File No. RP-2004-0188

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF the preparation of a handbook for electricity distribution rate applications [2006 Electricity Distribution Rate Handbook].

AFFIDAVIT OF JACK GIBBONS

(Affidavit Supporting Motion by Pollution Probe)

I, **JACK GIBBONS**, of the City of Toronto in the Province of Ontario, **MAKE OATH AND SAY:**

A. Introduction

1. I am an economist and a consultant to Pollution Probe and Director of the Energy Programme at Pollution Probe. I have provided evidence at OEB hearings on at least 10 occasions, and I am a former Toronto Hydro Commissioner. Attached as Exhibit "A" is a current copy of my *curriculum vitae*.

2. Except where I obtained information from other sources, I have personal knowledge of the matters discussed here. In cases where I obtained information from other sources, I state the sources of such information (including my references in square brackets), and I declare that I verily believe all such information to be true.

3. I swear this affidavit in support of the motion being brought by Pollution Probe with respect to free-ridership rates and joint programme attribution, and I do not swear this affidavit for any improper purpose.

B. Background to Pollution Probe's December 2004 Motion

4. On November 25, 2003, Ontario's then Energy Minister, the Honourable Dwight Duncan, announced that Ontario's electric utilities would be able to earn their full commercial return on capital effective March 1, 2005 if they reinvested "the equivalent of one year of these monies in conservation and demand management initiatives" [Ontario Ministry of Energy, News Backgrounder, "Ontario Energy Board Amendment Act Highlights Of The Proposed Changes", (November 25, 2003)]

5. However, at the time of Minister Duncan's announcement, the Ontario Energy Board's ("OEB's") status quo regulatory rules financially penalized electric utilities which reduced their customers' bills by helping their customers increase their energy efficiency. Specifically, the OEB's rules linked the utilities' distribution revenues and profits to their distribution volumes in kW and kWh. The higher their distribution volumes were, the higher their profits would be. Conversely, each kWh saved on the customers side-of-the-meter reduced a utility's profits.

6. Therefore, under the 2003 status-quo rules, it was not in the utilities' financial self-interest to spend their conservation and demand management monies in a manner which would provide the maximum possible electricity and bill savings for their customers. Specifically, it was in the utilities' financial self-interest to spend their conservation monies exclusively on utility side-of-the-meter conservation projects which would reduce their internal costs and not reduce their revenues and profits. Moreover, if they were to implement customer side-of-the-meter conservation programmes, it was in their financial self-interest to

implement programmes which would have only the minimum acceptable level of electricity and bill savings for their customers.

7. As a consequence, on November 12, 2004, Pollution Probe brought a motion asking the OEB for an Order establishing guidelines for a Lost Revenue Adjustment Mechanism ("LRAM") and a Shared Savings Mechanism ("SSM") for Ontario's electric utilities, which would permit such utilities to apply in a subsequent rate year for financial allowances in support of their fiscal 2005 energy conservation programmes.

8. An LRAM permits a utility to recover, in a subsequent rate year, the lost distribution revenues (plus carrying costs) that they experience as a result of their energy conservation programmes.

9. However, while an LRAM eliminates a "negative incentive" by removing a financial penalty for promoting conservation on the customer side-of-the-meter, it does not provide a utility with a "positive incentive" to aggressively and cost-effectively promote energy conservation.

10. An SSM, which provides the utility's shareholder with a small fraction (e.g. 5%) of the total net bill savings that are created by the utility's customer side-of-the-meter conservation programmes, can provide a utility with a positive incentive to develop and implement aggressive, innovative, and cost-effective customer side-of-the-meter conservation programmes.

C. The Board's Decision regarding Electricity Sector Conservation Incentives

11. In its landmark December 7, 2004 decision, the OEB, in response to Pollution Probe's motion, made the promotion of energy conservation profitable for Ontario's more than 80 electric utilities for the 2005 fiscal year. Specifically, the OEB approved Pollution Probe's LRAM and SSM proposals:

> With respect to incentive plans, or SSM as it's described, the Board proposes to adopt the plan put forward by Pollution Probe. The 5 percent figure appears to be reasonable in the circumstances. [RP-2004-0203, Transcript Volume 1, 7 December 2004, para. 23]

12. Pollution Probe's proposal is described in paragraph 17 of my affidavit supporting Pollution Probe's motion:

> It is accordingly my view from an economic and regulatory perspective that in order to create effective conservation promoting economic incentives in the electricity distribution sector, and to do so as soon as possible, an electric utility should be permitted to apply for a Shared Savings Mechanism (SSM) incentive beginning with fiscal 2005. The incentive for fiscal 2005 would be applied for subsequent to the year, and would be equal to a small fraction (e.g., 5%) of the total net bill savings that are created by the utility's fiscal 2005 "customer-side of the meter" conservation programmes.

