CLEAN ENERGY NH
Your Voice in All Energy Matters

Deborah Howland
Executive Director
New Hampshire Public Utilities Commission
21 South Fruit Street
Concord, NH 03301

July 31, 2020

Re: IR20-004, Electric Distribution Utilities Investigation into Rate Design Standards for Electric Vehicle Charging Stations and Electric Vehicle Time of Day Rates

Clean Energy NH Response to Supplemental Comments in Response to the July 14, 2020 hearing

Dear Executive Director Howland,

Clean Energy NH (CENH) appreciates the opportunity to respond to supplemental comments provided by the intervening parties in reference to Docket No. IR 20-004 and the July 14, 2020 hearing.

CENH strongly supports Time of Day rates, also known as Time of Use (TOU) rates, as an ideal rate design mechanism for EVs with many benefits to the grid, many of which were highlighted during the July 14th hearing. By using TOU rates, EV customers are able to (1) make informed decisions about when to charge, (2) adapt their charging schedules in order to reduce their energy costs, and (3) provide grid benefits by shifting demand to off-peak hours.

While some parties in IR 20-004 expressed concerns that TOU rates would lead to increased risk and cost associated with billing and metering, CENH counters that the benefits outweigh the potential costs and that looking beyond traditional utility metering to quantify usage and timing can help further reduce incremental costs. Offering an opportunity to utilize the most up-to-date third party technology already installed in many EV chargers, vehicles, or affordable external devices could provide the utilities with accurate and effective metering at a much lower cost. Other New England states are examining the possibility of using third party meter alternatives for EV metering or TOU implementation because it presents less cost to the utilities. For example, Massachusetts issued an order beginning phase 2 of the state's grid modernization investigation and it specifically references looking at alternatives to utility AMI meters to offer advanced metering capabilities for EV customers. [1]

CENH would like to re-assert its support of Staff's recommendation that the utilities file feasibility assessments for metering devices other than a utility-provided meter to identify the most appropriate and least cost approach to metering EV-only TOU service. Especially now

[1] Massachusetts Department of Public Utilities. (2020). D.P.U. 20-69 Investigation by the Department of Public Utilities on its own Motion into the Modernization of the Electric Grid – Phase Two. Retrieved from https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/12334560.

while EV adoption is still relatively low in NH, a TOU rate, utilizing third party technology, that empowers customers to respond to price signals, will yield expected grid benefits in a cost-effective manner. It is in the state's best interest to move forward in a timely manner with a statewide TOU offering for all EV ratepayers.

In their comments filed 7/24/2020, Eversource stated that empowering customers with time of use rate "requires customers to take affirmative actions" to be effective and that the utility's proposed approach of managed charging would be "taking that burden off customers". This is not, in fact, reflective of the advanced technology available to these customers already built in to their EV chargers and/or vehicles. Chargers and vehicles can easily be preprogrammed to charge during preferred times so to effectively respond to the price signal given by a time of use rate a customer would need to just program their device, set it, and forget it. If the charging need is immediate and the customer wants to override the pre-set preferences, they can do so easily from an app on their smart phone however, the default settings will remain ensuring the customer compliance with the desired outcome of the TOU rate.

CENH does not find demand management programs to be an acceptable alternative to TOU rates for NH at this time as mentioned by Eversource in their supplemental comments post-hearing. While demand management programs may be useful when used in conjunction with TOU rates and in areas that have much higher rates of EV adoption and use, early adopters of EVs in NH should be given the opportunity to make informed and rational decisions in their charging behavior. A TOU rate will change charging behavior consistently day-in-day-out while a demand management approach typically focuses on responding to specific peak events, therefore they do not serve the same function. Price signals, as provided by TOU rates, are the best method of providing benefits to the grid and the ratepayer.

Finally, during the hearing I mentioned that one possible approach to addressing the issue of demand charges is to replace demand charges with volumetric charges while public EV charger use is still low and to progressively phase the demand charge back in as EV charger use increases. Specifically, this refers to a "sliding scale tariff design" proposed by Rocky Mountain Institute[2] in a study where they found that this approach produced the most consistent and predictable cost of charging per mile across a range of utilization for public DC fast charging stations. As discussed during the hearing and in our previous comments, there are several effective approaches that can be used to address the significant barrier that demand charges pose on the development of public charging infrastructure needed to enable the market growth of EVs and the associated grid benefits.

Thank you for the opportunity to respond to supplemental comments provided by the intervening parties in reference to Docket No. IR 20-004 and the July 14, 2020 hearing. Please do not hesitate to reach out with any questions.

