RP-2005-0020

EB-2005-0529

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*

AND IN THE MATTER OF applications by electricity distribution companies for approval of distribution rates for 2006

AND IN THE MATTER OF THE GENERIC ISSUES PROCEEDING

AFFIDAVIT OF RALPH LUCIANI

I, Ralph Luciani, of the City of Oakton, Virginia in the United States of America MAKE OATH AND SAY:

1. I am a Vice-President of the consulting firm CRA International. I have worked as a consultant analyzing economic and financial issues affecting regulated industries, with a particular focus on the electricity industry, for almost 20 years. I have a Master of Science degree in Industrial Administration and a Bachelor of Science degree in Engineering and Economics from Carnegie Mellon University. A copy of my *Curriculum Vitae* is attached as Exhibit A to this affidavit.

2. My firm, CRA International, was retained by Greater Toronto Airport Authority to provide expert opinion in this matter in respect of issues relating to Standby rates and related rate design. Attached as Exhibit B to this affidavit is a report that was prepared by CRA under my supervision. It accurately sets out my conclusions and opinions with respect to the Standby rates issue.

SWORN BEFORE ME in the District of Columbia, United States of America, this 8th day of December 2005.	
Notary Public	Ralph Luciani

CHRISTINE McCAFFREY
Notary Public of District of Columbia
My Commission Expires October 14 2007

CHRISTINE McCAFFREY NOTARY PUBLIC DISTRICT OF COLUMBIA

21478436.1

This is **Exhibit "A"** referred to in
the Affidavit of

RALPH LUCIANI

Sworn before me in the District of Columbia,
United States of America, this 7th day of December, 2005

Notary Public

CHRISTINE McCAFFREY
Notary Public of District of Columbia
My Commission Expires October 14, 2007

CHRISTINE McCAFFREY * DISTRICT OF COLUMBIA * NOTARY PUBLIC

INTERNATIONAL

RALPH L. LUCIANI

Vice President

M.S. Industrial Administration, Carnegie Mellon University

B.S. Electrical Engineering and Economics, Carnegie Mellon University

Mr. Luciani has nearly 20 years of consulting experience analyzing economic and financial issues affecting regulated industries. He has had a special focus on the electricity industry, where he has assisted electric utilities and merchant generating companies with business planning and restructuring, merger and acquisition analysis, resource planning, power solicitations, ratemaking, fuel and power supply contract negotiations, and environmental compliance strategy.

Mr. Luciani has assisted clients and their legal counsel in the management of numerous complex litigation matters, including electric utility prudence and rate cases, and assessments of economic damages in commercial disputes. He has appeared as an expert witness in a number of regulatory proceedings.

Prior to joining CRA, Mr. Luciani was a senior vice president at PHB Hagler Bailly, and a Director at Putnam, Hayes & Bartlett, Inc. Before that, he worked as an Edison engineer for the General Electric Company and as a financial analyst for IBM Corporation. Summarized below are a number of recent projects directed by Mr. Luciani involving the electric utility industry.

PROFESSIONAL EXPERIENCE

Power Solicitations—Mr. Luciani has assisted electric utilities in a number of solicitations for power. In one engagement, with client input, he formulated the RFP, conducted a bidder's conference, clarified initial bids, conducted follow-up negotiations, performed economic evaluations of the bids, negotiated final term sheets and definitive agreements, and obtained regulatory approval for the final agreements through consultation with State PUC staff.

Generation Valuation Lecturer—Over a five-year period, Mr. Luciani served as the lead lecturer and instructor of an advanced training course on generation valuation under cost-of-service rates and under market-based pricing offered annually to senior and mid-level staff at a large U.S. investor-owned utility.

Stranded Cost Derivation—Mr. Luciani presented testimony before four state public utility commissions on the quantification of the stranded cost associated with the deregulation of generation. He has formally evaluated each of the possible methods for deriving stranded cost, including the related adjustments for taxes and merchant financial risk, in assessing the compensatory amount of stranded cost recovery due any utility.

Transmission Ratemaking—Mr. Luciani presented testimony before the FERC on behalf of a group of companies seeking to join a Regional Transmission Organization regarding transmission ratemaking and calculations of earned returns for transmission activities.

RTO Cost Benefit Studies—He developed the financial models used to derive the economic and rate impacts to stakeholders in three major cost-benefit studies of Regional Transmission Organizations (RTOs), and has provided related testimony in a number of state proceedings.

Municipalization—He assisted an electric utility in deriving the exit charges, including stranded generation cost, to be assessed for a proposed municipalization of a portion of the electric utility's service territory.

