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February 26, 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-2009-0260
Cambridge and North Dumfries Hydro Inc. – 2010 Cost of Service Application
Energy Probe Argument

Pursuant to Procedural Order No. 3, issued by the Board on February 4, 2009, please find attached two hard copies of the Argument of Energy Probe Research Foundation (Energy Probe) in the EB-2009-0260 proceeding for the Board's consideration. 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: John Grotheer, Cambridge and North Dumfries Hydro Inc. (By email)
James Sidlofsky, Border Ladner Gervais LLP
Randy Aiken, Aiken & Associates (By email)
Intervenors of Record (By email)

Energy Probe Research Foundation 225 BRUNSWICK AVE., TORONTO, ONTARIO M5S 2M6
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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 Cambridge and North Dumfries Hydro Inc. 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

February 26, 2010

CAMBRIDGE AND NORTH DUMFRIES HYDRO INC.
2010 RATES

EB-2009-0260

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 Cambridge and North Dumfries Hydro Inc. ("CNDHI") effective May 1, 2010.

This Argument is limited to the unsettled issues as identified in Attachment A to the Settlement Agreement updated February 17, 2010. Where possible, Energy Probe has used the Settlement Agreement appendices as references to figures as they currently stand as a result of the settled issues.

B – REQUIREMENT FOR A LEAD/LAG STUDY

CNDHI 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, page 92). CNDHI has not undertaken a lead/lag study (VECC Interrogatory #11) because it did not believe it would be cost effective to conduct such a study for the current application.

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.

Of even more concern is that CNDHI is moving to monthly billing effective November 1, 2010. CNDHI will be collecting revenues from customers on an accelerated basis compared to the status quo. All else being equal, this should reduce the level of working cash required by the utility as it will collect money from its customers quicker and more frequently under monthly billing.

Energy Probe submits that the Board should direct CNDHI to undertake a lead/lag study in time for its next rates rebasing cost of service application. As shown in Attachment D of the Settlement Agreement, the 2010 test year working capital allowance is $17,537,926 and represents approximately 16.8% 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 $1,169,000 in rate base and represents more than 1.1% 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 6.75% (also shown in Attachment D of the Settlement Agreement), a one percentage point change in the 15% factor currently used to estimate the working capital allowance is equal to $78,900 in the revenue requirement. Over the four year cost of service and IRM period, this amounts to more than $300,000. 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.

Energy Probe notes that CNDHI should not be considered a small distributor with a small working capital requirement. It has a rate base in excess of $100 million and serves more than 63,000 customers.

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 the 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 Attachment C to the Settlement Agreement, the power supply expenses (including commodity costs, transmission costs, rural rate assistance and wholesale market service costs) total \$106,617,900. Using the 15% factor, these costs translate into an amount of \$15,992,685 or more than 91% of the total working capital allowance shown in Attachment D to 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 in Exhibit 2, page 92, 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 Attachment D of the Settlement Agreement the working capital allowance component of rate base in 2010 is $17,537,926. This represents 16.8% of the total rate base of $104,518,021. Table 1 of Exhibit 2 illustrates that the level of the working capital allowance been very stable over the last several years. Over the 2006 through 2009 period, the level of the working capital allowance has ranged from $17.9 million to $19.0 million.

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 $4,180,721 in 2010 (calculated as 4% of $104,518,021 total rate base shown in Attachment D of the Settlement Agreement). The resulting shortfall in deemed short-term debt in 2010 as compared to the working capital level is $13,357,205.

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 rates as shown in Attachment D of the Settlement Agreement and the short-term interest rate of 2.07% 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 agreed upon long-term debt rate of 4.99% and the short-term debt rate of 2.07%.

	2010
Long-term Debt Rate	4.99%
Short-term Debt Rate	2.07%
Difference	2.92%
Deemed Shortfall	$13,357205
Interest Cost Impact	$390,030

This amount represents a significant proportion (approximately 1.7%) of the total base revenue requirement of just over $23.2 million (Attachment D 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 $1,560,000 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. It 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 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 17%.

