RP-2004-0188

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF the preparation of handbook for electricity distribution rate applications.

Written Submissions On Behalf Of
Energy Probe Research Foundation

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Draft 2006 Electricity Distributor Rate Handbook

Introduction

How these matters came before the Board

1. In its decision RP 1999-0034, issued January 18, 2000, the Board decided to implement a three year PBR plan which would be used to set rates until 2002 without off ramps. The express intention of the Board in that decision was that the three-year term would allow the collection of sufficient data for the Board and the industry to assess the various mechanisms and would establish a baseline for second generation PBR. (Decision With Reasons, RP 1999-0034, para. 2.1.11) The Rate Handbook then in place required utilities to undertake cost allocation studies and directed Board Staff to initiate a mid-term review to design the next generation of PBR. The Rate Handbook introduced Market Based Rate of Return (MBRR) and the resulting PILS adjustments.

2. Following the Rate Handbook, 24 large utilities filed applications for new rates in May 2000 with overall residential bill increases averaging 8.5%. Notices of these applications, including the total bill impact on residential customers, were published in local newspapers.

3. On June 7, 2000 the Minister of Energy, Science and Technology issued a policy directive to the Board under section 27 of the *Ontario Energy Board Act, 1998* (the "Act"). On June 19, 2000, the Board provided the Minister with a plan to respond to the directive which included holding a generic proceeding to reconsider aspects of the Rate Handbook. In addition, on June 20, 2000, the *Ontario Energy Board Amendment Act, 2000* (or Bill 100) was introduced. Bill 100 received First Reading before the Legislative Assembly rose for summer recess. Bill 100 would have imposed restrictions on the right of LDCs to follow the rules set out in the Rate Handbook.

4. In the RP-2000-0069 decision issued by the Board September 29, 2000 on the Generic Hearing regarding The Minister's Directive to the Ontario Energy Board dated June 7, 2000, the Board spread the recovery of MARR over three tranches and authorized the creation of interest-bearing deferral accounts to track market transition costs for eventual recovery.

5. Bill 100 was withdrawn by the government in November 2000.

6. On August 19, 2002, the Board issued a letter to stakeholders advising of the extension of then existing PBR plan by one year, with the result that the Second-Generation Performance Based Regulation plan was rescheduled to commence on March 1, 2005. Board proceedings related to PBR development were announced for 2003 and 2004. To facilitate cost allocation studies, data collection by LDCs was ordered to commence in “early 2003”.

7. On Dec 9, 2002, the Government of Ontario passed Bill 210, the *Electricity Pricing, Conservation and Supply Act, 2002*. The Government mandated that written approval of the Minister of Energy must accompany any distribution or transmission rate application made to the Board, and that, absent Ministerial approval, the rates in effect on November 11, 2002 remain in effect until at least May 1, 2006.

8. The Government introduced the *Ontario Energy Board Amendment Act (Electricity Pricing) 2003* (Bill 4) on November 25, 2003. At the same time, the Government announced that distributors could begin recovering the balances in their regulatory asset accounts over four years, beginning March 1, 2004.

9. By letter of January 21, 2004 the Board initiated a consultation process to review further efficiencies in the electricity distribution sector. On March 15, 2004, Ontario Energy Board released a summary of stakeholder submissions on the efficiencies in the electricity distribution sector.

10. On June 16, 2004 the Board announced its process for establishing 2006 electricity distribution rates with the intent that these new distribution rates will be effective on May 1, 2006.

11. This recitation of how the current matter came before the Board demonstrates that since the collapse of the previous regulator in 1998, the Ontario electric LDCs have operated in a largely unplanned PBR regime. The only off ramp has been with respect to recovery of regulatory assets associated with "market opening" in May 2002. Although the Board originally intended to continue PBR, there is no path toward PBR currently announced. On the current schedule, a fulsome review of costs will not take place until 2008. This represents at minimum a ten year period of non-regulation. For some LDCs, the period of non-regulation may be significantly longer, depending on when their case was reviewed by the previous regulator. Energy Probe is concerned that this extremely long period of non-regulation represents a significant risk to the LDCs and their customers. Financial stability, continuing capital asset care, and deferrable maintenance practices like forestry are all aspects of utility integrity that depend on effective oversight.

Overview of Energy Probe's Submissions

12. Energy Probe's argument does not address all issues. The argument follows the chapter headings as set out in the 2006 EDR Handbook Draft 2, with Conservation and Demand Management (C&DM) added at the end. The only exception to following the draft handbook chapters in sequence is with respect to Section 3.2 where comment is contained in Energy Probe's remarks on Sections 6.2.2 and 8.3.

Chapter 4

Section 4.3.1 Non-IT- related

1. Energy Probe recommends using a materiality threshold expressed as a percentage of fixed assets for non-IT related capital investment. Adopting a materiality threshold expressed in dollar value may cause unfairness, especially for LDCs with assets that happen to be close to an arbitrary boundary. Assuming an LDC with a $99-million rate base, the Alternative 1 materiality threshold based in dollar value would represent 0.076% of the rate base. However, for an LDC with a $100-million rate base, its materiality would be 0.15%. For these reasons, Energy Probe recommends Alternative 2, the one that only includes the materiality threshold as a percentage of fixed assets.

Section 4.5 Capitalization Policy

1. As discussed in Energy Probe's response to Undertaking E.10.1, which is discussed in greater detail in Chapter 14, we recommend that applicants file information regarding capitalized operating expenses. These data could be used for benchmarking purposes.

2. Although Energy Probe recommends against benchmarking capital costs for the 2006 EDR, if benchmarking is to be applied to capital cost, we recommend excluding capitalized operating expenses. Instead, these expenses should be added to operating cost for benchmarking operating costs.

