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Staff Report to the Board

Rate Design for Commercial and Industrial Electricity
Customers

Rates to Support an Evolving Energy Sector

EB-2015-0043

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A. Rate Design for Commercial and Industrial Customers

A.1 – Introduction

In response to the changing landscape and customer expectations, a new electricity rate design is needed to enable more customer choice in investments and technology while ensuring that reliability of the electricity distribution system is maintained. Customer behavior and use of the grid is changing. Their dependence on, and relationship with the distribution grid varies greatly and is increasing in complexity. Traditional consumers continue to draw electricity from the grid to power their operations. Active customers are trying to reduce their bill by managing the amount or timing of their use through behaviours and technology. Advanced customers may expect the grid to supplement their self-generation, to provide backup power, to provide 'storage-like' support, or to deliver their produced electricity to other customers depending on price. The direct impact of these new, emergent uses and expectations of the grid is related to the size and number of customers that change their use of the system. The distribution network is necessary to serve the needs of all of these customers, whether traditional users or those selecting new technologies which rely on the system.

The rate design adopted for distribution service needs to reflect the value of the system while reflecting and encouraging sound economic choices, including investments by distributors necessary to maintain reliability. In response to this ongoing evolution and the challenges it presents, the OEB launched a policy initiative in 2013 to consider the redesign of distribution rates.

On April 3, 2015, the OEB released its policy, A New Distribution Rate Design for Residential Electricity Customers¹ (the April Report). The policy on residential rates in the April Report emphasized simplicity and increasing customer understanding of the fixed nature of the distribution service. The policy recognizes that customers primarily value connection to distribution services and the essential service of billing. The OEB's general policy for distribution rate design outlined in the report is to better reflect the relationship between distributor costs and service to customers by increasing the amount of revenue collected through the fixed rate, and reducing the amount of revenue collected through the usage rate. The OEB started this process by a gradual move to

¹ [EB-2012-0410 Board Policy April 2015](#)

fully-fixed distribution rates for residential customers, a process that is now nearly complete..

Built to meet the instantaneous needs of all connected customers, there are few costs in the distribution system that change with the energy that flows through the grid. Distribution assets are designed to deliver power reliably and have by their nature long service lives and largely fixed costs. However, where needs are changing or assets are approaching the end of their useful life, distributors have opportunities to address customers' emergent expectations through system plans in ways that can lower costs for all customers.

Under the current rate design, a customer that lowers its consumption also reduces its volumetric charge. This can lead to the customer not paying the cost of system assets that it may still need as a result of its technology choice or that were built specifically for them. This shifts risk and costs unfairly to other customers.

The current rate design of fixed and volumetric charges does not align well with the changing use, expectations and value to some customers. It can lead to uneconomic decisions by the customer and shifting of costs to more traditional customers who are either unable to, or choose not to, adopt new technologies.

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

On May 28, 2015, the OEB announced² the next stage in its redesign of distribution rates with a focus on commercial and industrial customers. The OEB identified as key objectives for the redesign along with the ones enumerated in the April 2015 Report:

- To support innovation for customers given the evolution of supply
 - Customers' ability to leverage new technology
 - Customers' ability to manage their bill through conservation
 - Customers' understanding of the value of connection

² [EB-2015-0043 May 2015 Announcement Letter](#)

- To increase efficiency
 - To maximize use of the current system
 - To optimize investment for long-term cost containment

- To stabilize distribution revenue
 - To enable technology changes
 - To support conservation
 - To facilitate investment planning

In order to develop rate design options that would meet these objectives and address consumers' interests, OEB staff consulted with a wide group of stakeholders between May 2015 and March 2016. An OEB Staff Discussion Paper³ (the Staff Discussion Paper) was issued March 31, 2016 setting out a number of options for redesigning electricity distribution rates for non-residential consumers.

In December 2018, the OEB released its Strategic Blueprint: Keeping Pace with an Evolving Energy Sector⁴, the OEB's strategic direction through 2022. The Strategic Blueprint notes the previous work done on residential distribution rates and stresses both incenting utilities to focus on long-term value for money and least-cost solutions, and rates that support the efficient use of infrastructure and enable greater customer choice and control. The OEB stated that it would achieve this goal by continuing the redesign of the electricity distributor rates to give all customers a better signal regarding the cost of delivery.

This OEB Staff Report to the Board (the Report) provides OEB staff's recommendations and proposals for proposed commercial and industrial rate design changes. These recommendations have been developed through an extensive process of consultations with affected consumer groups, data gathering and analysis, all of which is detailed below. The recommendations consider the implementation matters related to the recommended changes and in particular propose mitigation strategies to ensure the reasonableness of bill changes.

In developing these recommendations, staff has been guided by the objectives set out in the *Ontario Energy Board Act, 1998*, the OEB's Strategic Blueprint and the May 2015 letter.

³ [EB-2015-0043 Staff Discussion Paper - Rate Design for Commercial and Industrial Electricity Customers: Aligning the Interests of Customers and Distributors](#)

⁴ [OEB Strategic Blueprint 2017-2022](#)

A.2 – Developing Staff’s Recommendations

The OEB described the initial consultation for the general service part of the project in May 28, 2015 suggesting that the metering available for these customers gave a much bigger opportunity for using price signals for both optimizing the use of the system and focussing on long-term cost drivers for investment and cost containment.

Staff received 19 written responses on the Staff Discussion Paper issued in March 2016. These comments provided stakeholder insight into the merits of each option and aided staff in refining the potential designs, narrowing the range of options for further study. Following the review of the comments, staff engaged in further data gathering and analysis to develop a set of proposed rate designs that could be further discussed with customers in these classes.

Based on the comments and research, OEB staff continued with analysis on proposals that seemed to have some stakeholder support and would meet the objectives set out by the OEB. These are represented in the Navigant report attached as Appendix B and the materials presented by staff in consultation in 2016 and 2017. Navigant looked at data for low-volume general service customers for an appropriate group that would be comparable to residential customers to consider fixing the distribution charge for that group. As was done for residential customers, a mock tariff was developed and sample rate impacts were assessed. A sensitivity analysis of each scenario was undertaken to better understand what kind of cost shifting from active customers to more traditional customers would result from conservation and distributed generation.

Stakeholder Engagement on Staff Proposals

Staff also commissioned Ipsos Public Affairs to undertake a qualitative analysis⁵ of small business customers in Ontario to give a better understanding of who they are, what types of businesses they operate, and how they use electricity in their businesses. This survey was intended to help staff understand what each of the proposals would mean for this group. The Ipsos survey suggested that small business consumers are less price sensitive and, like residential customers, could benefit from a more stable, predictable bill.

⁵ The report from Ipsos on the survey is available on the OEB’s website in conjunction with this Report.

OEB staff took the analysis results⁶ to direct consultation with customers from September through November 2017. The purpose of the discussions was to describe OEB staff's proposals and identify possible implementation issues.

Staff reached out to those most affected either as individual customers or customer groups in order to further understand the effects of these proposed changes. Staff met with representatives of customer associations who might be affected by the change in rate design including the School Energy Coalition, and the Association of Major Power Consumers in Ontario. Staff engaged directly with customers including meetings with the Canadian Manufacturers & Exporters Standing Committee on Energy, the Association of Major Power Consumers in Ontario's Board of Directors, and the Combined Heat and Power consortium of the Association of Power Producers of Ontario. Staff also presented two webinars for the members of the Canadian Federation of Independent Business and met with groups that are relatively new to the OEB's processes including members of the Ontario Association of Physical Plant Administrators and representatives for Energy Storage Ontario. Staff also met with distributors through the Electricity Distributors Association and Coalition of Large Distributors to discuss potential implementation issues.

Stakeholder input from these consultations resulted in further data gathering, research and analysis that has informed revised proposals and recommendations that are laid out in this Report.

A.3 – Structure of this Paper

Section B of this paper, provides, a description of the current basis for rates, explanation of the changes in the way electricity distribution systems are operating and a brief summary of OEB staff's recommendations for new rate design for the non-residential rate classes.

Section C provides details of the current rate design and explains the recommended rate design changes for the existing *general service 50kW and under* of demand class (GS<50kW).

⁶ [Staff Proposals Presentation for Consultation](#)

Section D provides details of the current rate design and explains the recommendations for rate design for the *general service with 50kW and over of demand* class and the *Intermediate* and *Large* customer classes.

Appendix A contains a collection of OEB staff analyses that are meant to provide a deeper understanding of how customers within the general service less than 50 kW distribution rate class behave. This appendix also describes the various datasets that were provided to the OEB by select distributors that allowed modelling of options and impacts to assist the OEB in its policy direction

Appendix B is a report by Navigant Consulting on work commissioned by the OEB. Navigation developed mock tariffs from staff's proposals and did impact analysis on the customer data. They also prepared sensitivity analysis on the impacts of conservation and distributed generation.

B. BACKGROUND

B.1 – Changing Landscape of the Electricity Grid Use

As discussed in the Introduction, customer behavior and use of the grid is changing. As suggested in a recent McKinsey Report⁷ on disruptive technology, it is expected that, over a very short timeframe, distributed solutions will become more competitive with grid-supplied energy. Customers are looking to distributed energy resources (DERs) to lower their costs and increase flexibility. DERs include distributed generation to replace grid supplied power, storage to allow arbitrage of commodity costs and guarantee supply, and implementing demand response or conservation measures to increase efficiency and reduce overall consumption and demand.

Figure 1⁸ shows the decline in transmission-connected demand over the past decade in Ontario. The successive graphs show a general decline in grid-supplied power. Some of that is a decline in load but it is also a result of an increase in distribution-connected generation. The decline in early morning demand is a result of increased wind. The decrease in morning demand and steepness of the afternoon increase is typical of systems with imbedded solar power.

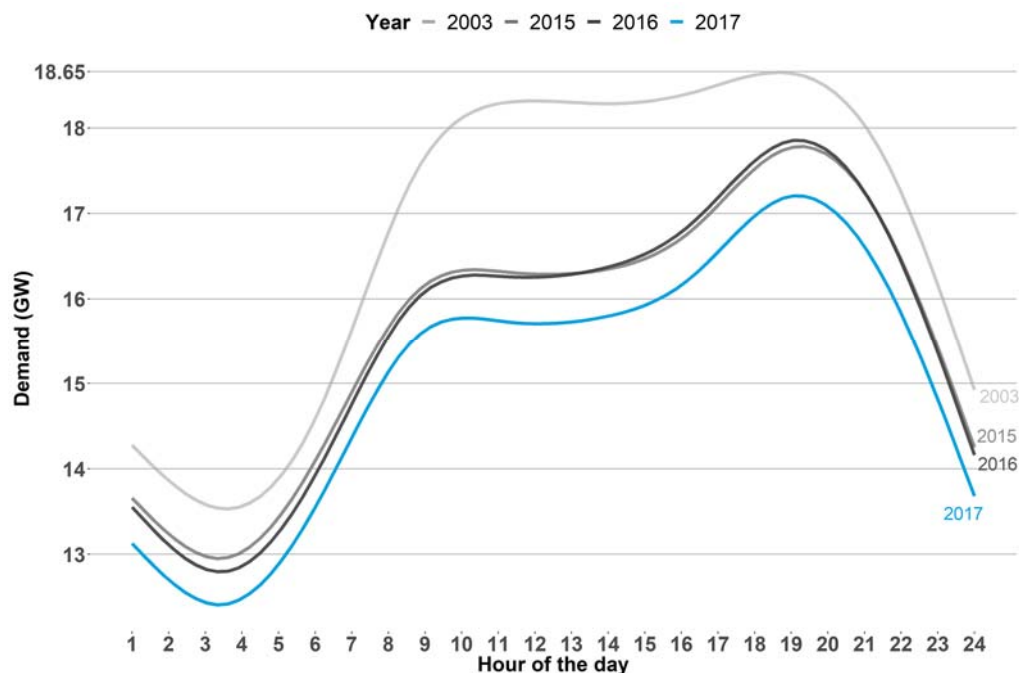


Figure 1: Average daily provincial transmission connected demand over time

⁷ [Disruptive Technologies: Advances that will transform life, business, and the global economy](#)

⁸ Data source is IESO.

Grid connection is expected to provide not only energy to meet customer requirements, but provide back up supply, for customers with DERs, when those resources are off line. In the case of renewable energy, the grid may also be expected to 'store' excess energy generated, to be consumed at a later date under a net metering arrangement.