It should be noted that the distributor has actual and forecasted long-term debt of $38,019,703 (Attachment G of Settlement Agreement), while the deemed long term debt is more than $58,530,092 (calculated as 56% of $104,518,021 total rate base shown in Attachment D of the Settlement Agreement). The difference between the deemed long-term debt and the level of actual long-term debt is $20,510,389. If a portion of this amount of deemed long-term debt equal to the shortfall between the deemed amount of short term debt and the working capital allowance component of rate base was simply classified as short-term debt, the short-term debt component of rate base would increase to 16.8%, in line with the level of short term assets in rate base. Based on the 2.92% differential in rates calculated above, this would reduce the revenue requirement by more than $390,000 and reduce rates by this amount in the following three years.

Equally important, it should also be noted that moving part of 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 will be updated by the Board based on January, 2010 information.

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 $104,518,021 as shown in Attachment D to the Settlement Agreement and the deemed equity component of 40%, the common equity forecast for 2010 is $41,807,208. 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 $209,036 and when grossed up for taxes using the marginal rate of 28.53% shown in Revised Table 43 of Attachment F to the Settlement Agreement is more than $290,000.

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 do not clearly do no 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 9.75% 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 9.25%. The shareholder of the distributor that has no such costs, however, is allowed to earn an after cost return on equity of 9.75%.

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- THE HARMONIZED SALES TAX

a) The Issue and the Amount

The provincial sales tax ("PST") and the goods and services tax ("GST") have been combined into a harmonized sales tax ("HST") effective July 1, 2010. The PST is included as part of the expense included in an OM&A expense and as part of the cost of capital expenditures. This is different from the GST. The GST is not included as part of the cost of an OM&A expense or as part of the cost of a capital expenditure. The GST paid by a utility is a credit that is used an offset to the amount of GST collected. The difference between the amount collected and amount paid is remitted to the government.

The HST will operate in a similar manner to the GST. The effect of this change for businesses will be a reduction in OM&A expenses and capital expenditure costs related to the PST.

Energy Probe submits that it is important that ratepayers receive the benefit of the lower costs for businesses associated with the elimination of the PST, in line with the policy of the Government of Ontario.

In response to Energy Probe Interrogatory #1, CNDHI has provided estimates of the PST included in the 2010 OM&A and expenditure forecasts and that no adjustments to these forecasts to reflect the changes related to the elimination of the PST and the implementation of the HST. CNDHI also provided historical estimates of the amount of PST included in both OM&A and capital expenditure costs for 2006 through 2009 in the Energy Probe response.

The estimated costs of the PST included in the 2010 OM&A expense forecast is $86,017, while the amount included in the 2010 capital expenditure forecast is $338,418. Based on the historical PST figures provided for both OM&A and capital expenditures, along with the levels of OM&A and capital expenditures in those years, Energy Probe submits that the forecasts provided for 2010 are reasonable and should be accepted by the Board.

In the response to Board Staff Supplemental Interrogatory # 42 and in its Argument-in-Chief on Unsettled Matters dated February 19, 2010, CNDHI offers a number of reasons for not reducing the OM&A and capital expenditure forecasts related to the elimination of the PST effective July 1, 2010.

The first of these reasons include the belief that the Board should deal with this change as an industry-wide issue. Energy Probe submits that this is not required for those distributors that are rebasing under a cost of service application. The elimination of the PST is a change in taxes applicable to the distributor. There are a number of other tax changes that occur in 2010 and have been accepted by CNDHI as part of the Settlement Agreement in response to the interrogatory process, including the change in the provincial tax rate, the changes in the small business deduction and the elimination of the provincial capital tax, also effective July 1, 2010. The elimination of the PST is no different. It is a tax that will no longer be incurred by CNDHI as of July 1, 2010.