3. Energy Probe also recommends that LDCs file total capitalized operating expenses broken down by cost category. In particular, LDCs should report 2004 total assets associated with operating expenses broken down by Wires & Connection Services, Settlement and Customer Care (either combined as Energy Probe recommends or separate as Mr. Camfield recommends), and Administration Activities. As a proxy, these expenses could be associated with expenses exceeding a threshold as indicated in Chapter 4 of the Handbook.

Chapter 5

Section 5.0 Cost of Capital

1. According to the 2006 Rate Handbook, Draft 2 p. 37:

   Cost of Capital = DxDR + (1-D) x ROE

2. This calculation provides the absolute dollar amount but not the weighted average cost of capital, which is identified in the text. To calculate the weighted average cost of capital, the text should say,

$$CostofCapital = \left(\frac{D}{D+E}\right) xDR + \left(\frac{E}{D+E}\right) xROE$$

Section 5.1 Maximum Return Equity

1. We do not believe that it is appropriate to create a variance account tracking the difference between the 2006 Handbook-issued rate and the Board's updated maximum return. We believe that the Board should set the maximum allowed return on equity for 2006 using the most current data available at the time of the Board decision.

2. Therefore, Alternative 1 and 2 should replace as follows:

   The Board will determine the maximum allow return on equity for 2006 using the most current data available at the time of the 2006 rate Board decision.

3. Setting a maximum allowed return on equity at the time of filing the 2006 the rate applications gives rise to some implementation problems. We believe that 2006 rate application proceeding should involve the following steps:

   a) Assuming that June 30, 2005 is the LDCs' deadline for the rate application, the following data will apply for calculating the Long Canada Bond Rate (LCBR):

   - the 3-and 12-month outlook for 10-year Government bonds using June 2005 Consensus Forecast; and
   - average daily difference between 10 and 30 years bond rates in May 2005, using Bank of Canada data.

- It is recommended that the OEB post these data on its website in the first days of June 2005.
- At the time of the rate application, LDCs will apply rates based on the LCBR rate defined in June 2005. The 2006 EDR Model will use the LCBR rate as an input. The model should be designed easily accommodate revisions to reflect LCBR changes.

b) in a second stage, the Board will provide a Decision with Reasons on 2006 rates and set an updated LCBR rate, taking into account the most current available date

c) based on the Board decision, LDCs will apply for final rates soon after the Board decision.

Section 5.2 Debt Rate

1. For LDC debt held by an affiliated entity, Energy Probe recommends using the lower of the actual debt rate and the deemed debt at the time of issuance, which is Alternative 2. We think that the deemed debt rate at the time of issuance should be taken into account instead of the current deemed debt rate. Energy Probe suggests that the LDCs should not incur gains or loses as a result of adopting a current deemed rate that does not reflect debt market conditions at the time debt was issued.

Chapter 6

Section 6.0

1. With respect to the detailed distribution expense data that LDCs will file (p. 47), we suggest that LDCs enter distribution expense data at *Tab Trial Balance of the 2006 EDR Model* according to Alternative 1 for reporting 2004 distribution expenses. Instead, for 2002 and 2003, LDCs can follow Alternative 2 and enter data at *Tab_Grouped Trial Balance of the 2006 EDR Model*, in aggregated groupings. For the Test Year, the additional detail is needed but for the prior years, the value of the information is less and therefore there is less justification for burdening the LDCs with the additional administrative cost of producing it.

Section 6.2.2 Bad Debt Expense and Section 3.2 Test Year Adjustments

1 Chapter 3 of the 2006 EDR Handbook, Draft 2, refers to bad debt as an unusual event as part of the "Non-routine/unusual Tier 1 Adjustments" and specifically identifies the issue of bankruptcy of a major customer. According to point four of the Schedule 3-2, LDCs should explain why claimed bad debt should be subject to an unusual adjustment.

2. Section 6.2.2 addresses this issue as a subsection of Chapter 6.2, Detailed Reporting for Specific Distribution Expenses, and provides specific guidelines associated with Account 5335 that are excluded in Chapter 3. Section 6.2.2 includes all bad debt expenses. Minimum filing requirement involve all bad debt expense as reported in Account 5335, segregated by customer class. As well, minimum filing requirements provide a definition of materiality and it is stated that the applicable materiality value will be calculated within the 2006 EDR model.

3. We believe that bad debt should be separated into what might be considered routine and extraordinary bad debt.

4. Energy Probe believes that rates should reflect an acceptable rate of bad debt and that defined as a percentage of the total bill. The problem is to define the appropriate bad debt rate.

5. 1999 rates, which form the origin of rates to be applied in 2006, reflected some allowance for bad debt. Before adjusting the bad debt allowance, the Board should compare the revenue earned by each utility from the bad debt allowance in current rates against the actual routine incurred bad debt expenses excluding major customer failures. If this comparative information is not available, it would be best to not adjust the routine bad debt allowance until more detailed cost of service examinations are undertaken.

6. If the Board is presented with sufficient information to demonstrate that the existing bad debt allowance in rates is insufficient to cover routine bad debt, then it will be necessary to define an appropriate adjustment to the rate for bad debt. One means to do this is to adopt the benchmarking approach. Proper benchmarking will require that LDCs use a common criterion to measure bad debt. Unfortunately, the bad debt definition provided in the USofA is general and we are not sure that LDCs are reporting bad debt expense on a common basis. In light of the USofA, Account 5335 shall be charged with amounts sufficient to provide for losses from uncollectible utility revenues. As a result of the broad definition provided by the USofA, we suggest that LDCs provide further details on the criterion adopted in recording bad debt.

7. Another benchmarking approach that might be considered is to compare practices in other jurisdictions in Canada in order to assist in determining an acceptable bad debt rate.

8. In addition to routine bad debt, bad debt allowances should be considered for extraordinary events such as the bankruptcy of a customer that is large enough to impose a significant burden on the utility. In this case, we think that the approach reflected in Chapter 3 is appropriate.

Section 6.2.5 Employee Total Compensation

1. We believe that every LDC should report average total compensation regardless of the number of employee. However, possible legal concerns should be taken into account regarding the privacy of information. We have no submissions on potential legal issues.

