General Comments

In establishing the extent to which a topic was considered to be a generic issue, the following criteria were used:

- Issues of principle with material implications for multiple distributors are appropriate for inclusion in a generic hearing;
- Issues for which a party might propose a common test of prudence (for example, a comparator test) or a common solution (for example, an allowance based on cost per customer) are candidates for the generic issues list; however,
- Issues which have been dealt with expressly in the Report of the Board (RP-2004-0188) or in the 2006 Electricity Distribution Rate Handbook are not appropriate for inclusion; and,
- Issues that are simply common to many utilities, but which rely primarily on the specific facts or circumstances should not be included.

As a result, the following four main issues, and sub-issues, were identified by the Board and included in its Procedural Order No. 3, dated November 17, 2005:

1. Smart Meters

   1.1 Should the Board authorize the inclusion of capital and/or operating costs related to the general roll-out of smart meters (i.e., as distinct from any pilot programs in CDM plans) in the 2006 revenue requirements of utilities?

   1.2 If so, should utilities recover a standard amount in rates (e.g. cost per customer) or should each utility propose a smart meter budget for inclusion in rates?

   1.3 If a standard amount is used how should it be calculated?

   1.4 Alternatively, should deferral accounts be established and the amounts spent on smart meters be recovered in future rate periods?

   1.5 What accounting requirements should be established for reporting and monitoring smart meter spending?

2. Deferral Accounts

   2.1 Regulatory Costs

   2.1.1 Should the Board permit utilities to record their costs of consultants, legal counsel and direct incremental disbursements related to all regulatory proceedings in Account 1508, for the purpose of subsequent review and disposition?

2.1.2 What 2004 regulatory costs should be recorded as a credit for purposes of a regulatory cost deferral account?

2.2 Revenue Losses Attributable to Unforecasted Distributed Generation

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?

3. Generalized Standby Rates for Load Displacement Generation

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

3.2 Should the Board permit utility-specific approaches to the design of stand-by rates?

3.3 If so, what should that design basis be?

4. Other Deferral Accounts

4.1 Should the Board establish deferral accounts for the purpose of subsequent review and disposition for any of the following?

4.1.1 Rate mitigation revenue shortfalls,

4.1.2 Low Voltage Charge variances,

4.1.3 Material Bad Debt.

The purpose of this submission is to ensure that a reasonable set of options or alternatives for each issue are placed before the Board, and to provide some of the pros and cons of these options in order to assist the Board in its deliberations and decisions.

The format of this submission will be to address each of the issues, and sub-issues as necessary, in turn.

1. Smart Meters

Background

Bill 21, *An act to enact the Energy Conservation Leadership Act, 2005, and to amend the Electricity Act, 1998, the Ontario Energy Board act, 1998 and the Conservation Authorities Act* was introduced by the Minister of Energy on November 3, 2005. Included in this legislation are numerous references to smart meters and the smart metering initiative. It is assumed that, following public consultations and review by the Standing Committee on Justice Policy in February 2006, this legislation will be enacted, together with any required Regulations and Ministerial Directives, prior to May 1, 2006.

Subsequently, the distributors will receive direction from the government early in 2006 that will require them to begin implementing smart meter programs.

The legislation, if passed and enacted, could give different direction on how smart metering is to be deployed, the organizations involved and hence the role of distributors in the roll-out of smart meters, and therefore may impact on the timeframes and the costs of smart metering deployment. Some flexibility is thus needed.

A number of distributors have proposed smart meter budgets and spending to be funded through increments to their 2006 rates.

If the funding for this undertaking is not addressed in smart meter legislation, the Board will be required to authorize and monitor costs for recovery by distributors.

Discussion

All but three of the electricity distributors that have filed rate applications for 2006 distribution rates on the basis of a historical test year (adjusted or unadjusted), in accordance with the guidelines of the 2006 Electricity Distribution Rate Handbook. Under this approach, 2004 costs, revenues and load statistics have been used as proxies in the establishment the 2006 revenue requirement and subsequent rates, with allowances for certain adjustments. Distributors were allowed to apply for costs related to smart meter programs beyond the third tranche amounts, although few have elected to do so in advance of further direction from the Government, such as may come from the enactment of Bill 21.

Three electricity distributors have applied for 2006 rates based on a forward test year (reflecting 2006 costs and demand forecasts) and some have proposed amounts related to smart meter acquisition, installation and operation in 2006.

The overall situation represented by the large number of 2006 distribution rate applications currently in front of the Board is that few applications currently propose costs to be recovered in rates to fund the deployment and operation of smart meters in the current rate year should the Government direct that they do so. It should be remembered that these applications were developed by the distributors and submitted to the Board prior to the introduction of Bill 21.

Universal deployment of smart meters over the 2006 to 2010 period as proposed by the Government represents a significant cost to the industry and, ultimately, to ratepayers. Many, if not all, distributors may face difficulties in starting smart meter deployment in the absence of certain rate regulatory treatment – and in particular in having some amounts of monies available to fund these activities. While currently there is uncertainty in the absence of specific Government direction, Board staff anticipate that this will be rectified somewhat through the enactment of Bill 21 and the associated Regulations and Ministerial Directives. Board staff suggest that the inclusion of some revenue requirement amount and probably collected as a fixed monthly amount per applicable customer would be an appropriate way to allow distributors to expeditiously implement the Government's plans once these are announced.