The second reason for not wanting to reduce the OM&A and capital expenditure estimates in 2010 for costs that will no longer exist is that CNDHI has concerns over the cost impact of the switch from PST to HST is unknown and may never be known. CNDHI states, without supporting evidence, that prices may increase as suppliers fail to pass through the full tax reduction in their prices. Energy Probe submits that there is no evidence to support this position. The province is in the midst of a severe economic downturn. Suppliers are already cutting prices to maintain business. A review of the GDPIPIFDD which the Board uses to determine the inflation rate for the IRM adjustment reflects that the inflation level associated with final domestic demand has fallen significantly during the lean economic times. Statistics Canada reports that the GDPIPIFDD has fallen from an increase of 3.3% on a year over year basis in the fourth quarter of 2008 to 2.8% in the first quarter of 2009, to 1.8% in the second quarter and to 0.6% in the third quarter (http://www.statcan.gc.ca/daily-quotidien/091130/t091130a6-eng.htm). Clearly, the economic downturn is having an impact on prices.

Energy Probe further notes the Government of Ontario, as part of its policy on sales tax reform included in the 2009 Ontario Budget stated that studies show that most of the cost savings to businesses from removing the embedded sales taxes are passed on to consumers through lower prices and that a recent C.D. Howe report found that in the GST harmonization in the Atlantic provinces the majority of the savings passed through to consumers in the first year[1].

CNDHI also states that it believes the impact on the capital expenditures is not material. Energy Probe disagrees. As noted above, the PST related to the 2010 capital expenditures of $338,418, so the reduction to reflect the July 1, 2010 elimination of the PST is one half of this amount or $169,209.

Energy Probe submits that both the OM&A expense forecast and the capital expenditure forecast for 2010 should be reduced to reflect the July 1, 2010 implementation date for the HST and the elimination of the PST.

Energy Probe submits that the Board should reduce the OM&A expense by $43,009 (one-half of the forecasted amount included in 2010 expenses) and reduce the capital expenditures by $169,209 (one-half of the forecasted amount included in 2010 capital expenditures). This will provide ratepayers with the reductions related to the elimination of the PST, consistent with government policy.

b) Need for a Variance Account

As indicated in the responses to Board Staff Supplemental Interrogatory #42, CNDHI is concerned with the administrative costs associated with trying to track the PST costs no longer paid after July 1, 2010. In addition, CNDHI expresses concern about its ability to accurately track these reduced expenses.

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[1] Michael Smart, "Lessons in Harmony: What Experience in the Atlantic Provinces Shows About the Benefits of a Harmonized Sales Tax," *C.D. Howe Institute Commentary*, July 2007.

Energy Probe submits that given the reasonable estimates of the PST costs included in the 2010 OM&A and capital expenditure forecasts, that there is no need for a variance account around the proposed reductions noted above. The forecast is adequate for rate making purposes.

If, however, the Board determines that a variance account should be established, Energy Probe submits that the wording of the account should be similar to the deferral account as found in the EB-2009-0139 Settlement Agreement (pages 4-5) dated January 22, 2010 for Toronto Hydro-Electric System Limited which is replicated here:

> *"Beginning July 1, 2010 and until THESL's next cost-of-service rebasing application, track in a deferral account the incremental Input Tax Credit it receives on non-pass-through items that were previously subject to Provincial Sales Tax and become subject to Harmonized Sales Tax. The intention of this account is to track the incremental change due to the shift from Provincial Sales Tax to the Harmonized Sales Tax and the amounts THESL receives through the incremental Input Tax Credit. Tracking of these amounts will continue in the deferral account until THESL's next cost of service application is determined by the Board or until the Board provides guidance on this matter, whichever occurs first. For example, Cost of Power and all other upstream charges applied to THESL by the IESO and/or Hydro One are excluded from this calculation, and to qualify for this treatment the cost of the subject items must be determinative of distribution revenue requirement (including capital and distribution expenses). THESL will apply to clear the balance in the variance account as a credit to customers at the next opportunity for a rate change after the account balance information becomes available."*

The reference to a deferral account would be replaced with a variance account.

