Ontario

Ontario Energy Board
Commission de l'énergie de l'Ontario

Staff Discussion Paper

EB-2015-0043

Rate Design for Commercial and Industrial Electricity Customers: Aligning the Interests of Customers and Distributors

March 31, 2016

TABLE OF CONTENTS

A. OBJECTIVES

A.1 – Introduction

The pace of change enabled by significant technological advancements is affecting how energy is produced, transported and consumed. These advancements will enable greater consumer autonomy. Very real changes will emerge in energy consumer expectations and the way in which they engage with the energy market and service providers. Consumers will be much more actively involved in energy choices than they are today. The way customers are charged for their use of the grid should reflect and encourage sound economic choices.

The OEB took a major step in April 2015 by changing the structure of Ontario's residential electricity distribution rates. After extensive consultation with distributors, customers, customer representatives, conservation advocates and other stakeholders, the OEB released its report, Board Policy: A New Distribution Rate for Residential Electricity Customers[1] (the April Report). The OEB announced that its general policy for rate design is to increase the amount of revenue collected through the fixed rate, and reduce the amount of revenue collected through the usage rate. It began implementation of this policy by directing electricity distributors to restructure residential rates so that all the costs for residential distribution service are collected through a fixed monthly charge.

In the April Report, the OEB stated that its policy for residential rate design will help achieve three main objectives:

- It will enable residential customers to leverage new technologies, manage costs through conservation, and better understand the value of distribution services.
- It is a fairer way to recover the costs of providing distribution service.
- It will provide greater revenue stability for distributors, which will position them for technological change in the sector, removing any disincentive to promote conservation, and help with their investment planning.

The OEB is continuing rate design reform with this next phase focusing on all commercial and industrial classes in electricity. There are approximately half a million of these customers in Ontario. They are only 10% of the total number of customers but account for nearly two thirds of the load and 38% of distribution revenue.

[1] Materials related to the previous stage are available on the OEB website at EB-2012-0410

As with the previous phase of the policy initiative, the OEB intends to increase the link between how customers use the system and how they pay for it. This link ensures fairness and economic outcomes for the customer and the distributor while also ensuring the electricity system continues to meet the needs of all participants. The OEB intends to do this through the use of innovative rate designs that incentivize customers and influence their behaviour.

A.2 – Objectives

In the April Report, the OEB stated that its goal is to equip customers with the information and the tools they need to make informed choices about how they use energy and:

- Enable customers to leverage new technologies, including self-generation using renewable resources
- Help customers manage their bills through conservation
- Help customers better understand the value of electricity service

The OEB's objective is to facilitate customer choice by ensuring that the new rate designs support innovation and enable access to energy options. The policy on residential rates emphasized simplicity and increasing customer understanding of the fixed nature of the distribution service. Customers should pay their fair share for the assets and services that they use and receive fair value for the services that they provide.

In looking at commercial and industrial customers, the OEB also intends to increase efficiency in the sector by optimizing use of the current system and optimizing investment for long-term cost containment. Current distribution rate designs are not fully linked to distribution cost drivers i.e. customer and demand, both connection and peak.

The industry now has the opportunity to use data from smart and interval meters to design rates that link to cost drivers more closely, particularly rates that vary by time of day. By basing rate design on the cost drivers for distribution systems, it will align the interests of distributors and customers. Customer decisions in their own interest are also in the interest of the distributor. Actions that customers take to reduce their bills will lower long term investments by distributors and help contain future distribution system costs. This is a goal that the OEB is interested in ultimately applying to residential customers as well.

New rate designs could encourage greater economic use by customers of distributed energy resources. Distributed energy resources[2] (DER) are becoming more cost effective and increasing penetration. Customers with DER will impact the distribution system design and operation. DERs receive value from being connected to the distribution system. Their connection may result in additional costs. In turn, DER can provide value to the distribution system depending on the kinds of services they can offer, and when and where they can offer them. Rate design will need to balance these aspects.

A.3 – Scope

Rate design is about how a distributor collects money, not about how much it collects. The OEB will ensure that the change from one rate design to a new one will be revenue neutral. This project will not change the revenue requirement that is approved as a result of a proceeding for any distributor.

Rates for each class are established based on the OEB-approved costs allocated to each class. To the extent possible, the OEB will maintain existing rate classifications in order to avoid causing changes to the underlying cost allocations by class. This will also make it more transparent that the change is revenue neutral.

Commercial and industrial customers are classified into different rate classes according to their size as measured by their peak electricity consumption in kilowatts (kW). In practice that means current customers in the classifications of:

- general service under 50 kW (GS<50)
- general service over 50 kW (GS>50)
- intermediate customers (Intermediate) whether that is defined by the distributor as over 1500 kW, 3000 kW
- large customers (Large) that are generally defined as over 5000 kW

The way that the commodity, transmission, and other services are charged will not be affected. The OEB will address natural gas rate design in due course to coordinate with the performance-based ratemaking cycles of the investor owned utilities.

[2] DER: Distributed Energy Resources including demand response, distributed generation (including micro-grids), and storage (including electric vehicles).

A.4 – The Structure of this Paper

This staff discussion paper is the next stage of a consultation on rate design for commercial and industrial electricity customers and is meant to solicit stakeholder input on issues, potential rate designs, and analysis prepared by staff.

The structure of this staff paper is a discussion of general issues concerning rate design and presentation of several rate design options. For each customer class, staff presents the advantages of several potential rate designs and gives an illustration of how they might be structured with accompanying rate impacts. Section G is a discussion of how ancillary benefits from distributed energy resource may be included.

In Appendix A, there is an example of each of the rate options with modelling of customer impacts based on customer data provided by several of the larger distributors. These examples are meant to illustrate the concepts and allow comparison between the options. These are not the real impacts that would be seen by any individual customer since they are based on a limited amount of historical data.

Stakeholders are asked to comment on any aspect of these issues and are prompted with specific questions in the various sections.

B. ALIGNING THE INTERESTS OF CUSTOMERS AND DISTRIBUTORS

B.1 – Distribution Cost Drivers

The biggest cost drivers for electricity distribution systems are customer numbers and peak demand.[3] In economic terms, the primary products of the distribution system are connection to the grid and peak capacity.

Customer Connection
There are costs that are associated with being a customer of the distribution system that do not vary except with the overall number of customers: the cost of putting and maintaining a place in the Customer Information System, delivering a bill and processing payment; maintaining a call centre and personnel; maintaining service centres, equipment and personnel; and metering appropriate to each customer. As customer numbers grow, these costs grow.

Customer Demand
OEB staff note that there are actually two types of customer demand: 1) customer-specific demand used to size the equipment for customer connection (sometimes called design demand or connection demand) and 2) aggregated demand that determines the sizes of assets that are meant to serve many customers.

At lower voltages (residential and GS<50), the equipment to address a customer's design demand, i.e. the service drop, is relatively standard, similar in cost, and is almost entirely recovered through subsequent rates. Rural properties with long connection lines or other special circumstances may require a customer contribution[4] over the standard costs. At higher voltages, in particular for Large customers, the connection may be more specialized and the assets and costs to serve the individual customer show greater variability. It may also require a customer contribution. This "use demand" depends on the type and efficiency of the installed equipment and any behind-the-meter generation or storage. Because it depends only on the individual use, it could happen at any time and is called non-coincident.

[3] "Empirical Research in Support of Incentive Rate Setting In Ontario," Pacific Economics Group Research, LLC, May 2013,, p54.
[4] An economic evaluation is performed typically over the 25 year horizon to calculate any up front capital. In the first five years if the load is less than predicted, there is a true up. After 5 years the rate payer pool takes accountability if the load is less than required to fund the expansion. Cost responsibility and contribution calculations are out of scope for this project.

Aggregated demand affects the system and equipment that serves more customers. The higher the connection voltage in the system, the more customers are contributing to the sizing of the distribution system equipment. There is not a perfect relationship between the total customer demand and equipment sizing because of the "lumpy" nature of utility investment. Because this is the accumulation of many customers' loads, it happens at peak times and is called coincident.

