Electric Delivery Rates for Electric Vehicle Charging

Prepared for: Ontario Energy Board

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List of Common Acronyms

C&I	Commercial and Industrial
CDM	Conservation and Demand Management
CP	Coincident Peak
CPC	Coincident Peak Contribution
DC	Direct Current
DCFC	Direct Current Fast Charging, where "public DCFCs" refers to publicly accessible DCFC charging stations
DER	Distributed Energy Resource
EV	Electric Vehicle
EVI	Electric Vehicle Integration
GA	Global Adjustment
HOEP	Hourly Ontario Energy Price
IESO	Independent Electricity System Operator
kVA	kilovolt-ampere
kW	kilowatt
kWh	kilowatt-hour
LDC	Local Distribution Company
MWh	megawatt-hour
NCP	Non-Coincident Peak
OEB	Ontario Energy Board
RPP	Regulated Price Plan
RTD	Regional Transportation District
RTSR	Retail Transmission Service Rate
TOU	Time of Use
TWh	terawatt-hour

EXECUTIVE SUMMARY

As part of the Ontario Energy Board's (OEB's) Electric Vehicle Integration (EVI) initiative, the OEB is undertaking activities to facilitate the efficient adoption of electric vehicles (EVs). One workstream of the EVI initiative pertains to delivery costs and how current rate design may impact EV deployment in Ontario. This report examines the current electricity delivery rates for EV charging and alternative rate design options that could support the efficient integration of EVs in Ontario. The scope of this study is limited to electricity delivery rates for distribution-connected commercial EV fleets (e.g., public transportation, delivery trucks, etc.) and public direct current fast charging (DCFC) stations ("public DCFCs").

Electricity delivery rates for commercial and industrial (C&I) customers are primarily based on the customer's peak demand. Demand charges reflect the maximum amount of power a customer uses over a specific interval - usually 15 minutes - during a billing cycle. C&I customers are charged based on demand because doing so reflects principles of cost causality: peak demand is a major driver of costs for a distribution system, and therefore customers who have higher peak demand (i.e., whose usage creates the need for more infrastructure and thus more costs for the system as a whole) are charged more. While generally accepted as appropriate for most C&I customers, this rate design can be problematic for customers whose usage profile is atypical.

Industry stakeholders and EV charging service providers have raised concerns about the impact of electricity delivery costs, especially demand charges, on EV charging infrastructure adoption – particularly for owners of commercial EV fleets and public DCFCs. These two electricity customer types have unique load profiles, which under the current rate structure have electricity bills that are more impacted by demand-based charges versus energy-based charges. For example, commercial EV fleet charging is routine, predictable, may be amenable to longer charging times, and is generally undertaken by customers who, with incentives, have the ability to be more price responsive. Whereas the use of public DCFCs at present is mainly intermittent and from customers who need fast and reliable charging on-demand. As a result, public DCFCs have a low load factor usage pattern because they provide customers with high power to EVs during short, infrequent charging sessions.

Utilization, or load factor, is the average demand divided by non-coincident peak (NCP) demand, where NCP demand represents the highest peak demand drawn by a customer in a monthly period regardless of the time the peak occurs. Canadian public DCFCs averaged 5% utilization in the 2019 to 2021 period, but utilization is expected to increase with EV market maturity (i.e., as the adoption of EVs increases).

Impact of current rate design on EV customers

To evaluate the impacts of current rate design on EV customers, Power Advisory undertook four streams of research: a jurisdictional scan, a literature review, interviews with a small number of Ontario stakeholders (including EV charging service providers, commercial EV fleet owners and service providers, and local distribution companies (LDCs)), and modelling electricity bills for various EV charging scenarios using the electricity rates from six representative Ontario LDCs.

The modelled electricity bills for public DCFCs showed that demand charges are a significant share of these customers' electricity bills relative to other Class B customers (as defined by Ontario Regulation

429/04). However, the modelled electric bills for commercial EV fleets produced more mixed results since the impact of demand charges varied based on the fleet's size, driving, and charging patterns, and LDC.

Table 1. Summary of Current Rate Design Bill Impact for EV Customers

Load Profile	Average Rate[1] ($/kWh)		Demand Charge Share (%)	
	Urban Low[2]	Rural High[3]	Urban Low	Rural High
DCFC 2x50kW[4] 5% Utilization	0.29	0.53	48%	72%
DCFC 2x50kW 10% Utilization	0.23	0.40	43%	68%
DCFC 2x50kW 30% Utilization	0.15	0.21	23%	45%
Food Delivery - 10 Vehicles	0.15	0.23	29%	52%
Beverage Delivery - 10 Vehicles	0.13	0.17	19%	39%
Bus Depot - 25 Vehicles	0.14	0.20	25%	48%
Typical Customer[5]	0.12	0.15	12%	28%

[1] The Average Rate refers to the per-kWh rate for electricity calculated by dividing monthly costs for both delivery and commodity by the customer's total monthly energy consumption in kWh.

[2]A representative LDC with predominately urban service territory with relatively low demand changes.

[3]A representative LDC with predominantly rural service territory with relatively high demand charges. The two representative LDCs in this table do not reflect the full range of demand charges in the province; there are, for example, LDCs with rural service territories with lower demand charges and LDCs with urban service territories with higher demand charges.

[4] This refers to a public DCFC with two charging ports, each capable of providing 50 kW of power.

[5] The Typical Customer profile is based on an average day from hourly Ontario Demand in 2015 through 2021, net of Regulated Price Plan demand (sourced from the Independent Electricity System Operator (IESO) Smart Metering Entity) and directly connected industrial load (sourced from IESO public reports).

<u>Alternative rate design options</u>

Alternative rate design options were developed with the aim to better align charger utilization, LDCs' costs of servicing those chargers, and the electricity bills that charger owners must ultimately pay, while also recognizing the differences between the two use cases. Rate design options were determined based on jurisdictional review, discussions with a sample of Ontario stakeholders, and a literature review of practices for EV-specific delivery rates. Two alternative rate design options were ultimately identified and advanced for quantitative evaluation. Those two options were a time of use (TOU) demand charge to address the needs of commercial EV fleets, and a low load factor rate with multiple variations to address public DCFCs, as follows:

1. TOU Demand Charge - Some delivery costs are recovered using demand in daily peak hours, other delivery costs continue to be recovered using NCP demand.
2. Low Load Factor Rates
    a. Single Tier - Reduced demand charge for customers below a certain load factor threshold.
    b. Multiple Tiers - Reduced demand charges for customers that step up as load factor increases.
    c. Demand Transition Charge - Reduced demand charge for customers with low load factor, with some delivery costs recovered using TOU energy charge instead. As the load factor increases, the energy charge is phased out and the demand charge increases.

1. *TOU demand charge for commercial EV fleets.*

A TOU demand charge would recover fixed distribution costs related to coincident peak (CP) based on customer demand in a daily, multi-hour peak period, which would be expected to fall sometime during daytime hours. As a result, commercial EV fleets participating in this rate would be able to reduce their electricity costs by scheduling consumption during off-peak times and minimizing peak demand during the peak period of the TOU demand charge. As modelled by Power Advisory, commercial EV fleets that reduce their demand in the peak period can reduce their total bills by 15 to 23%.

Table 2. Bill Impact of TOU Demand Charge for Commercial EV Fleets

	Urban Low			Rural High		
Load Profile	Average Rate, Status Quo ($/kWh)	Average Rate, TOU Demand Charge ($/kWh)	Bill Reduction (%)	Average Rate, Status Quo ($/kWh)	Average Rate, TOU Demand Charge ($/kWh)	Bill Reduction (%)
Food Delivery - 10 Vehicles	0.15	0.13	-17%	0.23	0.18	-20%
Food Delivery - 100 Vehicles	0.14	0.12	-15%	0.18	0.15	-18%
Beverage Delivery - 10 Vehicles	0.13	0.11	-15%	0.17	0.14	-15%
Beverage Delivery - 100 Vehicles	0.13	0.11	-15%	0.16	0.14	-15%
Bus Depot - 25 Vehicles	0.14	0.11	-19%	0.20	0.15	-23%
Bus Depot - 250 Vehicles	0.14	0.12	-20%	0.20	0.15	-23%

Implementing a TOU demand charge could cause electricity bills for some customers to increase because the TOU demand charge has been designed to be revenue neutral for the general service greater than 50 kW rate class for each LDC. Therefore, if costs associated with the peak period are recovered across a smaller pool of demand that no longer includes some commercial EV fleets, the rate (in $/kW) would need to increase in order to maintain revenue neutrality. This would lead to higher electricity bills for other customers depending on the share of total demand which would avoid the peak period. By 2035, commercial EV fleets could make up approximately 1.8% of general service greater than 50 kW demand. If that demand were able to avoid the peak period with a TOU demand charge, and all other things being equal, average electricity bills for the remaining general service greater than 50 kW customers would be expected to increase roughly by 0.2% to 0.3%, depending on LDC.[1]

To the extent that loads respond to a TOU demand charge by changing their consumption profile, there may be system-wide savings in capacity, transmission, distribution, and energy costs. These potential additional savings were not quantified in this analysis.

[1] The bill impact depends on the pace of commercial vehicle fleet electrification and uptake of the TOU demand charge, which are both uncertain. In addition, commercial vehicle depots may not be evenly distributed across LDC service territories. The bill impact in some LDCs could be higher than the range presented here if the LDC has a higher concentration of commercial EV fleets.

2. Load factor rate for public DCFCs

A low load factor rate is presented in three variations, but each recognizes that customers with low load factors are less likely to contribute to CP demand than typical general service customers. In recognition of such, the low load factor rate offers customers a lower demand charge while their load factor is below a given threshold. Implementing this rate would substantially reduce electricity bills for most public DCFCs.

Table 3. Bill Impact of Low Load Factor Rates for 150 kW DCFC with 5% load factor

Rate Option	Energy Use (kWh/ month)	Urban Low			Rural High		
		Monthly Bill ($)	Monthly Savings ($)	Bill Reduction (%)	Monthly Bill ($)	Monthly Savings ($)	Bill Reduction (%)
Status Quo	5,400	1,442	-	-	2,769	-	-
Option 2a	5,400	963	-478	-33%	1,837	-933	-34%
Option 2b	5,400	935	-506	-35%	1,783	-987	-36%
Option 2c	5,400	1,074	-368	-26%	1,900	-870	-31%

Most public DCFCs would save hundreds of dollars per month under any of the three variations. However, the rates modelled by Power Advisory may not fully alleviate the issue of demand charges at stations with utilization rates that are persistently below 5% or those served by LDCs with high demand charges allocated to NCP demand, both of which are more likely to occur in rural service territories.

As with the TOU demand charge, reallocating costs among customers would have an impact on the remaining general service customers, though that impact would depend on the number of customers availing themselves of the low load factor rate. Power Advisory estimates that by 2035 Option 2a would increase average electricity bills for the rest of the general service greater than 50 kW rate class by 1.7% to 2.8%, depending on LDC, given the expected uptake of public DCFCs and utilization of 10%.

<u>Other considerations</u>

Offering different electricity rates for commercial EV fleets and public DCFCs is one way to assist in managing the cost for these customers to facilitate the adoption of EVs in Ontario. There are also other options that could be explored, such as:

1. Optimize the company's/charging station's overall energy use.
2. Load control programs offered by the utility company.
3. Investments in distributed energy resources (DERs).

Further, there may be opportunities for other customer types to participate in the two alternative rate options considered. For example, it is likely that there are C&I customers in addition to commercial EV fleets whose demand is already primarily in the overnight hours or who could shift their load to off-peak periods: for example, energy storage facilities, hydrogen-producing electrolyzers, and potentially some manufacturers. Similarly, there are likely existing general service customers who have a low load factor (for example, irrigation in the agricultural sector), as well as other industrial users of pumps, compressors, saws, and milling machines. If additional customer types (i.e., beyond commercial EV fleets and public DCFCs) were given the opportunity to reduce their delivery charges through participation in the alternative rate designs, then additional analysis would be required to understand implications including system impacts and potential for cost shifting.

Next steps

Power Advisory suggests two work tracks that the OEB could pursue should it wish to further develop the alternative rate options proposed in this report:

- Assessment of implementation considerations on areas such as eligibility for the alternative rates, local versus province-wide implementation, etc.; and
- Refinement of the rate design options themselves to test more closely some of the assumptions and inputs to the modelling in this report.

1. OVERVIEW OF ONTARIO ELECTRICITY SECTOR AND EV RATE DESIGN

As part of the Ontario Energy Board's (OEB's) Electric Vehicle Integration (EVI) initiative,[2] the OEB is undertaking activities to facilitate the efficient adoption of electric vehicles (EVs). The Minister of Energy's mandate letter of November 2021 to the OEB requested the OEB take steps to facilitate the efficient integration of EVs into the provincial electricity system[3]. In September 2022, the OEB launched the EVI initiative to inform the actions the OEB may take to ensure the efficient integration of EVs with the electricity system in Ontario; the Minister's letter of direction from October 2022 confirmed support for the OEB's work plan related to EV integration, and referenced distribution rates for EV charging including concerns related to demand charges.[4] As such, one workstream of the EVI initiative pertains to delivery costs and the review of "demand charges and the way in which these may be designed to appropriately allocate costs while facilitating the efficient integration of EVs."

This report examines the current electricity delivery rates for EV charging and examines alternative rate design options that could support the efficient integration of EVs in Ontario. The scope of this study focuses on electricity delivery rates applicable to distribution-connected commercial EV fleets (e.g., public transportation, delivery trucks, etc.) and public EV fast charging stations. These two electricity customer types have unique load profiles, which under the current rate structure have electricity bills which are more impacted by demand-based charges versus energy-based charges.

In Ontario, electricity rates are "unbundled", meaning electricity bills contain distinct charges for the supply of electricity to the customer (i.e., the commodity), the delivery of electricity to the customer's premises, and various regulatory and administrative charges. Although different ways of structuring each distinct charge on a customer's electricity bill may also affect EV adoption, changes related to commodity costs and other regulatory and administrative charges are not within the scope of this study.[5] This study also excludes EV charging at personal residences and any general service customers less than 50 kW. These two customer types have fixed delivery rates and energy-based delivery rates, respectively, as opposed to demand-based delivery charges. This study focuses on the impact of demand charges for commercial EV charging customers, as these customers have unique load profiles which impact their application.

Electricity delivery rates for commercial and industrial (C&I) customers are primarily based on the customer's peak demand. Demand charges reflect the maximum amount of power that a customer used over a specific interval - usually 15 minutes - during a billing cycle.

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[2] Ontario Energy Board, *Electric Vehicle Integration* (2023), https://engagewithus.oeb.ca/ev-integration

[3] Ontario Minister of Energy, *Mandate Letter to the Chair of the OEB* (November 15, 2021), https://www.oeb.ca/sites/default/files/mandate-letter-from-the-Minister-of-Energy-20211115-en.pdf

[4] Ontario Minister of Energy, *Letter of Direction to the Chair of the OEB* (October 21, 2022), 3. https://www.oeb.ca/sites/default/files/letter-of-direction-from-the-Minister-of-Energy-20221021.pdf

[5] There are a number of other proceedings underway or recently concluded in this respect, including the Ultra-Low Overnight price plan (https://engagewithus.oeb.ca/overnight-price-plan) and the dynamic pricing pilot for non-RPP Class B customers (https://engagewithus.oeb.ca/dynamic-pricing-pilot).

As identified in the results of the OEB's Survey of Local Distribution Companies and EV Charging Service Providers on facilitating the integration of EVs in Ontario,[6] various policies related to electricity distribution and ratemaking present barriers to efficient and cost-effective EV charging. Industry stakeholders and EV charging service providers have raised concerns about the impact of electricity delivery costs, and especially demand charges, on EV charging infrastructure adoption – particularly for owners of commercial EV fleets (i.e., buses, delivery trucks, etc.) and public direct current fast charging (DCFC) charging stations ("public DCFCs").[7] For example, charging service providers "unanimously agreed they were concerned with the impact of demand charges on future EV supply equipment deployment".[8]

As this report shows, other jurisdictions have for many years used alternative ways of designing electricity delivery rates for customers whose demand or load shapes are in one way or another outside of normal patterns. Interest in potential alternative rate designs is salient in Ontario as customer adoption of EVs is increasing at a rapid pace, therefore, creating a need for charging infrastructure. Ontario is not the only jurisdiction that is reviewing demand charges to remove barriers associated with EV adoption, be it driven by stakeholders or in the explicit fulfilment of public policy objectives.

The following activities were conducted in order to arrive at alternative rate design options which would facilitate the efficient integration of EVs:

- Quantitative assessment of the cost of current electricity delivery rates for commercial EV fleets and public DCFCs in Ontario.
- Qualitative analysis with respect to potential challenges for commercial EV fleets and public DCFCs, consisting of:
    - Semi-structured interviews with a selection of EV charging service providers, commercial EV fleet owners and services providers, and local distribution companies (LDCs) in Ontario; and
    - A literature review and jurisdictional scan to review rate design alternatives that have been considered, piloted, or implemented in other North American jurisdictions.
- Development and evaluation of alternative rate design options for commercial EV fleets and public DCFCs, including:
    - Evaluation of options using principles of good rate making and OEB objectives per *Ontario Energy Board Act, 1998*.

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[6] Guidehouse Canada for the OEB, *Facilitating the Integration of Electric Vehicles in Ontario* (January 2023). https://www.rds.oeb.ca/CMWebDrawer/Record/776475/File/document

[7] DCFC, sometimes referred to as "Level 3 charging", is a term used to refer to EV charging that outputs power at higher levels than alternating current chargers such as those found in private residences, allowing for the vehicle to be charged in less time. DCFCs typically have input voltages of 200-600 volts and power output of 50 to 350 kW.

[8] Ibid., 27.

    - Calculation of the economic impact of each alternative for commercial EV fleets and public DCFCs in Ontario, as well as impacts on other customers.

- Other considerations, including options for customers to mitigate delivery costs and qualitative evaluation of the rate design options from the perspective of other customers.

The remainder of this report is organized as follows:

- Section 2 – Evaluation of the impacts of the current rate design for electricity delivery costs
- Section 3 – Jurisdictional review (i.e., key themes and learnings)
- Section 4 – Process for selecting alternative rate design options, quantitative evaluation, and assessment of rate design principles.
- Section 5 – Summary of other options for commercial EV fleets and public DCFCs to mitigate delivery costs.
- Section 6 – Impacts of the alternative rate design on non-EV customers
- Section 7 – Observations and conclusions
- Section 8 – Next steps

2. IMPACT OF CURRENT RATE DESIGN ON EV CUSTOMERS

Electricity delivery charges are designed to recover the cost of transporting electricity from generating stations across the province to the customer's home or business. In accordance with section 78 of the *Ontario Energy Board Act, 1998*, charges for the transmission and distribution of electricity must be set by order of the OEB.

For the purposes of setting delivery rates, electricity customers are divided into classes, with different delivery rates applying to customers based on what rate class they are in. In Ontario, that segmentation takes place based on a customer's non-coincident peak (NCP) demand, which is the maximum demand, generally measured in kilowatts (kW), that the customer draws at any point during the billing period.[9] C&I customers with peak demand greater than 50 kW have delivery costs calculated predominately based on the maximum demand drawn during the billing period; this is referred to as a demand charge.

C&I customers are charged based on demand because doing so reflects principles of cost causality: peak demand is a major driver of costs for the distribution system,[10] and therefore customers who have higher peak demand (i.e., whose usage creates the need for more infrastructure and thus more costs for the system as a whole) are charged more. This rate design, while generally accepted as appropriate for most C&I customers, can be problematic for customers whose usage profile is atypical, and particularly for customers who may have a high peak demand but little sustained electricity consumption over time or whose peak demand occurs in hours when the system is otherwise underutilized. For example, a public DCFC that is in use for a few dozen hours over the course of a month and which, therefore, would be considered a small customer in terms of its total energy consumption, would receive a high electricity bill if a single EV drew high demand while charging[11].

Peak Demand and Coincidence

The electricity system is designed to accommodate the maximum power needs at the most energy-intensive time of day or year. In Ontario, peak demand for the system as a whole is generally late afternoon in July or August: to avoid blackouts, the provincial grid must be built to both produce and deliver enough electricity to meet demand at the highest-demand hour of the year. Similar principles apply at a local level, where peak demand may be at a different time of day or in a different season (depending on local weather and usage patterns) but where the system must be built to meet that demand whenever it is. Building a robust electricity system that can be relied on even at periods of extremely high demand is costly, hence

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[9] Power Advisory understands that different LDCs have slightly different methods for calculating a customer's peak demand.

[10] See, for example *A New Distribution Rate Design for Residential Electricity Customers,* Ontario Energy Board (April 2, 2015), 10. https://www.oeb.ca/oeb/_Documents/EB-2012-0410/OEB_Distribution_Rate_Design_Policy_20150402.pdf

[11] Power Advisory understands that some utilities will classify a public DCFC in the general service over 50 kW class simply on the basis of the charging station's power rating at the time the account is established. Even if classified as below 50 kW, the utility's rate reclassification process (which varies from one LDC to another) may result in the public DCFC being moved to the general service over 50 kW even if it only occasionally exceeds 50 kW of demand.

the connection between peak demand and system costs referred to above, and the rationale for billing customers based on their peak demand.[12]

However, when a C&I customer's peak demand is not coincident with the system peak (provincial, local, etc.), it incurs high demand charges but arguably does not materially contribute to the system costs incurred to meet system peaks. In other words, if EV charging occurs at night when there is little other demand on the distribution and transmission networks, it is likely that billing the EV customer on a simple peak demand basis, the same as if it were being used mid-day, would not be reflective of the actual costs the EV charging was causing the grid to incur.

