Ontario Energy Board

Staff Discussion Paper

Rate Design for Recovery of Electricity Distribution Costs

EB-2007-0031

March 31, 2008 (Revised June 6, 2008)

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1 Introduction

1.1 The Electricity Distribution Rate Design Review Process

One of the rate-setting initiatives set out in the Ontario Energy Board's business plan is a comprehensive electricity distribution rate design review. This review is intended to consider the need for, and approaches to, changes in distribution rate design in light of industry changes and emerging issues. These include the commercialization of electricity distributors, developments in metering, increased distributed generation and conservation and demand management activities, among others. This project focuses on designing a rate structure that recovers the revenue associated with distribution costs. As such, it is distinct from Board-led projects on commodity pricing or revenue associated with conservation and demand management activities by distributors.

Rate Design for Electricity Distributors (EB-2007-0031)[1] is intended to culminate in the Board issuing a policy framework for electricity distribution rate design. Models of options would then be undertaken and any resulting rate design changes would be used in setting rates in the future.

1.1.1 Papers and Consultation

Phase 1

On March 30, 2007, the Board posted a Board staff Discussion Paper[2] to solicit comments from interested stakeholders about the following areas:

- Underlying principles;
- Classes of service; and
- Rate design components and issues.

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[1] http://www.oeb.gov.on.ca/html/en/industryrelations/ongoingprojects_ratedesign-electricitydist.htm

[2] http://www.oeb.gov.on.ca/documents/cases/EB-2007-0031/staff-paper_ratedesign_20070330.pdf

The Discussion Paper attempted to establish a common nomenclature for, and a discussion of some key rate design concepts.

The Board received nineteen submissions in response to the March 2007 Discussion Paper. Those submissions and subsequent discussion by the Board refined the scope for the project and has allowed the Board to articulate its view of principles in developing a new rate design.

Phase 2

Board staff commissioned Elenchus Research Associates (ERA) as a consultant to provide expert advice on rate design matters that are in scope for this project, including a consideration of relevant experience in other jurisdictions.

Board staff and ERA have met with interested parties for a series of consultation meetings in relation to their comments on the Staff Discussion Paper and other issues. These meetings took the form of group consultation meetings held October 17 and December 16, 2007 and January 16, 2008. Meeting materials from those sessions are available on the Board's website as previously cited. In addition, ERA met individually with many stakeholders for more detailed insight into positions.

The consultant's information and the input from the consultation meetings have resulted in this Staff Discussion Paper. The purpose of this Staff Discussion Paper is to elicit stakeholder comment. To that end, staff has described various rate design options with invitations to comment on specific areas. The invitations to comment are intended to stimulate discussion and stakeholders are welcome to comment on any issues raised in the paper. Stakeholder comments will considered in Board staff's further formulating policy proposals for the Board members to consider.

1.2 The Scope of the Electricity Distribution Rate Design Review

The Board Staff Discussion Paper, released on March 30, 2007, suggested a number of potential issues regarding distribution rate design. Based on comments received and subsequent discussion, the Board refined the scope of the project.

The project deals with distribution rates only. It does not include transmission charges or commodity charges, except in the form of distribution losses. It does not include the level of specific charges which are intended to be a pass-through of costs. These are the subject of another Board process (EB-2007-0722) currently underway[3].

The primary focus of this paper is to discuss options for these main issues:

- Customer classifications;
- The fixed / variable split;
- Rate structure and billing determinants including load displacement generation and interruptible rates; and
- Revenue recovery of system losses.

1.2.1 Rate Harmonization of Consolidated Distributors

The initial Staff Discussion Paper raised the issue of common rate orders and rate harmonization as a means of facilitating distributor mergers.

The Board has concluded its consultation on Rate Making Policies Associated with Distributor Consolidation (EB-2007-0028). The project consulted with stakeholders on the rate making issues, including rate harmonization, that may be associated with certain distributor mergers, acquisitions, amalgamations and divestitures. The Board

[3] http://www.oeb.gov.on.ca/html/en/industryrelations/ongoingprojects_provisionofservice.htm

issued its Report of the Board[4] on July 23, 2007. This Staff Discussion Paper will not revisit any of the issues determined through that process.

The project, as it moves to implementation, will continue to consider the concept of using a single rate order (with revenue pooling mechanisms) for multiple distributors, particularly small distributors. Although it is not a particular subject of this paper, it is worthwhile noting that the jurisdictional survey found such arrangements in France and Italy.

1.2.2 Distributed Generation

The Board has two consultation processes underway that directionally address issues related to distributed generation: Distributed Generation – Rates and Connection (EB-2007-0630) and Transmission Connection Cost Responsibility Review (EB-2008-0003).

The issue being addressed in the Distributed Generation – Rates and Connection consultation (EB-2007-0630) is development of a standard methodology for quantifying benefits from distributed generation.

The question of whether distributed generators should pay regulated "use of system charges" was initially an issue in the Rate Design project. However, the recently announced, third project related to distributed generation (Distribution Connection Cost Responsibility Review) will examine the issue of cost responsibility associated with the connection of generation facilities to electricity distribution systems. This Review will include consideration of the merits of regulated "use of system" charges as a method of recovering costs that may be the responsibility of the distributed generator. As such, the merits or implications of such charges will not be discussed in this paper. However, if such charges are to be implemented, their design will be addressed at a later stage of

[4] http://www.oeb.gov.on.ca/documents/cases/EB-2007-0028/report_ratemaking_20070723.pdf

the Rate Design for Recovery of Electricity Distribution Cost consultation. In the event, the Board will consult further on development.

Furthermore, the decision to initiate the Distribution Connection Cost Responsibility Review has resulted in cost responsibility issues being removed from the Distributed Generation – Rates and Connection consultation. The issues of rate classification and standby rates for load displacement generation are now part of the Rate Design project.

The Distribution Connection Cost Responsibility Review will commence later this year once the Transmission Connection Cost Responsibility Review (EB-2008-003) has been substantially completed.

1.3 Scope of the Staff Discussion Paper

The purpose of this Staff Discussion Paper is to describe in more detail the issues and options that are within scope of the rate design review. The paper will draw on previous stakeholder comments; research undertaken by Board staff and the consultant; and consultation meetings held with groups and individual stakeholders over the past year. In general, Board staff finds that there was not a clearly preferred option for most issues. Staff outlines the pros and cons of the various options and the implications of certain decisions on other issues.

In this paper, Section 1 is a review of the project and progress thus far. Section 2 is a background review of the current electricity distributor rate design and the driver for this project. Section 3 is a statement of the Board's priority principles in moving forward.

Section 4 discusses customer classifications while a number of key rate design issues are commented on in Section 5. Sections 6 through 13 address rate design options for the eight possible rate classes identified in section 4: single phase secondary; three phase secondary; primary; sub-transmission; embedded distributors; load displacement generation; unmetered scattered load and metered scattered load.

Section 14 addresses the treatment of revenue recovery associated with distribution system losses. The next steps in the Rate Design review are outlined in Section 15.

1.3.1 Follow-on Issues

Through comments and consultation, Board staff identified several issues that will require work for the results of Phase 2 to be implemented. These are noted but will not be discussed in this paper:

- mitigating rate impacts;
- revision of the economic evaluation for customer contributions;
- development of a framework for negotiating cost-based, customer-specific contracts; and
- implications of the simple bill.

2 Background

2.1 Rate Designs Typically Used by Ontario Electricity Distributors

Historically, many aspects of an electricity distributor's rate design were driven by metering considerations. Cost/benefit considerations drove the metering technology that was adopted for types of various customers. Small customers used the simplest and least expensive meters. Larger users received more costly and capable meters.

The most basic meters, accumulation meters that provide only a kWh measurement whenever they are read, have typically been used for residential and small general service (GS) customers. Thermal demand meters which provide a kWh measurement whenever they are read and a record of the single peak demand since the last reading are used for larger customer that are charged on a demand basis. Interval meters that provide a record of kWh and kVA consumed over discrete time periods, often 15 or 30 minute segments, were used only for the largest customers.

The introduction of smart meters that record hourly consumption will radically change the information available for residential and smaller GS customers (<50 kW). With more information available for billing and operational purposes, the link between billing determinants and distributors cost drivers can be reconsidered.

Distributors' costs are driven by the number of customers and system capacity. The system is designed with enough capacity to serve its customers needs. Costs on some parts of the system are driven by distribution system peaks and other parts of the system by the non-coincident peaks of consumers. Since the unbundling of electricity rates in 1999, the distribution rate structure for any class has been a simple two part rate: a fixed monthly customer service charge and a volumetric charge. Within the family of volumetric measures, demand is the more direct proxy. Energy is less direct.

Thus, where the only available metered measurement is the kWh, customers must be classified to be as homogeneously as possible so that load profiles and assumptions will allow the kWh to be a proxy for the preferred kW measurement. Since the only measurement available for smaller demand customers is the non-coincident peak demand, other assumptions must be made to use that as the billing determinant.

2.1.1 Class Structures Typically Used by Ontario Electricity Distributors

When rates were unbundled in preparation for the restructuring of the electricity sector in Ontario in 1999, the Board maintained the then-existing rate classes, which were:

- residential;
- general service customers with peak monthly demand under 50 kW (“GS <50 kW”);
- general service customers with peak monthly demand equal to or over 50 kW (“GS ≥50 kW”);
- and large users applying to customers with peak monthly demand equal to or over 5000 kW.

Distributors were also given the option of applying for other classes, including an intermediate general service class applying to customers with peak monthly demand equal to or over 3000 kW. Most distributors also maintain separate classes for street lights and sentinel lights and unmetered scattered load.

2.1.2 Billing Determinants Typically Used by Ontario Electricity Distributors

The rates were set for each class based on the costs allocated to that class and an assumption of the incremental distribution charge for an additional unit of supply. For energy metered customers, the incremental unit was the kWh. For demand metered customers, the incremental unit was the kW.

Boundary Issues

In its Decision with Reasons in proceeding RP-2000-0069 (the “RP-2000-0069 Decision”), the Board acknowledged a potential difficulty at the boundary between rate classes, particularly where customers move from the GS <50 kW class to the GS ≥50 kW class. That is, a customer in the GS <50 kW class who may cross, even marginally, the 50 kW threshold can face a major bill impact. This is due not only to the different fixed monthly customer charge and different variable rate, but also to the difference in being billed on a kWh versus a kW basis. In paragraph 3.5.7 of the RP-2000-0069 Decision, the Board acknowledged this issue and directed that, for purposes of utility filings for establishing initial rates, utilities shall "continue to bill these customers as if they were in the same under 50 kW category up to a demand level of 100 kW" until such time as the Board addresses the cross-over issue.

There is a similar issue for customers at the 3000 kW boundary, if the distributor has an intermediate class, and at the 5000 kW boundary, if the distributor has a large use class. In these cases, the difference is in the fixed monthly customer charge and the demand rate, but does not entail a change in billing determinant.

This project is the first opportunity that the Board has had to address these issues. The new metering technology suggests one obvious solution to the 50 kW boundary issue in that the billing determinant for both the under and over classifications could be the same.

Use of Billing Demand

The practice of most Ontario distributors for demand metered customers has been to determine the "billing demand" - the value used for billing purposes - based on the higher of the kW demand reading or 90% of the kVA demand reading in a billing period. This only applies where the meter installation provides both kW and kVA readings. Typically, only customers with demand over 500 kW or 1000 kW have such meters, although in some service areas, customers with demand over 200 kW do as well.