Customers have expectations for service from their distribution company that go far beyond energy delivery. These expectations require the distributor to not only maintain adequate system capacity, but also to increase the flexibility of the distribution system to further enable customer choice and innovation. While most local distribution systems have some capacity in providing services, incremental investments are expected to be required to meet the evolving nature of use of the grid. One of the principles of rate design is that the customers who benefit from investments should pay for the benefits, such as flexibility.

This unique combination of needs, expectations, customer behaviours, and end-of-life asset conditions can lead to symbiotic arrangements for the benefits of specific customers and the distributor's entire customer base. When planned appropriately, it can deliver value at a lower cost. Generation and / or storage on the customer's premises benefits the customer by reducing the commodity bill and increasing resiliency since self-generation can provide power when supply from the grid is not possible. It also has benefits to the provincial grid such as; reducing losses and site specific benefits such as voltage support. Freeing capacity by effectively reducing site load can benefit the system by delaying the need for investment or allowing other loads to connect to lines that are nearing capacity.

The existing rate design results in a customer that lowers its consumption reducing its volumetric distribution charge. This leads to the customer not paying the cost of system assets that it may still rely on as a result of its technology choice or decisions about consumption. This shifts risk and system costs on to other customers.

The distribution system was built to meet the instantaneous needs of all connected customers and there are few costs in the distribution system that change with the energy that flows through the grid. The costs of most distribution assets are largely fixed due to the type of investment and their relatively long-lived nature. These assets are designed to deliver power reliably. However, where needs are changing or assets are approaching the end of their useful life, distributors have opportunities to address customers' emergent expectations through system plans in ways that can lower costs for all customers.

The current rate design of fixed and volumetric charges does not align well with the changing use, expectations and value to some customers. It can lead to uneconomic decisions by the customer and shifting of costs to more traditional customers who are either unable to, or choose not to, adopt new technologies.

B.2 – Basis for Current Rate Designs

Rate design is about how a distributor collects money, not about how its revenue requirement is set. The OEB approves the revenue requirement that each Ontario distributor uses to provide service including to operate and maintain its system and to invest in new lines and equipment. Ultimately in whatever policy is finally decided, the OEB will ensure that the change from one rate design to a new one will be revenue neutral. New rate design policies will not change the revenue requirement or class allocations that are approved as a result of a proceeding for any distributor. However, as with any change, the approach used to determine the value and the cost to each customer means that some customers will pay less each month and some will pay more.

The current approach and historic rate design for commercial and industrial customers was established in 1999 for market opening. It was a typical fixed/variable rate design that had been in place for many years prior to market opening when the price reflected an all in electricity cost. Fundamentally, this was founded upon the basis that grid supplied energy was the primary source of power and thus could be used to measure and estimate the relative value of a customer's use of the grid.

These rate designs were developed based on cost causality and had reflected an all in cost of electricity. A cost allocation study identified cost drivers that were customer related, demand related, or energy related. A customer charge (or fixed charge) recovered customer-related costs including a portion of minimum system costs. Demand charges recovered demand-related costs both coincident and individual. Customer and demand related costs are the primary drivers of distribution system costs. Energy charges were set to recover energy-related costs. Energy-related costs are primarily based on commodity and are not further discussed here.

For the GS<50kW rate class, meters that measured demand were previously too costly to install. Less expensive energy meters were installed and in order to approximate demand, assumed load profiles were used to map demand in kW into consumption in kWh. This assumed that all general service customers had approximately the same

load shape. It also assumed that increases in consumption were linear with increases in demand (i.e. increased consumption increased maximum demand). On average this resulted in a fair determination of costs to customers. However, in specific outlier instances, some customers are billed more than they should while others received a bill lower than the cost causality principle would expect.

B.3 – Current Classes of Customers

Distribution customers are primarily grouped into classes based on the demand they put on the grid. The only class that is dependant on end use is residential.

Residential customer class. This class is by far the most numerous. Individually, they have a limited impact on the size of the grid. They are connected to the secondary voltage system⁹ of the distributor and share this part of the system with GS less than 50kW class. The fixed-rate design changes made in EB-2012-0410 have been almost entirely implemented with 2019 rates.

General Service less than 50kW of demand class. There are minor variations in the way that Ontario distributors define the GS<50kW class. However, typically 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. The voltage shows that they are connected to the secondary system with the residential customers.

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.

⁹ Electric power distribution is the final stage in the delivery of electric power; it carries electricity from the transmission system to individual consumers. Distribution substations connect to the transmission system and lower the transmission voltage to medium voltage ranging between 2 kV and 35 kV with the use of transformers. Primary distribution lines carry this medium voltage power to distribution transformers located near the customer's premises. Distribution transformers again lower the voltage to the utilization voltage used by lighting, industrial equipment or household appliances. Often several customers are supplied from one transformer through secondary distribution lines. Commercial and residential customers are connected to the secondary distribution lines through overhead service wires or underground service cables. Customers demanding a much larger amount of power may be connected directly to the primary distribution level or the sub-transmission level.

General Service greater than 50kW of demand class. GS \geq 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 even if they do not currently have any Large customers. Some distributors¹⁰ do not have an Intermediate or Large class of customers so this class represents all of their commercial customers over 50 kW. 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.

Intermediate and Large Customers Classes. Not every distributor has Intermediate customers. The boundary is generally set between 1500kW and 3000kW.

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 purposes¹¹ 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, a hospital complex, or university campus. Some might be large industrial customers like a steel mill or car plant but these might also be connected directly to the transmission system.

B.4 – Proposed New Rate Designs to Support the Sector

The recommended rate designs for the different non-residential classes set out in this Report are the result of the extensive analysis and consultation that OEB staff has conducted following the issuance and receipt of comments on the March 2016 staff paper, including, targeted, face-to-face consultations in 2017.

Staff believes these new rate designs for the commercial and industrial rate classes will meet the OEB's objectives for rate design of supporting innovation for customers, increasing efficiency of the system, and helping distributors invest in their systems.

¹⁰ Hydro One Networks Inc. has classes called: Urban General Service Demand Billed, General Service Demand Billed, Distributed Generation and Sub Transmission classes.

¹¹ "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.

The recommended rate designs will in staff's view:

- support innovation for customers by
 - ensuring all commercial and industrial customers of every class can reduce their bill through conservation of the commodity,
 - allowing some customers to reduce their bill through lowering overall demand through conservation, and
 - allowing customers who do not have the opportunity to reduce their bill through lowering demand to benefit from a simpler, more predictable bill.

The recommended rate designs will increase efficiency of the system by encouraging economic decisions regarding investment in distributed energy resources. The designs will ensure that customers who install distributed energy resources do not shift costs to other customers and maintain fairness in the recovery of costs of maintaining a reliable and flexible distribution system.

The recommended rate designs will facilitate investments to modernize the grid in a paced and prioritized manner that will support customer choice and efficiency.

The brief descriptions and Table 1 below summarize OEB staff's recommendations for the proposed rate design for each customer group. Chapters 3 and 4 discuss them in more detail.

General Service under 50kW customers: Because of the significant diversity in this rate class, the recommended design involves splitting the GS<50kW class into a GS<10kW group and GS 10 to <50kW group

GS< 10kW customers are similar to residential customers in how they use the distribution system. Staff is recommending moving to a fixed distribution rate similar to residential rates. These customers will see a more stable, predictable bill that reflects the value to them of connection to the grid. Customers can leverage new technologies and manage costs through conservation.

GS 10kW to less than 50kW customers would see a rate based on the maximum consumption in a single hour over the billing period (kWh/h). The change would increase the link between the bill and the impact of their demand on system capacity requirements. The proposed rate design enables these customers to seek approaches to reduce their bill through adoption of demand management technology or distributed generation including net metering).

General Service over 50kW customers would see no change to the underlying rate structure. Staff is recommending that customers installing distributed generation would be subject to a new capacity reserve charge (CRC). The CRC would ensure that they continue to pay for capacity that is maintained in the system to serve them.

Large customers would see no change to the underlying rate structure but would see the new CRC described above. Large customers who adopt new technology such as batteries would also have the ability to choose a level of service that suits their needs and reflects the value of the connection to them.

Table 1: Summary of Proposed Rate Design Changes

Class	Current Rate Design	Proposed Rate Design
General Service Less than 10 kW		Monthly Service Charge (fully fixed – average cost)
General Service 10 to less than 50kW		Monthly Service Charge + demand charge (per kW)
General Service 50kW and Over		Monthly Service Charge + demand charge (per kW) + Capacity Reserve Charge
Large (over 5000 kW)	Monthly Service Charge + demand charge (per kVA)	Monthly Service Charge + demand charge (per kVA) + Capacity Reserve Charge <ul style="list-style-type: none"> • Emergency Backup • Maintenance • Bypass

C. GENERAL SERVICE LESS THAN 50kW OF DEMAND CLASS

C.1 – Customers

The small commercial class includes customers such as small retail outlets, offices, bulk metered multi-residential units of up to 6 apartments or townhouses and most farms. For the typical¹² customer, the distribution charge represents 11 to 42% of the total bill. The median is 37%.¹³ We heard from distributor groups that many customers in this group are tenants and have limited ability to make decisions about equipment and investments. It is therefore less likely that they will invest in distributed generation or other types of DERs to lower their bills, however they will invest to manage commodity costs through conservation programs.

Compared to residential customers, these customers have much greater variety in their load profiles: how much energy they use and when. Some customers have a very flat load profile where their energy use is fairly constant over 24 hours and 7 days. Other customers have spikier use as equipment turns on and off over the course of a day. Load factor, the average load divided by the maximum load over a specified period, is a measure of those spikes.

OEB staff analysed the data of 103,000 customers across 5 distributors to understand the load shapes of customers in the less than 50kW class. Figure 2 below groups customers by their load shape rather than their absolute demand. A customer whose demand peaks at 1 kW with the same profile as a customer at 15 kW will be grouped together. So customers with the A profile have a load factor close to 1 and customers with the C profile have a much lower load factor.

¹² 2000 kWh/month is a typical GS<50 customer.

¹³ The median is the value separating the higher half of a data sample from the lower half.

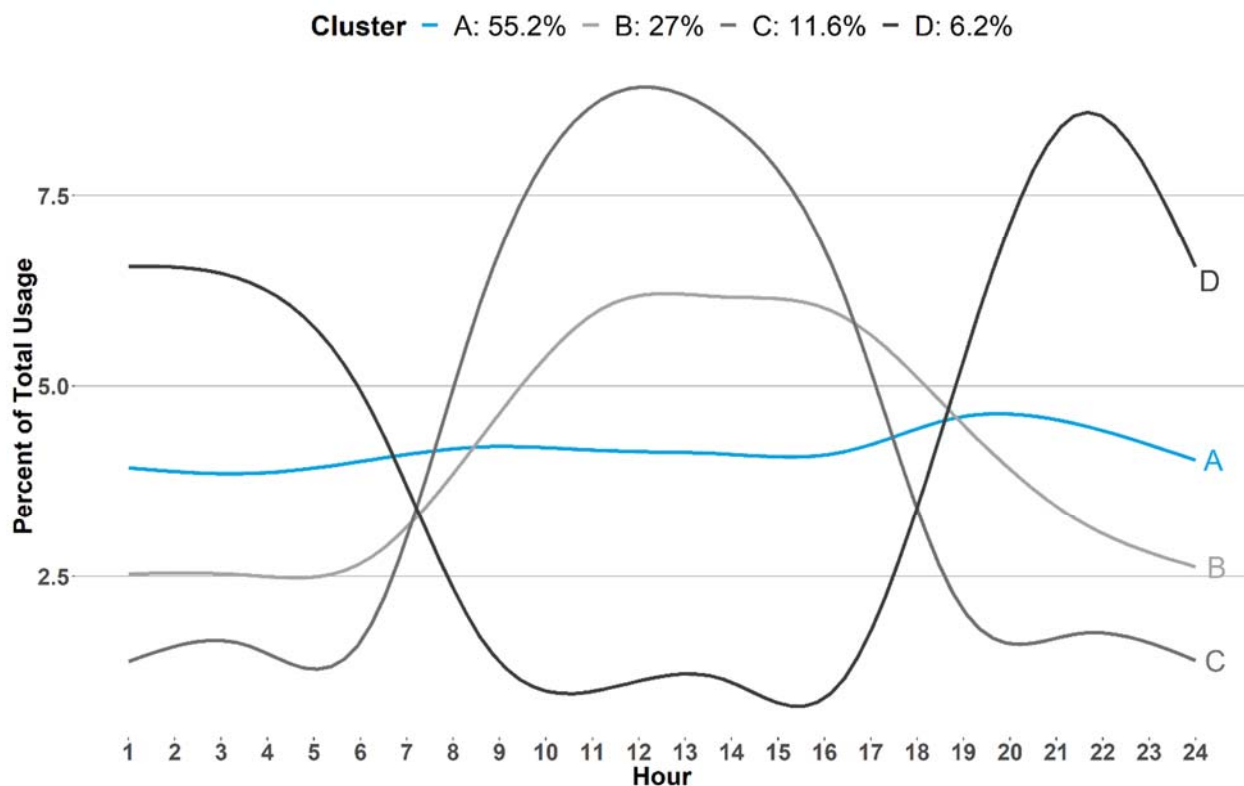


Figure 2: Generalized Load Profiles for GS<50¹⁴

The graph shows that over half of GS≤50 customers already have a relatively flat use profile. About another quarter use energy primarily during the day. The balance have off-peak demand profiles.

