Ontario Energy Board | Commission de l'Énergie de l'Ontario

Ontario

RP-2005-0020
EB-2005-0529

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

AND IN THE MATTER OF a proceeding initiated by the Ontario Energy Board to make certain determinations of matters raised in applications by electricity distribution companies for 2006 rates pursuant to sections 19(4) and 78 of the Ontario Energy Board Act, 1998.

BEFORE: Gordon Kaiser
Vice Chair and Presiding Member

Cathy Spoel
Board Member

DECISION WITH REASONS

March 21, 2006

INTRODUCTION

Background

This proceeding arises from Applications filed by a large number of electricity distribution companies in Ontario for the approval of distribution rates to be effective May 1, 2006.

The Board determined that there were a number of common issues that could best be determined on a generic basis, and accordingly issued a Procedural Order on November 2, 2005 proposing a list of common or generic issues.

Following the receipt of submissions by the interested parties listed in Schedule B to this Decision, the Board issued a Procedural Order on November 17, 2005 that approved the list of common or generic issues, and subsequently held oral hearings in the matter on January 10 and January 12, 2006.

The Issues

In this proceeding, the Board requested and received submissions from interested parties on four broad issues. The first related to smart meters, and in particular whether capital and operating costs related to smart meters should be included in the 2006 revenue requirement. The Board also requested submissions on whether utilities should recover a standard amount, and if so, how the standard amount should be calculated. In addition, the Board invited submissions on whether deferral accounts should be established to record the amounts spent on smart meters.

The second issue concerned the establishment of deferral accounts for certain regulatory costs.

The third issue concerned whether the Board should develop a standardized methodology for standby rates, and if so, what the design basis should be. The Board in its notice recognized that standby rates will increase in importance as load displacement generation increases, and that many utilities may find it difficult to calculate customer-specific standby rates. A related issue was whether the Board should establish deferral accounts to record lost revenue attributed to reduced loads caused by load displacement distributed generation.

The last issue concerned whether the Board should establish deferral accounts for the disposition of rate mitigation revenue shortfalls, low voltage charge variances, and material bad debt.

SMART METERS

It is widely understood that the Province faces an increased need for electricity supply. It is also clear that a major element of the Government's strategy to deal with this problem is enhanced conservation programs. An important element of the Government's conservation program is the smart meter program, first announced by the Premier of Ontario in April 2004. At that time the Government stated that 800,000 smart meters would be installed by 2007 and there would be a smart meter in every home and business by 2010.

Subsequently, on July 16, 2004, the Minister of Energy issued a Directive to the Board under Section 27.1 of the *OEB Act* requiring the Board to develop, and upon approval by the Minister, implement a plan to achieve the Government's program. Following an extensive stakeholder process, the Board submitted its proposed smart meter implementation plan to the Minister of Energy on January 26, 2005.[1]

On February 27, 2006, the *Energy Conservation Responsibility Act, 2006* received third reading. A major element of that legislation concerns the smart meter program. The legislation established a smart metering entity to implement the smart meter program, and if authorized, to have exclusive authority over these activities. Other objectives of the smart metering entity include the collection of data, and the right to own and operate databases. The legislation also provides non-discriminatory access to distributors, retailers, and the OPA to the data, and the telecommunication system that transmits that data.

The legislation provides that the meters will be installed by all Ontario electricity local distribution companies (LDCs), or "any other person" licensed by the Board to do so. The types of meters to be used will be prescribed by regulations, OEB Codes, or OEB Orders.

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[1] The "Smart Meter Implementation Plan Report", available at: http://www.oeb.gov.on.ca/documents/communications/pressreleases/2005/press_release_sm_implementationplan_260105.pdf

While the specifics of the legislation will be in regulations yet to be promulgated, it is clear that the LDCs in the Province bear a major responsibility, subject to the regulatory oversight of the Board, for the implementation of the Government's smart meter plan.

Thirty four electricity distributors were designated as Applicants for purposes of this Generic Issues proceeding. Of these, ten have included specific expenditures on Smart Meters in their 2006 Distribution Rate applications.[2] This spending is over and above spending on pilot programs previously approved as part of third tranche CDM initiatives[3]. Of these ten utilities, four also requested variance accounts to track any differences between planned and actual spending on Smart Meters.