2.1.3 Fixed/Variable Split Used by Ontario Electricity Distributors

When distribution variable rates were set in 1999 to represent the incremental unit, it represented an unacceptable rate impact for some rate classes in some distribution service areas. Rate impacts were capped and any further increase was added to the fixed rate. The cost allocation studies filed by Ontario distributors showed that there is still a wide variation in the ratio of fixed charges for virtually all customer classes.

2.2 The Planned Rollout of Smart Meters in Ontario

Through the requirements of the Distribution System Code (the “DSC”), the Board has mandated interval meters for new customers (as of 2002 when the DSC was amended) with annual average demand over 500 kW and existing customers with annual average demand over 1000 kW [1 MW]. Several distributors, in their Conditions of Service, set the level at 200 kW.

The policy of the Government of Ontario is to have all homes and small businesses in Ontario smart metered by the end of 2010. The current Smart Metering Initiative will see meters capable of providing hourly consumption readings installed for all customers, residential or general service, with under 50 kW of demand.

There is a gap whereby customers with demand over 50 kW but less than 200 kW will continue to have demand readings that are not time-correlated.

As a result, complexity of metered data is increasing for smaller volume customers. This represents a significant opportunity for rate design in the newly re-metered industry. The simplifications, assumptions, and proxies that have been used in rate design as a result of lack of metered data need to be re-examined. This is the chance to ask what a rate design would look like if the Board was starting with a blank page.

3 RATE DESIGN PRINCIPLES

The Board identified three rate design principles for the purposes of this process. These principles encompass all of the "Bonbright attributes of a sound rate structure[5]" identified in the March 2007 Staff Discussion Paper:

1. full cost recovery;
2. fairness; and
3. efficiency.

3.1 Full Cost Recovery Principle

The Board's legislated mandate includes the maintenance of a financially viable distribution industry. This is consistent with the Full Cost Recovery Principle that the level and design of rates should be sufficient to provide each distributor with a reasonable opportunity to recover its revenue requirement. This view has several implications, including the following.

- Each distributor's rates should be determined by the level of costs that are reasonably and prudently incurred by the distributor to provide service to its customers. The expected revenue (i.e., based on normal weather and other conditions) should therefore equal expected costs.
- To the extent that the actual costs and revenue are uncertain, resulting in uncertainty in relation to a distributor's net income and deemed return on equity, expected costs should include an allowed return on equity with an appropriate risk premium.
- For a distributor's rates to be effective in recovering the required revenue, they should be practical, clear and uncontroversial.

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[5] Principles of Public Utility Rates, Bonbright, James C., et al., Public Utilities Reports Inc., 1988, pp. 383-384.

3.2 Fairness Principle

The Board's view of just and reasonable rates encompasses the fairness principle that customers should, in general, pay rates for distribution service that reflects the costs they "cause" as determined by a Board-approved cost allocation study. In consultations, all stakeholders supported this principle.

The implications of this principle, which is often referred to as the "User Pay" principle, include:

- revenue responsibility by class should normally result in revenue-to-cost ratios of approximately 1.0; and that
- within classes, the rate design should, in principle, correspond as closely as practical to the cost drivers captured in a distributor's cost allocation study.

Historically this second point has further meant that:

- the customer charge for each class should correspond to the value of the customer-related costs divided by the average number of customers in the class;
- the demand charge for each class should correspond to the value of the capacity-related costs divided by the peak demand (kW) of the class; and
- the energy charge for each class [where variable rates are based on energy measurements] should correspond to the value of the commodity-related costs divided by the total consumption (kWh) of the class.

However, it was also generally accepted that fairness among customers is not achieved by designing rates so as to result in revenue-to-cost ratios that are precisely equal to 1.00 for each customer class and for all customers. The reasons include:

- the process of allocating costs is not precise since it involves judgments and allocations that are deemed to be reasonable and fair although costs cannot be said to be "caused" in any clear way by any particular customers or classes;

- rate stability is an aspect of fairness that may limit the rate of change in rates over a particular time period;
- the value of service may be relevant in evaluating the fairness of rates when class revenue-to-cost ratios deviate from 1.00 and when the implicit revenue-to-cost ratios of different customers within a class differ.

3.3 Efficiency Principle

Although rejecting the idea of a strict marginal cost approach, the Board directed that consideration be given to driving efficiency of the distribution system in considering rate design options. The Board found that efficiency of rates involves two key concepts. Rates should encourage customers to maximize use of existing assets: static efficiency. Rates should encourage existing and new customers to use the system in ways that lead to rational growth: dynamic efficiency.

Stakeholders held a range of views on the efficiency considerations that should be considered in the rate design process.

The prevailing view among distributors is that in designing distribution rates the applicability of the efficiency principle should be limited to the efficient use of the distribution system. The implication of this view is that price signals resulting from the rate design should be consistent with efficient utilization of the distribution system and not be used to drive more efficient utilization of the transmission system or power consumption.

Environmental advocates on the other hand consider it to be in the public interest to ensure that distribution rates are designed so that they do not conflict with, and preferably enhance, the overall efficiency of electricity consumption. The primary implication of this view is that the distribution rate design should be consistent with the charges that consumers will pay for the commodity (time of use prices and/or real time prices).

Australia, the United Kingdom and some jurisdictions on the United States use long run incremental costs in setting delivery rates[6].

3.4 International Experience with Innovative Rate Designs

Ontario seems to be fairly advanced in its approach to distribution rates, even compared with many jurisdictions installing smart meters. Smart meter rates (e.g. California, Australia, and Italy) have tended to focus on influencing commodity use and reducing demand through time dependent pricing[7].

The survey indicates that there is a prevalence of rate design practices that exhibit the features of traditional retail rate design, as characterized by the following fundamental properties:

- they have been set at the same level for broad classes of customers (e.g. all residential customers) whose patterns can vary widely;
- retail rates are typically set at a fixed level that reflects the broad average of the hourly costs to serve customers over a year or a season;
- traditional retail rates focus largely on recovering utilities' historical embedded costs rather than reflecting forward-looking costs.

It has been difficult to identify comparative jurisdictions with Ontario's combination of an unbundled electricity industry, cost regulated delivery systems and large-scale implementation of smart meters. Thus, there are significant information gaps with respect to the market impacts of alternate rate designs. Therefore staff believes that it may be appropriate to undertake studies or implement and test multiple options before committing to a single approach.

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[6] See the Board's website http://www.oeb.gov.on.ca/html/en/industryrelations/ongoingprojects_ratedesign-electricitydist.htm, Survey of Other Jurisdictions.

[7] For detailed information on regions investigated, please see the Board's website, Survey of Other Jurisdictions.

Also in discussions with stakeholders, staff is of the view that different rate design methods may be appropriate for different distributors (e.g., winter-peaking North versus summer-peaking South).

4 Customer Classifications

It is generally accepted that the principle of fairness discussed in the previous section requires a rate design that results in "like" customers being charged for distribution service on the same basis while "unlike" customers are charged on different bases. Hence, like customers are grouped into customer classes for billing purposes. The "unlike" customers in different classes can then be charged on the basis of different rate designs (different billing determinants and rates) that reflect the differences in the way they cause distribution costs.

By defining customer classes appropriately, the regulator can ensure that there are no inordinate cross-subsidies between the customers in different customer classes. In theory, the rate design for any particular customer class can then be structured to minimize inappropriate intra-class cross-subsidies while embedding cross-subsidies that are deemed to be appropriate.[8]

The traditional rate design that was discussed in section 1.3 was largely consistent with this conceptual approach; however, limitations on metering have resulted in what, in the view of most stakeholders, is an inequity that can be addressed once smart metering has been implemented for all customers. The inequity arises because a significant proportion of distribution costs are capacity-related costs while metering technology has required the variable charge to be based on energy (kWh) rather than demand (kW). When energy (kWh) is the primary billing determinant for a customer class, it follows that high-load-factor customers will subsidize low-load factor customers in that the causal costs of low-load-factor customers will be under-recovered relative to the causal

[8] For example, regulators typically maintain postage stamp rates within defined geographic areas which results in an under-recovery of causal costs for expensive to serve customers and over-recovery of causal costs for inexpensive to serve customers. This approach avoids locational differences in the cost of distribution service when it is deemed to be inappropriate.

costs of higher load factor customers. This intra-class cross-subsidy could be reduced or eliminated by introducing capacity or demand as a billing determinant for the customers classes that currently are billed on the basis of a monthly customer charge and an energy charge (generally, residential and GS<50 kW customers for whom thermal demand and interval meters have not been economic). The introduction of smart metering will facilitate the introduction of a new rate design that addresses this intra-class cross-subsidy.

Furthermore, the reduction or elimination of intra-class cross-subsidies related to load factor differences may have an impact on the appropriate definition of customer classes. To the extent that existing customer class differences have served primarily to distinguish between types of customers that on average have significantly different load factors, the elimination of intra-class cross-subsidies related to load factor differences will remove the rationale for maintaining separate customer classes. This consideration raises that possibility that the distinction between residential and the smaller general service customers will no longer be relevant if demand or capacity is introduced as a billing determinant for all customers.

4.1 Issues Relevant to Establishing Customer Classes

As is noted above, causal costs are determined through a cost allocation study that determines for each customer class:

- customer-related costs that can most directly be recovered through a monthly customer charge;
- demand-related (or capacity-related) costs that can most directly be recovered through a demand (or capacity) charge; and
- energy-related costs that can most directly be recovered through an energy charge.

It is generally accepted that customers should be grouped into classes so that:

- the per-customer costs for customers within a class are similar enough for them to be subject to a standardized per-customer charge;
- the per kW (or kVA) costs for customers within a class are similar enough for them to be subject to a standardized demand or capacity charge; and
- the kWh costs for customers within a class are similar enough for them to be subject to a standardized energy charge.

Hence, separate customer classes are required only when the appropriate per-customer, demand/capacity or energy charges are sufficiently different between identifiable groups of customers to justify different rates. The factors that would justify the establishment of different classes can be identified by asking the following questions:

1. what categories of costs are significantly different for different types of customers; and
2. are the cost differences among types of customers large enough to justify establishing separate customer classes with different rates?

Staff and stakeholders have identified the following factors that give rise to cost differences that may be significant enough to justify the creation of separate classes.

- Differences in customer-related costs related to:
  - service connection;
  - metering; and
  - customer service.
- Differences in demand or capacity related costs related to:
  - power quality both in voltage or harmonic control and firmness of supply.

Where customers are billed on an energy basis for the volumetric rate, there may be significant energy-related distribution costs on a proxy basis that justify establishing separate rate classes.

4.2 Options for Customer Classes

The existing approach to customer classification relies primarily on the size of customer and load profile differences as the basis for defining customer classes. One option for defining customer classes is to retain the existing approach.

From a technical standpoint, a distribution system can be divided into several levels based on functionality.