Section 6.2.7 Distribution Expenses Paid to Affiliates

1. Regarding data consistency for the purposes of benchmarking and the item *Proposed Additional Filing Guidelines*, we recommend Alternative 1. Alternative 1 provides for data on cost-based pricing where it is used to price affiliate services and a description of if and how the absence of a market is established before using cost-based pricing. As well, we also recommend Alternative 1 in the item *Additional wording*. Applicants should face additional scrutiny if they fail to follow a material requirement in the Affiliate Relationship Code transfer pricing and shared services rules. (Note a small typo in Alternative 1 where the first "of" should be "to".)

Chapter 8

Section 8.3, C&DM, Smart Meter, and Regulatory Asset Amortization Revenue Requirement and Chapter 3.2 Test Year Adjustments

1. Regarding the amortization of any C&DM spending that does not result in the creation of tangible assets directly owned or controlled by the LDC, Energy Probe recommends that this spending be expensed and not depreciated or included in rate base. For any C&DM spending that is capitalized, the value of these assets should be maintained in a regulatory assets account. Similarly for smart meter assets, Energy Probe recommends that they be maintained in a regulatory assets account similar to the transition related CIS assets required for the 2002 "market opening".

2. We agree with 2006 EDR Handbook, Draft 2, that the revenue requirement associated with C&DM, Smart Metering and Regulatory Assets must be allocated on a different basis that the allocation applied to the base revenue requirement. In the particular case of regulatory assets, the Board defined guidelines in the RP-2004-0117 Decision with Reasons on the allocation criteria to be applied for regulatory assets accounts. Among these accounts, Board directions included LV costs.

3. LV costs are also addressed in the draft Handbook. Chapter 3 includes a group of expenses associated with low voltage/wheeling to be included as *Tier 1 Adjustments: Distribution Expenses* such as:

a) LV recovery amounts approved by the Board in Phase 2 RRA
b) Proposed LV recovery amounts for the period January 2004 through May 2006
c) Proposed Hydro One LV rates post-May 2006
d) Wheeling charges in cases where there are no established rates in place.

4. With respect to LV recovery of amounts approved by the Board in Phase 2 RRA, we believe that these costs deserve a particular consideration in 2006 rates. LV recovery involves historic regulatory assets as well as annual recovery by Hydro One of $25.6-million in LV costs

from embedded, acquired and direct customers. We agree that 2006 rates will include the respective amortization relative to amounts approved in Phase 2 RRA.

5. Regarding LV recovery amounts for the period January 2004 through May 2006, we believe that Hydro One should apply to recover this amount in the 2006 rate application and follow the same methodology the Board approved in RRA Phase 2 in allocating LV costs.

6. In addition, we believe that the $25.6-million LV cost relative to 2006 should also be recovered through Hydro One's 2006 rate application. In this regard, rates ordered on August 30, 2002 pursuant to RP-2000-0023 should be put in place in May 2006. It should be noted that implementation of this decision was affected by Bill 210. Hydro One's LV rates should be reviewed as part of comprehensive cost allocation and rate design review. We believe that Hydro One's LV rates should not be reviewed in the 2006 EDR proceeding. Thus, the $25.6-million LV cost should not be reflected in the base revenue requirement. Accordingly, this amount should be subtracted from the Hydro One's base revenue requirement.

7. In addition, Hydro One's LV cost should be reflected in 2006 embedded distributor and direct customer rates. In order to allocate Hydro One's LV cost of $25.6-million to embedded distributors and direct customers, we suggest using the same criterion defined by the Board in Phase 2 decision on RRA in allocating LV cost.

8. With regard to the possibility that Hydro One proposes an additional LV cost recovery or other LDCs apply for LV wheeling charges, we believe that Board approval for any new LV wheeling rate is outside the scope of this proceeding and is therefore not discussed further here.

Schedule 8-3: Regulatory Asset Amortization

1. The Schedule 8-3 includes a table setting out the information that applicants will file associated with regulatory assets. In light of the Board decision on Phase 2 RRA, we suggest expanding the table as follows:

Regulatory Assets	Balance at	Amortization	Allocation

	April 30, 2006 (including interest)	in 2006	Method
Regulatory Assets approved by the Board in Phase 2 RRA			
Retail Cost Variance Accounts			Customer Count
Environmental Costs			Distribution Revenues
Bill 210 Cost			Customer Count
Transition Cost			Customer Count
RSVA and 1571 Accounts			Consumption
Hydro One LV Costs			(1)
Hydro One Variance in Energy Cost Recoverable			Consumption
Regulatory Assets for the period January 2004 through May 2006			
Retail Cost Variance Accounts			Customer Count
Environmental Costs			Distribution Revenues
Bill 210 Cost			Customer Count
Transition Cost			Customer Count
RSVA and 1571 Accounts			Consumption
Hydro One LV Costs			(1)
Hydro One Variance in Energy Cost Recoverable			Consumption
LV recovery amounts to recover post-May 2006			
LV recovery amounts to recover post-May 2006			(1)

(1) According to Phase 2 RRA, Hydro One's LV costs are allocated to Acquired LDCs, Embedded Distributor and Direct customers in proportion to how the LV costs are incurred. Hydro One's LV costs as applied to Acquired LDCs are allocated to customer classes on distribution revenue basis. It appears that the same criterion is applied to Embedded Distributor customer classes.

Chapter 9

Section 9.2 Determinants of the Appropriate Share of the 2006 Revenue Requirement for Each Class, Sub-Class, or Group

1. The second paragraph of the Chapter 9.2 should say:

   The methodology uses the 2004 rates minus the recovery of the first phase of the regulatory assets in 2004 **and 2004 PILs** . These rates are provided on Sheet 2 of the 2004 Rate Adjustment Model (RAM). (insert the bolded text)

2. With respect to the fourth paragraph of Section 9.2, for utilities with a positive growth rate in 2003 and 2004 for kWh/customer and kW/customer ratios, we recommend using 2004 kWh/customer and kW/customer data for calculating the ratios of each class, sub-class, or group's dollar amount to the total. If growth rates are not positive in 2003 and 2004, average kWh/customer and average kW/customer statistics should be applicable.