Modelling Current Delivery Charges

To examine the impacts of Ontario's current electricity delivery charges on commercial EV fleets and public DCFCs, Power Advisory developed a model to generate sample electricity bills. The analysis took the following steps:

- Review of the general service rates of all Ontario LDC service territories.
- Segment service territories by the size of per-kW demand charge (high/medium/low) and location (urban/rural) to aid in selecting representative service territories for building out profiles.
- Develop EV charging profiles for both commercial EV fleet charging and public DCFCs use cases, based on publicly available data from the Rocky Mountain Institute,[13] the National Renewable Energy Laboratory,[14,15] and the Electric Reliability Council of Texas/Brattle Group.[16]
- Generate sample electricity bills for commercial EV fleets and public DCFCs by combining the representative service territories' delivery charges and assumed commodity costs with the EV charging profiles. Details on assumptions and this methodology are available in Appendix A.

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[12] Some customers may not be willing to pay the high costs of continued service even at peak periods; rate options for such customers are common in the natural gas sector and are being explored for certain electricity customers in Ontario. See IESO's consultation on an Interruptible Rate Pilot, https://ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Interruptible-Rate-Pilot

[13] Garrett Fitzgerald and Chris Nelder, "DCFC Rate Design Study", *RMI*, https://rmi.org/insight/dcfc-rate-design-study/

[14] Brennan Borlaug et al., "Heavy-duty truck electrification and the impacts of depot charging on electricity distribution systems", *Nature Energy* 6, (2021): 673–682. https://doi.org/10.1038/s41560-021-00855-0

[15] Madeline Gilleran. et al., "Impact of electric vehicle charging on the power demand of retail buildings", *Advances in Applied Energy* 4, (2021). https://doi.org/10.1016/j.adapen.2021.100062

[16] The Brattle Group, *ERCOT EV Allocation Study: Methodology for Determining EV Load Impact at the Substation Level* (October 13, 2022), https://www.brattle.com/insights-events/publications/ercot-ev-allocation-study-methodology-for-determining-ev-load-impact-at-the-substation-level/

The sample electricity bills generated by this analysis allowed Power Advisory to:

- Describe the cost of demand charges as a proportion of a customer's total electricity bill, and
- Calculate an equivalent per-kilowatt hour (kWh) rate for the demand charges for comparative purposes (i.e., an average rate).

Throughout this report, customer electricity costs will sometimes be expressed as a per-kWh or "average rate", calculated by dividing monthly costs by the customer's total monthly energy consumption in kWh. Average demand charges and the average rate for total electricity bills, including both delivery costs and commodity costs, will be presented in this manner.

Sample of Current Demand Charges

Demand charges of Ontario's LDCs range from approximately $8/kW to $24/kW. Some Ontario LDCs have separate general service rate classes for larger customers, which typically have lower demand charges and higher fixed charges. Figure 1 shows the charges for a 300 kW customer.[17] The height of each bar represents the total general service load (TWh) in all LDCs whose demand charges for a 300 kW customer fall within each range.

Figure 1. Range of Demand Charges for a 300 kW Customer in Ontario

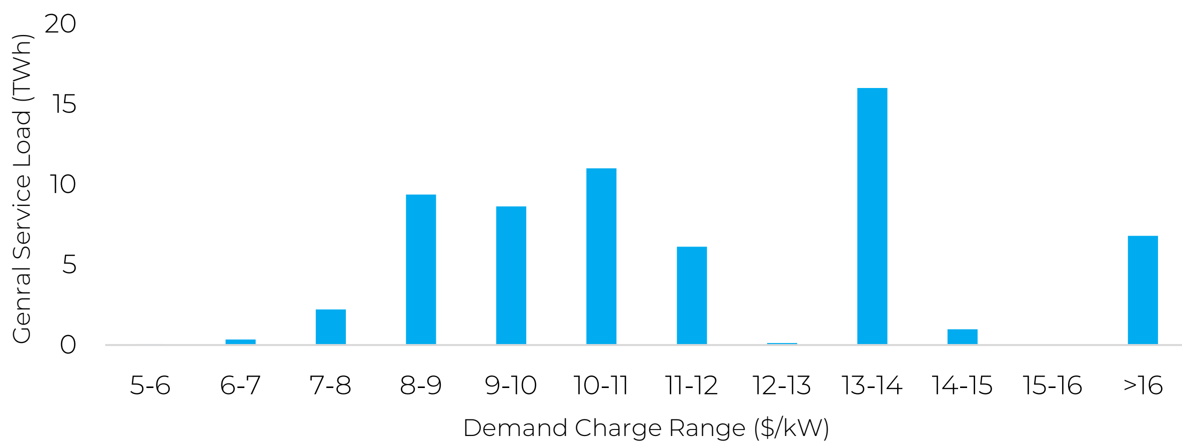


Table 4 provides an overview of demand charges for six LDC service territories selected to represent three clusters of demand charges in existing rates for urban LDCs (i.e., those LDCs serving predominantly urban areas) and rural LDCs (i.e., those LDCs serving predominantly rural areas). LDCs were classified as "low" if the LDC's demand charge was below $10/kW, "moderate" if it ranged from $10-$12 per kW, and "high" if above $12/kW. Demand charges are shown for 300 kW customers; some LDCs have slightly different rates for higher power customers.

[17] Commercial EV charging customers could span a broad range of peak power demand, but 300 kW would not be unusual. Public DCFCs offering six 50 kW ports or two 150 kW ports would consume up to 300 kW. A commercial EV fleet of 20 to 30 vehicles could reasonably consume up to 300 kW while charging.

Table 4. Representative Demand Charges for a 300 kW Customer

Representative Service Territory	Demand Charge ($/kW)
Urban Low[1]	8.83
Urban Moderate	11.55
Urban High	14.04
Rural Low	8.85
Rural Moderate	11.20
Rural High[2]	24.21

[1] A representative LDC with predominately urban service territory with relatively low demand changes
[2] A representative LDC with predominantly rural service territory with relatively high demand charges

In this report, electricity bills for EV charging customers will be compared to electricity bills for other general service customers. The "Typical Customer" load profile is based on the average day from hourly Ontario Demand in 2015 through 2021, net of Regulated Price Plan demand (sourced from the Independent Electricity System Operator (IESO) Smart Metering Entity) and directly connected industrial load (sourced from IESO public reports). Table 5 outlines how non-commodity related costs are recovered for the Typical Customer assuming 300 kW NCP demand. Demand charges account for 75% to 97% of all non-commodity related charges on a Typical Customer's electricity bill.

Table 5. Non-Commodity Related Cost Recovery, by Representative Service Territory, for a Typical Customer

Service Territory	Fixed Delivery Charges	Demand Charges	Other Energy-Based Charges*
Urban Low	4%	82%	14%
Urban Moderate	2%	86%	11%
Urban High	3%	97%	0%
Rural Low	7%	74%	19%
Rural Moderate	4%	75%	22%
Rural High	2%	93%	6%

** Other Energy-Based Charges include regulatory charges such as Wholesale Market Service Rate, Capacity Based Recovery, and Rural or Remote Electricity Rate Protection Charge. These charges may be temporary rate riders and may be either positive or negative.*

Commercial EV Fleets

Electricity bills for commercial EV fleets were modelled using three different fleet types (beverage delivery, food delivery, and buses), with each fleet being modelled for 10 to 25 vehicles and with a fleet size ten times higher. The load profiles, shown in Figure 2, were selected to represent a reasonable range of commercial vehicle types, fleet sizes, and schedules that are currently feasible to electrify. More details on load profile development are available in Appendix B.

Figure 3 presents average (i.e., expressed per-kWh) demand charges for the different fleet types and sizes. The range of average demand charges is $0.02/kWh to $0.12/kWh. The variation in demand charges between different fleets in the same service territory can be attributed to factors such as the shape of the load profiles, the difference between a peak day and an average day, and the size of the fleet. Larger commercial EV fleets may be placed into different rate classes with lower demand charges, or they may have different load profiles than smaller fleets of the same vehicle type.

Figure 2. Commercial EV Fleet Daily Load Profiles

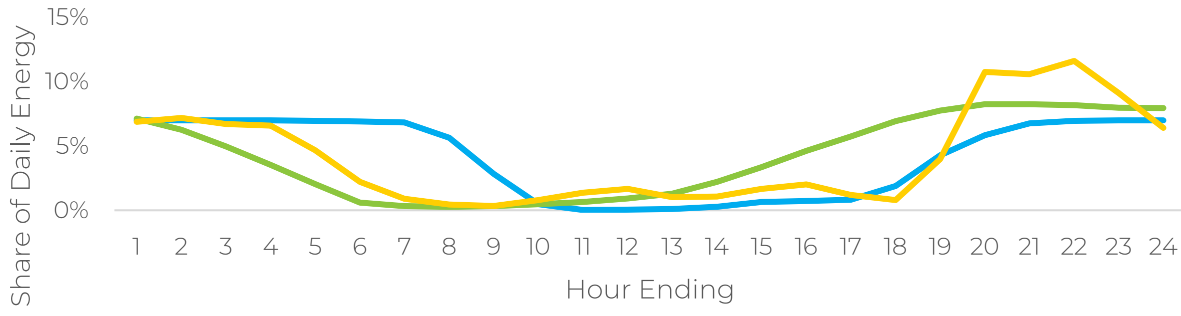
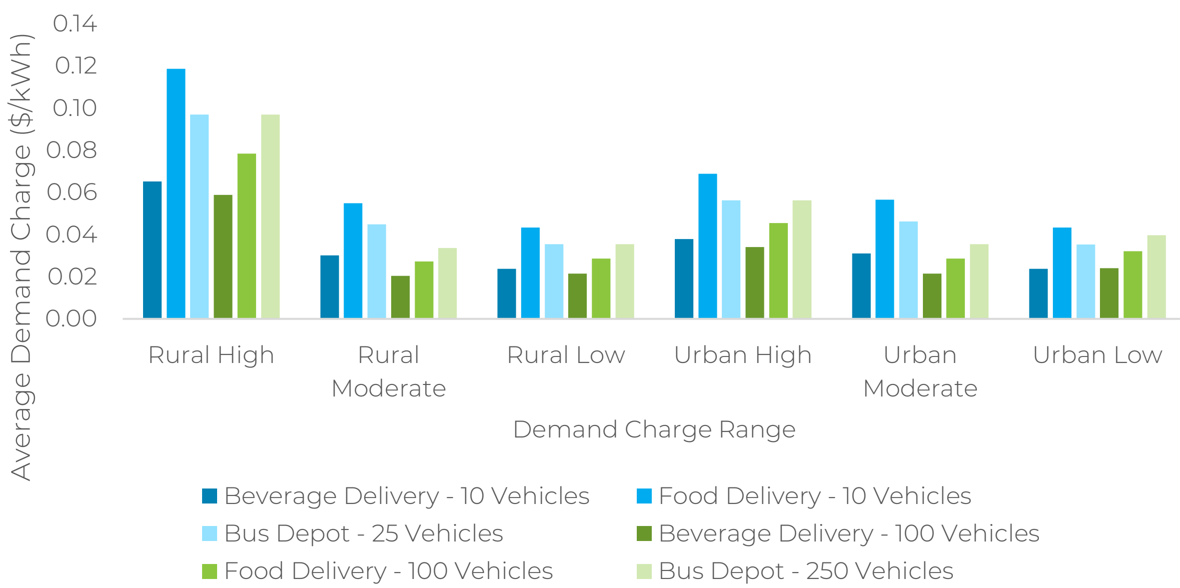


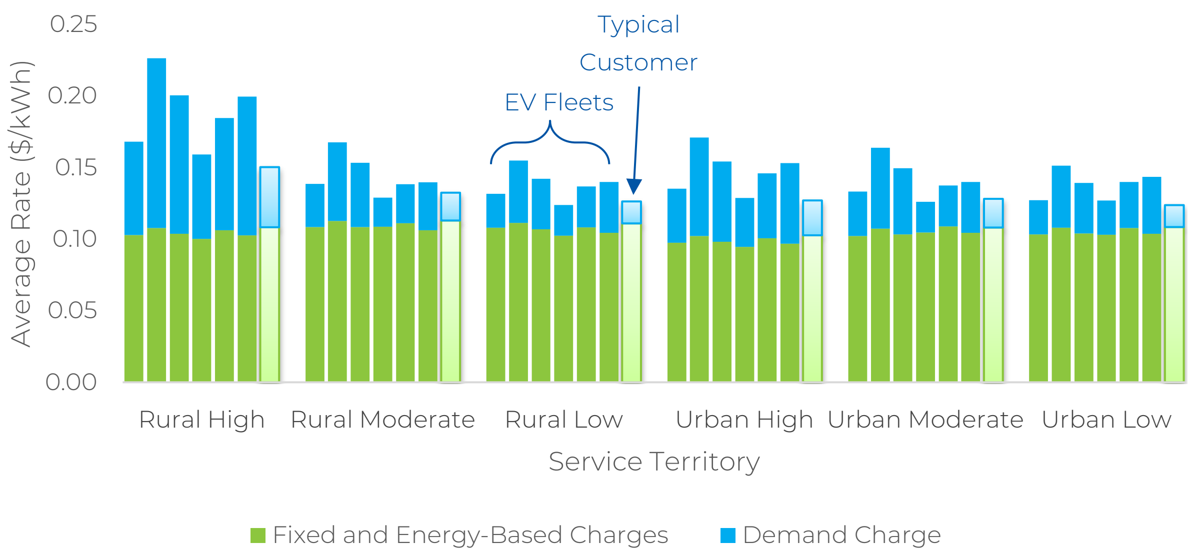
Figure 3. Average Demand Charge for Commercial EV Fleets



Average rates (i.e., per-kWh rate including both delivery costs and commodity costs, etc.) for commercial EV fleets range from $0.12 to $0.23/kWh. Figure 4 shows the average rates for the six EV fleets considered in Figure 3. The rightmost column in each cluster is the average rate for a Typical Customer. Demand charges tend to make up a larger share of the total bill for commercial EV fleets (16% to 52%) compared to a Typical Customer (12% to 28%).

Fixed charges vary considerably between service territories but in most cases are reasonably low when expressed on a per-kWh basis. The bulk of energy-based charges are from the commodity cost, which is the same for all service territories. For commercial EV fleets, an all-in electricity cost of $0.15/kWh is comparable to diesel priced at $0.33/litre for lower speed fleets where EVs have the greatest efficiency advantage.[18]

Figure 4. Average Rate for Commercial EV Fleets and Typical Customer



The challenges for commercial EV fleets are related to fair cost allocation. The NCP demand portion of delivery costs is a substantial part of their total electricity bill. Commercial EV fleets with NCP demand that occurs overnight cause little or no incremental transmission or distribution costs for the rest of the system beyond the local connection costs to serve the fleet's NCP demand. This may result in commercial EV fleets unfairly subsidizing other customers through their demand charges. In addition, there may be potential for system-wide cost savings if there is a stronger incentive for commercial EV fleets with flexible schedules to shift their charging to off-peak times.

Public DCFCs

$$\text{Load Factor} = \frac{\text{Average Demand}}{\text{NCP Demand}}$$

Electricity bills for public DCFCs were modelled for a range of different utilization rates. At present in Ontario, public DCFCs have low load factor usage patterns because they provide high power to EVs during short, infrequent charging sessions (Figure 5). Utilization, or load factor,[19] is the average demand divided by NCP demand. Canadian public DCFCs averaged 5% utilization in the

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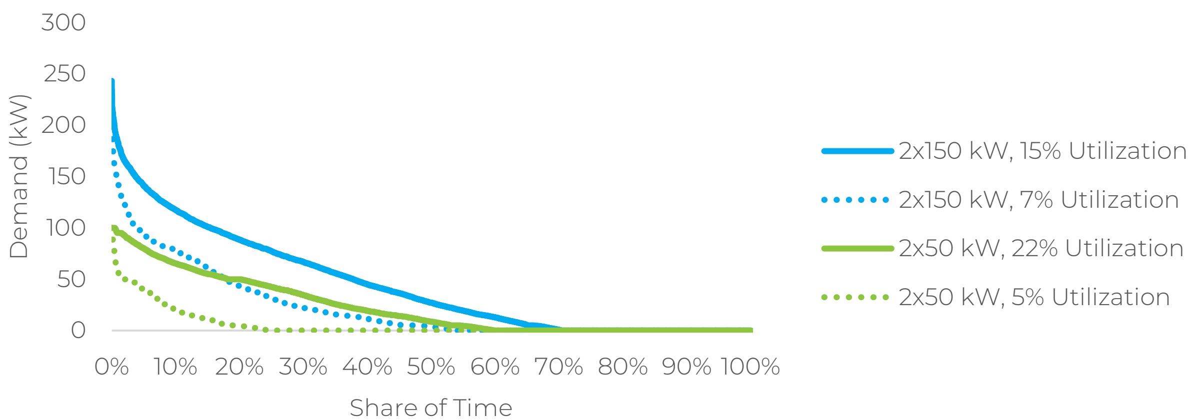
[18] In other words, an electrified urban delivery fleet with an average speed of around 25 kilometres per hour that is charged at $0.15/kWh would have the same fuel costs as a conventional delivery fleet paying $0.33/litre for diesel. From 2019 to 2022, the retail price of diesel in Toronto averaged $1.35/litre (Statistics Canada, *Table 18-10-0001-01 Monthly average retail prices for gasoline and fuel oil, by geography*). The efficiency advantage of electric motors compared to diesel engines decreases at higher speeds.

[19] Henry Ruderman, Mark D. Levine and Peter Chan, "The effect of energy conservation measures on residential Electricity Demand and Load Shape". *Lawrence Berkely National Laboratory* (1986).

2019 to 2021 period,[20] but utilization is expected to increase with EV market maturity (i.e., as adoption of EVs increases). However, even with market maturity it is likely that utilization will remain lower for public DCFCs than for the average general service customer; this is because public DCFC operators can be expected to install additional ports once utilization reaches a certain threshold (e.g., 18%). Keeping utilization rates relatively low is necessary to prevent drivers having to wait in queues to access chargers, which would largely undermine the premise of fast charging, as discussed further in Section 4.1.2. Thus, while utilization rates are likely to increase from where they are now in Ontario, the business model for public DCFCs means that demand charges may be a persistent issue.

Figure 5. Duration Curves for Various Public DCFC Utilization and Power Levels



Load duration curves in Figure 5 were constructed by sorting a full year of simulated load data from highest to lowest to demonstrate how frequently load exceeds various demand levels, with the blue and green lines representing public DCFCs with two charging ports, each capable of providing 150 kW of power or 50 kW of power, respectively. For example, the 2x150 kW, 7% utilization DCFC exceeds 100 kW only 4% of the time. The area under the load duration curve represents the total energy consumed by the DCFC in the year.

In a normal day, a public DCFC will spend most of its time drawing nearly zero power. This will be punctuated by several short charging sessions. In Canada, public DCFC usage sessions average 28 minutes.[21] Occasionally, both ports at a 2-port station will be in use and the station may draw its maximum demand. Averaging many independent stations together yields a load profile that picks up in the morning and peaks in the late afternoon, with higher load on Fridays and weekends. There are minor variations in this average profile from different sources (Figure 6). More details on load profile development are available in Appendix B.

[20] Government of Canada, *2022 Biennial Snapshot of Canada's Electric Charging Network and Hydrogen Refuelling Stations for Light-duty Vehicles*, https://natural-resources.canada.ca/energy-efficiency/transportation-alternative-fuels/resource-library/3489

[21] Ibid.

Figure 6. Average Daily Load Profile of Public DCFCs

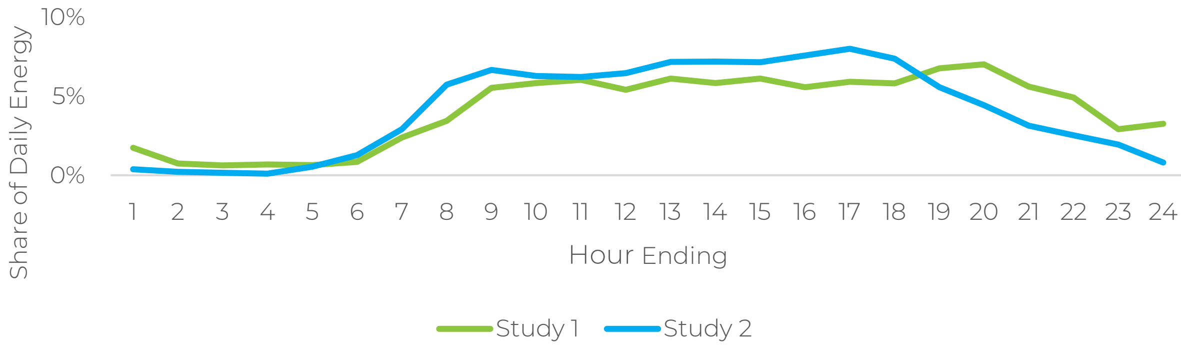


Figure 7 expresses the average rate (i.e., delivery costs and commodity costs, etc.) for different utilization levels and service territories. The modelling produced the following results for public DCFCs across the six representative service territories:

- At current utilization rates (5%), total average rates currently range from $0.15/kWh to $0.53/kWh and average demand charges range from $0.14/kWh to $0.38/kWh.
- At 30% utilization rates, the range of average demand charges would fall to $0.04/kWh to $0.10/kWh.
- At 5% utilization, demand charges for a Class B customer[22] with a typical two-port 50 kW charging station would make up 43% to 72% of the customer's total monthly electricity bill.

Average demand charges decrease quickly as utilization increases. Most public DCFCs in Ontario currently price electricity sold to drivers in the range of $0.40 to $0.60/kWh.[23] In terms of range added, charging an EV at $0.60/kWh is comparable to gasoline priced at $1.23/litre.[24] In the Rural High service territory, average rates exceed $0.60/kWh when utilization falls below 4%. At low utilization, it is difficult for public DCFC operators in some areas to recover their operating costs.