Generation Valuation—Mr. Luciani performed a market valuation of the generation portfolio of a major generation company. His assessment was used as the basis for restatement of the portfolio's value on the company's balance sheet as part of the spin-off of the assets into an unregulated subsidiary.

Mergers and Acquisitions—On several occasions, Mr. Luciani has analyzed the potential acquisition of electric utilities, gauging the impact of state restructuring plans on asset value and earnings, and formulating transmission and distribution pro forma financials.

Power Marketing—He prepared affidavits in a FERC proceeding analyzing the profitability of a power marketer's trading activities.

Performance-Based Ratemaking—Mr. Luciani formulated a performance-based ratemaking (PBR) plan, for an electric utility, and presented the plan, which included distribution system and call center operating measures, to the state public utility commission.

Distribution System Benchmarking—He formulated a benchmarking analysis to compare the costs and corresponding rates for the distribution system of an electric utility to the systems of neighboring utilities.

Nuclear Plant Sale—He evaluated competitive strategies for a nuclear power plant in a restructured electricity market and prepared a report for the Company's Board of Directors that resulted in a decision to sell the plant. Mr. Luciani assisted in the negotiation of the sale of the nuclear plant to a third party, including conducting detailed economic analyses of the various offers for the facility and assessing the complex income tax effects that would result from the sale.

Organizational Restructuring—Mr. Luciani acted as the lead facilitator in a 12-month project that functionally unbundled the operation and management of a vertically integrated electric utility into stand-alone profit centers.

Merchant Plant Market Assessments—Mr. Luciani has evaluated the economics and financing of a number of merchant generating plants under alternative market price and performance scenarios.

Environmental Regulations—He has assisted electric utilities in formulating strategies for meeting provisions of the Clean Air Act regarding SO_2 and NO_x emissions.

Retail Market Strategy—Mr. Luciani assisted an electric utility in formulating an evaluation model to assess the profitability of new retail loads in a competitive market. Mr. Luciani also developed a financial model for a company seeking utility investment in its product offering to be used to reduce on-peak demand in residences.

Restructuring Planning—He has advised a number of electric utilities in formulating and evaluating restructuring plans for a transition to state retail competition.

Fuel Supply—Mr. Luciani assisted an electric utility in negotiating the terms of a buyout and replacement of a long-term coal supply contract, and in obtaining regulatory approval for the resulting rate treatment and deferred recovery mechanisms.

Mr. Luciani has testified before the Arkansas, Kansas, Louisiana, Maryland, Missouri, Pennsylvania, and Ohio public utility commissions, and the Federal Energy Regulatory Commission (FERC). On a number of occasions, he has also provided expert testimony on behalf of United Parcel Service (UPS) in U.S. Postal Service rate proceedings before the U.S. Postal Rate Commission.

This is **Exhibit "B"** referred to in
the Affidavit of

RALPH LUCIANI

Sworn before me in the District of Columbia,
United States of America, this 7th day of December, 2005

Notary Public

CHRISTINE McCAFFREY
Notary Public of District of Columbia
My Commission Expires October 14, 2007

CHRISTINE McCAFFREY * NOTARY PUBLIC * DISTRICT OF COLUMBIA

RP-2005-0020

Before the Ontario Energy Board

Setting Rates for Standby Service and Distribution Service to Customers with Load Displacement Generation

Prepared by:

CRA International

December 8, 2005

For:

Greater Toronto Airport Authority

A. INTRODUCTION AND SUMMARY

Load displacement generation is generally understood to result in important economic and environmental benefits. In order to achieve the full potential of load displacement generation in Ontario, and the economic and environmental benefits resulting from that generation, it is essential that retail customers receive accurate economic signals regarding the costs and benefits of investing in, and using, load displacing devices.

Ontario has initiated a number of policy initiatives to improve the accuracy of the economic signals seen by retail customers. Restructuring of the generation and transmission sectors of the electricity market has led to more accurate and more transparent prices for electricity supply and transmission as unbundled services. Now the Ontario Energy Board (OEB) is turning to the task of providing accurate signals regarding the costs and benefits associated with load displacement generation at the distribution system level. In this proceeding, the OEB is seeking input on two issues related to these costs and benefits, generalized standby rates for load displacement generation (Generic Issue 3) and deferral accounts for revenue losses attributable to unforecasted distributed generation (Generic Issue 2.2.1).

In our opinion, OEB policy regarding the design of standby rates for load displacement generation should be guided by four major principles. First, a customer in a given rate class will consider its rate for distribution service as well as its rate for standby service when evaluating the economics of a load displacement device. Therefore both rates are relevant and the rate for standby distribution service should not be established in isolation from the rate for (regular) distribution service. Second, the rates for standby distribution service for a given class of customers (rate classification), and for regular distribution service to that same class, should both be set according to the same cost of service principles in order to provide accurate economic signals. Third, load displacement generation has potential benefits for distribution utilities in terms of avoided capital costs, reduced system losses and improved reliability. The rates for standby and regular distribution service to customers with load displacement generation should reflect those benefits. Fourth, the existing rates for distribution service do not appear to be uniformly based upon cost of service principles and should not be used as a starting point for the development of standby rates.