3. Regarding the discussion on the appropriate kWh/customer and kW/customer ratios to use, we think that the ratios defined in the paragraph fourth of the Chapter 9.2 should be applicable to the 2006 Rate Application Model (2006_Draft_ RAM.xls spreadsheet).

Chapter 10

Section 10.6 Distributed Generation

1. The appropriate rate treatment for distribution charges associated with service to distributed generation is a highly complex area that has received little attention so far in the 2006 EDR process. By comparison, the appropriate rate treatment for transmission charges associated with service to distributed generation received extensive attention from the Board in RP 1999-0044.

2. Alternative 2 presented in Chapter 10.6 proposes a major change from the status quo. Alternative 2 would provide a credit mechanism to be addressed to distributed generation. In particular, transmission charge reductions associated with RP 1999-0044 will be shown as a credit to the distributed generation.

3. Energy Probe is concerned that perverse incentives would result from Alternative 2, potentially leading to stranded costs for transmitters and distributors. Further, we believe that the gap between the energy market price at the distributor's wholesale market supply point and the cost of producing replacement power with the distributor generator is an efficient incentive to encourage distributed generation.

4. We believe that if incentives regarding Distribution Generation are to be implemented through LDC rates, the implications and alternatives should be discussed in detail. Thus, Energy Probe recommend status quo; that is Alternative 1.

Schedule 10-2

1. With respect to the table at the bottom of the page 110 regarding the data LDCs must file on Unmetered Scattered Load, Energy Probe suggests including data on the number of connections for 2002, 2003 and 2004. We note that some utilities have considered each connection to be a customer where a single entity paying rates may have multiple connections while other LDCs have considered the number of customers more directly. This difference in counting customers has skewed the comparison of data between utilities.

Chapter 14: Comparators and Cohorts

1. Energy Probe urges the Board to endorse benchmarking. In testimony, Energy Probe's witness, Mr. Adams stated:

> MR. ADAMS: Our purpose in being here and presenting this evidence to the Board is to encourage the Board to send a message to the interested parties and to the regulated utilities that benchmarking is some place that Ontario ought to go in future. The process of developing good benchmarks, benchmarks that will be durable and valuable in the longer term, is going to take significant effort. The LDCs need to be parties to that discussion. They have the data that's needed to undertake the work and have a depth of understanding of their businesses that the process needs to share if benchmarking is to be successful.
>
> At the same time, the high-cost LDCs will be motivated in a direction that may not be conducive to the ultimate success of the benchmarking project, and they need to be clear for everyone that the process of benchmarking should move forward. That's my plea today. (TR 10: 804-805)

2. Energy Probe's overall recommendations on the content of Chapter 14 were presented in response to Transcript Undertakings E.10.1 and E.10.2.

3. The purpose of Energy Probe's Chapter 14 submissions is to comment on the scope of quantitative techniques for LDC cost analysis, discuss the application of benchmarking for both 2006 and the longer term, discuss a small number of concerns with some aspects of Mr. Camfield's evidence, comment on data and disclosure issues, and present ideas for a process to move forward with benchmarking for 2006 and beyond.

Scoping the Inclusion of Quantitative Cost Analysis in the 2006 EDR Process

4. Energy Probe suggests renaming this chapter of the Handbook from "Comparators and Cohorts" to the more generic title of "Benchmarking". Energy Probe's witness identified comparators and cohorts as a subset of benchmarking:

> MR. MacINTOSH: With your indulgence, Mr. Chair, we have some brief direct evidence today. Mr. Adams, Mr. Camfield has described benchmarking as a composite measure of performance. Do you agree with that definition? And how would you contrast benchmarking relative to comparators and cohorts?
>
> MR. ADAMS: I support the definition that Mr. Camfield has offered. In my view, benchmarking covers a broad class of quantitative techniques for

> measuring performance. I consider that comparators and cohorts might properly be considered as a subset of the wider class of benchmarking.
> (Trans. Vol. 10: 773-775)

5. In the Regulatory Assets Review and Recovery process, the Board applied aspects of benchmarking to the review of customer education costs which might not strictly be considered an application of comparators and cohorts but was nonetheless useful to the Board in reaching a determination on transition cost claims. The Board may wish to leave its options open for the application of benchmarking techniques.

Purpose of Benchmarking

6. Mr. Camfield's evidence defined using comparators and cohorts mechanisms for the purpose of highlighting cost drivers. The evidence demonstrates the appropriateness of using comparators and cohorts mechanisms by presenting statistically significant relationships between cost indicators and cost drivers. With respect to the implementation of comparators and cohorts, the evidence provides the following guidelines:

> LDC costs should be organized and reported for unbundled distribution services, and the Comparators and Cohorts mechanism, should it be pursued, should be implemented for each service. Unbundled services include Wires and Interconnection Service, Settlement, and Customer Service categories. Organizing the cost of distribution in terms of these unbundled services will be necessary to gauge LDC performance and to identify the cost of possibly expanded customer service activities of the LDCs in the future. (Ex. B/4 p. 29)

7. Mr. Camfield suggested that the identification of anomalies resulting from the use of comparators and cohorts should be addressed at the level of unbundled services, in particular at the level of the four cost categories proposed. By focusing his analysis on unbundled services, Mr. Camfield was proposing a bottom-up approach to gauge LDCs performance.

8. All witnesses on this subject supported the use of benchmarking and comparators and cohort as screening tools to assist in the setting of just and reasonable distribution costs.

Summary and Criticisms of Robert Camfield's Evidence

9. Robert Camfield's recommended approach for the analysis of comparators and cohorts involves four steps:

1) the factor and correlation analysis of data: data include input cost, inputs and output quantities and cost drivers.