Board staff point out that a deferral account is used to accumulate investments and expenses incurred by electricity distributors for specific activities (such as smart meters) for potential future recovery or other disposition. It is suggested that the use of and reliance on a deferral account for smart meters could pose risks to meeting the Government's timelines or have other unintended consequences. Further, the use of a deferral account could lead to increased carrying costs of these amounts by distributors, which costs would ultimately be borne by the distributor's ratepayers. In the absence of incremental cash flow through rate revenue, a distributor will have to find its own funding to initiate its acquisition and deployment of smart meters. In doing so, a distributor may decide, due to financial constraints, to forego, during a current period, other investments and expenses in order to fund deployment of smart meters, thus deferring needed investments and maintenance and posing a risk of decreased service quality and reliability – in the short- or long-term. In addition, distributors may face unnecessary costs and difficulties raising capital for their smart meter programs if recovery is seen to be delayed and/or uncertain.

Board staff do note, however, that the deferral account approach has been used in similar contexts. In its December 1, 2005 submission, Hydro One Networks recommended the deferral account approach as being the most suitable approach at this time. Hydro One Networks stated that it did not foresee difficulties in funding a smart meter program once Government direction is given. However, Hydro One Networks is different from most other Ontario electricity distributors, and some distributors, particularly those serving smaller customer bases or whose financial circumstances are more risky, may find the deferral account approach as being insufficient or lacking.

Board staff note that an alternative means of funding the costs of acquiring and installing smart meters and of related investments and operational expenses (such as billing system changes) can be made through a revenue requirement increment beyond what would currently be calculated in the distributor's 2006 distribution rate application.

This revenue requirement increment would apply to the following non-interval metered customers whose services are metered:

- Residential;
- General Service < 50 kW except for the following sub-classes;
    - Unmetered Scattered Load;
    - Streetlighting
- General Service > 50 kW with demand < 1000 kW.

The Board's report on smart metering, issued to the Minister of Energy on January 25, 2005 in accordance with the Minister's Directive recommended this approach:

Cost

> *The implementation plan proposes that the capital and operating costs of the smart meter system be included in a distributor's delivery rates that are charged to all customers in a particular rate class, whether or not they have a smart meter. In addition, it proposes that the costs related to old meters and other distributor assets that are made obsolete by the introduction of smart meters continue to be included in distribution charges.*
>
> *It is proposed that costs be included in the distribution rate as soon as a distributor starts to install smart meters. Because it will take several years to complete the installation of smart meters in a distributor's area, the impact on customer bills will be small initially. It will rise as the implementation program progresses. In the initial period, the incremental costs will include some data management and billing system changes that are needed for all customers and a portion of the meter and communication infrastructure. Initial stranded costs will be low since most of the existing meter[s] and equipment used for manual meter reading will remain in service for several more years until … all [are] finally changed out by 2010.*
>
> *The total capital cost through to 2010 for the proposed system (meter, communications, installation and distributor system changes) is estimated at $1 billion. The net increase in annual operating cost for the province, when all meters are installed, is estimated to be $50 million. Eventually when the project is complete, the cumulative costs might require a monthly charge of between $3 and $4 to cover capital and operating costs.*
>
> *The cost estimates in the preceding paragraph, and in the report, are for illustration only. … (page vi)*

Board staff suggest that the revenue requirement amount be set at the outset, and only adjusted over time to reflect inflationary and technological changes that would cumulatively affect the total unitized costs of smart meter deployment and operation to all customers.

Once smart meter deployment is complete, this amount would cease, although there would likely be an adjustment to a distributor's approved rates to reflect the amortization rate for smart meters as well as net operating expenses changes due to smart metering technologies.

As noted above, the Board report suggested that a monthly amount of around $3 to $4 per customer would be required to recover the capital and operating costs of smart meter deployment. However, this approach assumed that the distributor would be responsible for all capital and operating expenses associated with smart meters. Bill 21 includes other possibilities. Based on the Bill 21 as currently under consideration by the Government, it is possible that distributors may not bear all such costs.

Board staff acknowledge the uncertainty at the current time, but consider it appropriate that some incremental revenue requirement should be considered by the Board to determine a standard amount applicable to all electricity distributors and that would in effect act as “seed money” to allow each distributor to start funding smart meter deployment once Government direction is announced. One approach that could be considered in the establishment of this amount would be based on a top-down approach; namely, to recover the amount corresponding to the O&M expenses and the amortization/depreciation expense for smart meter-related assets.

An amount calculated in this manner should be sufficient to allow each distributor to collect sufficient monies to begin the purchase and gradual deployment of smart meters and associated systems and processes in accordance with the Government’s current timelines, without affecting the distributor’s financial “wholeness”, and without impacting, at least financially, on the distributor’s ability to undertake other necessary and prudent expenditures integral to providing safe and reliable electricity distribution services.

Board staff suggest that this approach should be applicable to each distributor. Given the current uncertainty, but on the expectation that the Government will provide direction on smart meter deployment by the spring of 2006, Board staff suggest that a common approach would be more appropriate compared to distributor-specific approaches. Thus, if the Board were to accept this option, it would replace the amounts currently applied for by individual distributors that have applied for smart meter costs in their 2006 rate applications.

