Ontario Energy Board

Staff Discussion Paper

Rate Design for Electricity Distributors: Overview and Scoping

EB-2007-0031

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1 Introduction

In 1999 the Board conducted a limited-scope review to unbundle the existing rates into the separate components of commodity, transmission and distribution. As part of this process, the Board also introduced a distribution rate design that included a fixed monthly service rate and a volumetric rate.

In the eight years since that exercise, the structure of the electricity industry and the market model have changed considerably. Industry change and emerging issues include restructuring of the sector, developments in metering and increased distributed generation and conservation and demand management activities, among others.

As discussed in greater detail in section 2, such developments have prompted the Board to commence a review to determine whether changes in distribution rate design are warranted and, if so, what those changes should be. To that end, the Board has asked staff to consider electricity distribution rate designs from first principles; in other words, to consider the most appropriate electricity distribution rate design for Ontario assuming that the Board and distributors are starting with a clean slate.

This staff Discussion Paper is the first phase of this initiative. This Discussion Paper provides an overview of the stages of rate design, as well as a common nomenclature for, and a discussion of, some key rate design principles. It is intended primarily to solicit input from interested parties that will enable Board staff to better understand which areas, if any, might be a priority for distributors and consumers. Staff expect to issue a paper in the fall of 2007 containing recommendations on rate design.

This Discussion Paper sets out some of staff's initial thoughts in relation to the following three main topics:

- Underlying principles;

- Customer classes; and
- Rate design.

This Discussion Paper is organized as follows:

Section 2 explains some of the reasons that the Board is undertaking this initiative now.

Section 3 describes the regulatory principles that have been identified by staff as appropriate to support just and reasonable distribution rates.

Section 4 describes the stages of rate-making. It includes a short discussion of cost allocation issues that are more fully explored in the Board's Cost Allocation Review (EB-2005-0317). The section gives a description of customer classes: the primary way of grouping distributor customers. All other issues of cost allocation and applicable rate design flow from the decision on the appropriate grouping of customer classes.

Section 5 provides an overview of elements that potentially go into the development of a comprehensive rate design.

In each of the above sections, Board staff have suggested areas for comment by posing a series of questions. Section 6 is a summary of those questions. The questions are not intended to be exhaustive, and interested parties should comment on any aspect of this Discussion Paper or any other consideration that they feel is relevant.

2 Rationale for Rate Design Review Initiative

There are several developments and emerging issues that have led the Board to introduce this initiative: restructuring of the section, follow-up to the 1999 rate design, increased interest in distributed generation and load displacement, increased conservation and demand management activity by distributors and implementation of advanced metering. These are outlined in more detail below.

2.1 Restructuring of the Sector

As part of the electricity industry restructuring in 1999, municipal electric utilities were required to incorporate under the *Business Corporations Act*. In conjunction with this commercialization of the sector, the body regulating distributors changed from Ontario Hydro to the Ontario Energy Board. The nature of the rate regulation regime for commercial entities has brought the revenues and costs related to the independent segments of distribution, transmission and generation into a renewed focus. The rate setting environment has shifted from that of a somewhat vertically integrated public power system to a dismantled system with stand alone commercial entities at each level. The industry structure was in transition when many of the rate design decisions that underpin today's rates were adopted.

This paper discusses a myriad of issues that are considered in the designing of rates. It is important to give due regard to any institutional differences related to the sector restructuring that may give rise to the rethinking of rate design.

2.2 1999 Rate Design

The Board established the current rate design by adopting the Electricity Distribution Rate Handbook to govern first generation performance-based regulation for licensed electricity distributors. In the Decision with Reasons issued in the proceeding leading up to the Electricity Distribution Rate Handbook[1] and in the subsequent Decision with Reasons in proceeding RP-2000-0169, [2] the Board acknowledged the potential difficulties imposed by the new rate design. As an example, the general service rate classification split at 50 kW has created a number of implementation issues for distributors and customers.

The Board stated that it would initiate a review of the rate design, specifically for the general service classification, as soon as practical. Several issues, including the rate freeze, the phase-in of the market-based rate of return, the implementation of distributor-led CDM activities, and the length of the cost allocation review, delayed that work until now.

2.3 Distributed Generation and Load Displacement

In 1999, distributed generation and load displacement was not as prevalent as it is becoming today. Government policy initiatives to encourage the development of new sources of clean generation, such as standard offer contracts and net metering, have created a heightened interest in distributed generation. As of March 26, there were 33 contracts signed with the Ontario Power Authority for over 200 MW of capacity.

The Board recently held a consultation on amendments to the Distribution System Code and the Retail Settlement Code related to distributed generation and load displacement. The Board received a number of comments on the issue of cost responsibility and the allocation of costs related to distribution system and network upgrades associated with the connection of embedded generation facilities. Similarly, concerns were raised regarding the manner in which load customers are charged for their distribution service if the load customers have a generation facility connected behind their meter. The Board indicated at that time that these issues would be examined as part of the rate

[1] Ontario Energy Board, Decision with Reasons in proceeding RP-1999-0034, dated January 18, 2000.
[2] Ontario Energy Board, Decision with Reasons in proceeding RP-2000-0169, dated September 29, 2000.

design review initiative.[3] Currently, Board staff is also examining standby rates and rate class issues in relation to distributed generation in the context of the current rate design. The outcome of that project may be a temporary solution (for implementation in 2008 rates) pending completion of this broader rate design initiative.

