Electric Delivery Rates for EV Charging: Summary Presentation

Ontario Energy Board

May 24, 2023

Background: EVI Delivery Costs

- Ontario Energy Board (OEB) is undertaking activities to facilitate efficient adoption of electric vehicles (EVs) through the EV Integration (EVI) initiative
    - One workstream pertains to delivery costs and how current rate design may impact EV deployment in Ontario
- Power Advisory's 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
- Per OEB's Survey of Local Distribution Companies and EV Charging Service Providers on facilitating the integration of EVs in Ontario, charging service providers responding to the survey "*unanimously agreed they were concerned with the impact of demand charges on future EV supply equipment deployment*"

Study scope included:	Study scope did not include:
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")	• Residential customers • Changes to commodity charges such as the Hourly Ontario Energy Price (HOEP) or Global Adjustment (GA)

EVI Delivery Costs: Study Activities

- Quantitative assessment of 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
  - 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*
  - 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

Key Terms: Demand Charge

- 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

Demand Charges appear as line items on a customer's electricity bill

Manufacturing Company XYZ

Billing Date: July 20
Your Service Type: General Service - Demand
Your Local Hydro Company

Account Number
0000 0000 0000

Meter Number
000 000

How we calculated your charges

Metered Values	
Metered Consumption	45,000 kWh
Metered kW Demand	150 kW
Metered kVA Demand	161 kVA
Loss Adjustment Factor	4.8%

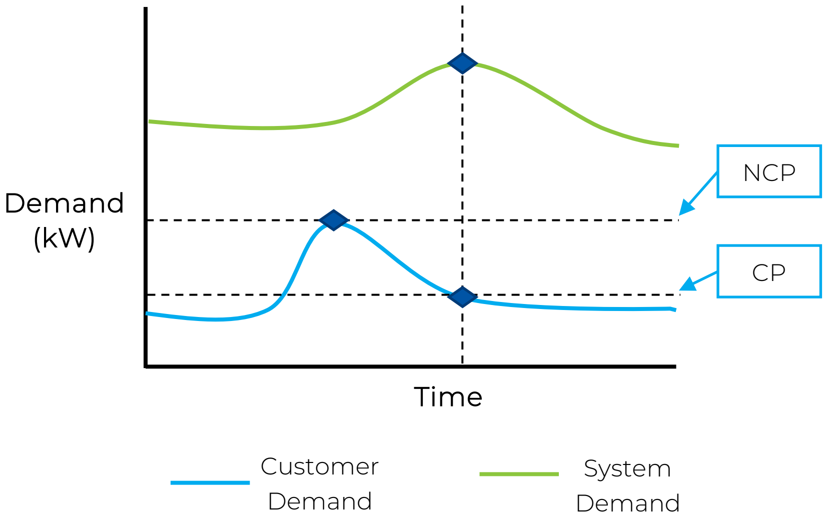
Calculated Values	
Adjustment Consumption	47,160 kWh
Power Factor	93.2%
Billing Demand	150 kW

Line Item	Rate($)	Amount	Total
Hourly Ontario Energy Price	0.0136	47,160 kWh	$641.38
Global Adjustment	0.1128	47,160 kWh	$5,319.65
Regulatory: Wholesale Market Service	0.0057	47,160 kWh	$268.81
Standard Supply Services	0.25	-	$0.25
Delivery: Monthly Service Charge	150.00	-	$150.00
Delivery: Distribution Charge	5.00	150.0 kW	$750.00
Delivery: Transmission Network	2.75	150.0 kW	$412.50
Delivery: Transmission Connection	2.00	150.0 kW	$300.50

Total Monthly Electricity Charges $7,843.09

Key Terms: NCP & CP

- Non-Coincident Peak (NCP) demand represents the highest peak demand drawn by a customer in a monthly period regardless of the time the peak occurs
- Coincident Peak (CP) demand represents the highest peak demand drawn by a customer in a monthly period at the time the system peak demand occurs



Key Terms: DCFC & Load Factor

- Direct Current Fast Charging (DCFC) is sometimes referred to as “Level 3 charging”
  - 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
- Utilization, or load factor, is the average demand divided by NCP demand
  - Canadian public DCFCs averaged 5% utilization in the 2019 to 2021 period, but utilization is expected to increase with EV market maturity