13. On page 110 of its *RP-2004-0188 Report of the Board* (2005 May 11), the Board re-confirmed this shared savings incentive for fiscal year 2006.

D. The Board's Implementation of the Incentives – The Total Resource Cost Guide

14. On December 10, 2004, the Board approved applications by certain utilities to invest in conservation and demand management ("CDM") on the condition that the applicants file quarterly and annual reports including cost benefit analyses on their CDM initiatives.

15. This condition of approval became standard to all approvals of utility funds for CDM. Overall, the Board has approved over $163 million worth of CDM plans to be implemented by the utilities over a three year period ending in September 2007.

16. On September 8, 2005 the OEB issued its *Total Resource Cost Guide* (the "*Guide*" or "*TRC Guide*") which outlines the required analysis and techniques to perform a Total Resource Cost ("TRC") Test cost benefit analysis.

17. The net benefits calculated according to the TRC Test measures the net energy cost savings created by the utilities conservation programmes. According to the SSM, 5% of the net TRC Test benefits are to accrue to the utilities' shareholders as conservation profit bonuses.

E. The *TRC Guide*'s treatment of free-ridership rates and joint programme attribution rates.

18. The *Guide's* proposals with respect to free-ridership rates and joint programme attribution rates dramatically reduce the utilities' incentive to achieve the maximum possible energy cost savings for their customers and/or permit the utilities to earn excessive shareholder incentives. Attached as Exhibit "B" are the relevant excerpts from the *Guide*.

a) Free-ridership rates

19. The net kWh savings of a utility-sponsored energy conservation programme can be described with the following formula:

Savings = (UATES) x (NUD) x (1-FRR)

Where: Savings = kWh/year
UATES = Unit Annual Total Energy Savings
NUD = Number of Units Delivered
FRR = Free-ridership Rate

20. As page 15 of the *Guide* notes, a free-rider is a utility programme participant who would have installed a measure on his or her own initiative even without the programme.

21. In the above formula, the net kWh savings are reduced according to the percentage of participants who would have adopted the measure without the programme. This means that, the lower the free-ridership rate is, the greater the net kWh savings associated with a utility conservation programme will be. Therefore, everything else being equal, the lower the free-ridership rate is, the greater the net energy cost savings of a conservation programme will be.

22. As the OEB has noted, "free ridership is a function of program design". [*Guide*, Appendix A, p. 6] That is, the way a programme is designed can affect whether the free-ridership rate is higher or lower, and by varying the design of a programme, it is possible to reduce a programme's free-rider rate.

23. For example, assume that a residential electric heat pump costs $10,000 and that the heat pumps' existing market share is 5%. If a utility offers a $100 rebate on the purchase of a heat pump, the free-rider rate will probably be very high (e.g. 90%) since very few people are likely to be motivated to purchase a heat pump in response to a rebate which is only equal to 1% of its purchase price. That is, virtually the only people who will collect the rebate will be people who would have purchased the heat pump without the rebate.

24. However, if a utility offers a rebate of $8,000 per heat pump, it is reasonable to assume that the free-ridership rate will be very low (e.g. 10%) since the rebate constitutes a very high proportion of the total cost of the heat pump (80%) and since the pre-rebate market share of heat pumps was very low.

25. As a consequence, if the SSM is to motivate the utilities to maximize energy cost savings, it must motivate them to design and implement programmes that will keep the free-ridership rates as low as practically possible.

26. However, the *Guide* lists 103 free-ridership rates (for specific measures and custom projects) that the utilities can use to calculate the net energy cost savings of their conservation programmes (e.g. the free-rider rates for energy efficient refrigerators and air-conditioners) *irrespective* of their programmes' actual programme design or implementation procedures. For 101 of the 103 free-ridership rates, the rate is 10% or less. Under the *Guide*'s procedures, the utility can use the OEB-approved low free-ridership rates to calculate the bill savings of its conservation programmes even if the programmes' actual free-ridership rates are much higher (e.g. 90% or 100%).

27. Since the utilities under this approach can use the OEB approved rate even if their programme has much higher (i.e. worse) free-ridership rates, the utilities have virtually no financial incentive to minimize the actual free-ridership rates and thus maximize the *actual* net bill savings of their conservation programmes.