Of the remaining 24 electricity distributors, three requested deferral accounts to track any spending on Smart Meters with a view to future recovery from customers. The Applications of the other 21 utilities contained minimal, if any, spending on the Smart Meters. The same is true most of the other LDCs in Ontario.

Three electricity distributors (Toronto Hydro, Hydro Ottawa, and Hydro One) applied for 2006 rates based on a forward test year. Together, they account for a significant portion of the electricity supply in the Province. Toronto Hydro and Hydro Ottawa both filed applications that included smart meter operating and capital costs in their 2006 rates. Hydro One did not.

Positions of the Parties

The Board's January 26, 2005 Report to the Minister of Energy proposed that smart meter capital and operating costs should be included in distributor's rates. Board staff in this proceeding argued that a fixed monthly amount per customer should be included in 2006 rates.

Toronto Hydro is a leading example of an LDC that intends to include these costs in rates, with a $52 million investment proposed for 2006. While Toronto was confident of its budgeted capital and operating costs relating to this rollout, it nevertheless requested

[2] These are: Bluewater Power Distribution, ELK Energy, Enersource Hydro Mississauga, Essex Powerlines, Festival Hydro, Horizon Utilities, Kingston Electricity Distribution, Hydro Ottawa, Toronto Hydro, and Veridian Connections. A further 11 utilities who were not named as applicants in this proceeding have also submitted smart meter plans with their 2006 rate applications.

[3] In previous individual Decisions for 2005 rates, the Board approved spending on CDM programs that was linked to each distributor's third installment (or 'tranche') of the allowed Market Based Rate of Return.

a variance account to track estimated-to-actual differences. Toronto argues that a deferral account is not appropriate as it will not allow for recovery of smart meter expenditures in the same period as the costs are incurred. Hydro Ottawa took a similar position.

Hydro One takes the opposite position to Toronto Hydro and argues that inclusion of smart meter costs in 2006 rates would be inappropriate in its case. Hydro One claims that its implementation program will likely be delayed due to the rural nature of its customer base, and it is unnecessary to increase rates until such expenses are incurred. Accordingly, Hydro One argues for a deferral account.

Other parties argue that utilities should have an option. Both the Electricity Distributors Association and the Consumers Council of Canada advocate flexibility, with utilities having the option to utilize the funding approach that best meets their circumstances.

The Vulnerable Energy Consumers Coalition (VECC) argues that both capital and operating costs for smart meters should be included in 2006 rates provided the Board reviews them for prudence. VECC did oppose a ruling that all utilities should be required to include a standard amount in 2006 rates. In fact, VECC argued that where a utility proposed a 2006 rate increase greater than 10%, the utility should be directed to remove any smart meter spending from its application.

As indicated, Board Staff takes a different view and argues that a standard fixed monthly amount per customer should be included in the revenue requirements of all utilities filing for 2006 rates. Board Staff oppose deferral accounts because they could impose delays and increase carrying costs. Board Staff also argue that without specific funding, distributors might neglect other required expenditures in order to fund smart meters.

Energy Probe also opposes the Board Staff position, arguing that the details of the smart meter program are still unclear. Given this uncertainty, Energy Probe argues that the utilities cannot reasonably be expected to prudently budget spending and design programs for implementation in 2006. Rather than include these costs in 2006 revenue requirements, Energy Probe recommends that utilities should be tracking all smart meter spending in deferral accounts for future disposition. Energy Probe specifically opposes the Toronto Hydro approach as being unnecessarily risky.

Board Findings

There is a wide spectrum of utilities in Ontario and their requirements differ. Large utilities such as Toronto Hydro may be positioned to move forward early and may have more accurate forecasting tools to assist in the budgeting process. Forecasting will never be perfect and a variance account is appropriate to track the differences between actual and forecasted amounts.

Toronto proposes two variance accounts. The first is a capital variance account which incorporates return on investment and amortization components. The second is a smart meter Operations Maintenance &Administration variance account that will reflect actual amounts spent plus carrying costs. The Board accepts this approach.