While the size of system investment required is driven by the peak demand, customers also consume power at other "off-peak" times. Considered from the economic standpoint, off-peak demand is a co-product of the primary product and can be 'sold' at reduced prices as an additional source of revenue while peak capacity draws the primary revenue. Lower off-peak prices will encourage customers to make better use of existing distribution system assets and reduce the need for new capacity expansion.

B.2 – Current Rate Designs Out of Sync

Because of historical limits on metering technology, individual customers have rarely been charged based on their actual contribution to coincident peak but rather, an assumed contribution to peak based on customer classifications and load profiles. With the increase in the number of customers who have time sensitive metering, OEB staff believes it is possible to more closely align the rate design with the cost driver.

For GS>50, customers are charged based on their monthly maximum demand regardless of when it occurs. In Figure 1[5] for a typical distributor, staff contrasts the red line which represents the demand on which customers are billed against the bill line, which represents their demand during the peak hours. To create this graph, staff used 7am to 7pm to mimic the peak hours as charged to wholesale transmission rates[6]. When the red and blue lines are coincident, the customer is actually being charged based on its contribution to peak. When the blue line is below the red line, the customer is being charged peak rates for off-peak use. A price that does not differentiate between demand that drives cost and demand that does not, fails to align the interests of the customer and the distributor.

[5] The two curves represent a sample of GS>50 customers' average any-time (red) and 7am-7pm (blue) max demand. The plot shows that a portion of customers appear to have an average max demand that is outside the 7am-7pm period.
[6] In the Rate Schedule for Provincial Transmission Service, the Network Service Billing Demand is defined as the higher of (a) customer coincident peak demand (MW) in the hour of the month when the total hourly demand of all PTS customers is highest for the month, and (B) 85% of the customer peak demand in any hour during the peak period 7AM to 7PM (local time) on weekdays, excluding the holidays as defined by the IESO. The peak period hours will be between 0700 hours to 1900 hours Eastern Standard Time during winter and 0600 hours to 1800 hours Eastern Standard Time during summer, in conformance with the meter time standard used by the IMO[sic] settlement systems.

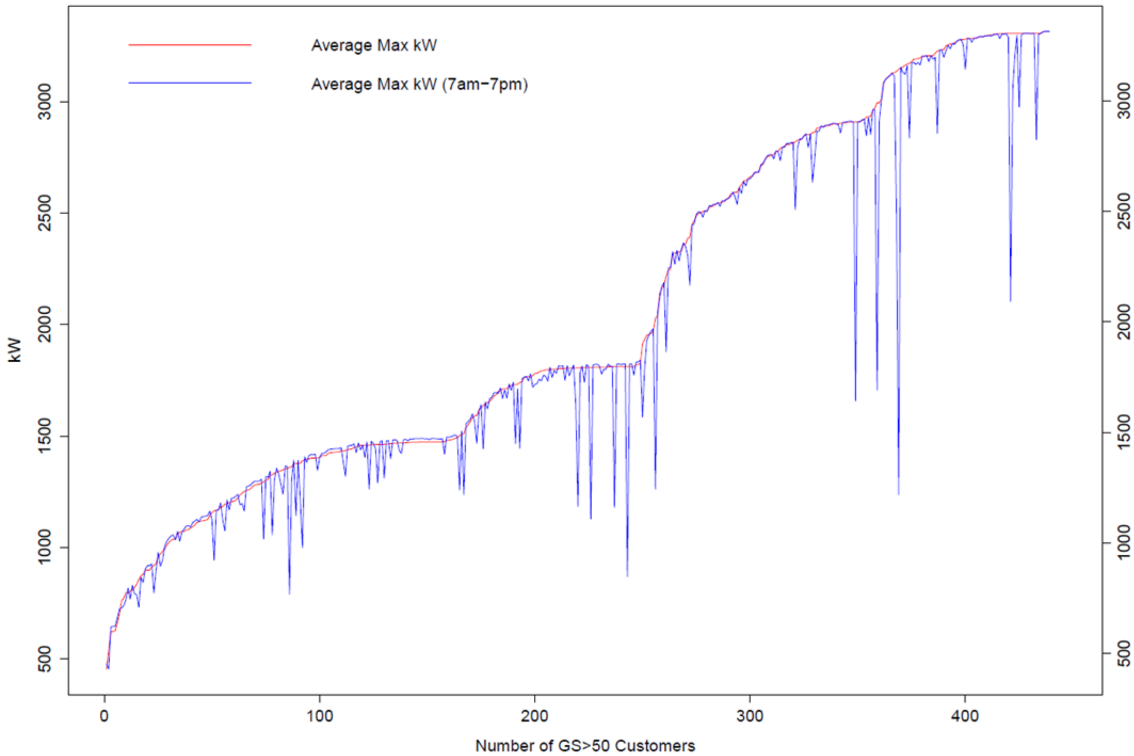


Figure 1: GS>50 customers billing demand compared to peak demand

In Ontario[7], the OEB uses the minimum system as part of the basis for the monthly customer service charge. The minimum system is a theoretical model, commonly used in cost allocation exercises. It imagines the assets that would connect all customers to the network without any capacity. i.e. A distribution system of poles and wires, transformation and meters that carry no current. This allows the full cost of the capacity in the system to be allocated to customers according to their share of the peak capacity that exists in the real system. In practice, the peak load carrying capacity (PLCC) adjustment avoids double counting some demand capacity in the minimum system model. The OEB requires all distributors to calculate and file[8] a calculation of the minimum system with peak load carrying capacity adjustment. In analysing the options, OEB staff used the PLCC with adjustment as the fixed charge for each class.[9] In many cases for distributors and classes, this is less than the current approved fixed charge.

Staff welcomes comments by stakeholders as to what measure should be used to set the fixed charge for each class (the Monthly Service Charge).

[7] Many US utilities use a basic service charge meant to recover only the meter and billing costs. This would be comparable to the monthly service charge that currently applies to FIT-contracted generators.
[8] As part of their cost of service rate filings.
[9] In some cases, the fixed rate was adjusted to avoid introducing perverse incentives at the boundary of intermediate classes. This is noted in the description where necessary.

Staff has provided three examples to show how different these measures can be for Ontario distributors. The following pie charts represent two measures for a distributor. Fig 2b shows how much of its revenue the distributor gets from each of the customer classes. Figure 2a shows how much of the revenue from the GS<50 class comes from fixed and variable charges. These charts will be different for every distributor in Ontario. Two other examples are given in Figures 3 and 4 respectively.

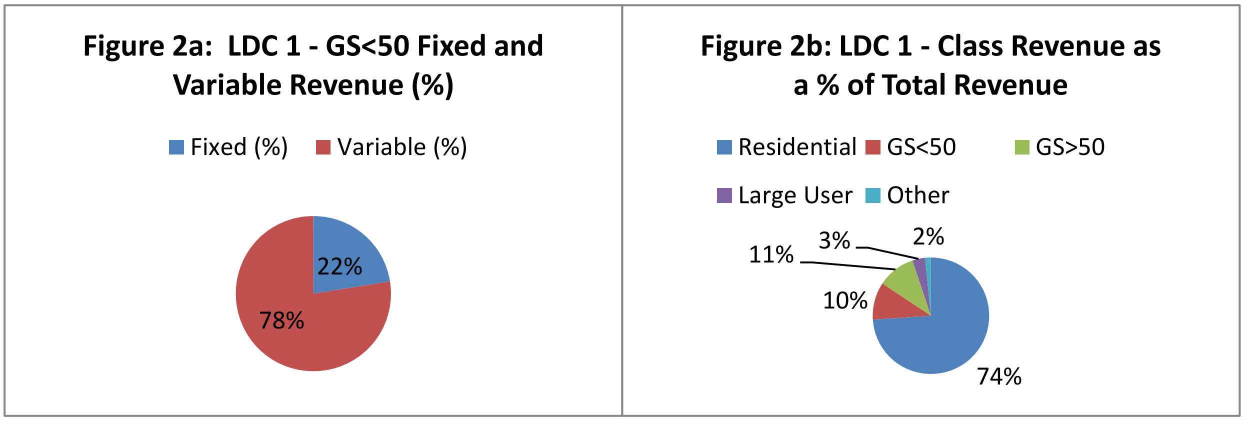


Figure 2: Ratio of Fixed to Variable Revenue and Portion of Revenue by Class for LDC1