Board staff suggest that the charges that result from the application of this methodology may, on a unitized basis, turn out to be similar to that forecasted and applied for. In subsequent years, a distributor-specific approach may be appropriate, where warranted by the circumstances, although the expectation is that a common methodology and charge amount would be administratively easier for the Board, and for most distributors.

Board staff suggest that there are data on record in this proceeding, both in the rate applications of distributors who have filed for incremental smart meter amounts, and in the submissions and interrogatory responses of distributors, that would allow the Board to determine an incremental revenue requirement to be included in the rates. Assuming the Government’s direction is given sufficiently in advance this spring, this may provide further guidance. While the level of the charge amount may not be precise, it should be close. As a component of this option, Board staff suggest that a variance account be authorized. The inclusion of a variance account approach, discussed later, allows for overall corrections periodically, and the charge amount itself could be revised in subsequent rate years as better information becomes available.

Board staff suggest that it is appropriate for this component be applied to all customers in the applicable classes and sub-classes. All customers would be billed regardless of when they actually will be converted to a smart meter – be it early in the program in 2006, in mid-program, or even towards the end, around 2010. All applicable customers are, in effect, providing the amounts needed to fund the acquisition, deployment and operation of smart meters during this multi-year “implementation period” in parallel with the outlays that the distributor will make to install and operate smart meters and associated or altered systems.

Board staff note that this revenue requirement would be collected in rates and could provide electricity distributors with some revenue in advance of the expected expenditures actually being incurred, but suggest that, given the circumstances, this is a reasonable approach.

The incremental charge as proposed may also be contemplated as a “social benefit cost” that the affected customers will be paying. Even before an affected customer has been converted to smart metering, the customer may receive an indirect benefit in the following way: to the extent that customers who have already been converted to smart meters take advantage of the information on their consumption and alter their consumption patterns and levels as a result, even customers without smart maters may benefit upon the relief upon electricity supply and demand in the province and resultant relief upon commodity prices.

The difference between revenues collected through this smart meter rate component and the costs expended by the distributor would be booked to a variance account. It is likely that costs related to ongoing operating expenses related to smart meters and the amortization expenses of acquired and installed assets of smart meters and associated capital assets (e.g. billing system hardware, meter reading systems) would need to be tracked separately. Under normal regulatory practice, the balance in the variance account would be subject to carrying charges, calculated on the monthly balance and using a Board-approved short-term interest rate. In this way, a distributor will be motivated to deploy smart metering technology in close parallel with the collection of the monies to fund this deployment.

Board staff suggest that a monitoring plan could be part of this approach. Distributors would be required to file, no less frequently than annually, the monthly balance of the variance account and the annual amounts recovered in rates and the expenditures related to smart meter deployment. Board staff further suggest that where the fiscal year-end variance is more than five percent (5%) of the amounts recovered in rates for that year, the distributor could be required to provide an explanation of the overage or underage. The distributor could also provide its year-end cumulative deployment of smart meters to the applicable customer base. This would be expressed as both a quantity (number of customers) and as the percentage of the applicable customer base that has been converted to smart metering technology. Such monitoring would also include cost data related to smart meter assets, associated systems, and installation and operating expenses reported in aggregate and on a unitized basis.

Board staff note that a monitoring plan is also be appropriate under the deferral account approach, although the scope of the monitoring plan may differ. Under the deferral account approach, monitoring would primarily be concerned that the distributor is achieving the phased deployment of smart meters throughout its customer base in alignment with the Government's timelines, as the prudence of the amounts expended and accumulated in the deferral account would be dealt with through the rate-setting process.

Board staff further suggest that the reporting information could be filed with the Board as part of the Record-keeping and Reporting Requirements, and the Board should make the information publicly available, such as by publication on the Board's website. Publication of the information would allow electricity distributors, interested parties and the public to compare distributors' performance amongst each other, and would provide a motivation for efficient deployment by any distributor. For example, such comparisons could motivate distributors, where practical, to establish partnerships to acquire and implement necessary smart metering, systems and back office technologies on a more cost-effective basis than if they were to each act independently.

Board staff suggest that, at this point, the options described for collection of necessary funding (through a monthly fixed charge, the use of a variance account for the tracking and disposition between amounts collected in rates and the amounts expended by distributors), along with regular monitoring, are flexible enough to be adapted to comply with the legislation as finally enacted while managing any over- or under-funding during the deployment of smart meters. However, the Board may have to adapt the plan – such as updating the unitized amount to be collected from applicable customers – based on the legislation as enacted.

Board staff note that regardless of the approach adopted, there will need to be a regulatory mechanism or process for the Board to examine the prudence of a distributor's costs related to smart meters and to approve the amounts.

2. Deferral Accounts

2.1 Regulatory Costs

2.1.1 Should the Board permit utilities to record their costs of consultants, legal counsel and direct incremental disbursements related to all regulatory proceedings in Account 1508, for the purpose of subsequent review and disposition?

Discussion

Under the historical test year approach, ‘internal’ regulatory costs for consultants, legal counsel and direct incremental disbursements incurred in 2004 (other than those assessed by the Board) would serve as proxies for the costs in 2006. Certain distributors contend that such costs are material and are difficult to forecast, and have applied to record such costs in Account 1508 for subsequent disposition and recovery rather than accepting the 2004 value. If the Board were to grant the request, it may wish to accord deferral account treatment to all distributors.