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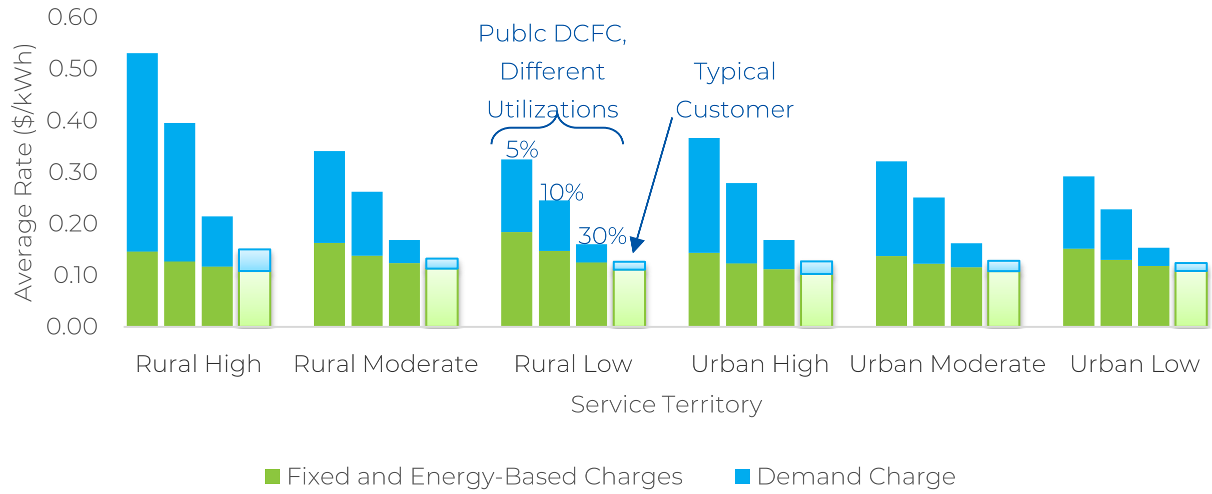
[22] Class B customers are defined by Ontario Regulation 429/04, *Adjustments Under Section 25.33 of the Act*, made under the *Electricity Act, 1998,* https://www.ontario.ca/laws/regulation/040429

[23] Note that federal regulations until recently required EV charging stations to bill on the basis of time rather than quantity of electricity dispensed. DCFC pricing is generally not consistent or transparent. Posted Tesla Supercharger pricing for one station in Toronto ($0.33/min below 60kW, $0.65/min between 60 and 100 kW, $1.05/min between 100 and 180 kW, and $1.70/min between 180 and 250 kW) was converted to energy-based rates for the range of power levels (prices sourced from https://driveteslacanada.ca/supercharger/tesla-adjusts-supercharger-fees-canada-again/). On February 20, 2023 Measurement Canada approved a temporary dispensation that allows charging station operators to charge for electricity in kWh (https://ised-isde.canada.ca/site/measurement-canada/en/consultations/temporary-dispensation-level-3-electric-vehicle-supply-equipment).

[24] Conversion based on average EV efficiency of 0.2 kWh/km (consistent with Independent Electric System Operator (IESO) Annual Planning Outlook, https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/Dec2022/Demand-Forecast-Methodology.ashx) and combustion vehicle efficiency of 24.2 miles per gallon (https://afdc.energy.gov/data/10310).

Figure 7. Average Rate for Public DCFCs and a Typical Customer



Overall Findings from Analysis

The analysis of the current delivery rates shows that the business case for public DCFCs is challenged with present low utilization rates. It would be very difficult for a public DCFC operator to recover the operating and capital costs of the station. While public DCFC utilization is expected to improve with the maturity of the EV market, the current delivery rate design is likely a barrier to public EV charging and has the potential to slow down the deployment of fast charging stations; particularly in some areas on the province where utilization is low.

Table 6. Summary of Current Rate Design Bill Impact for EV Customers

Load Profile	Average Rate[1] ($/kWh)		Demand Charge Share (%)	
	Urban Low[2]	Rural High[3]	Urban Low	Rural High
DCFC 2x50kW 5% Utilization[4]	0.29	0.53	48%	72%
DCFC 2x50kW 10% Utilization	0.23	0.40	43%	68%
DCFC 2x50kW 30% Utilization	0.15	0.21	23%	45%
Food Delivery - 10 Vehicles	0.15	0.23	29%	52%
Beverage Delivery - 10 Vehicles	0.13	0.17	19%	39%
Bus Depot - 25 Vehicles	0.14	0.20	25%	48%
Typical Customer[5]	0.12	0.15	12%	28%

[1] *The Average Rate refers to the per-kWh rate for electricity calculated by dividing monthly costs for both delivery and commodity by the customer's total monthly energy consumption in kWh.*

[2] *A representative LDC with predominately urban service territory with relatively low demand changes.*

[3] *A representative LDC with predominantly rural service territory with relatively high demand charges. The two representative LDCs in this table do not reflect the full range of demand charges in the province; there are, for example, LDCs with rural service territories with lower demand charges and LDCs with urban service territories with higher demand charges.*

[4] *This refers to a public DCFC with two charging ports each capable of providing 50 kW of power.*

[5] *The Typical Customer profile is based on the average day from hourly Ontario Demand in 2015 through 2021, net of Regulated Price Plan demand (sourced from the IESO Smart Metering Entity) and directly connected industrial load (sourced from IESO public reports).*

With respect to commercial EV fleets, costs due to demand charges vary considerably between type, size, and location of the fleet. While commercial EV fleets, unlike public EV charging, charge EVs for their own use and hence do not need to be concerned about the spread between the cost of electricity purchased and dispensed, they generally need to be able to build a business case for electrification. In scenarios where demand charges make up significant portions of the electricity bill it may be challenging to do so.

Implications from Customer's Perspective

Interviews with commercial EV fleet operators, charging infrastructure and energy service providers, and Ontario LDCs were conducted to gain additional insights into how demand charges may be impacting EV infrastructure deployment. These interviews were of a small cross-section of stakeholders; however, their feedback was consistent with the OEB's survey of LDCs and charging service providers.[25]

Feedback from commercial EV fleets and charging network operators

The discussions with commercial EV fleet and charging network operators revealed that customers generally fall into two categories:

- Customers whom fleet conversion and/or installation of public DCFCs was driven by economics, and
- Customers for whom there were broader considerations beyond simple profitability (for example, environmental or net-zero goals).

Private-sector fleets must generally have a strong business case for electrification, generally predicated on electricity costing significantly less than diesel fuel. However, some fleets (such as those in the broader public sector, such as public transit) have been given government or shareholder mandates to electrify; while these fleets were cognizant, to varying degrees, of the costs associated with electrification and were very interested in mitigating costs to the extent possible, they acknowledged they had to electrify to align with public policy.

A similar range of motivations exists for public charging: some businesses install public charging stations on their premises with the expectation that offering EV charging will eventually be a new source of revenue; the total cost of electricity is therefore a vitally important input into the business case. However, Power Advisory's research showed other businesses install public charging for more diverse reasons – for example, as a convenience for customers, as a means to attract customers into a store or encourage them to linger, or to meet corporate sustainability objectives.

Customers who are highly sensitive to the economics of EV charging expressed concern about the immediate impact of demand charges on electricity bills, and further the uncertainty about the impact of electrification on demand. Even where electrification had objectives beyond just profitability, customers indicated the barriers posed by high electricity bills had the potential to slow deployment. One fleet owner with operations in multiple provinces indicated that there are significant disparities in electricity costs

[25] Guidehouse Canada for the OEB, *Facilitating the Integration of Electric Vehicles in Ontario* (January 2023). https://www.rds.oeb.ca/CMWebDrawer/Record/776475/File/document

between provinces which impacts how their company phased in the electrification of its fleet (i.e., could mean prioritizing electrification in other provinces over Ontario).

Feedback from LDCs

Feedback from Ontario's LDCs was mixed, with some reporting that their customers had clearly raised the demand charge issue with them, and others not considering it to be an issue. There did not appear to be a direct correlation between LDC size and the degree to which demand charges were perceived to be "a problem". A view that was consistent between LDCs was that given the cost and effort that go into billing changes, the solution being sought with any prospective rate changes would need to be demonstrably better than the status quo.

3. JURISDICTIONAL REVIEW OF EV RATE DESIGN ALTERNATIVES

To better understand how other jurisdictions have approached the impact of demand charges for commercial EV fleets and public DCFCs, a review of EV-specific delivery rates in British Columbia, Quebec, California, Colorado, Wisconsin, New York, Connecticut, and Massachusetts was conducted.[26] This section of the report highlights the key themes and applicable lessons learned for Ontario from the scan. Specific details from the scan are presented in Appendix C.

There is considerable diversity in how utilities and regulators have approached EV-specific delivery rates for commercial EV fleets and public DCFCs. Some jurisdictions introduced EV-specific delivery rates because they were required to do so by law (e.g., New York), others in response to customer requests (e.g., British Columbia), others due to more general policy direction (e.g., Quebec). Regarding rate making principles, some jurisdictions (e.g., Wisconsin) had explicit research and learning objectives as part of EV ratemaking, which in turn allowed for more flexibility and liberties in setting rates. In other jurisdictions (e.g., Connecticut) regulators have followed traditional economic approaches to ratemaking or attempted to blend economic with public policy objectives.

With respect to how different jurisdictions have approached the design of modified delivery rates for commercial EV fleets and public DCFCs, some rates were developed in response to specific known or reasonably foreseeable conditions and customer needs, while others were more open-ended, attempting to capture larger ranges of customers and charging behaviours. Regulators have used both traditional fully allocated costing (e.g., in Colorado) and marginal costing (e.g., in British Columbia) in setting rates for EV charging,[27] a choice that may be influenced by public policy objectives. Finally, in jurisdictions with vertically-integrated utilities, bundled commodity and delivery charges, and/or regulatory control of commodity rates (i.e., unlike Ontario), utilities have greater flexibility to offset the decreases in distribution revenue that may result from modified or lower demand charges with increased commodity prices, and/or to consider total utility revenue growth from incremental electricity sales to EV customers as part of the justification for offsetting demand charges for EVs.

It should be noted that BC Hydro's Overnight Rate, which calculates demand charges based only on daytime peak demand (i.e., peak demand incurred between 6:00 am and 10:00 pm), is also the most noted rate design option referred to when interviewing EV charging customers.

Interviews with customers also revealed their desire for harmonization in deploying charging infrastructure across Ontario's LDCs, given that each has slightly different policies and protocols for things like connections, metering, and billing. This observation was also supported in the jurisdictional scan. In

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[26] The review included understanding: the drivers for introducing new rate design; the options that were considered; the specific design and rationale for the chosen rate structure; and other features or considerations that might be relevant for Ontario.

[27] Fully-allocated costing refers to the ratemaking practice whereby the rates charged to customers are designed to recover the full costs – both direct and indirect – of serving those customers. Marginal cost ratemaking means setting rates on the basis of only the additional, or marginal, costs that a new customer (or customer class) causes the utility to incur.

jurisdictions with multiple LDCs, regulators strongly encouraged or even required LDCs to harmonize, at least at a high level, their alternative rate designs for EV charging (e.g., in New York and Massachusetts).

On the whole, the jurisdictional scan revealed the following lessons:

- Ontario is not the only jurisdiction considering the uncertainty around how to approach rates for EVs. Both mature and advancing EV markets are responding to increased adoption of this unique electricity customer resulting in changing electricity consumption profiles. Unlike traditional loads whose profiles are well-established, EV deployment, usage, and charging is likely to change in the coming years. Therefore, the regulator should consider balancing for customers' desire for stable and predictable rates with developing a rate that is fully "future-proof".

- A closer examination of cost causality could justify near-term rate setting exercises for EV-specific delivery charges. It is challenging for rate classes to perfectly reflect all class members' usage and cost causality profiles, but other jurisdictions have observed that certain EV charging behaviour can deviate so markedly from its class profile that some kind of different treatment may be warranted.

- Finally, different utilities and customers will likely have different needs, therefore adjustments to rates should consider flexibility. Commercial EV fleet charging is not the same as public charging. Similarly, the solutions sought in one utility's service territory may not be applicable or desirable in another's, and the regulator should consider the trade-offs of province-wide versus local or regional solutions.

4. SELECTION AND ANALYSIS OF ALTERNATIVE RATE OPTIONS

As described in the preceding sections of this report, Ontario's current rate design for delivery charges can be a barrier to the deployment of commercial EV fleets and public DCFCs, with distinct reasons for each. The research undertaken for this report showed that there were material differences between public EV fast charging and fleet charging in terms of the customer's charging behaviour and experience, and therefore in the challenges facing each customer type.

Commercial EV fleet charging is routine, predictable, may be amenable to longer charging times, and is generally undertaken by customers who may have the incentive and ability to be more price responsive. For commercial EV fleets, demand charges are especially challenging in the early phases of electrification as fleets gradually convert combustion engines to electrical ones, and when a small number of vehicles can trigger high demand charges and significantly impact the customer's electricity bill. However, even as fleets grow, commercial customers who are used to being afforded various tools to manage their electricity bills can be frustrated that they have little ability to manage delivery charges as they are currently structured. Furthermore, unless carefully managed, the very high demand that can be drawn by arrays of Level 2 EV chargers (as might be found in a fleet depot) can push a customer from one rate class into another, potentially creating additional uncertainty and cost.

Whereas the research showed that use of public DCFCs at present is mainly from intermittent customers who need fast and reliable charging on-demand and who may not be willing to accept lower charging speeds or shifting time of electricity consumption (e.g., so as to allow the public DCFC operator to avoid demand charges or peak periods). Under those circumstances, demand charges are a challenge primarily while utilization is low: public DCFCs are likely to experience relatively little use (and hence relatively little revenue) but may nonetheless be subject to significant demand charges. This severely undermines the business case for the charging station, which in general is reliant on revenue from drivers using the DCFCs being greater than the cost of electricity dispensed.

Alternative rate design options were developed with the aim to better align charger utilization, LDCs' costs of servicing those chargers, and the electricity bills that charger owners must ultimately pay, while also recognizing the differences between the two use cases. The option analysis used the results from the jurisdictional review, discussions with a sample of Ontario stakeholders, and a literature review of practices for EV-specific delivery rates. The process for identifying alternative rate design options sought to review a maximal number of potential rate design options, then used various assessment criteria to narrow the options before settling on the recommended options, further discussed below. The process was as follows:

- Step 1: Compile master list of alternative rate design options based on learnings from jurisdictional scan, literature review, and interviews.
- Step 2: Evaluate potential alternative rate design options using assessment criteria and Bonbright principles.
- Step 3: Develop shortlist of alternative rate design options.
- Step 4: Conduct quantitative evaluation of short-listed alternative rate design options.

See Appendix D for full details of the evaluation process and selection process.

Two alternative rate design options were ultimately identified and advanced for quantitative evaluation. Those two options were a time of use (TOU) demand charge to address needs of commercial EV fleets, and a low load factor rate with multiple variations to address public DCFCs. These options were selected for further evaluation in this report because they provided the best combination of responsiveness to customer concerns, feasibility of implementation, and alignment with prior OEB guidance on rate design for C&I customers as well as general best practices for rate design. Each of the two options could operate or be introduced independent of the other.

Table 7. Alternative Rate Design Options Considered for Further Evaluation

Option	Addresses	Description
1. TOU Demand Charge	Commercial EV Fleets	Some delivery costs recovered using demand in daily peak hours, other delivery costs continue to be recovered using NCP demand.
2a. Low Load Factor Rates: Single Tier	Public DCFCs	Reduced demand charge for customers below a certain load factor threshold.
2b. Low Load Factor Rates: Multiple Tiers	Public DCFCs	Reduced demand charges for customers that step up as load factor increases.
2c. Demand Transition Charge	Public DCFCs	Reduced demand charge for customers with low load factor, with some delivery costs recovered using TOU energy charge instead. As load factor increases, the energy charge is phased out and the demand charge increases.

The remainder of this section will evaluate potential rate designs for TOU demand charges and low load factor rates. To illustrate a broad range of possible outcomes, the Urban Low and Rural High service territories set out in Table 4 will be used. Section 4.1 will further develop the economic rationale for the alternative rate design options and calculate illustrative electricity delivery rates. Section 4.2 will further discuss the alternative rate design options in the context of OEB objectives and ratemaking principles. Section 4.3 will model the electricity bill impacts of applying the rate design alternatives for commercial EV fleets, public DCFCs, and typical general service customers. Section 4.4 will provide a summary of findings.

4.1 Description of Alternative Rate Design

The economic rationale for both the TOU demand charge and the low load factor rate is based on the distinction between NCP demand and coincident peak (CP) demand. Distributor assets that serve a small number of customers, which are often at lower voltages, must be sized to peak demand that could happen at any time (i.e., NCP demand). Higher-voltage assets are more likely to serve multiple customers and are sized to the highest demand of the aggregate load profile. Costs associated with these higher-voltage assets are most appropriately recovered based on a customer's contribution to the peak of the aggregate load profile (i.e., CP demand).

A 2016 OEB Staff Discussion paper discussed these system cost drivers and proposed various 3- part and/or TOU demand charges which considered measures of both CP demand and NCP demand.[28] The proposal received mixed feedback from stakeholders and did not proceed at the time. With changes in technology, evolving customer priorities, and new end uses such as EV-related loads, there may be renewed interest in exploring allocation of some fixed costs based on CP contribution.

4.1.1 *TOU Demand Charge*

As discussed further in Appendix D, a demand charge based on a single monthly CP hour would likely be too complex to implement and manage. Instead, a TOU demand charge could recover a portion of fixed costs based on customer demand in a daily, multi-hour peak period. The TOU demand charge proposed here would calculate a customer's total demand charge as the sum of (a) the customer's peak demand in the peak period multiplied by the peak period $/kW demand charge and (b) the customer's NCP demand multiplied by the NCP $/kW demand charge. For conventional loads, NCP demand will likely occur during the peak period. For an overnight load, peak demand in the peak period could be substantially lower than NCP demand.

The specifics of such a rate would require further analysis and consultation to determine. Two important design features are the timing of the peak period and the costs which are shifted from NCP demand to peak period demand.

There are trade-offs when selecting the length of the daily peak period. The timing of CP is uncertain. It may vary from year to year and between geographic areas. A longer peak period would increase the likelihood of including the CP. A longer peak period would also limit the number of customers that would be able to avoid peak period demand charges, reducing the impact of the rate on other customers. To be useful for commercial EV fleets, the off-peak period would need to be sufficiently long to charge the fleet and occur during hours when vehicles are not in use. Finally, a peak period could be defined every day or only on a subset of days such as non-holiday weekdays. This analysis uses a peak period from hour ending 8 to hour ending 21 every day.

Given the peak period, the next step is to determine which demand-related costs would continue to be recovered based on NCP demand and which costs would be shifted to peak period demand. This decision should be guided by principles of cost causation. In other words, costs associated with higher-voltage equipment that is shared among many customers are more appropriately allocated according to a measure of coincident demand.

Electricity distributors are charged for transmission service at the Uniform Transmission Rates, which are set annually by the OEB. The majority of transmission costs are recovered from distributors based on the demand at a supply station during a peak period, and the remainder is charged based on NCP demand at the station. Transmission costs are currently recovered from a distributor's customers through Retail Transmission Service Rates (RTSRs) based on the customer's NCP demand. Because distributors incur

[28] Ontario Energy Board, *EB-2015-0043 Staff Discussion Paper* (March 31, 2016), Section B.1 and Section D, https://www.oeb.ca/oeb/_Documents/EB-2015-0043/Staff_Discussion_Paper_RDCI_20160331.pdf

transmission costs based on the aggregate load profile of all their customers at a supply station, recovering transmission costs using a measure of each customer's CP demand could bring rates into closer alignment with cost causation.

The OEB's Cost Allocation Model for Electricity Distributors classifies a share of an LDC's assets and costs as demand-related, which is further subclassified between CP demand and NCP demand. Land, Land Rights, Buildings and Fixtures, Leasehold Improvements, Transformer Station Equipment, and Storage Battery Equipment are classified to CP-related demand. Shares of other distribution plant sub-functionalized to serving loads above 50 kV are also classified as CP-related demand. The allocation of demand-related assets is an input in the calculation of the composite allocators used to allocate general plant and some operations, maintenance, and administration (OM&A) accounts.

This analysis will consider allocating 100% of RTSR and CP-related distribution costs to peak period demand. The impact of this change varies considerably between LDCs. RTSRs account for 63% of all demand charges in the Urban Low service territory and only 17% of demand charges in the Rural High service territory. For the Urban Low territory, 23% of the LDC's demand-related costs are classified as CP-related. The share is 43% in the Rural High territory. For the purpose of this analysis the same share of demand-related revenues is considered CP-related for each service territory, though in practice an LDC's level of demand-related costs may not be precisely aligned with demand-related revenues on a class-by-class basis.

Table 8. TOU Demand Charge Illustrative Rate Design

Category	Urban Low		Rural High	
	Current Rates	TOU Rates	Current Rates	TOU Rates
Retail Transmission Service Rate ($/kW)	5.68	5.68 / (1 – 5%) = 5.98	4.09	4.09 / (1 - 5%) = 4.31
Distribution Volumetric Rate, CP-Related ($/kW)	0.71	0.71 / (1 – 5%) = 0.75	8.37	8.37 / (1 - 5%) = 8.81
Distribution Volumetric Rate, NCP-Related ($/kW)	2.38	2.38	11.01	11.01
Other NCP Charges ($/kW)	0.05	0.05	0.73	0.73
Total CP Charges ($/kW)	0	6.73	0	13.12
Total NCP Charges ($/kW)	8.82	2.43	24.20	11.74

Table 8**Error! Reference source not found.** shows the difference between current charges[29] and the charges that will be modelled for the TOU demand charge in the Urban Low and Rural High service territories. If any customers have their NCP demand in the off-peak period, then total peak period demand will be lower than total NCP demand. Maintaining revenue neutrality would require the same amount of RTSR and CP-related distribution costs to be recovered from a smaller number of kilowatts compared to current rates. Customers that take advantage of the TOU demand charge would experience electricity bill savings that are offset by electricity bill increases for remaining customers in the general service greater than 50 kW rate class. For illustration, the demand charges calculated in Table 8 assume that total peak

[29] Current charges refer to those in effect in 2022 in Ontario.

period demand is 5% lower than total NCP demand. All other components of the electricity bill would remain the same.