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

Key Terms: “Typical Customer” & “Average Rate”

- In this study, electricity bills for EV charging customers are compared to electricity bills for other general service customers
- “Typical Customer” load profile is based on the average day from hourly Ontario Demand in 2015 through 2021, net of Regulated Price Plan demand and directly connected industrial loads, sourced from
  - Independent Electricity System Operator (IESO) Smart Metering Entity), and
  - IESO public reports
- Customer electricity costs will sometimes be expressed as a per-kWh or “average rate”
  - “Average rate” is 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

Assessment of Current Rate Design for Commercial EV Fleets and Public DCFCs

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

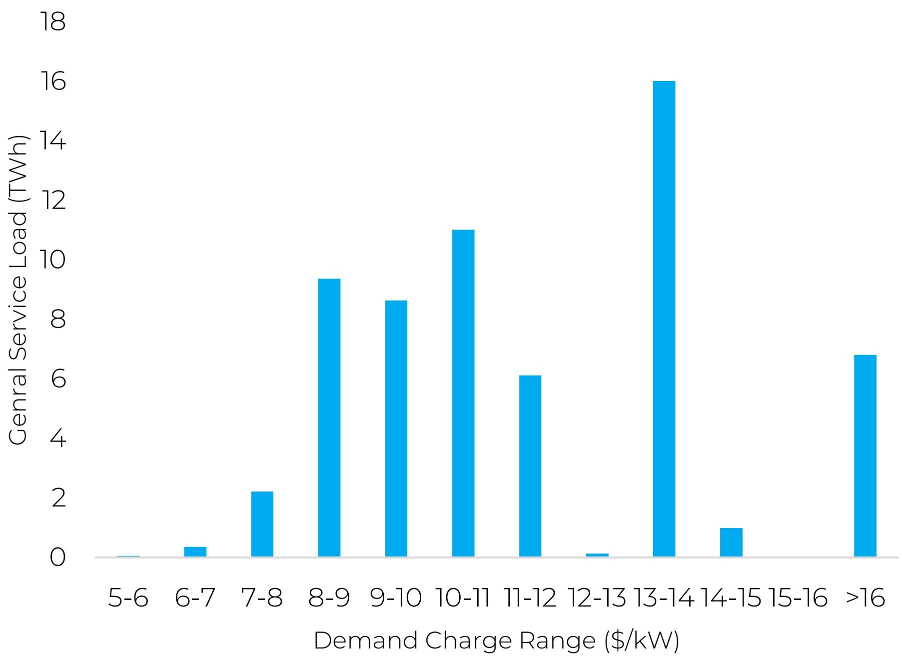
Generate sample electricity bills for commercial EV fleets and public DCFCs by combining the representative service territories' delivery charges and assumed commodity costs with the EV charging profiles

Range of Demand Charges for a 300 kW Customer in Ontario

- Demand charges of Ontario's LDCs range from approximately $8/kW to $24/kW

- 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

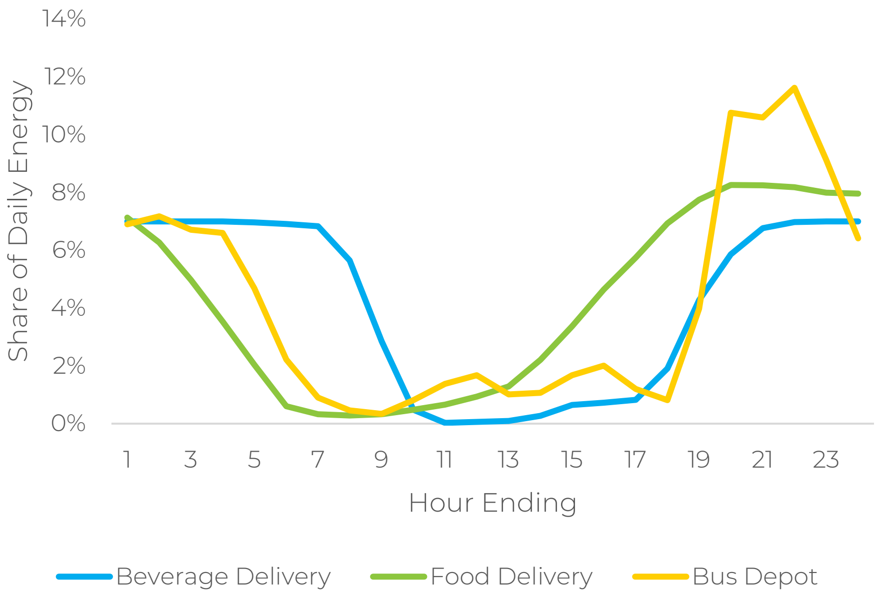
Representative Service Territory	Demand Charge ($/kW)
Urban Low	8.83
Urban Moderate	11.55
Urban High	14.04
Rural Low	8.85
Rural Moderate	11.20
Rural High	24.21