Some distributors are expressing concern that there is the possibility of incremental costs being incurred post 2004 for OEB related initiatives. They were not able to forecast and hence not provided the ability to recover incremental regulatory costs from rates. They have requested the establishment of a deferral account for this purpose.

The OEB Accounting Procedures Handbook established USoA #5655 for the direct purpose of recording Regulatory Expenses (see Appendix A). The intention of this account is to record all of a distributor’s annual regulatory operational expenditures, which includes costs other than OEB related expenditures. The structure of this account is such that, when recorded correctly, it establishes a logical base for determining regulatory costs included in rate base.

The Board in the 2006 EDR model extended to the distributor the opportunity to include the incremental change in “OEB Annual Dues and Other Regulatory Agency Costs” from 2004 to 2005 as part of the determination of the revenue requirement.

Board staff offer two options for consideration in respect to this issue. The first option is to approve the generic deferral account as requested. The second option is not to approve the creation of the requested deferral account.

With respect to the first option, Board staff note that in the past the Board has provided “blanket” deferral accounts for the express purpose for recovery of costs not provided for in the distributor’s rate base. These costs are normally generic to all distributors resulting from common circumstances.

The basic question, therefore, that needs to be explored by the Board is whether the requested deferral account is necessarily generic to all distributors and can a singular common circumstance be identified. Or, would they be more the result of a one time or transitional situations.

Board staff consider that the nature of the regulatory costs that are being proposed for recovery have the potential to be, but are not necessarily, common to all distributors. Board staff suggest that it would be necessary for the Board to be very clear in the definition of regulatory costs and how they are to be calculated and reported.

Board staff note that the creation of such a deferral account imposes additional regulatory burden for the distributor as well as the Board for its review and disposition. There is also a concern with regard to the development of an appropriate mechanism which will be required for the review of the recovery of deferred amounts. Board staff would encourage the Board to utilize the "Four Test Criteria" should this mechanism be employed (as outlined in Appendix B).

Another consideration is the type and nature of regulatory expenses that would be included in the requested deferral account. The boundary of regulatory expenses can go beyond OEB proceedings. They can encompass audits or reviews by other regulatory bodies (i.e. the ESA, OEFC, IESO, and OPA). Board staff suggest that the specificity as to the expense must be tightly drawn to prevent overlapping of normal operational regulatory costs and those that would be considered incremental.

There is the requirement to create the mechanism for review and administration in adjudicating the recovery of deferred amounts. Board staff would remind the Board that the Accounting Procedure Handbook USoA #5655 provides the mechanism for distributors to use for individual applications in respect to recovery of incremental regulatory costs. Board staff would also encourage the Board to utilize the "Four Test Criteria" should this mechanism be employed (as outlined in Appendix B).

Finally, Board staff note that deferral accounts could lead to protracted considerations of prudency and could create unnecessary uncertainty of ultimate cost recovery. In addition, they require rigorous due diligence by both the distributor and Board staff.

The alternative is to not approve the creation of the requested deferral account. Board staff recognize that there is a real potential for financial impairment from incremental regulatory costs and the reason for the distributors' concern. By not approving the creation of a deferral account, there is no mechanism to address this concern. A distributor, however, does have the right to approach the Board at any time for rate relief when it considers it necessary.

2.1.2 What 2004 regulatory costs should be recorded as a credit for purposes of a regulatory cost deferral account?

Discussion

The OEB Accounting Procedures Handbook USoA # 5655 (see Appendix A) identifies for accounting purposes the type and nature of expenses a utility will record in respect to regulatory expenses.

Regulatory costs should be considered as four types. The first type would be regulatory assessment costs. These are normally fees charged by the various regulatory bodies to the utility under the authority of provincial government legislation. The fees may be in the form of annual or periodic assessment usually for the purpose of regulatory board cost recovery.

The second type of costs is the result of ongoing regulatory operational expenses incurred by the utility on a regular basis. These costs would normally include the cost of dedicated staff or consultants and the related overhead expenses employed to complete regular regulatory reporting and application submissions.

The third type of costs results from the requirement of a utility to present or defend applications or submissions. These costs are not considered to be part of the utilities' regular annual operational expenses. They usually involve the retention of external legal counsel and industry expert consultants.

The fourth type of expense results from incidental fees or assessments levied by a regulatory body as a result of utility or industry specific regulated bodies cost recoveries.

The Board has in practice (e.g. the Boards letter December 20, 2004 "Deferral Account to record OEB Cost Assessments under the Accounting Procedures Handbook") provided to all utilities the ability to place in a deferral account the excess amount of regulatory assessment fees in the incident of material fee assessment escalation. This normally results from either Board initiated or multi-utility applications when assessment fees are significantly increased. This use of a blanket deferral account is defensible in the fact that it impacts most or all of the utilities in the same way, it is common or generic among the industry.

For the most part the first and second types of expenses are normally scrutinized for reasonableness by the Board as part of the prudence review in a cost of service application. The third and fourth types of regulatory costs are usually the result of Board initiated actions on an individual or singular basis that is not generic to the entire industry, and should normally be subject to the Four Criteria Test (see Appendix). These are best reviewed as individual applications and recovery should be prescribed on a case by case basis.