28. This flaw could lead to a significant net reduction in the *actual* bill savings that are produced by the electric utilities 2005 and 2006 conservation programmes. For example, assume that:

a) half of the utilities' total conservation budget, namely $81.5 million, is spent on customer side-of-the-meter conservation prorammes;[1]

b) the conservation programmes' ratio of net bill reductions to utility spending is 12 to 1;[2]

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[1] To-date the OEB has approved over $163 million of conservation spending by Ontario's electric utilities over a three year period ending in September 2007. [Ontario Energy Board, *News Release*, "OEB Issues *Total Resource Cost Guide* for 2005 and 2006 Conservation and Demand Management Plans", September 8, 2005]

c) the programmes' actual free-rider rates are 90% (i.e. 90% of the participants would have adopted the conservation measure even without the programmes); and

d) the OEB's *Guide* allows the utilities to calculate their bill savings assuming a 10% free-rider rate.

29. Under this scenario, the utilities' conservation programmes will create an *actual* net bill savings for their customers of $97.8 million [$81.5 million x 12 x (1-0.9)]. However, since the OEB allows the utilities to assume that their free-rider rate is only 10%, their *calculated* bill savings will be $880.2 million [$81.5 million x 12 x (1 – 0.1)] and their SSM incentive will be $44.01 million [$880.2 million x 5%]. That is, the SSM incentive will equal 45% -- a large portion -- of the actual net bill savings in fact created by the utilities ($44.01 million/$97.8 million).

30. Alternatively, if the utilities develop and implement excellent programmes, whose actual free-rider rates are 10% (that is, 90% of the programme's participants would not have undertaken the measure in the absence of the programme), the actual net energy cost savings will be $880.2 million [$81.5 million x 12 x (1 – 0.1)], and , the actual net energy cost savings will rise by $782.4 million relative to a 90% free-ridership rate [$880.2 million - $97.8 million]. However, their SSM incentive will remain constant at $44.01 million.

31. If the *Guide*'s *a priori* free-rider rates system is used in the above two situations, the utilities and their shareholders will receive the *same* profit bonuses through the SSM calculations despite a large variation in actual net energy cost savings to customers. As a result, the utilities will have no financial incentive to increase

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[2] Enbridge Gas Distribution is forecasting that its 2005 conservation programmes will have a ratio of net bill reductions to utility spending of 12 to 1. [EB-2005-0001, Ex. L, Tab 9, Sch. 1, Chris Neme,

their customers' energy cost savings (by $782.4 million in the discussed example) by adopting programme designs and procedures which will lower their actual free-rider rates from 90% to 10%.

32. In my opinion, the solution is for the *Guide* to change from an *a priori* or preset free-ridership rate system to an evidence-based system. That is, utilities must provide some evidence to back up the free-ridership rate they have used.

33. My **recommendations** are accordingly as follows:

a) The *Guide's* list of 103 *a priori* free-rider rates should be rescinded;

b) If a utility wishes to obtain approval for the free-rider rate(s) of one or more of its conservation programmes, prior to programme implementation, it must provide the OEB with evidence to support the reasonableness of its proposed free-rider rate(s); and

c) Alternatively, when a utility submits its SSM claim, after the end of its fiscal year, it must provide evidence to support the reasonableness of its estimated free-rider rates.

b) Attribution rates in joint programmes

34. In some cases, a conservation programme may be more effective if it is jointly carried out between an electrical LDC and some other organization.

35. For example, Natural Resources Canada (NRCan) has developed a number of excellent conservation programmes (e.g. ENERGY STAR for New Homes) which could be co-marketed by Ontario's electric utilities.

Implementing Enbridge's Role in Ontario's Conservation Culture, p. 2.]

36. If a conservation measure is co-marketed, the question arises as to how much of the results of the conservation programme should be credited to the utility and how much to the other organization. This is particularly relevant if the utility can claim a financial bonus under an OEB approved Shared Savings Mechanism for conservation savings the utility has achieved.

37. According to page 16 of the *Guide,* a utility can claim 100% of the net benefits associated with a conservation programme which the utility jointly markets with a non-rate regulated third party (e.g. NRCan).

38. It is my opinion that this rule will permit the utilities to earn excessive SSM incentives. In effect, the utilities may get a financial bonus for conservation which they did not bring about.

39. For example, assume that:

a) In the absence of any co-marketing by Utility A, NRCan's conservation programme will reduce the energy costs of Utility A's customers by $100 million; and

b) If the programme is co-marketed by Utility A, the programme will reduce the energy costs of Utility A's customers by $101 million.

40. Under this scenario, Utility A will receive an SSM incentive of $5.05 million ($101 million x 5%) for reducing its customers' energy costs by $1 million. That is, the company's SSM incentive will be more than 5 times greater than the actual energy cost savings that it has created for its customers.