Commercial EV Fleets

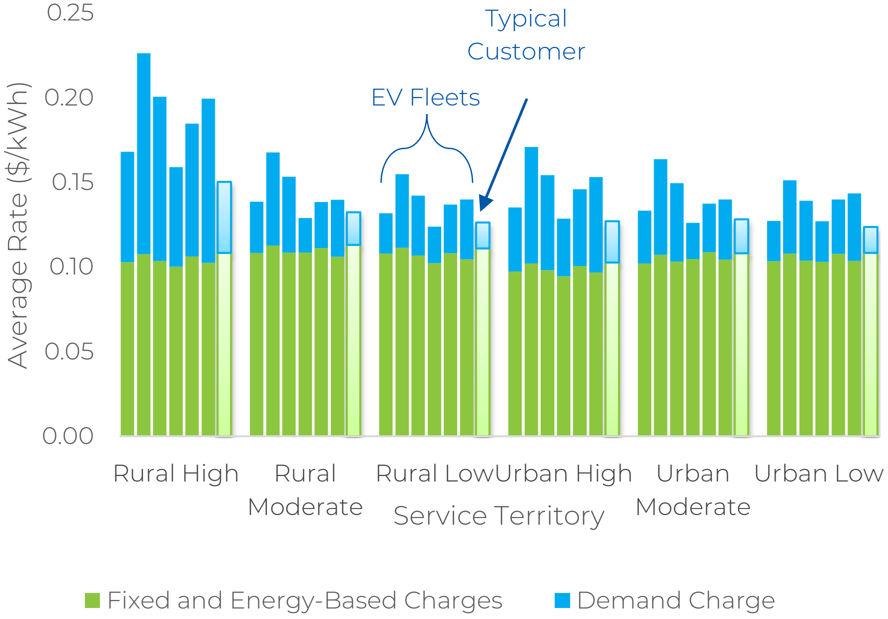
Commercial EV Fleets: Daily Load Profiles

- Electricity bills for commercial EV fleets were modelled using three different fleet types
  - beverage delivery,
  - food delivery, and
  - Buses
- Each fleet type was modelled for 10 to 25 vehicles and with a fleet size ten times higher
- Load profiles were selected to represent a reasonable range of commercial vehicle types, fleet sizes, and schedules that are currently feasible to electrify