GS<50kW customers have experience with time dependent commodity prices. Although 80% of small and medium sized businesses¹⁵ indicated that the price they paid was the most important electricity 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 that is open from 10am to 6pm regardless of electricity prices.

The biggest group of customers (Group A) has a relatively flat profile: they use the same amount of energy on peak and off. The customers who have peakier demand

¹⁴ Christophe Genolini, Xavier Alacoque, Marianne Sentenac, Catherine Arnaud (2015). kml and kml3d: R Packages to Cluster Longitudinal Data. Journal of Statistical Software, 65(4), 1-34. URL <http://www.jstatsoft.org/v65/i04/>

¹⁵ See BEWorks and IPSOS Reid research released on Nov 16, 2015 in support of the RPP Roadmap at [RPP Roadmap | Ontario Energy Board](#)

(Groups C and D) may not be able to shift any more use to off peak periods. Many business customers have indicated that their ability to shift use is limited. Retail stores and restaurants have little control over their open hours and busy times. The combination of the IESO provincial curve in Figure 1 and the OEB RPP roadmap research cited above, suggest that the customers who have peak use have a lot of peak use but may not be willing or able to change.

The OEB is in the process of developing new Time of Use commodity rates¹⁶ for these customers that will help them focus on bill reductions through reducing and shifting use. The OEB has developed a five-point plan to redesign the RPP to respond to policy objectives, improve system efficiency, and give consumers greater control. One of the major elements of the Roadmap is implementation of pilots for new pricing mechanics and non-price mechanisms. The pilots will provide the OEB with the information necessary to design new tools for customers to manage their electricity usage and provide for increased system efficiency. As part of this plan, the OEB will undertake a comprehensive revamping of the RPP that will make incremental changes over the course of the plan. This staged approach will provide consumers with adequate time to understand and adapt to any changes in the TOU pricing structure and any rate design changes.

C.2 – Current Design

Currently, customers in the general service less than 50kW of demand class are charged for distribution service on a fixed and variable basis. They have a fixed monthly service charge (MSC) and a variable charge that is based on their consumption over the month in kWh. As described earlier in Section B.2, consumption was used as a proxy for demand since meters capable of measuring demand as well as consumption were not justified based on the total billing for each small customer. It was assumed that each additional kWh was being added on the same load profile and driving maximum kW.

Distribution charge = Monthly Service Charge (\$)
+ Consumption rate (\$/kWh) x Monthly Consumption (kWh)

Under the current rate design, a customer with a flat load profile (line A in Figure 2 above) but the same consumption as someone with a higher demand profile (line B in Figure 2) would pay the same amount for distribution. However, the cost to the system

¹⁶ Ibid.

to serve customer B is higher. Customers like A were to a certain extent subsidizing customers like B. Given the metering available to the class, that was unavoidable.

C.3 – Proposed New Rate Design Approach to the Under 50kW class

Comments on the Staff Discussion Paper proposed splitting the GS<50 kW class into two groups. The suggestion was that the smallest group would be made of customers with under 10 kW of maximum demand. These would be analogous to residential customers. They would typically be served at the very lowest voltages and have single phase service. Most would be traditional customers for whom electricity service and costs are not a main focus of their business. Like residential customers, they might benefit from a more stable and predictable bill and can focus on conservation of the commodity as a means a more practical means of managing costs.

The second group would be those at and above 10kW of demand to less than 50 kW (GS 10 to 50kW). These would typically still be served from the secondary system but might be at slightly higher voltages or have 3 phase service to accommodate their higher demand. The Ipsos qualitative study suggested that these customers might be slightly more knowledgeable about their energy use although it is still not a focus of their business.

In the Staff Discussion Paper, staff had proposed a 3-part distribution charge made up of a monthly service charge and 2 demand charges (one measured during a time dependent peak period and one non-coincident, 'anytime' measurement). In the written comments, several stakeholders agreed that such a rate structure was highly cost reflective. However, they questioned the ability of customers who were currently billed on a consumption basis to understand it or effectively respond to it. Staff now consider that moving these customers from a consumption charge to a single non-coincident demand charge is a step toward both making their rate more cost reflective to inform them about the nature of the system and the value of their connection. They can also reduce their bill by reducing and shifting the timing of their consumption of the commodity. The focus on efficiency will allow them to directly reduce their costs.

C.4 – Proposed New Rate Design for General Service Under 10 kW

The smallest general service customers are comparable to residential customers in their use of the system. These customers are generally connected on the lowest voltage system.

The OEB chose a fully fixed distribution rate for residential customers to provide certain benefits. Staff believes that those benefits also apply to these small commercial customers. It will provide a more stable, predictable bill for customers for whom electricity use is not top of mind. It is a fairer way to bill customers who essentially receive the same benefit from the system – that of a reliable connection. And it will recover the costs of providing distribution service while preventing the shifting of costs from advanced customers to active and traditional customers.

Smaller customers are more focused on technology and behaviours that help them reduce their overall bill by saving energy. However their changes in consumption are not likely to impact distribution system costs as they are unlikely to make large investments in DERs or other technology or equipment given the high cost of those investments. This view is based on the input we received from the very small customers that energy costs are not a significant component of their overall business costs. The proposed rate design allows them to focus on energy conservation to manage cost while ensuring that each customer is paying their share of the costs for a reliable distribution service. The fixed rate will also help customers understand the fixed nature of the assets that are serving them, achieving the objective of providing better information to customers about their service.

In our analysis as shown in Figures 3 and 4 below, the average maximum monthly demand¹⁷ for residential customers is 5.3 kW and for GS<10 kW customers is 3.9 kW. In each of the plots below, each grey dot represents a customer's maximum demand for the month. The black lines represent average maximum demand for all customers that month. Half of all customers that month had an average maximum demand between the two red lines.

¹⁷ The data supplied by participating distributors was hourly consumption data. The measure here is consumption over an hour which is one measure of demand.

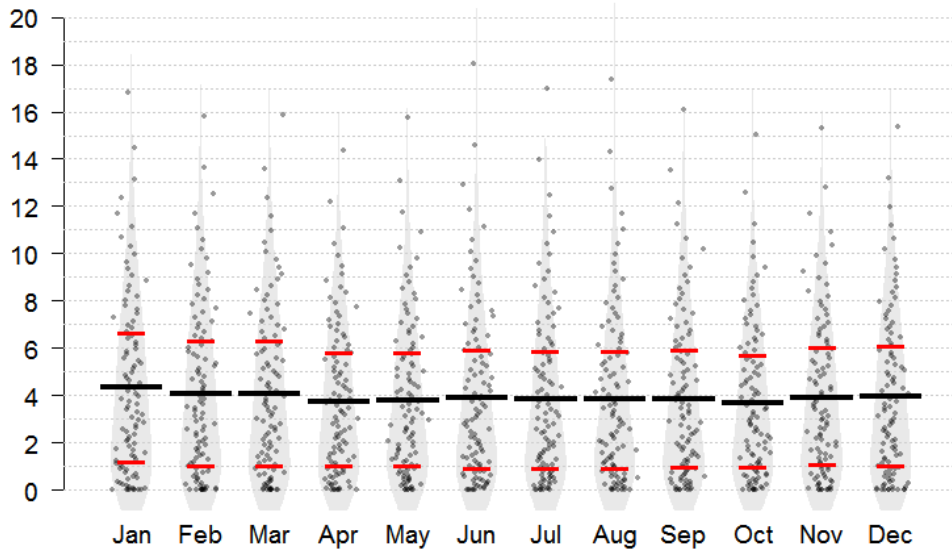


Figure 3: Monthly GS<10 Peak Demand

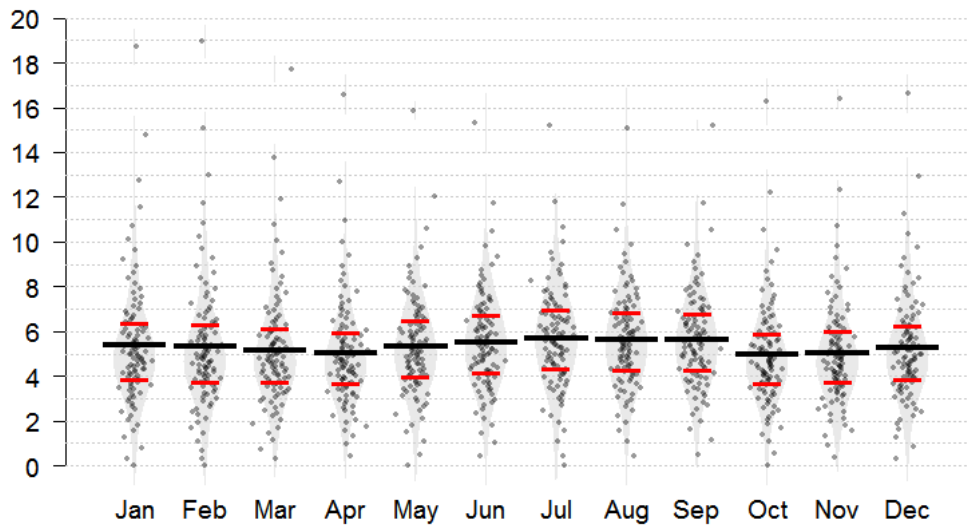


Figure 4: Monthly Residential Peak Demand

Distribution charge = Monthly Service Charge (\$)
(average cost for the subclass)

Staff proposes that all distributors should move to a fully-fixed rate for general service customers with a maximum demand of 10 kW and under. Staff further proposes that the tariff sheet definition of these customers be based on the average of the highest hourly consumption in one billing month in a calendar year and the highest hourly consumption in the two months on either side of that peak month (for a total of 5 months). This approach to making a change in class definitions has been adopted by the OEB before.¹⁸ The OEB “chose the 5 month period as a significant, sustained period during which a customer’s usage would reflect the assets needed to meet its requirements. To do otherwise would result in other customers subsidizing seasonal customers.” It also avoids a customer being classified according to a single month that is not indicative of general use. The intent was to avoid classifying a customer based on a single high demand month which could be an aberration. Rules on reclassification of customers are detailed in section 2.5 of the Distribution System Code.

OEB staff is recommending the fixed charge be determined based on the costs that are allocated to the subclass divided by the number of customers. For a discussion of allocation issues for implementation see section C.6. We developed a sample mock tariff for each of the distributors who provided customer profiles based on their customers and their revenue requirements. For a listing of the mock tariffs that were developed and used for bill impact studies, see Appendix B.

During our consultation, a distributor representative suggested that instead of using 10 kW as the boundary between the two new classes, we use 2000 kWh per month. Based on our research, if this approach were adopted, most of the customers with extremely high impacts would be moved into the lower consumption class. They would still see a bill increase because of their low use but it would not be as large. The advantage of this approach is that it would mitigate increases for some customers. The disadvantage is that it would not be moving to align the rate design with the cost drivers related to the value of the connection, i.e. peaky customers would not be paying for the demand that they put on the system.

¹⁸ [EB-2007-0722 Notice of Amendments to the Distribution System Code for Customer Reclassification](#)

Mitigating Customer Impacts

The OEB has a policy of mitigating rate and bill impacts as a result of changes in rate design. The OEB implemented its residential rate design policy over four years to provide customers the opportunity to adapt to the changes and make changes in the way they consumed. In considering recommendations for rate design for the GS<10kW customers, OEB staff have undertaken analysis and modelled potential bill impacts as well as mitigation strategies. The following sets out the results of the modelling and our proposed mitigation strategy. The analysis presented here is intended to be illustrative. From the customer data and existing tariffs used for analysis, staff cannot predict the exact bill changes that would emerge for any particular customer. This would depend on the implementation of the policy to an individual distributor through its rate application.