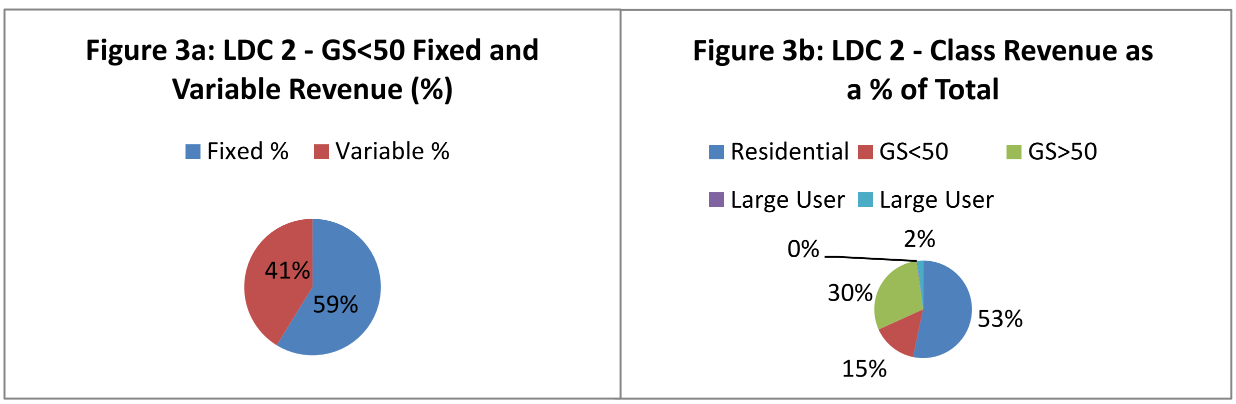
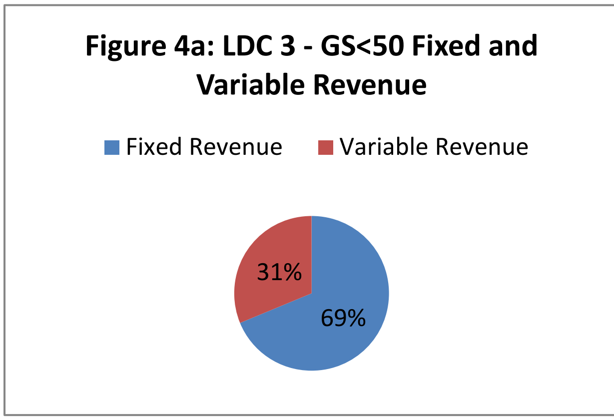


Figure 3: Ratio of Fixed to Variable Revenue and Portion of Revenue by Class for LDC2



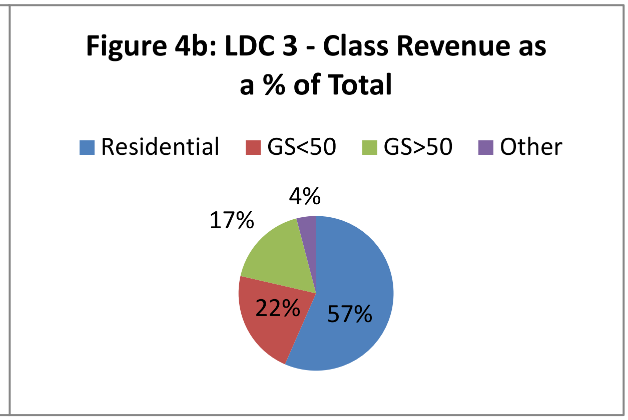


Figure 4: Ratio of Fixed to Variable Revenue and Portion of Revenue by Class for LDC3

They also vary considerably in how much of the revenue allocated to any particular class is collected through a fixed charge. In fact, there is almost no correlation between the overall revenue collected from the GS<50 class with the amount of revenue that is collected through a fixed charge.

B.3 – Staff Meetings with Stakeholders

For this phase of the rate design review, the OEB began with a letter[10] outlining current OEB policy and several issues that staff considered relevant to the discussion.

1. Valuing connection to the system: The OEB has typically allocated costs to a fixed charge based on a minimum system process.
2. Valuing capacity: Using price signals to align the interests of customers and distributors to optimize use of the system and contain long-term costs.
3. Valuing distributed energy resources: Recognizing the costs and benefits of distributed energy resources to the system without harming customers who do not participate.
4. Rate stability: Customers moving from one rate class to another can find that their bill changes dramatically. Design Commercial/Industrial rates to avoid that sudden transition at the boundaries of rate classifications.
5. Rate goals: The OEB has identified the objectives for the rate design. Stakeholder comments on the residential project suggested that, within those objectives, a desirable rate design would be: cost driven; customer controlled; and forward looking.

[10] All OEB documents in relation to this project can be found at EB-2015-0043

OEB staff used this list[11] to lead small group meetings[12] with several interested stakeholders. The following comments from the meetings provided early input to guide research and options for analysis.

- Valuing peak capacity is a fair way to charge for a portion of distribution service. It represents a cost to the system. Pricing that reflects reality avoids both inefficient bypass and intra-class subsidies.
- Different rate classes should have different approaches. Smaller users need more predictability for rates and bills. Large users need more flexibility to control their costs. Distributors need flexibility to address the requirements of large customers which may vary considerably. One customer may be looking for the least expensive possible service. The next may be looking for tight power quality requirements or uninterrupted service.
- Valuing distributed energy resources (DER) should be location specific. Load control and balancing, VAR support, and frequency response are all benefits that the system could need in specific locations.
- Clarity and ease of explanation should be key considerations in selecting designs. Premature communication on charges can cause uncertainty and concern for customers.
- Distributors are concerned about the expense of changes to Customer Information Systems (CIS) if design changes are too far from the existing structure.
- Consumer groups and the environmental groups want customers to be able to take action to manage their bills.
- Efficiency groups want rates that are structured to reflect costs and avoid any intra-class subsidies or hidden subsidies for DER.
- Generator groups want to align the interests of distributors and generators so that distributors are willing to reduce barriers to connection.

B.4 – Customer classes

Rate classes are designed to group customers that put similar demands on the system so that they are causing the same kind of costs. The commercial and industrial rate classes in Ontario are primarily meant to represent the voltage of their connection and therefore the levels of the system that they are accessing.

Figure 5 is a simplified representation of a distribution system. GS<50 customers are mostly connected to the low voltage (or secondary) system and share the cost of its

[11] The list has been changed to remove questions used in discussion.
[12] Agendas and meeting notes are also available on the project website.

assets with residential customers.[13] GS>50 customers are mostly connected to the high voltage (or primary) system and share its costs with the lower voltage customers (residential and GS<50 classes). Each classes' share of the costs is allocated to it according to its aggregated demand. This is also how the cost of the sub-transmission system is shared between the other rate classes and the intermediate and large customer classes which are connected to the highest voltages up to 44 kV.