---

[2] Fitzgerald, Garrett, and Chris Nelder. *DCFC Rate Design Study.* Rocky Mountain Institute, 2019. http://www.rmi.org/insight/DCFC-rate-designstudy

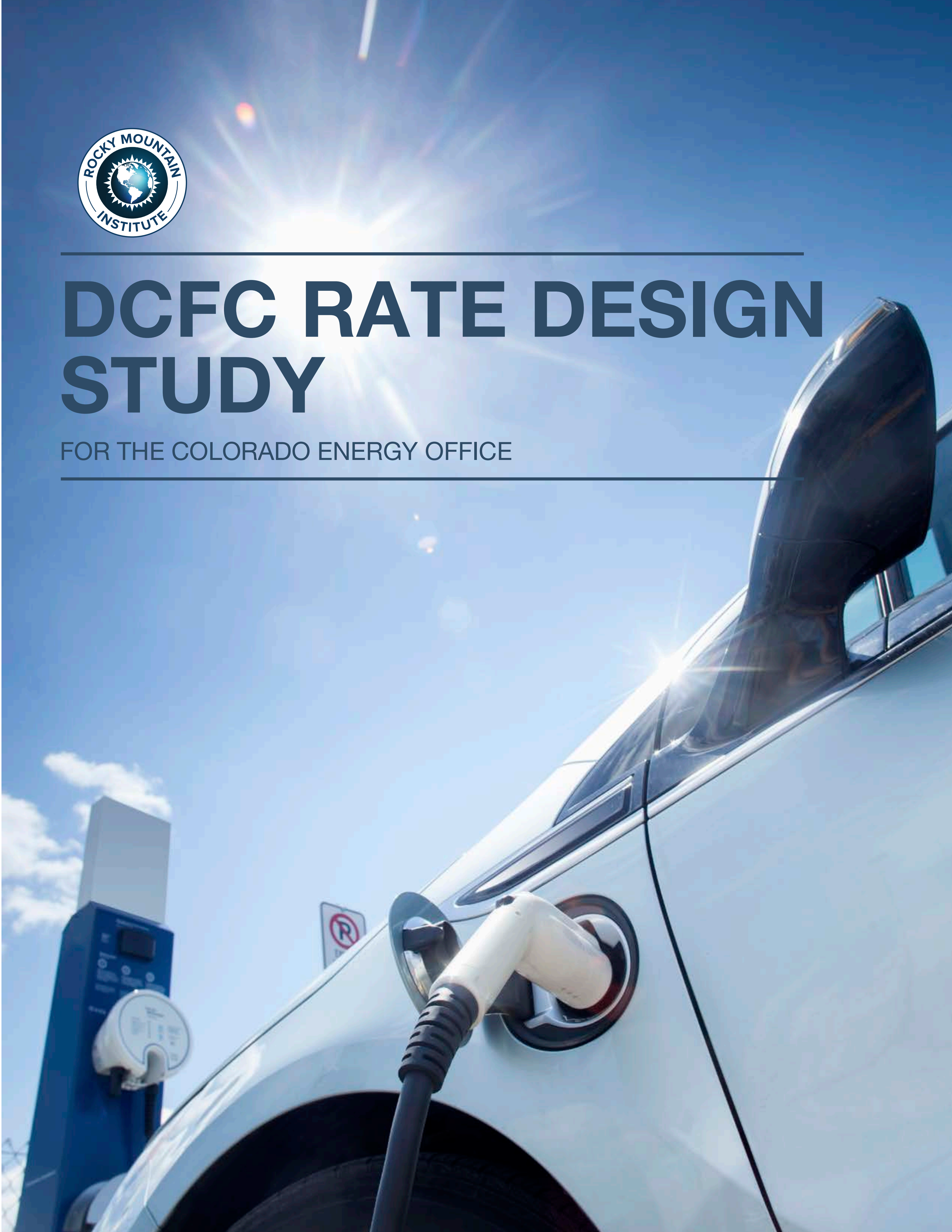
CLEAN ENERGY NH
Your Voice in All Energy Matters

Sincerely,

Madeleine Mineau
Executive Director, Clean Energy NH
madeleine@cleanenergynh.org

DCFC RATE DESIGN STUDY

FOR THE COLORADO ENERGY OFFICE



AUTHORS & ACKNOWLEDGMENTS

AUTHORS
Garrett Fitzgerald and Chris Nelder
*Authors listed alphabetically. All authors are from Rocky Mountain Institute unless otherwise noted.

CONTACTS
Garrett Fitzgerald, gfitzgerald@rmi.org
Chris Nelder, cnelder@rmi.org

SUGGESTED CITATION
Fitzgerald, Garrett, and Chris Nelder. *DCFC Rate Design Study.* Rocky Mountain Institute, 2019. http://www.rmi.org/insight/DCFC-rate-design-study

Revised February 2020.

ACKNOWLEDGMENTS
This work was commissioned by the Colorado Energy Office (CEO).

TECHNICAL NOTE
Due to incorrect data we received from the original sources we consulted for this report, the results we reported for the bus depot portion of the analysis are inaccurate. These are the only portions of this report which are affected by this faulty data. The Xcel tariff actually includes riders (fees) that were not disclosed to us, and which may increase the energy components of a bus depot's monthly bills by as much as 100 percent. Additionally, the values supplied to us for the bus depot's monthly peak demand were incorrect; when correctly modeled, the demand component of the bus depot's monthly bills could be as much as 150 percent higher. The reader should also be aware that after this report was completed, certain changes were made by an administrative law judge to the proposed Xcel S-EV rate, which were subsequently approved by the Colorado PUC. Those changes are not reflected in this report.