For example, consider a customer in the Urban Low service territory with an NCP demand of 100 kW and peak period demand of 50 kW. Because their peak period demand is much lower than their NCP demand, this customer would have a lower bill under the TOU demand charge.

Current Demand Charge:

100 kW * ($2.38/kW + $0.71/kW + $5.68/kW + $0.05/kW) = 100 kW * $8.82/kW = $882

TOU Demand Charge:

100 kW * ($2.38/kW + $0.05/kW) + 50 kW * ($0.75/kW + $5.98/kW)

= 100 kW * $2.43/kW + 50 kW * $6.73/kW = $579.50

4.1.2 *Low Load Factor Rate*

Electricity customers with low load factors are generally less likely to contribute to CP demand than typical electricity customers. Consider a 2-port public DCFC with 7.5% utilization. During the day, there will be a handful of charging sessions using a single port and lasting less than an hour. Occasionally, both ports will be in use and the station will draw its maximum demand. Figure 8 shows how the daily load profile for the public DCFC can have a brief peak that may be coincident with the system peak. It is more likely that the CP demand for the station is less than 50% of its NCP demand.

When Hydro Quebec proposed Rate BR (a rate class specific to public DCFCs – see Appendix E for more detail), it made the same claim,[30] noting the company already had a low load factor rate (Rate G9) which was based on the same rationale. Translated to English below:

> *"In general, the higher the load factor of a load, the more likely it is to be peak coincident. Below a load factor of 30% (i.e., 216 hours of use per month), the coincidence at the peak decreases rapidly as the load factor decreases.*
>
> *Thus, a lower use of the maximum power demand justifies a lower demand charge to recover power costs. It is on this basis that the G-9 tariff is calibrated, which is designed for load factors of less than 30%. The demand charge is in fact reduced so as to correspond to a proportion of 30% of that of Rate M and, in return, the energy charge is increased so as to recover in energy the difference between the demand charges of the two prices."*

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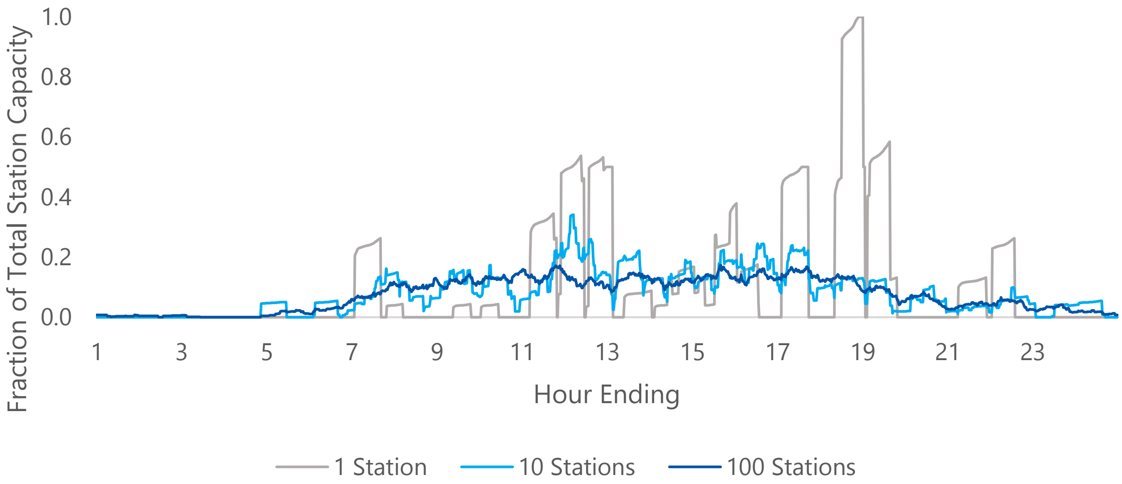
[30] Hydro Québec, *Stratégie Tarifaire* (July 28, 2016), section 4.1.5. http://publicsde.regie-energie.qc.ca/projets/382/DocPrj/R-3980-2016-B-0052-Demande-Piece-2016_07_28.pdf

Figure 8. Daily Load Profiles of 2-Port Public DCFCs, Average 7.5% Utilization[31]



Aggregating multiple public DCFCs will result in a smoother load profile because each station's load profile is different. The daily profile of 100 public DCFCs approaches the average daily charging profile, which peaks at less than 18% of the sum of all 100 individual NCP demands. In contrast, the peak demand of 100 different office buildings would be nearly as high as the sum of all 100 individual peaks because their load profiles have a high load factor and similar shape.

The illustrative low load factor demand charge will provide a discount on RTSR and CP-related distribution costs (collectively, CP-related delivery costs). In the expressions below, Coincident Peak Contribution (CPC) controls the magnitude of the discount. This CPC coefficient is intended to recognize the relationship between load factor and likelihood of contributing to CP demand.

Current Demand Charge: $NCP * (D_{CP} + D_{NCP})$

Low Load Factor Demand Charge: $NCP * (CPC * D_{CP} + D_{NCP})$

Where:

NCP = Customer Non-coincident Peak (kW)

CPC = Coincident Peak Contribution

D_{CP} = Demand Charge ($/kW), Coincident Peak-Related

D_{NCP} = Demand Charge ($/kW), Non-coincident Peak-Related

[31] Madeline Gilleran et al., "Impact of electric vehicle charging on the power demand of retail buildings", *Advances in Applied Energy* 4, (2021). https://doi.org/10.1016/j.adapen.2021.100062

The next step is to set reasonable values for CPC in each option:

- In all options, the CPC coefficient will be set to 1 for load factors above 15%
- Option 2a: a single CPC coefficient will be used for load factors below 15%
- Option 2b: a multi-tier rate with four tiers and four separate CPC coefficients below 15% load factor
- Option 2c: a demand transition rate with the same tiers as Option 2b and lower demand charges offset by a small energy-based charge.

Typical customers who are ineligible for the low load factor rate would effectively be assigned a CPC of 1. The discount on CP-related costs received by a low load factor customer (i.e., CPC) should be related to the customer's likelihood of contributing to CP demand relative to a typical customer.

The average load factor for all customers in the general service greater than 50 kW rate class is approximately 54%.[32] As a starting point, Power Advisory will assume a linear relationship between load factor and likelihood of contributing to CP demand, which will be called Theoretical CPC.[33] Setting Theoretical CPC to 1 for a customer with the average load factor of all general service greater than 50 kW customers yields:

Theoretical CPC = Load Factor / 54%

Then, CPC for each tier will be chosen to approximate Theoretical CPC as closely as possible. CPC for Option 2a and Option 2b was selected based on the average of Theoretical CPC for each tier (Figure 9). CPC for Option 2c is arbitrarily set to be 0.04 lower than Option 2b, with the difference recovered using a small energy-based charge.

Selecting the threshold and/or tiers for a low load factor rate – and the energy-based component for Option 2c – would require further analysis and consultation. Anecdotally, charging network operators will consider adding ports to an existing station when the load factor reaches 18% to reduce the risk of queues.[34]

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[32] Based on data for 2021 from the OEB Yearbook of Electricity Distributors

[33] This assumption ignores differences in average load profile between typical General Service customer and EV charging stations. Because the load profile for EV charging stations is more concentrated in the daytime than other loads, a higher CPC for a given load factor may be appropriate.

[34] RMI, *DCFC Load Factors* (December 7, 2021), https://www.akenergyauthority.org/Portals/0/Alaska%20Electric%20Vehicle%20Working%20Group/2021.12.07%20DCFC%20Load%20Factors%20Presentation%20by%20RMI.pdf?ver=2021-12-20-153041-013

Figure 9. Deriving Coincident Peak Contribution Coefficients for Low Load Factor Rate

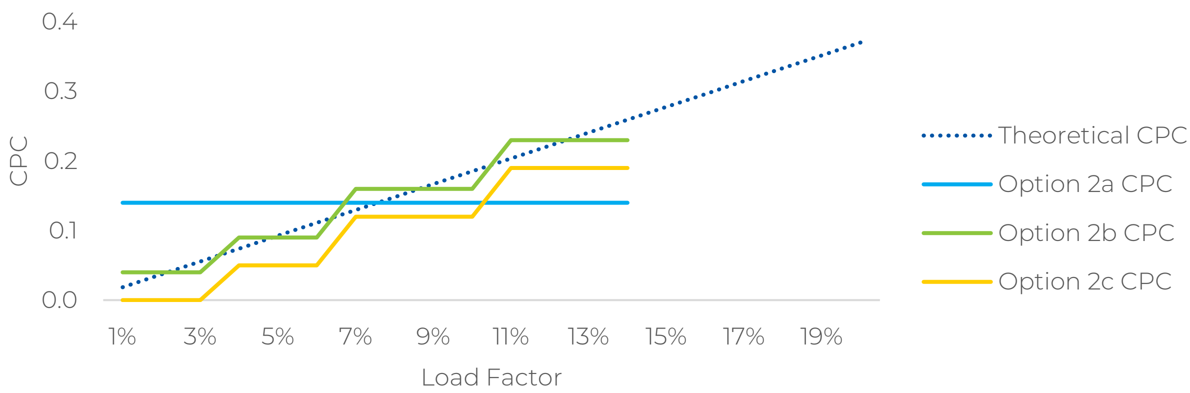


Table 9. Low Load Factor Illustrative Rate Design, Urban Low Service Territory

Load Factor	Option 2a: Single Tier		Option 2b: Multiple Tiers		Option 2c: Demand Transition Rate	
	CPC	$/kW	CPC	$/kW	CPC	$/kW*
0 to 3%	0.14	0.90	0.04	0.26	0.00	0.00
3 to 7%	0.14	0.90	0.09	0.58	0.05	0.32
7 to 11%	0.14	0.90	0.16	1.02	0.12	0.77
11 to 15%	0.14	0.90	0.23	1.47	0.19	1.21
above 15%	1.00	6.39	1.00	6.39	1.00	6.39

*Includes TOU energy charge as discussed in the paragraph below

In the Urban Low service territory, the demand charge for RTSR is currently $5.68/kW and the demand charge for CP-related distribution costs is currently $0.71/kW. The combined demand charge for all CP-related delivery costs is $6.39/kW. Table 9 demonstrates how CP-related delivery rates would be discounted for low load factor customers in Options 2a, 2b, and 2c. Option 2c also includes a TOU energy charge to offset its lower demand charges relative to Option 2b. The TOU energy charge in Option 2c was modelled using the same time periods as the winter 2022-2023 Regulated Price Plan (RPP) TOU rates. The RPP TOU rates are multiplied by a scaling factor for the five Load Factor bins in Table 9. From lowest load factor to highest, the scaling factors are 0.35, 0.25, 0.15, 0.05, and 0.00. For greater clarity, there would be no TOU energy charge for customers with a load factor above 15%.

NCP-related demand charges, fixed delivery charges, and existing energy-based delivery charges would remain the same for low load factor customers.

4.2 Evaluation of Alternative Rate Design Options Using Principles of Good Rate Design

In this section, the rate design alternatives are evaluated against Bonbright's principles of just and economic ratemaking[35] and other considerations. The Bonbright principles are ten "attributes of a sound rate structure" often used as a framework for identifying the relevant principles in the development of any cost recovery regime. The OEB's four statutory objectives are aligned with these principles, and other considerations such as demand management and regulatory burden have been incorporated into the evaluation. A more comprehensive discussion of the evaluation of rate design options is provided in Appendix E.

Table 10. Rate Design Principles and OEB Objectives

To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.	To inform consumers and protect their interests with respect to prices and the adequacy, reliability and quality of electricity service.
• Effective • Revenue Stability • Appropriately Priced • Regulatory Burden • Grid Readiness • Practical and Simple	• Static Efficiency • Rate Stability • Fair • No Undue Discrimination • Free from Controversy • Differences for commercial EV Fleets and public DCFCs
To promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances.	**To facilitate innovation in the electricity sector.**
• Local and Provincial Demand Management	• Dynamic Efficiency • EV Adoption Level

[35] James C. Bonbright, Albert L. Danielsen, David R. Kamerschen, *The Principles of Public Utility Rates* (Second Edition, 1988), Public Utilities Reports, 383-4.

Table 11. Evaluation of Alternative Rate Design Options with Rate Design Principles

Principles and other Considerations	TOU Demand Charge	Low Load Factor Rates
Effective Appropriately Priced No Undue Discrimination	Demand charges are higher at system peak times so customers are appropriately incentivized to shift demand to off-peak periods. Like the status quo, customers are incentivized to manage peak demands and avoid causing capacity-related costs.	Differences in the cost causality of customers within a rate class[36] can be distinct to the extent that introducing different rates based on other characteristics may be appropriate.[37] Low load factor and demand transition rates have reduced demand charges (or no demand charges) for customers that are less likely to contribute to CP demand. Their overall cost causality is lower than customers with high load factors, resulting in lower demand charges. The TOU element of the energy charges in demand transition rates appropriately incents customers to shift demands to off system peak times.
Practical/Simple Regulatory Burden	LDCs can have a range of peak periods and the marginal cost of distribution at peak times can also differ by LDC. Time periods and the appropriate shares of revenue to be collected during the different periods would likely require additional analysis or load studies during the rate-setting process, creating a regulatory burden.	The increased precision that is possible with ranges of load factor thresholds, separate demand charges at each threshold, and TOU energy charges comes with the cost of determining the appropriate rate structure. The rate structure may differ by LDC depending on the cost of additional capacity and coincidence of low load factor customers within its service territory.

[36] Implementation of EV rate designs could include the introduction of new rate classes or adjustments to existing rate classes. Though new rate classes would theoretically remove the risk of intra-class cross-subsidization, this analysis considers the risk of cross-subsidization among customers that would remain in the same class under status quo rate design even if they do not remain in the same class.

[37] Currently, some LDCs have a single General Service greater than 50 kW rate class while others have multiple rate classes for general service customers with peak demands above 50 kW. Of 70 service territories in the OEB 2021 Distribution Rates Database, 23 have multiple rate classes for General Service customers with maximum demands of 50 kW to 4,999 kW.

Fair Freedom from Controversy	TOU demand charges are relatively simple and understandable to customers. Although RPP TOU rates are not applicable to commercial EV fleet and public charging customers, that rate structure applies to commodity costs for residential and small general service customers – ensuring that individuals managing EV charging are generally familiar with TOU forms of rate design. The familiarity with TOU charges in the province can be beneficial for stakeholders to understand the reasoning for this rate design and avoid controversy.	C&I EV charging is a relatively new type of customer for LDCs. Those customers do not yet contribute a material share of class revenues so this rate design would not materially shift costs to existing customers in the short run. In the long run, an appropriate low load factor rate would be aligned with the incremental costs of the EV charging customer demand, leaving remaining C&I customers without material changes to their rates. In the case of existing low load factor customers, migration to a lower demand charge would increase the revenues to be collected from non-low load factor customers relative to the status quo. The higher rates for high load factor customers can be considered fair and without undue discrimination because those customers contribute more to peak demands and cause higher costs on a per billed kW basis. However, any rate design that leads to higher distribution bills for existing customers would not be free from controversy.
Rate Simplicity Rate Stability	TOU rates currently in place for the majority of RPP customers are based on provincial peak demands. On a province-wide basis, peaks are typically in the afternoon hours in the summer months to meet cooling loads. The majority of LDCs have a summer peak, however, many LDCs have distribution peaks in the winter months in the early evening hours.[38] It would be inefficient for LDCs to charge customers higher demand charges for consumption at times the LDC does not experience high CP demand. If LDC distribution peaks occur at different times than provincial peaks, it would cause complexities and confusion to EV charging customers.	A low load factor rate with a single tier has the benefit of simplicity. A customer that maintains a low load factor would have stable rates but the transition from below-threshold rates to above-threshold rates can have a significant impact on a customer's distribution bill. The concern can be mitigated with multiple low load factor tiers.

[38] In 2021, 72% of Ontario LDCs had higher summer peak demands than winter peak demands. OEB 2021 Electricity Utility Yearbook, General Statistics https://www.oeb.ca/ontarios-energy-sector/performance-assessment/natural-gas-and-electricity-utility-yearbooks#elec

Static Efficiency Differences for Commercial EV Fleets and Public DCFCs	Distribution bills for commercial EV fleets could be managed if customers have the ability to shift consumption to off-peak hours. Distribution bills for public DCFCs can be uncertain because they have less control over when their customers will be charging, either on peak or off peak. There could be an issue of unstable bills for customers who cannot manage demand periods.	This rate design methodology provides appropriate incentives to both commercial EV fleets and public DCFCs. The cost to commercial EV fleets will be lower and TOU energy charges will incent fleet managers to shift demands to off-peak periods. The cost of EV public charging will also be lower if the customer has a low load factor. The cost will increase if public demand for its EV charging increases.
Demand Management	TOU demand-based charges are effective in demand management, as they provide an incentive to minimize demand during peak hours.	Demand transition charges that combine low load factor rates with TOU energy charges promote demand management. Though incentives to manage peak demands are somewhat less than the status quo, the incentive increases as load factors and contribution to peak demands increases. However, low load factor rates reduce the incentive for EV charging customers to manage demands. The rates do not incent customers to shift demand to off-peak periods.
Dynamic Efficiency EV Adoption Level	TOU demand-based charges include some dynamic efficiency given their ability to modify the peak windows. This rate structure would likely enable flexible commercial EV fleets to shift to off-peak consumption, but the impact is uncertain for public charging. More generally, the incentive to shift demand to off-peak periods could be beneficial for other types of customers.	Low load factor rates reduce peak demand charges that can be a barrier to entry. Customers can maintain lower rates as long as their load factor remains low. For EV public charging, demand charges would increase as public demand for EV charging increases. Commercial EV fleets could manage their consumption and demands to maintain the low load factor rate. Demand transition charges are designed to increase the recovery of demand-related costs and demand charges as a customer's load factor increases. This transition reduces the barrier to entry that low load factor customers face.

4.3 Economic Impact of Alternative Rate Design

This section applies the alternative rate design options developed for the Urban Low and Rural High service territories per Section 4.1 to the EV profiles introduced in Section 2. The reduction in electricity bill for an EV charging customer will be quantified relative to current rates.

For commercial EV fleets, this section will demonstrate how a TOU demand charge could affect charging behaviour and lead to lower local CPs in distributors' systems. Separately metered EV fleet customers (or dedicated depots) will be the primary focus, but a case study will consider a combined commercial EV fleet and typical general service customer profile (i.e., an EV fleet embedded behind the meter of an existing customer's service). For public DCFCs, this section will demonstrate how a low load factor rate can reduce utilization risk. The potential impact of the rate options on other customer classes will be discussed at a high level.

Analysis for this section uses the same assumptions as the customer bills modelled in Section 2.

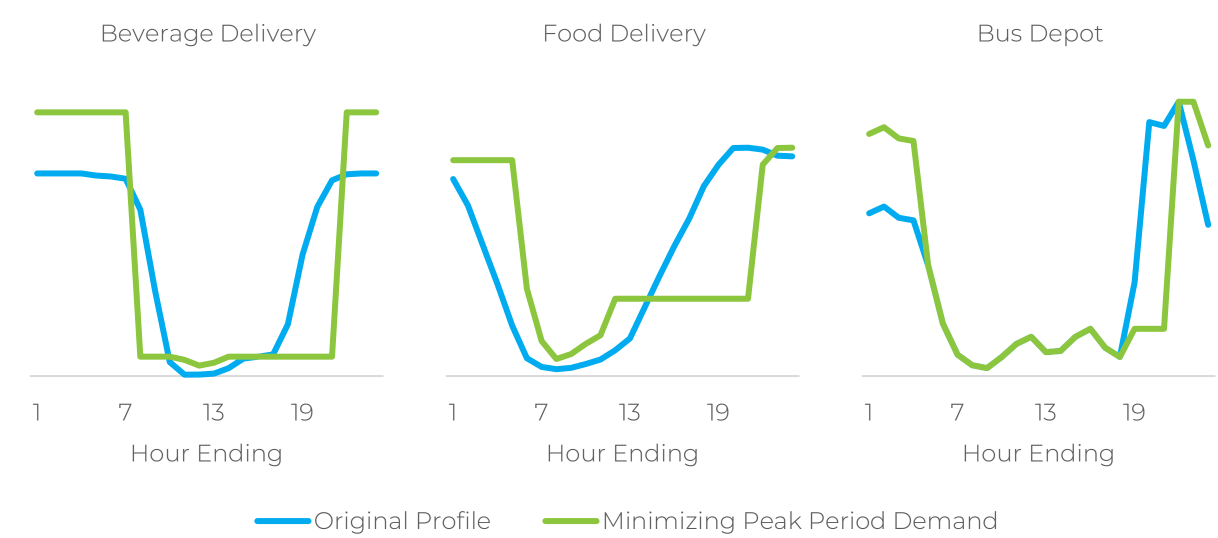
4.3.1 *TOU Demand Charge*

The impact of a TOU demand charge for customers depends on the timing of their peak demand. Customers with peak demand during the day would likely have higher bills compared to current rates. Customers that peak overnight, when demand charges are lower, would have lower bills.

Commercial EV fleets and other flexible loads would be able to reduce their electricity costs by scheduling consumption during off-peak times and minimizing peak demand during the peak period of the TOU demand charge. To the extent that loads respond to a TOU demand charge by changing their consumption profile, there may be system-wide savings in capacity, transmission, distribution, and energy costs. As discussed in Section 4.1, this analysis does not include the rate impact of potential system-wide savings. The TOU demand charge considered in this section is designed to be revenue-neutral for the representative LDC.

To illustrate the impact of this rate design alternative on an EV depot, the commercial EV fleet charging profiles introduced in Section 2 were modified to minimize peak period demand while still respecting vehicle schedules (Figure 10). See Appendix B for more details on the modified load profiles.