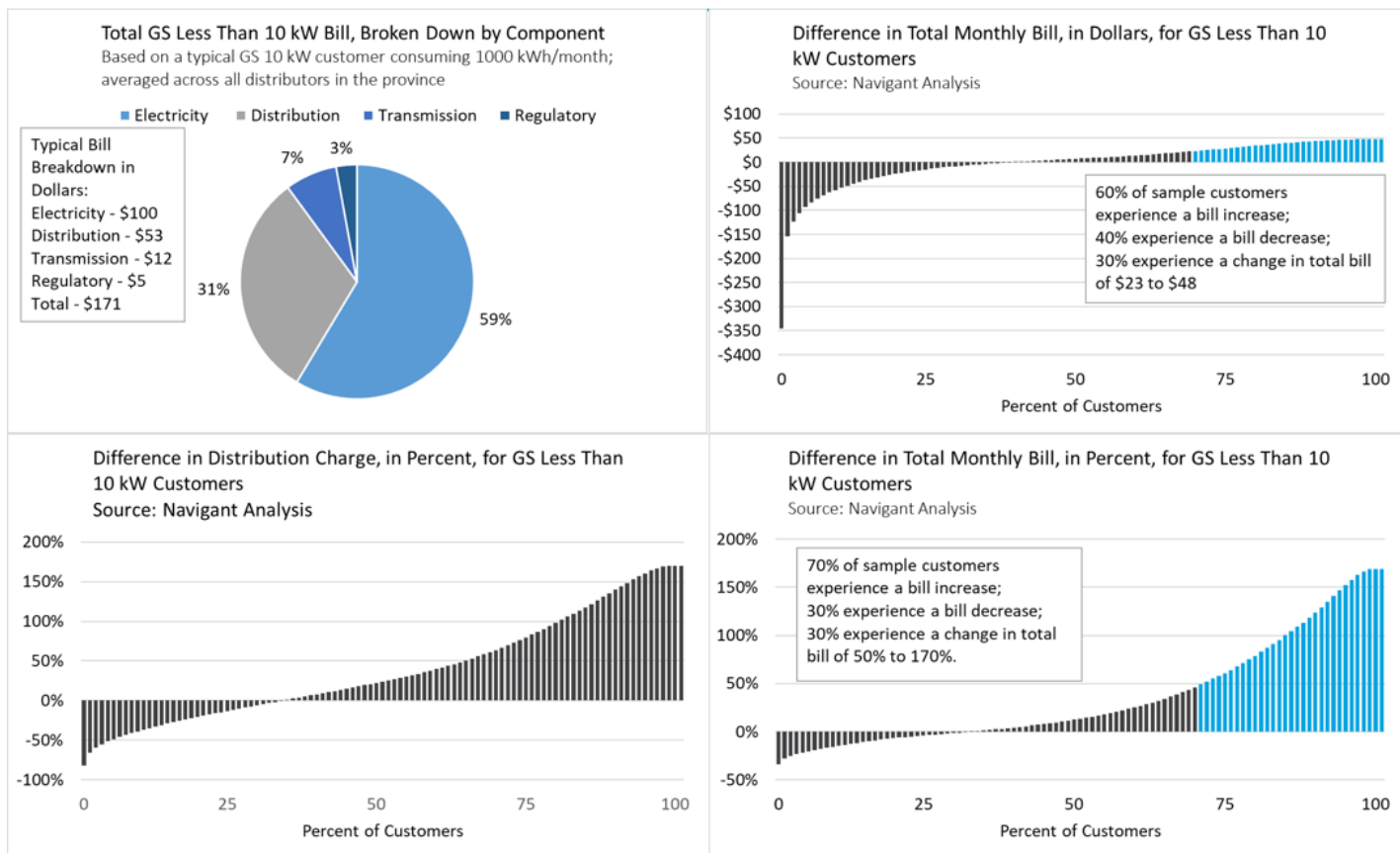


Figure 5: Analysis of Customer Impacts for the GS<10kW Group

Based on the customer data that staff have received from a subset of distributors, the average bill for this customer group is \$171 per month, but can vary from \$140 to \$224 per month, depending on the distributor that serves them. For the customers in our

data set, the distribution charge is 17 to 45% of their total bill. The median is 30%. The basis of the rate design changes are designed to be revenue neutral, i.e. the average customer will not see a change to their bill from distribution charges.

Customers with a higher than average consumption will see a distribution charge decrease. Customers with a lower than average use will see a distribution charge increase. Table 2 shows how customers in this lowest volume group would be impacted. The very low users with higher bill impacts in Table 2 tend to have high capacity demands on the system i.e. they have very peaky use. As discussed earlier the distribution system is driven by the capacity requirements of its customers, not the energy needs. These high peak demand low energy use customers' cost to the system is similar to other customers with the same demand but who may use much more energy and are currently paying a much higher share of the distribution system costs. Ultimately, a change to the rate design should result in all customers paying their fair share of the distribution costs instead of there continuing to be a level of spreading costs in the class that results in some customers being subsidized by others.

Ipsos did a qualitative research project on small business pricing for OEB staff. In-depth interviews with a small number¹⁹ of representative customers suggested that they are relatively insensitive to price changes in electricity. This is usually because the electricity bill is a relatively low part of their overall operating costs. Nevertheless, staff proposes a rate mitigation strategy similar to the one used for residential customers to transition to the new rate design. The intent is to make sure that any bill increases as a result of this policy are manageable for the customer. The changes to residential rate were implemented over 4 years to keep monthly increases under \$5 per month. The changes as a percentage of bill for these customers will be slightly more because the overall bills are larger.

The table below shows total bill changes²⁰ for groups of customers.

¹⁹ Ipsos conducted in-depth interviews with 13 business customers under 50 kW.

²⁰ These total bill calculations show the estimated change to the customer's total bill (commodity + distribution + transmission) based on the estimated change to the distributor charge. More complete analysis is available in Appendix A.

Table 2: Representative Percentile Changes in Customer Total Bills for GS<10kW Customers

Distributor	Decrease	Increase less than 20%	Increase more than 20%
Orangeville Hydro	35%	55%	10% (average ~\$11 per month)
Powerstream	35%	50%	15% (~\$12)
Toronto Hydro	35%	30%	35% (~\$24)
HONI UGe	35%	30%	35% (~\$20)
HONI GSe	30%	15%	55% (~\$35)

As discussed above, the customers that see a bill increase have lower than average consumption. Those with a large bill increase are very low users. Under the proposed fully-fixed rate design approximately 55% of HONI GSe <10kW customers in the data set are expected to experience a total bill increase greater than 20%. Given this result of the proposed new rate design, staff undertook a further examination of the sample data for HONI GSe customers and identified that the average consumption per month is much lower than the sample from other distributors; 1,858 kWh compared to 2,407 kWh. Also, a large proportion of HONI GSe customers (approximately 9%) consume less than 50 kWh (exceptionally low consumption). Only 2.5% of customers of all other distributors combined consume below 50 kWh per month. Figures 6 and 7 show how many customers fall in a particular consumption range.²¹

²¹ For clarity only the first 50% of the same data is shown.

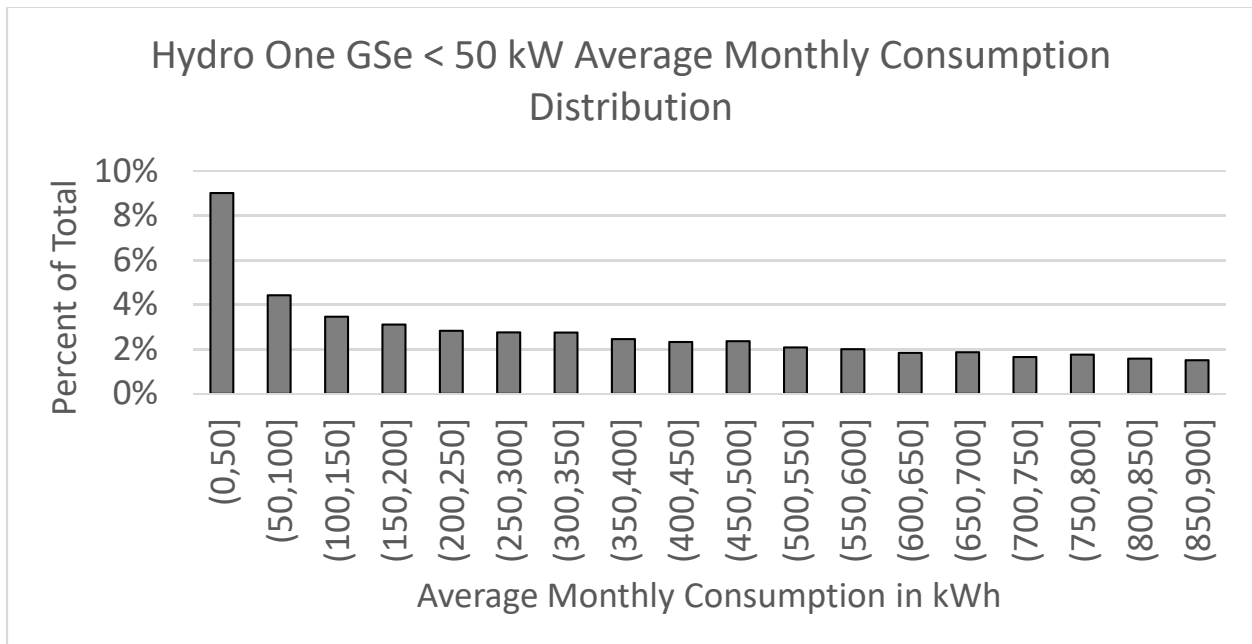


Figure 6: Average Monthly Consumption for HONI GS<50kW customers

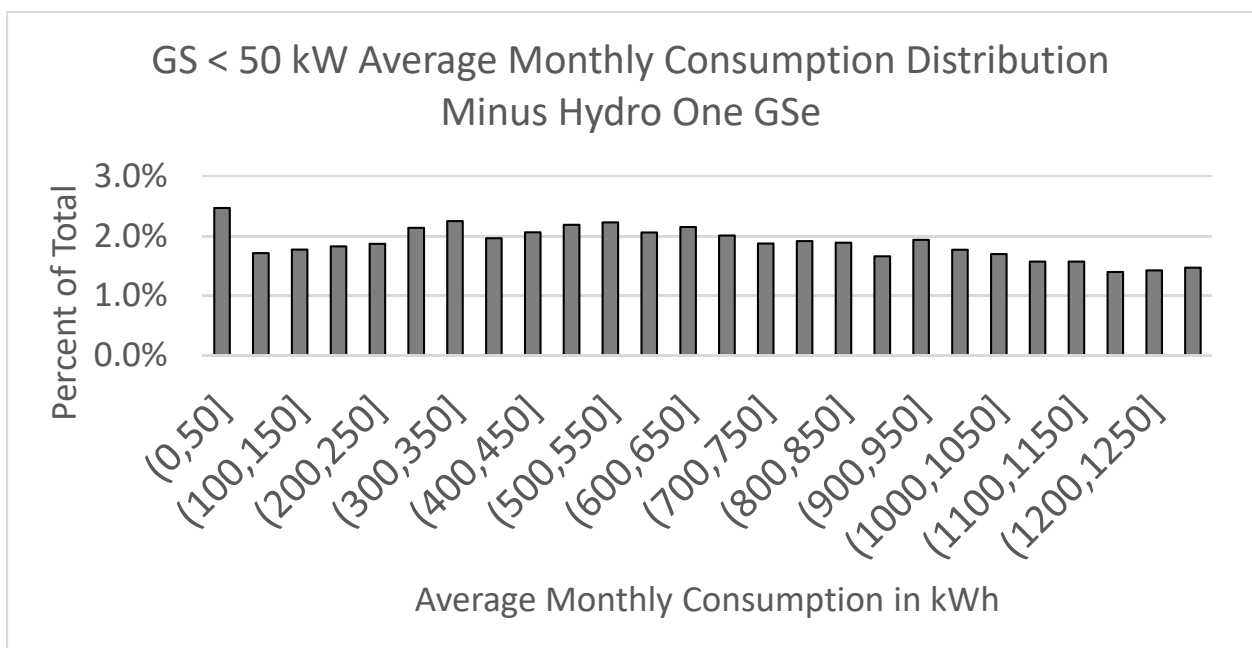


Figure 7: Average Monthly Consumption for All Other Distributors GS<50kW customers

In addition, low volume HONI GSe customers experience the biggest change, compared to other sample distribution customers, from fixed/variable split to fully-fixed

distribution rate because of the current low monthly charge²². These impacts can be mitigated through careful implementation in a way similar to that done for residential rate changes. Staff's proposed mitigation strategy is to gradually reduce the monthly consumption rate while correspondingly increasing the fixed monthly service charge. That is, each year the \$/kWh (monthly) charge decreases and the MSC increases to try to recover the same amount of revenue. Staff propose that this be done over 5 years. Customers who are identified as having high bill changes can be targeted for conservation programs or helped to make changes that will help lower overall costs.