Images courtesy of iStock unless otherwise noted.

ABOUT ROCKY MOUNTAIN INSTITUTE
Rocky Mountain Institute (RMI)—an independent nonprofit founded in 1982—transforms global energy use to create a clean, prosperous, and secure low-carbon future. It engages businesses, communities, institutions, and entrepreneurs to accelerate the adoption of market-based solutions that cost-effectively shift from fossil fuels to efficiency and renewables. RMI has offices in Basalt and Boulder, Colorado; New York City; the San Francisco Bay Area; Washington, D.C.; and Beijing.

TABLE OF CONTENTS

TABLES

FIGURES

EXECUTIVE SUMMARY

The economics of operating direct current fast chargers (DCFCs) for electric vehicles (EVs) are typically very challenging and do not generally permit a viable business opportunity while EV adoption is in its early stages and charger utilization rates are low. The primary problem in most cases is that demand charges on the applicable utility tariffs are far greater than the revenue the charging stations generate, as our reports have demonstrated.[1] To address this issue, Public Service Company ("Xcel Energy") has proposed a new rate for DCFCs. The State of Colorado has commissioned this study as part of its analysis of the new Xcel rate.

In this study, we perform a comparative analysis of several proposed tariffs that are specifically designed to meet the needs of the unique type of load presented by DCFCs, aiming to understand the costs they might impose on operators of public high-speed EV-charging networks in Colorado and the utility revenues that will result from them.

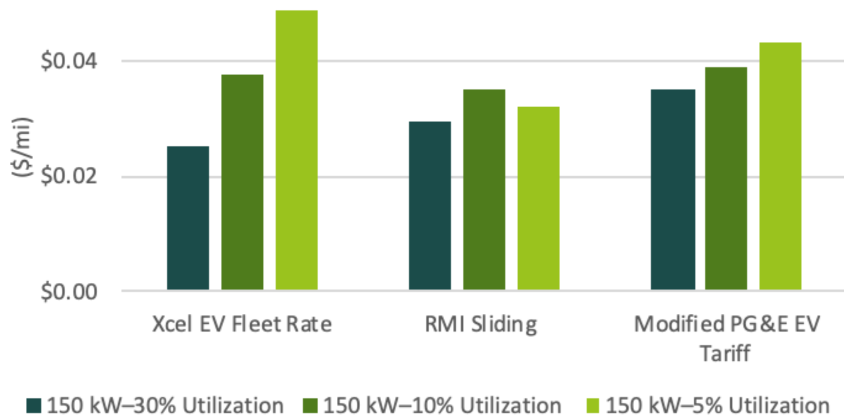
This project modeled the cost of service for DCFC charging stations over a period of 10 years using the following parameters:

- Three tariffs:
    - One proposed by Xcel Energy that features a low fixed monthly charge, lower demand charges than the existing tariff most DCFC stations are currently on in their service area, and added charges for energy consumed during "critical peak pricing" (CPP) periods.
    - One from PG&E that eliminates demand charges, offers a three-tier time-of-use (ToU) pricing regime for energy, and requires the customer to select a high fixed monthly "subscription" charge based on their expected consumption.
    - One from RMI that includes Xcel's fixed charge, offers a two-tier ToU regime for energy pricing, and uses a sliding-scale approach under which volumetric rates for energy decrease and demand charges increase over time as a function of the utilization rate.
- Three load profiles:
    - A public DCFC charging depot with two dual-port 50 kW chargers
    - A public DCFC charging depot with two dual-port 150 kW chargers
    - A transit bus depot with twenty-five 100 kW chargers
- Three utilization rates on public DCFCs:
    - 5%, which is representative of many DCFCs today
    - 10%, which is representative of the utilization rates that a public DCFC might experience in a maturing EV market within five years or so
    - 30%, which is representative of the utilization rates that a public DCFC might experience in a mature EV market

The key criterion by which we judge the three tariffs is the cost per mile of range delivered to the vehicle, assuming an energy efficiency of 3.4 miles per kilowatt-hour (kWh).[i]

[i] Although there is a significant range of energy efficiencies among current models of EVs, just as there is for internal combustion vehicles, we selected 3.4 miles/kWh as a good modeling benchmark. We chose this benchmark because it matches the best-selling EV on the US market, the 2018 Tesla Model 3, and is close to the energy economy of other comparable and popular EVs, such as the 2018 BMW i3, the 2018 Chevrolet Bolt, and the 2018 Nissan Leaf. The US Department of Energy rates the fuel economy of EVs in terms of kWh per 100 miles; we have inverted that to miles per kWh (29 kWh per 100 miles = 3.45 miles/kWh). Source: US Department of Energy, http://bit.ly/2YYhVd6

FIGURE 1: PER-MILE COSTS UNDER EACH TARIFF FOR A 150 KW CHARGER



Our analysis shows that the RMI sliding-scale tariff design results in the most consistent and predictable cost per mile for all utilization rates of both 50 kW and 150 kW public DCFC charging stations. The RMI tariff also results in the lowest cost of energy at the 5% utilization rate, which, of the utilization rates we modeled, is the closest to typical real-world experience. This is vitally important, because while EV adoption is still in its early days and utilization rates on public DCFCs are low, costs must be low enough to encourage charging station operators to continue to deploy more public charging stations. Even while delivering the lowest cost of energy, the RMI tariff is designed to generate the same revenue as Xcel would receive under its own tariff design over the 10-year modeling period.