Based upon those principles, we recommend that the OEB require distribution utilities to address the development of standby rates by rate classification as part of its Cost Allocation Review proceeding (EB 2005 0317). Having all parties consider the allocation of costs to standby service as part of that proceeding should ensure that, for each rate class, both standby rates and distribution rates will be developed using a consistent set of generally accepted cost allocation and rate design principles. In conjunction with that cost allocation process distribution utilities should quantify the various benefits of load displacement generation (e.g., avoided cost, reduced system losses, improved reliability) and incorporate those benefits into the development of rates and/or credits for customers with load displacement generation.

Finally, we conclude that a Deferral Account should not be established for revenue losses attributable to unforecasted distributed generation until there is evidence of the magnitude of the actual level of unforecast load loss. This will require a method for measuring the level of unforecast load losses as well as for calculating the lost revenues attributable to that unforecast load loss and the avoided costs resulting from that unforecast load loss.

B. GTAA LOAD DISPLACEMENT GENERATION

The situation facing the Greater Toronto Airport Authority (GTAA) provides a concrete example of the need for distribution utilities to develop new distribution rates and standby rates based upon a consistent set of cost of service principles, and why those rates should reflect the benefits of load displacement at the distribution level.

The GTAA is a large retail customer that has traditionally met its entire load through purchases, with delivery provided by its local distribution utility, Enersource. GTAA is one of nine customers in Enersource's Large User rate class. Like most utilities, Enersource has grouped customers with similar load characteristics into classes for rate making purposes. Utilities group customers in this way because the costs they incur to serve customers in any given rate class are driven by the load characteristics of the customers in that class.

GTAA has a very large demand, in the order of 36,000 kW (36 MW) and a relatively flat pattern of usage during any given day and within any given month. During any month its maximum demand may occur either in a peak period[1], or an off-peak period. Enersource currently bills GTAA and other Large User customers based upon their maximum demand in a peak period during each month. It is proposing to change this billing determinant to the maximum demand during a month regardless of when that maximum demand occurs. Such a change would have little impact on GTAA because, as indicated in Figure 1, in any month there is relatively little difference between its maximum demand during peak periods and its maximum demand during off-peak periods.

The GTAA is currently commissioning a gas-fired generating unit ("Cogen Facility") with a total capacity of 118 MW in winter and 90 MW in the summer. Thus, GTAA is about to have both load displacement and embedded generation. In hours when the market price of electricity is greater than the GTAA's cost

[1] Enersource defines its peak period to be 7 a.m. to 11 p.m. on weekdays excluding statutory holidays.

of producing power the GTAA plans to run the Cogen Facility to meet its own load as well as to sell power into the IESO-administered market. In fact the GTAA has entered a Clean Energy Supply Contract (CES Contract) with the Ontario Power Authority for 90 MW. Based upon the current outlook for electric market prices, the GTAA expects that it will be economic to run the Cogen Facility during some, or all, of the hours in peak periods each month. During the remaining hours in each month it will be more economic for GTAA to purchase its power from the grid with delivery via Enersource.

In response to these developments, Enersource is proposing to bill GTAA a standby charge that would be applied to GTAA's "gross load", i.e. its peak load regardless of how GTAA meets that load. The proposed standby charge would be equal to the distribution charge for Large Users, currently $2.5409 per month per kW respectively[2]. Under this proposal, GTAA would effectively continue to pay Enersource the same monthly amount as if it had never built and operated its Cogen Facility.

In its pre-filed evidence for its 2006 Rate Application, Enersource stated that it had considered four alternative methods for calculating standby charges. One alternative that Enersource identified was a standby charge based solely upon the revenue requirements associated with those distribution assets it uses to serve the GTAA. This charge was calculated according to marginal cost principles under the OEB rate design set out in Schedule 10-6 of the 2006 Electricity Distribution Rate (EDR) handbook. Under that approach Enersource would bill GTAA $0.39 per peak kW per month times its gross load. (Note that this rate is only 15% of the current rate for distribution service, indicating that the $2.54/kW may be recovering more costs than those that Enersource incurs to serve Large User customers.) However, under the expected cycling nature of its Cogen facility, GTAA will be taking distribution service from Enersource in the same month as it is taking standby service. Under that mode of operation we assume that the distribution rate of $2.54/kW would supersede the lower standby rate of $0.39/kW, in order for Enersource to avoid recovering the same costs twice, and again GTAA would effectively continue to pay Enersource the same monthly amount as if it had never built and operated its Cogen Facility.