E – LOAD FORECAST

a) The Methodology

CNDHI uses a forecast methodology that consists of a number of distinct steps. The methodology is described in detail in Exhibit 3, Tab 2, Schedule 2 beginning at page 7.

The first step in the process is the use of a multifactor regression analysis to model total monthly system purchased energy over the historical period for January, 1996 through December, 2008. The second step involves using the equation to forecast volumes for 2009 and 2010. The third step involves adjusting the forecasted 2009 and 2010 purchase figures by an average loss factor to convert purchases into total weather normalized billed energy.

The fourth step involves an analysis of the annual kWh usage per customer for each rate class, along with the forecasted number of customers/connection in each class and the weather sensitivity by rate class. This creates a non-normalized forecast of kWhs for each rate class which is then aligned to the normalized billed energy forecast. The final step involves the conversion of the kWh forecast to kW's for those classes where the distribution volumetric charge billing determinant is kW's.

Energy Probe supports the use of the methodology used by CNDHI. Although Energy Probe believes that the regression analysis should be conducted on individual rate classes and their associated monthly billed kWhs, it is aware that sufficient reliable data on a rate class basis is not yet available for this approach to produce reliable results.

Energy Probe does not take issue with the second, third or fourth steps noted above. However, Energy Probe submits that there are significant issues in the first and final steps in the process. Each of these two steps is discussed below.

b) The Multifactor Regression Analysis

The equation used by CNDHI is shown at pages 14 & 15 of Exhibit 3. Energy Probe submits that this equation is flawed and should not be used to model purchased energy. CNDHI recognized the problems associated with this equation, being insignificant t-statistics on some variables and implausible signs on the coefficients of others. As indicated in their Argument-in-Chief on Unsettled Matters dated February 19, 2009, CNDHI is now proposing to utilize the equation crafted in response to VECC Interrogatory #14(c).

Energy Probe has confined its argument on this issue to the equation provided in response to VECC Interrogatory #14(c) given that CNDHI recognizes that this is an improvement over the equation used in the evidence. Energy Probe agrees that the VECC equation is an improvement. It no longer has the problem of a coefficient with an incorrect sign (population) as did the original equation. This is a step in the right direction.

However, Energy Probe submits that the VECC equation still has two major flaws.

The first of these flaws is that it still includes a variable that has a t-statistic that is significantly less than 2.00. This variable, the Spring Fall Flag has a t-statistic of only 0.13, indicating that at any reasonable level of confidence, the coefficient is statistically not different from zero.

CNDHI has indicated that its objective was to develop a multi-regression model that achieved an R^2 value higher than or equal to 95% (Board Staff Interrogatory #9(b)). In the response to Energy Probe Interrogatory #16(b) CNDHI further indicates that no variables with a t-statistic of less than 2 but greater than 1 were removed from the final version of the equation. However, CNDHI did not apply this to the VECC equation. It left the Spring Fall Flag in the equation despite a t-statistic of only 0.13.

Energy Probe submits that this is not appropriate.

Energy Probe submits that CNDHI has put too much significance on the R^2 statistic that relates to the goodness of fit. A good fit is important. However, a good fit is irrelevant if some of the estimated coefficients have incorrect signs or are statistically no different from zero with a reasonable level of confidence.

The emphasis on the goodness of fit is also overblown in the rationale used by CNDHI. The R^2 statistic is the coefficient of determination for a regression equation and represents the proportion of the total variance in a dependent variable that is explained by the regression. In other words, the R^2 statistic is a measure of the explanatory power of the regression. However, it is widely acknowledged that the use of the R^2 figure must be used carefully in comparing regressions[2].