41. My **recommendation** is accordingly that the *Guide's* attribution rule should be re-written as follows: A utility can claim 100% of the *incremental* net benefits

that it creates when it co-markets a conservation programme with a non-rate regulated third party.

42. If this recommendation is accepted by the OEB, Utility A would earn a SSM incentive of $50,000 ($1 million x 5%) in the example above for co-marketing NRCan's conservation programme.

F. Timeliness of Pollution Probe's Motion

43. The Ontario Independent Electricity System Operator ("IESO") released its *18-Month Outlook: An Assessment of the Reliability of the Ontario Electricity System* on September 27, 2005. Attached as Exhibit "C" is a copy of the report's Executive Summary. According to page iii of the IESO's report:

> The peak demand of 25,414 megawatts (MW) set in August 2002 was exceeded on seven separate occasions this past summer, resulting in a new Ontario peak demand record of 26,160 MW on July 13, 2005. Sustained high temperatures and humidity levels combined with limitations on supply, both from domestic generation and imports, presented a number of challenges for the IESO in managing the reliability of the electricity system…

44. As a result of the strain on the system, the IESO was required to repeatedly activate emergency control actions. These included issuing Public Appeals for customers to reduce their use of electricity on 12 days and implementing sustained five per cent voltage reductions on August 3 and August 4 in order to reduce demand and maintain power supplies to Ontario consumers.

45. In order to avoid persistent use of emergency control actions for future conditions similar to the summer of 2005, the IESO is pursuing a number of initiatives targeted to be in place before the summer of 2006.

46. The IESO also notes that conservation measures can make a difference:

> The government has set aggressive targets for energy conservation to reduce peak electricity consumption by 5 per cent by 2007. However, because the impact of new conservation initiatives is as yet difficult to forecast, the effects of these new conservation efforts are not reflected in the Ontario demand forecast used in this Outlook. These conservation efforts can make a significant difference.

47. The IESO report, and much of the information in it, was not available at the time of earlier considerations of the *Guide*. The IESO report highlights the possible importance of electricity conservation measures and the possible importance of implementing those conservation measures as soon as possible.

48. The previously discussed issues surrounding free-ridership rates and joint programme attribution rates could affect the conservation incentives applicable to a large number of Ontario utilities in the near future. As a result, these issues may affect the degree to which many utilities bring about electricity conservation in Ontario in the near future, which in turn may effect whether or not the serious negative possibilities described in the IESO report (e.g. "persistent use of emergency control actions") can be avoided. This is therefore probably a good time to take a fresh look at the aspects of the *Guide* previously discussed.

SWORN before me at)
the City of Toronto, in)
the Province of Ontario, on)
this 14th day of October, 2005)

A Commissioner for taking affidavits, etc.
Basil Alexander.

JACK GIBBONS

Curriculum Vitae

This is Exhibit A referred to in the affidavit of Jack Gibbons sworn before me, this 14th day of October 20 05

A COMMISSIONER FOR TAKING AFFIDAVITS

Jack Gibbons

Experience

Principal, Public Interest Economics
2000 – Present

Director, Energy Programme, Pollution Probe
2000 – Present

Chair, Ontario Clean Air Alliance
1997 – Present

Commissioner, Toronto Hydro
1995 – 1997

Senior Economic Advisor, Canadian Institute for Environmental Law and Policy
1989 – 2000

Project Manager, Ontario Energy Board
1985 and 1986 - 1989

Economist, Energy Probe
1979 – 1982

Education

Graduate Studies, University of British Columbia
1982 – 1984

Master of Arts, Queen's University
1979

Bachelor of Arts (Honours), University of Toronto
1977

Testimony

Mr. Gibbons has testified before the Ontario Energy Board on approximately ten occasions.

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

This is Exhibit B referred to in the affidavit of Jack Gibbons sworn before me, this 14th day of October 2005

A COMMISSIONER FOR TAKING AFFIDAVITS

TOTAL RESOURCE COST GUIDE

September 8, 2005

2.0 Adjustment factors in the TRC Test

In performing a TRC analysis, several adjustments must be made to the benefits side of the equation. These adjustments include:

- free ridership of participants;
- attribution of the benefits, and
- persistence of the measures.

2.1 Free Riders

Free rider adjustments are one of the key components for the TRC test. The standard definition of a free rider is "a program participant who would have installed a measure on his or her own initiative even without the program."[10]

Costs and benefits associated with free ridership should be assessed as part of the TRC analysis. In determining overall savings, these participants are excluded from the benefits attributed to the program. The equipment costs associated with these participants is similarly excluded from cost side of the equation.[11] However, it should be noted that all program costs associated with free riders must be included in the analysis. As such, programs that have high free ridership are self-evident in the marketplace (i.e. they do not rely on a LDC promotion) and therefore are less cost effective for the LDC to pursue since the program costs are included in the TRC calculation while the benefits are not. Free rider estimates are established through market studies and initial values have been provided in the Assumptions and Measures List.