Average Rate for Commercial EV Fleets Compared to a Typical Customer

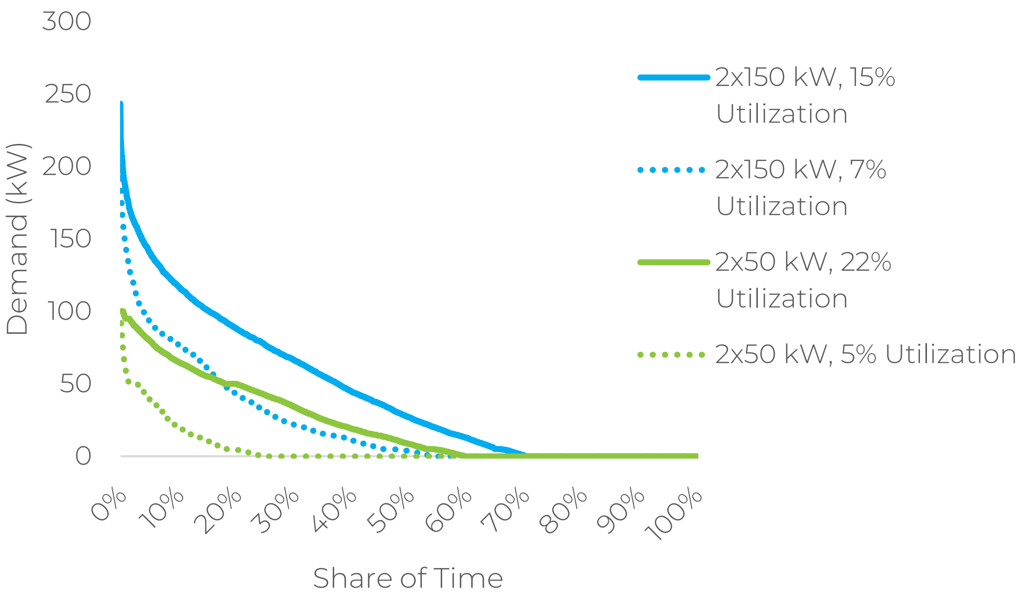
- Fixed charges vary considerably between service territories but in most cases are reasonably low when expressed on a per-kWh basis
- Bulk of energy-based charges are from the commodity cost, which is the same for all service territories
- For commercial EV fleets, an all-in electricity cost of $0.15/kWh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



Public DCFCs

Public DCFCs: Load Duration Curves

- At present in Ontario, public DCFCs have low load factor usage patterns because they provide high power to EVs during short, infrequent charging sessions
- Load duration curves were constructed by sorting a full year of simulated load data from highest to lowest to demonstrate how frequently load exceeds various demand levels
- For example, the 2x150 kW, 7% utilization DCFC exceeds 100 kW only 4% of the time
- Area under the load duration curve represents the total energy consumed by the DCFC in the year

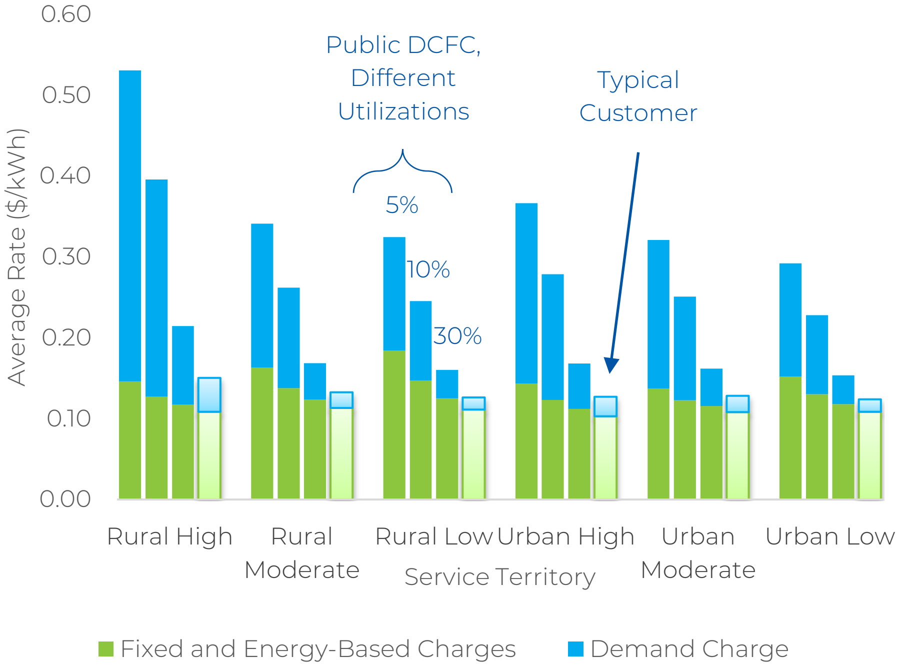


Average Rate for Public DCFCs compared to a Typical Customer

- 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 with a typical two-port 50 kW charging station would make up 43% to 72% of the customer's total monthly electricity bill



Summary of Findings

Summary of Current Rate Design Bill Impact for EV Customers

Load Profile	Urban Low Average Rate ($/kWh)	Rural High Average Rate ($/kWh)	Urban Low Demand Charge Share (%)	Rural High Demand Charge Share (%)
DCFC 2x50kW 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	0.12	0.15	12%	28%

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Findings for Commercial EV Fleets

- 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
    - 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
- 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

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Findings for Public DCFCs

- 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
    - 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
- Charging an EV at $0.60/kWh is comparable to gasoline priced at $1.23/litre
    - In the Rural High service territory, average rates exceed $0.60/kWh when utilization falls below 4%
- 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

Alternative Rate Design Options

Compile master list of alternative rate design options based on learnings from jurisdictional scan, literature review, and interviews.