Enersource has not provided a detailed study of either the costs that it will actually incur to provide standby and distribution services to the GTAA under its new mode of operation, or the costs that Enersource might avoid as a result of GTAA's embedded generation. (For example, Enersource may be able to free up space on one of the several 27.6 kV feeders that it has traditionally used to serve the GTAA now that, as part of the Cogen Facility project, it has connected three 44 kV feeders to the GTAA.) Enersouce has acknowledged that the most accurate way to establish a standby charge is to prepare a

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[2] Enersource is also proposing an administration charge of $600/month. For regular distribution service to the Large User class Enersource has a monthly customer charge of approximately $12,000 in addition to the distribution charge.

cost of service study, but Enersource will not prepare such a study until a standard methodology is established through the Cost Allocation Review.

Thus, both the standby rate and the distribution rate are key components of what GTAA will pay to Enersource. The level and design of each rate could influence GTAA's future decisions regarding the mode in which to operate its Cogen Facility. As such, standby rates are not the only distribution costs considered by a customer with load displacement generation or embedded generation such as GTAA, and hence should not be viewed in isolation from the distribution rates that such a customer would pay.

C. HOW CAN DISTRIBUTION SYSTEMS BENEFIT FROM LOAD DISPLACEMENT AND EMBEDDED GENERATION?

Load displacement generation is generally expected to result in important economic and environmental benefits[3] [4]. Most of the benefits identified to date have been at the generation and transmission level, including:

- Lower Air Emissions,
- Lower Transmission System Maintenance Costs,
- Reduced Transmission System Losses
- Delayed Investment In Transmission Capacity
- Lower Ancillary Service Costs
- Market Power Mitigation

Less attention has been paid to the potential benefits of load displacement and embedded generation at the distribution level, as regulators are only now having the opportunity to assess those benefits. The primary potential benefits of such generation to a distribution utility are avoided capital and operating costs, reduced distribution system losses and improved reliability[5] [6]

Load displacement and embedded generation can enable a distribution utility to avoid capital costs by reducing the peak load at a particular location on the system below a threshold level that would otherwise trigger an investment in new distribution plant. The avoided costs represent the savings in capital costs from deferring or reducing the level of capital investment required to meet load growth. Operating costs

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[3] Electricity Conservation and Supply Task Force, *Tough Choices: Addressing Ontario's Power Needs*, January 2004

[4] *Request for Proposals for 2,500 MW of New Clean Generation and Demand-Side Projects*, Ontario Ministry of Energy, September 13, 2004.

[5] Ontario Ministry of Energy, *Electricity Transmission and Distribution in Ontario – A Look Ahead*, December 21, 2004.

[6] OEB, *Standard Offer Program for Eligible Distributed Generation Staff Discussion Paper*, November 17, 2005. EB-2005-0463

associated with these deferred or reduced capital investments are also avoided. The exact level of avoided cost will depend upon the specific circumstances of the distribution utility and the embedded generation. For example a distribution utility experiencing high load growth likely will have a higher avoided cost due to embedded generators than a distribution utility facing slower load growth.

Hydro One has estimated the value of avoided distribution capacity on its system due to Conservation and Demand Side Management (CDM) to be $6.50 per year per kW of avoided demand (RP-2004-0203/EB-2004-0533, June 15, 2005 letter to OEB). This estimate is based upon Hydro One's assessment of the value of annual investments in distribution stations, feeders emanating from transformer stations and LV facilities that it could avoid due to reductions in peak demand resulting from CDM programs. Their analysis basically entails running their distribution system expansion model first assuming normal load growth absent any CDM, and then a second time assuming a lower level of demand due to the impact of CDM. Their analysis is included as Attachment 1 to this report. Distribution utilities could use the same methodological approach to estimate the avoided costs from load displacement or embedded generation

A second potential benefit from this generation is a reduction in distribution system losses. The average level of losses on Ontario distribution systems is in the order of 3% to 4%. This is not a trivial quantity. At an annual province-wide consumption of 150 billion kWh[7], distribution losses represent 4.5 to 6 billion kWh a year. Embedded generation has the potential to reduce these losses simply by reducing the quantity of electricity that a distribution utility has to deliver to its customers each year, particularly during peak periods. In addition, distribution utilities may experience lower losses during periods when an embedded generator is injecting power into their system.

The third potential benefit from embedded generation is an improvement in distribution system reliability. One possible source of improvement are the upgrades to the distribution system that are made as part of the interconnection agreements with the embedded generator. These can provide additional back-up for distribution services. Another possible source of improvement is the ability of the embedded generator to inject power into the distribution system when certain distribution system assets are out of service.

