taxable income and the rate for manufacturing and processing (M&P), mining, logging, farming and fishing is 12 per cent. The small business CIT rate currently is 5.5 per cent.

The government is proposing to cut CIT rates, beginning July 1, 2010, as follows:

- the general CIT rate would be cut from 14 per cent to 12 per cent and further reduced to 10 per cent over three years;
- the CIT rate on M&P and resource sectors would be cut from 12 per cent to 10 per cent;
- the small business CIT rate would be cut from 5.5 per cent to 4.5 per cent; and
- the small business deduction surtax of 4.25 per cent would be eliminated.

The following table sets out the proposed CIT rate cut plan:

Ontario's Proposed Corporate Income Tax Rate Cut Plan **Table 6**

	Rates (Per Cent)			
Date	**General**	**M&P[1]**	**Small Business[2]**	**Small Business Deduction Surtax[3]**
Current	14	12	5.5	4.25
July 1, 2010	12	10	4.5	0
July 1, 2011	11.5	10	4.5	0
July 1, 2012	11	10	4.5	0
July 1, 2013	10	10	4.5	0

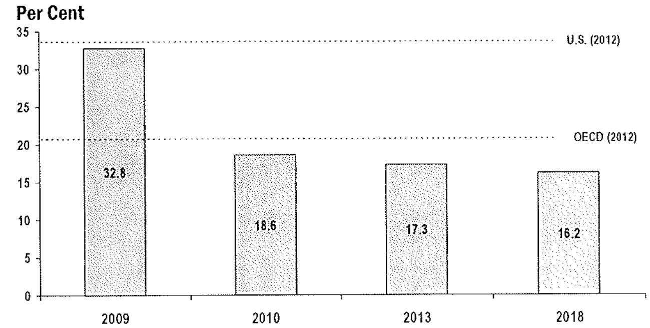
1 Income from manufacturing and processing, mining, logging, farming or fishing.
2 Applies to Canadian-controlled private corporations (CCPCs) on the first $500,000 of active business income.
3 Applies to CCPCs on taxable income between $500,000 and $1.5 million.
Note: The proposed tax rate reductions would be pro-rated for taxation years straddling the effective dates.

Lowering the CIT rate to 10 per cent would enhance Ontario's competitiveness and create a more efficient tax system that would encourage investment and increase productivity.

When the proposed Ontario CIT rate cuts are fully implemented, Ontario's combined federal–provincial CIT rate of 25 per cent would be lower than the current average Organisation for Economic Co-operation and Development (OECD) corporate tax rate of 26.7 per cent. Compared to the U.S. Great Lakes states — Ontario's key competitors for jobs and investment — Ontario's combined rate would be 15 percentage points lower than the average combined federal–state general CIT rate and more than 11 percentage points lower than the average combined manufacturing rate.

The proposed Ontario CIT rate reductions, together with the conversion of the RST into the single sales tax, would also cut Ontario's marginal effective tax rate (METR) on new capital investment in half, when those measures are fully phased in. This would make Ontario one of the most competitive jurisdictions in the industrialized world in terms of the taxation of new capital investment by corporations.

Cutting Ontario's Marginal Effective Tax Rate on New Investment* **Chart 1**



* Includes the Ontario CIT rate cuts and single sales tax proposed in this Budget, the phase-out of Ontario's capital tax by July 1, 2010, and the reduction in the general federal CIT rate to 15 per cent by 2012
Sources: Ontario Ministry of Finance and Finance Canada.

The Ontario METR, which includes federal taxes, currently stands at 32.8 per cent. The sales tax and CIT measures proposed in this Budget, together with previously announced Ontario and federal tax cuts, would bring Ontario's marginal effective tax rate in 2010 down to 18.6 per cent — below the OECD average of 21.8 per cent. Following the completion of the proposed CIT rate cuts in 2013, the Ontario rate would fall further to 17.3 per cent. When the restrictions on input tax credits under the single sales tax are phased out in 2018, the rate would decline to 16.2 per cent.

This would promote increased foreign and domestic investment and productivity in Ontario.

Eliminating the Small Business Deduction Surtax

The small business deduction provides a lower CIT rate of 5.5 per cent to Canadian-controlled private corporations (CCPCs) on the first $500,000 of active business income. Currently, the benefit of the small business deduction is gradually phased out on taxable income between $500,000 and $1.5 million. In 2008, the small business deduction provided over $1.1 billion of tax relief to CCPCs in Ontario.