C.5 – Proposed New Rate Design for General Service 10 to 50kW

Staff is proposing moving these customers from a consumption charge to a single non-coincident demand charge as a step toward both making their rate more cost reflective and providing better information regarding the value of their connection. This will bring them in line with GS>50kW and Large customers in being billed according to the cost driver.

Distribution charge = Monthly Service Charge (\$)
+ demand rate (\$/kWh/h) x highest hourly consumption in
the billing period (kWh/h)

Staff is proposing that the billing determinant for the proposed GS 10 to 50kW class should be defined as maximum consumption over an hour interval during the billing period (kWh/h).

²² Our mock tariff resulted in change from a \$28 monthly service charge and \$.056 variable rate to a \$75.50 monthly fixed charge. For a HONI GSe customer consuming between 0 and 50 kWh a month this represents a \$47.5 to \$44.7 increase in total bill.

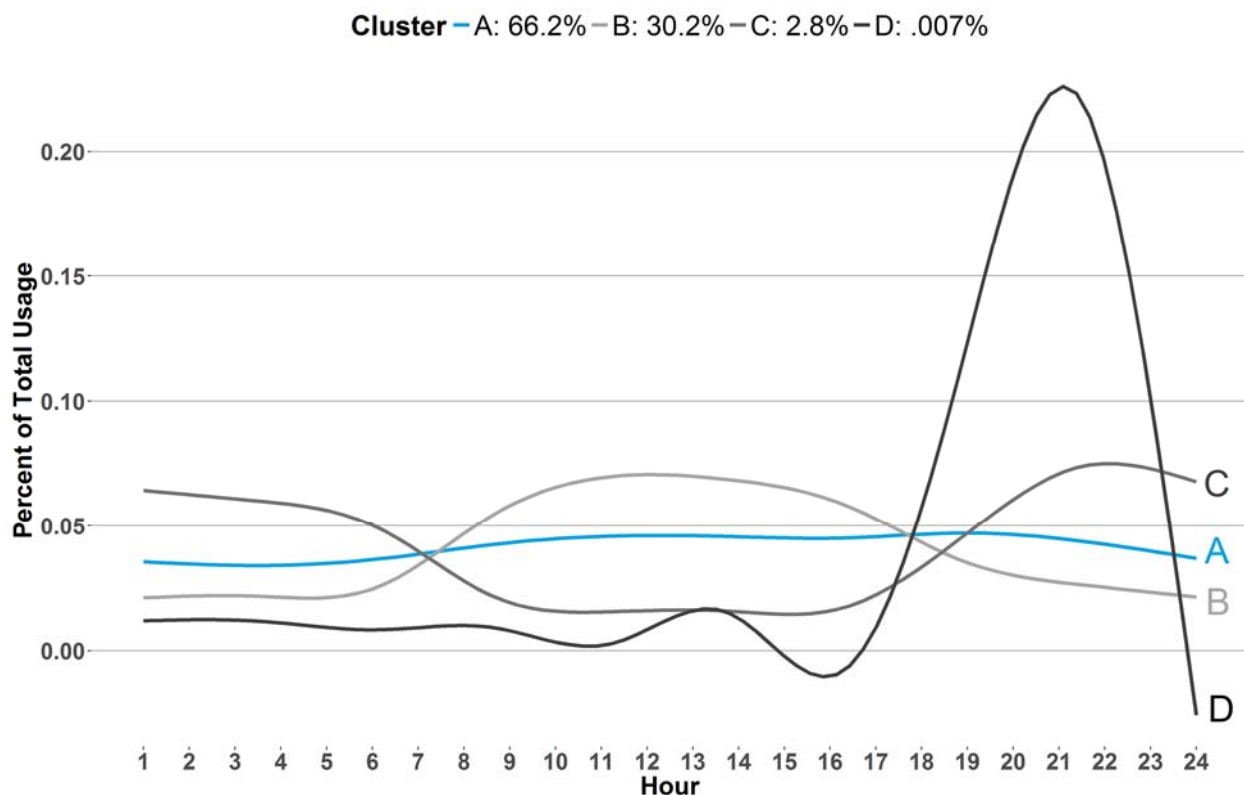


Figure 8: Grouping plot of load profiles for customers in the GS 10 to 50kW group

This rate class is made up of a number of different kinds of customers. This group is still relatively unlikely to install distributed generation due to the low focus on electricity bills and lower rate of ownership of their premises. As seen in Figure 8 above [the grouping plot], they all use the system in different ways. Under the current rate design, a customer with a flat load profile (line A in Figure 8 above) but the same consumption as someone with a higher demand profile (line B in Figure 8) and extremely peaky customers (line D in Figure 8) would pay the same amount for distribution. However, the cost to the system to serve customers B and D is higher. To some extent, customers like A are subsidizing customers like B and D. Until now, a meter that could measure demand has been cost prohibitive for this group. They have been billed on monthly consumption (kWh) as a proxy for billing them on the more cost reflective measure of demand. Now, all GS<50 kW customers have a smart meter capable of providing an hourly consumption measurement (kWh/h) as a measure of instantaneous demand on the system. Moving to an hourly demand charge from a monthly consumption charge will make the charge fairer by being more cost reflective. In other words this makes the charge fairer for all customers in this group while still allowing customers to make choices relying on the flexibility of the distribution system.

Staff believe that the proposal for this group satisfies the objectives set out by the OEB. Customers will have the ability to use innovative technology to manage their bill. The interests of the customer and the distributor are linked in that the customer has an incentive to reduce demand through conservation, efficiency, or distributed energy technology which will, in turn, reduce the need for investment by the distributor. By building this greater efficiency into their system planning, the distributor can right-size the system and contain long-term costs.

The proposed change in the rate design for this group will better reflect the value and cost causality relationship between the customer use/reliance on the distribution system and the cost to ensure that the distribution system is available for the customer.

All customers under 50kW have a smart meter. The smart meter does not measure an instantaneous demand but rather the consumption over an hour. The IESO has confirmed to OEB staff that the Smart Meter Entity will be able to provide this billing determinant to the distributors for these customers. Before implementation, the operational processes of both the MDMR and the distributors CIS systems will have to be synched to ensure that the request and response are compatible. In other words, the MDMR and the CIS systems of the distributors will have to be tested to make sure that the correct parameter is being sent and that the information flows smoothly.

Currently, customers who are reclassified from under 50kW to over 50 kW see a large bill increase due to a discontinuity in the current rate structure. One of the goals of this project is to lessen the existing boundary issue at 50 kW. The move to an hourly-consumption-based rate will help as it will eliminate the situation where a customer with a low load factor has been paying a low monthly consumption bill but begins to pay a higher demand bill when switched to the GS \geq 50 class. Under the proposed new rate design, the customer will already be paying according to an approximation of demand.

Mitigating Customer Impacts

The 10-50 kW group of customers are diverse types of businesses, and have vastly different consumption patterns over the day, month and year, as well as the timing of their peak demand. As a result, their current distribution related charges vary significantly. Rate design changes to better align their use of the system to the costs that are being caused by their use are less easily determined, without greater understanding of each circumstance. The proposed rate design changes are designed to be revenue neutral for the distributor, and the average customer based on consumption and demand would not see a change to their distribution charges.

However, since the basis for the rate design is to change from volumetric to demand (peak), each customer will experience a difference. A customer with higher consumption but a flatter profile will see a decrease and a customer with lower use but higher demand will see an increase. The high use, or peaky, customer would be expected to engage in demand management through DERs or other technology.

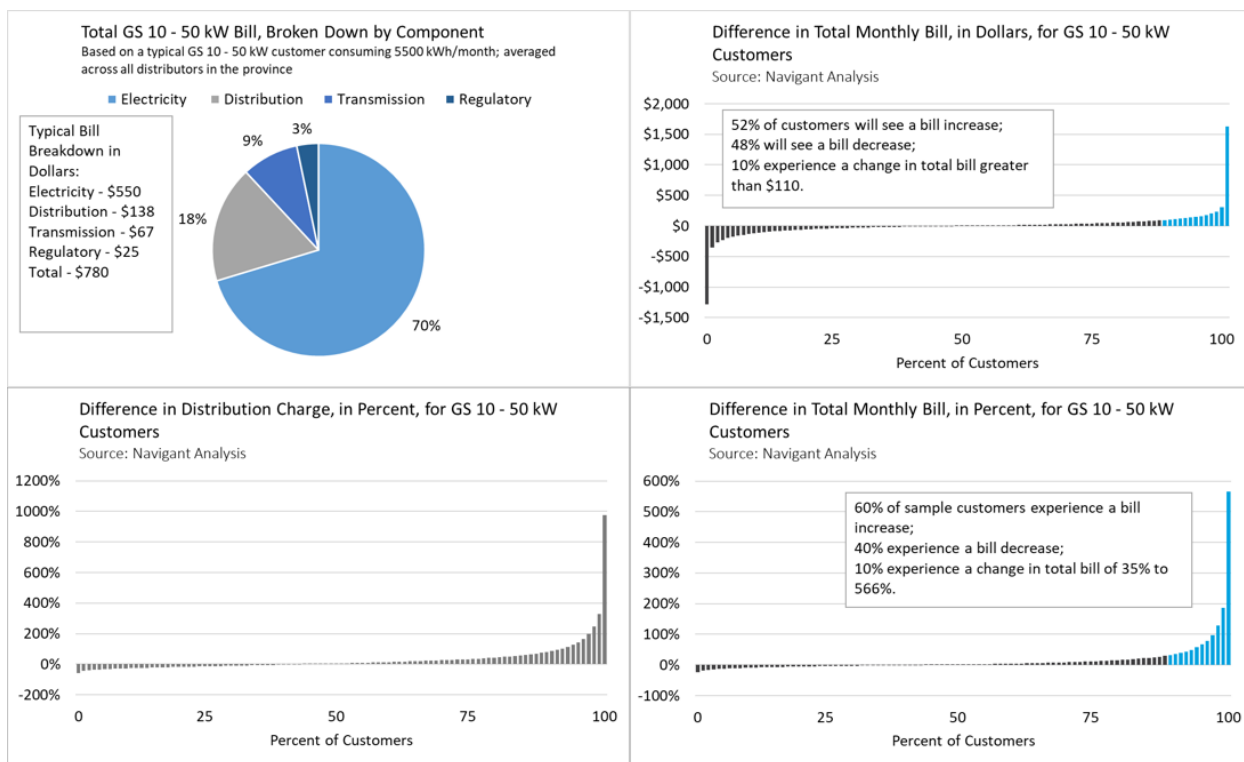


Figure 9: Analysis of Customer Impacts for the GS 10 to 50kW Group

Appendix A includes an examination of characteristics for GS 10 to 50 customers that show the most impact from our mock tariffs. Those with very large increases (the bar on the extreme right of the graphs in Figure 9) are very few in number and with unusual use patterns. Analysis concludes that customers that have a large change in total bill in dollars are not similar to customers that have a large change in total bill by percentage.

OEB staff is proposing a rate mitigation strategy to make any bill increases as a result of this policy more manageable for the customer, similar to the proposals for the under 10kW class. Staff’s proposed mitigation strategy is to gradually reduce the monthly consumption rate while correspondingly increasing the hourly consumption rate. i.e. each year the \$/kWh (monthly) charge decreases and the \$/kWh/h (maximum hour) increases to try to recover the same amount of revenue. Customers who are identified

as having high bill changes can be targeted for conservation programs or helped to make changes that will help lower overall costs.

Customers in this class can control their own bill by lessening their maximum hourly consumption and thereby their demand on the system through conservation, efficiency, demand control or installation of generation. They can also lower their bill by managing the amount and timing of their consumption of the commodity.

The table below shows total bill²³ changes for groups of customers from our analysis.