Distributors and potential distributed generators have called into question the rate treatment of distributed generation and load displacement. Distributors often charge standby rates to recover the investment in the assets and the cost associated with "standing by" of the distribution system. Distributed generators and customers with load displacement are not sure that the charges are a fair representation of the costs that they impose on the system.

2.4 Conservation and Demand Management

Conservation and demand management activities are increasing over time. The Board recently released its *Report on the Regulatory Framework for Conservation and Demand Management by Ontario Electricity Distributors in 2007 and Beyond*[4]. In that *Report*, the Board indicated that two issues related to the rate treatment of conservation and demand management could be addressed as part of the rate design review initiative: consideration of alternative mechanisms to address lost revenue due to changes in demand and consideration of alternative incentive mechanisms. The former mechanisms would apply regardless of the source of funding for the conservation and demand management program while the latter would apply only to programs funded through distribution rates.

Unforecasted conservation and demand management activities can have the effect of eroding distributor revenues due to lower than forecast throughput. Distributors recover fixed distribution costs through both a fixed and variable rate, which is set based on a

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[3] See the Board's Notice of Amendment to a Code dated October 30, 2006 and the letter of the Board dated November 1, 2006 (Board file number EB-2006-0226).
[4] Issued March 2, 2007 (Board file number EB-2006-0266).

forecast of consumption. If actual consumption is less than the forecasted amount used for rate-setting purposes, the distributor earns less revenue that it otherwise would have, all things being equal. This can act as a disincentive for distributors to deliver conservation and demand management programs. Currently, the mechanism to compensate for distributor-induced lost revenues is a lost revenue adjustment mechanism ("LRAM"), which is a retrospective adjustment designed to recover revenues lost from conservation and demand management activities undertaken by a distributor in its service area in a prior year.

Given a certain level of resources, the distributor must make a trade-off between pursuing a CDM activity versus a distribution activity. A shared savings mechanism is a shareholder incentive whereby the net savings (as calculated by the total resource cost test) created by CDM expenditures on customer-side of the meter programs are split between the ratepayer and the shareholder. In its *Report*, the Board determined that distributors continued to need a shareholder incentive to encourage them to participate in CDM in the short term. Incentive mechanisms for conservation and demand management funded through distribution rates are a revenue requirement issue rather than a rate design issue. It will therefore not be considered as part of this project but may be reviewed in the context of the development of the third generation incentive regulation framework, scheduled to start in the spring of 2007.

In addition, when customers with time-dependent pricing take action to shift their peak usage from the distribution system peak, they get a benefit from lower commodity costs. However, they do not get a benefit from shifting their peak from the distribution system peak since all rates are billed against their monthly peak regardless of when it occurred.

2.5 Advanced metering

As smart meters are implemented, more and more customers will have hourly data available. As a result, fewer assumptions may need to be made in allocating costs. In addition, this presents opportunities to design and implement distribution rates in a manner that was not previously possible.[5]

The design and associated costs of a distribution system are based on the location of the distribution assets. Distribution assets located close to the point at which power is taken from the transmission grid are generally designed based on the peak demand of the distribution system. Distribution assets located closer to the customer are generally designed based on the customer's peak demand or, more likely, the peak demand of a group of customers that live or do business in a certain vicinity within the distributor's service area.

Generally, since most distribution system designs are based on the peak demand of a group of neighbouring customers, each rate class's contribution to peak demand is used to allocate demand-related distribution costs. Since peak demand metering data has not been available for residential and small commercial customers (the majority of customers by number), consumption data mapped to an assumed load shape by customer class has been used as a proxy to allocate cost to these customer classes. Information from smart meters will provide actual peak demand information and eliminate the need for proxies.

Similarly, the meters for the next most numerous group of customers (commercial customers with peak monthly demand of 50 kilowatts or more) record only a peak within the read period without information as to when that peak demand occurred.

The largest users (fewest in number) have meters that provide consumption data on a 15-minute basis and also measure power factor. Although the meters could be used to determine the customer's contribution to the distributor's peak, large customers are

[5] Veronica Irastorza, "New Metering Enables Simplified and More Efficient Rate Structure", *The Electricity Journal*, December 2005.

currently billed based on their respective demand, regardless of whether it coincides with the distribution system peak.

The current smart metering initiative is limited to residential and small business customers. It is important to note that the underlying assumption of this Discussion Paper is that all customers will have meters capable of supplying hourly data before a new rate design is implemented. Also, if classes of service are changed significantly, distributors may have to undertake a new cost allocation study in order to allocate costs according to those new classes of service.

3 Principles of Rate-making

The Board's ultimate responsibility is to set rates that are just and reasonable. It has been left to the discretion of the Board to select, amongst available approaches, the rate-setting methodology that is optimally suited to achieving that end and to the Board's guiding objectives as set out in section 1(1) of the *Ontario Energy Board Act, 1998*.

Building upon the legislative foundation, Board staff believes that the Board's statutory responsibility is best fulfilled, and its statutory objectives in relation to electricity distribution are best promoted, using distribution rates that are designed on the basis of a number of guiding principles set out below.

In 1961, James C. Bonbright[6] described eight regulatory principles for establishing rate structures. Although other experts[7] in the field of public utility rates have revised and refined these principles, they are still largely used today.