2) the determination of cost drivers with regression analysis: the evidence advocates using regression techniques in order to explain how various cost drivers and output quantities (i.e., the right hand side (RHS) explanatory variables) jointly determine cost, as well as the identification of the statistical significance of explanatory variables. Four business activity cost categories are defined: cost analysis of wires and interconnection service, settlements, customer service, and administration. Whereas wires and interconnection service category addresses capital and operating costs, for the three other categories the analysis deals exclusively with operating costs. Mr. Camfield's prefiled evidence suggests that energy conservation should be included with customer service.

3) the determination of the cohorts with statistical clustering analysis, grouping LDCs according to similarity (magnitude) of RHS variables.

4) the inspection of comparative diagnostics.

10. Mr. Camfield's recommendation to separate the analysis of settlements from customer service was the most controversial aspect of his proposal according to the other C&C witnesses, both of whom recommended merging these activities for the purposes of cost analysis. Both Dr. Lowry and Mr. Adams suggested that disaggregating settlements from customer service may give rise to additional accounting uncertainties. Energy Probe notes that existing accounting rules require the LDCs aggregate the reporting of these costs.

11. Although it attracted little attention at the hearing, Mr. Camfield's suggestion to roll C&DM costs into customer service costs does not appear to be an appropriate approach. C&DM costs are rising rapidly for Ontario LDCs and these costs are subject to special and focused regulatory attention.

12. Camfield's recommendation that Hydro One be excluded from C&C analysis was not based on the results of cluster analysis or other types of analysis but on an *a priori* judgment. (TR 6: 1152, 1158) ECMI suggested in its cross-examination that there may be small utilities that appear to have similar density characteristics relative to Hydro One. The discussion during the hearing of excluding Hydro One from the C&C analysis concentrated on Wire & Connection Services. From the perspective of other costs categories, we believe that there is no reason that Hydro One should be excluded from the analysis. For example, the specific characteristics of Hydro One, such as its legacy or its particular market served, do not justify exempting it from the benchmarking of administration costs or customer care costs.

Convergence of Recommendations of Benchmarking Witnesses

13. There were many points of agreement among the witnesses presenting on comparators and cohorts. These areas of general agreement included:

- benchmarking could be used to identify best practices
- recognition of the generic problem of measuring capital stock. (See for example Mr. Camfield's remarks at TR 6: 196.)
- unit cost regressions should be analyzed, (TR 6: 1268)
- age of assets should be considered as a cost driver, assuming adequate data can be assembled
- The OEB should seek to develop benchmarking beyond a screening tool into a more comprehensive performance assessment. (TR 6: 203)

14. Mr. Camfield seemed to acknowledge that it may be best for the analysis of disaggregated business activities to combine the customer service categories – settlements and customer service – into one. (TR 6: 232)

Outsourcing to Affiliates

15. Camfield recognizes outsourcing to affiliates to be a challenge for the analysis (TR 200-201) but does not discuss virtual utilities.

16. Outsourcing to affiliates is likely to present a significant challenge to benchmarking analysis in Ontario, although the issue was hardly broached during the hearings. There appears to be a broad range of outsourcing arrangements to affiliates among LDCs. As an extreme example, Enersource Hydro Mississauga Inc. appeared before the Board in 2004 as an applicant for recovery of regulatory assets. None of the Enersource witnesses called by the utility worked for the regulated entity -- all worked for unregulated affiliates.

17. The Board grappled with a similar issue when, during its brief period of TPBR, Enbridge outsourced significant core utility functions to affiliates. To deal with rebasing Enbridge's costs, the Board found it necessary to order the affiliates to present cost information. Based on the information this order produced and other considerations, in RP 2002-0133 the Board ordered a $7-million reduction in O&M claims for Enbridge. Energy Probe suggests that the Board may find a similar process necessary for establishing rates for 2006.

18. As discussed later, Energy Probe supports the creation of a working group with a mandate from the Board to examine disclosure and analysis issues. We believe that the issue of outsourcing to affiliates should be included in the mandate of this group.

19. We note that according to Chapter 6.2.7, Distribution Expenses Paid to Affiliates, LDCs must report detailed affiliate transactions. In addition, LDCs should file data for benchmarking where the data is disaggregated by cost category (Wires & Connection Services, Settlement, Customer Care and Administration).

Intuitive Benchmarks

20. Benchmarking is a field characterized by clashing expert opinions, special jargon, and complex statistical techniques. However, we believe that some simple, intuitively obvious benchmarks can be of assistance to the Board.

21. During his cross-examination of Dr. Lowry on behalf of Schools and also during his submissions on Issues Day (Issues Day TR 1: 41), Mr. Shepherd developed the idea of using rates for defined customer types and volumes of usage as an additional screening tool.

22. Comparative rates analysis could be developed simply and quickly by Board Staff in the form of a rate ranking of utilities by distribution bills to serve different defined customers.

23. Energy Probe suggests that this approach will be valuable to the Board and should be endorsed for the purposes of 2006 rate setting. Using such a ranking as a screening tool, the Board can ensure that its limited resources are focused on the higher cost utilities.

24. An index of earned returns on invested capital could also be used as a screening tool. Unusually high or low returns should be of concern to the regulator.

25. Furthermore, benchmarking rate levels could provide to the Board with a rate checking tool and a verification method for the 2006 EDR model.

Reasons for Benchmarking Both Disaggregated or Sub-divided Costs And Total O&M

26. Benchmarking disaggregated or subdivided costs as proposed in the Camfield evidence would complement the analysis of total O&M costs recommended in the Lowry (see for example TR 7: 120-121) and Adams evidence.

27. Identifying statistically significant explanatory variables based on input prices, output prices, inputs, outputs and Z factors as defined in Robert Camfield's evidence can guide the development of top-down analysis of operating cost.