For example, the value of R^2 will remain the same or increase as more explanatory variables are added to the equation – it cannot decrease. This means that the addition of an explanatory variable such as a random variable totally unrelated to the dependent variable can increase the R^2 value. This means that an increase in the R^2 value by itself does not mean the equation will provide a better forecast.

It is also inappropriate to compare the R^2 of two regression equations with different numbers of explanatory variables. It is an appropriate use of the R^2 to compare regressions if the number of explanatory variables is the same.

Comparison of the R^2 value from the equation without the population variable as an explanatory variable to the equation with it included as done by CNDHI in the response to VECC Interrogatory #14(c) is not valid since the two equations do not have the same number of explanatory variables.

A more accurate comparison of the goodness of fit across equations that have a different number of explanatory variables is the adjusted coefficient of determination, or the adjusted R^2. The adjusted R^2 takes into account the number of explanatory variables. It can decline as the number of explanatory variables is increased, effectively indicating that the added variables are masking some of the explanatory power of other variables.

Energy Probe submits that econometric modeling is an inexact science. However, as with any science there are basic tenants that need to be followed and observed. Energy Probe submits that econometric modeling is not merely a matter of regressing demand against a list of potential explanatory variables and accepting the outcome based on the

[2] See, for example, Econometric Models, Techniques, & Applications by Michael D. Intriligator, 1978, Prentice-Hall, Inc.

best R^2 statistic. The estimated model needs to pass basic reasonableness tests, the first of which is – Are the coefficients plausible in sign? – and the second of which is – Are the estimates significant at a reasonable level of confidence? If not, it does not matter what the R^2 is. The R^2, or more accurately, the adjusted R^2 is relevant only in comparing equations that first pass these reasonableness tests.

The second flaw in the equation is that CNDHI has included a "CDM" variable that is a linear trend variable that begins in January of 2006. The CDM trend variable is an increasing number from 1 to 36 staring in January of 2006. There is no evidence based justification for why the variable only begins in January of 2006. This assumption implicitly means that there was no conservation taking place prior to 2006. This is not true. As electrical appliances were replaced with more energy efficient models there was natural conservation taking place. Similarly, houses built in the recent past tend to be more energy efficient than those of an earlier vintage. Again this would have been reflected in consumption levels prior to 2006.

Energy Probe submits that the Board should direct CNDHI to utilize the equation provided in the response to Board Staff Interrogatory #9(c) to forecast the purchased energy volumes. This equation is superior to that used by CNDHI (in the original evidence and to that estimated in response to VECC Interrogatory #14(c)) in that all of the estimated coefficients have signs that are as expected and they are all statistically significant at high confidence levels. This equation passes the reasonableness tests noted above. Neither of the CNDHI equations passes these tests.

This equation produces a test year forecast of 1,541,693,000 kWh. This estimate should then be updated to reflect the lower Ontario GDP forecast as provided in the response to VECC Interrogatory #14(f). As indicated in the Argument-in-Chief, this update would reduce the forecast by approximately 8,673,000 kWh. Based on the starting point noted above, the kWh forecast for 2010 would be approximately 1,533,020,000 kWh. Energy Probe submits that this is an appropriate forecast.

Energy Probe notes that in the Argument-in-Chief CNDHI has indicated that the actual 2009 purchased amount was 1,450,836 MWh. Energy Probe does not believe this information is provided anywhere in the evidence or the interrogatory responses and should be ignored by the Board. This figure is stated to be an actual purchase figure. If so, it is irrelevant in that it has not been normalized to reflect differences between actual and normal weather in 2009. As a result it cannot be compared to the forecast for 2009 or to the forecast for 2010 which are based on different weather assumptions.

c) Billed kW Forecast

As noted above, the final step of the CNDHI forecast methodology involves the conversion of the kWh forecast to kW's for those rate classes that are billed on a kW basis. CNDHI has four rate classes that are billed based on a charge determinant of kW's – GS > 50 to 999 kW, GS 1000 – 4999 kW, GS > 5000 kW and Streetlights (Exhibit 3, page 24).