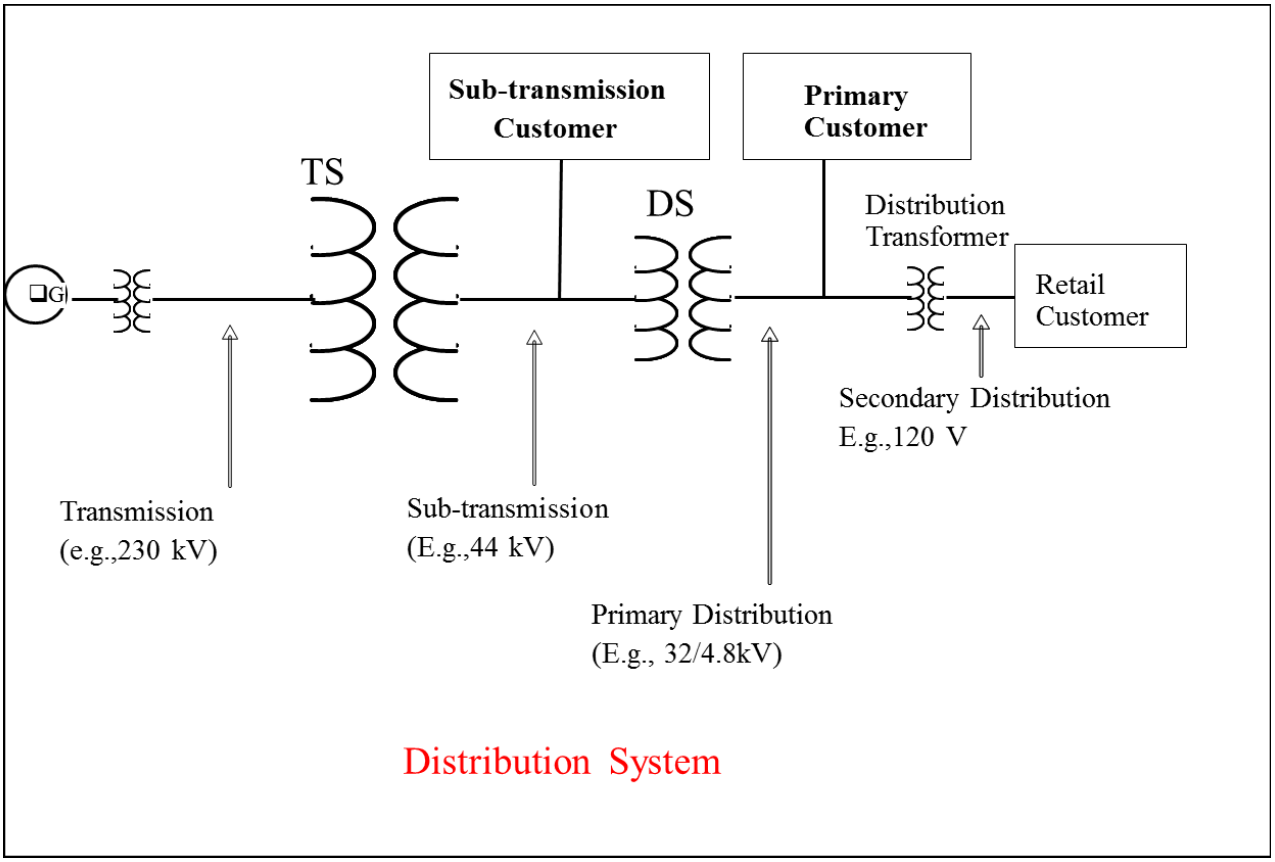


Figure 5: Simplified illustration of an electricity distribution system

The contribution to peak that the class allocation is based on is developed through load profile studies of representative customers. But not all customers in a class are "representative". Some customers are using more energy at peak times[14] and contributing more to this peak. Others are using more energy off-peak or at a steady rate and are contributing less to this peak.

[13] Residential and GS<50 customers are in different rate classes because of differences in load profile and load factor. Otherwise, they are similar in the type of assets that serve them.
[14] Load factor is defined as the average load divided by the peak load in any given time period.

There are, however, other considerations beyond the size of a customer's load. Some jurisdictions[15] have suggested that customers can also be grouped according to their interaction with the grid. They are different not just in how high their demand is, but what kinds of services they expect or conversely, wish to supply.

- **Traditional consumers** want to use electricity how and when they choose and just pay the bill either because they are indifferent to price or they find it difficult to change.
- **Active consumers** want to actively manage their use to control their bills in response to price signals or for social or environmental reasons.
- **Prosumers** want to interact with the grid by providing services or responding to system operation.

This suggests that some customers, in each class, may never be interested in actively participating in DER or complex relationships with the grid. However, the customers who are interested are sophisticated enough to understand some of the system issues of the grid and how it affects their installations and connections.

The design and operation of the system should be relatively indifferent to whether a customer's measurement of use at a connection represents pure load, load that is reduced by behind the meter generation, or load that is being reduced through conservation or active control.

Current OEB staff thinking is that the underlying rate design should be readily understandable to the traditional customer and reward the active customer for reducing one of the primary cost drivers i.e. peak capacity. Reducing peak capacity will lower the distributor's investment needs to meet peak capacity and save money over time. Building this driver into the rates will align the interests of the customer and the distributor. The expectation is that a rate design that addresses underlying cost drivers will lead to each customer paying their fair share of the system. The intention is to avoid creating specialized rate classes for load displacement generation and net metered customers and charges like standby rates that can be a barrier to customer choice. OEB staff further thinks that prosumers who are actively engaging with the system have a level of knowledge and sophistication that may allow more advanced rate designs to apply to them.

Staff invites comments on how any of the options will be affected by large amounts of net metering.

[15] "Staff White Paper on Ratemaking and Utility Business Models," CASE 14-M-0101 – Proceeding on the Motion of the Commission in Regard to Reforming the Energy Vision, State of New York Department of Public Service, July 28, 2015, p85.

B.5 – Rate Design

Rate design is the part of the regulatory process where the focus turns to the customer. Rate design is about how the previously determined and allocated revenue requirement will be recovered from the customer. Traditional Bonbright principles[16] (of which cost causality is often the most influential) and standard economic concepts of price signals can be used to try to influence customer behaviour to align the interests of customers and distributors.

The rate design white paper of the New York Public Service Commission as part of their "Reforming the Energy Vision" (REV)[17] raises the possibility of distribution rates that vary by location (e.g., through congestion pricing), time (varying by time of day) or attribute (such as the distribution of not only energy, but capacity or ancillary services). With respect to location, distribution rates in Ontario do vary by the distributor so there is some location factor but that is primarily driven by the individual distributor's costs. Some distributors have urban, sub-urban or rural rate classes to account for differing costs to serve in these situations. In both cases, these differences are driven by differences in cost, rather than dealing with the costs associated with congestion.

With respect to time sensitive pricing, Ontario is fortunate in that prices for energy are already separated as the commodity charge and temporally based as RPP TOU or hourly spot price (HOEP). This is made possible by nearly all customers having either a smart meter or, for the largest customers, an interval meter.

As of August 21, 2020, the OEB is requiring interval meters to be installed for all larger business customers[18]. As a result, virtually all load customers in Ontario will have either a smart meter that measures energy use on an hourly basis or an interval meter that typically measures energy use on 15 minute basis. The right infrastructure will be in place to support mechanisms to encourage customer flexibility.

Many of the ancillary services are purchased by the IESO under contract or through markets and charged to customers through the Wholesale Market Service Charge. Ancillary services would typically include voltage control and frequency response. The

[16] Bonbright principles are the series of attributes commonly balanced to produce a sound rate structure. From Principles of Public Utility Rates, Bonbright, James. C. et al., 1988, p 383.
[17] State of New York Department of Public Service, "Staff White Paper on Ratemaking and Utility Business Model," CASE 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, p 88.
[18] On May 21, 2014, the OEB issued a Notice of Amendment to a Code which amends section 5.1.3 of the Distribution System Code to require a distributor to install a MIST meter on any installation that is forecast by the distributor to have a monthly average peak demand during a calendar year of over 50 kW. The Amendments come into force on August 21, 2014.

IESO has begun to procure such services from distributed energy resources, notably energy storage connected to distribution systems.

OEB staff is proposing options that attempt to increase the locational, temporal and ancillary aspect of distribution rates.

OEB staff notes the RPP Roadmap[19] which suggests that addressing peak demand at the transmission level is the primary focus of the RPP pricing scheme. The OEB view is that distribution rates should address distribution costs and therefore distribution peaks.