Table 3: Representative Percentile changes in customer total bills

Distributor	Decrease	Increase less than 20%	Increase more than 20%
Orangeville Hydro	40%	40%	5% (average ~\$50 per month)
Powerstream	50%	45%	5% (~\$50)
Toronto Hydro	50%	40%	12% (~\$90)
HONI UGe	50%	40%	10% (~\$114)
HONI GSe	40%	35%	25% (~\$120)

The customers with higher bill impacts in Table 3 tend to have very low energy consumption but very high capacity demands on the system i.e. they have very peaky use. As discussed earlier the distribution system is driven by the capacity requirements

²³ Including distribution charges and RPP commodity charges.

of its customers, not the energy needs. These high peak demand low energy use customers' cost to the system is similar to other customers with the same demand but who may use much more energy and are currently paying a much higher share of the distribution system costs. Ultimately, a change to the rate design should result in all customers paying a fair share for the cost of maintaining a reliable distribution system instead of there continuing to be a level of spreading the costs across all customers in the class leading to that results in peaky users being subsidized by others.

To better understand the bill impacts, staff were interested in the types of businesses who would see increases or decreases. The customer data provided by distributors for analysis did not include any information on business types. However, the US Department of Energy has created typical electricity use profiles for several business sectors and premise sizes in different parts of the country. In an attempt to further understand the impacts that the recommended rate design changes would have on customers, OEB staff ran the DOE profiles of several typical businesses through our mock tariffs. We used businesses where the typical profile was less than 50 kW and the files for businesses theoretically located in northern states. The profiles used were for: small office, quick-service restaurant, and mid-rise apartment, located in New York; Pennsylvania, Michigan, Ohio, Vermont, Maine, Massachusetts, Connecticut, Rhode Island, and New Jersey. In all cases, these business types saw average bill decreases from our mock tariffs varying from 2.6% to 7%.

Table 3: US Department of Energy Constructed Electricity Profiles for Businesses

Customer type	Average hourly demand in kw	Average monthly maximum demand in kw	Average monthly consumption in kwh	Average bill change in %
Small office	7.3	14.9	5,341	-2.6
Quick-service restaurant	21.5	31.5	15,738	-7
Mid-rise apartment	25.9	48.8	18,911	-4

Looking at the Ontario data for all customers, the bill impacts for a small number of customers are quite high on a percentage basis. Analysis shows these outlier customers to be substantially above average in the ratio of hourly consumption to monthly consumption. That is, they are very low users with exceptionally peaky requirements. They have low use and have consequently been paying a low distribution

service bill. However, they have a higher impact on the network and capacity has been built into the system to ensure that their needs are met. It is not clear what these customers are doing to have this unusual profile. They do not conform to any of the DOE profiles for common businesses. They would benefit the most from conservation or distributed energy resource programs to reduce their maximum demand in relation to their consumption. Distributors could potentially identify them from billing and smart meter data and target them for conservation programs to help mitigate bill increases.

C.6 – Implementation Issues for GS < 50 kW

Staff is proposing that the changes in the GS<50kW class take place without changes to the cost allocation studies currently in use. A discussion of the incorporation of already planned changes to the cost allocations is discussed immediately below. To keep the new rates revenue neutral, there should be a calculation of the expected revenues under the existing rate structure and the new designs would be set to collect that amount.

The GS<10kW fixed rate would be based on the amount of revenue from the class divided by the number of customers.

During an IRM period, revenues are increased by a percentage based on inflation, performance, and capital spending. The amount of revenue to be collected from the GS <10kW class can be increased from the previous year by whatever the increase appropriate to the GS< 50 class is determined to be.

One step in setting rates is allocating the costs of running a distribution system among the classes of customers that are served. An amount of the costs of building and maintaining the system is allocated to each class according to their share of the total demand. The rates for each class are set to recover allocated costs.

In consultation, stakeholders raised the issue of whether these new customer groups would be full classes or subclasses. As subclasses, the costs allocated to the group would be split according to the current revenue derived from each group. As full classes, a cost allocation study would have to be done before the change could be made.

Proceeding with subclasses would make implementation faster. However, allocating costs to full classes prior to making the change would be more cost reflective. Given the

changes that have already been occurring in the way the customers use the distribution system, staff is proposing to move quickly to address the cross-subsidization and minimize any further impacts on customers. The OEB has already announced a requirement²⁴ that all distributors must update load profiles for all classes. These load profiles should make use of more detailed up to date information available from actual customer meters.²⁵ Staff propose that the GS<50kW class be split into subclasses as soon as possible after the rate design policy decision and that distributors create full class profiles and divide them into classes when they update all their class load profiles as required by the new guidelines. Some distributors who have updated load profiles already or who have robust load forecasting could possibly make full classes earlier.

²⁴ [Filing Requirements for Electricity Distribution Rate Applications](#) issued July 12, 2018

²⁵ Ibid section 2.7.1

D. GENERAL SERVICE 50kW and OVER, INTERMEDIATE & LARGE CUSTOMER CLASSES

The approach to the GS \geq 50kW, all Intermediate classes and the Large customer classes is essentially the same. For the purposes of this paper, we will discuss them together and identify any differences between the customer classes where appropriate.

D.1 – Customers

GS \geq 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 even if they do not currently have any Large customers. For these customers, the distribution charge represents between 2.8 and 20% of the total bill. The median is 7%. Some distributors²⁶ do not have an Intermediate or Large class of customers so this class represents all of their commercial customers over 50 kW. 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.

Not every distributor has an Intermediate customer class. The boundary is generally set at 3000kW. For some, the boundary is at 1500 kW.

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 purposes²⁷ 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, a hospital complex, or university campus. Industrial customers such as an automotive plant would also be a large customer. For these customers, the distribution charge represents between 2 and 11% of the total bill. The median is 5%.

²⁶ Hydro One Networks Inc. has classes called: Urban General Service Demand Billed, General Service Demand Billed, Distributed Generation and Sub Transmission classes.

²⁷ "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.

D.2 – Current Designs

The current rate design for GS≥50kW is a fixed Monthly Service Charge and a variable rate based on the maximum monthly kW regardless of when it occurs (non-coincident peak or NCP).

**Distribution charge = Monthly Service Charge (\$)
+ demand charge (\$/kW) x maximum monthly demand (kW)**

Large customers are billed a fixed monthly service charge and a variable rate based on apparent power (kVA) as a proxy for the demand on the system. Large customers are typically billed on kVA to take into account whether or not the distributor has to install special equipment to manage power quality in order to serve them. The OEB does not propose to change the definition of “billing demand” for the Large class of customer.

**Distribution charge = Monthly Service Charge (\$)
+ real demand charge (\$/kVA) x maximum monthly real demand (kVA)**

These rates are based on good rate design principles and are cost reflective of fixed and demand charges.

Current Standby Rates

Current Standby Rates were developed for load displacement generators. Load displacement generators are generally not treated as generators because they are not expected to inject electricity into the system. Net metered generators are expected to inject electricity to the system at some times while drawing from the grid at others, effectively using the grid as a virtual storage battery. They may impose new costs on the system because of the way that the generator operates.

Eleven Ontario distributors currently have standby rate classes. Distributors have applied for these charges only if they felt it was needed in their service area. The applications have been made at different times with different approaches and the OEB has considered each one as the case arose. This has resulted in considerable variation in these rates. A standby charge is generally a separate tariff regardless of size with a demand-only rate based on measured demand over the month. Some of these tariffs are based on allocated costs and some on estimates of cost. How distributors calculate the rate and measure the billing determinant vary considerably.

D.3 – Changes Proposed for GS \geq 50, Intermediate and Large Customers

GS \geq 50kW customers, Intermediate and Large customers are already billed on demand so their bill is already reflective of distribution system cost drivers. In written responses to the Staff Discussion Paper, there was some support for a 3-part distribution rate (fixed monthly service charge and two demand rates – one coincident and one non-coincident) as being more cost reflective than the current 2-part rate. We also heard very strongly in consultation that these customers were already dealing with many changes, both in general business conditions and the electricity bill. These customers also pointed out that they had often made previous business decisions for investments and operations based on managing their bill, including to participate in the Industrial Conservation Initiative peak demand reduction program. Changes to the rate design could undermine those decisions.

Based on the feedback and further research, staff are now proposing that there be no change to the underlying rate classes, basis for fixed charge, or rate design and allocations for these customers.

However, these customers are more likely to own their own facilities and make investments in distributed energy resources such as generation and storage to manage their bill. The objective of a change for these customers is to allow them to make decisions on investment in distributed energy resources for their own benefit based on sound economic principles. However, it is also important to prevent those decisions from negatively impacting more traditional customers through unintentional cost shifting. Those decisions should be integrated into distribution system planning where possible to harness the benefits of distributed energy resources for all customers.

On that basis, OEB staff are recommending a capacity reserve charge (CRC) be designed for customers who install distributed generation with or without storage to represent the cost of capacity that is being held in the system to supply their needs when their own generation cannot. Staff recommend that these would be mandatory for distributors to implement for distributed generation.

Staff's recommendation is that these CRC would replace any current standby charges and be technology specific. For larger customers, the CRCs could take into account the level of service that the customer needs (emergency backup service, maintenance service or basic connection) and the specific planning and locational circumstances of the distributor's system.

The design of the CRCs would achieve the following objectives as set out by the OEB in its May 2015 letter:

D.4 – Proposed Capacity Reserve Charges for Customers with Generation

Many GS \geq 50kW, Intermediate and Large customers will consider distributed energy resources as a way to lower their costs. The OEB Strategic Blueprint speaks to enabling innovation that enhances consumer choice and control. Staff have developed a proposal to enable customer choice while meeting the general rate policy of ensuring fairness in the recovery of costs to maintain a reliable distribution system. The intention is to ensure that distribution systems' pricing is not a barrier to customer innovation while ensuring that the costs of the system are fairly recovered from those who are using it. These changes will only affect those customers who have behind the meter generation.

Under the current rules, the following scenario has happened in more than one distribution service area. A customer in the large class of a distributor without a standby class who is already a load decides to install distributed generation for essentially all its load. Its transmission cost is billed based on gross load (i.e. the delivered load plus its self-provided load) as per the transmission rate order. It has reduced its monthly demand significantly except for the one month during which it services the generator where its demand on the distribution system is for its full load. Over the course of the year, the customer pays the fixed Monthly Service Charge and likely very else for distribution. As a result the distributor under-recovers for that class until it reviews the allocation of cost for all classes and resets rates.

Since total costs have likely not gone down, due to the long-term nature of distribution system investments, and therefore the revenue requirement for the distributor has not gone down, those costs are reallocated to other classes when rates are reset. The amount that those other classes have to pay goes up and the demand charges in all classes (including the large class) go up. Meanwhile, the distributor must continue keep the full capacity reserved for the customer's once a year servicing and the customer has no incentive to keep its once a year demand in off-peak times.

The OEB commissioned work by Navigant²⁸ that shows that relatively low penetrations of load reductions can have significant effects on distributor revenue.

Table 4: Distributor Revenue Impact of Reducing Demand using Current Tariffs

LDC	GS < 50	GS >= 50	Large
Entegrus	-4.5%	-8.8%	NA
Hydro One (Rural)	-7.9%	-9.7%	NA
Hydro One (Urban)	-7.3%	-9.6%	NA
Orangeville	-5.4%	NA	NA
PowerStream	-5.7%	-9.3%	-7.0%
Toronto Hydro	-6.2%	-9.8%	NA

Table 5: Distributor Revenue Impact of Reducing Demand Using Proposed Tariffs for GS < 50kW

LDC	GS<10	GS 10 - 50
Entegrus	0.0%	-6.6%
Hydro One (Rural)	0.0%	-9.2%
Hydro One (Urban)	0.0%	-8.7%
Orangeville	0.0%	-7.7%
PowerStream	0.0%	-7.5%
Toronto Hydro	0.0%	-8.1%

Source: Navigant Analysis

By implementing a Capacity Reserve Charge (CRC), charges that fluctuated with standby charges will become a fixed charge based on the amount of generation installed. This leads to a more cost reflective recovery of costs from these customers who are expecting the system to be there on demand.

Staff have provided some illustrative graphs to try to show the difference between standby charges, contract demand with penalties, and the proposed emergency backup service. Figures 10, 11 and 12 below provide a comparison of the way that standby, contract demand and capacity reserve charges would work. These graphs are to demonstrate and contrast the concepts and do not represent any particular jurisdiction. The grey bars are the underlying distribution charge based on measured demand. The orange bars represent extra charges based on the operation of the installed generation.

²⁸ See tables 6 and 8 in Appendix B.