As shown in Table 20 of Exhibit 3, CNDHI has used the average kW/kWh ratio over the 2003 through 2008 period to forecast the kW for these rate classes in 2009 and 2010.

Energy Probe submits that this approach is not appropriate given the trend in the ratios shown in Table 20. A review of these ratios reveals trends that are not being captured through the use of the averages over the 2003 through 2008 period. This is particularly so in the GS 1000 – 4999, GS > 5000 and Street Lights classes. In both of the GS classes, there is a clear trend to higher kW/kWh ratios shown between 2003 and 2008. Street Lights have a clear trend to a lower kW/kWh ratio over this period. Only the GS 50 – 999 class is relatively stable over this period.

Energy Probe submits that the Board should direct CNDHI to use the 2008 kW/kWh ratios to forecast the kW billing determinants for the 2010 test year. These ratios reflect trends over the 2003 through 2008 period and provide a more accurate forecast for the test year.

Applying the 2009 kW/kWh ratios to the forecast kWh's shown in Table 18 of Exhibit 3 increases the kW billing determinants for the GS 1000 – 4999 kW class by about 17,500 kW, for the Gs > 5000 kW class by about 8,000 kW and reduces the Street Lights figure by about 600 kW. There is no change to the GS 50 – 999 kW class since the 2008 figure and the average figure used by CNDHI are the same. Based on existing rates shown in Exhibit 8 (pages 24-25), this would increase revenues by approximately $63,500 in aggregate.

Energy Probe submits that the Board should direct CNDHI to calculate the kW billing determinants using the 2008 kW/kWh ratios rather than the average over the 2003 through 2008 period. This average fails to recognize the clear trends in 3 out of the 4 rate classes and results in an under forecast of revenues for the 2010 test year.

F – NORMALIZATION OF MONTHLY BILLING COSTS

CNDHI is forecasting that it will incur costs of $312,000 in annual costs associated with increases related to its move to monthly billing. This move is expected to take place late in 2010. As a result, CNDHI has included a portion of this annual cost, ($42,500) in the 2010 revenue requirement.

CNDHI proposes to include a normalized amount in the 2010 revenue requirement of $244,625 calculated as the sum of $312,000 in each of 2011, 2012 and 2013 plus the $42,500 in 2010, divided by 4 years.

CNDHI relies on the Board's Decision of December 1, 2009 for Greater Sudbury Hydro Inc.'s cost of service application (EB-2008-0230) for the proposed recovery.

Energy Probe does not believe that the comparison between the cost increase for Greater Sudbury Hydro and that for CNDHI is appropriate. The increased cost faced by Greater Sudbury Hydro was for maintenance costs. The increased cost forecast by CNDHI is for the move to monthly billing. CNHDI currently has a mixture of monthly and bi-monthly billing frequencies (Exhibit 4, pages 32-33). The increase in costs in mainly related to increased postage costs, additional bank charges and stationary/envelope costs.

Unlike the situation for Greater Sudbury Hydro, the increased costs to be incurred by CNDHI will have an impact beyond the increase in costs. This impact is in the cash flow of the distributor. By moving to monthly billing for all customers, CNDHI will receive revenue in advance of when it would have received that revenue from the customers that were billed bi-monthly. However, CNDHI has not provided any estimate of the impact that this would have the working capital allowance.

CNDHI did not provide a lead/lag study that could be used to estimate the change in the working capital allowance that would follow from the advancement of revenues to CNDHI. As noted earlier in this Argument, a 1% change in the 15% factor used by CNDHI would result in a change in the revenue requirement of $78,900. The impact of PILS would be in addition to this amount.

There may also be impacts on OM&A costs associated with moving to monthly billing that have not been fully taken into account beyond the 2010 test year. These impacts could be cost reductions associated with collection expense and reduced bad debt expense associated with the move to monthly billing. CNDHI acknowledge the potential for lower bad debt costs (Board Staff Interrogatory #18(a)). However, no forecast has been provided for the 2011 through 2013 IRM period.