Accordingly, we believe that of the three tariffs we analyzed, the RMI tariff strikes the best balance. We believe that by varying charges as a function of utilization, it is possible to satisfy three key objectives simultaneously: to create an attractive business opportunity for charging network operators, keep the cost of charging at or below the equivalent cost of refueling a conventional gasoline or diesel vehicle, and permit an appropriate level of cost recovery for the host utility.

For the transit bus depot, our analysis shows that the average cost per mile is lowest under Xcel's S-EV tariff for both charging scenarios we analyzed. Thus, we recommend that tariff for large, stable loads, such as those of a transit bus depot or other similar fleet-charging application.

PURPOSE OF THE STUDY

There is significant data showing that the economics of operating DCFCs for EVs do not permit a viable business in most of the United States, except in a few locations where utilization rates are high (generally, above 30%). In most cases, the demand charges on the applicable utility tariffs are far greater than the revenue the charging stations generate, as our reports have demonstrated.[1] As a result, several utilities and state regulatory agencies in the United States have begun exploring alternate tariffs that offer some form of demand-charge relief and enable a business opportunity for private-sector EV-charging service providers, while still affording appropriate cost recovery for the host utilities.

However, to the best of our knowledge, a comparative analysis of several such rates has not been performed until now. The purpose of this analysis is to evaluate three proposed rate design alternatives for DCFCs and understand how they might affect the cost of operating public high-speed EV-charging networks in Colorado—and the utility revenues that will result from them.

We hope that this analysis will be useful to the relevant agencies and utilities in Colorado and lead to a more viable and vibrant ecosystem of high-speed public charging stations in the state. We also hope this analysis will provide useful guidance to other regulatory jurisdictions that are grappling with the same question.

MODELING AND METHODOLOGY

This project modeled the cost of service for DCFC charging stations over 10 years using the following parameters:

- Three tariffs: one proposed by Xcel Energy, one proposed by PG&E, and one proposed by RMI.
- Three load profiles:
  - A public charging depot with two dual-port 50 kW chargers.
  - A public charging depot with two dual-port 150 kW chargers.
  - A transit bus depot with twenty-five 100 kW chargers.
- Three utilization rates on the chargers: 5%, 10%, and 30%.

Tariffs

We evaluated three tariffs, each of which was specifically designed for DCFC (high-speed EV-charging applications).

XCEL COLORADO'S S-EV TARIFF

This tariff was proposed by Public Service Company ("Xcel Colorado"), an investor-owned utility in Colorado, in May 2019 and filed with the Colorado Public Utilities Commission under Proceeding Number 19AL-0290E.[2] It applies to commercial and industrial customers who need secondary voltage electric service supply for the sole purpose of charging EVs on a separate meter.

The tariff includes the following elements:

- A fixed monthly charge.
- Two tiers of ToU pricing for energy, measured in kWh. The ToU price tiers are the same year-round. The "off-peak" rate applies from 9 p.m. to 9 a.m., and the "on-peak" rate applies from 9 a.m. to 9 p.m.
- A "critical peak" adder (additional) charge for energy, measured in kWh, which is applied for energy delivered during CPP periods. A CPP period is defined as a four-hour period occurring between noon and 8 p.m., which Xcel may call at its discretion based on the day-ahead temperature forecast and day-ahead generation reserve-to-load forecast. CPP periods may occur as many as 15 days in a calendar year.
- A demand charge, based on kW, which is calculated based on the highest demand measured during a 15-minute interval each month.

TABLE 1: XCEL'S S-EV TARIFF

Fixed Charge	$34.40	$34.40	$/month
Generation Charges	Winter	Summer	
On-peak	$0.054	$ 0.054	$/kWh
Off-peak	$0.027	$0.027	$/kWh
Critical peak	$1.50	$1.50	$/kWh
Demand Charges	Winter	Summer	
Demand	$5.63	$5.63	$/kW

PG&E'S EV-LARGE S COMMERCIAL EV TARIFF

This tariff was proposed by PG&E, an investor-owned utility in California, in November 2018 as part of California Public Utilities Commission Proceeding Number A1811003. It applies to commercial and industrial customers who need secondary voltage electric service supply for the sole purpose of charging EVs on a separate meter, and it was designed for fleet vehicles that need fast charging. Of the three variants in the PG&E Commercial EV tariff, we are modeling only the EV-Large S tariff, which offers secondary voltage for sites above 100 kW.