Practical	Rates should be simple to understand, accepted by the public (or uncontroversial) and feasible to implement.
Clear	Rates should have no ambiguity in their application.
Effective	Rates should recover the revenue requirement.
Stable for the utility	The utility should be able to recover its revenue each

[6] Bonbright, James C., Principles of Public Utility Rates, Columbia University Press, p. 291.
[7] Kahn, Alfred E., The Economics of Regulation: Principles and Institutions, Massachusetts Institute of Technology, 1988.

	year without excessive profits or losses.
Stable for the customers	Rates should be predictable enough for customers to make investment decisions.
Fair	To avoid cross subsidies, rates should follow the principle of cost causality; namely, that those who cause the costs should pay them.
Promote efficient use of resources	Rates should discourage wasteful use of the system.
Avoid undue discrimination	Actions taken to fulfill the other principles must not cause undue discrimination against or in favour of classes of customers.

These principles can be conflicting, and it is the task of the regulator to balance competing interests. For instance, a structure that promotes off-peak use of power to promote efficient use of the resource may be perceived as discriminatory toward and unfair to customers whose use of the system during peak periods is non-discretionary.

Board staff acknowledges that, as a result of evolution in the distribution sector, other less traditional principles might also be considered in designing distribution rates at this time.

For example, Ontario distribution rates could be designed to more specifically support Government policies, such as the following:

- to encourage conservation;
- to discourage peak system use; or
- to promote distributed generation.

Similarly, Ontario distribution rates could be designed to support Board regulatory policies, such as the following:

- to have consistency in distribution rates in Ontario; or
- to appropriately address distributors' business risk.

Are there any principles, beyond the generally accepted, traditional principles of rate-making listed above, that the Board should consider in designing distribution rates? What is the new principle's importance relative to the others?

4 Stages of Rate-making

Economic regulators set rates for monopoly utilities as a proxy for the action of competitive market forces. The objective is to establish rates that are just and reasonable and ensure efficient delivery of the service, whether that service is water, natural gas, electricity or any other monopoly service.

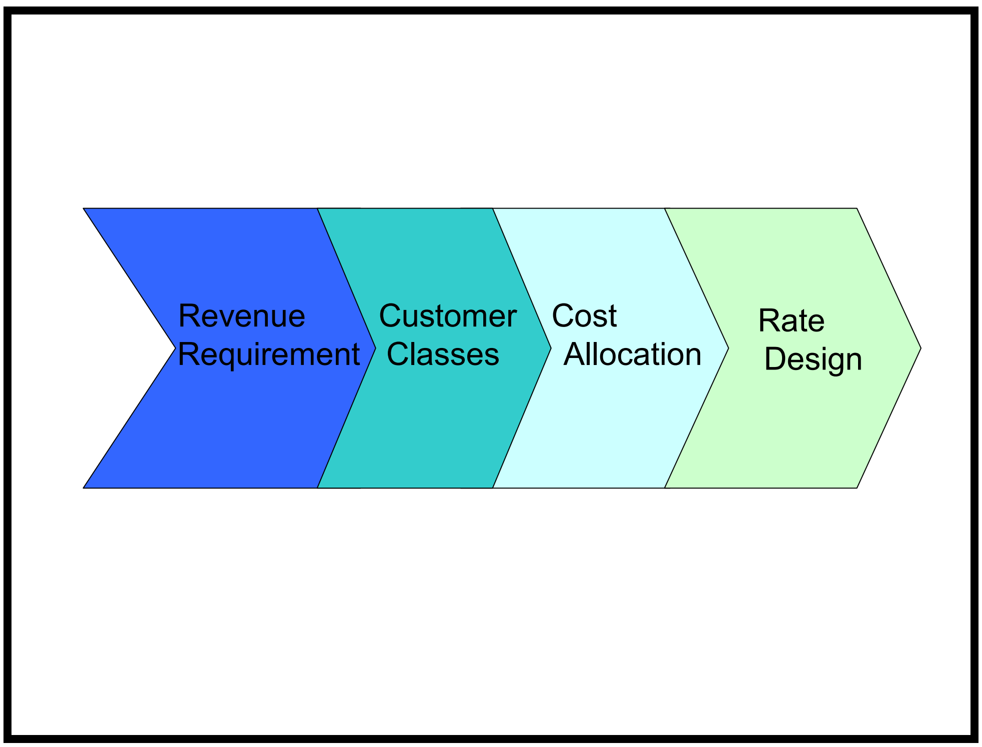

Figure 1: Stages of Rate-making

Figure 1 is intended to demonstrate how each stage of rate-making leads into and fits with the next. A rate order is generally the result of an approved revenue requirement being allocated according to an approved methodology, and recovered through an approved rate design.

The Board has already undertaken significant development on three of the four stages: the latest cost of service hearings for distributors were in 2006: informational cost allocation studies were filed in 2007 (the first since Ontario Hydro's in 1985); and the Board unbundled rates in 1999.

4.1 Revenue Requirement

In the simplest terms, an economic regulator determines how much revenue a utility needs in order to operate from year to year. This revenue requirement includes administration, operation and maintenance costs, depreciation, taxes, and a return on rate base. In a cost of service regime, the revenue requirement is based on a historic or a forward test year. In an incentive rate-making environment, rates are set for several years using an annual mechanistic adjustment including a performance incentive.

4.2 Customer Classes

Background

For the purpose of cost allocation and rate design, customers are typically grouped into classes. Customers are grouped into classes since it would not be practical or economically feasible to specifically track investments and costs incurred to provide service for each customer. It is important that rate classes be homogenous such that the use of average costs for a particular class is appropriate.