For some distributors, this distinction is already important as their peak demand occurs in winter whereas peak demand on the transmission system occurs in summer. Even for summer peaking distributors, an emerging challenge is the growing impact of solar generation whereby distribution systems are subject to the "duck curve"[20] problems discussed extensively elsewhere. Essentially, as the amount of energy provided by distributed solar generation increases, the load curve on the distribution system can shift to later in the day. Depending on the geographic diversity of solar penetration, this may no longer match the overall system peak.

OEB staff has modelled a number of rate designs for comparison. Staff tried to choose options for comparison that directly address the OEB's objectives.

- A simple, understandable base rate for traditional customers
- Value peak capacity to align customer and distributor interests
- Recognize a customer's costs and benefits to the system.
- Encourage conservation.

The table below is an overview of the design options proposed and analyzed by OEB staff. There are 6 basic options:

1. fully-fixed monthly charge
2. time-of-use kWh
3. energy usage blocks (cell phone plan)
4. minimum bill
5. three part demand rates
6. time of use demand rates

Not all basic options apply to every rate class. OEB staff have not proposed demand rates for GS<50 customers. We have tried to keep the options for this rate class simpler and usage based. However, we have proposed options that add a temporal element to distribution rates for all classes.

[19] EB-2014-0319
[20]/https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf

Proposed options for the GS>50 class are all demand based. Most of the proposals are in use in other jurisdictions.

The proposed options for the Large customer class are all demand based and have a temporal element.

Table 1: Design Options and Application to Classes

	Design Option	GS<50	GS>50	Int	Lrg
1	Fully fixed charge	√			
2	Time of Use energy • Fixed charge • Rate 1 for on-peak kWh • Rate 2 for Off-peak kWh	√			
3	Energy usage blocks • Customers choose a level of fixed charge for blocks of on-peak use • Overage charges	√			
4	Minimum bill: • Bill is the higher of the minimum bill level or the calculated bill	√ kWh	√ kW		
5	Three part demand rate • Fixed charge • Rate 1 for maximum demand during peak period • Rate 2 for maximum demand at any time		√	√	√
6	Time of Use demand • Fixed charge • Rate 1 for maximum demand during peak period • Rate 2 for maximum demand during the off-peak period		√	√	√

C. GENERAL SERVICE UNDER 50 kW OF DEMAND

There is minor variation in the way that Ontario distributors define the GS<50 class. A typical definition from a tariff sheet is:

> This classification refers to a non-residential account taking electricity at 750 volts or less whose monthly peak demand is less than or expected to be less than 50 kW.

Other distributors may or may not refer to the 750 volt specification. Some specifically include farms with polyphase service or bulk metered multi-unit residential establishments or townhouses under a certain number of units. Some distributors use the wording “is less than or *forecasted* to be less than [emphasis added].”

Research conducted for the OEB RPP Roadmap initiative suggests that this customer group is less price responsive than others. Although 80% of small and medium sized businesses[21] indicated that the price they paid for electricity was the most important issue for them, only about a quarter of them were aware that they were on TOU pricing for the commodity. Of those, only one third indicated that they had taken action to shift usage to off-peak times. Most small businesses suggested that they could not shift use because of their business hours. E.g. a retail outlet will be open from 10am to 6pm regardless of electricity prices.

C.1 – Current Design

The small commercial class includes customers such as bulk metered multi-residential units of up to 6 apartments or townhouses, most farms that have 3-phase service, and small retail outlets without significant electric equipment load. This may include corner stores depending on the amount of refrigeration and restaurants depending on the fuel for cooking and water heating. Because of the abundance of retail and food service, the typical use is primarily in peak hours.

The current rate design is a fixed charge with a variable per kWh charge. It contributed[22] between 8.6% and 55% of revenue to distributors. The amount of that revenue collected from fixed charges was between 1.5% and 78.1%.

[21] See BEWorks and IPSOS Reid research released on Nov 16, 2015 in support of the RPP Roadmap at http://www.ontarioenergyboard.ca/oeb/industry/regulatory+proceedings/policy+initiatives+and+consultations/regulated+price+plan

[22] Data on each distributor’s most recent COS model which can range from 2014-16.

Customers who are reclassified from under 50 kW to over 50 kW see a large bill increase due to a discontinuity in the current rate structure. One of the goals of the project is to eliminate the existing boundary issue at 50 kW. A secondary goal is to avoid introducing any new boundary issues as rate designs change. This will need to continue to be tracked as rate design options are refined and then implemented.

C.2 – Options considered for GS<50

The focus of the options has been to maintain variable billing by energy (kWh). Most options for GS< 50 are based on energy use as measured in kWh. Many jurisdictions are considering moving to demand based rates for smaller volume customers.

Stakeholders are invited to comment on this issue.

Table 2: Rate Options for GS<50

	Design Option	**Advantages**
1	Fully fixed charge	This option is the simplest and helps a customer understand the fixed nature of distributor assets.
2	TOU option • Fixed part based on OEB’s Cost Allocation Model Minimum System with Peak Load Carrying Capability (“PLCC”) adjustment • Variable part based on kWh in RPP on and off-peak time periods – will be the same across both winter and summer periods	This option values peak capacity in a simple way that customers will already be familiar with from time of use commodity pricing.
3	Energy use blocks • Fixed part of contract peak kWh blocks that a customer will choose from and pay accordingly • High variable part that will apply if the customer goes over their self-selected demand threshold • There is no delivery charge for kWh used overnight and on weekends (off-peak)	This option tries to bring a level of contract pricing to smaller volume customers. It fixes the distribution charge for each customer while valuing peak capacity.
4	Minimum bill: • Zero fixed charge • 100% variable rate with a minimum bill that represents the current use of 20% of customers	This option encourages conservation by keeping a high variable charge while providing the distributor with a fixed revenue stream.

C.3 – Option 1: Fully Fixed Charge

This option is analogous to the fully-fixed rate for residential classes that the OEB made policy in April 2015. As described in the April Report, a fully-fixed rate provides certainty for customers in terms of the distribution portion of their bill, fully compensates distributors for the short-term costs of service, and helps further understanding of the value of connection to the grid.

In comparison to residential customers, GS<50 are diverse in their use. Residential customers have very similar load patterns and are quite comparable in their use of the system. A retail store, a restaurant and a garage will all likely be in this class but have very different use profiles. Having them all pay average cost is less appropriate for them than residential customers.

GS<50 customers show a wider variation between what is used during peak periods and what is used off-peak than either residential customers or the larger commercial customers. See Figure 1 for an example.

This option might be appropriate for traditional customers but less so for active customers. It does not send a price signal about how a customer's actions affect long term costs of the system or allow any management of energy use to control distribution bills. This option makes distributors indifferent to increased penetrations of net-metered DER but does not encourage DER investment.

The analysis in Appendix A[23] shows that bill impacts are not symmetrical. Many more customers see bill increases than decreases. Lower demand customers see a large increase to average cost from their current bill.

Staff note that moving all GS<50 customers to an average cost, fully fixed rate would likely make the boundary issue at 50kW worse instead of better.

C.4 – Option 2: Time of Use Distribution Rate

The IESO report on commodity TOU[24] showed that these types of customers shifted up to 0.5% of load out of peak periods in response to price signals.[25] Studies show that

[23] Using Hydro One and PowerStream customers
[24] http://brattle.com/system/publications/pdfs/000/004/967/original/Impact_Evaluation_of_Ontario's_Time-of-Use_Rates-First_Year_Analysis_Faruqui_et_al_Nov_26_2013.pdf?1386626350
[25] Work done for the RPP Roadmap showed that residential customers decreased usage by 3.3 and 3.4% from the summer and winter peak periods respectively.

static differences in pricing tend to show decreased response over time. The follow-up IESO studies[26] showed a decrease in the response the second and third year. That response may be increased by increasing the price signal with cost-reflective distribution rates.

For the remaining options in GS<50, staff expect that load shifting and bill savings will increase by using what customers have already learned from TOU commodity pricing. Customers already know that peak hours cost more. To be most effective, the difference in peak and off-peak prices would have to be visible to the customer. Bill presentment is out of scope for this paper.