The tariff includes the following elements:

- A fixed monthly "subscription charge," which is based on 50 kW increments of connected load. The customer chooses in advance the level of demand they want to buy (e.g., 100 kW, 150 kW, 200 kW) and pays overage fees if their actual demand exceeds the service level they chose.
- Three tiers of ToU pricing for energy, measured in kWh. The ToU price tiers are the same year-round. The "off-peak" rate applies from 10 p.m. to 9 a.m. and from 2 p.m. to 3 p.m. The "on-peak" rate applies from 4 p.m. to 10 p.m. And the "super-off-peak" rate applies from 9 a.m. to 2 p.m.
- There are no demand charges with this tariff.

TABLE 2: PG&E'S EV-LARGE S TARIFF

Fixed "Subscription" Charge	$184.00	$184.00	$/50 kW per month
Generation Charges	Winter	Summer	
On-peak	$0.30	$0.30	$/kWh
Off-peak	$0.11	$0.11	$/kWh
Super-off-peak	0.09	$0.09	$/kWh

RMI'S TARIFF

This tariff is our own proposal, offered as an alternative for consideration by the Colorado Energy Office. Our tariff is designed to allow the same revenue recovery as Xcel's tariff over a period of 10 years, but in a fashion that will keep the costs incurred by DCFC station operators more stable and predictable under multiple use cases, load factors, and load sizes, and that will scale with utilization. We propose this sliding-scale approach for two reasons: (1) it obviates the need to guess when the market will mature such that customers can tolerate a conventional demand rate (as required by the "demand-charge holiday" approach proposed by some other utilities), and (2) it should remain scalable and suitable for a wide range of use cases and utilization rates for many years to come, while still affording a level of cost recovery that utilities will find acceptable.

The tariff includes the following elements:

- A fixed monthly charge, set at the same level as in Xcel's tariff.
- A two-tiered ToU energy charge, measured in kWh, that is the same year-round and decreases with utilization. The "off-peak" rate applies from 9 p.m. to 9 a.m., and the "on-peak" rate applies from 9 a.m. to 9 p.m., to match Xcel's proposed ToU schedule.
- A demand charge, measured in kW, that increases with utilization.

Our proposed tariff has two flavors: one for loads of 100 kW or less, which we used to model the costs for a dual-port 50 kW charger, and another for loads over 100 kW, which we used to model the costs for a dual-port 150 kW charger and for the bus depot. We took this approach to ensure that revenue recovery was matched between the Xcel and RMI tariffs for the various use cases we evaluated, but it is not unusual for a tariff to discriminate between different load classes in this way.

TABLE 3: RMI'S TARIFF FOR DEMAND OF 100 KW OR LESS

Fixed Charge	$34.40	$34.40	$/month
Generation Charges	Winter	Summer	
On-peak	Decreases with utilization from $0.068 to $0.007		$/kWh
Off-peak	Decreases with utilization from $0.022 to $0.002		$/kWh
Demand Charges	Winter	Summer	
Demand	Increases with utilization from $0.677 to $17.622		$/kW

Note: Values are rounded to three significant digits.