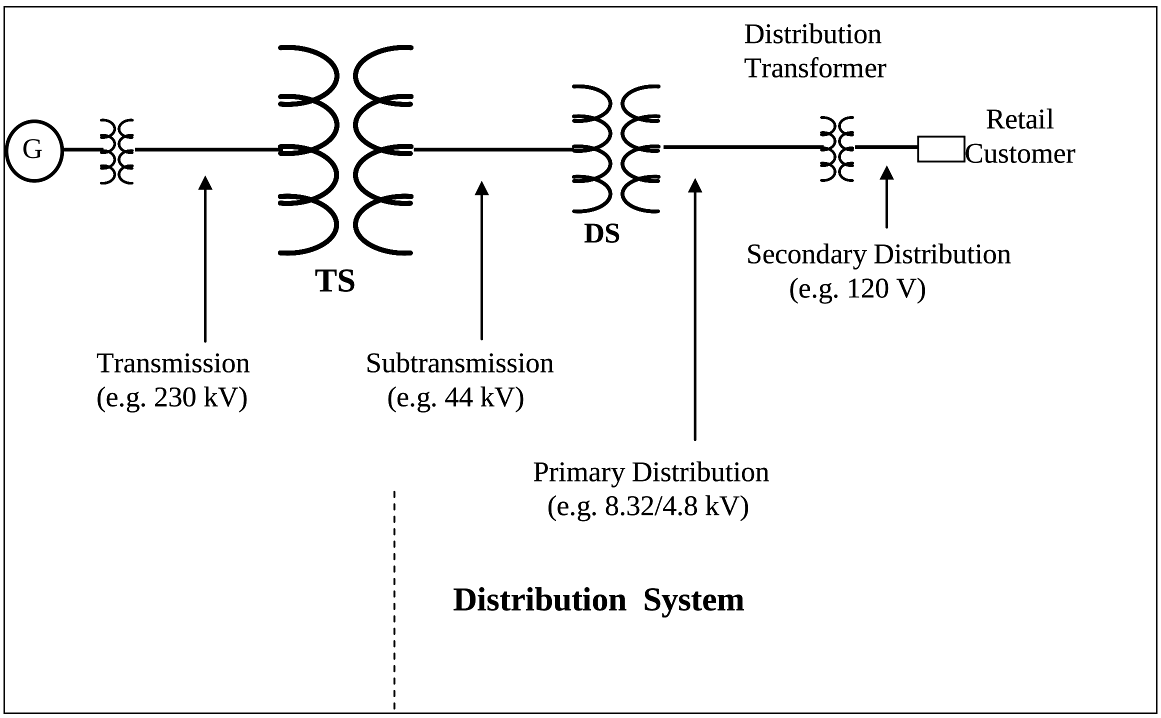

Figure 1: Distribution Voltage Levels

In taking power from the transmission system, the distributor may choose either:

- to have a 3-wire (i.e. without an integrated neutral) sub-transmission system to supply large 3-phase customers and substations that are, in turn, used to step down to a lower voltage 4-wire primary distribution system; or
- to step down from the transmission system directly to a higher voltage 4-wire primary distribution system that can be used to supply all classes of customer. In some cases the higher distribution voltage lines may also be

used functionally as a sub-transmission system to supply substations that step down to a lower voltage primary distribution system. In these cases, the lower voltage primary distribution system is used only to supply smaller volume customers while larger customers are required to take their supply from the higher voltage primary distribution system.

Based on historical development of the distribution system, the primary distribution system may have several different voltages.

For residential and many small volume customers, distributors supply power to the customer at the customer's utilization voltage level (< 750 V.). In these cases the power is further transformed down at or near the customer location from the primary distribution voltage level to a secondary voltage level that matches the customer's utilization voltage.

Because of the economic efficiencies associated with three-phase power, distributors use three-phase lines wherever economically feasible. Customers served from the sub-transmission or primary distribution systems typically take power at three-phase. Customers that are served from the secondary system can be either single-phase or three-phase.

The size of load of customers based on peak demand or annual energy generally corresponds to the voltage at which a customer connects to the distribution system. In turn, the voltage at which a customer connects to the distribution system is an indicator of the distribution facilities required to serve the customer (sub-transmission; primary, and secondary).

In the view of some stakeholders, a customer that connects at higher voltage should only be paying for the distribution costs that are incurred to supply power at that voltage. Hence, the customer classes should be based on the customer's connection voltage.

The primary alternate view is that customers are not always able to choose the voltage at which they connect to the system – the available options depend on the facilities in place. As a result, customers with identical power requirements may be served at different voltages simply due to the distribution facilities that are in place to serve their location. This view suggests that customer classes should be based on customer volume (demand and/or energy) where the class division is based on the notional optimal connection voltage.

It is recognized nevertheless that a customer that is served at higher voltage not only uses less distribution facilities, all other things being equal, but also must incur higher on-site costs to step down the voltage for use. From this perspective, it is fair to place customers with identical power requirements in different rate classes if they are served at different connection voltages.

A volume-based class definition would result in three volumetric classes based on standardized criteria for the service voltage used to connect customers:

- small volume (secondary-one phase);
- intermediate volume (secondary-three phase); and
- large volume (primary and sub-transmission).

The primary alternative would be to base the class definitions on the actual connection voltage (sub-transmission, primary, secondary-three phase and secondary-one phase) rather than standardized criteria.

Most customers would end up in the same class under either of these approaches. One disadvantage of the first approach is that it could create a boundary issue in that some customers could change classes as a result of small changes in demand that move them between classes although their actual service connection is unchanged.

In either case, it is generally recognized that there are several additional classes that may be required where they are relevant. These additional classes correspond to non-standard customers including:

- embedded distributors;
- load displacement generation;
- unmetered scattered load (street and sentinel lights); and
- metered scattered load.

The appropriate treatment of interruptible customers was also raised during the stakeholder sessions. There was concern that when interruptible rates are available to electricity customers they are rarely if ever interrupted. System benefits comparable to the foregone revenue due to the discount are rarely achieved; hence, the interruptible rates serve as a discount rather than a cost-based rate.

The general view of stakeholders in consultation was that interruptible rates (or more accurately ‘interruptible service’) should be an available tool for distributors to use to avoid expansion costs under limited circumstances.

Board staff welcomes comments on the appropriate role for interruptible rates.

- **Should they be offered and if so, in what circumstances should they be available?**
- **If interruptible rates are available, what rate classes should qualify for them?**
- **Should separate interruptible rate classes be established, or should they be a rate option within other rate classes?**

4.3 Evaluation of Options for Customer Classes

4.3.1 Connection Voltage

Board staff believes that cost causality (i.e., cost per kW) is closely linked to connection voltage.

An examination of sample data[9] for the customers of Milton Hydro Distribution Inc., suggests that customers could be divided into those using the sub-transmission, primary and secondary systems where the definitions are as follows:

- sub-transmission classes at 44kV, 27.6 kV or 13.8 kV;
- primary classes at 2400 V to 27.6/16 kV;
- secondary classes (under 750V) with 3 phase service; and
- secondary classes (under 750V) with 1 phase service.

Given the historical development of Ontario distribution systems and subsequent upgrades, there is overlap of the sub-transmission and primary voltages. Board staff is working with a definition that sub-transmission systems are defined as having 3-wire lines (i.e. without an integrated neutral) and primary systems as having 4-wire lines, regardless of the voltage, original purpose or current function of the line. It may be that not all distributors will have any lines falling into this definition of sub-transmission. Board staff feels the distinction should be maintained for those that do.

Tables 1, 2 and 3 show how customers in the current rate classes would map to these new, proposed classes and their average demand and consumption.

Table 1 shows the number of customers in the Milton Hydro customer sample dataset broken down by current customer class (rows) and proposed connection-based rate class (columns). All of the existing residential customers in the sample would be in the new Single Phase Secondary Class, along with about 12% of the current GS < 50 kW customers and about 3% of GS 50-999 kW customers. About 96% of the current GS 50-999 kW customers would be in the Three Phase Secondary Class along with the remaining GS <50 kW customers. Larger volume customers are split between the Three Phase Secondary, Primary and Sub-transmission Classes.

[9] Milton Hydro was selected because it has more than one year of smart meter data for its small volume customers. About 10% of Milton Hydro's customers were included in the sample data that were available for analysis for this project.

Table 2 shows the average annual peak of each group of customers with the class average annual demand for the existing classes (last column) and proposed classes (bottom row). Table 3 shows the average of the monthly peaks of each group of customers with the class average monthly peak demand for the existing classes (last column) and proposed classes (bottom row).

Table 1. Customer Count by Connection Voltage

	New Connection-based Class								
	Secondary - Single phase		Secondary - 3 phase		Primary (>4kV)		Sub-transmission		Total
Current Class	Count	%	Count	%	Count	%	Count	%	Count
Residential	1792	100%							1792
<50 kW	50	12%	353	88%					403
50-999 kW	7	3%	197	96%	2	1%			206
1000-4999 kW			3	33%	6	67%			9
5000+ kW					2	67%	1	33%	3
Total	1849	76.6%	553	22.9%	10	0.41%	1	0.04%	2413

Table 2. Average Peak kW by Connection Voltage

Average of Peak kW	**New Connection-based Class**				
Current Class	Secondary - Single phase	Secondary - 3 phase	Primary (>4kV)	Sub-transmission	Overall Class Average
Residential	5.4				5.4
<50 kW	9.5	12.3			12.0
50-999 kW	68.1	168.9	206.8		165.8
1000-4999 kW		1,648.8	2,112.0		1,957.6
5000+ kW			7,443.6	Not available*	7,443.6
Overall Class Average	5.8	77.0	2,797.3		33.7

* No sub-transmission customer was included in the Milton Hydro sample data.

Table 3. Average of Monthly kWh

Average of Monthly kWh	**New Connection-based Class**				
Current Class	Secondary - Single phase	Secondary - 3 phase	Primary (>4kV)	Sub-transmission	Overall Class Average
Residential	708				708
<50 kW	2,606	3,700			3,565
50-999 kW	24,165	67,667	49,607		66,013
1000-4999 kW		923,508	1,069,843		1,021,065
5000+ kW			3,766,650	Not available*	3,766,650
Overall Class Average	848	31,478	1,405,157		13,693

* No sub-transmission customer was included in the Milton Hydro sample data.

Currently, the customer class definition for General Service > 50 kW for many distributors includes the specification “taking electricity at 750 volts or less”. This appears to recognize the importance of the voltage level in classifying customers.

Board staff is interested in receiving submissions as to whether such a distinction is practical and such a classification is logical for distribution systems.

Secondary classes with 3 phase service might be further divided, if costs justify it, by volume usage such as: under 50 kW; 50 kW to under 500 kW; 500 kW to under 1000 kW; 1000 kW to 3000 kW; 3000 to 5000kW; over 5000 kW. Primary classes might also be sub-divided along the same lines.

Board staff welcomes comments on the appropriate levels of division and whether these are more appropriate as distinct classes or sub-classes.

4.3.2 Proxies for Voltage

In consultation, some representatives of distributors pointed out practical difficulties of trying to base classes on the engineering distinctions of sub-transmission, primary, and secondary systems. They pointed out that due to the historic development of many Ontario distribution systems, the definition is easier to describe than to discern in system drawings. In practice, it may be difficult to separate customers into the classes and perhaps even more difficult to explain to each customer how that classification was accomplished.

Because of these historic limitations on the physical system, it may be that the Board must accept proxies for defining classes and recognize that improved metering technology will not help eliminate them. Although it would be preferable to be able to define classes solely on the basis of the assets used to serve the customers, it may be necessary to accept volume-based approximations that represent the connection capacity.

If not the connection voltage, what is the best approximation to it: the demand, the amperage or a combination of the demand volume and voltage capacity?

Using a proxy for the system configuration and service voltage to set the class boundaries as suggested above could limit the number of main classes to 3 (i.e., not including “special” classes such as USL and possibly embedded distributors and DG). In consultations, stakeholders suggested that other factors such as metering technology and phases of service could justify additional classification distinctions based on cost causality principles.

If proxies are to be used, what are the appropriate thresholds?

5 Rate Design Issues

5.1 The Role of Cost Allocation

It is generally accepted that the primary reference point for designing distribution rates is a distributor's cost allocation study. A cost allocation study provides the best available indicator of the costs that are caused by each class of customers. Hence, when the revenue recovered from each customer class is approximately equal to the allocated costs of the class (i.e., revenue to cost ratio equals 1.0), the revenue responsibility of each class is considered to be fair.