Where utilities incorporate the cost of smart meters in 2006 rates, the question arises as to the appropriate amount per meter to include in the revenue requirement. The Board believes that amount should be $3.50 per meter for each month during the rate year that the smart meter will be installed (i.e., $3.50 per meter-month). This cost estimate is outlined in Schedule A to this Decision, which is a reproduction of Appendix C of the Board's Smart Meter Report (p. 103). The Board in that Report concluded:

> "Based on cost estimates prepared by working groups for the basic smart meter system being proposed, the incremental monthly cost for a typical residential customer may be between $3 and $4 a month once full implementation is complete in 2010. Because costs will be spread among all customers in a class from the outset of the project, the monthly charge will start low and increase to the $3 to $4 figure as more and more meters are deployed. For example, in year one of the project, much of the system changes and some of the common infrastructure may have been deployed but few of the actual meters, so a charge of $0.30 to $0.40 per month per customer would be sufficient to fund that part of the project. In year two the total deployment might reach 25% and the cost per month per customer would rise to $0.75 to $1.00 to pay for the cumulative investment. Eventually, all customers would have a smart meter and the cumulative costs might require a monthly charge of between $3 and $4 to cover capital and operating costs."[4]

[4] The Board's Smart Meter Implementation Plan Report, *ibid, p. 25*

In the end, $3.50 per meter-month may not be the correct charge. As previously discussed, utilities will maintain variance accounts to deal with the differences between estimated costs and actual costs.

This leaves the last and most difficult question; should utilities that have not proposed any expenditures on smart meters in 2006 rates be required to include a standard amount? The argument is that such an action will ‘jumpstart’ the program. Put differently, the program will become a reality as opposed to a matter of discussion and debate.

We should remember that the vast majority of Ontario utilities have not included any smart meter expenditures in 2006 rates beyond those amounts previously committed as part of third tranche expenditures. To be fair, these applications were filed prior to the recent legislation. Having said that, the government policy is clear and the timelines are tight.

The Board is of the view that given the increased need for electricity and the importance of conservation, specific funding should be included in 2006 rates by all Ontario utilities.

This will be an important step in the development of this technology. It will increase the effort and commitment by both utilities and technology suppliers. In the electricity sector costs are often driven by peak demand and the pricing mechanism is the most effective tool to shift that demand. Time-shifting demand offers substantial savings and Ontario stands to become a world leader in this technology. Given the recent legislation, no further delay is warranted.

As to the amount, the Board adopts the recommendation in the Board’s earlier report that year-one expenditures of $0.30 per residential customer per month are appropriate. Such an amount should be included in 2006 rates. Utilities should also establish variance accounts for both capital and operating expenses to track differences between this amount and actual costs. For this purpose, the $0.30 expenditure can be allocated to the capital cost and operating accounts in the same proportions as set out in Schedule A.

In addition, as a condition of granting the rate applications, all utilities will be required to file with the Board within 90 days of this Decision their plan for smart meter investment in the 2006 rate year. Furthermore, LDCs will be required to file quarterly and annual reports regarding the implementation of their programs in the same fashion as they currently do for third tranche CDM spending. The exact form and timing of this report will be detailed by the Board in a subsequent Procedural Order.

Those utilities that have filed specific smart meter spending plans for 2006 are granted approval, provided that these programs do not fall below the level of 2006 spending based on $0.30 per customer per month. Given the Board's Decision on this issue, deferral accounts for smart meter expenditures are unnecessary.

DISTRIBUTED GENERATION

In this proceeding, parties were asked to address two major issues regarding load displacement distributed generation. In requesting these submissions, the Board recognizes the increasing importance of distributed generation. As set out in the Energy Conservation and Supply Task Force Report, the potential benefits are extensive;

> "By supplying power near load it is possible to avoid or defer transmission and distribution investments that would otherwise be needed to supply electricity to the load.
>
> Reductions in transmission and distribution line losses due to reduced transmission and distribution distances. At times of system stress, distributed generation can enhance system reliability. Distributed generation projects are generally small and require less capital than larger centralized plants. Being easier to finance means more generation developers could undertake such projects leading to the inherent benefits of competition. Distributed generation can generally be permitted and constructed faster than larger installations." [5]

The first issue relates to the standby rates paid by distributed generators to the utility. The second issue is whether the utilities should have a mechanism to recover revenue losses attributed to unforecasted distributed generation.

[5] Energy Conservation and Supply Task Force Final Report to the Minister, p. 54, available at: http://www.energy.gov.on.ca/english/pdf/electricity/TaskForceReport.pdf

Standby Rates

The Board in this proceeding requested submissions on whether there should be a standardized methodology for standby rates or whether there should be utility-specific approaches to the design of such rates.