In the Decision and Order dated August 21, 2009 for London Hydro Inc. (EB-2008-0235) the Board stated:

> *"The Board will not accept London's proposal to "normalize" the PILs allowance to reflect the one-time nature of the CCA allowance for the CIS system. Normalizing or amortizing expenses over an IRM period should be an exceptional activity. The Board has routinely done it for regulatory expenses but that is because the regulatory expenses for the rebasing proceeding relate to some extent to the entire IRM period. The CCA amortization proposed by London is of a different nature. London seeks to amortize the CCA because it forecasts that its PILs in the balance of the IRM period will be substantially higher. To do so amounts to forecasting a key*

element of the revenue requirement beyond the test year. If the Company were to do so, then a comprehensive multi-year revenue requirement forecast would be required. The Board has little or no evidence as to future tax rates, OM&A expenditures, capital expenditures, etc; nor has London requested a multi-year cost of service. The Board finds that there is therefore no basis to grant the relief requested by London and that to do so would be inappropriate." (Page 26)

Energy Probe submits that the CNDHI proposal to normalize for monthly billing costs is similar to the situation in which London Hydro proposed to normalize the CCA allowance for a CIS system. The Board clearly indicated that the use of the "normalizing" approach over an IRM period should be an exceptional activity.

More importantly, in the view of Energy Probe, is the Board's comment regarding the fact that London Hydro forecast a key element of the revenue requirement beyond the test year without providing further evidence over the same period related to the related impacts of the normalizing proposal. This is the difference between the London Hydro Decision and the Greater Sudbury Hydro Decision. In the latter case, there were no other changes expected. In the former, the change would likely result in other changes beyond the test year.

Energy Probe submits that the situation with the CNDHI proposal is similar to that for London Hydro. In particular, there will a change to the working capital allowance that is directly related to the additional costs related to the move to monthly billing. There will be reductions in bad debt and collection expenses related to the increase in billing frequency and reduction in average billing amount. As in the case of London Hydro, CNDHI has not provided a comprehensive multi-year revenue requirement forecast to reflect the impacts that are the direct result of the increase expense to be incurred by CNDHI. The Board has no evidence before it with respect to the impact on other OM&A costs or on the impact on the working capital allowance.

Energy Probe therefore submits that there is no basis to "normalize" the cost of moving to monthly billing in 2010. However, if the Board determines that some normalization should be allowed, then Energy Probe submits that at a minimum the Board should reduce the working capital allowance from that calculated by CNDHI using the 15% approach.

In the 2010 test year working capital allowance calculated by Toronto Hydro-Electric System Limited (Exhibit J1, Tab 2, Schedule 7 of EB-2009-0139), the lead/lag study results in a weighted average percentage of approximately 11% on the cost of power and OM&A expenses. Energy Probe submits that the Board should take this percentage into account as a proxy for CNDHI when it moves to monthly billing.

CNDHI is proposing to increase the OM&A included in the 2010 revenue requirement by $202,125 ($244,625 normalized less $42,500 2010 forecast). Reducing the percentage used to calculate the working capital allowance from 15% to 12.5%, a figure still substantially higher than the 11% used by Toronto Hydro, would result in a reduction in the working capital allowance of approximately $2.9 million. At the forecasted weighted average cost of capital of 6.75% (Attachment D of the Settlement Agreement), this would result in a reduction in the cost of capital of $195,750. The additional reduction in PILS would result in more than offsetting the increase in OM&A proposed by CNDHI.

G – NORMALIZATION OF OTHER REVENUES

CNHDI is forecasting a reduction in shared services-related revenue of $110,000 in the 2010 test year. This is a the result of the discontinuation of water and sewer billing services to the City of Cambridge (an affiliate) and the Region of Waterloo as of September 1, 2010. The calculation of the $110,000 reduction in revenues is shown in the response to Energy Probe Interrogatory #24(f).