The cost allocation study also provides the best available indicator of how to recover a distributor's revenue requirement to ensure that the relative cost responsibility among customers within a class is fair. Within-class equity is achieved by adopting a rate design that sets:

- the monthly customer charge equal to 1/12th of the annual customer related costs for each class divided by the number of customers in each class;
- the annual demand/capacity charge equal to the capacity-related costs of each class divided by the peak demand (or total capacity) of customers in the class; and
- the energy charge equal to the energy related costs of each class divided by the total power usage of customers in the class (where variable rates are charged on an energy basis).

Although strict application of allocated costs will result in a fair recovery of a distributor's revenue requirement, deviations from the strict application of allocated costs are not necessarily unfair. Cost allocation studies involve a number of approximations that allocate costs on the basis of judgment rather than clear cut cost responsibility. As a result, the functional classification[10] of some costs and hence the most appropriate basis for recovering them is flexible. As a result, acceptable ranges for the recovery of costs using each billing determinant can be established more readily than precise proportions.

Furthermore, the resulting rate design is not necessarily efficient, easily understood by customers, or effective in achieving the various policy objectives that have been established by the Board. This section addresses various other issues that need to be considered in developing the Board's rate design.

5.2 Fixed/Variable Split

5.2.1 Price Signals in the Rate-setting Context

It is important to set the discussions of fixed and variable charges within the context of regulating public utility rates. Currently, Ontario electricity distributors are subject to a multi-year incentive rate making process. The Board holds a cost of service proceeding to set a distributor's revenue requirement. Those costs are flowed through the cost allocation methodology and applied to the rate design. For the following three to five years, those rates are subject to mechanistic adjustments that, in turn, adjust the revenue requirement by calculated amounts.

The long term variable costs arise out of the five to ten year (and longer) planning horizon. Given that rates are set over a much shorter period, it is not clear that there is a connection between long run variable costs and variable rates. In other words, Board staff are unsure of the economic link between customer behaviour and distribution investment.

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[10] The major steps in a cost allocation review are: i) to take the total revenue requirement, ii) functionalize all spending according to the major functions, iii) categorize all of the functions as demand related, customer related or energy related, and then iv) allocate each of those to a rate classification.

Because of the long history of cost-of-service electricity rates in Ontario, prices are closely linked to embedded costs. However, to the extent that the variable rates deviate from cost causality they represent prices rather than costs. The purpose of a variable rate would be to influence customer behaviour in a way that will impact distributor planning and change long-run incremental costs. It is not entirely clear how much customers respond to the variable rate price signal in order to control their bills. Conventional wisdom has held that small volume customers are not sensitive to price. Studies are just emerging regarding how customers (particularly small volume customers) respond to variable electricity prices. While they are subject to interpretation on persistence, the consistent result is that customers, even small volume customers, do respond to time dependent prices for both demand shifting and overall conservation[11]. Some evidence from other jurisdictions on this point is included in the Jurisdictional Survey/ Environmental Scan that accompanies this Discussion Paper[12].

In consultation, some stakeholders held the view that customers value stable electricity bills citing the popularity of equal billing programs as an example. However, Board staff's experience suggests that customers also prefer low bills; bills that they feel they can control or influence through use and that reflect their perceived value of the service.

Board staff welcomes comments on:

- **whether there is a necessary connection between long run variable costs and variable rates;**
- **whether variable charges are an effective means of controlling long –run variable costs in the rate-setting context; and**
- **whether customers respond to variable rates.**

[11] http://www.oeb.gov.on.ca/html/en/industryrelations/ongoingprojects_regulatedpriceplan_smartpricepilot.htm

[12] In particular see the California Statewide Pricing Pilot and the Ontario Pricing Pilot.

5.2.2 Current Cost Allocation

In the Cost Allocation Review (EB-2005-0317) dealing with current rate classifications and design, Board staff identified three potential levels for the fixed monthly customer service charge:

a) avoided costs (the cost of metering and billing);

b) directly related customer costs (a + administration and general overhead costs allocated to classes); and

c) the minimum system approach adjusted for Peak Load Carrying Capability (a + b + the cost of wires but no demand capacity).

In the Report of the Board: Application of Cost Allocation for Electricity Distributors (EB-2007-0667)[13], the Board decided that avoided costs, as defined above, would be the floor and the minimum system would be the ceiling level for monthly service charges. Distributors were instructed not to make changes to the monthly service charge that would result in a charge greater than the ceiling. At that time, consideration was not given to re-establishing an incremental cost as the basis for the variable rate.

The recommended range spans the range of definitions of the customer-related costs that are appropriately recovered through a monthly customer charge. Under the current rate design the balance of the revenue responsibility is recovered through the variable charge. At the present time the variable charge for the smaller volume customers is a kWh charge. For larger volume classes, the billing determinant for the variable charge is demand (kW or kVA).

As discussed above, basing the fixed/variable split on the results of a distributor's cost allocation study will result in a rate design that treats customers in a rate class fairly in that the relative bills of different customers reflect the relative costs that they cause.

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[13] http://www.oeb.gov.on.ca/documents/cases/EB-2007-0667/Report_Cost_Allocation_Review_20071128.pdf

5.2.3 The Rationale for a High Fixed Charge

Some stakeholders are of the view that it would be appropriate to adopt a rate design that establishes a high fixed charge. In the most extreme case, the entire revenue responsibility of a rate class could be recovered through a fixed charge. Two variants of a fixed charge have been identified:

- a fixed monthly customer charge that recovers all costs; and
- a fixed charge that is based on a known "variable" such as the service connection capacity or the prior year demand (peak hourly consumption, or a variant such as the average monthly peak demand).

The rationale for recovering distribution costs primarily through the monthly customer charge is that the costs of distributors are almost entirely fixed in the short run; hence a high fixed charge is consistent with short run efficiency. Furthermore, a high fixed charge would reduce risk for distributors and remove the risk of reduced revenue and net income in the event that throughput is below forecast due to more-than-forecast CDM results or any other factor. As discussed above, it is not clear that the fact that long-run costs are variable is counter to distribution rates being highly or fully fixed.

Another option for relying on a fixed charge to recover distribution costs would be to use a fixed charge that is based on the relative use that a customer makes of the distribution system. This approach could be designed so as to provide a price signal for customers to limit their peak demand (or capacity), while at the same time reducing uncertainty for customers with respect to their monthly distribution bill and for distributors with respect to their total revenue. This approach differs from a conventional demand charge (see below) because the monthly charge is based on a pre-established measure of the customers demand or capacity, such as the prior year peak demand or the service connection (e.g., service amperage for small volume customers).

5.2.4 The Rationale for a High Variable Charge

Other stakeholders were of the view that the rate design should have a low fixed component and a high variable charge. The rationale for recovering distribution costs primarily through a variable charge is that distribution costs are variable in the long run and an appropriate long run price signal will result in more efficient expansion of the distribution system. Costs other than customer-related costs increase in the medium and long run to accommodate the expected peak demand (or capacity) on each part of the distribution system; hence, customer consumption decisions may drive the long run investment decisions of distributors. It follows that it would be appropriate to price distribution services in a manner that provides a price signal for customers to limit their peak demand (or capacity).

Several billing determinants could be used as the basis for the variable charge:

- energy (kWh);
- demand (kW); or
- capacity (kW; kV or kVA).

A variable charge based on kWh (e.g., current energy charge) provides a signal to consume less energy. However, reducing total energy consumption does not impact directly on future distribution costs, except to the extent that an overall reduction in electricity results in reduced peak demand. One concern with relying on a kWh charge for recovering distribution costs is that certain measures that will reduce the necessary capacity of the distribution system may increase total demand. For example, shifting use from peak hours to off peak hours may results in increased total energy consumption, as in the case of technologies that store heat produced in off-peak hours for use during peak hours. In such cases, a kWh charge will penalize customers for adopting measures that use the distribution system more efficiently unless the energy charge is time-differentiated (e.g., TOU rates).

A variable charge based on capacity (i.e., service amperage) will provide a clear price signal to reduce capacity. This approach could be expected to be effective where capacity can be adjusted cost-effectively or can be contracted (contract demand with penalties for overruns), so that consumers will have an incentive to manage their required capacity that they can respond to. However, stakeholders had a number of concerns with this approach.

For most small volume customers, capacity is an embedded feature of a residential or commercial unit. As a result, there may be limited opportunity for customers to respond to this price signal. Furthermore, customers that reduce their demand will not be rewarded through lower bills unless they retrofit their service connection to a lower capacity.

For new units, capacity is likely to be established by the builder/owner and building code and/or ESA standards so that it is adequate for most potential occupants; hence, it may not provide an incentive for the end user to use the distribution system more efficiently due to the split incentive (owner wants adequate capacity for any potential tenant; tenant wants only the capacity required).

Load limiters could be installed so that small volume consumers could establish the equivalent of a contract demand, but distributors have suggested that the cost of this approach to responding to the individual consumer's capacity requirement would be prohibitive.

There is also concern that identifying the capacity of service connections would require periodic inspections, which could be costly and difficult.

A variable charge based on demand will provide a price signal to limit peak usage during the period used as the basis for the demand charge. Annual coincident peak demand (1-CP) is the ideal representative billing determinant in theory, but has practical limitations. It is a weak price signal since consumers do not know when the coincident peak will occur and therefore, they can do little to avoid it. In addition, use and demand not coincident with the peak has no associated cost so there is no conservation signal.

5.3 Revenue Stability

As noted above, one of the attractions to some stakeholders of relying on a high fixed charge to recover distribution costs is the revenue stability that results for distributors. Recognizing the concern with a high fixed charge, it was observed that if revenue stability is an objective of distribution rate design there are other mechanisms that could be used to stabilize revenues while avoiding the CDM disincentive for distributors that is inherent in any variable charge.

The Board has authorized the use of a Lost Revenue Adjustment Mechanism ("LRAM") to address this concern regarding CDM activities. However, some parties are concerned that an LRAM is not a practical means of addressing the issue for the electricity distribution sector in Ontario. An alternative approach that has been suggested is a Revenue Stabilization Adjustment Mechanism ("RSAM") which would rely on a variance account to capture, for subsequent disposition to customers, volumetric-related variances in revenue due to other factors such as weather and economic activity.

The RSAM is like a revenue cap or revenue decoupling mechanism. The primary benefit is that it offers revenue neutrality because it removes the risk associated with all revenue variances. A disadvantage is that the change in risk profile may need to be reflected in capital structure or allowed ROE. It would also put the onus on distributors to produce the load forecasts required for implementation of the mechanism. These issues have previously been discussed in conjunction with EB-2007-0673: 3rd Generation Incentive Regulation for Ontario's Electricity Distributors.[14] Currently, Ontario distributors are under a price-cap incentive rate-making regime.

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14 http://www.oeb.gov.on.ca/html/en/industryrelations/ongoingprojects_3rd_generation_incentive_regulation.htm

It is important to note that, to the extent that RSAM adjustments are added to variable rates and decrease the ratio of fixed to variable charges, they tend to increase deviation from cost causality while strengthening the conservation price signal.

One approach that could be used in the context of a variable demand charge would end up being very similar to a fixed charge based on the customer's demand. That is, there would be an interim charge being used during the year and an end-of-year reconciliation mechanism to adjust the actual effective rate to correctly reflect the total aggregate demand in the year that is used for billing purposes. In consultation, distributors stressed that any rate stability mechanism would have to be simply administered to be effective.

Board staff welcomes comment on revenue stability mechanisms.