Some sixteen of the 95 LDCs in Ontario have standby rates. As noted in the Board's recent discussion paper on the Standard Offer program[6] they incorporate many different approaches and a variety of charge determinants, including actual or anticipated maximum demand, kilowatt of reserved capacity, kVa rating, manufacturer's rated output of the cogenerator, and various monthly service charges. Some of the rates were established a long time ago, before re-structuring of the market. Others are new rates being proposed for standby customers in the 2006 rate applications.

One of the major intervenors on this issue was the Association of Power Producers of Ontario (APPRO). APPRO opposed standby rates that 'gross bill' the load. Such rates propose the same rate for standby service as they would if they were actually supplying electricity to the load. The utilities, on the other hand, argue that their costs are the same regardless of whether the load is used or not.

The generators, many of whom are represented by APPRO, claim that such gross billing charges are not cost-based, that they ignore the Board's 'Net Billing' decision[7] with respect to network transmission rates, and fail to take into account the benefits distributed generation provides. Such rates, they argue, are a disincentive to investment in distributed generation, and therefore contrary to government policy.

APPRO also argues that setting standby rates now is premature, as these rates should be developed in the context of the utilities' other distribution rates. They further argue that any generic standby rates should be developed as part of a standard cost allocation

[6] EB-2005-0463,Staff Discussion Paper: Standard Offer Program for Eligible Distributed Generation, p. 14; available at: http://www.oeb.gov.on.ca/documents/cases/EB-2005-0463/standard_offer-staffpaper-171105.pdf

[7] RP-1999-0044 Ontario Hydro Networks Company Decision ; available at: http://www.oeb.gov.on.ca/documents/cases/RP-1999-0044/dec.pdf

methodology, and note that this proceeding is now underway.[8] APPRO also argues that the Board's generic methodology may need to accommodate generation projects of different sizes.

Finally, APPRO argues that one of the options the Board should consider is to not have a standby rate at all. This reflects their view that distributed generation can significantly reduce system wide costs such as line losses, voltage stabilization, reduced transmission charges, and reduced transmission congestion. In this connection, they point out that distributed generation can be an alternative to new capital investment in distribution and transmission assets, including additional feeder lines, capacitor banks, and transformer stations.

Another important intervenor on this issue was the Greater Toronto Airport Authority (GTAA), a customer of Enersource Hydro Mississauga (EHM). The GTAA intervened in that utility's rate application as well as in this generic proceeding.

The GTAA, a non-profit corporation which operates Lester B. Pearson International Airport, recently commissioned a natural-gas-fired cogeneration facility, and entered into a clean energy supply contract with the Ontario Power Authority.[9] This new facility has the capacity to supply the GTAA's own power needs as well as supply power to the grid. GTAA is connected to the grid by way of a new interconnection with EHM's distribution system, and opposes EHM's application for a new standby rate.

To support its position, GTAA prefiled the evidence of Ralph Luciani, Vice-President of the consulting firm Charles Rivers Associates International, (CRAI).

The GTAA argues that standby rates should be based on costs. That is, they should not exceed the distributor's costs of supplying the necessary level of service to the distributed generator plus the regulated rate of return. They go on to state that standby rates should not only reflect the costs to the distributor of serving customers, but should also reflect any benefits the customer creates by the investment in self-generation and exported generation, including avoided costs, reduced system losses, and improved

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[8] The Cost Allocation Review, EB-2005-0317. See http://www.oeb.gov.on.ca/html/en/industryrelations/ongoingprojects_costallocation_review.htm

[9] See OPA Website, available at: http://www.powerauthority.on.ca/Page.asp?PageID=122&ContentID=959&SiteNodeID=154

reliability. GTAA claims that EHM ignores these principles, when it proposes that a load-displacement customer should simply be charged the same monthly rate for standby service as for standard distribution service. In response, EHM acknowledges that the appropriate basis for calculating standby rates is proper cost allocation that reflects the true cost of serving that particular customer class, but claims that such cost information is not currently available.

GTAA agrees that the cost information is not currently available and therefore submits that any standby rates set in this proceeding should be done on an interim basis. GTAA further argues that the Board in this proceeding should direct that standby rates for distributed generation customers should be developed of the basis of a full analysis of the costs and benefits to distributors of the assets developed by the standby customers. In this connection the GTAA submits that the Board should direct the cost allocation technical advisory group, which is currently underway, to address the development of a standardized methodology for standby charges in the rate methodology currently being developed.