Figure 10. Modelled Load Profile Response to TOU Demand Charge



It is important to emphasize that real-world EV fleets have heterogeneous schedules, and not all fleets will have enough flexibility to avoid a given peak period to the same extent as the profiles shown here. In addition, there may be cases such as the Beverage Delivery profile where avoiding the peak period leads to a higher NCP demand, potentially incentivizing the vehicle depot to invest in more charging ports or higher-power equipment. If a TOU demand charge were introduced, each commercial EV fleet would respond to the new rate based on its unique circumstances.

Two other profiles will be used to illustrate the impact of a TOU demand charge on other customers. The Typical Customer profile from Section 2 and a "mixed" profile created to represent the case where a commercial EV fleet is embedded behind the meter of an existing general service customer. The mixed profile is the sum of the Typical Customer profile and the modified Beverage Delivery profile, with each profile consuming equal total energy (Figure 11).[39]

Figure 11. Mixed Profile, Typical Customer and Commercial EV Charging

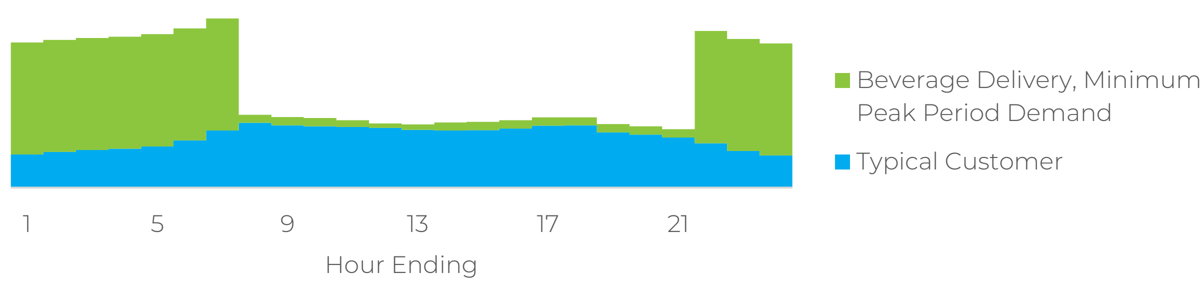


Table 12 outlines the electricity bill impact of applying the TOU demand charge developed in Section 4.1 to various load profiles. The average rate includes delivery charges (fixed, demand-based, and energy-based) and commodity costs, which are charged on an energy basis for Class B customers. Commercial EV fleet charging profiles which reduce their demand in the peak period can reduce their total electricity bill by 15% to 23%. The Mixed Profile (i.e., Typical Customer with embedded Beverage Delivery EV fleet) can reduce their total electricity bill by 6%. Most general service customers and public DCFCs would have a slight increase in their bills.

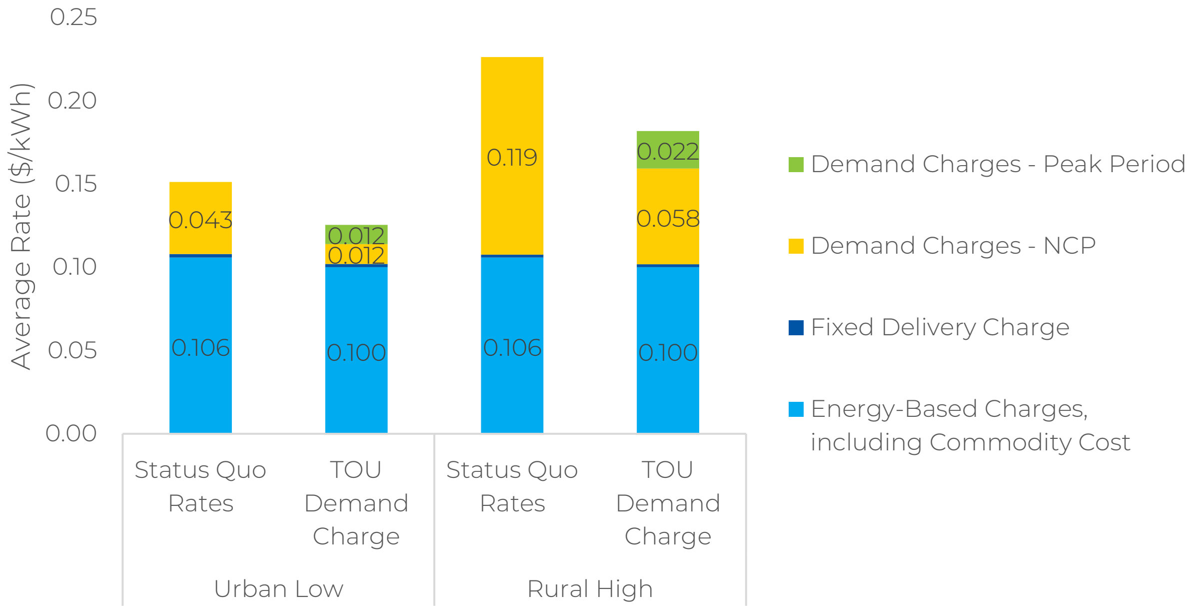
Electricity bill savings for commercial EV fleets are primarily from avoiding CP-related distribution costs and RTSR, which account for 14% to 21% of the status quo bill. There are also wholesale energy cost savings from shifting daytime energy use to overnight. Figure 12 provides more detail on the components of the average rate for the Food Delivery profile.

[39] It should be noted that in virtually all of the jurisdictions that Power Advisory surveyed, a customer wishing to benefit from an EV-specific rate must have the charging station on a separate meter. Some jurisdictions (e.g., Quebec, Massachusetts) also specify that certain ancillary loads may be on the same meter (e.g., lighting, fans, and cooling equipment for the chargers, etc.)

Table 12. Electricity Bill Impact of TOU Demand Charge for Class B Loads

	Urban Low			Rural High		
Load Profile	Average Rate, Status Quo ($/kWh)	Average Rate, TOU Demand Charge ($/kWh)	Bill Reduction (%)	Average Rate, Status Quo ($/kWh)	Average Rate, TOU Demand Charge ($/kWh)	Bill Reduction (%)
Food Delivery - 10 Vehicles	0.15	0.13	-17%	0.23	0.18	-20%
Food Delivery - 100 Vehicles	0.14	0.12	-15%	0.18	0.15	-18%
Beverage Delivery - 10 Vehicles	0.13	0.11	-15%	0.17	0.14	-15%
Beverage Delivery - 100 Vehicles	0.13	0.11	-15%	0.16	0.14	-15%
Bus Depot - 25 Vehicles	0.14	0.11	-19%	0.20	0.15	-23%
Bus Depot - 250 Vehicles	0.14	0.12	-20%	0.20	0.15	-23%
Mixed Profile	0.12	0.11	-6%	0.15	0.14	-6%
Typical Customer	0.12	0.12	0.5%	0.15	0.15	0.8%
DCFC 2x150kW 5% Utilization	0.27	0.27	2.0%	0.53	0.54	2.0%
DCFC 2x150kW 10% Utilization	0.22	0.22	1.7%	0.40	0.40	1.8%
DCFC 2x150kW 30% Utilization	0.15	0.15	0.9%	0.21	0.22	1.2%

Figure 12. Average Rate by Component, Food Delivery - 10 Vehicles

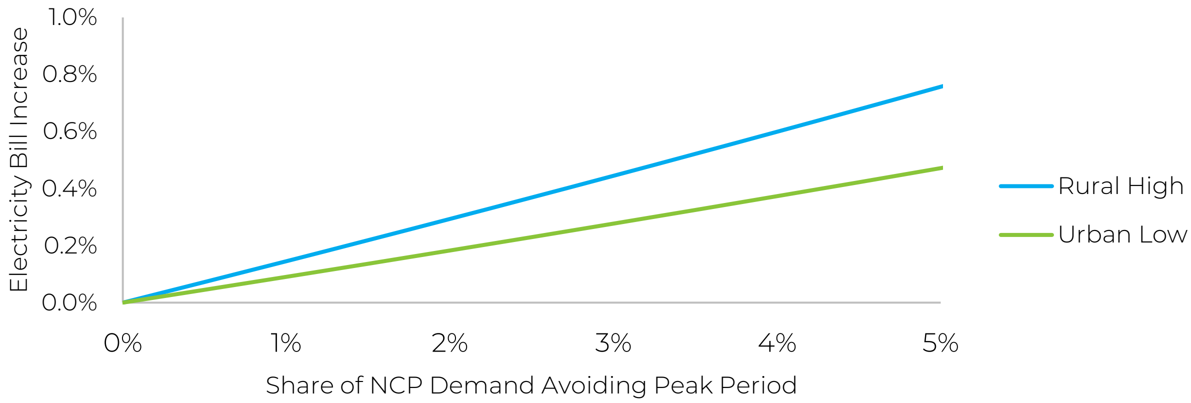


Impact on Other Customers

Implementing a TOU demand charge may cause electricity bills for some customers to increase. As discussed in Section 4.1.1, the TOU demand charge has been designed to be revenue neutral for the general service greater than 50 kW rate class for each distributor. If costs associated with CP demand are recovered across a smaller pool of demand, the rate (in $/kW) would need to increase. This would lead to higher electricity bills for customers that do not take advantage of the TOU demand charge. The amount of the electricity bill increase depends on the amount of total NCP demand that can avoid peak period demand charges.

The illustrative figures in this section assume that 5% of current NCP demand would be able to avoid the peak period under a TOU demand charge, leading to a 0.5% to 0.8% electricity bill increase for other customers. For example, if an LDC currently recovers CP-related costs across 1,000,000 kW of NCP demand and 5% of NCP demand can avoid the peak period, then that LDC would need higher demand charges to recover the same CP-related costs across 950,000 kW of peak period demand instead. Holding total costs constant is a conservative assumption because there are likely to be transmission and distribution cost savings that may be realized in the longer term if demand shifts to off-peak periods.

Figure 13. Typical Customer Bill Increase as a Function of TOU Demand Charge Uptake



The amount of NCP that can avoid the peak period is an important uncertainty in this analysis, but a high-level estimate of commercial fleet EV demand can provide some guidance. Data from the United States indicates that approximately 5% of total road vehicles are part of a commercial fleet.[40] Given the IESO's EV demand forecast of 17.7 TWh by 2035[41] and assuming the rest of the general service greater than 50 kW rate class consumes 49 TWh,[42] commercial EV fleets could represent 1.8% of total consumption (TWh) in the rate class by 2035 if they electrify at the same rate as personal vehicles. If 1.8% of NCP demand in the general service greater than 50 kW rate class avoids the peak period, there would be a 0.2% to 0.3% electricity bill increase for other customers. Bill impacts for other customers would be higher and more immediate if non-EV customers were also eligible for the TOU demand charge.

4.3.2 *Low Load Factor Rate*

The analysis in this section focuses on public DCFCs. Most customer types, including commercial EV fleet charging customers, have load factors greater than 15% and would be ineligible for the rate design considered here. Although public DCFCs are analyzed in this section, the rationale for a low load factor rate and its impact on average rates would be similar for other low load factor consumers.[43]

Figure 14 shows average rates for a public DCFC as a function of utilization for the three low load factor rate options discussed in 4.1.2. All rate options led to lower electricity bills when utilization is below 15%. In

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[40] U.S. Department of Transportation Bureau of Transportation Statistics, *National Transportation Statistics 2018*, Tables 1-11 and 1-14, https://www.bts.dot.gov/sites/bts.dot.gov/files/docs/browse-statistical-products-and-data/national-transportation-statistics/223001/ntsentire2018q3.pdf

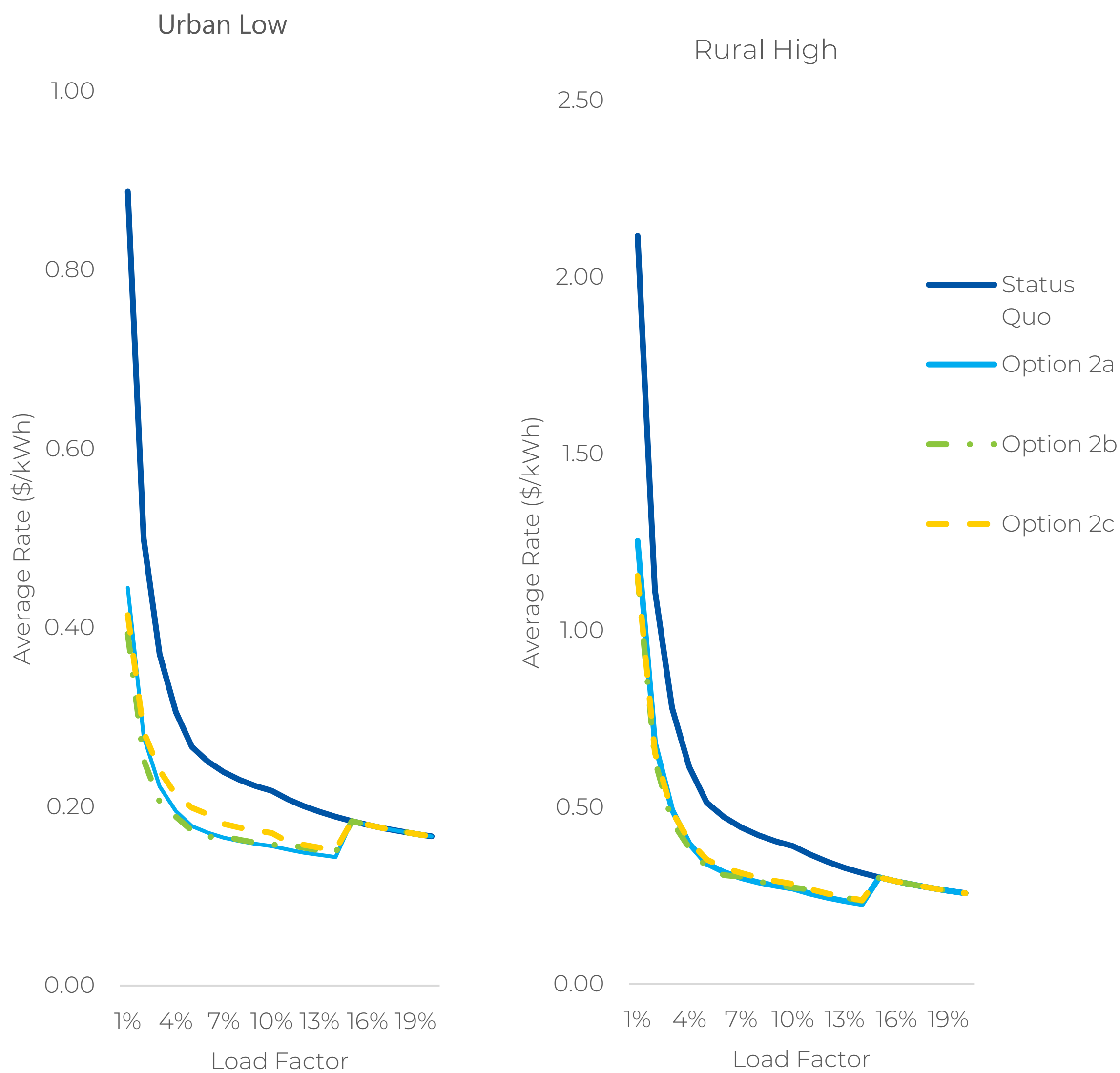
[41] IESO, 2022 Annual Planning Outlook Demand Forecast Module, Figure 13, https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/Dec2022/Demand-Forecast-Module-Data.ashx

[42] Based on 2021 consumption in the 2021 OEB Yearbook of Electricity Distributors.

[43] E.g., the agricultural sector, where the use of irrigation pumps is highly seasonal and can also exhibit notable demand variation in a day.

relative terms, the electricity bill reduction is greatest for customers with the lower load factors, with an electricity bill reduction of nearly 50% for a public DCFC with 1% load factor in the Urban Low service territory. Average rates still increase sharply when the load factor falls below 5%.

Figure 14: Bill Impact of Low Load Factor Rate for DCFCs



For a single 150 kW charging port with a 5% load factor, monthly electricity bill savings from the low load factor rate options range from $368 to $506, or 26% to 35%, in the Urban Low service territory and from $870 to $933, or 31% to 36%, in the Rural High service territory (Table 13).

Table 13. Bill Impact of Low Load Factor Rates for 150 kW DCFC with 5% load factor

Rate Option	Energy Use (kWh/ month)	Urban Low			Rural High		
		Monthly Bill ($)	Monthly Savings ($)	Bill Reduction (%)	Monthly Bill ($)	Monthly Savings ($)	Bill Reduction (%)
Status Quo	5,400	1,442	-	-	2,769	-	-
Option 2a	5,400	963	-478	-33%	1,837	-933	-34%
Option 2b	5,400	935	-506	-35%	1,783	-987	-36%
Option 2c	5,400	1,074	-368	-26%	1,900	-870	-31%

Evaluation of Low Load Factor Options

Low load factor rates can be designed in multiple ways. Each methodology improves the alignment of revenues and costs relative to the status quo, but also introduces additional rate complexity and regulatory burden.

A low load factor rate with a single tier is the simplest form of low load factor rate designs. This option is the least complex rate from a customer's perspective and adds the least regulatory burden to LDCs. The alignment of rate revenues and causal costs is improved over the status quo, but costs can still differ materially among low load factor customers. Without a tiered rate transition, a customer crossing the single threshold between low load factor rates and standard rates would experience a significant increase in their total electricity bill. The variability of rates between customers near the low load factor threshold can harm an LDC's revenue stability.

A low load factor rate with multiple tiers better aligns revenues with costs among low load factor customers, further reducing intra-class cross-subsidization. A rate design with multiple tiers comes with the drawbacks of additional rate complexity for customers and regulatory burden for LDCs. Multiple tiers reduce the bill impact of a customer with changing load factors to the benefit of the customer and to the LDC's revenue stability.

The demand transition charge is similar to the low load factor rate with multiple tiers but has the additional TOU energy charge component. The energy charge can add additional rate complexity for customers and regulatory burden for LDCs. Rate classes in Ontario are charged by either energy or demand and this rate design would introduce dual volumetric billing determinants. The TOU energy charge provides a marginally closer alignment of revenues and caused costs over the low load factor with multiple tiers. The TOU energy charge also provides an incentive for customers to shift demands off-peak, however, public DCFC customers are not expected to have control over their demand periods.

Impact on Other Customers

The electricity bill impact on other customers depends on the number of public DCFCs making use of the low load factor rate and their utilization. Power Advisory estimated public DCFC demand in 2035 to be approximately 1.7 TWh using two separate methods.[44] Assuming the rest of the general service greater than 50 kW rate class consumes 49 TWh,[45] public DCFCs at 10% utilization[46] could represent 3.4% of total consumption in the rate class by 2035. Option 2a leads to average rate reduction of $0.062/kWh in the Urban Low service territory and $0.121/kWh in the Rural High service territory, and a reduced average electricity bill between 28% and 31%, respectively, for public DCFCs at 10% utilization. If the electricity bill savings for these low load factor customers representing 3.4% of load are recovered evenly from the remaining 96.6% of load within the rate class, the resulting average electricity rates for a Typical Customer would increase by $0.0021/kWh (Urban Low) to $0.0042/kWh (Rural High) relative to the status quo. As a result, the Typical Customer would see an increase in their electricity bill of between 1.7% and 2.8% in 2035 depending on service territory.

Table 14. Estimated 2035 Electricity Bill Impact for Typical Customers

Value	Urban Low	Rural High
Average Rate Reduction for public DCFC at 10% utilization	$0.062/kWh	$0.121/kWh
Average Electricity Bill Reduction for public DCFC at 10% utilization (%)	28%	31%
Average Rate Increase for Typical Customer	$0.0021/kWh	$0.0042/kWh
Average Electricity Bill Increase for Typical Customer (%)	1.7%	2.8%

4.4 Summary of Findings

The modelling for the TOU demand charge showed that its implementation could reduce the total electricity bill for commercial EV fleet customers by 15% to 23% while also reducing CP demand in distribution systems. Such substantial load shifting could also lead to system-wide savings in capacity, transmission, and energy costs, though those were not the focus of the analysis. For public charging, the introduction of a low load factor rate could substantially reduce utilization risk for the public DCFC operator. For all of the low load factor rate variations that were modelled, public DCFC electricity bills would

[44] Method 1 uses a projection of the total number of fast chargers needed in Ontario by 2035 (12,677, from Updated Projections of Canada's Public Charging Infrastructure Needs, Table ES-2, Scenario 1, 2035 https://natural-resources.canada.ca/energy-efficiency/transportation-alternative-fuels/resource-library/updated-projections-canadas-public-charging-infrastructure-needs/24504 multiplied by Ontario share of 2035 population forecast in Statistics Canada Table 17-10-0057-01), average installed power of 150 kW and average utilization of 10%. Method 2 multiplies the IESO's most recent Electric Vehicle demand forecast for 2035 (17.71 TWh) by a 10% factor representing the share of total charging expected to occur at public DCFCs (IESO 2022 Annual Planning Outlook Demand Forecast Module, Figure 13 https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook)

[45] Based on 2021 consumption in the 2021 OEB Yearbook of Electricity Distributors.

[46] 10% utilization was modelled for this analysis assuming reasonable uptake of EVs in the future.

fall relative to current rates as long as utilization was below 15%, with the reduction in total electricity bill the greatest for lower load factors, i.e., a 50% decrease for a public DCFC operating at a 1% load factor.

Regarding the possibility of applying just a single alternative rate structure across both use cases (commercial EV fleets and public charging), the analysis showed that were the TOU demand charge applied to public fast charging, it could lead to higher rates relative to the status quo. Conversely, the nature of fleet vehicle charging means that fleets would likely exceed the threshold for eligibility as a low load factor customer (15%); fleet charging was therefore not modelled against the low load factor rate design alternatives.

Impact on Other Customers

The analysis also considered the impact that introducing these rates for EV charging would have on the rest of the general service customer base. The electricity bill impact would be closely tied to uptake of the new rates, but overall would be expected to be very small in the near term due to the low level of EV demand and less than 3% at anticipated EV demand in 2035. The analysis on other customers could be further refined once the precise parameters of the rates are more clearly defined following additional stakeholder consultation.