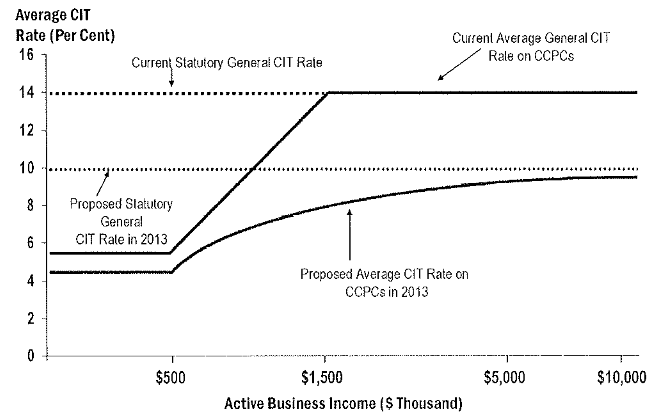
ELIMINATING A BARRIER TO SMALL BUSINESS GROWTH

Ontario's proposed elimination of the small business deduction surtax would make Ontario the only province not to claw back the benefit of the small business deduction.

The benefit of the small business deduction is phased out by a 4.25 per cent surtax that is applied in addition to the regular CIT rates.

As part of the government's plan to enhance the competitiveness of Ontario's corporate tax system, the government proposes to eliminate this barrier to growth for small businesses effective July 1, 2010. This would extend the benefit of the small business deduction to all CCPCs. If passed by the legislature, CCPCs would be taxed at the proposed new small business rate of 4.5 per cent, effective July 1, 2010, on the first $500,000 of active business income, regardless of income level. The proposed elimination of the small business deduction surtax and the general CIT rate cut to 10 per cent, in 2013, would provide all CCPCs with an average CIT rate on active business income of below 10 per cent.

Cutting Taxes for Growing Small Businesses **Chart 2**



Note: Graph not to scale. For illustrative purposes only.
Source: Ontario Ministry of Finance.

Based on legislation currently in place in other provinces, eliminating the surtax would make Ontario the only province not to claw back the benefit of the small business deduction.

This measure would be pro-rated for taxation years straddling the effective date.

Reducing the Corporate Minimum Tax

The CMT is calculated as the amount by which four per cent of adjusted net income for accounting purposes exceeds CIT payable. The CMT generally acts as a prepayment of CIT by providing for a carry-forward credit equal to the amount of CMT paid. The credit can be carried forward up to 20 years and may be applied to reduce CIT in years where CIT exceeds CMT. A corporation or an associated group of corporations with total assets under $5 million and annual gross revenues under $10 million does not pay CMT.

As a result of the CIT reform proposals in this Budget, a corresponding reduction in the CMT rate is necessary to ensure that corporations subject to the CMT are able to fully benefit from the proposed CIT rate reductions. In addition, the government is proposing to exempt more small and medium-sized businesses from calculating and paying the CMT.

It is proposed that effective for taxation years ending after June 30, 2010:

- the CMT rate be reduced to 2.7 per cent; and
- a corporation or an associated group with under $50 million in total assets or under $100 million in annual gross revenues would not pay CMT.

The 20-year CMT credit carry-forward mechanism would continue to apply.

The proposed rate reduction would be pro-rated for taxation years straddling the effective date.

Ontario's Legislated Plan to Eliminate Capital Tax

Capital Tax, which taxes business investment, is widely recognized as a barrier to attracting new investment. In 2004, the government set out a plan to eliminate Ontario's Capital Tax by 2012.

Since then, the government has accelerated the elimination plan and further relieved the Capital Tax burden on business. On January 1, 2007, Capital Tax rates were cut by an additional 21 per cent, and Capital Tax was eliminated for Ontario companies primarily engaged in M&P and resource activities.

On January 1, 2010, Capital Tax rates will be cut by one-third and the tax will be fully eliminated on July 1, 2010. The accelerated Capital Tax elimination plan has been fully legislated.

Ontario's Accelerated Capital Tax Elimination Plan — **Table 7**

		Rates (Per Cent)				
		Non-Financial Institutions		Financial Institutions		
				1st $400 Million of Taxable Capital	Taxable Capital Over $400 Million	
Date	**Deduction ($ M)**	**M&P and Resources[1]**	**Other Corporations**		**Non-Deposit Taking**	**Deposit Taking**
2004	5	0.3	0.3	0.6	0.72	0.9
Jan. 1, 2007	12.5	Eliminated	0.225	0.45	0.54	0.675
Jan. 1, 2008	15		0.225	0.45	0.54	0.675
Jan. 1, 2010	15		0.15	0.3	0.36	0.45
July 1, 2010	Legislated Accelerated Elimination Date					

Measures are pro-rated for taxation years straddling the effective date.

1 Primarily engaged in manufacturing and processing, mining, logging, farming or fishing activities in Ontario.