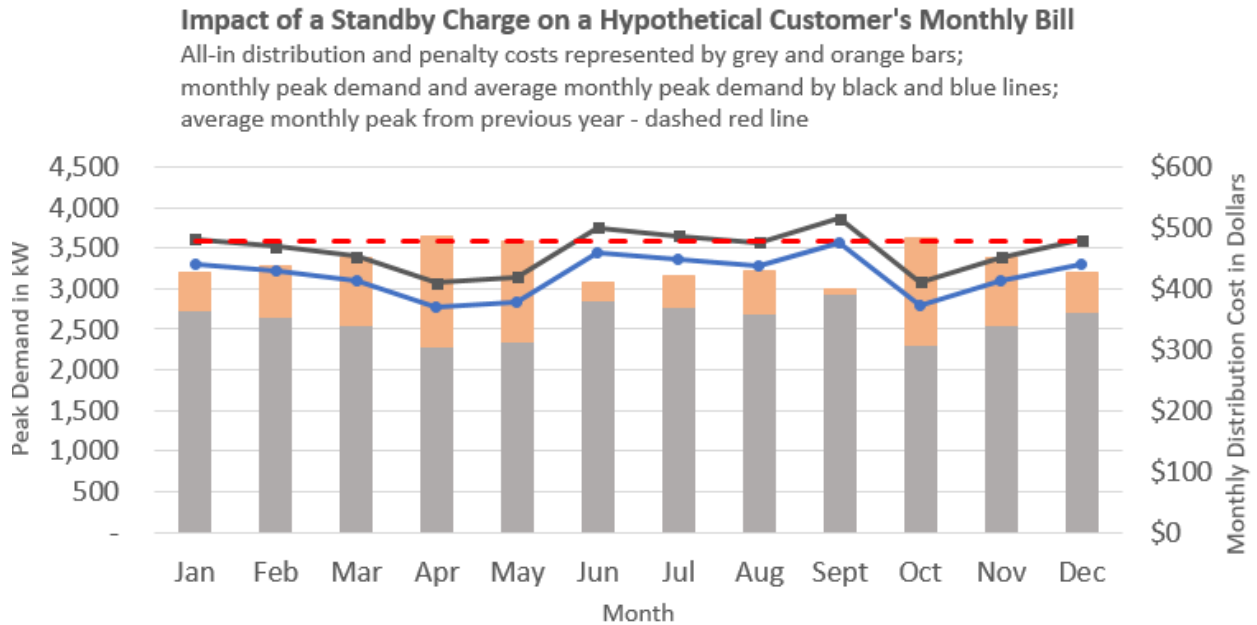


Figure 10: Sample of Standby Charge

For standby charges, there is a fluctuating charge to account for the amount of generation provided on-site. The grey bars are underlying demand charge and the orange bars are a standby charge meant to recover the distribution costs of “standing by” ready to supply the balance of the load being provided by the generator.

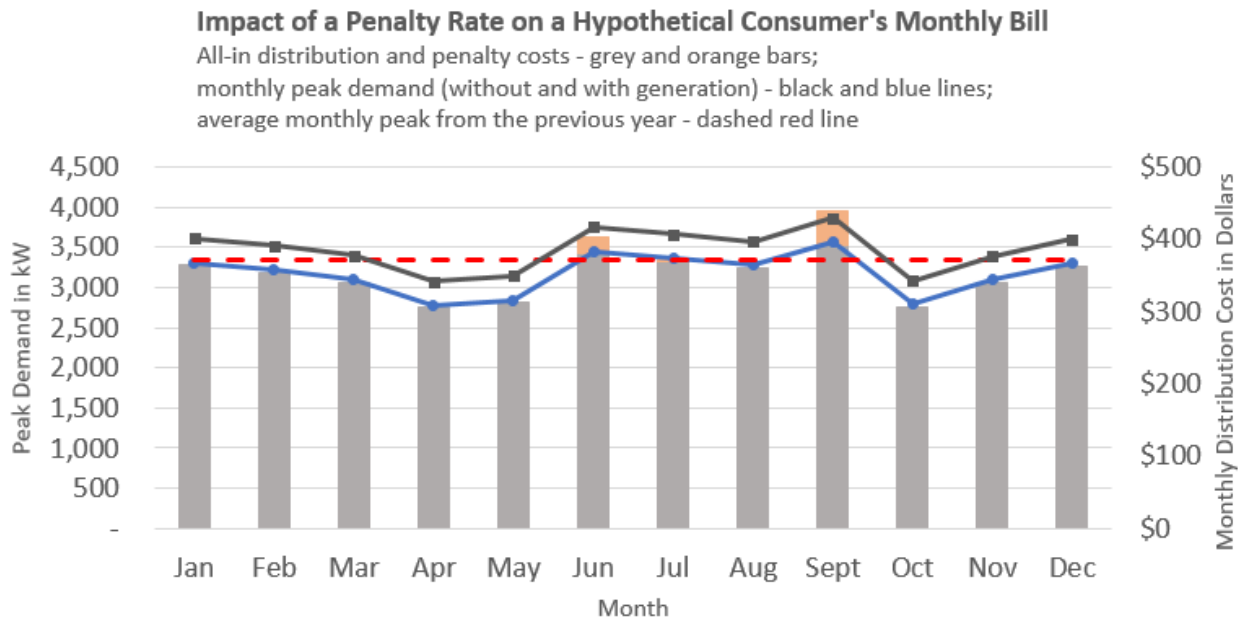


Figure 11: Sample of Contract Demand with Penalty Rate

For a contract demand, there is a penalty charge for demand above the contracted amount. The grey bars are the normal demand charge and the orange bars are penalty charges for going over the contracted demand. The penalty charge is at a significantly higher rate than the normal demand charge.

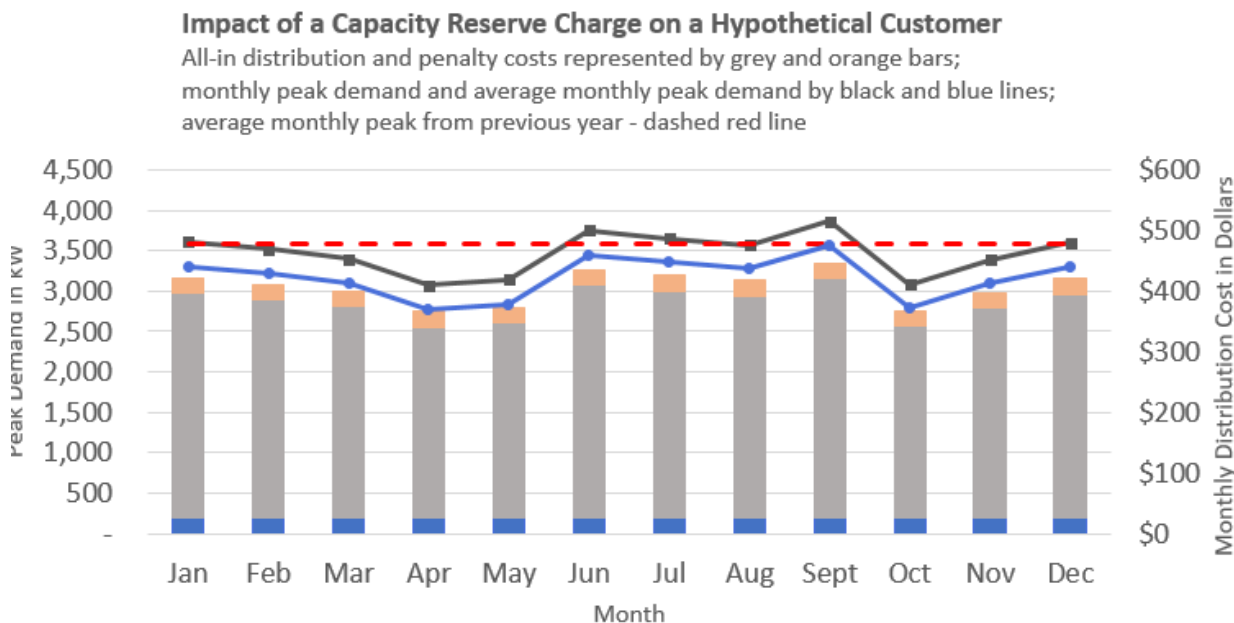


Figure 12: Sample of a Capacity Reserve Charge

For the Capacity Reserve Charge, the blue bars are the Monthly Service Charge, the grey bars are the demand charge for the class and the orange bars are the CRC. The CRC is a fixed monthly amount that represents a payment for capacity being held in the system that the customer will not otherwise be paying over the course of the year. Staff now recommend that it be based on the faceplate rating and the capacity factor of the generator and the underlying demand rate of the class.

The CRC payment is intended to compensate for capacity being held for the customer in the system. It should represent that value as closely as possible without either avoided costs that will end up being shifted to other customers or being a windfall for the distributor and skew the economic decisions of the customers.

Staff’s initial proposal for a CRC was to set a fixed factor intended to prevent distributors from over-collecting. The work by Navigant suggested that this factor would be 90%. Staff proposed that this factor would decrease over time as a generator proved reliable service to the distributor, and the need for back-up capacity lessened. Staff’s thinking was that this would provide an incentive for the operators to maintain their installation

and would allow distributors to reduce the capacity held in the system for that connection.

Staff took these ideas to customers with existing onsite and load displacement generators, such as the Ontario Power Plant Administrators Association, Canadian Manufacturers & Exporters and the Association of Major Power Consumers in Ontario. They pointed out that running a generator flat out to replace all load is typically not how they operate. They described other factors that influence how the customer runs its load displacement generator.

- Resource limited: Solar or wind or other renewable generators are often intermittent based on fuel availability.
- Emissions-limited: Emergency generators with a Certificate of Approval from the Ministry of Energy are limited to the number of hours they can run based on emissions. These generators may be running otherwise required tests of equipment in hours to participate in the ICI program.
- Requirements limited: Combined heat and power (CHP) plants may be heat following rather than having the goal of optimizing electricity output.
- System operations limited: Physical plant operators pointed out that their distributor will sometimes request that they not run for operational purposes of the host system.

Based on this feedback and further analysis of the system data, staff have revised the proposal for calculation of the CRC. The high level concept of the CRC remains the same. However, staff are now recommending that the proposed calculation reflect the expectation that generation is displacing load based on using a capacity factor. A capacity factor (CF) is the ratio of a generator's actual output over a period of time, to its potential output if it were possible for it to operator at full nameplate capacity continuously over the same period of time. Capacity factor is specific to the technology and more specifically to how the generator is run. For examples of potential capacity factors, see Table 6.

The CRC would be a fixed payment that is made monthly in addition to the variable charge for the metered maximum demand in the billing period. Unlike traditional standby charges that attempt to reach a contracted level every month, the CRC should recover the capacity payment on average over the year. By including capacity factor, the CRC would take into account the expectation that the customer will reach and pay for full or partial load at some point in the billing cycle.

Renewable energy generation is also referred to as intermittent generation since it depends on immediate fuel. At some point in each month or billing period, the sun will not shine or the wind will not blow during a customer's peak load. It is likely that the distributor will provide full service almost every month for renewable generation. The customer will pay the full distribution bill for its full demand load. The capacity factor for renewable plus storage installations would be higher. If the customer has its own storage, it is able to store power during times of generation excess and use this during periods when the renewable fuel source is not available. And if there was not enough of its own generation, it could store power from the grid to use when the renewable fuel source is not available. A customer with renewable generation plus storage would be able to manage to avoid drawing its full power from the grid and the capacity factor is higher.

Staff recommend that the only type of Capacity Reserve Charge available to GS $\geq 50\text{kW}$ customers is for full Emergency backup service.

Emergency backup service (EBS) is a full emergency service that is instantaneously (or nearly instantaneously) available if the customer's generator fails for any reason. Since the distributor must maintain full capacity for this customer including like-for-like asset replacement, the distributor should charge a capacity reserve charge that is based on the normal demand charge for the class and the full value (faceplate rating) of the generator and projected or historic levels of capacity factor.

EBS = Faceplate capacity rating x Demand rate of class x Capacity Factor

Some customers keep a generator on premises to provide their own emergency backup generation in the case of grid failure. Hospitals or large commercial buildings will sometimes do this in addition to manufacturers who want to ensure that they are not subject to a lengthy service disruption. These generators often use diesel for fuel and are subject to environmental restrictions and certification to limit their emissions.

Some customers are using these backup generators to participate in the Industrial Conservation Initiative (ICI) program. The ICI program allows participants to reduce their global adjustment costs and help the provincial system defer the need for investments in new electricity infrastructure that would otherwise be needed. These emission limited generators have a very low capacity factor and would pay a very low capacity reserve charge since the customer is expected to draw full load almost every month.