Classes are usually determined by similarity in service characteristics such as:

- Predominant use (i.e. residential, farm or business);
- Size of individual customer load;
- Customer peak demand;
- Diversity of load; and/or
- Metering type.

The current customer classifications are based on the end user of the electricity: namely, residential, general service or large user (i.e. greater than 5 MW). The general service class are further divided into sub-classes (i.e. general service < 50 kW, general service ≥ 50 kW, and unmetered scattered loads) as general service ≥ 50 kW customers have demand meters and the others do not.

Before addressing alternatives to the existing customer classifications and sub-classifications, staff notes that the existence of sub-classifications can affect the allocation of demand-related costs due to the attribution of system diversity benefits amongst classes or sub-classes of customers. When customers with differing consumption patterns are pooled into a group, diversity will result since the group's contribution to system peak will be lower than the sum of the individual customer peaks. This means that the allocation of costs based on the group's peak demand will be lower than if it was based on the sum of the individual customer peaks. The existence of sub-classifications raises the issue of how the benefits of diversity will be shared amongst customer groups.

There are two possible approaches to sharing the benefits of diversity:

i. diversity is shared within each separate group (i.e. a class of service) ; or

ii. diversity is shared within a main group (i.e. a main class of service such as general service) and the sub-groups (i.e. sub class of service such as general service < 50 kW and general service ≥ 50 kW), which collectively form the main group, share the benefits of the main group's diversity on a pro-rata basis.

For the purposes of cost allocation, the Board approved the use of the first approach because of greater simplicity and consistency with general North American cost allocation practices.

Rate classification options

Looking forward, the rate classification could be based on demand, amperage or voltage level. A rate classification based on demand would eliminate the current residential and general service classifications and be based only on the demand of the customer. Demand matches one of the most commonly measured quantities and could be based on the customer's peak demand or the customer's contribution to the distribution system peak. The Board could investigate potential levels for division such as less than or equal to 3 kW, less than or equal to 10 kW, less than or equal to 20 kW, etc.

Rate classifications could also be based on voltage of the customer's connection, such as:

- sub-transmission or high voltage system (44 kV, 34.5 kV, 25 kV, 23 kV);
- middle voltage or primary system (27.6/16 kV, 25/14.4 kV 13.8/8 kV, 12.48/7.2 kV, 8.32/4.8 kV, 4.16/2.4 kV);
- low voltage or secondary system (600/347 V – 3 phase, 208/120 V - 3 phase, 120/240 V single phase); or
- the low voltage could be subdivided into 3 phase and single phase service.

Voltage-based rate classes have often been considered in other jurisdictions but have never been implemented. Arguments against voltage classes are that customers do not have any control over their connection voltage since the distributor makes that determination. However, customers do not have choice over their current rate classification either.

Under service amperage classifications, there could be many classes. Consistent with the demand approach, a rate classification based on service amperage would eliminate the current residential and general service classifications, and new classifications would be established based on customer service amperage such as 200, 400 or 1000 amps, etc. This has many cost causality advantages. The advantage over the voltage classes is that customers have some choice over their service amperage. Customers making investment decisions on the electrical equipment they intend to use would consider the ongoing fixed connection fees of the various service amperage ratings. A business case for higher efficiency equipment and facilities would consider the avoided cost of a larger service rating. This would occur either at the design-build stage or when customers require an upgrade due to an expansion of their facilities.

What is the most appropriate basis for determining the service classifications for Ontario distribution customers?

Should sub-classifications be maintained? If so, what is the most appropriate method to allocate diversity benefits?

4.3 Cost Allocation

Cost allocation studies serve the following main purposes:[8]

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

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

i. customer density;

ii. load factors;

iii. distribution planning criteria; and

iv. vintage of plant.

Cost allocation studies play a major role in assessing the reasonableness of rates. Principles other than cost causality may also be considered by regulators when setting

[8] Ontario Energy Board, Cost Allocation Review: Staff Discussion Paper, September 2005, p. 5.

just and reasonable rates. They can include rate stability, customer acceptance and supporting conservation.

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

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

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

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

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

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

5 Rate Design

As a general rule, electricity distributors in Ontario cannot charge for the distribution of electricity except in accordance with an order of the Board.[9] The Board's rate orders set out a tariff of rates and charges for the distribution services that distributors provide.

Distributors charge amounts that are variously referred to rates, fees or charges. Recurring or periodic charges that are applied against some multiplier such as customers per month, kWh or kW are referred to in this section as rates. They are usually associated with use of the system and are meant to recover the asset investment and operating costs over time.

Fees or charges are event specific and are applied as "user pay" fees. They are usually cost based. For example, disconnection fees are meant to recover the specific costs incurred in disconnecting a customer. Late payment charges are meant to recover the costs of debt collection and the carrying costs of outstanding balances. The customer-specific or situation-specific nature of these fees or charges brings them outside the scope of this rate design review project. By way of exception, section 5.4 of this Discussion Paper considers whether connection fees for new generation facilities should continue to be cost based or should be converted to use-of-system charges.

In 1999, to prepare for the restructuring of the electricity sector, the Board led an industry task force (the "1999 Task Force") to unbundle the existing electricity rates into commodity, transmission and distribution components. The report[10] prepared by the 1999 Task Force has been instrumental in the development of this Discussion Paper.