FIGURE 2: RMI'S TARIFF FOR DEMAND OF 100 KW OR LESS

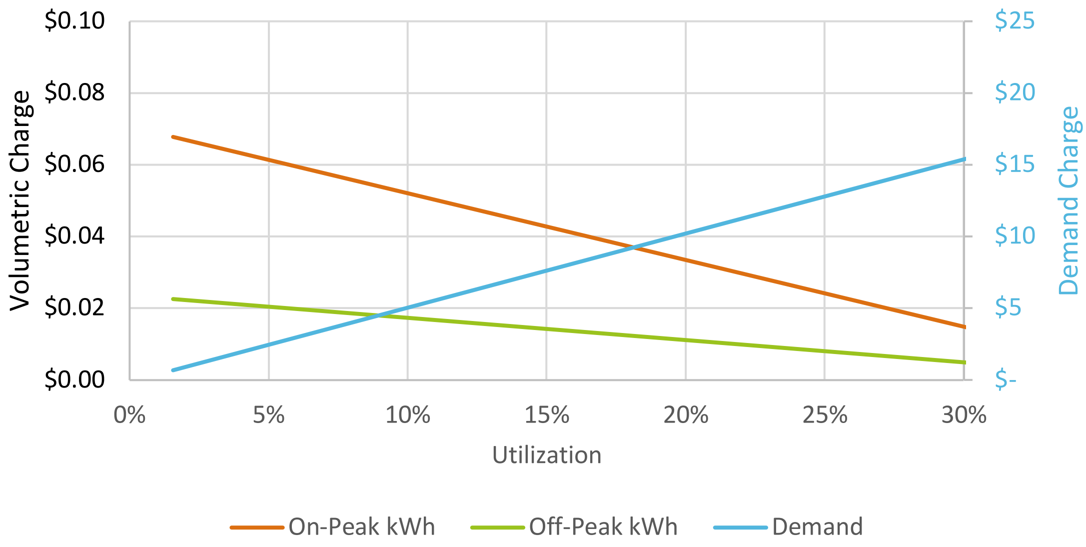
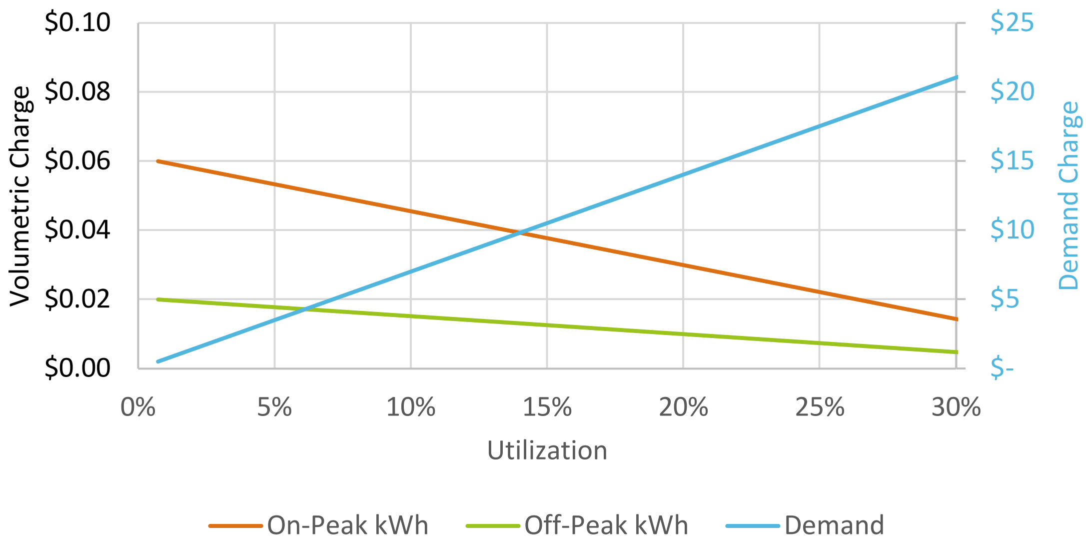


TABLE 4: RMI'S TARIFF FOR DEMAND OVER 100 KW

Fixed Charges	$34.40	$34.40	$/month
Generation Charges	Winter	Summer	
On-peak	Decreases with utilization from $0.060 to $0.010		$/kWh
Off-peak	Decreases with utilization from $0.020 to $0.003		$/kWh
Demand Charges	Winter	Summer	
Demand	Increases with utilization from $0.50 to $23.00		$/kW

Note: Values are rounded to three significant digits.

FIGURE 3: RMI'S TARIFF FOR DEMAND OVER 100 KW



Load Profiles

We evaluated the tariffs against the following typical, indicative load profiles:

1. Two public DCFC load profiles, representing urban locations where members of the public use the charging stations opportunistically and randomly, mostly during daytime and evening hours. We used data from DCFCs in urban locations because that's where the majority of DCFC stations are located and where utilization rates will be higher.

   Two variants were evaluated:
   - A site with two 50 kW DCFCs. Each charger has two cords, each of which can dispense 50 kW simultaneously.
   - A site with two 150 kW DCFCs. Each charger has two cords, each of which can dispense 150 kW simultaneously.

2. A transit bus load profile representing the load at a bus charging depot with twenty-five 100 kW chargers, each of which has one cord capable of dispensing 100 kW. It is assumed that charging is actively managed by a bus fleet operator to take advantage of low-cost hours of the utility tariff and avoid costly demand charges and other adders on a given tariff, and that charging mostly takes place outside of working hours.

Utilization Rates

We define "utilization rate" as the total time a charger is actively charging divided by the duration being evaluated. In this report, we use a one-month time period to calculate station utilization. For example, in a month with 30 days, there are 720 hours. If a charger were in use for a total of 36 hours over the course of the month (on average, 72 minutes a day), the charger would have a 5% utilization rate (5% of 720 hours is 36 hours).

In the United States, most DCFC charging stations are on tariffs that are prohibitively expensive for DCFC network operators while utilization rates on the chargers are low. Since most of the country still has a relatively small number of EVs on the road, utilization rates on the chargers are generally low, where the tariffs impose very high demand-charge costs on the network operators because of the spiky, infrequent nature of the load of a public DCFC. We detailed this issue in depth in our March 2017 report, *EVgo Fleet and Tariff Analysis*. We believe that when utilization rates on DCFC charging stations increase to roughly 30%, the charging stations will be able to operate profitably under a typical utility tariff while at the same time offering pricing to EV drivers that is at parity with refueling using gasoline or diesel.[ii] But until the EV market matures considerably and the demand for public DCFC charging grows to increase the utilization rates of the chargers, most tariffs currently offered by utilities are untenable and are inhibiting the growth of public fast-charging networks.