Board Findings

The Board agrees with the submissions of various parties that distributed generation can yield system-wide benefits for electricity distribution in the Province. These benefits need to be recognized in the appropriate standby rates. It is also clear that the older standby rates may not be based on any true cost allocation principles.

It is also evident that the new standby rates proposed in this proceeding by a number of distributors do not have a proper cost foundation due to the lack of available data. The Board agrees that proper costs and benefits allocation should be employed in setting these rates. However, the cost allocation process currently underway before the Board is nearing completion and its terms of reference did not specifically include this issue.

In the meantime, in order to protect the interests of all parties involved, and not to create any disincentives to investment in this important technology, all existing and proposed standby rates should be declared interim, pending further review of these important principles.

The Board believes that efficient localized generation including load displacement generation can and will provide benefits to the provincial electricity system and to ratepayers. The Board also believes that a standard methodology across all utilities is preferable, but notes that a standard methodology does not necessarily mean identical rates.

The starting point for the development of the standard methodology would be the proper allocation of costs to those that cause the cost, as well as a quantification of the benefits. The Board will address this matter in the upcoming review of distribution rate design[10].

Revenue Losses Due to Load Displacement Distributed Generation

Of the thirty four distributors designated as applicants in this proceeding, only one, Hydro One Networks, requested a variance account to track revenue losses resulting from distributed generation. In its December 1 2005 submission, Hydro One Networks states that:

> "Distributors will lose revenues when distributed generators displace load that otherwise would have been purchased by customers from the distributor. The lower sales volume will be reflected immediately in actual billing data, but related revenue shortfalls may be recovered by distributors only after they are allowed to re-set their rates.
>
> Distributors should be able to recover the foregone revenue resulting from distributed generators coming on-stream in the period between rate re-sets."

VECC submitted that as a general practice utilities should not be permitted to record in a deferral account lost revenue due to unforecasted load losses from distributed generation. The VECC argument is that utilities generally have six to twelve months notice of new distributed generation projects, and for those utilities with potential projects, the size is often very small.

With respect to Hydro One's claim that the potential revenue loss is $17.6 million, VECC says that that value is only illustrative, and that Hydro One should be aware of such

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[10] This review is noted in the Board's Draft 2006-2009 Business Plan (p. 2), available at: http://www.oeb.gov.on.ca/documents/industryrelations/keyinitiatives/0609busplan/about_bplan0609-211105.pdf

projects in advance. VECC submits that potential lost revenue will be mitigated in part by the standby rates that load displacement customers will pay to utilities.

The GTAA also opposed the establishment of deferral accounts to record foregone revenue amounts, stating that the distributor should be aware of impending load loss due to distributed generation projects. GTAA argued that load forecasts are often inaccurate, and both new load and lost loads can occur during the course of the year. They also noted that the deferral account approach assumes that there are no offsetting avoided costs resulting from the distributed generation.

Board Findings

The extent to which distributed generation will develop is not clear. Nor for that matter, is the degree to which the utilities can forecast the revenue consequences. Nonetheless, the promotion of this investment is an important element of the Government's energy policy. To the extent that the regulatory process can support that policy, it should. One step, as indicated previously, is to establish the correct standby rates that reflect both the costs and benefits of this investment.

The other is to ensure that the utility remains whole. It is true that standby rates may mitigate lost revenue if in fact those standby rates are properly set. The Board believes that it is premature at this time to establish deferral accounts to record foregone revenues due to unforeseen load losses arising from distributed generation. This matter can be addressed at the time the Board considers the standard methodology for standby rates.

DEFERRAL ACCOUNTS

The Notice establishing these proceedings questioned whether certain deferral accounts should be established on an industry-wide basis for four different cost categories. In the previous part of this Decision the Board dealt with the issue of deferral accounts for revenue losses attributed to distributed generation. Four other deferral accounts also need to be addressed.

The first is regulatory costs. Should the Board permit utilities to record their costs of consultants, legal counsel, and direct incremental disbursements related to all regulatory proceedings? A related question is what regulatory costs should be recorded as a credit for the purposes of the regulatory costs deferral account.

The Board also asked parties to address the merits of deferral accounts for three other categories, rate mitigation revenue shortfalls, low voltage charge variances, and material bad debt.