As shown in the response to SEC Interrogatory #13, CNHDI has given notice to the City and to the Region that it will cease to provide water and sewer billing/collection services beyond October 1, 2010. No explanation as to why CNHDI no longer wants to provide these services was provided.

Energy Probe accepts the forecasted reduction in revenues of $110,000 for the last quarter of 2010, but does not accept the "normalization" proposal of CNHDI as being appropriate. CNHDI proposes to normalize the lost revenues of $440,000 in 2011 through 2013 (the IRM period) with the reduction of $110,000 in the last quarter of 2010 for a normalized reduction over the four year period of $357,500. Started another way, CNHDI is proposing to reduce the revenue associated with the water and sewer billing services to be provided in 2010 from $330,000 to $82,500.

As explained in the response to Energy Probe Interrogatory #24(f), the costs associated with providing these services fall into three types of costs: direct costs, shared costs and overall general. Direct costs, which represent about 36% of the total costs, have been removed from the costs to be recovered. The remaining 64% of the costs (shared and overall general) associated with these services remain in the revenue requirement.

CNDHI has not provided a forecast beyond the test year to show how it intends to deal with reducing the costs that were previously shared with the water and sewer billing services. Nor has CNDHI provided any forecast of mitigation measures it expects to take over the next number of years to reduce overall general costs that are no longer recoverable through the charges for water and sewer billing and collection services.

In addition, CNDHI has not provided a forecast for any of the Other Distribution Revenues shown in Table 23 of Exhibit 3 beyond the 2010 test year. Other than interest and dividend income, these other sources of revenue have remained stable or have increased since 2007.

With respect to interest and dividend income, Energy Probe notes the significant variance recorded in the account, as shown in Exhibit 3, pages 34 and 35. CNDHI acknowledges that the revenue in this account fluctuates because of the variance in short-term interest rates and the level of surplus funds. In 2006, actual revenues in this account were more than $630,000 higher than the Board approved amount. The declines in 2008 and 2009 are primarily the result of lower interest rates.

CNDHI has forecast low interest rates for 2010 (Exhibit 3, page 35). However, it has not provided any forecast beyond 2010, when interest rates are generally expected to increase. Even a small increase in interest rates would offset the $440,000 in lost revenues from water and sewer billing and collection services in 2011 through 2012. For example, based on average cash balances of $20,000,000 (Energy Probe Interrogatory #24(g)), an increase of one percentage point in short-term interest rates would generate an additional $200,000 per year in revenue for CNDHI.

Energy Probe submits that normalizing revenues over an IRM period should only be done in an exceptional circumstance and only when a distributor has provided a full forecast for all such revenues over the full IRM period. CNDHI has, in essence, forecast a key element of the revenue requirement beyond the test year by forecasting the loss of the $440,000 associated with water and sewer billing and collection services. It has not, however, provided a forecast for other key revenues, such as interest and dividend income, specific service charges, late payment charges, rent from electric property and so on for the same period.

Consistent with the EB-2008-0235 Decision and Order dated August 21, 2009 for London Hydro referenced above in relation to the normalization of monthly billing costs, Energy Probe submits that the Board should deny the normalization for one particular source of other distribution revenues as it has little or no evidence as to future revenues from any of the sources shown as Other Distribution Revenues in Table 23 of Exhibit 3.

H – 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.

As indicated in the Settlement Agreement at page 20, CNDHI has noted that at this time its billing system is not capable of creating distinctions among customers of the same rate class with respect to rate riders.

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 CNDHI 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.

I - COSTS

Energy Probe requests that it be awarded 100% of its reasonably incurred costs. Recognizing the size of Cambridge and North Dumfries Hydro Inc., 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

February 26, 2010

Randy Aiken

Consultant to Energy Probe