28. The rankings of the relative efficiencies of each of the utilities for each of the four unbundled services examined in the proposed comparators analysis can be compared against the ranking resulting from top-down analysis of cost.

29. As noted in Energy Probe's evidence, analysis of sub-divided costs and total O&M provides a greater assurance to the Board of useful results in the identification of anomalies.

> If there are significant cost tradeoffs between the four unbundled services or accounting issues that reduce the ability to accurately compare results for unbundled services accurately, more aggregated top-analysis may be able help in the identification of these deficiencies. (Ex. B11 para. 64)

Disclosure Issues

30. Energy Probe's witness recommended an open process for data reporting and analysis. Mr. Adams noted:

> I don't see the harm, particularly, I don't see a great danger that the utility's reputation will be damaged in a way that hurts their commercial position. (TR 10: 876-877)
>
> …their customers are not going to leave because of what they learn about a utility's labour practices through a benchmarking study. (TR 10: 910)
>
> …I think the harm that might arise by disclosure of the detail that we're talking about here is relatively limited. (TR 10: 913)

31. Similar comments were offered on Issues Day by Mr. Shepherd on behalf of the Schools.

32. Energy Probe suggests that in public utility regulation, there ought to be a presumption of disclosure. Monopoly utilities are unlikely to be harmed by disclosure.

33. The degree of disclosure that prevails in the regulatory process is a reflection of whether regulation is tending toward the judicial or bureaucratic model. The Board's mandate contains both adjudicative and rule making powers, thereby giving the Board some discretion with respect to matters like disclosure. Energy Probe urges the Board to maintain the strength of the quasi-judicial function of the Board.

34. Bureaucratic methods of decision making may appear to the inexperienced observer to provide efficiency advantages over more cumbersome quasi-judicial methods. This appearance of efficiency is a mirage. The Board's very long tradition of successfully applying quasi-judicial methods in gas contrast sharply in the quality of results compared with the even longer tradition of bureaucratic decision making with respect to electricity.

Process for Applying Benchmarking for 2006

35. In her concluding remarks, Ms. Lea suggested, "A follow-up workshop with stakeholders which deal with data requirements and the specifics of the analysis may be useful." (TR 12: 1010) Energy Probe endorses that suggestion.

36. For benchmarking to succeed in assisting the Board in its consideration of rates for 2006, additional work is needed. The embryonic evidence presented to date must be supplemented and debated. Debates must be moved to resolution.

37. We suggest that a group be formed with an initial mandate to produce recommendations on filing requirements and to outline how the analysis will take place once the data is produced. On the question of data collection, we note ECMI questions about historic data availability (TR 10: 813-840) as an example of some of the complications that must be addressed.

38. A working group appears to be the best available forum to consider technical econometric and statistical issues. For example, proper statistical benchmarking will require examination of regression quality. We recommend taking into account possible concerns such as heteroscedasticity and multicolinearity. The working group might also develop a recommendation on the most appropriate methods for determining cohorts, such as tree clustering, two-way joining and k-means clustering.

39. With respect to the composition of the group, we suggest that the Board make available both internal and external staff. The LDCs should be limited to sectoral representation (perhaps high cost, medium cost and low cost utilities). Customer groups who have been active in this area should also have an opportunity for effective representation. We further suggest that an independent chair be retained with expertise in the field.

40. As discussed previously, outsourcing to affiliates should be considered by the working group.

41. When the working group recommendations are presented to the Board, the Board might invite comments so that contentious issues can be identified and various positions argued prior to resolution.

Benchmarking Beyond 2006

42. We believe that the use of benchmarking is a learning process. Stakeholders are at a beginning stage in using this tool. The first application of benchmarking to LDC rates was in the RRA Decision With Reasons. Proposals for applying benchmarking to 2006 rates represent a development from this starting point. Energy Probe is confident that these initial steps represent an important advance in using an appropriate tool for reviewing prudence and the right way to move for fair and efficient regulation.

43. Energy Probe believes that if the Board endorses benchmarking, directs LDCs to support the process of benchmarking development, and provides adequate support for benchmarking development, the result is very likely to be of assistance in future oversight of LDCs.

44. As Energy Probe recommended during the consultation session on LDC efficiency in February 2004, the OEB should develop, present and maintain an ideal utility model using best practices and external references and recognizing efficiency drivers.

45. A benchmarking approach should be designed to quantify efficiency drivers and identify best practices. Whereas a benchmarking approach limited to input data from Ontario LDCs risks

systematic bias, Energy Probe recommends that external information should be included wherever appropriate.

46. The Ontario electric distribution sector's overall labour cost (price x productivity) should be benchmarked against external references, like regulated gas distributors, possibly for 2006 but certainly for the next review of costs. Losses might be benchmarked against those of other utilities. Interjurisdictional cost analysis could be applied to issues like the cost of servicing remote communities, a concept Mr. Camfield acknowledged as potentially useful. (TR 6: 1173)

Chapter 16: Conservation and Demand Management

1. Energy Probe will present its submissions on C&DM by responding to the five key decision points that Board Staff requested comment on. They will include several suggestions for the Board.

2. The five key decisions points identified by Board Staff in their submissions, Transcript Volume 11, commencing at paragraph 1034, were:

- Revenue Protection
- Shareholder Incentive
- Level of C&DM Spending
- Regulatory Treatment of Spending
- Loss Factor Incentives

3. Board Staff noted in their submissions at paragraph 1047, that Mr. A.J. Goulding, the expert witness called by Board Staff, in his report, set out six criteria that might be used to evaluate any models put forward for regulating C&DM:

- Administrative Simplicity
- Bill Impact
- Regulatory Consistency
- Incentives Compatibility
- Financial Stability
- Universality

Revenue Protection, Shareholder Incentive and Regulatory Treatment of Spending

4. It is the position of Energy Probe that no Lost Revenue Adjustment Mechanism needs to be incorporated into a C&DM program. Rather than introducing a complex second best solution to overcome the perverse incentives resulting from the current inefficient rate design, Energy Probe recommends that the Board focus instead on correcting the rate design deficiency directly. The collection of fixed costs and variable rates, which creates the perverse impact to the LDC to suffer from conservation gains, also causes other problems, such as weather variability in earnings. There are multiple reasons to move ahead with rate reform instead of LRAM.