Regulatory Costs

During the development of the 2006 Electricity Distribution Rate Handbook, explicit provisions were made in the filing requirements to adjust for material differences in 2004 historical data including OEB assessment costs. In the end, a specific Tier 1 adjustment was agreed upon and is set out in the Board's Report.[11]

The Board agrees with Schools that it is questionable whether it is useful to re-open this issue. Some parties noted that utilities always have the option of applying for a forward test year, if they believe that an historical test year with adjustments would not accurately reflect their financial results. Very few utilities selected that option.

Generally speaking, most of the LDCs were in favour of deferral accounts for this category of costs, and most of the intervenors are opposed.

The Board finds that it is not necessary to establish a generic deferral account for this category of costs. As a number of parties point out, it is always open to any applicant if it demonstrates special circumstances different from other LDCs to make a specific application for a deferral account that relates to their circumstances.

Requests to reflect updated OEB assessment costs as part of the 2006 Rate Handbook's Tier 1 adjustments for 2006 rate will be dealt by the Board in that process.

Rate Mitigation

The Board, in establishing this proceeding, also asked parties to comment on whether a generic deferral account should be established for rate mitigation. There is general acceptance of the rate mitigation principle and some intervenors such as Schools set forth a hierarchy of actions to be used by LDCs to mitigate rates.

Assuming a utility has carefully considered alternative means of mitigating a large rate increase, the Board believes it should recover its full revenue requirement from ratepayers. To the extent such a utility has to modify its revenue requirement in order to

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[11] Ibid, p. 12

manage rate impacts to customers, the Board accepts that those deferred revenues should be recorded in a deferral account for recovery from customers in the following year.

The question is whether this should be done on a generic basis. VECC, by way of example, submitted that there is no need to make a general decision that accords a deferral account for rate mitigation revenue shortfalls to all utilities. They argued that the number of cases where such an account would be required would be very limited, and that granting such an account should be done on a case-by-case basis. And as VECC points out, rate mitigation strategies consist of more than simply deferring the collection of revenue. As Schools have pointed out, there are other actions that can be taken including re-scheduling work and capital investment, and adjustments to rate design. All these need to be considered on a case-by-case basis. It is the Board's view that there is no need to establish a generic deferral account for rate mitigation. Clearly, any requests would be of a limited nature and can be dealt with on a case-by-case basis.

Low Voltage Charges

Over half the applicant utilities are embedded utilities subject to low voltage or wheeling charges from a host distributor. While in some cases these charges represent a small portion of the embedded distributor's service revenue requirement, in other cases these charges are significant.

As Board Staff has noted it its submission, the LV issue is somewhat complex, in that distinctions need to be made first between host and embedded distributors, and second between 'pass-through' costs and charges for the use of distribution assets.

When a host distributor provides service to an embedded distributor, two elements may be involved. Depending on the metering configuration, the host distributor may be billed for transmission system charges incurred on behalf of the embedded distributor to serve the embedded distributor's load. In addition to incurring the transmission system charges, the host distributor provides a distribution service using the host's own assets to the embedded distributor by conducting the power across its system to the embedded distributor. These are referred to as wheeling charges. Commodity and related charges such as the Wholesale Market Service charge are settled directly between the embedded distributor and the IESO.

From the perspective of the embedded distributor, both of these costs are ‘upstream’ costs that are incurred to bring power to its distribution system. For the embedded distributor, both the transmission charges that are initially incurred by the host and the host’s own distribution charges for the use of its system are ‘pass-through’ charges that the embedded distributor incurs on behalf of its customers.

For embedded utilities, the major difference between transmission system charges and wheeling charges is that the former are passed through to customers using a separate retail transmission service rate, while the wheeling charges are currently classified as distribution costs and built into the approved distribution rates for each customer class. As a result, the revenues collected by the embedded distributor from its customers to cover the costs of wheeling are not subject to variance account treatment, and may differ appreciably from the corresponding costs.

VECC supports the establishment of a variance account for embedded utilities to track and record differences between the charges incurred by an embedded utility from a host distributor for wheeling services, and the revenues collected by the embedded utility from its customers for the use of that service. It was VECC’s submission that such charges for embedded distributors are analogous to the transmission, connection, and transformation charges that transmission-connected distributors in the Province pass through to their customers, and for which a comparable variance account already exists.

Schools also concluded that Hydro One low voltage charges are uncontrollable expenses and should be treated in a similar fashion to transmission charges, and therefore be recorded by embedded distributors in appropriate retail settlement variance accounts. Schools noted that Veridian Connections has assumed that these variances should be recorded as part of the RSVA connection account.