5.4 Billing Determinant Options

5.4.1 A Price Signal for Short Run Distribution Consumption Efficiency

If the objective of the rate design is to provide a price signal to use the distribution system in a manner that is consistent with short run distribution system efficiency, recognizing that most distribution costs are fixed in the short run, it would be consistent to adopt a rate design that relies heavily on a fixed charge.

5.4.2 A Price Signal for Long Run Distribution Utilization Efficiency

If the objective of the rate design is to provide a price signal to use the distribution system in a manner that is consistent with long run distribution system efficiency, recognizing that most distribution costs are variable in the long run, it may be consistent to adopt a rate design that relies heavily on a variable charge. Furthermore, since most distribution costs are driven by peak demand (or capacity) the appropriate billing determinant from this perspective would be demand (or capacity).

With smart metering, billing could be based on the peak hourly demand in the year or any shorter period within the year (i.e., seasonally, monthly or daily). The challenge in adopting this approach is that the distribution system does not experience a single coincident peak. Rather the timing of the coincident peak may differ for different elements of a distributor's system. For example, individual feeders may peak at different times, and for a distributor with multiple connections to the transmission system, the peaks for each connection are unlikely to coincide.

Hence, for practicality and simplicity it would be more appropriate to use non-coincident peak as the billing determinant. This approach would provide a very simple and understandable signal to consumers to manage their use so as to limit their peak usage whenever it occurs.

In order to provide a clear and simple price signal for consumers to limit their demand that is coincident with periods when portions of the distribution system are congested, it may be appropriate to limit the application of the peak demand as the billing determinant to peak usage periods.

A further rationale for adopting this simplified approach is that peak instantaneous demand and not peak hourly demand is the actual system capacity determinant. The system peak from a design perspective will not necessarily occur in the hour with annual peak demand.

5.4.3 A Price Signal for Energy Efficiency

If the objective of the rate design is to provide a price signal to consume power in a manner that is consistent with generation efficiency, it would be consistent to adopt a rate design that corresponds to the pricing of the commodity (e.g., time of use ("TOU") pricing).

Australia has TOU network tariffs which are based on the differential costs of supplying network capacity at different times of the day (reflective of long run marginal costs)[15].

The Board’s current design for TOU commodity prices, the Regulated Price Plan (the “RPP”) is based on a three-part structure (off-peak, mid-peak, peak) with an approximate 1:2:3 price ratio. In addition, based on RPP consumers’ load shapes, the Board’s TOU commodity prices have a single peak structure in the summer and a double-peak structure in the winter.

Weekday peak hours are from 11 a.m. to 5 p.m. in the summer and 7 a.m. to 11 a.m. and 5 p.m. to 8 p.m. in the winter. Weekday mid-peak price hours are 7 a.m. to 11 a.m. and 5 p.m. to 10 p.m. in the summer and 11 a.m. to 5 p.m. and 8 p.m. to 10 p.m. in the winter. Weekday off-peak prices apply from 10 p.m. to 7 a.m. and 24 hours a day on weekends and holidays, year round.

Stakeholders agreed that a TOU distribution rate should keep the same time periods as the RPP commodity structure to make it easier for customers to understand and follow.

[15] Survey of Other Jusisdictions.

6 Rate Design for the Single Phase Secondary Class

If the approach to customer classification set out in section 4 is adopted, it can be expected for the typical distributor that the single phase secondary class will include:

- almost all customers that are currently in the residential class,
- a significant portion of customers that are currently in the general service under 50kW, and
- a few of the customers that are currently in the general service over 50 kW.[16]

This combining of customers from the existing rate classes is a logical consequence of the introduction of smart meters and the replacement of energy with demand/capacity as the billing determinant for the variable portion of the bill. While the energy charges required to recover costs allocated to the residential and general service classes often differ significantly, the demand or capacity charges that are appropriate for recovering allocated costs for these classes will not differ significantly. The allocated costs per kW will be the same for all customers in the new Single Phase Secondary Class since they all use the same distribution facilities.

In the absence of smart meters, the primary rationale for the traditional separation of residential and small general service customers into separate rate classes is the difference in average load factor for these two classes. With the widespread implementation of smart meters, this average load factor difference can be addressed through the rate structure (i.e., using demand/capacity as the billing determinant for the variable charge) rather than through the definition of customer classes. In other words, since the introduction of a demand/capacity charge will reduce or eliminate the cross-subsidy of low load factor customers by high load factor customers within a class, there

[16] See Table 1 at page 18 for the customer counts for Milton Hydro.

is no need to maintain separate classes where the difference in allocated costs between groups of customers is caused primarily by the difference in average load factor.

6.1 Single Phase Secondary Class Rate Design Options

Four billing determinant options are addressed during the stakeholder consultations for small volume customers including those that would be in the Single Phase Secondary Class:

- 100% fixed monthly charge;
- a variable charge that recovers capacity-related costs as determined by each distributor's cost allocation study by using the capacity of the customers' connection as the billing determinant;
- a variable charge that recovers capacity-related costs as determined by each distributor's cost allocation study with the customers' peak hourly demand as the billing determinant; or
- a variable charge that recovers capacity-related costs as determined by each distributor's cost allocation study with a time of use energy charge that is differentiated for hours identified as off-peak, on-peak and possibly super-peak.

6.2 Design of a 100% Fixed Monthly Charge

Some stakeholders are of the view that because distribution costs are essentially fixed in the short run (i.e., within the period for which rates are fixed), that the revenue requirement of each distributor should be recovered through a fixed charge. The simplest fixed charge rate design for the Single Phase Secondary Class would be a monthly customer charge equal to 1/12th of the annual total costs allocated to the Single Phase Secondary Class divided by the number of customers in the Single Phase Secondary Class.

A 100% fixed charge would result in certainty with respect to the monthly distribution charge for customers and would eliminate volumetric-related risk for the distributors associated with weather and other factors that affect the annual consumption of smaller volume customers.

A concern with this rate design for smaller volume customers is that the cost responsibility differences among customers would not reflect the costs they cause as determined by the distributors cost allocation studies (i.e., capacity-related costs). To address this concern in a 100% fixed charge rate design, it may be appropriate to include in the design a number of subclasses that would group customers according to the capacity requirement (see section 6.3 below).

A further concern is that unless subclasses are part of the design there would be no incentive for customers to use the distribution system in a manner that is consistent with the efficient expansion of the distribution system in the medium to long term. In the view of some stakeholders, this concern is not significant because the distribution portion of the typical customer's total bill is not large enough to influence the customer's use of the distribution system in any case.

6.3 Design of a Variable Charge Based on Capacity

If the rate design for the Single Phase Secondary Class is structured to recover the capacity related costs as indicated by a distributor's cost allocation study by means of a capacity charge, then the rate structure would consist of:

- a monthly customer charge equal to 1/12th of the annual customer related costs allocated to the Single Phase Secondary Class divided by the number of customers in the Single Phase Secondary Class; and
- an annual capacity charge equal to the capacity-related costs allocated to the Single Phase Secondary Class divided by the peak demand (or total capacity) of customers in the Single Phase Secondary Class.

The pros and cons of implementing capacity charges for small volume customers were discussed at some length in the stakeholder sessions. In the end there was general agreement that it would not be practical to introduce a capacity charge for small volume customers (i.e., the Single Phase Secondary Class).

Conceptually, the rationale for charging all customers including the single phase secondary class on the basis of their required capacity is compelling. The most direct driver of distribution system costs is the aggregate capacity of its customers. Even if peak demand is typically below the capacity that is appropriate to use for design purposes to ensure that the system achieves acceptable reliability standards, the most direct cost driver is required capacity, not actual demand in any particular year. The efficiency of the distribution system would therefore be facilitated by introducing a mechanism that provides an incentive for customers to identify accurately and commit to a maximum capacity. Distributors could then reinforce and expand their systems as necessary to accommodate the “contract” demand of their customers, taking into account diversity benefits in determining the required system capacity to meet the requirements of their customers.

The primary difficulty with this view, however, is that if it is used for billing purposes and for system design, the capacity values being used for each customer should represent the actual maximum demand that a customer will place on the distribution system.

There can be little doubt that at the present time the capacity of the service connections (amperage) of small volume customers is a crude proxy for the capacity those customers actually require and will use. Building codes and electrical safety standards require builders to install service connections that are sufficient to accommodate customers safely, with the result that the capacity will tend to be excessive for most customers given the wide range of consumption patterns among electricity customers. Measurement of actual loads on parts of the distribution system and sampling techniques provide much better data for efficiently designing a distribution system than simply aggregating the service connection capacities of customers. Consequently, for a capacity charge to facilitate the efficient design and development of the distribution system, it will be necessary to determine the actual capacity requirements of customers rather than the rated capacity of installed service connections.

Consequently, the customer must be able to select the capacity value that meets his/her individual power requirements. Conceptually, each customer should establish a "contract demand" that is enforceable either through substantial penalties for exceeding the allowed demand or through a physical constraint (load limiter) on the maximum power the customer can draw.

The most practical approach to introducing a capacity charge for small volume customers would be to use each customer's service connection amperage as the billing determinant for the recovery of costs not recovered in the monthly customer charge. At the present time, however, the reality that the capacity of the service connections of small volume customers is a poor proxy for their actual capacity requirement raises three concerns.

- If the amount charged to customers is not determined by their actual capacity requirement based on their actual electricity usage, the resulting charges will not be fair in terms of the charges corresponding to causal costs.
- If distributors increase the capacity of their systems on the basis of the aggregate rated capacity of customer connections rather than actual aggregate demand, the distribution systems will be overbuilt and the rate design will not result in an efficiently sized distribution system. This is because the actual aggregate demand would deviate from the aggregate rated capacity due to both underutilization of each customer's rated capacity and diversity benefits
- Unless each customer is able to determine the capacity of his/her service connection and increase it or decrease it as their requirements change (e.g., establish a contract demand on an annual basis, subject to the capacity of the distribution system being adequate), the capacity charge will not serve as an effective price signal for efficient use of the distribution system by consumers. As a result, it will not result in increased distribution system efficiency in terms of its utilization or capacity.

Stakeholders have observed that it would be prohibitively expensive to address these concerns. For example, it was suggested that customers could control their individual capacity by installing load limiters for every customer. However, distributors were concerned that the cost of this solution would be prohibitive. An approach that can be implemented without an investment beyond that of installing smart meters would be more cost effective.

Concern about the practicality of using capacity as the billing determinant resulted in a general consensus that, in principle, demand would be preferred as the billing determinant.

6.4 Design of a Variable Charge Based on Demand

If the rate design for the Single Phase Secondary Class is structured to recover capacity-related costs as indicated by a distributor's cost allocation study through a demand charge, then the rate structure would consist of:

- A monthly customer charge equal to 1/12th of the annual customer related costs allocated to the Single Phase Secondary Class divided by the number of customers in the Single Phase Secondary Class; and
- An annual demand/capacity charge equal to the capacity-related costs allocated to the Single Phase Secondary Class divided by the peak demand of customers in the Single Phase Secondary Class.

In principle, a demand charge should be based on each customer's annual coincident peak (1-CP) demand since required capacity is based on the total demand at the time of the coincident peak. This approach to designing a demand charge has several practical problems, especially if it were applied to small volume customers.

- As noted in section 5.4.2, distribution systems do not experience a single coincident peak on all parts of the system. Hence, for practicality and simplicity it would be more appropriate to utilize non-coincident peak as the billing determinant, which provides an understandable signal to consumers to manage their use so as to limit their peak usage whenever it occurs.