5. Model 4, as presented in the London Economics International report prepared for the OEB, ***Overview of C&DM Practices in North America and potential alternatives for Ontario*** (the "LEI Report"), portrays a user pay scenario with distribution rates calculated on a fixed connection charge basis.

6. Distribution pricing is based on a flat monthly connection charge per customer and the shared savings mechanism is based on customer bill savings. As described in the LEI Report:

> … Generation services would continue to be charged volumetrically. Utilities would recalculate rates by customer class to determine the flat monthly charge each would pay in order to fully meet the utility's annual revenue requirement. Flat rates would be based on the projected number of customers per customer class for the coming year. An annual true-up mechanism would be used to calculate a surcharge or a credit for the following year based on the actual number of customers within the customer class for the previous year.
>
> The use of a flat rate pricing mechanism for distribution services should make utilities indifferent to the volumes on their system from a revenue perspective, removing one potential obstacle to C&DM initiatives. However, to overcome inertia, and to provide utilities with some upside from C&DM, Model 4 incorporates a retrospective shared savings mechanism, in which the utility receives a bonus based on 50% of achieved reductions in customer bills in the previous one year period. 50% of C&DM costs are expensed, and 50% are capitalized over 5 years, under the assumption that a portion of the C&DM benefits are immediate and the remainder are realized over 5 years; thus, the split between expensing and capitalizing the costs matches the timing of the expected benefits.
> (Exhibit C1, 8.1.4)

7. It is the recommendation of Energy Probe for the Board in its ongoing decisions to support moving directionally toward a flat monthly connection charge per customer and a shared savings mechanism based on customer bill savings. Indeed the Board has been gradually increasing the fixed rate in its decisions within the regulation of gas distribution utilities.

8. Energy Probe wishes to point to the submission made in RP-2004-0203 on Motions Day December 6, 2004, RESPONSE TO MOTION RECORD OF POLLUTION PROBE DATED NOVEMBER 12, 2004 by Woodstock Hydro Services Inc. Re: Electric Utility LRAM for fiscal 2005. The submission by Woodstock Hydro was authored by Mr. Ken Quesnelle, Vice-President, Assistant General Manager of Woodstock Hydro and Mr. Bruce Bacon, a senior consultant with Elenchus Research Associates.

9. Mr. Quesnelle made oral submissions to the Board Panel in support of the written submission, and stated:

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> Woodstock Hydro proposes LDC distribution charges move to a full 100 percent fixed charge, or full fixed charge rate structure, and with the volumetric distribution charge being eliminated.
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> A full fixed charge would eliminate the need for the LRAM as the LDC would be indifferent to the reductions in kilowatt hours and kilowatts. The full fixed charge would be designed to be revenue neutral within each rate class and there would be a provision made to have a full fixed charge for various levels of consumption. I just point out that our paper goes into detail as to how the starting point of that would be, but I'd like to emphasize that we're looking at transitional issue. We see, at the end of the day, that a customer's charge would be based on their ability to draw power, and that is what our cost causality is, not on the volumetric. And that a move towards that frees up the LDC to engage in demand-side and conservation programs without the fear of the LRAM regulatory burden.
> (RP-2004-0203 Transcript Volume: MOTIONS DAY)

10. And again at Paragraph 245:

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> A full fixed charge would eliminate the need for the LRAM as the LDC would be indifferent to the reductions in kilowatt hours and kilowatts. The full fixed charge would be designed to be revenue neutral within each rate class and there would be a provision made to have a full fixed charge for various levels of consumption. I just point out that our paper goes into detail as to how the starting point of that would be, but I'd like to emphasize that we're looking at transitional issue. **We see, at the end of the day, that a customer's charge would be based on their ability to draw power, and that is what our cost causality is, not on the volumetric. And that a move towards that frees up the LDC to engage in demand-side and conservation programs without the fear of the LRAM regulatory burden.** (emphasis added)

11. It may be argued by some intervenors that moving toward flat monthly connection charge per customer would discourage customer conservation activities at the margin. However, in response to cross examination by Mr. Poch, representing the Green Energy Coalition, the Board's expert stated:

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> MR. GOULDING: However, as a regulatory economist, I am a great believer in getting prices right and in providing appropriate price signals. I think one of the challenges for small customers, and one which -- and I want to add that this is outside of the 2006 box in which our evidence is placed, but that, you know, as we see an evolution towards realtime meters and realtime pricing, the conservation incentive is going to come from an exposure to some measure of commodity price volatility. And I believe that that's appropriate.

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> I understand that, in the current rate-making structure, and given the structure of default and supply, that there may be an argument that moving to flat-rate pricing changes the incentives to conserve on the customer. But what we want to be doing, I believe, is sending the appropriate price signals to customers, and I believe that -- well, let me step back. It's not my role to make any particular recommendation regarding any of the four models, and I shouldn't go beyond that.

12. It is the submission of Energy Probe that moving directionally toward a flat monthly connection charge per customer and a shared savings mechanism based on customer bill savings meets the six evaluation criteria put forward by Mr. Goulding: administrative simplicity, bill impact, regulatory consistency, incentives compatibility, financial stability and universality.

Level of C&DM Spending

13. At paragraph 1037 of Transcript Volume 11, Mr Millar in his submission outlines the alternative approaches, as he sees them, for rendering a decision on the level of C&DM Spending:

> … The Board may choose to allow distributors to bring C&DM proposals, including budgets, to the Board for approval. In this case, there would not be a preset cap or spending requirement. Alternately, the Board could set a reasonable spending level, either as a cap or as a spending requirement. The evidence we heard on this point offered a range of spending between about 1 percent and 5 percent of total gross revenues.