[7] Independent Electricity System Operator. *10 year Outlook: Ontario Demand Forecast*, July 8, 2005, Table 2.1.

D. HOW SHOULD DISTRIBUTION UTILITIES DEVELOP RATES FOR STANDBY DISTRIBUTION SERVICE AS WELL AS FOR NORMAL DISTRIBUTION SERVICE TO CUSTOMERS WITH LOAD DISPLACEMENT GENERATION?

In our opinion, OEB policy regarding the design of standby rates for load displacement and embedded generation should be guided by four major points or principles. The first principle is that distribution companies should strive for consistency between standby rates and distribution rates within each rate class, because both rates are relevant to decisions that a customer in a given rate class will be making regarding load displacement generation. The remaining three principles address the approach that distribution utilities should follow to ensure that consistency, specifically:

- establish standby rates and distribution rates, by rate class, according to the principles of cost causation;
- reflect the benefits of load displacement and embedded generation in the standby rates and distribution rates applicable to customers with such generation; and
- do not derive standby rates from distribution rates that were not set based on the principles of cost causation.

The first point or principle - strive for consistency between standby rates and distribution rates within each rate class – is based on the fact that both rates provide relevant economic signals to a retail customer regarding the economics of a load displacement device. Based on that fact, standby rates for customers in a given rate class should not be set in isolation from rates for regular distribution service for the corresponding rate class. This importance of both rates to a customer with load displacement generation was demonstrated earlier with respect to GTAA, and is illustrated more generically below.

When determining whether to invest in load displacement generation, a retail customer in a given rate class faces a wide range of possible options in terms of both the capacity of the unit and the mode of operation. In terms of capacity, the retail customer can choose between a unit that can meet only a portion of its maximum demand, all of its maximum demand, more than its maximum demand with provision for sale into the grid or none of its maximum demand (i.e. no investment). Similarly in terms of operating choices, that retail customer can choose between running in all hours (baseload mode) and running only in hours when electricity market prices are above a specific threshold (peaking mode). In evaluating the economics of these various options, the customer should consider the rate it will be billed for the regular distribution service it takes, if any, as well as the standby rate it will be billed when it is meeting its load through its on-site generation. Thus, standby rates are only one component of the potential distribution service costs that customers face when considering load displacement generation, and should not be established in isolation from distribution rates.

The second key point regarding rates for standby distribution service and regular distribution service is that they should both be set according to the same cost of service principles. This point is based upon the importance of providing customers with accurate economic signals in order to maximize societal benefits through economic efficiency. If a distribution utility charges standby and distribution rates that are greater than the costs it actually incurs to provide those services, it will provide an incorrect economic signal to the customer regarding the costs and benefits of investing in, and using, load displacement generation. That incorrect signal may discourage the customer from investing in the load displacement generation and in turn lead to societal costs, all of which would be economically inefficient. Similarly, if the utility is charging a particular rate class standby and distribution rates that are less than its costs, it again will provide an incorrect economic signal that may encourage investments in embedded generation that are not economically efficient from a societal perspective. Thus, in order to achieve the full potential of load displacement generation in Ontario, and the economic and environmental benefits resulting from that generation, it is essential that retail customers receive accurate economic signals in the form of standby rates and distribution rates, by rate class, set based upon cost causation and cost of service principles.

Our third point is that the rates for standby and regular distribution service to customers with load displacement generation should reflect the benefits of that generation to the distribution utility. This point or principle is related to the second point regarding the establishment of rates on the basis of cost causation. In order to set their rates on that basis utilities will need to begin by quantifying the various benefits of load displacement generation (e.g., avoided cost, reduced system losses, improved reliability) to their specific distribution system by rate class. Their next step would then be to reflect those benefits in rates by rate class. The best way to accomplish that integration would be to use the data on those benefits in the cost allocation process. An alternative approach would be to translate the benefits into rate credits that would be given to customers with load displacement generation

Our final point is that the existing rates for distribution service do not appear to be uniformly based upon cost of service principles and therefore should not be used as a starting point for the development of standby rates. For example, there are indications that existing distribution rates are not uniformly based upon a distinction in distribution assets, and costs, by voltage level. It is important that distribution utilities make this distinction by voltage level because they typically serve very large customers using only the high voltage, or primary level, assets on their system. This issue was discussed in a Cost Allocation Working Group report on Load Data Collection dated September 23, 2003[8]. The Board subsequently

[8] *First Report of Cost Allocation Working Group*, September 23, 2003, RP-2003-0228.

sent Load Data Collection Directions[9] to all distribution companies indicating that any distributor planning to include a rate classification by voltage in its cost allocation filing should include the appropriate load and financial data. More recently, Staff has discussed the need for data on costs by primary and secondary voltage in their Discussion Paper on the Cost Allocation Review. An excerpt from that Discussion Paper is presented in Attachment 2. If a distribution utility does not make a distinction between its primary level costs and its secondary level costs, it may allocate costs associated with certain low voltage, or secondary level, assets to large customer rate classes when in fact it does not use those specific assets to serve those rate classes. Such an allocation would result in rates that do not reflect cost causation.