→

Evaluate potential alternative rate design options using assessment criteria and Bonbright principles.

→

Develop shortlist of alternative rate design options.

→

Conduct quantitative evaluation of short-listed alternative rate design options.

Alternative Rate Design Options Considered for Further Evaluation

1. TOU Demand Charge for Commercial EV Fleets - 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 for Public DCFCs
   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.

- Economic rationale for both the TOU demand charge and the low load factor rate is based on the distinction between NCP demand and 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)

Jurisdictional Examples: EV Rates

TOU Demand Charge	Low Load Factor Rates
British Columbia • An overnight rate, which calculates demand (for billing purposes) using only the EV 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	Quebec • Rate BR is a blended demand/energy charge for EV charging stations • It eliminates a separate demand charge for EV customers in the rate class, instead offering three tiers that an EV 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

TOU Demand Charge

Category	Urban Low Current Rates	Urban Low TOU Rates	Rural High Current Rates	Rural High TOU Rates
Total CP Charges ($/kW)	0	6.73	0	13.12
Total NCP Charges ($/kW)	8.82	2.43	24.20	11.74

- Commercial EV fleet charging is often 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
- TOU demand charge could recover a portion of fixed costs based on customer demand in a daily, multi-hour peak period
  - Expected benefits to Commercial EV fleets given load profile and off-peak consumption
- Specifics of such a rate would require further analysis and consultation to determine
  - Length of the daily peak period must consider trade offs
  - Which demand-related costs would continue to be recovered based on NCP demand and which costs would be shifted to peak period demand.
- Methodology for developing the rate for the purpose of this study leveraged OEB's Cost Allocation Model for Electricity Distributors which classifies a share of an LDC's assets and costs as demand-related, which is further subclassified between CP demand and NCP demand

Electricity Bill Impact of TOU Demand Charge

Load Profile	Urban Low Average Rate, Status Quo ($/kWh)	Urban Low Average Rate, TOU Demand Charge ($/kWh)	Urban Low Bill Reduction (%)	Rural High Average Rate, Status Quo ($/kWh)	Rural High Average Rate, TOU Demand Charge ($/kWh)	Rural High 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%

*Commercial EV Fleet behind-the-meter of typical customer

TOU Demand Charge Impact on Other Customers

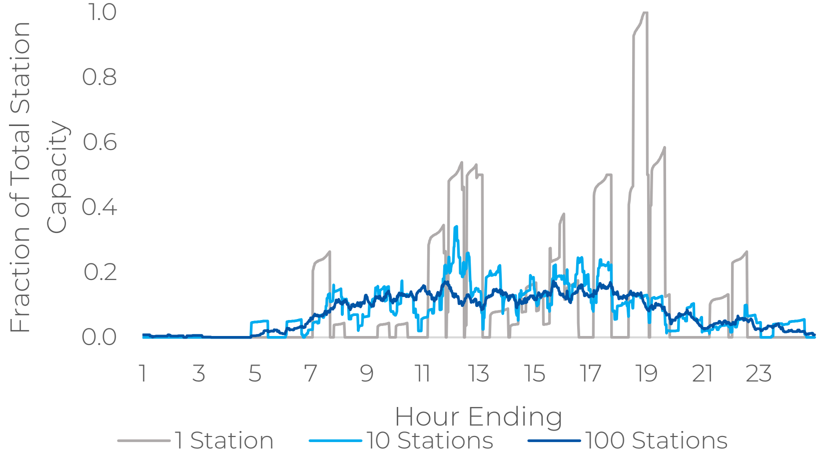
- TOU demand charge has been designed to be revenue neutral for the general service greater than 50 kW rate class for each distributor
  - If costs associated with CP demand are recovered across a smaller pool of demand, the rate (in $/kW) would need to increase
- Amount of NCP that can avoid the peak period is an important uncertainty in this analysis, but a high-level estimate of commercial fleet EV demand can provide some guidance
  - Given the IESO's EV demand forecast of 17.7 TWh by 2035 and assuming the rest of the general service greater than 50 kW rate class consumes 49 TWh, 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