However, VECC concluded that variance accounts for wheeling services for host distributors should not be established, since for host distributors wheeling service is essentially no different than other distribution services, the rates for which are all set on a prospective basis with no provision for a variance account. The embedded distributor is simply another (perhaps large) customer for the host distributor, insofar as the use of the host’s distribution system is concerned. VECC noted that Hydro One, the largest host distributor in the Province, supported this position.

The Board finds it is appropriate for embedded distributors to maintain and or establish variance accounts for charges related to the delivery of power to the boundaries of their systems. These charges would include the host distributor wheeling charges, and to the extent necessary and not already in place, transmission system or LV charges incurred by the host distributor effectively on behalf of the embedded distributor. There was general agreement between the parties that establishing such accounts was acceptable as the variation in this category of charges is outside the control of the embedded utilities. This will provide consistent treatment for all utilities for pass-through costs of a similar nature.

With respect to host distributors, the Board finds that if it is necessary due to metering configurations and existing settlement arrangements for the host to be billed for transmission system or LV charges on behalf of the embedded utility, the host should pass these charges through to the embedded utility on an exact basis if possible. If that is not possible or practical at the current time, these pass-through charges may be recovered in the same manner as the host recovers these charges from the rest of its customers, i.e., by means of a retail transmission service rate subject to variance account treatment.

With respect to a variance account for the host distributor's own wheeling service provided to the embedded distributor, the Board agrees that there is no pertinent distinction between an embedded distributor and any other customer of the host. Therefore, the Board will not establish such an account.

Material Bad Debt

Material bad debt is defined in the 2006 EDR Handbook as amounts exceeding 0.2% of total distribution expense (p. 46). Of the 34 electricity distributors designated as Applicants in this proceeding, only one, Enersource, requested an Order from the Board authorizing the establishment of a deferral account to record material bad debt attributed to its large customers.

On this issue, the utilities generally supported a deferral account to record material bad debts, while the intervenors were opposed.

VECC's position was the most detailed of all the intervenors. They argued that there is no need for the Board to make a general decision on a deferral account for bad debt for all utilities. They point out that over half of the applicant distributors responding to VECC's interrogatories have not experienced any material bad debts in the three year period 2002 to 2004. They further point out that Enersource in its application acknowledged that "As such failures are not anticipated to occur in a typical year this account is more in the nature of a contingency."

Aside from the infrequent nature of bad debt, VECC was concerned that the establishment of a deferral account creates an expectation that these costs will be recovered in rates. The Board acknowledges that this is a concern when deferral accounts are established. There is often an expectation, despite the fact that deferral account balances are always subject to review. For this reason, the Board is always cautious in establishing deferral accounts.

The Board concludes that a generic system-wide deferral account for material bad debt is not warranted at this time. The incidents are infrequent, and to the extent that incidents arise, they can be dealt with on a case-by-case basis.

Implementation of Accounting Treatments Specified in This Decision

In this Decision the Board has authorized the creation of various variance accounts. The details of the accounting for these accounts will be prescribed by the Board by way of a Procedural Order at a future date.

DATED at Toronto, March 21, 2006

ONTARIO ENERGY BOARD

Original signed by

On Behalf of the Panel
Gordon Kaiser
Presiding Member and Vice Chair

SCHEDULE "A"

Summary of Base Smart Metering System Costs and Benefits [12]

Total New Capital cost/month	*based on amortizing capital cost of $250 over 15 years* [13]	$2.47
Total Operating Cost/month	*sum of operating costs in Table 2* [14]	$1.42
Total operating savings/month	*sum of operating benefits in Table 1* [15]	-$0.39
Net cost per month residential customer		**$3.50**

[12] Smart Meter Report Appendix C, p. 103

[13] Includes gross up for PILS and credit for existing meter cost

[14] Smart Meter Report Appendix C, p. 116

[15] Smart Meter Report Appendix C, p. 103

SCHEDULE "B"

Parties Making Submissions

Association of Power Producers of Ontario
Chatham Kent Hydro
Consumers Council of Canada
Electricity Distributors Association
Energy Probe
Enersource Hydro Mississauga
Essex Powerlines
Greater Toronto Airports Authority
Horizon Utilities
Hydro One Networks
London Property Management Association
School Energy Coalition
Toronto Hydro-Electric System Ltd
Vulnerable Energy Consumers Coalition