2.2 Revenue Losses Attributable to Unforecasted Distributed Generation

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?

Discussion

Some distributors have expressed concerns that their revenues are being unfairly reduced as a result of this issue, due in part by the application of volumetric rates. The distributors earn a significant portion of their revenue based on the amount of kW Demand consumed by a customer. Given that the level of the revenue requirement assigned to a particular class or sub-class of customer is fixed, the rates that are approved by the Board to recover this amount are based on the kW demand from a historical actual or forecasted test year (i.e. the denominator of the equation). In order for the distributor to continue to recover its revenue requirement from this group of customers, it must assume a similar kW demand in the future. With distributed generation, however, the potential for the maintenance of the kW demand is diminished. Therefore the distributor bills and collects less revenue with no offsetting compensation. This is similar to the situation of a distributor suddenly or unexpectedly losing a large customer. With current government initiatives promoting the use of distributed generation, the distributors submit that their ability to accurately forecast their next rate year's load is reduced. Therefore they are seeking a mechanism to provide assurance that they will not be financially harmed.

The issue being put forward to address this is the establishment of a deferral account for the purpose of recording for future recovery of the difference between the revenues to be recovered based on the rate application forecasts and the actual revenues received in the rate year.

There are two distinct types of generation that can be addressed in respect to distributed generation. They are described as a merchant generator, which is a generator whose sole or primary purpose is to produce electricity and insert it into the distribution system, and a load displacement generator, which is a facility of a normal distributor's customer whose electrical usage is wholly or partially off-set by use of its self-generation facility.

The distributor's knowledge of a new merchant generation facility is much greater than a load displacement facility. The timing of the start up of this type of facility is typically known far enough in advance that the impact from such an installation on the distributor's load and load profile can be accommodated in either the distributor's regular rate application or a special rate submission. Therefore, any unforecasted load losses are most likely to be associated with the installation of a load displacement facility within a customer's operation, which the distributor may not be aware of. As a result, this discussion focuses only on load displacement generation.

Board staff present three options for consideration. The first option is to approve the creation of a deferral account. The second option is to not approve the creation of the requested deferral account. The third option is for the Board to consider the installation of a uniform application of standby charges that would incorporate this matter as a component.

With respect to the first option, Board staff note that in the past the Board has provided "blanket" deferral accounts for the express purpose for recovery of costs not provided for in a utility's rate base. These costs are normally generic to all utilities resulting from common circumstances.

Board staff suggest that the question that needs to be explored by the Board is whether the requested deferral account is necessarily generic to all utilities and can a singular common circumstance be identified. Or, would the need for such an account be more the result of a one time or transitional situation. Board staff suggest that the type and nature of load losses that are being proposed for recovery are not necessarily common to all distributors. As a result, Board staff suggest that it would be necessary for the Board to be very clear in the definition of acceptable losses and how they are be calculated and reported.

Board staff also note there is the potential for the deferral account to replace the utility management's responsibility to be diligent in its operation. Board staff suggest that utility management should be performing regular surveillance of customer demands on its system and applying appropriate rates and charges as necessary (such as standby charges, discussed in Issue 3) in a consistent manner to ensure that all its customers are treated fairly.

Board staff note that the creation of such a deferral account imposes additional regulatory burden for the distributor as well as the Board for its review and disposition. There is also a concern with regard to the development of an appropriate mechanism which will be required for the review of the recovery of deferred amounts. Board staff would encourage the Board to utilize the "Four Test Criteria" should this mechanism be employed (as outlined in Appendix B).

Finally, Board staff note that deferral accounts of this nature do not necessarily ensure the recovery of amounts in the future by the utilities. Deferral accounts create uncertainty in a utility's financial reporting and could have some unfavourable financial impacts.

The second option for the Board's consideration is to not approve the creation of the requested deferral account. Board staff recognizes that there is a real potential for financial impairment from lost load and the reason for the distributors' concern. Any distributor, however, does have the right to approach the Board at any time for rate relief.

The third option is for the Board to consider the installation of a uniform application of standby charges. This is presented in a subsequent discussion in Issue 3. Board staff suggest that standby charges can be viewed as a rate mechanism that is available to be applied in this type of circumstance. Board staff suggest that the application of standby charge ought to be viewed as a fair means of achieving the Board's role in assuring fairness in rates and elimination of cross subsidization of costs.

3. Generalized Standby Rates for Load Displacement Generation

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

Board staff note that most load displacement generation facilities are or will be small in scale and the impact of their load may not warrant a study starting from first principles. Furthermore, most distributors will not require standby rates and those that do will have only one or a few customers who may need stand-by service.

Board staff are aware that the Board is undertaking a broad examination of electricity distribution rate design as a component of its cost allocation study. This study is already in the midst of reviewing allocation of distribution costs. As one outcome of this endeavour, the Board may develop a standardized methodology for stand-by rates. Given that, Board staff suggest that the issue is whether a standardized methodology is required for stand-by rates to be applied in 2006, and perhaps for one or two years after that, pending implementation of the comprehensive review of distribution rates.

One option for the Board to consider is to not develop a standardized methodology for the near term, and to consider the applications as submitted by distributors on a case by case basis. The 2006 Handbook provided some standardization with guidelines for two situations. Under these guidelines, a distributor with an existing stand-by rate should continue the rate in 2006. A distributor applying for a stand-by rate for the first time, or applying to modify its existing rate, finds in the Handbook a framework for the cost and load data that could be used to support the application.