Low Load Factor Rate

Load Factor	Option 2a: Single Tier ($/kW)	Option 2b: Multiple Tiers ($/kW)	Option 2c: Demand Transition Rate ($/kW*)
0 to 3%	0.90	0.26	0.00
3 to 7%	0.90	0.58	0.32
7 to 11%	0.90	1.02	0.77
11 to 15%	0.90	1.47	1.21
above 15%	6.39	6.39	6.39

* Option 2c includes an additional time-of-use delivery charge

- 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
  - Aggregating multiple public DCFCs will result in a smoother load profile because each station's load profile is different



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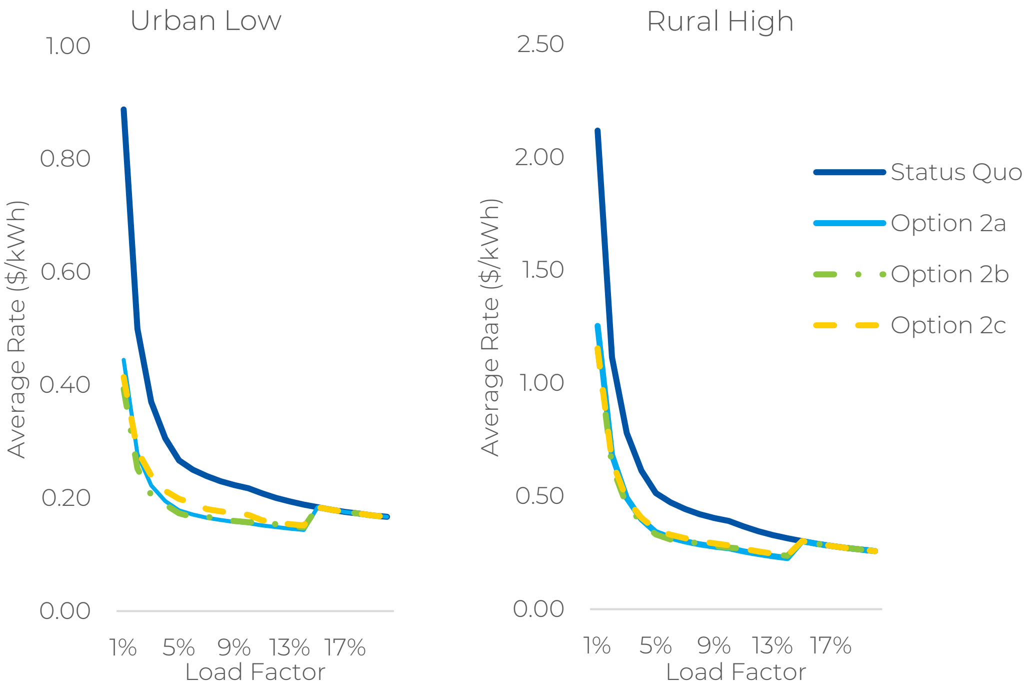
Bill Impact of Low Load Factor Rate for DCFCs



- All rate options led to lower electricity bills when utilization is below 15%
- In 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%

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

Rate Option	Energy Use (kWh/month)	Urban Low Monthly Bill ($)	Urban Low Monthly Savings ($)	Urban Low Bill Reduction (%)	Rural High Monthly Bill ($)	Rural High Monthly Savings ($)	Rural High 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%

Low Load Factor Rates Impacts on Other 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%

- 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
  - Assuming the rest of the general service greater than 50 kW rate class consumes 49 TWh, public DCFCs at 10% utilization could represent 3.4% of total consumption in the rate class by 2035
  - 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

Options for EV Customers to Mitigate Delivery Costs

Optimize company's/charging station's overall energy use.

Load control programs offered by the utility company.