Therefore, it is important to test any proposed tariff under multiple utilization rates to understand what kinds of costs it will impose on DCFC network operators today, in the early days of EV adoption, and what those costs might be in a growing and mature market. Accordingly, we modeled the public DCFC loads under the following utilization rates to represent a 10-year period of rapid growth in EV adoption:

- A 5% utilization rate for the first three years to represent a typical public DCFC load in today's early EV market
- A 10% utilization rate for the next three years to represent what a typical public DCFC load might be when the market begins to grow
- A 30% utilization rate for the next four years to represent what a typical public DCFC load might look like as the market matures

Methodology

Here, we detail the important assumptions and methodological details used in our modeling.

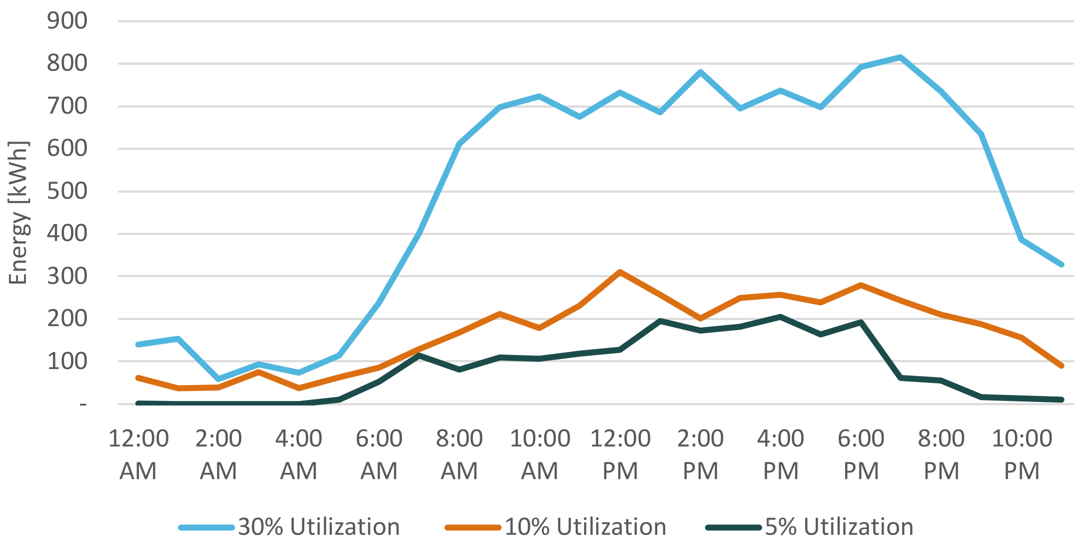
LOAD PROFILES

Public 50 kW load profiles

The 50 kW load profiles were aggregated and anonymized from various sets of real-world data provided to us by high-speed charging network operators under nondisclosure agreements. We used this data to create load models for all three utilization scenarios from dual-port stations with actual utilizations close to 5%, 10%, and 30%.

[ii] We use the top-selling midsize car in the United States—the Toyota Camry, with 29 mpg fuel efficiency in the city—as a proxy for the typical internal-combustion vehicle in the United States (Source: Focus2Move, http://focus2move.com/usa-best-selling-cars). At the current average national cost of gasoline ($2.70/gallon) and the current average cost of gasoline in Colorado ($2.62/gallon), the cost per mile for fuel is $0.09/mile (Source: AAA, http://gasprices.aaa.com).

FIGURE 4: LOAD PROFILE FOR A 50 KW DUAL-PORT DCFC



From those load profiles, we used the observed 15-minute peak demand to calculate the demand charges.

TABLE 5: PEAK DEMAND LEVELS FOR A 50 KW DUAL-PORT DCFC

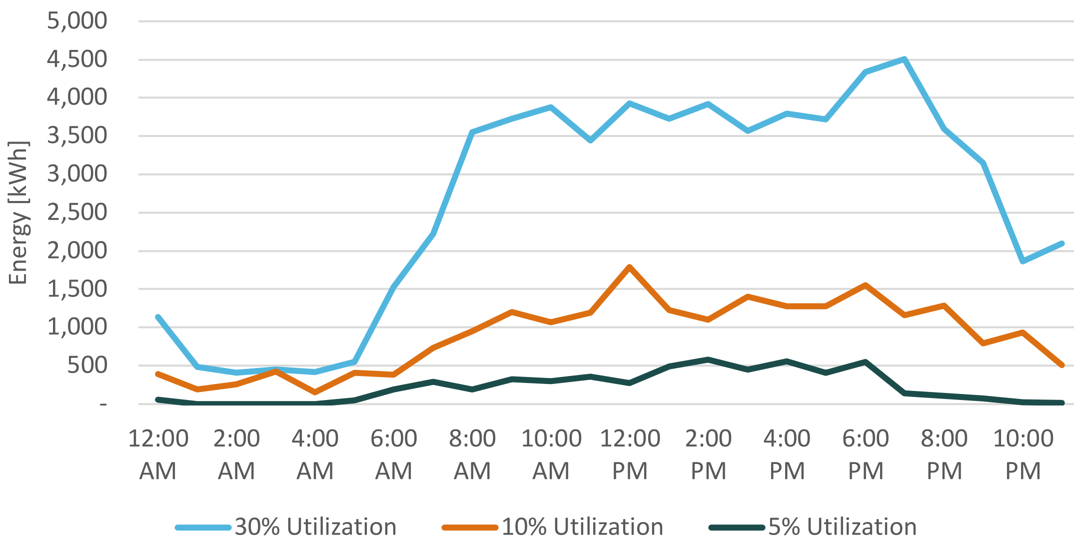
Utilization	15-Minute Peak Demand (kW)
30%	88
10%	81
5%	58