2.2 Attribution

A fundamental issue for the evaluation of CDM programs is whether the effects observed after the intervention occurs can be attributed to the intervention under evaluation (otherwise known as causality).

Since it can be expected that there will be multiple delivery points of CDM, including other electric LDCs, gas LDCs, electric retailers, gas marketers, the Ontario Power Authority and various levels of government, it is important to understand the Board's guidelines for the attribution of benefits especially in light of a potential claim for shareholder incentive.

This section outlines the guidelines for attributing benefits between OEB regulated CDM delivery LDCs and for savings associated with other resources.

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[10] Violette, Daniel M. (1995) Evaluation, Verification, and Performance Measurement of Energy Efficiency Programs. Report prepared for the International Energy Agency.

[11] Eto, J. (1998) Guidelines for Assessing the Value and Cost-effectiveness of Regional Market Transformation Initiatives. Northeast Energy Efficiency Partnership, Inc.

While attribution is not a true adjustment to the TRC test, this issue is important for those LDCs that plan on seeking a shareholder incentive. The Board advises LDCs that they are allowed to claim 100% of the benefits associated with a CDM program in which they jointly market and deliver the program with a non-rate regulated third party.

The following discussion addresses the issue of attribution of benefits of a CDM program with respect to the potential claim of a shareholder incentive from ratepayers. In the case that a shareholder incentive is recovered, it must be paid by those ratepayers who are receiving the benefits of the program, therefore, guidelines have been established to attribute the benefits of a program along geographic and industry boundaries.

2.3.1 Attribution Guidelines for CDM Programs

The formula for determining savings associated with a CDM program is:

Savings = (UATES) x (NUD) x (1-FRR)

where;

Savings – kWh/yr and/or other resource measure;

UATES – Unit Annual Total Energy Savings

NUD – Number of Units Delivered

FRR – Free Ridership Rate

In order to estimate the savings attributable to the LDC program an attribution rate is added to the previous formula to get:

Attributable Savings = (UATES) x (NUD) x (1-FRR) x (AR)

where;

AR – Attribution Rate

In most cases, the attribution rate will be 1.0, indicating that the LDC should claim in its TRC calculation all of the benefits associated with the CDM program.

The following discussion illustrates three cases where attribution may be an issue.

Case 1- Programs delivered jointly by LDCs with single energy savings (i.e. electricity):

In this case, several LDCs work together to market and deliver a CDM program. Each participating LDC is allowed to claim the benefits associated with the program (electricity and water) in their service area. The determining factors are the location of the participants and the benefits associated with the program. Therefore, in this case, the Attributable Savings would be:

Attributable Savings = (UATES) x (NUD_{SA}) x (1-FRR) x (AR)

NUD_{SA} - number of units delivered in a LDC's service area.

AR = 1

Case 2 – Multi energy savings in cross sector (gas and electricity) jointly delivered CDM program:

In this case, a gas and electric LDC jointly market and deliver a CDM program. Each participating LDC is allowed to claim all of the benefits associated with the energy type they distribute (i.e. gas LDCs would claim the gas savings and electricity LDCs would claim the electricity demand and energy savings). Other benefits, such as water savings, need to be allocated between the gas and electric LDC partners proportionally based on the dollar value of gas and electric TRC savings (i.e. where electricity savings represent 60% of the TRC savings of a program, the electric LDC will claim 60% of the water savings).

Case 3 - Multi energy savings in an individually delivered DSM/CDM programs:

In this case, a LDC works independently to market and deliver a CDM program. The LDC's program may have energy savings additional to the primary energy savings targeted by the program. Common examples of these are Low Flow Shower Head and Programmable Thermostat programs. In these cases, the benefits of the programs will be electricity and other resource savings (i.e. gas and water). As in Case 1, the savings formula would be:

Attributable Savings = (UATES) x (NUD) x (1-FRR) x (AR)

Where UATES incorporate the savings of other energy sources.

2.4 Persistence

Persistence is a measure of how long a CDM measure is kept in place by the customer. Persistence is important for all energy efficiency interventions as a lack of persistence can have very significant effects on overall net program savings estimates. For example, if an energy efficient measure with a 15-year lifetime is removed after only two years, most of the savings thought to result from that installation will not materialize.