This option bases the variable charge on the energy used in peak and off-peak periods. A higher rate will apply to peak kWh than off-peak kWh.

The distribution charge will be in the form:
Charge = Monthly Service Charge + On-peak rate x on-peak usage + Off-peak rate x off-peak usage

This option charges more to those customers who are contributing more to the distributor's peak capacity needs. It should encourage load shifting (which also results in energy conservation) and better use of existing distribution assets. The analysis in Appendix A[27] shows symmetry in the bill impacts with most being under 20% of the bill and under $10 per month.

C.5 – Option 3: Energy use blocks

The third option for GS<50 customers is analogous to a typical cell phone or Internet plan where customers contract for specific numbers of minutes at specific prices. For the distribution rate, OEB staff proposes that customers contract for a specific number of peak kWh based on their past and expected usage. Their distribution charge will be fixed every month but will depend on a customer's peak use. There will be a relatively high per kWh charge for going over their contract usage. Customers can decide whether they want the lowest possible charge based on their previous use and risk overages or are willing to pay a higher charge for the certainty of a fixed bill every month. The highest charge is essentially an 'unlimited' plan.[28]

---

[26] http://www.ieso.ca/Documents/reports/Final-Analysis-of-Ontarios-Full-Scale-Roll-Out-of-TOU-Rates.pdf
[27] Using Hydro One and PowerStream customers
[28] Customers will continue to pay per kWh for their commodity according to whatever plan they have: RPP TOU, HOEP or retailer contract.

This option is a way to bring contract use, common in higher volume users, to a smaller volume class. Prior to the April Report, staff had proposed an option that charged customers a fixed rate based on their use. Several stakeholders felt it was a good starting point but was itself unworkable. Staff suggests this option as being forward looking and under a customer's control. It encourages customers to actively manage their bill on a go-forward monthly basis. Although the option appears to only charge for on-peak use, the fixed nature of the charges ensures that every customer makes a contribution.

A net-metered customer could plan to generate enough to cover his own use and select a low block. If there isn't enough generation to cover the load, the customer will pay overage charges.

This option would likely require distributors to notify customers by telephone, text or e-mail that they were approaching their usage limit and that they should take action to reduce use in order to avoid overage charges. Staff welcome comments on what changes might be needed to bill this through the CIS systems.

At this point, OEB staff have not proposed what the overage charge would be for a customer exceeding the contracted block of kWhs. Staff currently feel that it should be a fairly high rate to discourage customers from underestimating their use. As modelled, the combined fixed charges return all the revenue required for the class.

The model used in the analysis in Appendix A[29] has 5 different blocks of use. The first, basic block is lower than the current monthly service charge. Customers in this block show large bill decreases by percentage equivalent to $20 to $30 per month. The largest customers who are the highest demand or close to the cut-off to the next block have small bill decreases. Customers who show a very large increase are near the bottom of a threshold. They have incentive to try to get into the lower block.

C.6 – Option 4: Minimum Bill

This option is really a variation on any rate design.[30] It derives the charges and rates as in a previous example with the additional overlay of a minimum charge. If the total distribution charge were to fall below a pre-set amount, the bill applies that amount as the minimum distribution bill.

[29] Based on Hydro One and PowerStream customers
[30] In the fully fixed design, the minimum bill is the fully fixed charge.

This is a common rate design in the United States. The fixed portion is set very low so that the variable rate is higher. However, if use would result in a charge below a dollar value set as the minimum bill, the customer is charged that minimum amount.

The advantage to this rate is that it is thought to drive conservation for higher volume customers since the reward for reducing is greater. The assumption is that higher use is during on-peak. Below the minimum bill, there is no incentive to conserve or shift.

It also provides a default level of revenue recovery for the distributor and guarantees that any customer who is connected is paying a portion of the fixed costs since the distribution portion of the bill can only be reduced to the minimum bill level. Because of this, it is often a response to increasing levels of net metering.

The bill calculation is essentially:
Bill = the higher of (minimum bill level) or (Fixed Monthly Charge + Variable charges)

For simplicity in the example, staff modelled a fully variable rate based on maximum monthly demand with no fixed charge.

However, the minimum bill is set at a low to moderate level of use. Any customers whose demand is below that level will pay the minimum bill. In two of our examples, the minimum bill is lower than the current fixed charge resulting in many customers with a bill decrease. The bill increases are likely for high demand customers who see an increase due to the increase in the variable charge.

If stakeholders favour a minimum bill approach, staff invites comments on preferences for the underlying rate design.

D – General Service Over 50 kW

D.1 – Current Design

GS>50kW customers are typically connected to the higher voltage system. These customers are the most diverse of any class with draws from 50 kW up to whatever other rate class the distributor has. All distributors have an upper limit to this class. Some distributors[31] do not have an Intermediate or Large class of customers so all higher volume commercial and industrial customers are in this class. This class will include multi-residential buildings that are bulk metered, livestock intensive or greenhouse farming, larger retail and big box stores, and smaller industry like a print shop or metal forming.

The current rate design is a fixed Monthly Service Charge and a variable rate based on the peak monthly kW regardless of when it occurs.

Some of these options look similar to the options for the GS<50 except using kW instead of kWh (i.e. customer demand instead of consumption). Staff is keeping the same numbering system as in Table 1 to help discussion. i.e. a three part demand rate option is always option 5.

D.2 – Options considered for GS>50

All options for GS< 50 are based on demand as measured in kW as is currently the case. By the end of 2020, all GS>50 customers will have meters capable of time of use measurement.

Table 3: Rate Options for GS>50

	Design Option	**Advantages**
4	Minimum bill: • Zero fixed charge • 100% variable rate with a minimum bill that represents 20% of customers	This option encourages conservation by keeping a high variable charge while providing the distributor with a fixed revenue stream.

[31] Hydro One Networks Inc. has classes called: Urban General Service Demand Billed, General Service Demand Billed, Distributed Generation and Sub Transmission classes.

5a	Three part demand rate • Fixed part based on OEB's Cost Allocation Model Minimum System with PLCC adjustment • Variable 1 based on maximum demand during peak period • Variable 2 based on maximum demand at any time • Peak is 7 am to 7 pm	This option values connection demand and aggregate demand separately. It is expected to be fairer and provide more revenue stability than peak and off-peak alone.
5b	As 5a • Peak is 3pm to 9 pm	
6a	Time of Use • Fixed part based on OEB's Cost Allocation Model Minimum System with PLCC adjustment • Variable 1 based on maximum demand during peak period • Variable 2 based on maximum demand during the off-peak period • Peak is 7 am to 7 pm	This option values peak capacity. Staff has modelled options that do or do not value off-peak capacity.
6b	As 6a • Variable 2 is 0	

D.3 – Option 4: Minimum bill

This option is really a variation on any rate design.[32] It derives the charges and rates as in a previous example with the additional overlay of a minimum charge. If the total distribution charge were to fall below a pre-set amount, applies that amount as the minimum distribution bill.

This is a common rate design in the United States. The fixed portion is set very low so that the variable rate is higher. However, if use would result in a charge below a dollar value set as the minimum bill, the customer is charged that minimum amount.

The advantage to this rate is that it is thought to drive conservation for higher volume customers since the reward for reducing is greater. Once again, the assumption is that higher use is during on-peak. Below the minimum bill, there is no incentive to conserve or shift.

It also provides a default level of revenue recovery for the distributor and guarantees that any customer who is connected is paying a portion of the fixed costs since there is the distribution portion of the bill can only be reduced to the minimum bill level. Because of this, it is often a response to increasing levels of net metering.

The bill calculation is essentially:
Bill = the higher of (minimum bill level) or (Fixed Monthly Charge + Variable charges)

[32] In the fully fixed design, the minimum bill is the fully fixed charge.

In the example for discussion purposes, staff is making the underlying design a 100% variable rate although this is not necessarily the case with minimum bills.

The increases are less than 30% with most decreases also less than 30%. More customers see an increase than a decrease.