- Since the timing of the coincident peak is not known in advance, it would be difficult for customers to limit their use of electricity during the one-hour peak or peaks across the distribution system.
- The share of distribution costs borne by different customers would probably be determined primarily by fortuitous events, such as whether a customer happened to be away on holiday at the time of the system peak.

From the perspective of practicality, it would be more appropriate to base a demand charge on each customer's non-coincident peak. This approach could be viewed as a proxy for each customer's required capacity (at least in relative terms). Given the diversity of life and business styles among the smaller volume customers that would be evident in the single phase secondary class, it may be appropriate to limit the non-coincident peak used for billing purposes to the peak that occurs during time periods (months of the year, days of the week and hours of the day) during which distribution system peaks are likely to occur. In this way, for example, a customer that uses power primarily during off-peak hours would pay for distribution services on the basis of the peak demand during the periods where overall demand tends to be high.

Stakeholders also suggested that basing a small volume customer's distribution charge on a single hour's peak demand might prove to be a weak signal for customers to use the distribution system efficiently. A customer that has a high usage hour early in the high demand season, which may not coincide with the distribution system peak, may not be concerned with limiting demand subsequently. It may be preferable to implement a demand charge methodology that provides a price signal for customers to limit their demand during all of the hours of the year that are defined as peak hours – that is months of the year, days of the week and hours of the day during which peak demand on the distribution system of the particular distributor may occur. For example, the demand charge could be based on:

- the customer's monthly peak demand (this could be limited to peak months, or applied to all months in order to ensure that the charge is as easily understood by customers as possible);

- the customer's daily peak demand (this method is currently used by some sub-meterers); or
- the customer's demand during pre-defined peak hours in the year (this approach may require availability of an equal billing plan to smooth out the demand charges since they would vary quite dramatically from bill to bill assuming peak periods are limited to only a few months of the year).

In the event that some single phase secondary customers do not have smart meters installed at the time the new rate design is introduced, it may be necessary to establish an alternate billing method that can be used on an interim basis for these customers.[17] If that is required, it would be necessary to ensure that the rate design for customers without smart meters treats them fairly compared to customers with smart meters. One possible approach would be to use available smart meter data to establish the relationship between annual consumption by single phase secondary customers and their average load factors. The volume to average load factor relationship could then be used to estimate the demand of customers without smart meters based on their energy consumption. This estimate of demand could then be used for billing purposes until smart meters are installed for these customers.

6.5 Design of a Time of Use Distribution Rate with a Consumption Determinant

Some stakeholders suggested that the most effective way to modify the behaviour of small volume customers, and thereby increase the efficient use of distribution systems would be to implement a time of use (TOU) energy charge as a proxy for a demand charge. A TOU energy charge can be viewed as a proxy for a demand charge for customers with smart meters because a demand charge in the smart meter context is

[17] There will be some single phase secondary class customers that do not have smart meters if the rollout of smart meters is not 100% completed by the date that the new rate design is implemented by a distributor. This situation could also arise for customer with demand above 50 kW, as discussed in section 2.2.

essentially a energy charge for one or more one hour periods during the year in any case. For example:

- a 1-CP demand charge is, in effect, a demand charge that recovers all capacity-related costs on the basis of a one-hour TOU “super-peak” in the year with a TOU charge of zero in all other hours;[18] and
- a 12-CP demand charge is, in effect, a demand charge that recovers all costs on the basis of the twelve monthly one-hour TOU peak hours in the year with a TOU charge of zero in all other hours.

Similarly, a demand charge that is designed to charge customers based on the hourly demand in a broader base of hours that are pre-defined as the hours during which the peak in distribution demand may occur looks very much like a TOU charge. In fact, it becomes indistinguishable from a TOU charge if there is a reduced charge, rather than no charge in the off-peak hours.

The potential advantages of a TOU distribution charge is that it may be more easily understood by the average consumer than a demand charge. In particular, they will know in advance which hours are on-peak and which hours are off-peak. In addition, if the TOU periods correspond to the TOU commodity periods, the number of different rate periods during which there are different all-in rates will be reduced. Fewer rates periods are likely to be easier to communicate to customers.

Furthermore, assuming there is a reasonable correspondence between the periods during which commodity demand peaks and the periods when distribution demand peaks, the commodity and TOU peak pricing signals will reinforce each other. This should result in a more efficient customer response to the pricing signals than would otherwise be the case in practice.

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[18] As noted earlier, smart meters in Ontario will not measure the true instantaneous peak demand. They simply measure the energy consumption in one-hour periods.

It must be noted, however, that while the commodity and distribution peaks are likely to be aligned reasonably closely for summer peaking distributors in Southern Ontario, there will be a misalignment between the commodity peaks and distribution peaks for winter peaking distributors in Northern Ontario. It may therefore be appropriate to define consistent peak periods of the day and week throughout the year; however, the commodity super-peaks may differ for Northern and Southern distributors and the relative pricing of the winter and summer peaks for Northern distributors may not match up with the commodity peaks.

Arizona Public Service, the largest electricity distribution company in Arizona has developed several TOU rate options including stand alone TOU delivery rates[19].

6.6 Single Phase Secondary Customer Rate Changes

Customers in the Single Phase Secondary Class may be expected to experience significant changes in their distribution bills as a result of the move from kWh based billing to billing on the basis of demand or capacity. The differences arise for two reasons.

1. At the present time customers within the small volume classes (residential and GS <50) are billed on the basis of their energy consumption rather than demand. In effect, each customer is charged for distribution service as if their load factor was equal to the average load factor for their class. Relative to their actual causal costs as determined by each distributor's cost allocation study, customers with below-average load factors are subsidized by above-average load factor customers. This cross-subsidy will be reduced or eliminated by the introduction of some form of demand charge.
2. The new Single Phase Secondary Class will comprise customers that are currently in the residential and general service classes. To the extent that the revenue-to-cost ratios for the existing classes differ, there will be a shift in cost

[19] See Survey of Other Jurisdictions.

responsibility since each former class will move to the revenue-to-cost ratio of the new class. Hence, for example, if the revenue-to-cost ratios for a distributor's existing classes were 0.95 for the residential class and 1.05 for the general service classes, while the revenue-to-cost ratio for the new Single Phase Secondary Class is 1.0, it follows that the relative responsibility for the distributor's costs that are recovered from current residential customers will increase while the cost responsibility of the current GS customers will decrease.

The resulting shift in intra-class and inter-class cost responsibility raises important policy questions.

In principle, should distribution customers pay rates that are more reflective of the costs they cause due to load factor difference based on each distributor's cost allocation study?

Should the revenue-to-cost ratio for the new Single Phase Secondary Class be constrained in any way by the prior revenue-to-cost ratios of the existing Residential and GS classes?

The magnitude of rate changes that can be expected as a result of implementing each of the approaches outlined above is illustrated using Milton Hydro's actual smart meter data for its customers. This section is included for illustrative purposes only as to the magnitude of the potential change from current rates. The models are using a limited amount of data from one distributor that has been collected under current cost allocation guidelines. Although efforts have been made to align the data with the proposed structures, these efforts have involved judgement and no firm conclusions can be drawn. In the event that any rate design changes are implemented, the Board would apply appropriate migration methods to protect the interests of consumers.

Tables 4, 5 and 6 show the estimated rate changes on customers that would be included in the Single Phase and Three Phase Secondary Classes based on the assumption that customers are billed on the basis of their monthly peak demand. In order to determine approximate results that would be indicative of the rate impacts that could be expected for Ontario distributors, the existing three smallest volume rate classes (Residential, GS<50kW and GS 50kW-999kW) were combined and treated as a single Secondary Class. Differences between the Single Phase and Three Phase Secondary Classes are expected to be minor compared to the impact of merging the classes. Furthermore, results for Milton Hydro will be indicative at best for bill impacts of the change across all distributors, given the many differences among distributors.

Table 4: Rate Impacts for Existing Residential Customer

Monthly Energy (kWh)	Load Factor	$ Change	% Change in Distribution Charges	% Change in Total Bill
100	10%	**$2.25**	**12.37%**	**8.50%**
250	15%	**$2.43**	**11.78%**	**5.88%**
500	20%	**$1.63**	**6.60%**	**2.47%**
750	20%	**$2.49**	**8.63%**	**2.74%**
1,000	25%	**($0.62)**	**(1.89%)**	**(0.54%)**
1,500	30%	**($4.86)**	**(11.81%)**	**(2.94%)**
2,000	35%	**($10.23)**	**(20.73%)**	**(4.76%)**

Table 4 shows indicative rate changes for customers currently in the Residential Class. In order to isolate the impact of the rate design changes, the rate comparison is based on the rate that would result in revenue-to-cost ratios of 1.0 in each scenario. The illustrative customer usage levels and load factors shown in Table 4 cover a broad range from low usage/low load factor to high usage/high load factor within the Residential Class. Customers with the lowest usage/load factor levels would experience moderately large increases while those with the highest usage/load factor levels would experience significant bill reductions. The primary reason for these differences is the elimination of the intra-class cross-subsidy from high load factor customers to low load factor customers.

Table 5: Rate Impacts for Existing General Service < 50 kW

Monthly Energy (kWh)	Load Factor	$ Change	% Change in Distribution Charges	% Change in Total Bill
1,000	25%	**$1.86**	**6.09%**	**1.66%**
2,000	30%	**($1.94)**	**(4.33%)**	**(0.93%)**
5,000	35%	**($14.85)**	**(16.89%)**	**(2.99%)**
10,000	40%	**($44.23)**	**(27.68%)**	**(4.53%)**
15,000	45%	**($83.04)**	**(35.85%)**	**(5.71%)**

Table 5 shows indicative rate changes for customers currently in the GS<50kW Class. Again, the rate comparison is based on the rate that would result in revenue-to-cost ratios of 1.0 in each scenario in order to isolate the impact of the rate design changes. The illustrative customer usage levels and load factors shown in the table cover a broad range from low usage/low load factor to high usage/high load factor within the GS<50kW class. As was the case in the Residential Class, customers with the lowest usage/load factor levels experience increases while those with the highest usage/load factor levels experience large reductions. Again, the primary reason for these differences is the elimination of the intra-class cross-subsidy from high load factor customers to low load factor customers. Because the illustrative volumes and load factors for the GS <50 class are larger than those for the Residential Class (Table 4), the increases are smaller at the low volume/load factor end and the bill reductions are larger for the higher volume/load factor customers.

Table 6: Rate Impacts for Existing General Service 50-999 kW

Monthly Energy (kWh)	Demand (kW)	$ Change	% Change in Distribution Charges	% Change in Total Bill
15,000	60	**($44.49)**	**(19.16%)**	**(2.88%)**
40,000	100	**($35.04)**	**(10.40%)**	**(0.97%)**
100,000	500	**$59.46**	**4.30%**	**0.56%**
400,000	1,000	**$177.58**	**6.60%**	**0.50%**

Table 6 shows indicative rate changes for customers currently in the GS 50kW-999kW Class, again based on rates that would result in a revenue-to-cost ratio of 1.0. The illustrative customer usage levels and load factors shown in the table cover a broad range from low usage/low load factor to high usage/high load factor within this Class. The impacts are the reverse of the previous cases because rates for GS> 50 kW class are already based on demand rather than energy usage; hence, there is no pre-existing intra-class cross-subsidy from high load factor customers to low load factor customers. Instead, the effect of including these customers in the Primary Class is to change the fixed-variable split – i.e., the fixed monthly charge is reduced and the variable kW charge is increased. As a result, customers with smaller volumes in this class would experience decreased bills while customers with larger volume would experience increased bills.