Investments in distributed energy resources (DERs)

Participation by Non-EV Customers

- This report did not evaluate participation by non-EV customers; however, the implications for the potential inclusion of non-EV customers are reviewed
- If additional customer types 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
  - 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

TOU Demand Charge	Low Load Factor Rates
Customers whose demand is already primarily in the overnight hours or who could shift their load to off-peak periods: • energy storage facilities, • hydrogen-producing electrolysers, and • potentially some manufacturers.	Customers who have a low load factor, for example: • irrigation in the agricultural sector, • other industrial uses of pumps, compressors, saws, and milling machines, etc.

Implementation Considerations (1/3)

Consideration	Discussion
Opt-in versus mandatory	• Options / modelling presented assumed opt in basis. • 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	• EV-specific rates offered in other juridictions typically 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 • 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

Implementation Considerations (2/3)

Consideration	Discussion
Eligibility	• Alternative rate design options proposed could possibly benefit other customers that are not involved in EV charging • 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	• Balancing regulatory complexity versus responsiveness to customer concern and desire to see consistency of practices across Ontario • 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

Implementation Considerations (3/3)

Consideration	Discussion

New rate classes vs. designing new rates within existing rate classes	• 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
	    • Transparency of the costs allocated to EV charging customers and effectively remove intra-class cross-subsidization and easier for customer to understand
	    • Add regulatory burden to LDCs and could increase billing costs.
	• Could be implemented without new rate classes by introducing a new output worksheet in the OEB cost allocation model

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Appendix: Additional Explanation

Typical Customers: Impact of Demand Charges

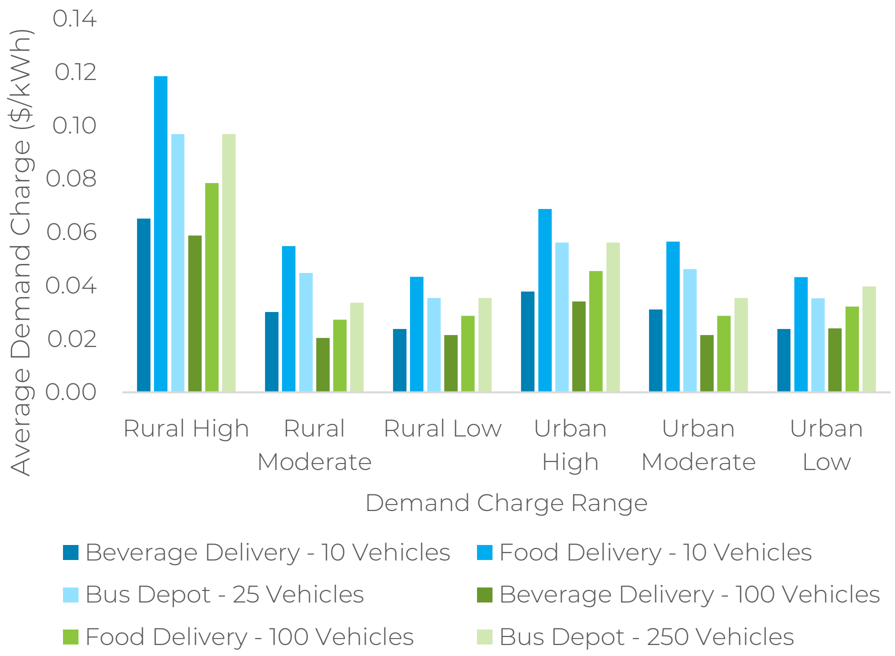
- Non-commodity related cost recovery by representative service territory for a Typical Customer (300 kW) are shown below
- Demand charges account for 75% to 97% of all non-commodity related charges on a Typical Customer's electricity bill

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: Average Demand Charge Per Status Quo Rates

- Range of average demand charges is $0.02/kWh to $0.12/kWh
- 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



TOU Demand Charge Illustrative Rate Design

Category	Urban Low Current Rates	Urban Low TOU Rates	Rural High Current Rates	Rural High 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

- LDCs are charged for transmission service at the Uniform Transmission Rates
  - Majority of costs recovered from LDCs based on the demand at a supply station during a peak period, and the remainder is charged based on NCP demand at the station
  - Retail Transmission Service Rates (RTSRs) based on the customer's NCP demand
- 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