5. OPTIONS FOR EV CUSTOMERS TO MITIGATE DELIVERY COSTS

Offering different electricity rates for commercial EV fleets and public DCFCs is one way to assist in managing the cost for these customers to facilitate the adoption of EVs in Ontario. There are also other options that could be explored. Like many other load customers, there are different strategies that can be employed for EV customers to help manage their electricity costs. Some of these strategies can be employed by the customer themselves while other strategies would require government involvement. A key factor for managing delivery costs depends on whether the commercial EV fleet or public DCFC can operate flexibly. In the absence of flexibility, there needs to be an incentive to encourage the customer to manage their load in such a matter to reduce or mitigate their delivery costs.

Mitigation Options

Managing EV charging improves overall system efficiency and can reduce the customer's costs. Avoiding load during peak system hours puts less strain on the system for incremental peak resources, which is true for both the bulk system as well as individual distribution systems. There are various options that should be considered to manage load, noting that each varies in terms of complexity and may require mature knowledge of energy management and/or the support of a third party.

1. Optimize company's/charging station's overall energy use.
2. Load control programs offered by the utility company.
3. Investments in distributed energy resources (DERs)[47]

5.1 Optimize Company's/Charging Station's Overall Energy Use

EV charging has considerable flexibility.[48] Personal vehicles in the U.S. are parked approximately 96% of the time; commercial vehicles are driven more but are still often parked for twelve or more hours of the day,[49] though this can vary between businesses.

Commercial EV fleets: Optimizing the overall energy use for fleets will often require the assistance of an energy management system, with visibility into the load of an entire facility to manage it to optimize for peak reductions. This mitigation strategy is often most effective when there is a TOU rate: fleet owners can build their business practices around the TOU periods to mitigate high demand charges. This approach also provides fleets with predictability, as they can readily calculate the impact that energy management strategies will have on their electricity bills. Therefore, even if business needs require charging during peak

[47] Feasibility Study of DCFC + BESS in Colorado: A technical, economic and environmental review of integrating battery energy storage systems with DC fast charging

[48] With the exception of public DCFC customers.

[49] Charging and Discharging of Electric Vehicles in Power Systems: An Updated and Detailed Review of Methods, Control Structures, Objectives, and Optimization Methodologies

hours, the customer will at least be cognizant of what that will cost. Under the current rate structure, customers technically can manage their load to reduce their NCP demand but when meeting the business needs requires charging during peak hours, the fleet owners only option is to charge at peak time; therefore, not all EV customers are able to manage their load to avoid high demand charges. This ability is a function of the flexibility and nature of the business.

Public DCFCs: Load management is more challenging for charging stations as they are subject to consumer demands. One method of incentivizing customers to assist in managing charging station load could be by rewarding customers for charging during off-peak hours.

5.2 Load Control Programs Offered by the Utility

The IESO's Capacity Auction allows for participation from demand response. However, the current structure and market rules of the Capacity Auction limits the participation of EV customers. Moving forward, the IESO's DER Market Vision and Design Project will enable heterogeneous aggregation of certain resource types. Once this work is complete it could provide an opportunity for EV charging customers to participate; however, it likely will not address the challenges for public DCFCs, as their charging times are a function of customer requirements for on-demand charging.

Therefore, currently in Ontario there are no load control programs that are specifically targeted towards EV customers.[50] Due to the average EV customer's unique characteristics it is challenging for these customer types to participate in traditional load control programs. That being said, as EV adoption increases the potential for load control programs (e.g., smart charging) also increases[51]. Load control programs not only offer customers electricity bill relief but would also benefit the grid during times of system constraints. The Minister of Energy's September 23, 2022, directive to the IESO also calls for greater involvement of LDCs in conservation and demand management (CDM) programs, which could provide LDCs an opportunity to offer distribution-level load control programs. In other jurisdictions, depending on the nature of the delivery rate, load control programs are often offered to offset/manage demand charges, although these load control programs were specifically targeted to EV customers and not mass marketed to all customer types. For example, Eversouce offers an opt-in demand response program to help reduce demand charges (See Appendix C for more details).

5.3 Investment in DERs

Stationary storage could be installed alongside public DCFCs or commercial EV fleets and used for peak shaving, distribution grid upgrade deferral, and reducing energy costs through time-shifting energy demand. On-site DERs offer customers the ability to mitigate peak demand and may enable participation

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[50] In October 2022 the Ontario government announced a number of new CDM programs, one of which was for residential air conditioning load control. This program has yet to be launched. https://news.ontario.ca/en/backgrounder/1002356/ontario-to-provide-new-and-expanded-energy-efficiency-programs

[51] See IESO's DER Potential Study, https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/DER-Potential-Study

in the IESO-administered markets. Depending on the size and nature of the DER, the resource could potentially participate in the IESO's Capacity Auction, though this is often a cumbersome process and requires a sophisticated understanding of energy management.

There is likely a small fraction of sophisticated and large customers that would use behind-the-meter DERs to manage their commercial EV fleets as well as their entire load (large warehouses, postal and courier sorting stations, etc.). Therefore, although this is a technically feasible option it may not be accessible to all customers, particularly if their interest is in only managing their EV charging cost rather than that of a larger facility.

6. PARTICIPATION OF NON-EV ELECTRICITY CUSTOMERS

This section briefly considers the opportunities that other customer types might have to participate in the two proposed alternative rate options.

TOU Demand Charges

It is likely that there are C&I customers in addition to commercial EV fleets whose demand is already primarily in the overnight hours or who could shift their load to off-peak periods: for example, energy storage facilities, hydrogen-producing electrolysers, and potentially some manufacturers.

Just as with commercial EV fleets, having other customers shift their demand to overnight periods would reduce CP demand on the distribution system (and likely on grid overall), potentially reducing distribution system costs to the benefit of all customers.

Low Load Factor Rates

Similarly, there are likely existing general service customers who have a low load factor, for example irrigation in the agricultural sector, as well as other industrial uses of pumps, compressors, saws, and milling machines, etc.

Customers with a low load factor are less likely to have their demand coincide with system peak but currently pay the same demand charge as any other customer in the class, better aligning these customers' delivery rates with the costs they cause to the system could provide an opportunity to stimulate growth and economic development in those industries.

Considerations

The quantitative analysis presented in this report, has made certain assumptions. For example, the analysis assumes that overnight usage of the distribution and transmission systems would be light relative to the peak periods that the network is built to serve, that light network usage implies less strain on the network, and that therefore overnight users can justifiably be said to be responsible for causing fewer network costs. The analysis also assumes a linear relationship between load factor and the likelihood of contributing to peak demand, which in turn suggests a customer with a very low load factor is statistically unlikely to be charging at times coincident with system peaks.

If additional customer types (i.e., beyond commercial EV fleets and public DCFCs) were given the opportunity to reduce their delivery charges through participation in the alternative rate designs, then it is possible that the validity of some of the assumptions underpinning the analysis would be eroded. For example, if larger numbers of customers were to shift demand to overnight hours as a result of the introduction of TOU demand charges, it is possible that increased system demand overnight could result in fewer overall cost savings to the distribution system.

Similarly, if enough low load factor customers draw power from the grid at various points throughout the day, then taken in aggregate the likelihood of some portion of those customers' demand coinciding with system peak grows. Furthermore, if more and more customers were to move from the regular general service class to a low load factor rate, cost shifting caused by the departure of those class members would be amplified.

7. CONCLUSIONS

In recognition of the different barriers that commercial EV fleet customers and public DCFC operators have said they experience in Ontario, the analysis highlights that there is a rationale to consider alternative rates designs.

Commercial EV Fleets

The challenges that commercial EV fleets experience with demand charges are variable, and a reflection of the heterogeneity of fleets themselves. Modelling shows that the cost of demand charges for commercial EV fleets would vary significantly depending on the customer's LDC, its size, and its charging pattern. Furthermore, the impact those costs have on the viability of fleet electrification is also variable depending on whether fleet electrification is being pursued primarily for economic reasons, or whether environmental or other business objectives are also a material consideration.

Customers indicated that demand charges, as currently structured, are a concern for at least some fleets. Many commercial EV fleets have a unique load profile relative to other general service customers in that all or nearly all consumption occurs overnight when system costs are generally lower. This report suggests that the introduction of a TOU demand charge for commercial EV fleets would more fairly allocate distribution costs across the general service customer base; that reallocation would lower a commercial EV fleets' total electricity bills by 15% to 20%, bolstering the economics of fleet electrification in a manner consistent with government policy while better linking delivery charges with cost causality, and aligned with best practices for ratemaking. Shifting usage to off-peak times could also benefit an LDC's customer base overall by lowering distribution system costs through reductions in CP demand, although this assumption would need to be further quantified by examining LDC-specific data.

The practice of a one-size-fits-all solution will inevitably frustrate some customers, particularly those who are unable to substantially shift their charging patterns. The real-world charging behaviour of commercial EV fleets would depend on their schedules, and not all fleets will have enough flexibility to fully avoid charging at peak times. Ultimately, if a TOU demand charge were introduced, each commercial EV fleet would respond to the new rate based on its unique operating characteristics. Furthermore, the introduction of a new rate for fleets (assuming it is designed to be revenue neutral) would lead to rates going up for the remaining general service customers in the class, at least until such time as the system-wide benefits of reductions in CP demand could be reflected in rates. The electricity bill increase for the remaining customers could be as high as 0.3% by 2035 in a reasonable commercial vehicle electrification scenario.

Public DCFCs

The challenges that demand charges pose for public fast charging are relatively straightforward to characterize. Power Advisory's modelling showed that at the low utilization levels that are typical in Canada (and many other North American jurisdictions) at present, i.e., 5% utilization, all-in electricity costs range from $0.15/kWh to $0.53/kWh and are even higher at the lower levels of utilization seen at less-frequented charging stations. At those average rates, demand charges would make up 43% to 72% of the customer's total monthly electricity bill, based on a Class B customer with a typical two-port 50 kW charging station.

Because the primary challenge with public DCFCs is from low utilization, the rate option considered for public DCFCs responds to the utilization issue directly, while also making provision for the increased utilization the stations are expected to see as the uptake of EVs in Ontario increases. The low load factor rate options reflect the understanding that at low load factors, public DCFCs are unlikely to substantially contribute to CP demand, and that there is therefore an element of intra-class cross subsidization from public DCFCs to the rest of the general service class.

The low load factor rates proposed here seek to better align cost causality with demand charges by offering a lower demand charge while the customer's load factor is below certain thresholds and would result in substantial electricity bill reductions for public DCFC operators. However, the rate options designed and modelled by Power Advisory would still not fully alleviate the impact of demand charges on stations with persistently low utilization rates (below 5%), or those served by LDCs with relatively high demand charges allocated to NCP demand; both of these are more likely to occur in rural areas. Shifting revenue out of the general service greater than 50 kW class would mean that electricity rates would need to increase by between $0.0021/kWh and $0.0042/kWh, or 1.7% to 2.8%, for the remaining customers in the rate class given anticipated DCFC demand by 2035.

Observations on Both Rate Options

Both rate options could lend themselves to adoption by other customer types beyond just EV charging; however, the modelling undertaken for this study focuses on the impact that shifting fleet and public charging to the alternative rates would have, rather than a broader base of customers. Additional research and analysis would be necessary if these rates are to be offered to additional customer types.

Overall, Power Advisory believes that the two rate options put forward in this report largely address the concerns expressed by customers to the OEB; incorporate the feedback received in both surveys and interviews with LDCs, fleets, and charging operators; reflect principles of good rate design; and are generally aligned with the alternative rate designs that other North American jurisdictions have proposed for commercial EV charging.

8. NEXT STEPS

This report examined two rate design alternatives for further consideration in Ontario. In order to further determine the reasonableness of these options two tracks of further work should be considered.

1. Assessment of implementation considerations
2. Refinement of the rate design alternatives

Assessment of Implementation Considerations

Much of the analysis in this report has focused on modelling and defining the alternative rate design options, while the details of implementation have not been discussed. However, the research did highlight a number of considerations for implementation. Those considerations include:

Opt-in versus mandatory

The options and modelling presented in this report assume that the rates would be offered on an opt in basis. However, Power Advisory recognizes that opting into (rather than being assigned) a certain delivery rate class is unusual in Ontario. Giving customers the ability to opt into or out of a given delivery rate, while likely preferrable from the customer perspective, may make the ratemaking process challenging. The possibility of integrating the opt in/out process for these rates with LDCs' existing rate reclassification processes may be worth exploring.

Separate metering

As noted elsewhere in this report, the jurisdictional scan revealed that EV-specific rates generally require the charging station to be metered separately from the existing facility's or premise's main load potentially with provision for including ancillary equipment. However, there is a cost to establishing a new utility account, and it is possible that some customers have already installed DCFCs connected to their existing service. Requiring those customers to re-wire their facilities to separate EV charging infrastructure such that it can be separately metered may not be feasible for all customers.

Eligibility

The alternative rate design options proposed in this report could possibly benefit other customers that are not involved in EV charging, but whose load profiles are similar to EV charging use cases. While in principle the rates proposed here could be offered to those customers, the modelling was undertaken specifically for the commercial EV fleet and public DCFC use cases.

In order to confirm the reasonableness of offering any alternative rate option explored in this report to non-EV customers further research would be necessary to identify what customers other than EVs might benefit from the alternatives proposed. Expanding eligibility for those rates would likely also require an evaluation of the cost impact of a larger customer base on the non-participating customers who would remain in the original class(es), as well as any potential unintended consequences (i.e., cross subsidisation, rate instability, etc.) that may ensue.

Province-wide vs LDC-by-LDC

The mixed feedback from LDCs as to the need for any alternative rate design and the costs they would incur to implement any rate changes suggests that requiring all LDCs to offer the alternative rates to their customers – even if only a handful of eligible customers might exist in a given LDC's service territory – could be excessively burdensome. At the same time, commercial EV fleet and charging operators expressed concern about the challenges that they have already encountered in deploying EV charging infrastructure across Ontario, given the need to work with dozens of LDCs, each with its own policies for connections, metering, determination of rate classification, etc.; adding another variable in the form of alternative rates in some but not all LDC territories would likely compound that concern.

This report, while not conducted on an LDC-by-LDC basis, shows that the demand charges and the economic feasibility of commercial EV fleet or public DCFCs may be likelier to be an issue in some LDC service territories (especially those with higher nominal demand charges) but not necessarily in all. Power Advisory notes that when a similar issue arose in a somewhat different context (concerns about the affordability of certain LDCs' residential distribution rates), the government of Ontario chose to provide targeted assistance to just those LDCs' customers via the Distribution Rate Protection program[52].

New rate classes vs. designing new rates within existing rate classes

TOU demand charges and low load factor rates can be implemented as one or two distinct rate classes, or as modifications to the existing general service rate classifications. Introducing new rate classes in the OEB's cost allocation methodology can allow for a more precise allocation of costs to public DCFCs and commercial EV fleets, including directly allocated costs. This would provide transparency of the costs allocated to EV charging customers and effectively remove intra-class cross-subsidization. Introducing new rate schedules would make rates easier to understand for customers, especially if other charges on the tariff sheet such as RTSRs and low voltage charges differ between EV and non-EV customers. New rate classes, however, can add regulatory burden to LDCs and could increase billing costs. Public DCFCs and commercial EV fleets are emerging customers so there may be few customers in each rate class, thereby increasing the year over year variability of the class's characteristics and reducing rate stability over time. Additionally, maintaining a rate class with few customers can introduce potential confidentiality concerns.

The EV rate designs could be implemented without new rate classes by introducing a new output worksheet in the OEB cost allocation model similar to the existing line transformer and microFIT output worksheets. The outputs of the worksheet can be used to set differential rates within a rate class in a manner analogous to general service customers that receive the transformer ownership allowance. TOU demand charges could be implemented with an output worksheet that identifies the shares of capacity-related costs allocated by CP demand and NCP demand. Low load factor rates could

[52] This program effectively caps the distribution charges that residential customers of eight specific LDCs pay; the difference between the cap and the LDC's actual distribution rate is funded by government subsidy. See Ontario Regulation 198/17 at https://www.ontario.ca/laws/regulation/170198

be implemented by assigning a share of CP demand to low load factor customers and remaining customers. Another option is to treat the EV rate classes as separate for the purposes of cost allocation and rate design without modifying the tariff schedules. This option would provide the same transparency in cost allocation as introducing new rate classes while reducing some of the regulatory burden associated with introducing and maintaining additional rate classes.

Refinement of the Rate Design Alternatives

In designing the two rate design alternative options certain assumptions were made in order to build out the rates and model their economic impact. While those assumptions were consciously made and have been justified throughout this report, other assumptions leading to different design parameters may have been reasonable as well. Some of the conclusions and/or assumptions made, include:

- The need for alternative rate design options for commercial EV charging customers – at least two interview subjects questioned the need for and benefit of alternative rate design options for commercial EV fleets and public DCFCs given that the charges should be factored into business investment decisions.
- The two rate design alternative options, with distinct rates for each of the two use cases considered (fleets and public charging) – while other jurisdictions also have multiple rate options for EV charging, having different rates for different and highly specific use cases is uncommon.
- The design of the rates should be revenue neutral and should seek to reduce the amount of cross-subsidization within existing rate classes.
- For both rate design alternative options, cross-subsidization was reduced by bundling transmission costs and CP-related distribution costs for simplicity and adjusting the allocation of these costs based on load characteristics. Other implementations of these options could take a different approach.
- For the TOU demand charge, the definition and duration of the off-peak period - adjusting the period earlier or later in the evening, and lengthening or shortening its duration, would impact a customer's ability to shift their demand. This would have implications for those customers' cost savings and for the rate impact on other general service customers.
- For the low load factor rates, which variation(s) should be offered? If the tiered low load factor or the demand transition variations were selected, how many tiers should there be? What should be the thresholds between each tier? What should be the corresponding escalations between thresholds? For the demand transition rate, how much of delivery costs at each tier should be energy-based rather than demand-based?
- That implementing the proposed rate options would pose a relatively minor and acceptable degree of regulatory and/or cost burden on LDCs.

Power Advisory appreciates this opportunity to complete this study and we welcome next steps in presenting this report to stakeholders for further input.

APPENDIX A. METHODOLOGY FOR ESTIMATING TOTAL ELECTRICITY BILLS

To put demand charges in the context of reasonable total electricity bills, a methodology is needed to estimate other bill components.

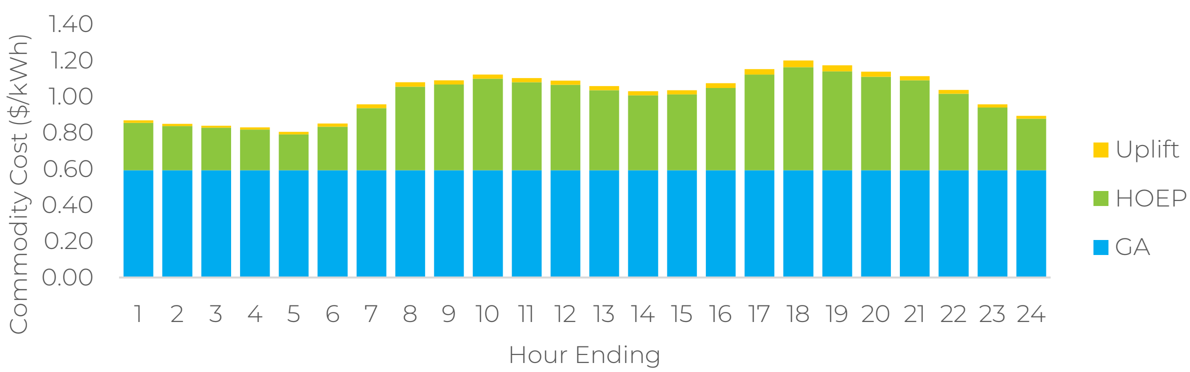
Fixed delivery costs and energy-based delivery costs are unique to each LDC service territory. Rates for the Urban Low and Rural High territories are provided in Table 15. Fixed charges vary significantly between LDCs. Some LDCs have a separate rate class for higher-power general service customers (e.g., 1,000 to 4,999 kW), which in some cases have fixed charges exceeding $1,000/month.

Table 15. Representative Fixed and Energy-Based Delivery Rates

Category	Urban Low	Rural High
Fixed Charges ($/month)	139.25	118.25
Energy-Based Charges ($/kWh)	0.0039	0.0039

The commodity cost was modelled using three components: Hourly Ontario Energy Price (HOEP), Global Adjustment (GA), and Uplift.

Figure 15. Assumed Commodity Costs



HOEP was modelled by taking the average of market prices for the 2018 to 2022 period by hour of day and scaling up to an assumed future average value of $40/MWh.[53] Global adjustment was modelled by subtracting the assumed average HOEP from the sum of actual average HOEP and GA for 2021 and 2022.[54] Uplift was modelled similarly to HOEP, by taking the average daily price pattern for the 2018 to 2022 period.

[53] Energy price forecasting is beyond the scope of this report. The average HOEP in 2022 was $44.96/MWh. While natural gas prices in the next few years are expected to be lower than 2022, other factors such as supply/demand balance and carbon pricing policy are putting upward pressure on energy prices. Because of the inverse relationship between HOEP and GA, the average HOEP assumption has a very small impact on total commodity cost.

[54] The implementation of the Comprehensive Electricity Plan in 2021 significantly reduced Global Adjustment, so historical data prior to 2021 is not representative of future expectations.

The average commodity cost for each representative customer is calculated by applying their average daily load profile to the total commodity costs illustrated in Figure 15.

The "average rate" referred to in this report is modelled to include delivery charges (fixed, demand-based, and energy-based) and commodity costs, which are charged on an energy basis for Class B customer; taxes and distributor losses were not included in the total bill modelling.