There is a compelling argument for accounting for persistence in the assessment of CDM cost effectiveness, especially for measures which are easily retrofitted such as compact fluorescent light bulbs. However, at this time, LDCs should assume 100% persistence in assessing CDM cost effectiveness unless otherwise updated by the Board.

5.0 Assumptions and Measures List

The Assumptions and Measures List data were developed using secondary research, augmented by expert input as required. All data points were cross-referenced with a minimum of two sources. Where possible, recent Canadian experience and data was used. All savings data were based on an understanding of average electricity loads in typical applications in each sector. Cost data were collected from a variety of sources including retailers and distributors. Free rider values are also provided for all measures.[13]

[13] While it is recognized that free ridership is appropriately applied at the program level, the Assumptions and Measures List provides an estimate to facilitate cost effectiveness analysis.

-Appendix A-

Board's Views on Stakeholder Comments on the *Draft Guide to Total Resource Cost Analysis*

Preamble:

Further to the Board's decision of December 10, 2004 (RP-2004-0203), in the Application by the Coalition of Large Distributors[1] for approval to recover funds to be invested in conservation and demand management (CDM), the Board has developed the Total Resource Cost (TRC) Guide. In the Decision, the Board stated that:

> *The methodology with respect to that cost-benefit analysis should be determined in advance, and the Board suggests that a working group be formed with Board Staff and representatives of each of these utilities, with possible involvement from the intervenor community involved in this case. We don't want to face an argument a year from now as to what the methodology should be for this cost-benefit analysis. So in the interim we should work out the methodology, but a year from now, the Board would like to receive from each of these utilities a cost-benefit analysis on the initiatives that have been conducted up until that date.*[2]

This condition of approval became standard to all approvals of LDC funds for CDM. Overall, the Board approved $163 million worth of CDM plans to be implemented by the electricity utilities over a three year period ending in September 2007.

Pursuant to that Decision the Board commissioned a consultant to prepare the Draft TRC Guide. The TRC analysis consists of the methodology of cost benefit analysis that will be required by the Board. The Draft Guide was posted on the Board's website on July 6, 2005 and the Board received comments from the stakeholder community on or about July 18, 2005.

The Board thanks all parties for their submissions on the *Total Resource Cost Guide*; stakeholder input was valuable in developing the final version of the Guide. The Guide is designed to be a practical tool for local distribution companies (LDCs) to perform Total Resource Cost (TRC) analysis.

The Board received submissions on the Guide from Appliance Recycling Canada Inc. (ARCI), Building Owners and Managers Association of the GTA (BOMA), Cornerstone Hydro Electric Concepts Association Inc. (CHEC), Electricity Distributors Association (EDA), Enbridge Gas Distribution Inc. (Enbridge), EnerSpectrum Group (EnerSpectrum), Guelph Hydro Electric System Inc. (Guelph Hydro), Hydro One Networks Inc. (Hydro One), Pollution Probe, Total Energy Advice and Management Ltd. (TEAM), Toronto Hydro Corporation (Toronto Hydro) and Vulnerable Energy Consumers' Coalition (VECC).

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1 The six distributors include; Enersource Hydro Mississauga Ltd., Hamilton Hydro Inc., Hydro Ottawa Ltd., PowerStream Inc., Toronto Hydro Electrical System Ltd. and Veridian Connections Ltd.

2 RP-2004-0203 Decision on the CDM applications by the Coalition of Large Distributors. December 10, 2005, Paragraph 83.

effectiveness of these programs. Simplifying assumptions must be made to manage the evaluation of projects practically.

With respect to Enbridge's submission, the guidelines regarding attribution of benefits are for the purposes of making a claim for lost revenue and/or a shareholder incentive. So long as the costs, lost revenue, and shareholder incentive are recovered from those ratepayers who receive the benefit of the CDM program with no-cross subsidization, parties are free to design partnership arrangements which achieve the greatest benefit. In regard to the issue addressed by Guelph Hydro, the Board feels the issue is addressed appropriately by the Guide. Collectively, the group of gas and electric LDCs will be allowed to claim 100% of the benefits of the program. Individually, each LDC will be allowed to claim the portion of the benefits that is within its service territory and of its energy type. This situation is addressed by Cases 1 and 2 in combination.

With respect to the submission by Pollution Probe and VECC, the Board recognizes there is a potential for LDCs to claim the benefits of a program in which their involvement was minimal. However, this situation would be the exception and the Board supports the development of partnerships with third parties to create efficiencies in the delivery of CDM programs. Further, the Board has the jurisdiction to make adjustments to the incentive awards to the LDCs through its rate cases.