D.4 – Option 5: Three part demand rate

This option is a way of using smart meters to increase the link between the rate and cost causality[33]. It recognizes the two separate demand measures of the customer and charges for each: the design/connection demand and the peak/capacity demand.

The first part of the charge is a fixed monthly service charge to reflect the direct customer costs.

The second part is a variable rate based on the 'anytime' demand or non-coincident peak (NCP) demand to represent the cost of the design demand. The design demand charge pays for the connection to the grid and should represent the cost of the assets dedicated to that customer. Those assets are sized independently of time of use so the design demand charge applies to the maximum demand of the customer regardless of when it occurs. This charge could be based on the monthly maximum demand as is the current demand charge or it could be a more fixed charge with a ratchet so that it is more consistent with the fixed nature of the connection. Our example uses the maximum monthly demand.

The third part is a variable rate based on on-peak demand or coincident peak demand (CP) to represent the customer’s contribution to peak capacity requirements.

If the customer has its maximum demand during the peak hours, then the same demand value will apply to both rates. If the customer has its maximum value outside the peak hours then the peak demand is less or zero, whatever is measured during that period.

The bill calculation is:
Distribution bill = Monthly Service Charge + Maximum Monthly demand (kW) x Anytime rate + Maximum peak demand (kW) x peak rate.

[33] OEB staff does not have any evidence to suggest that this rate is currently in use in any jurisdiction. It has been proposed by Amparo Nieto of ERA Economic Consulting.

It can also be expressed as:
Distribution bill = MSC + $Demand_{NCP}$ x $Rate_{NCP}$ + $Demand_{CP}$ x $Rate_{CP}$

Staff is providing two examples to illustrate the possible variation in structure for this basic rate design. The OEB view is that distribution rates should address distribution costs and therefore distribution peaks. These peak hours will be distributor specific, may vary by season, and could shift over time. Therefore OEB staff has provided examples of both a broad distribution peak and a much narrower peak to show the differences in rates and rate impacts for the two scenarios.

This rate is closely linked to cost drivers. It ensures that a customer pays for fixed customer costs, customer connection and contribution to peak capacity. The intent is to eliminate the need for specialized charging for distributed generation or net metering since the underlying distribution rate is recovery from customers according to their use. The peak demand rate would reward customers for generation on-peak but also charge them for use when their generator was down for maintenance or repair.

Staff is interested in comments on whether the NCP rate should be a monthly maximum or some kind of ratchet that would reflect an annual peak.

Option 5a - A broad peak coincident with transmission peak

This example defines the peak period very broadly as 7 am to 7 pm to match the period used to define the transmission peak period for the network pool.

Approximately 20% of customers[34] see a decrease of more than 20% on their bill. These are the customers with maximum use outside the peak hours. Most bill increases are less than 5% of the bill.

This option should encourage shifting demand to off-peak for bill reductions compared to current rates and the new, higher peak rate. For distributed generation, it will encourage generation on peak when it is needed. Assuming that generation is off–line for servicing once a month or once a year, the monthly maximum demand should cover the customers design cost and ensure that they pay their share of the distribution system.

[34] Based on customers from PowerStream, Hydro One, Hydro Ottawa, Veridan, Horizon and Enersource.

Option 5b - A narrow peak to match a specific distribution peak

This example defines the peak more narrowly as 3 pm to 9 pm. This is representative of a distribution summer peak with significant solar penetration resulting in a “duck” curve previously discussed. This would allow each distributor more flexibility to address its own system peak.

Compared to the broader peak, this option shows slightly higher percentage bill changes, both increases and decreases. The increases go from being mostly under $25 to being mostly under $200. Compared to the broader peak, there are almost the same number of customers with bill increases and decreases.

D.5 – Option 6: Time Of Use Demand Rate

This is similar to Option 5, the three part rate, except that there is a peak charge and an off-peak charge instead of a peak charge and an anytime charge. If a customer's maximum demand is during the peak period, only one charge applies. However, there may or may not also be a charge for whatever the customer's maximum demand is during the off-peak period. The lower the off-peak charge, the more exposed the distributor is to net metering revenue erosion.

The form of the equation is:

Bill = Monthly Service Charge + Maximum Peak Demand x On-Peak Rate + Maximum Off-Peak Demand x Off-Peak Rate

Option 6a - Peak and off-peak

For this example[35], the peak period is 7 am to 7 pm and the peak to off-peak charge is arbitrarily set to 3 times the off-peak charge. The broader peak period was selected to match the period for the Network Billing Demand used to calculate the Network Service charge for wholesale provincial transmission service. This should encourage shifting since on-peak demand is specifically valued.

Compared to the three part rate, changes are more extreme. Bill increases and decreases of over $250 are more common. Most impacts (increases and decreases) are still below 20%.

[35] Based on customers from PowerStream, Hydro One, Hydro Ottawa, Veridan, Horizon and Enersource.

Option 6b - Off-peak is free

According to economic theory, the value of the co-product is zero. To truly drive off-peak use, the distribution rate for off-peak demand could be valued at zero. Ontario used to occasionally value off-peak generation load at below zero. One Texas utility is valuing off-peak use (commodity and delivery) at zero to use wind power that is surplus to normal load.

This example uses the same peak hours as option 7a but sets the off-peak price to zero.

This should maximize peak shifting since demand can be used for free in off-peak hours. The incentive will be maximized since off-peak commodity pricing is also low.

The impacts based on current use are fairly comparable to TOU rate with an off-peak charge. The difference would be seen in the distribution revenue as customers responded to the rate.

E – Intermediate Customers

Some distributors have intermediate level customers with various ranges of demand. The most common is from 3000 kW to the 5000 kW of the Large class. Others have more thresholds at 500 kW, 1000 kW or 1500 kW depending on their system configuration. OEB staff is not proposing to alter these classifications in any way. The design options presented largely overlap the GS>50 and Large options.

OEB staff has concentrated in these examples on keeping the fixed charge at PLCC with adjustment, but avoiding boundary issues at the class thresholds. Most of these boundary issues would be solved by increasing the fixed charge for higher demand classes. For the purposes of the option examples, staff forced the models to offset the potential for “gaming” using the PLCC charge. The monthly service charge that intermediate customers are facing is somewhere in between the PLCC charge and their current charge while still remaining revenue neutral.

E.1 – Current design

Current rates for Intermediate customers generally look the same as rates for GS>50 customers. The current rate design is a fixed Monthly Service Charge and a variable rate based on the maximum monthly kW regardless of when it occurs.

E.2 – Options considered for Intermediate Customers

All options for Intermediate customers are based on demand as measured in kW as is currently the case.

Table 4: Rate Options for Intermediate Customers

	Design Option	Advantages
5a	Three part demand rate • Fixed part based on OEB’s Cost Allocation Model Minimum System with PLCC adjustment • Variable 1 based on maximum demand during peak period • Variable 2 based on maximum demand at any time • Peak is 7 am to 7 pm	This option values connection demand and aggregate demand separately. It is expected to be fairer and provide more revenue stability than peak and off-peak alone.
5b	As 5a • Peak is 3pm to 9 pm	

6a	Time of Use • Fixed part based on OEB's Cost Allocation Model Minimum System with PLCC adjustment • Variable 1 based on maximum demand during peak period • Variable 2 based on maximum demand during the off-peak period • Peak is 7 am to 7 pm	This option values peak capacity. Staff has modelled options that do or do not value off-peak capacity.
6b	As 6a • Variable 2 is 0	

E.3 – Option 5: Three Part Demand Rate

Once again, this rate is meant to capture three distinct cost drivers:

- the fixed monthly service charge for the minimum system
- the non-coincident rate for design demand
- the coincident demand for aggregated demand

The link to costs could be made more specific by allowing distributors to set their own peak period, by setting different peak times in different seasons. As for any rate design, the trade-off is between accuracy of the price signal and simplicity and understandability of the rate.

Example 5a – Broad Peak

In this example, the peak period is 7am to 7pm.

Most customers see less than a 5% change in their bill. For these large customers, that is still up to $500 per month.