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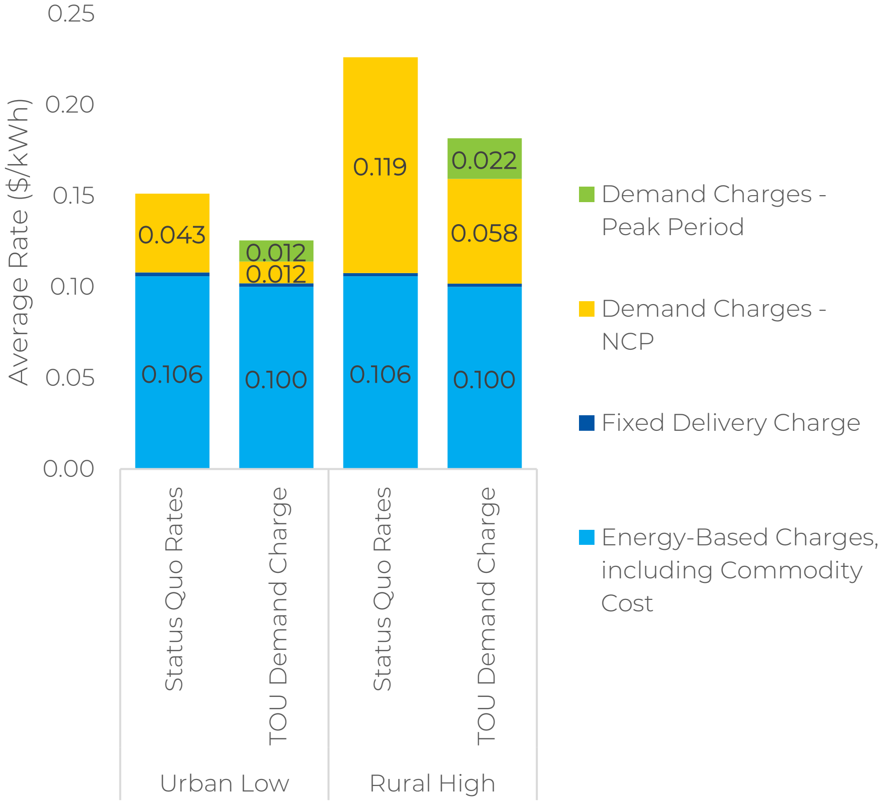
Example: Average Rate by Component (Food Delivery – 10 Vehicles)

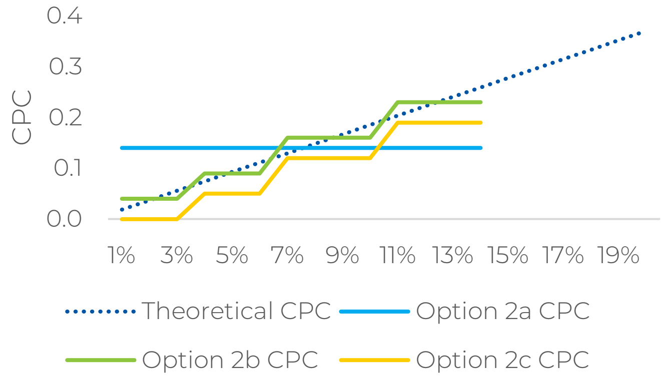


- Electricity bill savings for commercial EV fleets are primarily from avoiding CP-related distribution costs and RTSR, which account for 14% to 21% of the status quo bill
- There are also wholesale energy cost savings from shifting daytime energy use to overnight

Low Load Factor Illustrative Rate Design, Urban Low

- Load factor demand charge would provide a discount on RTSR and CP-related distribution costs (collectively, CP-related delivery costs)
- Illustrative rate designed would reflect likelihood of contributing to CP, i.e., Coincident Peak Contribution (CPC)
  - This CPC coefficient is intended to recognize the relationship between load factor and likelihood of contributing to CP demand

Load Factor	Option 2a: CPC	Option 2a: $/kW	Option 2b: CPC	Option 2b: $/kW	Option 2c: CPC	Option 2c: $/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



* Option 2c includes an additional time-of-use delivery charge (see next slide)

Low Load Factor Illustrative Rate Design, Option 2c TOU Component

- Time-of-use energy charge is in addition to the $/kW demand charge for Option 2c
- Set at 35%, 25%, 15% and 5% of the Winter RPP rates