APPENDIX B. EV CHARGING PROFILES

Commercial EV Fleets

Commercial vehicles are used by businesses rather than personal transport. There is a wide range of commercial vehicles of different sizes and purposes, ranging from delivery vans and light trucks to buses and semitrucks.

EVs typically have lower range than comparable combustion vehicles and take much longer to refuel. As a result, electrification is more likely to be practical and cost-effective for commercial vehicles with relatively short-distance routes and regular schedules. Examples include delivery vehicles, service vehicles (e.g., maintenance vans), and some kinds of buses. These vehicles commonly operate during the day and return to a central depot at night.

This report focuses on commercial EVs with a predictable overnight charging pattern that have some flexibility in the timing of their charging demand. Not all commercial vehicles meet this description. There are many different usage patterns, and some commercial EVs would be unable to adjust their charging demand to take advantage of an alternative rate design. Other commercial vehicles are ill-suited to electrification and may require solutions such as hydrogen or biofuels to decarbonize.

Load profiles for commercial EV fleets can be derived from measuring consumption at operating EV depots or by simulating profiles based on generic vehicle schedules and daily energy demand. For each profile used in this study, Power Advisory has compared at least two independent sources.

Delivery vehicles were modelled using a study led by the National Renewable Energy Laboratory (NREL) which leveraged their Fleet DNA database of vehicle operating data.[55,56] The study provided profiles for both an average day and a peak demand day, which were used to determine monthly total energy and monthly NCP demand respectively. The study also provided profiles for three charging strategies: charging as soon as possible, charging as late as possible, or charging to minimize NCP demand. The third profile was used for modelling charging under current demand charges, and the other two profiles were used to estimate the "envelope" of charging profiles that may be possible given different rate designs. The profiles were cross-checked against a study performed by The Brattle Group for Electric Reliability Council of Texas - ERCOT (Figure 16).[57]

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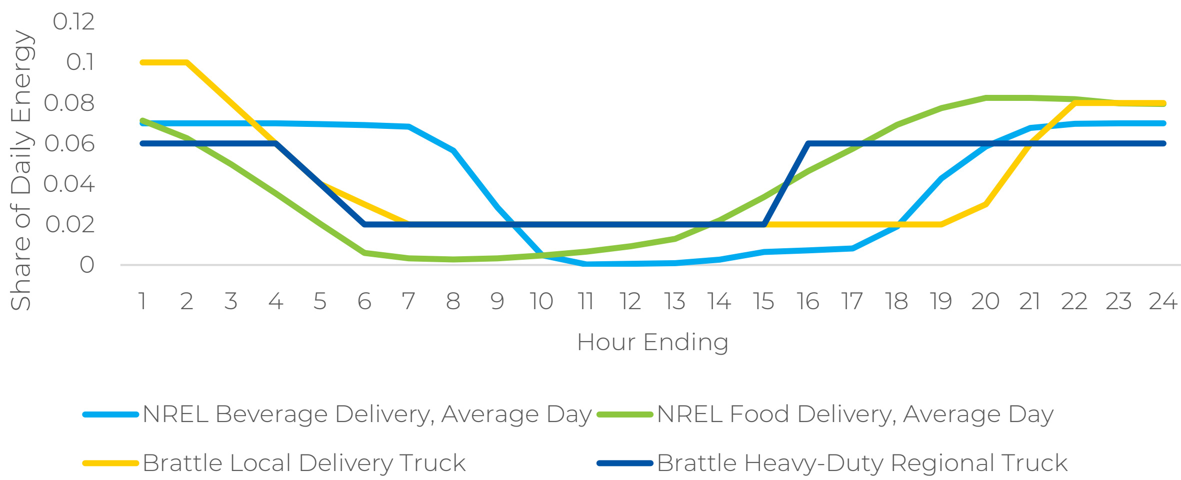
[55] Brennan Borlaug et al., "Heavy-duty truck electrification and the impacts of depot charging on electricity distribution systems", *Nature Energy* 6, (2021): 673–682. https://doi.org/10.1038/s41560-021-00855-0

[56] National Renewable Energy Laboratory, *Fleet DNA: Commercial Fleet Vehicle Operating Data*. https://www.nrel.gov/transportation/fleettest-fleet-dna.html

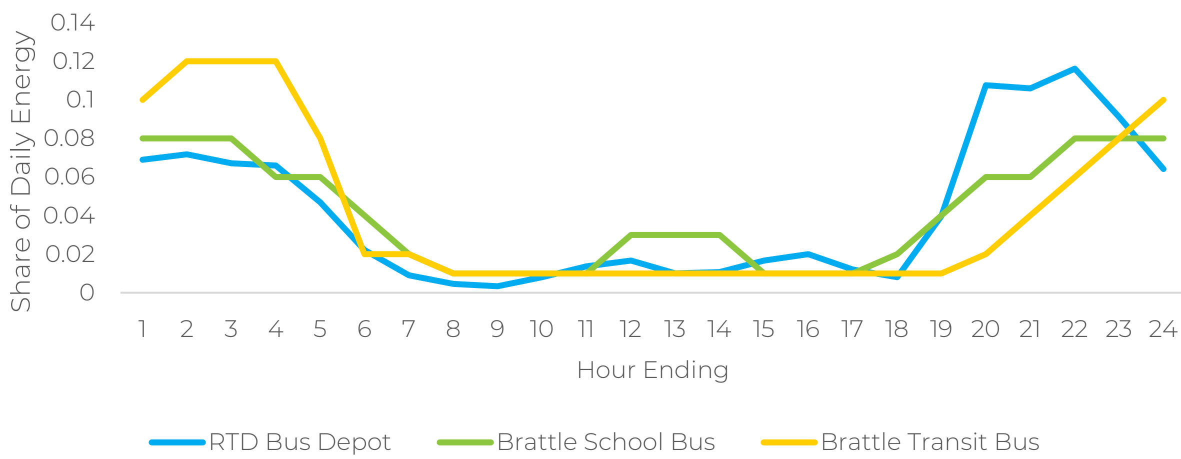
[57] The Brattle Group, *ERCOT EV Allocation Study: Methodology for Determining EV Load Impact at the Substation Level* (October 15, 2022), https://www.brattle.com/insights-events/publications/ercot-ev-allocation-study-methodology-for-determining-ev-load-impact-at-the-substation-level/

Figure 16. Comparison of Delivery Vehicle Charging Profiles



Transit buses were modelled using a measured profile from Regional Transportation District (RTD), the transit agency for Denver, Colorado. The profile was published in a Rocky Mountain Institute (RMI) study for the Colorado Energy Office.[58] The profiles were cross-checked against the same Brattle Group study as delivery vehicles. For the TOU demand charge evaluated in Section 4.3.1, the RTD bus depot profile was assumed to have sufficient flexibility to shift demand in hours ending 19 through 21 to later in the overnight period, similarly to the Brattle Transit Bus profile.

Figure 17. Comparison of Bus Charging Profiles



Public DCFCs

There are a number of publicly available datasets (both measured and simulated) for public EV charging load profiles. This report relied on two main data sources: aggregated and anonymized real-world profiles

[58] Garrett Fitzgerald and Chris Nelder, "DCFC Rate Design Study", *RMI*, https://rmi.org/insight/dcfc-rate-design-study/

from the RMI DCFC Rate Design Study which was also used for the transit bus profile (footnote 58) and an NREL study which simulated a full year of charging profiles at minute granularity based on probability distributions of vehicle arrival time and initial state of charge.[59] Hourly charging patterns in both studies were generally aligned with measured profiles for a large Canadian dataset of public fast charging stations in the Biennial Snapshot of Canada's Electric Charging Network and Hydrogen Refuelling Stations for Light-duty Vehicles (footnote 20).

Other than the times that charging sessions occur, the load profile of a public charging station depends on its power level, the number of ports, and its utilization. All these variables are changing over time as technology advances and the EV market matures.[60]

Most charging ports installed today can provide 50 kW, but higher power levels are becoming more popular. More equipment manufacturers are offering DCFCs capable of up to 350 kW. Similarly, newer EV models tend to have higher levels of DC power acceptance. Higher power levels will allow for shorter charging sessions.

Among non-Tesla charging stations, the most common number of ports is two and very few stations have more than four. Tesla stations in Canada typically have eight ports but may have as many as 24. With increased use of EVs and emphasis on redundancy, the trend is towards more ports per station.

To support the analysis of the range of utilization in Section 4.3.2, hourly average load profiles for 5%, 10%, and 30% utilization were taken from the RMI study and profiles for intermediate utilization levels were estimated using linear interpolation.

The NCP demand of an EV charging station is not necessarily its total rated charging power. Power levels fluctuate during a charging session and seldom reach the full rated power. In addition, multi-port stations with low utilization are unlikely to have all ports in use at full power simultaneously. The RMI study estimated monthly peak power for a 2-port 150 kW station based on a real-world dataset (Table 16). Peak power was interpolated to intermediate utilization levels in the same manner as the hourly average load profile.

Table 16. Peak Demand for a 2-Port 150 kW DCFC

Utilization	15-Minute Peak (kW)
30%	264
10%	243
5%	174

[59] Madeline Gilleran, et al., "Impact of electric vehicle charging on the power demand of retail buildings". *Advances in Applied Energy* 4, (2021). https://doi.org/10.1016/j.adapen.2021.100062

[60] Markets with fewer EVs per person are likely to have lower DCFC utilization, while a denser DCFC network serving more vehicles is likely to have higher utilization. https://theicct.org/wp-content/uploads/2021/06/US_charging_Gap_20190124.pdf

APPENDIX C. DETAILED JURISDICTIONAL OVERVIEW

In selecting the jurisdictions to review and include for comparative purposes in this study, Power Advisory sought out those regions of North America that had ambitious EV adoption targets and which had (or were in the process of developing) charges or rate designs that were specifically intended to address the barriers posed by existing electricity delivery or demand charge structures. The comparison sought to include both Canadian and US jurisdictions, and preliminary research identified British Columbia, Quebec, California, Colorado, Massachusetts, and New York as those that could serve as good guides for Ontario. Through subsequent discussions with OEB staff, Power Advisory added Wisconsin and Connecticut to the jurisdictional scan.

The key questions that Power Advisory sought to ask about each jurisdiction were ones like: what were the general motivations for introducing an EV-specific delivery rate? How were those rates designed? What, if any, specific objectives or outcomes where they intended to achieve? Which actors were involved in the rate design process, and in what ways (e.g., private industry, government, regulators, utilities, etc.)? What additional factors were taken under consideration in a given jurisdiction when designing a new rate?

The following paragraphs contain brief overviews of each of the jurisdictions we surveyed, as well as a hyperlink to the source material should the reader wish to obtain additional detail about the design of the respective rates:

British Columbia – two EV-specific delivery rates are offered,[61] each applicable only to fleet electrification (i.e., electric fleet vehicles or vessels that are operated by the customer):

- An overnight rate, which calculates demand (for billing purposes) using only the customer's peak demand incurred between the hours of 6:00 am and 10:00 pm, i.e., overnight demand is excluded. This rate is designed for fleet vehicles that recharge overnight at the depot.
- A demand transition rate, which provides a temporary demand charge "holiday" followed by a phased-in demand charge for customers that cannot exclusively charge their fleet overnight and require enroute charging during daytime hours. This rate has a demand charge of $0/kW for the first six years (2020-2026) followed by the introduction of an annually escalating demand charge for an additional six years (until 2032).

Quebec – one EV-specific rate, as well as a low load factor rate that is not end-use specific:

- Rate BR is a blended demand/energy charge for EV charging stations. It eliminates a separate demand charge for customers in the rate class, instead offering three energies based tiers that a

[61] BC Hydro, *Fleet Electrification Rates*, https://app.bchydro.com/accounts-billing/rates-energy-use/electricity-rates/fleet-electrification-rates.html

customer would move through as their demand increases: for demand up to 50 kW; demand over 50 kW with load factor up to 3%; and incremental demand with higher load factors,[62]

- Rate G9 is available to customers with peak demand over 65 kW but whose average load factor over the preceding year is under 26%[63]

Rate BR is officially classified as an experimental rate, and to benefit from it the customer must agree to provide Hydro-Québec with non-identifying data from charging stations. While the rate is designed for EV charging stations and is separately metered, up to 10 kW of demand may be incurred on the account for additional or ancillary purposes (e.g., lighting).

California – the California Public Utilities Commission has approved EV-specific rates for commercial and industrial customers for the state's three large investor-owned utilities:

- Southern California Edison's commercial EV rates (TOU-EV-7, -8, and -9) offer a five-year period (2019-2023) without demand charges, followed by a phase-in of demand charges from 2024-2028. Customers are charged for usage at TOU rates based on energy consumed;[64]
- Pacific Gas & Electric offers commercial and industrial subscription-based EV rates (BEV1 and BEV2), in which the subscription purchases blocks of demand (in 10- or 50-kW increments) that are designed to replace traditional demand charges;[65]
- San Diego Gas & Electric's EVHP rate also offers a subscription-based model that eliminates separate demand charges; customers subscribe in blocks of 10 or 25 kW, combined with an energy-based TOU charge.[66]

Colorado – the state's largest electric utility, Xcel Energy, offers two EV-specific rate plans for commercial and industrial customers, both of which include a standard demand charge plus TOU energy rates; one plan also incorporates critical peak pricing. Additionally, there are separate regulated rates that are

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[62] Hydro Québec, *Rate BR,* https://www.hydroquebec.com/business/customer-space/rates/rate-br-experimental-rate-fast-charge-stations.html

[63] Hydro Québec, *General rate for customers with limited power demand*, https://www.hydroquebec.com/business/customer-space/rates/rate-g9-general-rate-limited-use-power.html

[64] Southern California Edison, *Rate Schedules*, https://www.sce.com/sites/default/files/inline-files/TOU-EV-7_8_9%20Rate%20Fact%20Sheet_WCAG_0.pdf

[65] PG&E, *Charge your EVs for less*, https://www.pge.com/pge_global/common/pdfs/solar-and-vehicles/ev-charge-network/BusinessEVrate-fs.pdf

[66] SDGE, *Save Money with SDG&E's Lowest EV Charging Rate*, https://www.sdge.com/sites/default/files/documents/SDGE.PYDFF_EVHP%20Fact%20Sheet%202022_FINAL.pdf

charged to users of Xcel-owned public DCFCs; this class was created in response to a directive from the state utility regulator requiring Xcel to install 20 to 25 stations in underserved areas.[67]

Wisconsin – Power Advisory examined the rates offered by Madison Gas & Electric,[68] which offers commercial and industrial customers:

- A general (i.e., not EV-specific) low load factor rate (the Low Load Factor Provision), which reduces by the demand charge by half for any customer whose annual load factor is less than 15%;[69] and
- Three experimental EV-specific rates:
    - Electric Vehicle Fleet Pilot 1, which provides discounts on demand charges for four years, the discount being reduced annually until in year 5 the full standard demand charge applies;[70]
    - Fleet Electric Vehicle Charging Experimental Pilot Rider, offered at up to 15 charging stations and in which the utility provides the customer with charging equipment (at a nominal per-day rate), and in which participating customers allow the utility to optimize EV charging and view charging data so that it can analyze energy use, vehicle charging patterns, and reactions to managed charging. Standard rates apply per the customer's existing rate class;[71]
    - Apartment and Workplace Electric Vehicle Managed Charging Experimental Pilot Rider, offered to a maximum of 25 customers annually who contract for a charging station(s) workplace/apartment building for a period of seven years. The customers must agree to allow the utility to manage vehicle charging (e.g., reduce power to the EV charger during peak periods, shift EV charging to lower-cost periods, stagger EV charging start times to

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[67] Public Service Company of Colorado, *Electric Tariff,* https://www.prod2.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Regulatory%20Filings/PSCo_Electric_Entire_Tariff.pdf

[68] This utility was selected because of the three Wisconsin utilities that were reviewed (the other two being Wisconsin Public Service and Wisconsin Electric Power Company), Madison Gas and Electric had the most developed/enduring EV rates, as well as being the only one with the low load factor rate.

[69] MG&E, *Low Load Factor Provision*, https://www.mge.com/customer-service/for-businesses/electric-rates/low-load-factor-provision

[70] MG&E, *Electric Vehicle Fleet Pilot 1*, https://www.mge.com/MGE/media/Library/pdfs-documents/rates-electric/e14-2-0-ScheduleEVF.pdf

[71] MG&E, *Fleet Electric Vehicle Charging Experimental Pilot Rider*, https://www.mge.com/MGE/media/Library/pdfs-documents/rates-electric/e14-5-0-14-5-1-Schedule-EVF-2.pdf

reduce rebound peaks, or initiate EV charging sessions when renewables are available), and to view users' charging patterns.[72]

New York – In 2022 the New York Public Service Commission held a proceeding in response to a state law passed in 2021[73] that required each utility to file an EV charging commercial tariff, that specifically offered "alternatives to traditional demand-based rate structures." The regulator issued a decision in the proceeding in January 2023,[74] in which it ordered utilities to immediately implement a 50% rebate against demand charges at public DCFCs; it extended that rebate to all commercial EV charging in upstate New York, while ordering the utilities downstate to immediately implement a managed charging program with adders for specific use cases (upstate utilities must do the same but have more time to do so).

All of these immediate solutions will eventually be replaced by a blended energy-based TOU charge with a demand charge; customers will move through four different tiers based on their load factor, with the lowest tier (load factor below 10%) not paying any demand charges. Customer with load factors above 25% would not be eligible for the rate. Utilities have been given a certain amount of time to file rates in response to this order. Prior to the issuance of this order, Power Advisory reviewed the commercial and industrial rates offered by Consolidated Edison; while they were not EV-specific, some of the they offered different means of billing demand that could have been helpful for EV charging, e.g., TOU demand charges, contracted based demand plus overage charges, mixes of fixed and variable demand charges, and various combinations thereof.

Connecticut – Eversource (Connecticut's primary utility has an "Electric Vehicle Rate Rider"[75] for public charging stations; while initially available only at Eversource-owned chargers, it has since been expanded to all public charging stations including on-street parking, public parking spaces in lots or garages, and private charging stations enrolled in a managed charging program (the Workplace & Light-Duty Fleet Charging Program). This rate rider adjusts the relevant demand charge ($/kW or $/kVA) to an energy-based charge ($/kWh): the kWh consumption rates are calculated by dividing the applicable commercial and industrial rate class's total allocated demand-related costs by the class's total billed kWh; pass-through charges that are normally billed by demand are converted to energy charges by the same method. This rate is designed to help customers with low load factors; a hypothetical customer with a load factor equal to the load factor of the full rate class would not experience any savings from being in the EV class.

[72] MG&E, *Apartment and Workplace Electric Vehicle Managed Charging Experimental Pilot Rider,* https://www.mge.com/MGE/media/Library/pdfs-documents/rates-electric/e14-7-0-14-7-2-Schedule-EV-4.pdf

[73] New York Public Service Law, section 66-s https://www.nysenate.gov/legislation/laws/PBS/66-S

[74]Order Establishing Framework for Alternatives to Traditional Demand-Based Rate Structures https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={2043A628-EC7D-4064-9F32-662D82598760}

[75] Eversource, *Connecticut Electric Vehicle Rate Program*, https://www.eversource.com/content/residential/account-billing/manage-bill/about-your-bill/rates-tariffs/electric-vehicle-rate-program

Massachusetts – Amendments made in 2021 to the Transportation Act[76] require the state's three utilities to file for regulatory approval of, among other things, at least one commercial tariff or program that utilizes alternatives to traditional demand-based rate structures for EV fast charging, including of fleet vehicles; the regulator consequently directed utilities to file proposals for commercial EV rates that addressing that requirement. The regulator also provided guidance on what those proposals ought to look like, namely utilities were directed to consider the following options for alternative demand charge structures: converting demand-based charges to energy-based charges; rebates or discounts of the demand charge for charging at off-peak hours; and sliding scale demand charges based on the load factor of the EV charger.

The rate proposals ultimately filed with and approved by the regulator,[77] while not identical, largely featured rates with both demand-based and energy-based charges, the proportion of which varies by load factor i.e., as load factor increases, the demand charge increases, and the energy charge decreases). The proposals suggest three load factor tiers, with customers in the lowest tier (load factor of 0-5%) having the demand charge portion of the rate set at 0 and then escalating to 25% and 50% of the standard demand charge in the subsequent two tiers. Utilities must implement these rates within six months of the proceeding closing.

Relatedly, House of Representatives bill 5060 (2022)[78] requires the state's utilities to submit proposals for how they will offer customers credits or rebates for charging EVs during off-peak hours, which credit proposals must be approved by the regulator by June 30, 2023. In developing those rebates, the law requires utilities to consider the value of avoided transmission and distribution costs (among other things).

[76] Acts of 2020, Chapter 383, sec. 29 https://malegislature.gov/Laws/SessionLaws/Acts/2020/Chapter383

[77] Order of the Massachusetts Department of Public Utilities, case no. D.P.U. 21-90 https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/16827694

[78] The 193rd General Court of The Commonwealth of Massachusetts, *Bill H.5060*, https://malegislature.gov/Bills/192/H5060

APPENDIX D. ALTERNATIVE RATE OPTIONS CONSIDERED

Prior to settling on the two alternative rate design options considered in this report, Power Advisory held a workshop with OEB staff to review the various possibilities that had been identified through the jurisdictional scan and literature review. Table 17 presents the range of potential rate design alternatives contemplated.

Note that the references to "energy-based delivery charges" mean that the costs of delivery are allocated to customers based on their total electricity consumption (kWh) rather than on the basis of peak demand (kW). In Ontario, volumetric allocation of delivery costs solely on the basis of consumption rather than demand is the method currently used for general service customers with demand less than 50 kW.