Based upon these four principles, the distribution utilities in Ontario should be required to develop rates for standby distribution service, by rate class, according to the same cost of service principles that are used to set new distribution rates. The Board's Cost Allocation Review proceeding (EB-2005-0317) appears to be an ideal forum for establishing a standard, cost of service based, methodology for development of standby rates and distribution rates. This initiative is examining the principles, methodologies, filing requirements and model design that should apply to new cost allocation studies for electricity distributors.

E. SPECIFIC QUESTIONS REGARDING STANDBY RATES

The OEB posed the following specific question regarding standby rates for load displacement generation:

a. *Should the Board develop a standardized methodology for stand-by rates?*
b. *Should the Board permit utility-specific approaches to the design of standby rates, and*
c. *If so, what should that design basis be?*

a) Should the Board develop a standardized methodology for stand-by rates?

The OEB should require distribution utilities to develop standby rates by rate class as part of the Cost Allocation Review (EB 2005 0317) based upon the same cost allocation and rate design principles used to develop new distribution service rates for the corresponding rate class.

In order to develop standby rates that will be responsive to the needs of their customers, the OEB should require distribution utilities to consider a range of standby service load characteristics. As noted earlier, load characteristics are a key driver of the costs that a distribution utility will incur to provide the service. However, utilities should not be allowed to design standby rates based upon the simple assumption that all customers with load displacement generation will want the utility to stand ready to provide their gross load. Instead, utilities should be required to develop their standby rates in a manner that will allow

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[9] OEB. *Staff Discussion Paper*, EB 2005 0317, September 2005, Appendix 7, Board Load Data Collection Directions, Issue 13 g.

customers considering that service to choose the level of maximum demand for which they desire the utility to stand ready to serve. The need for this customer-oriented approach arises from the fact that customers have a range of possible load displacement generation capacities and operating modes from which to choose. They should also have the opportunity to choose the level of standby service that is most cost-effective in light of their particular options and needs.

In conjunction with their participation in the Cost Allocation Review, each distribution utility should be required to identify the costs that it will "avoid" as a result of a load displacement generation, and to determine how best to reflect those avoided costs in its distribution and standby rates to customers with load displacement generation. The rates developed under that process should be based on the costs that the utilities incur to provide those standby and distribution services by rate class.

b) Should the Board permit utility-specific approaches to the design of standby rates?

The OEB should permit utilities to apply for a utility-specific approach that is different from the standard method for limited, exceptional circumstances. In such applications the utility should be assigned the burden of justifying its proposed departure from the standard method. Utilities should have the latitude to respond to a unique situation with a customized approach. The OEB retains the right to determine if the customized approach is justified.

c) If so, what should that design basis be?

See the discussion under question (a).

F. DEFERRAL ACCOUNT ISSUES

The OEB also asks: (Generic Issue 2.2.1.) *Should utilities be permitted to record in a deferral account foregone revenue amounts attributable to unforecasted load losses arising from distributed generation?*

As a general matter, utilities should not be permitted to record foregone revenues attributable to unforecasted load losses arising from distributed generation absent evidence that the load losses could not have been forecast and reflected in their rate application. Given the various conditions that a customer must satisfy in order to install distributed generation, the utility should be aware of impending load loss due to such projects. Even then, such losses in load may in practice be offset by other changes in system load that had not been forecasted. Load forecasts are part of the planning process, and will never be wholly accurate in practice. Both new load and lost loads during the course of the year can be unpredictable, and lead to revenue collections (and utility costs) that will be different than projected. Such variations are generally not accounted for through a deferral mechanism.

Utilities in Ontario have the ability to adjust their rates annually. This minimizes foregone revenues. A rate mechanism should not be established until there is evidence of the magnitude of these unforecasted load losses. This will require a method for measuring unforecasted load losses. Moreover, an offsetting assessment of utility costs avoided through the unforecasted loss of load would be required.