Persistence of Measures

VECC submitted that using a 100% persistence factor will lead to overestimates of benefits since no other adjustments have been made to the measure assumptions.

View of the Board

While persistence is likely not 100% for most measures, for practicality the Board needs to make some simplifying assumptions. The assumption of 100% persistence may be revisited by the Board when better information becomes available.

Custom Project Free Rider Rate and Assessment Requirements

Many parties made submissions concerning the use of 30% as the default free rider rate for custom projects. The EDA submitted that while the Guide gives distributors flexibility to use other testing techniques or data, some distributors are concerned with the use of the default 30% free rider rate during this period of ramping up programs. BOMA submitted that since many custom projects are likely to include measures included in the Assumptions and Measures List, which have prescribed free riders, the default value of 30% appears to be inconsistent. CHEC submitted that the default value appeared high, especially where a program participant had not taken action prior to the distributors' intervention. Hydro One submitted that since the free rider rate was established from a market study conducted by Enbridge Gas Distribution Inc., it accepts the default value, but suggests it be reviewed once reliable data and information from electric utilities became available. Pollution Probe submitted that since the free rider rate is a function of program design, the Board should examine the program design of each custom project before assigning the free rider rate.

Enbridge submitted that the requirement that the statement "it is expected that each custom project will incorporate a professional engineering assessment of the savings" in the Draft guide may not be practical in all cases and that other methods of assessing benefits are valid. Further, Enbridge submitted that it was not clear if the savings estimates signed off by an engineer would require further scrutiny in the audit. Hydro One submitted that given the audit requirements for custom projects, the Board may wish to stress the need for utilities to factor such costs into their program planning.

View of the Board

The Board recognizes that free ridership is a function of program design, *inter alia*, and for any individual custom project the issue of freerider ship is binary. The participant would either have undertaken the measure without the distributors' involvement or it would not have (i.e. either a free rider or not). However, studies commissioned by Enbridge Gas Distribution Inc.[3] and Union Gas Limited[4] indicate on average, the level of free ridership (not including spill-over) was 30% or greater. Without better information, the Board will be guided by these values. While the Board acknowledges that setting a default rate is not perfect, if a distributor feels that these values do not accurately reflect their influence on a particular project, the distributor is free to complete a custom project free rider evaluation and file it along with its cost benefit analysis. With respect to the submission by BOMA, the Board is of the view that custom projects are those that involved customized design and engineering, rather than a combination of several measures provided in the Assumptions and Measures List which have pre-assigned savings and cost values. With respect to Pollution Probe's submission, the Board does not have the resources to complete its own evaluation of each custom project.

With respect to the assessment requirements for custom projects, the Board recognizes that there are other feasible methods to estimate benefits, however, since these projects are likely to be customized solutions which are not presented in the Assumptions and Measures List, it seems practical to require a professional engineering assessment of the savings. Lastly, with respect to Hydro One's submission, the Board feels that the Guide gives distributors appropriate guidance with respect to the costs for monitoring and evaluation.

Avoided Costs

VECC made submissions concerning the use of avoided costs. VECC submitted that the Guide does not address the issue of uncertainty in the values provided by the Avoided Cost Study. VECC also submitted that Hydro One's avoided distribution

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3 Summit Blue Consulting LLC. (2003) *Assessment of DSM Evaluation Processes for Business Markets Projects and Free Ridership Evaluation: Custom Project Attribution Evaluation Final Report.*
4 Summit Blue Consulting LLC. (2005) *Research to Establish Free Ridership Rates Final Report*

18-MONTH OUTLOOK:

An Assessment of the Reliability of the Ontario Electricity System

From October 2005 to March 2007

This is Exhibit C referred to in the affidavit of Jack Gibbons sworn before me, this 14th day of October 2005

A COMMISSIONER FOR TAKING AFFIDAVITS

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Power to Ontario. On Demand.

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24

Executive Summary

This 18-month Outlook provides the Independent Electricity System Operator's (IESO) assessment of the reliability of the Ontario electricity system from October 2005 to March 2007. The assessment incorporates the most up to date forecast information available as well as integrating experience gained from past operations, especially over the past summer.

The peak Ontario demand of 25,414 megawatts (MW) set in August 2002 was exceeded on seven separate occasions this past summer, resulting in a new Ontario peak demand record of 26,160 MW on July 13, 2005. Sustained high temperatures and humidity levels combined with limitations on supply, both from domestic generation and imports, presented a number of challenges for the IESO in managing the reliability of the electricity system. Coincident with the hot weather, available hydroelectric energy production was lower than forecast in the June 2005 Outlook, frequent temperature-related environmental limitations to generation production were encountered and the extension of a few planned outages to generation aggravated the energy situation. Similarly, with the transmission system operating at its limit to support the demand, numerous temperature related limitations were encountered.