In staff's previous proposal, installations like renewable energy and emissions-limited generators would have had to be exempted. Under the new proposal, the capacity factor should account for the expected level of charge for load.

The IESO included standard capacity factors in Feed In Tariff (FIT) contracts to recognize expected output. The IESO also uses capacity factors in their planning for the same reason. Table 2 is some typical capacity factors. Staff expects to be able to add to and refine this table before implementation. In addition, staff expects that for Large customers, especially those with existing installations, the Capacity Factor can be agreed between the customer and the distributor and potentially adjusted periodically.

Table 6: Samples of Capacity Factors for Technologies Based on IESO System Planning

Type	Installation	Capacity Factor
Solar	Rooftop – fixed	10
	Ground mounted – fixed	20
	With storage	50
Wind	Fixed	30
	Orienting	35
	With storage	50
Bioenergy	Standard	40
	With storage	50
CHP	Heat following	50
	Full operation	65
Fossil	Certificate of approval limited	15

Implications of the proposed approach

The CRC should make the distributor indifferent to the installation of distributed generation in the service area and so enable customers to install new technology.

Customers should be able to decide on installing generators based on the commodity savings and other factors relevant to their business (e.g. control of generation, power quality, reliability of supply, or non-economic factors like support for green energy). Their decision will not disadvantage other customers through cost shifting.

D.5 – Implementation Issues for Capacity Reserve Charges

Since the new CRC charges only affect customers that are making a change and adding distributed generation, the OEB expects that these can be implemented immediately subject only to appropriate changes in distributor CIS systems. Some customers have existing generators and may or may not be paying standby charges to their distributor. Staff proposes that any current standby charges would be converted to CRC at a distributor's next rate case.

Staff further proposes that any existing generators not currently subject to standby charges begin to pay CRC on a phased-in basis. Existing installations represent an investment by the customer based on the previous rules. At the same time, any existing installation has, from an accounting perspective, depreciated over time with a concurrent increase in return. Staff therefore proposes that the applicable amount of the CRC applied every year increase by 10% of the total. i.e. reach 100% of the CRC in 10 years. This would be in line with depreciation levels for a major asset so that the CRC is implemented only as an existing installation depreciates.

D.6 – Specific Service Options for Large Customers

Large customers are very sophisticated about their energy use. They often have someone whose responsibility is planning for energy use and how to minimize costs. Staff are proposing that they have more choice²⁹ with regard to their level of service and consequently the amount that they pay for it. This will allow them to make decisions that support their business and respond to the circumstances around them.

At the same time, their decisions can have immediate effect on the operation of the distribution system that ultimately affect the costs allocated and charged to other customers. Their business decisions must not be allowed to disadvantage other customers.

Their decisions should be coordinated with distribution system planning to ensure that distributors can take advantage of opportunities for cost containment and are not surprised by customer actions. Distribution companies will need to discuss with each

²⁹ In conjunction with the levels used in regional planning, staff are suggesting that these options only apply to Large class customers, those over 5MW of demand.

customer what level of service is required and how it will be accomplished. These customers are few in number and more individual attention is warranted. In addition to the Emergency backup service (EBS) available to $GS \geq 50kW$ customers, staff recommend that Large customers be able to choose Maintenance service or paying a Bypass charge.

Maintenance service (MS) would be negotiated with the distributor to provide full load at off-peak times at the distributor's discretion. Since the additional cost to the distributor is low for maintenance service, the charge should be lower than EBS. However, since the customer is abandoning load, there should be some form of recalculated economic test as an exit payment. It would include the net book value of dedicated assets and some upstream assets as well as the cost of the load limiter. The cost of removing and reinstalling the load limiter would be charged whenever the customer requires the service. Under this model, the customer is taking the risk of poor performance of the generator and that it will not be able to supply the load.

MS = Faceplate capacity rating x Demand rate of class x Maintenance Factor

Where Maintenance Factor is negotiated with the distributor such as between 25% and 50%. For the purposes of comments, assume that the OEB chooses 30% as the Maintenance Factor.

Bypass is when a customer is essentially taking most or all load off the system. There would be a calculation of the value of abandoned assets so that the remaining costs of assets built to serve the customer (in particular feeder lines, controls, and protection systems) are not passed to the remaining customers.

Bypass could be full for disconnection or partial where some load remains on the system. There will be an economic evaluation to determine the payment owing for the value of the abandoned assets to calculate a full or partial bypass charge.

Full Bypass charge = Net Book Value of abandoned assets and system costs based on the load being abandoned

Partial bypass is when the customer wants to permanently remove their load from grid service but maintain a connection to the grid. The customer may choose to reduce their load to some minimum and protect the rest with emergency backup or maintenance levels of service from the distributor. The customer should pay out the net book value (NBV) of connection assets built to serve them, offset by the expected continuing

revenue stream which may only be the Monthly Service Charge or may include some load and/or level of Capacity Reserve Charge.

During the OEB's consultation on the Regional Planning and Cost Responsibility Review³⁰ (Cost Responsibility consultation) which was recently completed, a number of stakeholders requested clarification in relation to how a bypass compensation charge in that consultation would work with the capacity reserve charge (CRC) being considered in this consultation.

The primary stakeholder concern was the potential for a customer being required to pay both charges to compensate the distributor for the same bypassed capacity (i.e., charged twice). In its Revised Notice of Proposal³¹ related to the Cost Responsibility consultation, the OEB noted that clarification was not possible at that time, since both bypass compensation and the CRC were at the proposal stage³². As a consequence, in that Notice, the OEB indicated it would address the relationship between the two charges, as part of this policy consultation process, once the Cost Responsibility consultation was concluded.

OEB staff notes that bypass compensation is broader in scope than the CRC. Unlike the CRC, it is not limited to cases of bypass involving embedded generation. For example, a bypass compensation charge would be applied where bypass is achieved through wires reconfiguration, such as a customer that shifts existing load from the distributor's facilities (e.g., transformation station) to its own duplicative facilities that the customer later constructed.

Where embedded generation is involved, renewable generation is also exempt from the requirement to provide bypass compensation. As a result, the comments requesting clarification appear to be limited to one bypass scenario in relation to where both charges could potentially be applied. That scenario involves the customer installing behind-the-meter non-renewable generation (e.g., natural gas CHP). OEB staff further notes that, as reflected in the final DSC amendments in the Cost Responsibility consultation³³, for distribution-connected customers, bypass compensation will also be limited to large consumers which the OEB concluded will be those with a non-coincident peak demand of 5 MW and above (i.e., large user rate class for distribution charges). In contrast, the currently contemplated threshold for the CRC is much lower as it would be

³⁰ EB-2016-0003

³¹ [Notice of Revised Proposal](#)

³² *Ibid*, p. 23

³³ [Notice of Amendments to Facilitate Regional Planning](#)

applicable to customers over 50 kW. However, under the CRC proposal, bypass options will only be available to Large customer classes.

Bypass compensation is now required for both *full* and *partial* bypass within the distribution system. The potential where bypass compensation and the CRC could be applicable is related to partial bypass. Under a full bypass scenario, the customer fully disconnects from the distributor's system. That would not occur under any CRC scenario since the customer is maintaining its connection to reserve capacity on the system, so they can use it as needed.

Based on the above, the only scenario where both charges could be applied is therefore where a large customer (over 5 MW) has embedded non-renewable generation to supply some of its load. Key differences on the implementation side are bypass compensation is a *one-time charge* – calculated based on the remaining net book value (NBV) of the bypassed asset(s) – due to a customer *permanently* removing its load from the distributor's system. In contrast, the CRC is an *ongoing charge* and the customer is *not permanently* removing a certain amount of load from the system. Instead, they are reserving capacity for when they need it from time to time.

Under the staff proposal for the CRC, the stakeholder concern noted above will never be realized. That is, there will never be a case where a customer would be charged both the CRC and bypass compensation in relation to the same capacity. A key reason for that is it will be based on *customer choice*; i.e., not determined by the distributor which charge is applied.

Paying bypass compensation may be the lower cost option for a customer over the longer term, but they would be assuming the risk of no longer being able to rely on the system to supply all of their electricity needs. In contrast, the customer would be able to continue to rely on the system when they need it if they opt to pay the CRC for the capacity they reserve, so it is like an insurance policy.

To use an analogy, the customer's decision is similar in nature to a customer deciding on whether they want to purchase and own their water heater (after they have rented it for some time) or continue to rent and pay an ongoing monthly charge. If they choose to pay the remaining NBV and own it, they assume the risk to repair and/or replace the water heater, whereas if they continue to rent, the risk remains with the company to service the water heater and/or replace it.

A hypothetical example is set out below based on a customer that has existing demand of 100 kW and they install gas-fired embedded generation that can supply 20% of their load.

Total existing customer demand	100 kW	
Demand supplied by new LDG gas generation	20 kW	BC or CRC applies
Demand remaining on distribution system	80 kW	Unaffected

In the example above, under staff's recommendation, if the customer opted to pay bypass compensation, the capacity allocated to them would be limited to 80 kW. On the other hand, if they opted to pay the CRC, they would still have access to the full 100 kW, but they would pay the CRC in relation to 20 kW in order to pay for services received from the distributor, including maintaining capacity on the distribution system that is reserved for them. OEB staff notes this is only an example, as the customer could opt to reserve less than 20 kW.

D.7 – Implementation Issues for Large Customer Options

Treatment of Demand Overages

One implementation issue for maintenance and bypass is how to ensure that customers do not access emergency backup service without paying for it. There could be some penalty imposed for customers who are only paying for the limited service but whose generator fails and end up using full emergency backup. This could be a physical limitation or financial penalties.

One possibility for a customer that remains connected to the grid is that the distributor installs a load limiter at the customer's service to ensure that it does not draw more than the agreed amount. Under this model, the customer is taking the risk of poor performance of the generator and that it will not be able to self-supply the load. A distributor who has limited capacity on a line or faces an end-of-life replacement decision many need to physically limit the demand that a customer can draw. In this case, a customer who discovers that it actually needs full emergency backup could end up paying significant fees to install and then reverse load limiters. The distributor may make decisions based on an expectation of the customer's reduced load that then needs to be served again.

Another way of dealing with overages is to apply penalty rates to any demand over the agreed load. Network providers in the UK apply excess capacity charges³⁴ to demand over the agreed supply capacity. The penalties try to discourage companies from exceeding their agreed supply capacity to assist the distribution network operators with balancing network usage. The penalty rate depends on the specific distributor but ranges from 15% to 106%³⁵ above the base demand rate.

When penalty charges apply, a customer is taking a business risk of overage charges but not an operational risk of not having enough service. A distributor with excess capacity may prefer to allow a customer to draw over the agreed demand and incur penalties that would offset charges for other customers rather than install more equipment to have a physical limitation. The application of penalties would prevent customers from trying to game the system by choosing a lower level of service and using the higher level.

Links to Distribution System Planning

For Large customers, economic tests could be done on an individual basis. These calculation could include credit for system benefits specific to the generator and location. However, the distributor should not continue on with business as usual planning models. The distributor should assume some risk of load change.

In consultation, customers noted that installation of a large distributed generator is not a momentary decision. Developing the business case, the dedication of capital, and construction is likely a 7 year program.

The OEB began asking distributors for specific, 5-year system planning information in 2009. The filing requirements for those plans have increased in detail since then. Distributors are also expected to find out their customers experience and expectations for service level and quality. OEB expects distributors to involve customers in planning. For larger customers, this could be discussing replacement plans as dedicated assets reach their end of life. Without evidence that these kinds of consultation have taken place, the distributor would not be entitled to include those assets in the economic evaluation of NBV.

³⁴ [Distribution Connection and Use of System Agreement \(DCUSA\) DCP161 - Excess capacity charges | Ofgem](#)

³⁵ [Professional Cost Management Group summary of excess capacity charges](#)

Implications of Maintenance Service and Bypass

Staff believe that the proposal addresses the objectives of the project.

- It addresses concerns of distributors and customers that the level of change in the sector is already overwhelming in that it maintains the status quo for underlying rate and only applies to advanced customer installing or operating distributed generation.
- It allows for customer choice in the level of service provided by the distributor of full emergency backup service, maintenance service, or full or partial bypass.
- Customers can choose to install distributed generation to lower their bills through savings on commodity. However, they will not avoid paying for the capacity maintained in the system and thereby shift costs to other customers.
- It enables technology implementation by making the distributor indifferent to customer installation of distributed generation.