The Voice of Ontario's Electricity Distributors

May 27, 2016

Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, Suite 2700
Toronto, ON M4P 1E4

Via web portal

Dear Board Secretary:

Re: Board File No. EB-2015-0043
Rate Design for Commercial and Industrial Customers

The Electricity Distributors Association (EDA) is the voice of Ontario's local electricity distribution sector, which consists of municipally and privately owned local distribution companies (LDCs). The distribution sector delivers electricity to 5 million residential, commercial, industrial and institutional customers throughout the province. The sector employs 10,000 people directly and holds $19 billion in assets; it has $1.9 billion in annual capital spending and $1.6 billion in annual operational spending; and makes hundreds of millions in direct contributions to both municipal and provincial revenues.

On March 31, 2016 the OEB issued its Staff Discussion Paper on *Rate Design for Commercial and Industrial Customers: Aligning the Interests of Customers and Distributors* (the Paper). The rate design options in the Paper are based on the existing customer classifications and are designed to ensure no changes to the underlying allocations to each class. The Paper asked stakeholders to comment on the rate options, rank the options in order of preference, suggest improvements to the rate options and address how customers would respond to the rate options.
The following are EDA's comments on the various rate options.

<u>General Service less than 50 kW (GS<50 kW) Class</u>

For the GS<50 kW class, consideration should be given to create a new subclass of General Service customers less than 10 kW. General Service customers less than 10 kW have similarities to the Residential class with respect to the types of facilities used for connection and should therefore have a similar rate design. With this new subclass, a fully fixed charge would appear reasonable and likely acceptable to these customers. There may be a number of operational issues which would need to be addressed to identify and maintain tracking of this new sub-class given that metering and CIS technology were not designed to accommodate tracking of kW data for this customer class. As a result, an approach which anchors on consumption data was determined to be more logical and practical. A threshold would need to be determined (for example, 4,000 kWh per month) through further analysis.

Given the concerns regarding the establishment of a new subclass, an alternative could be to use a minimum bill for the GS<50 kW class which would recover most of the connection costs for a typical general service customer. Customers that consume greater amounts of electricity than the minimum level would be charged a volumetric rate per kWh. The dollar value of the minimum bill should be set at a level above the utility's current monthly service charge. The minimum bill option, designed to meet specific objectives, provides similarities to the Residential rate design and a predictable bill (essentially fixed) for those at lower levels of consumption while providing an incentive to reduce for those that have higher levels of consumption.

A fully fixed charge for the entire GS <50 kW class may cause noticeable bill increases for some customers that are currently billed a low monthly service charge. However, this option is easy for customers to understand and if it were phased in over a period of time as with the Residential fixed charge, it might be accepted by customers. A fully fixed charge would be the best approach to address GS<50 kW customers with embedded load displacement generation.

The energy usage block rate option would be difficult to gain customer acceptance due to bill impacts. Customers just above a block threshold and customers who exceed their block amount would pay the overage charge. Another issue would be that this option would add unnecessary complexity with customers having to decide which block to choose. The energy usage block rate would also be very difficult to implement and administer. Firstly, to assign customers to blocks and then to track customer movement between blocks. Further, it is anticipated that some customers would not respond to block rate selection communications. For these customers, a default plan would need to be established. This default process would likely need to be described in each LDC's Conditions of Service, and the default may not necessarily reflect the needs of each particular customer. Billing systems would need to be updated and additional customer service personnel hired to answer customers seeking assistance. There is also a concern that customers will be confused when comparing to the Time-of-Use Price periods for energy usage. This option may not adequately address embedded load displacement generation if customers choose a block based on their net load.

Although the time of use kWh rate option appears to provide a better price signal for GS<50 kW customers to shift consumption, this option appears to be worse than the status quo in addressing the issue of General Service customers who implement embedded load displacement solar generation. With a lower off-peak rate, the amount recovered from these customers would be less than currently recovered and may not sufficiently recover the connection costs. Customers may have confusion in understanding and managing the on and

off peak times for distribution rate design versus time of use (on, off, mid) used for electricity commodity pricing.
While further stakeholder discussion, analysis and review is required, the preferred rate option for GS<50 kW is a fixed charge for customers under 10 kW and a minimum bill for the remainder of the class, or alternatively a fixed charge rate design.