14. While this was covered in cross examination by both Mr. Shepherd and Mr. Poch, at first in the discussion with Mr. Shepherd, the Board Staff's expert witness did not have a clear idea of the magnitude of this range in absolute dollar amounts. The range being presented is somewhere between $120,000,000 and $600,000,000. This is a magnitude at the high end approaching the level of an OPG Pickering nuclear cost over-run.

15. For 2006, during which most if not all LDCs will be involved in substantial C&DM activity due to spending incented by the 3rd tranche of MARR. Energy Probe submits that it is not reasonable for the Board to set either a cap on C&DM spending or a requirement for spending.

16. Distributors that feel they have cost effective programs that they can successfully initiate in 2006, should be permitted to bring forward their C&DM proposals, including budgets, for approval. A written hearing, or a process whereby there is stakeholder input, will allow those

LDCs with growing expertise to move forward after presenting their proposed programs, and would benefit from input from the Board or stakeholders. Alternatively, those LDCs that are challenged completing their 3rd tranche C&DM activities will not be disadvantaged.

17. In support of this position, Energy Probe wishes to point to the Reply Evidence of Hydro One Inc. Regarding Conservation and Demand Management Evidence Filings, filed January 18, 2005 in this process:

> Hydro One believes that the CDM funding level for utilities should follow Government policy and that each utility should establish a funding level and develop a portfolio of programs based on their appropriateness to its customer base and overall cost-effectiveness. We do not believe that appropriate funding levels can be achieved by applying a simple formula across all utilities.

Loss Factor Incentives

18. At paragraph 1039 of Transcript Volume 11, Mr Millar in his submission outlines the alternative approaches, as he sees them, for rendering a decision on loss factor incentives:

> As Board Staff see it, the two options are to do nothing, that is, maintain the status quo and treat efforts to reduce loss factor as a regular distribution activity, or to set a bar for performance within the rubric of C&DM.

19. There is a practical alternative to doing nothing or using C&DM to incent LDCs to make investments in line loss mitigation. Energy Probe notes that the ECMI evidence filed December 20, 2004, in this process proposed several alternatives to the "C&DM" approach:

> **ECMI Evidence for Procedural Order No. 2, Schedule B**
> **Conservation and Demand Management –Loss Factor Incentives**

20. In that Evidence, Mr White of ECMI presents four alternative treatments for Loss Factor Incentives. One of which, Alternative 3, does deal with utilizing C&DM whereby the LDC receives an incentive based on TRC, which is above mandated return, and therefore an SSM. Quoting from that Evidence at Page 7 of 17:

> The LDC receives an incentive based on the Total Resource Cost Test and receives an incentive above the normal return of the LDC. This is effectively a Shared Savings Mechanism The establishment of the appropriate level of Shared Savings benefit might be difficult. The initial level of 5% may be insignificant compared to the capital investments that may be required to achieve loss reduction. A more appropriate test may be a shorter term pay back period for the customers if the benefits of the loss reduction flow to those customers through the use of a reduced loss factor or the variance account. Any shared savings benefit should be outside of the normal return considerations established by the regulator.

21. As Mr. White points out, one of the problems associated with using a C&DM solution is that it is difficult to separate the loss reduction investment from normal capital expenditures. His recommended alternative provides no specific incentive to the utility, except the assurance that any investment made to decrease the loss factor goes into the rate base and the utility is allowed a return on it independent of any generic rebasing. Quoting from that Evidence at page 9 of 17:

> Alternative 4
> Accelerated recognition of loss reduction investments in the rate base is a reasonable alternative. Assuming that the separation of incremental loss reduction investment can be separated from normal investment, this alternative would be the simplest incentive alternative to introduce. It may produce a lower long term risk to the customers of over crediting the loss reduction investment as any rebasing of the assets would capture what is already identified as a real investment in the distribution system, whether motivated by loss reduction or other considerations.

22. Mr. White is thus recommending that for 2006 rates, loss reduction investments are made an exception and placed in the rate base. Energy Probe supports Mr. White's recommendation and notes that although it asks for a regulatory exception, it meets five out of the six evaluation criteria put forward by Mr. Goulding: administrative simplicity, bill impact, incentives compatibility, financial stability and universality.

Final Note

1. Energy Probe Research Foundation represents a substantial interest in the 2006 Electricity Distributor Rate Handbook process. The Foundation, Canada's third-largest environmental policy organization and Canada's largest energy policy organization, has over 30,000 supporters, half of them in Ontario, of which most have tangibly expressed interest in energy issues. Energy Probe also has a strong consumer focus and is frequently acknowledged in the press as a consumer watchdog. In recent years, Energy Probe has raised funds and acquired supporters on its strengths as a consumer and environmental organization. Energy Probe has a history of representing the interests of many Ontarians who are not financial supporters.

2. As the Board considers Energy Probe's submission, Energy Probe wishes to draw the Board's attention to the quality of its focused participation and its understanding of the issues. It also wishes to draw the Board's attention to the judicious use of its counsel, to the quality of its arguments, and to its recommendations.

3. This proceeding, together with the Recovery of Regulated Assets proceeding and the Canadian Cable Television Association proceeding, represents the beginning of public review of monopoly distribution utility costs, a process that we believe essential for the long-term sustainability of this essential sector. For understandable reasons, some of the parties appeared unaccustomed to the requirements of public cost review.

4. The amount of time invested by Energy Probe reflected effort understanding both the viewpoints of the LDCs and customer stakeholders, and the effort to understand and process the information generated.

5. Energy Probe has appeared before the Board for some 30 years, during which time it has been cited for its cooperative spirit, its often-unique perspective, and its contribution to the development of fair and reasonable rates for both individual consumers and commercial/ industrial purchasers of natural gas and electricity.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

February 14, 2005

David MacIntosh
Case Manager
Energy Probe Research Foundation