It should be noted, however, that this analysis does not separate the Single Phase and Three Phase Secondary Classes due to the limitations of available data. It can be expected that the effect of establishing a separate Three Phase Secondary Class, would include most of the existing GS 50-999 kW customers (see Table 1 at page 25), would be to increase the kW charge which would mitigate the size of the impacts shown in Table 6.

6.7 Residential Sub-Class

At the present time, there is a need to maintain a distinct residential class to be consistent with legislative requirements. Hence, a mechanism will have to be included that clearly identify customers that qualify as residential for purpose of Rural Rate Assistance and for commodity rates that are available specifically to customers under a certain demand load.

Is it sufficient to maintain a residential sub-class as a means of identifying residential customers for purpose of billing treatment that is available only to residential customers under current legislation?

7 Rate Design for the Three Phase Secondary Class

If the approach to customer classification set out in section 4 is adopted, it can be expected for the typical distributor the Three Phase Secondary Class will include:

- few, if any, customers that are currently in the residential class,
- a significant portion of customers that are currently in the general service under 50kW, and
- most customers that are currently in the general service over 50 kW.

The rationale for separating single phase and three phase secondary customers into different classes is that the customer-related costs as determined in each distributor's cost allocation study may be sufficiently different to justify different monthly customer charges. This difference, however, will only be relevant for distributors that do not recover the additional costs associated with three phase service in the connection charge levied in accordance with the Distribution System Code.

In cases where cost differences are recovered in rates, it can be expected that the capacity-related costs per kW for the two classes will differ due to the higher costs of transformation and connection for three phase service. As a result, the Single Phase Secondary and Three Phase Secondary classes are likely to have different variable charges if the same rate design approach is adopted for both classes.

The differences between the Single Phase Secondary and Three Phase Secondary Classes may justify adopting a different approach to rate design, however. In particular, since the Three Phase Secondary Class can be expected to be more responsive to price signals, in practice, it may be appropriate to implement a capacity or demand charge even if the TOU approach is adopted for the Single Phase Secondary Class. Furthermore, even if a demand charge is adopted for the Single Phase Secondary Class, it may be appropriate to adopt a demand charge for the Three Phase Secondary

Class that more narrowly defines the peak hours during which the demand charge is applicable. There are several factors that might justify a rate for the Three Phase Secondary Class that is more directly aligned to the capacity cost drivers;

- The Three Phase Secondary Class will include most customers that are currently in the GS>50 kW class and are used to paying a demand charge.
- The Three Phase Secondary Class customers that are currently in the GS <50 kW will tend to be those with higher electricity requirements and thus higher monthly bills. The dollar value of managing their electricity use will therefore be relatively large which should make them more responsive to price signals.
- The total number of customers in this class will be far lower than the number of customers in the Single Phase Secondary Class; so that customer education should be an easier and less costly process for distributors.[20] For example, there should be fewer customer service calls for explanations of the new charges.

Although each of the options outlined for the Single Phase Secondary Class could also be adopted for the Three Phase Secondary Class, the differences between these classes make the option of implementing a variable charge based on demand much more attractive for the Three Phase Secondary Class.

If the rate design for the Three Phase Secondary Class is structured to recover capacity-related costs as indicated by a distributor's cost allocation study through a demand charge, then the rate structure would consist of:

- A monthly customer charge equal to 1/12th of the annual customer related costs allocated to the Three Secondary Class divided by the number of customers in the Three Phase Secondary Class; and

[20] As Table 1 at page 23 shows, for Milton Hydro the number of Three Phase Secondary customers would be less than 1/3 of the number of Single Phase Secondary Customers.

- An annual demand charge equal to the capacity-related costs allocated to the Three Phase Secondary Class divided by the peak demand of customers in the Three Phase Secondary Class.

As noted in section 2.2, some distributors may have a smart-metering gap whereby customers with demand over 50 kW but less than 200 kW will continue to have demand readings that are not time-correlated. The gap may not be addressed before a new rate design is implemented. Consequently, some customers in the Three Phase Secondary Class may require a variant of the new rate design if the demand charge that is used depends on the peak period demand, which could differ from the monthly peak demand. The simplest and perhaps the fairest approach to adopt for billing these customers may be to treat the monthly peak demand as the peak period demand unless the customer can demonstrate that its operations result in power requirements that peak in off-peak periods.

Another consideration for this class is that it is conceivable that the Three Phase Secondary could include both three phase customers with smart meters (under 50 kW) and customers with interval meters that record the peak demand for periods less than one hour. It would be inequitable to charge customers the same rate for peak demands that are measured over different intervals. The one hour peak demand, which is the average demand over the 60 minutes) will be lower than the ½ hour or 15 minute peak demands, which are averaged over a shorter peak period. Most distributors address this currently by converting demand data into hourly demand data over either a clock hour or four continuous periods. It may be desirable for the Board to standardize this practice for consistency between distribution areas.

7.1 Three Phase Secondary Customer Rate Changes

It can be expected that the rate changes for customers that are reclassified as Three Phase Secondary Class customers will be similar to the rate impacts for customers classified as Single Phase Secondary customers. For distributors where it is appropriate to maintain separate Single Phase and Three Phase Secondary Classes, the cost difference will be small since they relate only to the transformers and downstream service lines.

Although a more precise indicator of the rate changes could be derived by undertaking a full cost of service study for the new rate classes, the estimated impacts shown for the Single Phase Secondary customers provides a good directional indicator of the changes that can be expected.

8 Rate Design for the Primary Class

The Primary Class is distinct because customers in this class use only the primary distribution facilities. As a result, costs associated with secondary distribution facilities would not be allocated to, or recovered from, this class. In general, all customers in the Primary Class will be customers that are in the GS >50 kW or higher classes and changes in the rate design will not be driven by the roll out of smart meters, since GS>50 kW customers are not included.

8.1 Fixed rates

As with all other classes, the view that design costs are sunk and costs of the existing system are fixed implies that rates in all classes including the Primary Class should be fixed. Possible ways to accommodate this viewpoint include:

- a fully fixed charge in which the Primary Class customer would pay a charge based on its total costs allocated to the Primary Class as determined in the distributor's cost allocation study; or
- rate ratchets where a capacity charge is based on a percentage of the maximum load of the previous year regardless of current monthly load.

8.2 Contract Capacity and Demand Based Rates

The complexities of a capacity charge identified in the discussion of the Single Phase and Three Phase Secondary Classes are less of a concern for the customers that would be in the Primary Class. The experience of Ontario distributors has shown that large volume customers are able to commit to a contract demand that establishes a maximum allowed capacity that can be used since they generally have a good appreciation of the load when their facilities are in full operation. Furthermore, their peak requirements are fairly stable and can be adjusted as necessary when they replace their electrical equipment or add facilities. The rate design for the Primary Class can therefore be structured so that the rates correspond closely to causal costs as indicated by a distributor's cost allocation study.

The resulting rate structure would consist of:

- A monthly customer charge equal to $1/12^{th}$ of the annual customer related costs allocated to the Primary Class divided by the number of customers in the Primary Class; and
- An annual capacity charge equal to the capacity-related costs allocated to the Primary Class divided by the sum of the maximum (or contract) demands of customers in the Primary Class.

It would also be feasible to implement a demand charge with the same basic design, except that the charge would be based on the actual monthly peak demand rather than a contract demand (i.e., capacity).

Board staff invites comment as to the appropriateness of these options.

8.3 Primary Customer Rate Changes

Although the class definition would change, a credible option would be to bill Primary Customers on essentially the same basis as they are currently billed. As a consequence, there will be no significant rate impacts unless a different billing option is adopted (e.g., full fixed rate).

9 Rate Design for the Sub-transmission Class

Some distributors may require a separate class for customers that use only sub-transmission facilities. Customers in the Sub-transmission Class differ from customers in the Primary Class because:

- Sub-transmission customers do not use either the primary or secondary facilities of the distributor; however, if they are over approximately 1000 kW demand they require a separate substation for which the costs must be recovered if supplied by the distributor;
- Sub-transmission customers will generally be wholesale market participants; hence, they cause less commodity risk for distributors (lower prudential requirement).

Not all distributors will require a Sub-transmission class as many do not have any customers that would fall into this class. Hydro One has applied for approval of a Sub-transmission class (EB-2007-0681).

Hydro One has adapted its Cost Allocation model to identify sub-transmission facilities and costs, which then provides the class revenue requirement that is necessary as a basis for the class. The cost allocation model distributed by the Board has the option of defining a “Bulk” cost function. The definition of “bulk” in the Board’s report (EB-2005-0317) is not linked to whether the distributor has any customers served at a sub-transmission voltage.

The rate design options for the Sub-transmission class are the same as those for the Primary Class. Furthermore, since both classes consist of large volume customers, it may be appropriate to use the same rate design for both classes. The only difference will be the level of the rate which will differ because of the difference in the facilities allocated to the two classes.

Board staff invites comment as to the appropriateness of each option and the advantages of using the same rate design for the Primary and Sub-transmission Classes.

10 Rate Design for Embedded Distributors

The Embedded Distributor classification applies to an electricity distributor, licensed by the Board, that is provided electricity by means of the host distributor's facilities. The host distributor has a rate on its tariff sheet for the embedded distributor. Historically, these arrangements developed because one distributor was closer to the spot where power was taken from the transmission grid than the other. A distributor may have more than one embedded distributor within its service area and may have more than one connection point for any one embedded distributor.

In many respects an embedded distributor is no different from any other load on the host distributor's system in that power is distributed from the transmission system to the point of connection with the customer (embedded distributor). The primary difference between an embedded distributor and the other loads of the host distributor is that while the total annual load of an embedded distributor is typically at a level commensurate with a large volume customer, the load profile is reflective of the embedded distributor's customers. Hence, the load profile and load factor is normally more reflective of small volume customers rather than one large customer.

Assuming the rate design applicable to embedded distributors recovers costs in a manner consistent with the cost drivers, as determined in the host distributor's cost allocation study, the embedded distributors will pay rates that reflect their causal costs unless their causal costs are significantly different from other customers in the same class. Exceptions will arise, for example, if the embedded distributor is located close to the host distributor's connection to the transmission system. In that case, the cost allocated to a separate Embedded Distributors Class are likely to be significantly less than the revenue that would be recovered if it is included in the Primary Class, which may include a number of large volume customers utilizing much more of the host distributor's facilities.

There are divergent views as to whether embedded distributors should be included in a class with other customers (e.g., Primary Class) or kept in a separate class so that they pay a rate that is more directly reflective of the actual use an embedded distributor makes of the host distributor's system.

Hydro One has applied for approval to include embedded distributors in its proposed Sub-transmission class (EB-2007-0681). In that proposal, the embedded distributor's additional cost of being treated as an ordinary "customer" would be offset to some extent by Retail Transmission Service rates that reflect the diversified load of the Sub-transmission class. In other words the embedded distributor would pay a lower rate than the provincial uniform rates paid by distributors that take service directly from the transmission system (EB-2007-0759).

Is there any need to maintain a separate class for embedded distributors?

If a separate Embedded Distributor Class is adopted, a variety of approaches could be adopted for designing the rate for this class.

10.1 Fixed rates

As with all other classes, the view that design costs are sunk and costs of the existing system are fixed implies that rates in all classes including the Embedded Distributor Class should be fixed. There are a number of ways to accommodate this viewpoint:

- A fully fixed charge in which the embedded distributor pays a charge based on its total allocated costs as determined in the distributor's cost allocation study; or
- Rate ratchets where a capacity charge is based on a percentage of the maximum load of the previous year regardless of current monthly load.