General Service greater than 50 kW (GS>50 kW) Class

With respect to the General Service class greater than 50 kW, who are presently charged a demand rate (kW) for the peak demand in the billing period, it appears that the best option to protect against solar penetration revenue loss and ensure recovery of the costs of standby facilities, is gross load billing or a standby charge with the current rate based on a demand charge. Although similar in concept, a standby approach requires a pre-established customer contract demand threshold (or demand ceiling), whereas gross load requires metering to measure both delivered load and self-generation load.

Of the rate options provided in the Paper, the minimum bill approach has some merit in terms of recovering some fixed costs but it may need to be set higher than proposed. As noted above for the GS<50 kW class, the dollar value of the minimum bill should be set at a level above the utility's current monthly service charge to ensure the recovery of fixed costs.

The three part rate option is designed to provide a price signal to reduce peak demand and recover some costs for the connection costs sized to meet the anytime demand. An issue is whether this price signal from this rate option and any of the following options would provide any additional incentive over the existing commodity price signal given that the distribution component is a small part of the overall bill. The complexity of the three part rate option may create some confusion, as this billing concept would be challenging for many customers to understand and control. The variation proposed with a 3 pm to 9 pm peak period would require significant billing system changes to implement, and likely further confuse customers with conflicting price signals from the commodity charges. The capability to gather hourly data for this customer class is limited until 2020 when all GS>50 kW customers are required to have MIST meters.

The concept of establishing different peak periods for different utilities has also been proposed. This concept is also unfavourable due to both complexity and "customer peak period shopping" and resulting load shape migrations. Taken to its furthest degree, this might result in businesses relocating to rate territories with the most advantageous peak for their operational load shape. The challenge is that for many small-to-mid sized utilities, large customers can essentially control and shape the timing of the utility peak. So if the large customer relocates (or closes), then the peak changes for all other customers in that rate class. This would necessitate further change in the peak pricing model.

The time of use demand charge has less merit than the three part rate as it increases the risk of revenue loss from customers with embedded load displacement generation. The variation option with no charges for demand in the off-peak period would significantly increase the risk of revenue loss and not recover standby costs.

Given the available rate options considered for the general service class over 50 kW, it is likely that gross load billing for local connection costs would be required to ensure recovery of the cost to hold facilities in place to service the load when the generator is down. Consequently, the preferred option is the existing demand charge with gross load billing. If not gross load billing, then a standby rate should be charged to customers with embedded load displacement generation.

Intermediate and Large Use Class

For the intermediate class and Large Use class the issues are the same as for the GS>50 kW class. The status quo with a standby charge appears best able to recover costs fairly. The larger and more unique the customer, the more likely that a prescribed default method will not appropriately recover for the increasing prevalence of customer load displacement investment. The three part demand rate would increase the revenue risk by some amount relative to the current rate but with an appropriate standby charge this would be mitigated.

With respect to a time of use demand rate for intermediate and Large Use, the issue remains as to whether the price signal will have any impact, given that commodity is a much larger amount than distribution on the bills for these customers. It would not have better cost tracking than the three part rate which charges a non-coincident demand charge. The variation with only a demand charge for peak demands in the peak period, would be the worst option for ensuring cost recovery of distribution costs as customers with embedded load displacement generation could save more from displacing their on-peak demand during the on-peak period than with the three part rate option.

The Paper suggested that a demand ratchet could be used to ensure recovery of standby facilities. The ability to fully recover standby costs will depend to some degree on how the demand ratchet would work. It would need to apply for several years as some embedded load displacement generation may be very reliable, and the customer may still want facilities in standby. Take, for example, a customer with two load displacement generators, for which the maintenance cycle is timed in an attempt to ensure that one generator is running at all times. A demand ratchet for the annual peak, as proposed in the Paper, would not recover standby costs as effectively as a standby rate. If a demand ratchet is adopted, we assume it would apply to all customers. It should also need to be set to only be triggered when the demand is a certain percentage above past peak demands. This would increase administration costs and cause problems for customers who would see a demand ratchet as disincentive to control peak demands, after a high peak is set. It would be preferable to allow customers with embedded load displacement generation to contract for standby or allow distributors to implement gross load billing.

If gross load billing were allowed, then the three part demand rate with a peak period of 7 am to 7 pm would be a preferable option for intermediate and Large Use customers. It would reward customers for shifting load off peak and still allow recovery of local connection facilities sized to meet the non-coincident peak. However, this rate option may present significant risk of rate shock to customers of those utilities with a low number of large users. If customers shift load off-peak, the remaining customer(s) will be required to pick up the cost of the savings at the next rebasing. Utilities need flexibility to establish rates to meet the expectations of customers to mitigate rate impacts, and maximize the use of existing utility assets.
The preferred rate option for intermediate and Large Use is the current demand rate with gross load billing or a standby charge.