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[9] *Ontario Energy Board Act, 1998*, section 78(2).
[10] *Report of the Ontario Energy Board Performance-based Regulation Distribution Rates Task Force*, May 18, 1999.

In some ways, rate design focuses more on the customer than does setting the revenue requirement or allocating the costs. It is the part of the rate-making process that looks outward to the customers and their use of the system, and how that use might change under different designs.

5.1 Rate design components

In devising a rate design, decisions must be made about several different components, including divisions within each service classification, billing determinants and ratio of fixed to variable rates. For each component there are several options. B.C. Hydro, for example, charges business customers based on three characteristics: demand, supply voltage and location in the province (two zones).

The 1999 Task Force considered many components and options in making recommendations for the Board's final determination on unbundled rates. Distribution rates for all classes consist of a fixed portion and a variable portion based on kwh consumption, kW of demand or kilovolt amp ("kVA") of apparent demand.

This section below outlines some of the components and the options within each. It is not intended to draw any conclusions about the appropriateness of any particular option, nor is the list of components necessarily exhaustive.

Are there other options for the components described below or other components not discussed here that the Board should consider as it moves forward?

5.2 Fixed and Variable Rates

Currently, distribution rates include both a fixed and a variable portion. Options include:

- Fixed monthly service rate to recover customer-related costs and a variable rate to collect the remaining allocated revenue requirement;
- 100% fixed monthly service rate; or

- 100% variable rate.

As demonstrated in the informational cost allocation filings, customer-related costs in the first option can be defined and calculated in three different ways:

- Avoided customer costs;
- Directly related customer costs; or
- A minimum system approach with peak load carrying capacity ("PLCC").

Each of these is further defined in the scenarios below.

In the current distribution rate design, the monthly fixed rate does not have a clear basis in any of the above definitions of customer-related costs. When rates were unbundled, the cost of power was subtracted from the total revenue of the bundled rate to determine a distribution revenue requirement for each class. A universal incremental distribution cost was deemed as the variable rate with the balance put into the fixed rate. Where this resulted in an unacceptable rate shock, the fixed rate was lowered and the variable rate increased until rate impacts were mitigated. The unavoidable outcome of this process was considerable variation in distribution rates across the province.

The cost allocation model used in the recent informational cost allocation studies produced customer unit costs per month for each rate classification. The cost allocation model generated three scenarios of cost-based, customer unit costs for each rate classification. It was expected that this information would be useful as a starting point for the electricity rate design project to assist in the evaluation of an appropriate fixed monthly service rate.

The three different bases for the fixed service rate are each reviewed in turn below.

Scenario 1: Avoided Costs

With a strict "avoided cost" approach, only meter-related, billing and collection costs are included. This approach has the advantage of focusing on the immediate costs of an additional customer. However, no administration and general overhead costs are applied.

Scenario 2: Directly Related Customer Costs

The directly related customer costs are the costs included in the avoided cost option but with the addition of an allocation of administration and general overhead costs.

Scenario 3: Minimum System Approach Adjusted for PLCC

The minimum system approach assumes that in addition to the directly related customer costs, a minimum-sized distribution system can be built to serve the minimum load requirements of the customer. For the purposes of the cost allocation study, the minimum load requirements or the PLCC of the minimum distribution system was assumed to be 400 watts per customer. The minimum system method involves determining the minimum size pole, conductor, cable and transformers required to serve the PLCC for each customer. The cost of these minimum sized assets defines the cost of the minimum size distribution system. These costs are classified as customer related costs and are translated into customer unit costs and then adjusted to exclude the PLCC. Theoretically, this produces a minimum system customer unit cost that assumes a minimum load of zero.

The ratio of fixed to variable rates is highly subjective. It can vary based on the definition of the minimum system and is guided largely by the regulatory philosophy of the regulator in question. In many parts of the United States, the fixed rate is driven down to the avoided cost level, which includes the cost of metering a customer and sending a bill. All costs for the system and administration are recovered from variable rates. This reflects the fact that customers want low bills when they have not used much electricity.

Some stakeholders argue that high fixed rates frustrate conservation efforts (or at least fail to augment the signal from the commodity price) since the delivery portion of the bill is relatively constant regardless of actions taken by the customer to reduce usage.

The argument often arises in the context of load displacement generation (a form of distributed generation). Connection assets are sized based on the requirements of a customer's load. The assumption is that those assets will be paid for over time through the collection of rates. At some point, the customer installs generation sufficient to supply some of its own load for some part of the year. All other things being equal, the distributor's revenue stream would then be insufficient to pay for maintenance and depreciation associated with the assets. Since, however, the load customer may nonetheless call upon the distribution assets to provide its electricity needs (i.e., when the generation facility is not running), the distributor may seek approval to charge a standby rate. The customer may then find it uneconomic to run its generator due to the change in rates. The issue of standby rates is addressed in section 5.4.

The conventional method of allocating distribution costs based on actual demand gives rise to the disparity between revenues and costs that occurs when the demand for which the system was designed and built does not materialize. This is due to the fixed nature of the asset relative to the variable nature of the demand (which is dynamic for a multitude of reasons).

The consideration of a customer's contribution to the distribution system costs in the conventional demand-based costing method occurs numerous times (typically monthly) throughout the life cycle of an asset that has been put in place to accommodate the potential demand.

An alternate approach would be to consider the contribution to the distribution system costs at the time of connecting a load based on the potential demand, measured by service amperage. This has the effect of crystallizing the cost contribution at the point in time that the customer decides what capacity it requires. This concept is based on the use of defining customer class by service amperage size that is discussed earlier in section 4.2.