ATTACHMENT 1

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Brian Gabel
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Regulatory Affairs

hydro one

BY COURIER

June 15, 2005

Mr. John Zych
Secretary
Ontario Energy Board
Suite 2601, 2300 Yonge Street
P.O. Box 2319
Toronto, ON.
M4P 1E4

Dear Mr. Zych:

RP-2004-0203/EB-2004-0533 Hydro One's Conservation and Demand Management Plan: Data on Avoided Electricity Costs

In accordance with the Board's direction and as discussed in our May 24th status memo on this matter, Hydro One is pleased to file avoided cost data for use in screening conservation and demand management ("CDM") programs. This information is provided in two parts. The first part is a consultant's report from Navigant Consulting Inc. which provides the avoided cost estimates for energy, generation capacity and transmission capacity. This is contained in Attachment A. The second part is an assessment by Hydro One of Distribution based avoided costs and this is contained in Attachment B.

The report submitted by Navigant Consulting provides the avoided cost estimates for energy, generation capacity and transmission capacity over the period 2006 through 2025, and the related assumptions, data sources and analysis methodologies. Estimates of environmental damages are also provided for the same time frame, should the Board decide that these should be used. The values for avoided costs of energy, generation capacity and transmission capacity are provided in Table 21, page 42 of the report. Values for environmental externalities appear in Table 22, page 43 and Table 23, page 44 contains avoided energy costs, which incorporate the environmental adders. It should also be noted that the report also provides avoided generation capacity costs for Demand Response type programs in Table 24, page 45 of the report. The section entitled "Application of Results" provides further directions, assumptions and caveats, which will help in the application of these estimates to the screening of various types of CDM programs.

Attachment B provides a preliminary high-level estimate of distribution based avoided costs from Hydro One for the period 2009 through 2012. This Hydro One assessment is based on the methodology developed by Navigant Consulting for the Transmission avoided costs.

Questions may be addressed to Carolyn Russell (Senior Advisor, Regulatory Affairs), who may be reached by phone (416) 345-5914, fax (416) 345-5866, or e-mail: carolyn.russell@HydroOne.com. Her address is Hydro One Networks Inc., 483 Bay Street, South Tower, 8th Floor, Toronto, Ontario M5G 2P5.

Yours truly,

Brian Gabel

cc. Mr. A. Fogwill, Applications Director, Market Operations hydro one

ATTACHMENT B

Preliminary Distribution Avoided Cost Assessment for Hydro One

To develop preliminary distribution based avoided costs, Hydro One utilized the same approach as that taken by Navigant, in developing avoided costs for transmission. This included an assessment of annual investments to major distribution plant attributed to load growth such as increasing the capacity of distribution stations, feeders emanating from transformer stations and LV facilities. Costs associated with directly connecting new customers, such as new radial supplies, provision of secondary services and metering were not included, as these investments are required to connect new developments and cannot be deferred by CDM programs.

The approach involved reviewing each planned addition to the distribution system for 2006 and establishing whether or not it was appropriate for avoidance or deferral via CDM programs. Distribution projects for 2006 are well defined and determined to be representative of a typical year. If the project was deemed to be a candidate for deferral, through CDM programs, its cost and related capacity were included in the assessment, similar to the approach used in the transmission analysis. The illustrative example appearing in Table 1.0 uses 2009 as the original need date. Since the 2006 costs were representative of a typical year they were escalated to 2009, by using a 2.5% escalation rate.

Table 1.0 below illustrates the level of avoided distribution costs that would be expected, under these assumptions. As with avoided transmission costs, the distribution avoided costs are capacity based.

Table 1.0 Hydro One Illustration of a Distribution Avoided Cost Analysis

Category	**2009**	**2010**	**2011**	**2012**
CDM Impact (assumed equal to demand growth)	180	180	180	180
New Need Date				X
Old need Date	X			
		(Cost in $Millions)		
Original Cost	19.92			
Avoided Carrying Charges on Original Cost Avoided	1.84	1.84	1.84	
Avoided O&M		0.20	0.20	0.21
Cost with Inflation				21.45
Net Avoided Cost	1.84	2.04	2.05	(1.32)
Levelized Avoided Cost ($millions)	1.26	1.26	1.26	1.26
Avoided Distribution Development ($2005/kW-yr)	6.50	6.50	6.50	6.50

As discussed by Navigant in their assessment of transmission avoided costs, it is important to recognize that this preliminary distribution avoided cost analysis allocates the avoided costs associated with deferring localized distribution capacity upgrade projects across the system-wide CDM impacts. As such, they will understate the value of CDM in those areas in need of localized distribution capacity upgrades and overstate the value of CDM in those areas that do not require localized distribution capacity upgrades.