Example 5b – Narrow Peak

In this example, the peak period is 3pm to 9pm to approximate the summer peak with solar penetration.

Compared to option 5a, the impacts are almost evenly split between increases and decreases. The dollar value is generally less than $250 or 5%.

E.4 – Option 6: Time of Use Rate

In this option, there is the monthly service charge and two distinct variable charges. There is one rate applied to the maximum demand during the peak hours and a separate rate applied to the maximum demand during the off-peak hours. It will never be the same measurement.

This simple model of peak and off-peak charges may be simpler for customers to understand compared to the more cost-reflective three part rate.

Example 6a – Off-peak Charge

In this example, there is an off-peak charge that may or may not represent the connection demand. It ensures that the distributor will derive some revenue from off-peak use.

There are slightly more customers with decreasing bills. Changes are generally less than $500 per month but up to 15% of the bill.

Example 6b – Off-peak is Free

In this example, the off-peak is considered to have no value and consequently has no charge. This is an extreme example.

This is the first example for Intermediate customers where the rate increase exceeded 20%. Some customers see increases over $2000 per month. The increase in the on-peak charge is being felt by peak users. This should encourage reductions and shifting. It may also encourage distributed generation that in the extreme under net metering could result in customers not paying enough to maintain the distribution system.

F – Large Customers

F.1 – Current design

Not every distributor has Large customers. Those that do fairly consistently define the class as follows:

> This classification applies to an account whose average monthly maximum demand used for billing purposes[36] is equal to or greater than, or is forecast to be greater than, 5,000 kW.

A Large customer might be an office/retail complex on the order of the TD Centre, a hospital complex, or university campus.

F.2 – Options considered for Large Customers

All options for Large customers are based on billing demand as measured in kW or kVA as is currently the case.

Not every distributor has Large customers and those that do may have very few. To preserve the anonymity of customer data, OEB staff received the information as a single file of large customer data. The rate used for comparison as the "existing" rate is an average of the contributing distributors. It is not the current Large customer rate for any Ontario distributor. In comparison with other rate classes, the current rate and the option rates have a relatively high fixed charge.

Table 5: Rate Options for Large Customers

	Design Option	Advantages
5a	Three part demand rate • Fixed part based on OEB's Cost Allocation Model Minimum System with PLCC adjustment • Variable 1 based on maximum demand during peak period • Variable 2 based on maximum demand at any time • Peak is 7 am to 7 pm	This option values connection demand and aggregate demand separately. It reflects cost causality.
5b	As 5a • Peak is 3pm to 9 pm	

[36] "Demand used for billing purposes" is the greater of the actual demand or 90% of the kVA to take into account the extra costs to the system imposed by poor power factor.

6a	Time of Use • Fixed part based on OEB's Cost Allocation Model Minimum System with PLCC adjustment • Variable 1 based on maximum demand during peak period • Variable 2 based on maximum demand during the off-peak period • Peak is 7 am to 7 pm	This option values peak capacity. Staff has modelled options that do or do not value off-peak capacity.
6b	As 6a • Variable 2 is 0	

F.3 – Option 5: Three Part Demand Rate

Once again, this rate is meant to capture three distinct cost drivers:

- the fixed monthly service charge for the minimum system
- the non-coincident rate for design demand
- the coincident demand for aggregated demand

The link to costs could be made more specific by allowing distributors to set their own peak period, by setting different peak times in different seasons. As for any rate design, the trade-off is between accuracy of the price signal and simplicity and understandability of the rate. Having a non-coincident demand rate should provide some rate stability for the distributor. The higher coincident demand rate should encourage shifting and DER to reduce peak demand.

Example 5a – Broad Peak

In this example, the peak period is 7am to 7pm. This reflects a broad peak. The example is based on customer data combined from all the contributing distributors.

Many more customers see a bill increase (75%) but the increases are fairly small as a percentage of the bill. They are mostly less than 3%. For customers using most of their energy off-peak, decreases can be up to 12% but are typically less than 5%.

Example 5b – Narrow Peak

In this example, the peak period is 3pm to 9pm to approximate the summer peak with solar penetration. Once again, the comparison uses all Large customer data provided and an average Large customer tariff.

As expected, the small peak is showing slightly more extreme bill impacts than the broader peak in 5a above. Some customers show a very large decrease in bill dollars (up to $10,000) but typically less than 30%.

Customer bill increases are generally less than 3% or $3000 per month.

F.4 – Option 6: Time of Use

In this option, there is the monthly service charge and two distinct variable charges. There is one rate applied to the maximum demand during the peak hours and a separate rate applied to the maximum demand during the off-peak hours. It will never be the same measurement.

This simple model of peak and off-peak charges may be simpler for customers to understand compared to the more cost-reflective three part rate although that is likely less of a consideration for Large customers

Example 6a – Off-peak Charge

In this example, there is an off-peak charge that may or may not represent the connection demand. It ensures that the distributor will derive some revenue from off-peak use.

The bill impacts are more symmetrical than the three part charge but generally larger in both dollar and percentages. Decreases are up to 20% and increases are up to 8%.

Example 6b – Off-peak is Free

In this example, the off-peak is considered to have no value and consequently has no charge. This is an extreme example.

The lack of off-peak charge seems to make up for the higher on-peak charge. Bill changes are less than with the off-peak charge. Bill increases are mostly less than 10% and decreases are less than 5%.

This rate should encourage peak shifting. The lack of off-peak revenue except for the fixed charge is risky for the distributor. There could be significant revenue losses from DER and load shifting.

G – Credits for Distributed Energy Resources

Customers vary by the size of their connection, their demand on the system and the way they interact with the grid. All of these can be taken into account in designing rates. Customers that are sophisticated enough to have generation on premises can understand that benefits are locational and must be automatic or under the control of the distributor. It may be possible to design underlying rates that avoid having special classes for distributed generation including rates that are appropriate for net metering for each rate class.

The benefits to the system from distributed energy resources are highly dependent on the source, the location, the availability and the controllability. Those benefits include voltage regulation, frequency response, and load control. The value of these benefits to distribution systems is entirely dependent on location and the distributor's ability to control them.[37]

Storage or demand response that the distributor can depend on (i.e. is under its control) can be used to defer or avoid capacity investments. Generation that provides automatic voltage support can take the place of distributor-owned equipment. The same resources in other places may not be of any benefit to the system.

Businesses that install generation or storage or who are willing to have their load controlled by third parties in exchange for bill reductions are sophisticated about their energy use. We can take advantage of these prosumers' higher level of engagement and better understanding of the electricity system to design credits (or allowances) for benefits from DER.

Thus credits could be determined and apply to specific customers in the same way that customer-owned transformer credits apply to Large classes now. The credits would be applicable if otherwise the distributor would have to pay for the benefit provided. E.g. Demand response or load control (either through reducing load or cycling storage at appropriate times) can delay upgrading capacity in an area; or voltage support can avoid investment in capacitor banks.

OEB staff sees a number of ways that these could be incorporated.

[37] or to respond automatically to system conditions such a frequency response. In Europe, automatic frequency response is part of the requirement for distributed generation installations and is manufactured into the equipment.

Planning: Where a distributor sees a need on its system as part of the planning process, it could offer installation subsidies to customers considering installations or payments to existing installations. These payments could be the net present value (NPV) of the deferred investment of the distributor. The benefits may be ancillary services that are either automatic or under the distributor's control or capacity reducing DER.

Operations: Where a distributor sees an ongoing need for operational flexibility, it could offer payments for control (dispatchability) of DER. Credits could be a small reserve payment for the right to control use and a larger time-differentiated payment for actually calling on the resource.

These payments would likely be based on a combination of the capacity of the response, the probability of availability of the response, and the controllability. E.g. a renewable generator may have a certain capacity and be dispatchable by the distributor but only be available based on the availability of the fuel. A contracted demand response may have a certain capacity and high availability but the customer wants the right to refuse dispatch instruction.

Staff is interested in comments from stakeholders on this issue.