As part of the applications currently before the Board, fourteen distributors have included a standby rate component. Eight distributors have applied for the continuation of an existing rate. These rates are not the outcome of a common methodology, and they differ in value and structure. For the six distributors that are applying for new or modified rates, the framework in the Handbook required detailed data that may have been unavailable to the distributors. The framework was not mandatory, and it was little used. As a result, the 2006 stand-by rates that distributors have applied for are not based on a standardized methodology, and they differ considerably with respect to rate design and rate levels.

The other option for the Board to consider is to develop a standardized methodology for immediate use. Board staff note that implementing a standardized methodology would necessitate revision of the stand-by rate component of the application by most or perhaps all of the aforementioned applicants. Depending on the methodology, Board staff suggest that the resulting rate levels could be significantly higher than existing levels and therefore bill impacts and any mitigation considered necessary could become an issue.

Board staff suggest that if the Board establishes a standardized methodology for the future, doing so immediately would establish a common starting point for all distributors. In addition, customers with existing and prospective load displacement generation facilities might benefit from the relative simplicity of a common approach and also the knowledge that the same methodology is being applied by different distributors in which the customer may have facilities. Therefore any differences in the level of rates among distributors are not as a result of the application of different methodologies.

Board staff suggests that, aside from the task of revising the application itself, implementing a standardized methodology does not have to be onerous. For example, if the stand-by rate is related in some way to the rate for the other customers in the class that do not have load displacement facilities, and therefore does not involve a new analysis of cost data, the calculation of the revised rate could be a straightforward exercise, with the main discussion centred around the level of the monthly billing determinant. However, if the standardized methodology requires analysis of the distribution system and operating costs associated with the load displacement generators, then Board staff suggest that precautions would be necessary to ensure that the data required is available and that the effort is proportional to the benefit. Board staff suggest that timing requirements/constraints would point to the former approach for 2006 rates.

It should be noted that the Handbook also provided a framework for a monthly administration charge. Those distributors that applied for approval of such a charge used the standardized methodology in that part of the charge. To this extent, the issue of standardized methodology does not have to be dealt with, because that is what has been used.

For the sake of completeness, Board staff note one other aspect to the issue of standardization, which is a uniform stand-by rate to be used by all distributors. Board staff suggest that this approach has the advantage of solving the first two issues, but puts an even greater onus on the third issue of how to design the rate. Board staff note that a uniform rate is inconsistent with how the Board and the industry have approached their tasks in other areas, and therefore this alternative has not been developed further in this submission.

3.2 Should the Board permit utility-specific approaches to the design of stand-by rates?

The second issue is whether the Board should permit utility-specific approaches to the design of stand-by rates. If the Board has determined in Issue 3.1 that a standardized methodology will not be developed, then utility-specific approaches are clearly permitted. The issue re-stated is then, if the Board develops a standardized methodology, will it nevertheless permit an applicant to use a different methodology?

Board staff suggest that the onus of showing that a different methodology is more suitable for a specific distributor's situation should be on the applicant – otherwise the advantage of the standardized methodology is lost.

To be clear, a standardized methodology could, and in fact generally would, still yield different rates for different applicants. This is consistent with the Board's decision (RP-2004-0188, p. 80) that a distributor-specific analysis of costs would be needed for stand-by rates.

With these clarifications, Board staff suggest that the advantage of allowing a utility-specific departure from the standard is that the Board could be flexible in what applications it would consider. The standardized methodology could be simpler because it would not have to allow for complex or unusual situations.

In other situations, the Board has permitted a utility-specific approach for a short period in a situation where the impact of going immediately to a new standard would be severe.

Rather than a simple modification or exception to the standard, an applicant might propose a peculiar approach. In general, if a standardized methodology has been developed, the advantage of the standard will be forfeited unless there is a strong presumption that it will be used. If the applicant is unable to show that the benefit of departing from the standard methodology outweighs the disadvantages of having to use the standard, then the standardized approach will prevail. The criteria for considering a departure from the standard might include how unusual the customer's or applicant's circumstances are, in terms of the customer's load or the applicant's system, and also how easy or difficult it is for the Board and stakeholders to understand the alternative approach that is being proposed.

In summary, Board staff suggest that if the Board decides for Issue 3.1 that a standardized methodology should not be developed, Issue 3.2 is moot. If it decides that a standardized methodology should be developed, and decides that utility-specific modifications will not be permitted, it jeopardizes acceptance of the standard and risks imposing unacceptable impacts on some customers.

3.3 If so, what should that design basis be?

Board staff consider that this issue depends to some extent on the previous two issues. If the Board decides that a standardized methodology should be developed (Issue 3.1) and that the Board would not permit utility-specific approaches to the design of stand-by rates (Issue 3.2), then Issue 3.3 becomes the seemingly straightforward task of determining what the best design should be.

Issue 3.3 is relevant in other permutations of the decisions on Issues 3.1 and 3.2 as well, but this submission does not attempt to trace through each of them.

Board staff note that there is a status quo in place for about a dozen distributors and that a comprehensive review process is already underway that is intended to produce refinements or perhaps supplant whatever is implemented for 2006.