10.2 Contract Demand (Capacity) Based Rates

As indicated in preceding sections, it is generally more practical for large volume customers to commit to a contract demand that establishes a maximum allowed capacity that can be used than it is for small volume customers to do so. However, in the case of an embedded distributor, its capacity requirement from hour to hour is determined by the aggregate demand of its customers. As a result, an embedded distributor is likely to have significantly less capability than a typical large volume customer to manage its demand so as to ensure that it does not exceed its contract demand.

Furthermore, limiting the capacity of an embedded distributor with a load limiter, for example, could compromise the reliability of its distribution system unless it is able to curtail some load when necessary to maintain system integrity.

10.3 Time-of-Use Based Charges

Time-of-Use based variable rates would provide a measure of protection to the host distributor and allow the embedded distributor to control costs by working with its customers to manage the embedded system peak demand.

Board staff invites comment as to the appropriateness of these options.

11 Rate Design for Load Displacement Generation

As previously mentioned, the scope of issues regarding distributed generation for the purpose of this paper has narrowed to appropriate rates for load displacement generation i.e. that comprises generation facilities that supply electricity to a specific load, displacing electricity supply that would otherwise be obtained from the local distribution system.

In consultation meetings, there was general agreement that generation facilities of less than 500 kW are not treated as load displacement generators and that distributors absorb the revenue changes as they would any other fluctuation in a customer's use. However, the meetings also highlighted the tension between user groups who ask that the distributed generation customers pay only for what they use and distributors who ask that customers pay for the assets installed to service their needs.

11.1 Fixed rates

Board staff understands the position of distributors who say that capacity is designed and held on a customer basis. To the extent that design costs are sunk and costs of the existing system are fixed, attempts to reduce the variable portion of the bill are avoiding prices rather than avoiding actual costs. If customer rates are a fully fixed charge for each rate class, then the distributed generator is simply another customer in the class.

There are a number of ways to accommodate this viewpoint:

- A fully fixed charge in which the distributed generator has the same charge as any other customer of the rate class;
- Rate ratchets where a capacity charge is based on a percentage of the maximum load of the previous year regardless of current monthly load; or

- A higher fixed charge based on the percentage that the generation facility represents of the distributor's total load i.e. the closer the generation facility gets to the distributors total load, the higher the fixed charge becomes.

11.2 Capacity-based rates

Board staff also understands the position of load displacement generators who point out that facility maintenance and downtime can be scheduled during times that there is excess capacity on the system and use of the assets is essentially free. The concern of distributor's other customers on the system would be unscheduled outages that could damage the lines and affect their service. To reduce ongoing rates, load displacement generators could contract with the distributor for one of the following arrangements:

- an increased customer contribution to offset the revenue required through rates;
- a load limiter to protect the upstream system from unscheduled outages, to be removed for scheduled maintenance and downtime; or
- a contract charge based only on the firm standby service with penalties for exceeding the maximum.

Some distributors have the third option in place now but charge retroactively if the contract maximum is exceeded. A load limiter would provide protection from a retroactive payment and both parties could be assured that it would be removed during appropriate periods for scheduled outages.

In the case that the charges are capacity based, load displacement generators could be a sub-class of the underlying class. This would be similar to the design in France where customer classifications are demand based but there are sub-classes based on 'subscribed' demand[21].

[21] See Survey of Other Jurisdictions.

11.3 Time-of-Use based charges

Time-of-Use based variable rates would provide a measure of protection to the distributor and allow the generator to control costs. A high on-peak penalty would provide inducement to the generator to offset its load during peak times while ensuring revenue for the distributor when assets are being used.

It does not entirely address the issue of revenue for assets “standing by” or risking system stability from unscheduled outages.

11.4 Load diversity

In consultation, stakeholders pointed out that there is no diversity credit for load displacement generation for the load reductions or the geographic dispersion of the facilities. When load displacement generation is sufficiently widespread, the overall risk to the system of designing for lower capacity requirements will be quite small and rates should reflect that. In the meantime, the lack of credit inhibits the development of load displacement opportunities.

Board staff invites comment as to the appropriateness of these options.

Is it advisable to assume the targeted end-state diversity in setting rates in order to stimulate projects?

12 Rate Design for Unmetered Scattered Load

Unmetered scattered load currently comprises one or more separate classes because the absence of a meter necessitates a different approach to rate design than other classes. The primary common characteristic of these loads is that they are individually small loads making it uneconomic to meter them individually. Loads in this category include:

- Street Lighting
- Sentinel Lighting
- Cable facilities

Typically, rates for these facilities consist of a fixed monthly service charge determined on the basis of either per connection, or per customer and a variable distribution rate on an estimated per kW basis.

Unmetered scattered loads are typically connected to the secondary facilities of a distributor. That is, they use and are allocated the cost of, sub-transmission, primary and secondary facilities. However, the service connection at each load point does not require the equipment that is needed for either single phase or three phase secondary customers. Further, a number of streetlights located close to each other might have a single connection, which is unlikely to happen with the other unmetered loads.

One of the primary challenges with respect to unmetered scattered load is estimating the unmetered load. This must be done using engineering estimates rather than direct measurement through metering. Since metering is the generally accepted preferred method of establishing the usage of customers, it may be appropriate to allow customers to request and pay for load studies to determine the demand and energy required for their loads. A particular difficulty is determining the amount of diversity benefit for a customer's scattered load when it is unmetered.

Given the nature of unmetered scattered loads, with one customer responsible for many geographically diverse consumption points, costs may be more closely related to the number of accounts than the number of connection points.

Board Staff invites comments on whether a separate unmetered scattered load class should be mandatory and the relative merits of billing for unmetered scattered load on the basis of customers and connections.

Board staff is also interested in submissions on the justification for separate classes for street lighting and sentinel lighting.

13 Rate Design for Metered Scattered Load

Some stakeholders have identified an issue with respect to the rate design for customers with multiple locations that can be characterized as metered scattered load. If a separate class were established for these types of loads, it could include, for example, school boards and some other MUSH sector customers.

At issue is whether a single corporate entity with multiple locations served by common secondary distribution facilities should be allowed a single bill with:

- an aggregation of demand for determining the demand charge (hence, customer would realize any diversity benefit which would provide an incentive to manage the customer's aggregate load efficiently); and
- a customer charge that reflects the savings associated with a single bill (e.g., lower customer service costs even if the facilities classified as customer-related are not common to multiple locations).

These metered scattered loads would typically be customers in the Single Phase or Three Phase Secondary Rate Classes. Hence, the rate design options set out in sections 6 and 7 would apply, as appropriate. It appears that the issues associated with metered scattered loads can be addressed without establishing a distinct class of customers. Rather the issues could be addressed by introducing appropriate billing terms and conditions and/or by establishing a subclass that would receive a credit reflecting the relevant cost savings compared to other customers in the class.

Board staff invites comment on whether the diversity benefit associated with multiple locations should be reflected in the rates paid by customers with metered scattered loads.

Board Staff also invites comment on whether customers with metered scattered loads should be able to aggregate their bills and be charged a single fixed monthly charge that reflects the reduced costs associated with the single bill.

14 Revenue Recovery of Distribution System Losses

This issue was added to the scope of the project as a result of stakeholder comments on the March 2007 staff paper. This project will deal only with the issue of recovering the revenue requirement associated with losses. The emphasis is on designing rates with price signals that will influence customer behaviour to reduce losses.

At the present time distribution system losses are recovered by charging the commodity charge and the retail transmission service rates on an approved volume (5) over the actual amount consumed by distribution customers. As a result, the energy cost differential between the power purchases at the point of interconnection with the transmission system (or host distributor) and the power sales to customers is passed through to customers by means of the approved margin. There is an annual reconciliation mechanism to ensure that the distributor does not over- or under collect for its costs due to variances between forecast and actual losses.

This approach to recovering costs associated with system losses is consistent with the view that the costs associated with system losses are commodity costs since the distributor is buying power at the Hourly Ontario Electricity Price but cannot recover the cost directly for power that is not delivered to customers. Put simply, the distributor must buy more power than its customers require due to the losses such that the effective cost of each kWh delivered is increased in proportion to system losses. Similarly it must buy more transmission service each month than the kW actually being delivered to its customers.

This project will not address how to encourage distributors to reduce losses. That issue is expected to be part of policy initiatives arising out of a project starting in the Office of the Chief Compliance Officer. A staff research paper, to be released shortly, will report on Ontario distributors' practices relating to distribution system losses. It has gathered information on how distributors measure and report losses, electricity distributors practices on how losses are managed and compared applicable rate setting practices with other jurisdictions.

Losses relevant to this project are limited to technical losses (i.e., the losses associate with the physics of the distribution system as reflected in the technical engineering equipment specifications). These losses correlate with the loading of the distribution system. As a consequence, it would be appropriate to recover these technical losses in a manner that applies a variable loss factor that is correlated to the loading on the system. That relationship and mechanism is the focus of comment in this paper.

14.1 Options for Recovering Revenues Associated with Distribution System Losses

In looking at technical losses and the recovery of revenues associated with them, the consultation group recognized the relationship between the loss ratio and system loading. That relationship could be consistent with the introduction of capacity or demand based rates that, in effect, recognize system loading in charging for use of the distribution system. For example, the markup on the customers commodity cost could be designed as follows:

- for HOEP customers (including retailers), the markup for losses could be based on hourly demand with the loss factor increasing with demand; and
- for commodity TOU customers, the loss factor could be higher for peak TOU periods than for non-peak periods, reflecting measured average distribution system losses in those periods.

Alternatively, all customers could pay for losses based on TOU factors. This approach would have the advantage of being simpler and being easier to establish based on the distributors actual measured losses. In consultation, stakeholders suggested that once smart metered data are available, it should be possible to quantify the relationship between demand and losses on a distributor basis, though not on a customer basis.

Board Staff invite comment on the most appropriate way to adjust the commodity for distribution system losses.

15 Next Steps

In this discussion paper, Board staff has invited comment on several issues requiring further stakeholder input. Stakeholders are asked to comment by May 30, 2008 according to Board procedures as outlined in the cover letter available on the Board's website.

The conclusions of the distribution connection cost project will also feed into the rate design process, giving information on distributed generation and use-of-system charges for generators.

In the next fiscal year, the Board will review all of the information provided and issue a policy paper reviewing the design of electricity distribution rates, including standby and distributed generation rates.

The survey of other jurisdictions shows that there is very limited experience with innovative rate designs for distribution services that take advantage of smart meters. Jurisdictions that have implemented smart metering typically use the smart meters either for billing for the commodity or for billing for bundled service with rates that recover the cost of both distribution services and the commodity. As a result, it needs to be recognized that Ontario will be breaking new ground in implementing a new distribution rate design that exploits the advantages of smart metering. It also needs to be recognized that the initial years following the introduction of a new rate design are likely to be instructive in that they will provide lessons in terms of the market response to the rate designs that are introduced.

Given the limited actual experience with innovative distribution rate designs, it may be reasonable to allow for some flexibility in the designs that distributors are permitted to implement during second cycle of Incentive Regulation. With the additional experience, the evidence may demonstrate that it would be appropriate to adopt a more prescriptive approach for the third cycle of incentive rate-making.

If the Board's policy paper directs changes in the rate classes, new cost allocation studies may have to be undertaken. Depending on the nature of the changes, these new studies may necessitate new data gathering exercises. Following the Board's policy paper, the Board will release a report identifying alternative models and data requirements to support the implementation.

At a point in the future, the Board will approve, on a selective basis, rates to reflect the conclusions set out in the Board's policy paper. Widespread implementation of the new rates for distribution delivery costs is not expected until after full roll-out of smart meters in the province after 2010.