Distributors point out that relatively few of their operating costs are truly variable on a year over year basis, and that variable rates increase their business risk. Variable rates also make distributors more adverse to conservation efforts, since all other things being equal, any actions taken reduces their revenue. The regulator may introduce mechanisms such as LRAM to address this. The higher the fixed portion of the rate, the more stable the revenue and the lower the need for an LRAM.

What are the principles that should inform the decision on fixed and/or variable rates?

5.3 Billing determinants

Billing determinants are the measure against which the periodic rate is applied to calculate a billing amount. Options include:

- Number of customers;
- Energy (kWh);
- Customer's peak demand;
- Customer's contribution to the distribution system peak demand;
- Connected voltage; or
- Customer's amperage.

The current billing determinant for every customer for the fixed rate is the number of customers per month. Regardless of when the meters are read, the fixed rate for a customer is calculated by multiplying the fixed rate by the number of months.

The variable determinant currently depends on the rate classification. For residential customers it is accumulated kWhs of consumption, since that is the metered data available for this group. For customers with over 50 kW of peak monthly demand, the variable determinant is kW of peak monthly demand since that is the metered data available for this group. Demand metered customers are also metered for kWh consumption to be applied to the commodity portion of their bill, but it does not affect their delivery rates (distribution and transmission). For very large customers, some distributors bill based on apparent power measured in kVA. For customers with poor power factor (large reactive power requirements compared to their real power requirements), kVA is a better measure of the assets required to serve their needs. Assets need to be sized to handle the apparent power and additional assets (such as capacitors) may be required to maintain power quality on local lines. All customers of whatever size have the motors that cause reactive power (refrigerators, air conditioners, fans, blenders, etc.) but the metering technology to measure it is not available at a reasonable cost.

The implementation of meters capable of providing hourly data allows more flexibility in the selection of appropriate billing determinants. It may be that these hourly readings will ultimately be able to be used as a basis for demand charges. Since kWh readings were only a proxy in distribution rates for demand use of the system, it will be technically possible for all customers to have kW as the billing determinant.

Using the customer's peak as the billing determinant was a result of the measurement technology available at the time. Hourly data would allow distributors to determine the customer's individual peak as well as the customer's contribution to peak at the time of the distribution system peak. Since some costs are driven by different peaks, it may be appropriate to have a three-part rate: the fixed rate, a distribution system demand rate and a customer demand rate. If the distribution system peak rate were higher than the customer peak rate, it would encourage off-peak usage on a cost causality basis without the need for promotional (and perhaps discriminatory) off-peak rates. There may, however, be issues regarding the customer's ability to understand the three-part rate and their ability to modify the behaviour that the three-part rate would be designed to achieve. Also, since the timing of the distribution system peak will tend to vary from month to month (even day to day) the distribution system peak would likely have to be arbitrarily fixed or the rate design might not be stable from the customer's perspective.

In 1982[11] and 1983[12], Ontario Hydro proposed bulk rates that would vary seasonally (winter and summer) and diurnally (day and night). However, these were largely based on costs of generation and were intended to affect capacity on the system. Commodity is now priced separately from distribution. Therefore, any rate classifications for commodity (such as the special rules that apply to residential customers under the Regulated Price Plan) do not need to be the same as the distribution service classifications.

Should the billing determinants be consistent for all customer classifications?

What are the most appropriate billing determinants for each customer classification?

5.4 Cost model for generation

Connection costs are currently treated differently for different types of customers. For generators, options include:

- Generators pay all connection costs;
- Generators pay shallow connection costs;
- Generators pay deep connection costs; and/or
- Generators pay use-of-system rates.

Currently, generators pay all of their connection costs up front.[13] The costs of the assets to serve generator customers are considered to be customer contributions and are not added to the rate base of the utility. These situational, one-time charges are characterised by some as a barrier to entry.

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[11] Ontario Energy Board, Ontario Hydro: Bulk Power Rates for 1983, H.R. 11, August 31, 1982.
[12] Ontario Energy Board, Ontario Hydro: Bulk Power Rates for 1984, H.R. 12, August 31, 1983.
[13] Generators connected to the distribution system usually pay some form of monthly bill as a load customer for the power that they draw while not operating.

Loads typically pay for their connection through rates. There may also be a contributed capital supplemental payment in those instances where the expected load would not produce sufficient revenue to cover the connection costs. The costs of the assets to serve load customers that are paid for through rates are added to the rate base of the distributor. Capital and operating costs are allocated and recovered in rates.

Both types of customers pay for their service, but on the basis of a different model. This is the case in virtually every jurisdiction in the world.[14] The difference usually arises in terms of the level of connection costs that the generator pays. In some jurisdictions, the generator pays the costs that are directly related to its service (direct or sole costs). In others, the generator pays for all system changes back to a certain level in the system, either to where it is networked or to a certain point of transformation (shallow charges). In yet others, the generator pays for all system changes throughout the system (deep charges).

In order to facilitate the connection of distributed generation, Ofgem is pursuing models where generators pay on the same basis as load customers[15] (generators will face fewer connection charges but pay use-of-system rates).