The simpler component of the standby rate is the monthly administration charge, which was suggested in the Handbook. The administration charge is not in place in any distributor. The Handbook provided a framework for the recovery of incremental costs that would be incurred by the distributor regardless of whether the customer's generation operated throughout the billing period or it required standby service. The charge applies every month and is in addition to the monthly fixed charge that applies to all customers.

The applications for standby rates had administration charges ranging from $0 (for those who did not include a charge) and from $95 to $375 for those that did include a charge. If there is to be a mandatory standard, the cost estimates will have to be examined and a value in this range selected by some means. If there is not a standard, there is still a need to examine the cost basis in each application.

The other part of the stand-by rate is the variable or volumetric charge. The charge determinant is the same as for other customers in the rate class – kilowatts per month for nearly all applicants, and kVA as the other method.

The issue lies in how to establish the charge determinant – by definition, the meter shows zero for the months during which the load displacement facility is in operation, and thus the stand-by rate will be used. There are two main approaches. The simpler one is to use the rating of the customer's generation, sometimes called the nameplate rating. A refinement on this approach allows for the fact that nameplate rating might be inaccurate and would allow for measured maximum output of the unit.

The alternative approach is to establish a contracted amount that the distributor stands ready to provide immediately to the customer if the generation is unavailable. This contracted amount could not be larger than the rating of the generator, but it could be smaller. The default value for the contract would be the nameplate rating.

The contract approach enables the customer to negotiate an amount that the distributor stands ready to provide, which may recognize that the customer does not usually use its generator at full capacity or that is commits to drop load to the contract amount. In one refinement of the approach, the amount would be increased automatically if the customer's load exceeded the contract amount.

The contract approach is more favourable to the customer than the nameplate rating approach. It has the disadvantage to the distributor of being somewhat more complicated.

In general, the contract approach is a fairer method of reflecting the cost of providing stand-by service and the value of receiving it.

A refinement on the contract approach is the overrun adjustment. If the customer's stand-by load exceeds the contract, the overrun adjustment is a penalty and a disincentive against negotiating too low a contract. The amount of the overrun is the amount in kW by which the customer's maximum load during the stand-by period exceeds the contract level. The penalty could take the form of increasing the contract level by the amount of the overrun, so that the stand-by power billing demand would be higher in the future. The increase would apply automatically for some period, and would likely affect the negotiated contract amount in the future as well. A refinement on the refinement would be to allow overruns with notice, and impose the penalty only when the overrun occurs without notice.

If the contract approach is a fairer method than the nameplate rating method, then the approach with overrun adjustment is fairer still. There is no need for an overrun adjustment if the stand-by charge is applied to nameplate rating. The advantage of the nameplate approach is that it is simpler than the contract method, and it is a lot simpler than the overrun variant of the contract method.

In addition, Board staff suggest that there are two sub-issues to consider. First, the stand-by charge applies only during those months when there is no consumption to apply the normal demand rate against. These months may be not very numerous, because the generator has to be available every hour of the month and it has to be the source of power chosen by the customer. In any event, the bill might be rendered more fairly on the higher of the stand-by charge and the consumption billing demand.

The other sub-issue concerns the distinction between distributed generation that is strictly load displacement from generation that is built to serve other customers. Board staff suggest that the issues in this proceeding are focused on the former only. As a result, Board staff consider that the issues involved with the GTAA unit served by the Enersource Hydro Mississauga distribution system are so different from the stand-by rate issues that this generic proceeding cannot do justice to them.

One criterion for the reasonableness of the level of the stand-by rate is how it compares to the demand rate that is used for the other customers.

Some applications do not specify how the billing demand is determined, and it is probably safe to assume for our purposes here that it is based on nameplate rating. Because the nameplate rating may be higher than the contract amount, and cannot be lower, one reasonable criterion for the reasonableness of the stand-by rate is that it should be at least a bit lower than the demand rate

If billing demand is established by contract, one line of argument is that the stand-by rate should be equal to the demand rate, because this represents fairly the cost of the capacity that is reserved by the distributor that the customer uses at its option without notice.

The applications for continuation of existing stand-by rates range from $0.56 to $2.60 per kW per month. The other applications are spread fairly evenly over that range. Two of the applications for new or modified stand-by rates are equal to the applicant's demand rate – one of them proposing that billing demand be established by contract and the other that it be equal to nameplate rating. One application is for a stand-by rate that is equal to 50% of the demand rate, reasoning that the rate should be equal to the demand rate but that it should be phased in due to the impact.

In summary, the dimensions for the rate design include the rate itself, how it compare to the demand rate for the class, how the billing demand is determined, and what disincentive there may be for exceeding a contract demand. As in any rate design, the existing rate and the impact on customers of changing the rate must be considered.

4. Other Deferral Accounts

4.1 Should the Board establish deferral accounts for the purpose of subsequent review and disposition for any of the following?

4.1.1 Rate mitigation revenue shortfalls,

Rate mitigation revenue shortfalls result when a distributor elects to reduce its revenue requirement and subsequently lower the bill impacts to its ratepayers. Essentially the distributor is giving up its claim to some component of earnings as provided by the Board. The question to be addressed by the Board is what exactly is the distributor foregoing and whether the action proposed to be taken is a true mitigation or a form of deferment of a perceived right.