Other Issues raised in the Paper

The Paper makes some operational assumptions about embedded load displacement generation. The Paper assumes that generation would be off–line for servicing once a month or once a year, and that a monthly maximum demand or an annual demand ratchet would ensure recovery of their share of the distribution system. Customers have more abilities to control their peaks when their generation is off-line for maintenance, such that recovery would not be assured through a demand ratchet. (See the above example of the customer with multiple generators.) Further, as technology continues to develop, distributors may be asked to standby with capacity in situations where the true potential delivered peak load is seldom seen. If a standby or gross load approach is not available, this scenario may evolve to a point where minimal, if any, recovery is earned by a distributor for standing by for a sudden, large load requirement.

The Paper is also seeking comments on potential credits to apply to embedded DG which is under control of the LDC and could provide demand response or load control to delay capacity and/or provide voltage support to avoid investments in capacitor banks. The EDA sees merit in further reviewing how this would work. In order to defer capacity upgrades, the controllable DG would need to be very reliable. In addition, if the credits are based on the present value of the deferred investment, there may be issues with committing to a credit amount when the present value of deferred investments could change substantially given changing assumptions about the future.

Feedback was also asked on what measure should be used to set the fixed charge for each class. The Paper uses the minimum system charge with the peak load carrying capacity (PLCC) adjustment for some of the rate options. Generally, the fixed charge should be at or above this level for each rate option, and should be at or above the distributor's current fixed charge.

The Paper notes that some jurisdictions are considering moving to demand based rates for smaller volume customers. Implementing kW demand charges for the GS<50 kW class would require significant changes to CIS systems and changes to the provincial MDM/R.

With respect to the classification of customers, an issue identified in discussions has been how to assign a customer with load displacement generation who is below the class threshold normally, but on a gross load basis, or when standby capacity is included, would be above the class threshold. The approach for classifying these customers using standby capacity should be stipulated in the LDC's Condition of Service.

In summary the preferred options, in order of preference for each class are as follows:
GS<50 kW Class:

1. Fixed charge for 10 kW
2. Fixed charge
3. Minimum bill
4. Time of use kWh rate
5. Energy use blocks

GS>50 kW Class:

1. Status quo with gross load billing
2. Status quo with standby charge
3. Minimum bill
4. Three part rate
5. Time of use
6. Three part rate variation
7. Time of use variation

Intermediate and Large Use Classes:

1. Status quo with gross load billing
2. Status quo with standby charge
3. Status quo with Demand Ratchet
4. Three part rate
5. Time of use
6. Three part rate variation
7. Time of use variation

The order for the preferred options is based on a preliminary review of practical implementation considerations and which best address the risk of not recovering the costs for providing standby facilities to customers with embedded load displacement generation. For larger customers, the existing rates with gross load billing or with a standby charge appears best able to address this risk.

With respect to the rate options based on time of use, presumably to incent load shifting, members have noted that that distribution costs are not a significant portion of a larger customer's bill. For General Service customers greater than 50 kW, the distribution component represents around 3% to 5% of the total bill. The additional incentive provided by a time of use distribution rate would be minimal. Members note that for larger customers the concerns are generally about the commodity and Global Adjustment portions of the bill. Members further note that recent customer engagement activities have reiterated the need to promote energy literacy amongst all rate classes, including GS<50 kW, GS>50 KW and Large Use customers. Providing customers with a simple, understandable base rate is a vital component to promoting energy literacy.

The EDA supports the OEB's efforts to provide solutions to address changes that will emerge in energy consumer expectations while balancing the needs of all stakeholders, including the promotion of energy literacy. The comments provided above are based on the analysis included in the Paper. More analysis is required to determine the impact to customers in order to make a more informed decision on what rate option will incent the desired behavior of customers within each utility. A number of our members are in the process of preparing comprehensive customer bill impact and sensitivity analyses based on the options included in the Paper. The assumptions being used for these analyses will be further refined as more clarity is provided in the next round of consultations. This will allow for a broader understanding of the potential range of customer impacts across the province.

The EDA looks forward to the next round of consultations focused on the preferred rate options which should also include a more in depth discussion on implementation issues such as cost of service model changes, CIS changes, billing changes, customer education, the approach to phase-in changes and timing.

Sincerely,

Teresa Sarkesian
President & Chief Executive Officer

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