One argument has been that charging merchant generators to use the system will simply cause them to raise the price of their output, and loads will end up paying that in any case. This is true regardless of the model under which generators pay for their connections. By increasing the rate base of the distributor to include generator connections, load customers could actually have their rates reduced since generators would end up paying more of the operation and maintenance costs of the system. Further analysis is required to determine whether a change to the Ontario model would

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[14] Commission for Energy Regulation, Electricity Tariff Design Review: International Comparisons, March 2004.

[15] Ofgem, Design of electricity distribution charges: Consultation on the longer term charging framework, May 2005

result in an undue burden on distributed generators compared to generation facilities connected at the transmission level.

With regard to Load Displacement Generation (“LDG”), when a distributor has LDG in their service area the distributor often charges standby rates. These rates are design to recover the investment and associated costs of the assets that are “standing by” to provide a distribution service when the LDG is not operating.

In the recent cost allocation studies conducted by distributors, the costs associated with the LDG rate classification have been determined by those distributors that have LDG of greater than 500 kW in their service area. The costs allocated to the LDG rate classification include the cost of providing distribution service to the base load that is the same as a standard distribution customer plus the distribution costs required to support the incremental load when the load displacement generator is not operating. The costs associated with incremental load can be viewed as the cost of providing the standby distribution service.

With some additional analytics, the results of the cost allocation studies could be used as a starting point to review the cost of providing standby distribution service to a load customer with LDG and potentially form the basis on which to design a standby rate. LDG service could lead to other savings or costs which may not have been directly identified in the cost allocation study but could be taken into consideration in the design of standby rates.

Should the Board pursue an analysis of use-of-system rates for distributed generation to investigate rates and determinants?

5.5 Consistency of the rate design

The design underlying rates can be the same for all distributors in a jurisdiction or can vary amongst them. Options include:

- All distributors use the same service classifications and rate design;
- All distributors within a given geographic region use the same service classifications and rate design; or
- All distributors with similar customer characteristics use the same service classifications and rate design.

Currently each distributor has its own distinct distribution rates.

One potential outcome of this project would be a single rate design model that would be applicable to all Ontario distributors. However, given the diversity in the province between distributors that have largely urban and suburban service areas and those that have largely rural service areas, a single rate design may not be appropriate. The Board could accommodate differences by allowing for a limited number of predetermined variations, like the current seasonal or agricultural rates.

The Board has previously articulated a desire for consistency on at least two issues; namely, the predetermined methodology for applications for an intermediate rate classification and the elimination of the existing time-of-use rate classification (which it was considered non-reflective of cost causality).

If a consistent rate design model is highly desirable, then a comprehensive model needs to be determined with precision. If it is less important, the Board could provide policy guidance in terms of approaches that are favoured over others.

How important is consistency of the rate design model across the province?

5.6 Rate harmonization

Distribution rates can be pooled or they can be individual to each distributor. Options include:

- Each distributor has a rate order based on its revenue requirement;
- Each distributor has the same rate order and revenues are pooled on a provincial basis; or
- Distributors within a given geographic region have the same rate order and revenues are pooled within that region.

Currently, each distributor has rates determined for its service area based on its individual revenue requirement. This can result in large differences between the rates charged to customers that are geographically close to one another. The Board tabulates estimated bills for customers throughout Ontario and publishes them on its website to facilitate comparison between utility service areas.[16]

By contrast, transmission rates are set by determining each transmitter's revenue requirement and then pooling them for cost allocation and rate setting purposes. The rate order for all transmitters is the same and each receives its overall share of revenue requirement All transmission customers have the same bill regardless of the transmission system to which they are actually connected. A single rate for transmission services was developed for reasons that do not exist in relation to distribution, including the effect of wheeling charges that would have arisen under other charging models. For transmission billing, the Independent Electricity System Operator collects customer payments and then distributes the money to the transmission companies according to their share of the total revenue. For distributors, the collection and true-up of funds would be much more complex.

Implementation of a similar scheme for distributors, would remove the geographic boundary issues where, for example, one customer is charged more than its neighbour. It might facilitate amalgamation of distributors by eliminating rate harmonization issues. The pooling of revenue might also represent an unacceptable level of cross-

[16] Available on the OEB website.

subsidization between low cost areas and higher costs areas. This might be brought to an acceptable level by pooling rates on a regional basis: selecting distributors for a specific pool based on geography and customer base.

Is one single rate order (or a few regional rate orders) to be used by all distributors a desirable outcome?

5.7 "Designer power"

The issue here is the extent to which all customers should receive a uniform level of service. Options include:

- All customers receive the same level of service; or
- Customers can pay higher rates for service options such as power quality or firmness of power.

Currently, all customers of a distributor receive essentially the same service. The Distribution System Code requirements for standards of service such as outage frequency and duration, voltage regulation, and service response are the same for all classifications of customers and all customers within a classification.

However, given the increased sophistication of many customers, a single standard of service at a single rate may be questioned. Some customers might be willing to pay for improved levels of service in terms of either firmness of supply or power quality.[17] Alternatively, some customers may be willing to have power interrupted when the system is stressed in order to enjoy lower rates. This would be analogous to cable or telephone systems offering basic and enhanced packages of service.

At the same time, the distributor may want to buy services, such as voltage support or counter flow that might reduce capacity constraints, from distributed generators. This

[17] Better than standard control of voltage or harmonics.

would likely depend on whether these services were available whenever the distributor needed them.

Should distributors offer various levels of service?

Should distributors be able to buy (offer credit for) services from customers?