As a result of the strain on the system, the IESO was required to repeatedly activate emergency control actions. These included issuing Public Appeals for customers to reduce their use of electricity on 12 days and implementing sustained five per cent voltage reductions on August 3 and August 4 in order to reduce demand and maintain power supplies to Ontario consumers.

In order to avoid persistent use of emergency control actions for future conditions similar to the summer of 2005, the IESO is pursuing a number of initiatives, targeted to be in place before the summer of 2006. These actions include the acceleration, where possible, of planned infrastructure projects, improving the capability of existing resources and establishing an Emergency Demand Response Program similar to those of neighbouring markets. Of particular importance is increasing the certainty of capacity and energy availability through day-ahead arrangements in the wholesale electricity market. When implemented, these arrangements will provide greater certainty of intertie transactions and internal resources and provide the IESO with improved planning capability with respect to potential energy limitations.

Under normal weather conditions Ontario is expected to be able to meet its capacity and energy needs. However, during periods when the supply and demand situation is tight, such as conditions experienced this past summer, or during extreme weather conditions, Ontario will need good performance from generation within Ontario and will rely on imports from neighbouring markets. The need for continued reliance on imports underscores the urgency to address limitations affecting the ability to import.

Increased supply scheduled to come into service over the 18-month timeframe of this Outlook is expected to slightly exceed forecast load growth over the same period.

Ontario Power Generation's plans to return Pickering A Unit 1 to service in the fourth quarter of 2005 will result in an increase of 515 MW to Ontario's electricity system. In addition, eight of the 10 projects from the provincial government's Request for Proposals for Renewable Generation are expected to be available. This includes approximately 350 MW of wind generation and 117 MW of gas-fired generation. Changes to nuclear unit capability will provide an additional 100 MW over the forecast period.

Hydro One's development of the second phase of the Parkway Transformer Station is scheduled for completion by the beginning of summer 2006 and will partially address the high loading of transmission facilities in the Greater Toronto Area (GTA) in the short term. However, additional transmission reinforcement and local generation capability is urgently required to avert the need to use emergency control actions and the increased risk of load shedding within the GTA.

The need for additional supply in the west GTA has reached a critical point with a minimum of 600 MW of new supply required before summer of 2007. Contingency plans are being prepared by the IESO to manage and contain the consequences of the problem until new generation is available.

Outside of the GTA, the transmission system is expected to be adequate to supply demand under the forecast conditions studied in this Outlook, with some exceptions. In those cases, the limitations experienced over the summer of 2005 must be addressed to minimize use of emergency control actions in the future. Limitations which need to be addressed include increasing the transfer capabilities in the Windsor area, northward into the Hamilton-Burlington area, and westward from St. Lawrence Transformer Station. Transmission in these areas limited the use of available Ontario generation and/or limited imports into the province during hot-weather, high-demand periods.

The government has set aggressive targets for energy conservation to reduce peak electricity consumption by 5 per cent by 2007. However, because the impact of new conservation initiatives is as yet difficult to forecast, the effects of these new conservation efforts are not reflected in the Ontario demand forecast used in this Outlook. These conservation efforts can make a significant difference.

The IESO demand forecast has been updated to reflect actual economic, demand and weather data through to the end of July 2005. Energy demand is expected to be 156.8 terawatt hours (TWh) for 2006, a 0.9 per cent increase over the projected energy demand for 2005 (155.5 TWh). The most significant change to the forecast is increased demand for the summer of 2006. The normal weather peak demand for the winter of 2006 is forecast to be 24,272 MW and the summer peak of 2006 is forecast to be 24,234 MW.

It is worth noting that the Ontario demand exceeded the 2006 normal weather summer peak forecast value (24,234 MW) on 18 days this past summer.

The following table summarizes seasonal forecast peak demands for the Outlook period.

Season	Normal Weather Peak (MW)	Expected Seasonal Peak (MW)	Extreme Weather Peak (MW)
Winter 2006	24,272	24,889	25,791
Summer 2006	24,234	25,926	27,378
Winter 2007	24,526	25,146	26,069

While extreme weather conditions have a lower probability of occurring, history shows that even seasonally average weather will include periods of more extreme conditions comparable to those experienced for long periods over the summer of 2005. Prudent planning dictates that the system be capable of operating reliably for these conditions without significant use of emergency control actions. This requirement drives many of the changes the IESO will be targeting to have in place before summer 2006 and in the longer term.

- End of Section -

Caution and Disclaimer