Board staff suggest that its submission included in Issue 2 of this submission is also applicable to this matter and, rather than repeating the options, refers the Board to that section.

4.1.2 Low Voltage Charge variances,

Discussion

The concept of low voltage (LV) charges resulted during deregulation of the energy market. In its previous form it was known as wheeling rates. Wheeling is the process of transmitting electricity across jurisdictional boundaries. The rate was determined to be the recovery of the cost of providing and maintaining the distribution line to support this transmission to users other than jurisdictional ratepayers.

With deregulation, the role of transmission became the responsibility of Transmitters or transmission entities (such as Hydro One Transmission). Transmission was defined as any transportation of electricity at greater than 50 kV. Transmission ends with connection to lines less than 50 kV. If this connection is directly to a distributor's own assets, there is no concern for LV charges. If the connection attaches to the line of an unrelated distributor and that distributor-owned line is used to carry electricity, in whole or in part, to another distributor, then the receiving distributor should compensate the carrier distributor. The purpose of the charge is to ensure that the ratepayers of the carrier distributor do not subsidize the costs properly born by the receiving distributor.

The carrier distributor is classified as a Host Distributor and the receiving distributor is classified as an Embedded Distributor.

The emergence of LV charges has been fraught with confusion. Confusion started in part with the post deregulation determination that the split of distribution and transmission would be at 50 kV. This resulted in Hydro One Distribution now providing low voltage transmission to embedded distributors for which it was not being compensated.

With the 2006 EDR process, some of the issues with respect to LV charges have been resolved. Host distributors can now apply for approval of LV rates and embedded distributors can apply for recovery of host distributor LV charges. However certain issues need to be resolved.

Embedded Distributors

The basic question that needs to be answered is whether LV recovery and charges for an embedded distributor should be recorded in the distribution cost component of the income statement or as a supply cost component. As a distribution component, a new variance account would need to be created for embedded distributors. As a supply cost component, it would flow naturally to an existing RSVA recovery account.

The argument to support LV charges as distribution cost component allocation is that these charges are created as a means of utilization of distribution assets as distinct from transmission assets. The 2006 EDR model is established on this basis. The forecasted LV charges are added to the revenue requirement by increasing the distributor's distribution costs as a Tier 1 adjustment. This would require a new variance account and accounting procedure to capture the difference. There is an accounting and financial reporting issue created by this approach. The variability in LV charges is significant and ultimately may result in materially overstated or understated earnings and cost for some distributors. This ultimately misrepresents public financial reporting and creates distorted comparisons between distributors.

Conversely, the argument for LV charges as supply cost component is that these charges are essentially related to getting the electricity to a distributor's jurisdictional border and therefore should be allocated as a flow through of costs and revenue with no risk/reward implication. The transaction could be assigned to USoA #1586 (as is the interim practice currently for Hydro One) or a new RSVA account could be established.

Board staff note that whichever option the Board decides upon there is a need to isolate the LV charge component from the current 2006 distribution rate prior to releasing rate approval.

Host Distributors

For the host distributor, Board staff suggest that its embedded distributor(s) is essentially just another customer and should be recognized and charged as such. This would require the host distributor to create a new customer class that would be required to assume its fair share of the distributor's revenue requirement.

4.1.3 Material Bad Debt.

Board staff suggest that its submission included in Issue 2 of this submission is also applicable to this matter and, rather than repeating the options, refers the Board to that section.

Appendix A

5655 Regulatory Expenses (Accounting Procedures Handbook)

A. This account shall include all expenses (except pay of regular employees only incidentally engaged in such work) applicable to utility operating expenses, incurred by the utility in connection with formal cases before the Board or other regulatory bodies, or cases in which such a body is a party, including payments made to a regulatory body for fees assessed against the utility for pay and expenses of such body, its officers, agents, and employees.
B. Amounts of regulatory expenses that by approval or direction of the Board are to be spread over future periods shall be charged to account 1525, Miscellaneous Deferred Debits, and amortized by charges to this account.
C. The utility shall be prepared to show the cost of each formal case.

Example items

1. Salaries, fees, retainers, and expenses of counsel, solicitors, attorneys, accountants, engineers, clerks, attendants, witnesses, and others engaged in the prosecution of, or defense against petitions or complaints presented to regulatory bodies, or in the valuation of property owned or used by the utility in connection with such cases.
2. Office supplies and expenses, payments to public service or other regulatory bodies, stationery and printing, traveling expenses, and other expenses incurred directly in connection with formal cases before regulatory bodies.

Note A: Exclude from this account and include in other appropriate operating expense accounts, expenses incurred in the improvement of service, additional inspection, or rendering reports, which are made necessary by the rules and regulations, or orders, of regulatory bodies.

Note B: Do not include in this account amounts included in account 1608, Franchises and Consents, or account

Appendix B

Four Criteria Test (see Chapter 5, Section 5.5.1 of the 2000 Distribution Rate Handbook, as revised November 3, 2000)

- **Causation**: the expense must be clearly outside of the base upon which rates were derived.

- **Materiality**: the cost must have a significant influence on the operation of the electricity distribution utility; otherwise they should be expensed in the normal course and addressed through organizational productivity improvements.

- **Inability of Management to Control**: the cost must be attributable to some event outside of management's ability to control.

- **Prudence**: the expense must have been prudently incurred. This means that the option selected must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.