5.8 Marginal cost

There are different potential cost bases for distribution rates. Options include:

- Rates are based on accounting costs;
- Rates are based on short run marginal costs;
- Rates are based on long run marginal costs; or
- Fixed costs are based on accounting costs and variable rates are based on long run marginal costs.

Whether based on an actual past year or a future test year, distribution rates in Ontario are currently based on accounting costs (or embedded costs). Under cost of service regulation, it is these costs that are allocated and put through the rate design model to arrive at the rate order.

Economic theory suggests that optimum resource allocation is achieved when prices are at marginal cost, being the cost to supply additional units of the service. The customer rate (fixed rate) would represent the cost of an additional customer to the system and the demand rate would represent the cost of supplying an additional kW to the customer. Rates based on marginal costs are thought to provide a better economic signal to customers about incremental use of the system and to provide a better signal for rational growth of the system.

It is generally accepted that short run marginal costs (e.g., set yearly) would not provide the rate stability necessary for the customer. However, the concept of basing rates on long run marginal costs (5 to 10 year horizon) is often investigated. Marginal cost pricing has not been widely implemented for two reasons. First, a long and detailed study is required to determine the marginal costs. Second, since collecting only marginal costs would not be enough to recover the revenue requirement, the marginal costs are adjusted by a factor that Bonbright called a 'quasi-tax'. Determining an appropriate factor for every service classification requires far more investigation than using accounting costs, and can be highly controversial.

Nevertheless, Ofgem has used incremental costs in its distribution reinforcement model since the 1980s, and is continuing to use long run marginal costs in the development of new network operator rate models.[18] The New South Wales distribution business in Australia uses incremental costs to set demand and capacity rates.[19]

The last time the question was before the Board in 1979, the Board stated as follows:

> The Board rejects the ECAPS [Electricity Costing and Pricing Study prepared by Ontario Hydro] proposal for marginal-cost-based pricing because of major problems of definition, determination, and implementation and recommends the continued use of accounting costs as the basis for costing and pricing.[20]

Should the Board investigate a rate design model based on long run marginal costs?

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[18] Ofgem, Design of electricity distribution charges: Consultation on the longer term charging framework, May 2005
[19] Independent Pricing and Regulatory Tribunal, NSW Electricity Distribution Pricing 2005/05 to 2008/09: Final Report, June 2004.
[20] Report to the Minister of Energy on Principles of Electricity Costing and Pricing for Ontario Hydro, **H.R. 5**, December 20, 1979.

5.9 Locational pricing

Distribution customers can be billed on different bases, depending on location. Options include:

- Postage stamp rates; or
- Locational rates.

Currently, distribution customers in Ontario are billed on a postage stamp basis. Just as with transmission charges, distribution rates are applied regardless of where the customer is located on the system even though the costs of serving customers in different locations could be quite different.

Ofgem has proposed locational rates for customers connected to the extremely high voltage system[21] equivalent to Ontario's transmission system. Rates would be dependant on fault level (related to the impendence of the system) and system load flow (related to direction). The intent, in conjunction with generation use-of-system charges, is to give price signals for the siting of new connections.

If one extreme is the single rate classification where all customers, having similar characteristics, have exactly the same rates applied, the opposite extreme is where each customer has an individual rate based on its location and use of the system. The primary disadvantages of the latter are complexity and tariff stability for the customer, since the rates would be highly situational and subject to change every time the system configuration changed.

Should the Board investigate locational rates for any customers connected to a distribution system?

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[21] Ofgem, Design of electricity distribution charges: Consultation on the longer term charging framework, May 2005

5.10 Impact of the Simplified Bill

Flexibility in bill presentation may be an important factor to consider in rate design. For example, rate design that is intended to provide price signals for one or more purposes may not achieve the objective if the price or rate in question does not appear on the customer's bill.

At the present time, the content of bills issued to the majority of Ontario consumers is prescribed to a large degree by law.[22] Among other things, distribution rates of whatever design are grouped with transmission charges and appear as a single line item under the heading "Delivery Charge". This can have the effect of blunting any signal intended to be sent through distribution rates.

Given the simplified bill, can a conservation and/or demand management effect be achieved through distribution rate design?

[22] *Information on Invoices to Low-volume Consumers of Electricity Regulation*, O. Reg. 275/04.

6 Summary of Questions

Rate Design Principles

- Are there any principles, beyond the generally accepted, traditional principles of rate design listed above, that the Board should consider in designing distribution rates? What is the new principle's importance relative to the others?

Customer Classes

- What is the most appropriate basis for determining the service classifications for Ontario distribution customers?
- Should sub-classifications be maintained? If so, what is the most appropriate method to allocate diversity benefits?

Rate Design Components

- Are there other rate design components or options that the Board should consider as it moves forward?
- What are the principles that should inform the decision on fixed and/or variable rates?
- Should the billing determinants be consistent for all customer classifications?
- What are the most appropriate billing determinants for each customer classification?
- Should the Board pursue an analysis of use-of-system rates for distributed generation to investigate rates and determinants?
- How important is consistency of the rate design model across the province?
- Is one single rate order (or a few regional rate orders) to be used by all distributors a desirable outcome?
- Should distributors offer various levels of service?
- Should distributors be able to buy (offer credit for) services from customers?
- Should the Board investigate a rate design model based on long run marginal costs?

- Should the Board investigate locational rates for any customers connected to a distribution system?
- Given the simplified bill, can a conservation and/or demand management effect be achieved through distribution rate design?