Table 17. Range of potential rate design alternatives

Rate option	Description	Found in:
Fixed delivery charge	Similar to a connection or customer charge; collects a fixed amount of revenue from each customer in the class regardless of usage or behaviour.	N/A - not covered in jurisdictional scan
Energy-based delivery charge (single rate)	Delivery costs are charged based on the quantity of energy consumed, and charged at a single per-kWh rate	Colorado, Connecticut
Energy-based delivery charge (tiered rate)	Delivery costs are charged based on the quantity of energy consumed, and charged at two per-kWh rates that are applied based on energy consumed up to and then beyond a given threshold	N/A - not covered in jurisdictional scan
Energy-based delivery charge (TOU rate)	Delivery costs are charged based on the quantity of energy consumed, and charged at two or more per-kWh rates that are applied based on the time-of-day electricity is consumed (e.g., a peak rate which is higher, and an off-peak rate which is lower; could also include mid-peak and/or super off-peak periods)	N/A - not covered in jurisdictional scan
Energy-based delivery charge (TOU with critical peak pricing)	Delivery costs are charged based on the quantity of energy consumed, and charged at two or more per-kWh rates that are applied based on the time of day electricity is consumed, with the addition of a critical peak price that is higher than the ordinary peak price and which is charged for electricity consumed during peak hours on the top 5 peak days of the years (with advance noticed provided to the customer)	N/A - not covered in jurisdictional scan
Demand-based delivery charge (NCP demand)	Delivery costs are charged based on NCP peak demand, and charged at a single per-kW rate	Ontario (current rate design for general service customers with demand >50 kW)

Demand-based delivery charge (CP demand)	Delivery costs are charged based on CP demand (the distributor's and/or overall grid's peak) and charged at a single per-kW rate	N/A - not covered in jurisdictional scan
Demand-based delivery charge (TOU)	Delivery costs are charged based on demand during two periods of the day, and charged at two per-kW rates accordingly: a higher rate for demand drawn during defined peak hours of the day, and a lower rate charged for demand at all other times	Wisconsin, British Columbia
Blended energy-based and demand-based delivery charge	Delivery costs are charged based on a combination of energy consumed and NCP demand.	Colorado, California
Low load factor rate	Similar to the demand-based delivery charge (NCP demand) currently used in Ontario, except that the customer is charged a discounted rate if their load factor is below a certain threshold. Could also have multiple rate tiers for different load factors.	Quebec, Wisconsin
Demand transition rate	A variation of the blended rate and the low load factor rate, where delivery costs are allocated based on a combination of energy consumed and NCP demand. The two components of the delivery charge are adjusted on a scale where the demand-based component becomes larger as load factor increases (or, in some places, on a fixed schedule as time elapses)	Quebec, British Columbia
Rebates	Rebates are provided to customers that charge EVs during certain (e.g., off-peak) periods	Massachusetts
Interruptible rate	Customers can be offered either an incentive or reduced demand charge if they agree (opt-in) to permit the utility to curtail their electricity usage under certain conditions (e.g., approaching distribution/system peaks)	Wisconsin
Location-specific demand charges	Demand charges could be designed to incentivize charging EVs at specific physical locations to take advantage of grid capacity in some areas and reduce the need for upgrades to accommodate EV charging in constrained areas.	N/A - not covered in jurisdictional scan

Ultimately, two main options were advanced to further evaluation as part of this study:

- a TOU demand charge, to address commercial EV fleets.
- a low load factor rate, with three variations, to address public DCFCs.

The rationale for selecting each of these is described below, as are the reasons for not selecting the other possible options.

Rationale for TOU Demand Charge

A TOU demand charge gives commercial fleet managers a simple and routine indicator of when to charge, and a straightforward billing/rate structure that allows fleets to easily predict their electricity bills. The general characteristics of fleet charging (e.g., consistency and predictability of operations, known number of vehicles and demand, charging at fixed locations) means that EV fleets are likelier to be able to respond to the price signals provided by TOU rates. Reducing the cost of off-peak charging is also consistent with principles of cost causality, given that there are hours of the day in which the distribution system experiences reduced demand compared to peak hours; charging at those hours would therefore be expected to create fewer system costs then charging at peak. Should this option be pursued Power Advisory suggest that further analysis may be needed to determine how much distribution costs vary between specific hours of the day, thereby guiding the times at which one or another rate would be charged and ensuring that rate-setting under this option adheres to principles of fair allocation of costs.

The predictable and stable rate structure provided by the TOU demand charge is warranted and perhaps necessary to provide fleet operators with enduring certainty about what they would pay if they were to electrify. This is in contrast to the transitional nature of the rate structures recommended for public EV charging (which are either transitional as time goes on or as demand escalates), an activity and business for which it can be expected there will be continuing uncertainty as to volumes.

Demand transition/low load factor rates (the two recommended options for public EV charging) are not being recommended for fleets given that there is likely to be less uncertainty with respect to utilization rates for EV fleets than with sporadic public usage of DCFCs. It is anticipated that businesses electrifying their fleets would have clear plans for EV deployment and reasonable ability to predict the impact that incremental vehicle conversions would have on a depot's electricity demand and total consumption.

Rationale for Low Load Factor Rates

The recommended rate options for publicly accessible EV fast charging (e.g., roadside chargers, charging arrays in parking lots etc.) should reflect the fact that users of those chargers may not tolerate demand management techniques that charging operators might otherwise have used to reduce demand charges (such as throttling or offering varying prices at different times of day), are sporadic, and may continue to be so for quite some time. Indeed, some stakeholders suggested the possibility that some chargers, e.g., in rural or remote areas, may never see a high degree of utilization.

The recommended options therefore acknowledge the differing degrees of utilization that public DCFCs can be expected to encounter, and also respond to concerns that the commercial deployment of public DCFCs is severely impeded by the fact that with current rate structures, proprietors may not recover enough from charging fees to recoup the high demand charges that can be triggered by a single customer.

Options not recommended for further analysis.

The remaining eleven alternative rate options that were identified were not moved to the next stage of review, the quantitative analysis. This subsection outlines the rationale for excluding those options.

The *fixed demand charge* was ruled out because such a charge would not align with the conclusions of the OEB staff report *Rate Design for Commercial and Industrial Electricity Customers,*[79] which only recommended a fully fixed distribution rate for general service customers with demand under 10 kW, i.e., below most public/fleet EV charging levels. Such a rate structure was also not observed in other jurisdictions.

The options for full *energy-based delivery charges* (either flat rate, tiered rate, TOU rate, or TOU with critical peak pricing) were ruled out for a number of reasons; firstly, it was not clear that merely converting from demand-based to energy-based billing would address the existing issues if the same underlying costs would still be fully recovered over a prolonged or even indefinite period of time (as opposed to via the transitional rate methodology). TOU and especially critical peak prices rates were additionally ruled out because of the challenges that customers would likely experience if they were "chasing" different peaks i.e., with respect to both delivery costs and for the commodity portion of the bill. Finally, stakeholders expressed that once utilization improves, continuing to charge based on total energy consumption could prove less advantageous than reverting to a demand charge. Given the challenges with precisely identifying and calibrating this crossover point for different customers and utilities, it seemed undesirable to pursue an option that would require close monitoring and eventual revision lest the "solution" ultimately prove more detrimental than the current rate construct.

A *CP demand* charge was ruled out because, as noted in the previous paragraph with respect to TOU and critical peak pricing, this option would likely be challenging for customers who would have to manage peaks for both the delivery and commodity portions of the bill (which may not have aligned), and because it is unclear what CP demand charges should be coincident to, e.g., to a local feeder peak, the LDC's overall peak, total provincial system peak, etc. Finally, this option would also introduce significant complexity for LDCs.

Rebates and interruptible rates were ruled out because these options are essentially programs rather than rate designs and thus were deemed out of scope for this research. In addition, managed charging (a plausible outcome at a public DCFC if either rebate for off-peak charging or an interruptible rate were introduced) would likely be unacceptable from a customer experience perspective, and thus contrary to the aim of lowering barriers to EV deployment.

Finally, *location-specific rates* were excluded from further analysis because customers would likely not have any visibility into such granular information as local feeder capacity, making effective implementation extremely challenging; in addition, the parameters of this rate would change based on changing load patters (new or retiring load), which would require adjustment and reduce predictability for customers.

[79] Ontario Energy Board, *Staff Report to the Board: Rate Design for Commercial and Industrial Electricity Customers* (February 21, 2019), https://www.oeb.ca/sites/default/files/OEB-Staff-Report-Rate-Design-20190221.pdf

APPENDIX E. EVALUATION OF ALTERNATIVE RATE DESIGN OPTIONS USING PRINCIPLES OF GOOD RATE DESIGN

In this Appendix, the rate design alternatives are evaluated against the OEB's objectives[80] referencing Bonbright's principles of just and economic ratemaking[81] and other considerations. The Bonbright principles are ten "attributes of a sound rate structure" often used as a framework for identifying the relevant principles in the development of any cost recovery regime. The ten attributes are as follows:

Revenue-related Attributes:

1. Effectiveness in yielding total revenue requirements under the fair-return standard without any socially undesirable expansion of the rate base or socially undesirable level of product quality or safety.
2. Revenue stability and predictability, with a minimum of unexpected changes seriously adverse to utility companies.
3. Stability and predictability of the rates themselves, with a minimum of unexpected changes seriously adverse to ratepayers, and with a sense of historical continuity.

Cost-related Attributes:

4. Static efficiency of the rate classes and rate blocks in discouraging wasteful use of the service, while promoting all justified types and amounts of use:
    a. in the control of the total amounts of service supplied by the company.
    b. in the control of the relative uses of alternative types of service by ratepayers (on-peak versus off-peak service or higher quality versus lower quality service).
5. Reflections of all of the present and future private and social costs and benefits occasioned by the service's provision (i.e., all internalities and externalities).
6. Fairness of the specific rates in the apportionment of total cost of service among the different ratepayers, so as to avoid arbitrariness and capriciousness, and to attain equity in three dimensions: (1) horizontal (i.e., equals treated equally); (2) vertical (i.e., unequals treated unequally); and (3) anonymous (i.e., no ratepayer's demands can be diverted away uneconomically from an incumbent by a potential entrant).

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[80] Ontario Energy Board Act, 1998, Section 1(1): https://www.ontario.ca/laws/statute/98o15

[81] The Principles of Public Utility Rates, James C. Bonbright, Albert L. Danielsen, David R. Kamerschen (Second Edition, 1988) Public Utilities Reports, pages 383-4.

7. Avoidance of undue discrimination in rate relationships so as to be, if possible, compensatory (i.e., subsidy free with no inter-customer burdens).

8. Dynamic efficiency in promoting innovation and responding economically to changing demand and supply patterns.

Practical-related Attributes

9. The related, practical attributes of simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability, and feasibility of application.

10. Freedom from controversies as to proper interpretation.

These ten principles and other considerations are evaluated within the context of the OEB's four statutory objectives for the electricity sector. The other topics considered are regulatory burden, grid readiness, local and provincial demand management, EV adoption levels, and the differences between EV Fleet customers and public EV charging stations.

<u>OEB Objective: To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.</u>

Sound rate design produces a rate that acts as an appropriate price signal for customers. A rate would not be effective if the incremental costs caused by an EV charging customer exceeds the revenues recovered from the customer. This scenario would lead to customers demanding more than what is economically efficient to the detriment of other customers (i.e., would require cross subsidization) and harm revenue requirement stability. Conversely, rates would not be statically effective if they are greater than incremental costs to the extent that customers are discouraged from consuming electricity when the customer would not impose costs on the distribution system, and it would be economically efficient to consume.

Some rate designs can create additional costs for LDCs, such as additional load analysis, new studies, or changes to billing systems. Economic efficiency should consider the regulatory burden of alternate rate structures.

TOU Demand Charges

Demand charges are higher at system peak times so customers are incentivized to shift demand to off-peak periods. Like the status quo, demand-related distribution costs are recovered fully with a demand-based charge, incentivizing customers to manage peak demands and avoid causing capacity-related costs.

LDCs can have a range of peak periods depending on the composition of customers, local climate, and access to natural gas to reduce heating loads. The marginal cost of distribution at peak times can also differ by LDC. Time periods and the appropriate shares of revenue to be collected during the different periods would likely require additional analysis or load studies during the rate-setting process, creating a regulatory burden. Additionally, some LDCs may have different peak times among non-contiguous areas of their service territories.

Low Load Factor Rates

Low load factor and demand transition rates have reduced demand charges for customers with high peak demands relative to overall consumption. This type of customer is less likely to contribute to CP demand, meaning their overall cost causality is lower on the distribution systems than customers with high load factors. The lower contribution to costs for a low load factor customer's peak demands relative to customers with higher demands, leads to a correspondingly lower demand charge.

Differences in the cost causality of customers within a rate class can be distinct to the extent that introducing different rates based on other characteristics may be appropriate. Currently, some LDCs have a single general service greater than 50 kW rate class while others have multiple rate classes for general service customers with peak demands above 50 kW. The different characteristics of the customers in the different classes lead to different charges. While typical OEB rate classes are delineated by the customer's peak demands, this rate would extend differential rates to customers based on their load factors.

A single tier low load factor is simple to understand and administer relative to a rate structure with multiple tiers. However, having multiple tiers allows for more precision in the alignment of costs and revenues.

The TOU element of the energy charges in demand transition rates appropriately incents customers to shift demands to off system peak times. High demands can still cause capacity-related costs to distribution assets that are further downstream (closer to the customer) even if those demands do not materially contribute to system peak demands.

With various ranges of load factor thresholds, separate demand charges at each threshold, and TOU energy charges, demand transition charges can be designed to be closely aligned with cost causation. Closely aligning the revenues collected from a customer with the costs imposed by the customer allows for rates to be economically efficient in providing the proper price signal. However, the increased precision comes with the cost of determining the appropriate rate structure. The rate structure may differ by LDC depending on the cost of additional capacity and coincidence of low load factor customers within its service territory.

The demand transition design's TOU energy rate without a demand charge removes the customer's incentive to manage its maximum monthly demands. Demand charges applicable when the load factor reaches a certain threshold reintroduces the incentive to manage demands, but since the demand charge is a smaller portion of the total bill than the status quo the incentive is lessened.

LDCs currently have one volumetric charge for distribution service and this method would introduce an additional billing determinant. While Power Advisory believes that it is unlikely that this would create billing issues or add material regulatory burden, this is something that could be confirmed through stakeholder consultation. Demand-billed classes are commonly charged energy-based rate riders and regulatory charges so billing systems can likely manage an additional energy-based charge.

<u>OEB Objective: To inform consumers and protect their interests with respect to prices and the adequacy, reliability and quality of electricity service.</u>

An appropriate rate design protects customers by minimizing cross-subsidization between customer classes and customers within a class. This analysis should consider the impact of changing the rates and revenues collected from EV charging customers will have on the revenue collected from the LDC's remaining customers; this evaluation should account for the inter-class equity of separate rate classes and the intra-class equity of customers within a rate class.

In the short run with a given revenue requirement, any changes to distribution revenues collected from a customer will necessarily impact other customers. Costs are allocated based on the characteristics of each rate class and the same rates are applicable to all customers within a rate class. If groups of customers within a class are considered separately for the purposes of rate design, the different characteristics of these sub-classes will result in different allocated costs and lead to different rates. Modifying rates to reflect a more precise allocation would not constitute undue discrimination, but it is not free from controversy given the impacts on other customers.

In the long run, the rates and revenues recovered from EV charging should be aligned with the costs the customer causes so additional costs incurred to serve EV charging is not recovered from a distributors' remaining customers.

Some forms of rate design could be offered as an optional rate, introducing the concept of customer choice to commercial and industrial rate classes. This can be beneficial to customers, but this concept is not currently used in setting distribution rates and would add complexity to the ratemaking process.

TOU Demand Charges

TOU demand charges are relatively simple and understandable to customers. Although Regulated Price Plan (RPP) TOU rates are not applicable to EV fleet and public charging customers, that rate structure applies to commodity costs for residential and small general service customers – ensuring that individuals managing EV charging are generally familiar with TOU forms of rate design. The familiarity with TOU charges in the province can be beneficial for stakeholders to understand the reasoning for this rate design and avoid controversy.

TOU rates currently in place for the majority of RPP customers are based on provincial peak demands. Customers are incentivized to minimize consumption at times when marginal costs are highest. On a province-wide basis, peaks are typically in afternoon hours in the summer months to meet cooling loads. The majority of LDCs have a summer peak, however, many LDCs have distribution peaks in the winter months in the early evening hours.[82] It would be inefficient for LDCs to charge customers higher demand charges for consumption at times the LDC does not experience high CP demand.

If LDC distribution peaks occur at different times than provincial peaks, it would cause complexities and confusion to EV charging customers.

The OEB's cost allocation model for electricity distributors classifies costs into CP-related and NCP-related categories. This assignment of costs within the OEB's existing model can be leveraged to set off-peak and on-peak demand charges.

[82] In 2021, 72% of Ontario LDCs had higher summer peak demands than winter peak demands. OEB 2021 Electricity Utility Yearbook, General Statistics https://www.oeb.ca/ontarios-energy-sector/performance-assessment/natural-gas-and-electricity-utility-yearbooks#elec

Distribution bills for EV fleet customers could be managed if customers have the ability to shift consumption to off-peak hours. Distribution bills for public charging stations can be uncertain because they have less control over when its customers will be charging, either on peak or off peak. The delivery charges for public charging stations may be similar between TOU demand charges and the status quo. There could be an issue of unstable bills for customers cannot manage demand periods.

TOU demand charges may be offered as an optional rate. This rate structure could be beneficial to other types of general service customers that have the ability to shift demands.

Low Load Factor Rates

The cost to EV fleet customers and public charging customers would be lower than the status quo as long as the customers continue to have low load factors. When EV charging load factors increase – and their demands are more likely to occur at the system CP demand – they would return to the variable rates paid by other customers with similar peak consumption patterns.

Low load factor customers would contribute less revenue on a billed kW-demand basis than other customers within a class, so the remaining customers would contribute more than the status quo.

C&I EV charging is a relatively new type of customer for LDCs. Those customers do not yet contribute a material share of class revenues so this rate design would not materially shift costs to existing customers in the short run. In the long run, an appropriate low load factor rate would be aligned with the incremental costs of the EV charging customer demand, leaving higher load factor customers without material changes to its rates.

In the case of existing low load factor customers, migration to a lower demand charge would increase the revenues to be collected from non-low load factor customers relative to the status quo. The higher rates for high load factor customers can be considered fair and without undue discrimination because those customers contribute more to peak demands and cause higher costs on a per billed kW basis. However, any rate design that leads to higher distribution bills for existing customers would not be free from controversy.

An LDC's distinction between rate classes should balance the practicality of managing a reasonable number of rates and rate classes with the precision applying rates that reflect the costs caused by different types of customers. The low load factor rate design methodology would move distributors toward a more precise allocation of costs at the expense of additional regulatory burden.

A low load factor rate with a single tier has the benefit of simplicity. A customer that maintains a low load factor would have stable rates but the transition from below-threshold rates to above-threshold rates can have a significant impact on a customer's distribution bill. The concern can be mitigated with multiple low load factor tiers.

Demand transition charges can be offered as an optional service.

This rate design methodology provides appropriate incentives to both EV fleets and EV charging stations. The cost to EV fleets will be lower and TOU energy charges will incent EV fleet managers to shift demands to off-peak periods. The cost to EV public charging will also be lower as long as the customer has a low load factor. The cost will increase if public demand for its EV charging increases.

OEB Objective: To promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances.

An appropriate rate design should provide the proper incentive for customers to avoid contributing to peak demands. An effective rate design will incent EV charging customers to avoid contributing to their LDC's CP demands and the provincial peak demands. Practicality and simplicity issues can arise if those peaks occur at different periods. Individual customers should be incentivized to manage their peak demand to avoid the need for investments in downstream assets near the customer.

TOU Demand Charges

TOU demand-based charges are effective in demand management, as it provides an incentive to minimize demands during peak hours.

Low Load Factor Rates

Low load factor rates reduce the incentive for EV charging customers to manage demands. The rates do not incent customers to shift demand to off-peak periods.

A rate based on load factors creates a potential disincentive to manage peak demands. This is a result of the peak demand remaining the billing determinant, meaning higher demands will lead to lower load factors. A customer may face lower distribution bills by concentrating demand in a manner that keeps the customer below the low load factor threshold.

Demand transition charges that combine low load factor rates with TOU energy charges promote demand management. Though incentives to manage peak demands is somewhat less than the status quo, the incentive increases as load factors and contribution to peak demands increases.

OEB Objective: To facilitate innovation in the electricity sector.

EV charging as a rapidly growing customer group. This type of customer generally has a low load factor, especially at the initial low levels of EV adoption, so its demand charges are high relative to the customer's energy consumption. This may create a barrier to entry for EV fleets and public DCFCs. To facilitate innovation in EV charging in Ontario, rates can be restructured to remove this barrier while maintaining full cost recovery.

The demands of EV fleets can be managed by shifting charging loads to off-peak times. Public EV charging customers have less control over the timing of their demands. An effective rate design should consider the characteristics of both types of customers to maximize innovation in the sector.

TOU Demand Charges

TOU demand-based charges include some dynamic efficiency, given their ability to modify the peak windows. This rate structure would likely to enable EV Fleets to shift to off-peak consumption, but the impact is uncertain for public charging. More generally, the incentive to shift demand to off-peak periods could be beneficial for other types of customers.

Low Load Factor Rates

Low load factor rates reduce peak demand charges that can be a barrier to entry. Customers can maintain lower rates as long as their load factor remains low. For EV public DCFCs, demand charges would increase as public demand for EV charging increases. EV fleets could manage their consumption and demands to maintain the low load factor rate.

Demand transition charges are designed to increase the recovery of demand-related costs and demand charges as a customer's load factor increases. This transition reduces the barrier to entry that low load factor customers face.

The status quo postage stamp rates for all customers with similar maximum monthly demands naturally leads to high load factor customers paying somewhat less than the costs they cause and low load factor customers payment more than the costs they cause. A certain range is reasonable for practicality, but EV charging customers can have a very low load factor to the point they cause materially lower costs and postage stamp rates could constitute cross-subsidization. A more precise recovery of causal costs with demand transition charges removes the potential for this cross-subsidization between customer classes.