This effect is expected to be significantly more pronounced with distribution costs since individual assets serve significantly fewer customers and are therefore more dependent on the penetration rates and effectiveness of local programs targeted at those few customers. CDM will have little or no distribution benefit in the areas where the distribution system experiences little or no growth. Hydro One experience indicates that a relatively low level of the avoided costs should be attributed to system wide avoided distribution costs and that calculations of localized avoided costs should be allowed and encouraged.

It should be noted that these distribution system avoided costs are preliminary in nature and are only applicable for customers supplied from Hydro One's distribution system. This includes Hydro One end-use distribution customers, embedded LDCs and LDCs supplied from Hydro One LV facilities. Accordingly, other LDCs would have to add avoided costs for their own part of the distribution system.

Finally, the avoided costs calculated by Navigant for energy, generation capacity, transmission capacity and environmental damages represent the costs at a wholesale delivery point – the interface between the transmission system and an LDC. Accordingly, LDCs should apply their approved loss factors to the avoided costs for these elements in order to account for losses experienced on the distribution system.

ATTACHMENT 2

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

Cost Allocation Review

Staff Discussion Paper

September, 2005

Section 2: Overview of Cost Allocation

Cost allocation studies serve the following main purposes:

- to allocate the costs to provide service to the various customer rate classes based on cost causation principles
- to assess the reasonableness of the rates charged to customers in relation to their allocated costs
- to support the design of rates

Factors that affect the costs of distribution facilities and operations and maintenance expenses include the following:

i. customer density
ii. load factors
iii. distribution planning criteria
iv. vintage of plant

Cost allocation studies play a major role in assessing the reasonableness of rates. Principles or objectives other than cost causality may also be considered by regulators when setting just and reasonable rates. They can include rate stability, customer acceptance and supporting conservation.

The first step of a cost allocation study consists of identifying costs that can be directly assigned to a particular rate class. For common costs or costs that are attributable to multiple customer rate classes, such as distribution lines, a three-step process is used:

1. Functionalization
2. Categorization (or classification)
3. Allocation

At the functionalization stage, the revenue requirement and rate base are separated into major functional costs centres (e.g. distribution, metering, billing, customer care, etc.) and sub-functions if applicable (e.g. high and low voltage distribution lines).

At the categorization or classification stage, the functionalized costs are further arranged into groups based on cost defining characteristics. The most common classifications are demand, energy and customer-related costs.

In the last step, categorized costs are allocated to the various customer rate classes based on appropriate allocation factors.

The allocated costs by rate class are then compared to revenues, and revenue to costs ratios are derived. If the allocated costs are in excess of the revenues (revenue to cost ratio less than one), the rate class is under-contributing towards the recovery of the revenue requirement based on the conventions that underpin the study. Conversely, if the allocated costs are lower than the revenue under existing rates (revenue to cost ratio larger than one), the rate class would be over-contributing towards the recovery of the revenue requirement.

2.1 Financial Information Requirements

A cost allocation study will allocate the test period rate base and revenue requirement to the various customer groups.

The basic financial information required to perform a cost allocation study is extracted from the Uniform System of Accounts (USoA) classification that is applicable to all electricity distributors. It will therefore be imperative that all distributors adhere to the uniform system of account classification in the manner prescribed in the Accounting Procedures Handbook, Article 220.

Load research and customer-related data for the test period are also required to allocate demand-related and customer-related costs respectively.

Meters and service drops also represent direct customer connections, but they are usually allocated based upon a weighted customer allocator.

6.2.4 Adjustments

Staff proposes that certain technical adjustments be made to the demand allocator factors.

Class NCP by Voltage

Line Losses

Demand allocation factors are derived from actual meter reading data. Meters are installed at different voltages. Adjustments must therefore be made for line/transformation losses to fairly compare interclass demand allocation factors.

Staff proposes that utilities use the same loss factors as the ones filed in the 2006 EDR applications when adjusting their metered load data to arrive at the demand allocators.

Primary v. Secondary

Customer loads should be adjusted to recognize the voltage at which they are metered.

For example, larger users can be excluded from the allocation of secondary voltage lines and transformers since they do not use secondary voltage facilities. On the other hand, residential and small commercial customers should share the costs of the primary and secondary lines (the joint cost portion) since they use both.

Based on the USoA, Ontario distributors may not have sufficient data to identify conductors by primary and secondary voltage. Staff suggests that appropriate additional filing requirements should be developed where other clear supporting information is available (such as engineering diagrams and asset details).

Any suggestions during the consultations for future improvements to the USoA to assist in tracking primary versus secondary distribution costs will be noted.

Peak-load Carrying Capacity ("PLCC") Adjustment

A Minimum System has a certain load carrying capability which can be viewed as being demand-related. As a result, the customer-related costs will have a demand component in them. If no adjustment is made, some customers (e.g. small users) may be allocated a disproportionate share of demand-related costs.