Public 150 kW load profiles

The 150 kW load profiles were modeled based on the 50 kW load profiles. Because 150 kW stations are relatively new and only a few have been deployed nationally, we were unable to obtain real-world data on their load profiles. Additionally, there are very few EVs on the road as of yet that can accept a 150 kW rate of charge. But most major charging station networks are now deploying 150 kW chargers, and auto brands such as Mercedes, Jaguar, Porsche, BMW, and Tesla have announced or produced vehicles that can accept a 150 kW rate of charge. Therefore, any new tariff—which we might assume would be in use for at least 10 years after being approved by a public utilities commission—should be tested in some fashion against 150 kW EV-charging loads.

Although there are other ways of approaching this modeling challenge, we elected to approach it as follows: the 150 kW load profiles were generated by applying the same hourly load shape as the 50 kW stations. We then increased the number of charging sessions until the resulting utilization matched the 5%, 10%, and 30% utilization rates in our modeling.

FIGURE 5: LOAD PROFILE FOR A 150 KW DUAL-PORT DCFC



To determine demand charges, we modeled the peak demand by proportionally increasing the 15-minute peak demand observed in the 50 kW load data. In other words, we multiplied the observed peak demand interval on a dual-port 50 kW station by 3 to increase it proportionally to the potential power output of a dual-port 150 kW station.

TABLE 6: PEAK DEMAND LEVELS FOR A 150 KW DUAL-PORT DCFC

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

Bus depot load profiles

The bus load profiles were compiled from data provided by RTD, the transit fleet operator in Denver, to generate a representative load profile. That data shows the average seasonal load for their fleet of 36 buses, which are charged on 100 kW chargers, but does not provide more discrete details, such as whether all chargers were ever in use at the same time, or what the maximum power output of each charger was. We scaled the original RTD data to 25 buses for the purposes of our modeling.

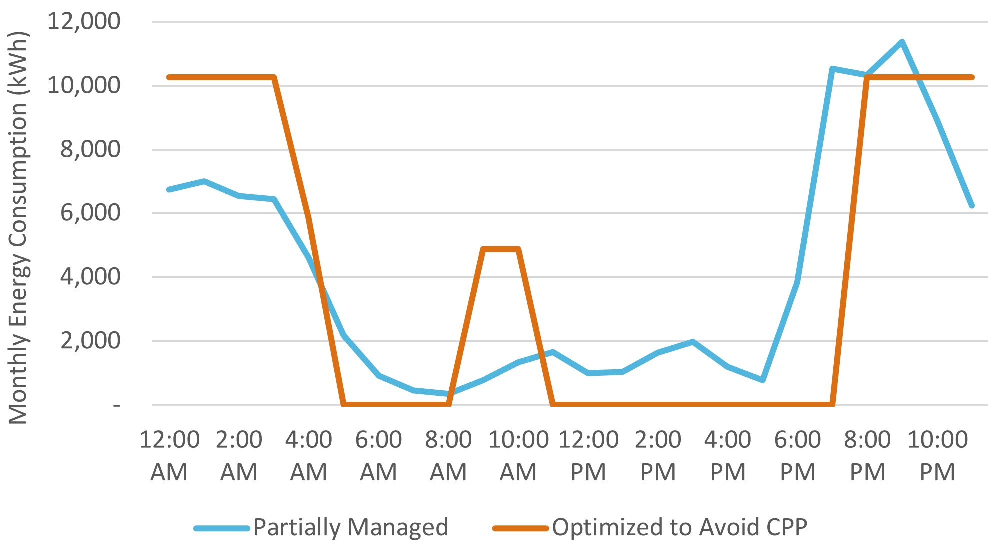
We modeled two types of load profiles for the bus depot:

- A “partially managed” load profile, which represents RTD’s actual charging at its bus depot today. RTD actively manages the charging of its fleet to try to minimize demand charges under Xcel’s existing Secondary General (SG) tariff, so this load profile is essentially optimized for that tariff. Many of the buses are currently charged between 6 p.m. and 9 p.m.
- An “optimized” load profile, which assumes that RTD would continue to manage charging to minimize costs in accordance with the particular characteristics of the new proposed tariffs. Because the off-peak rate in Xcel’s proposed S-EV tariff and in the RMI tariff begins at 9 p.m., we assumed that RTD’s optimized load profile for those tariffs would begin charging at 9 p.m. Because the off-peak rate for

PG&E's tariff begins at 10 p.m., we assumed that RTD's optimized load profile for that tariff would begin charging at 10 p.m.

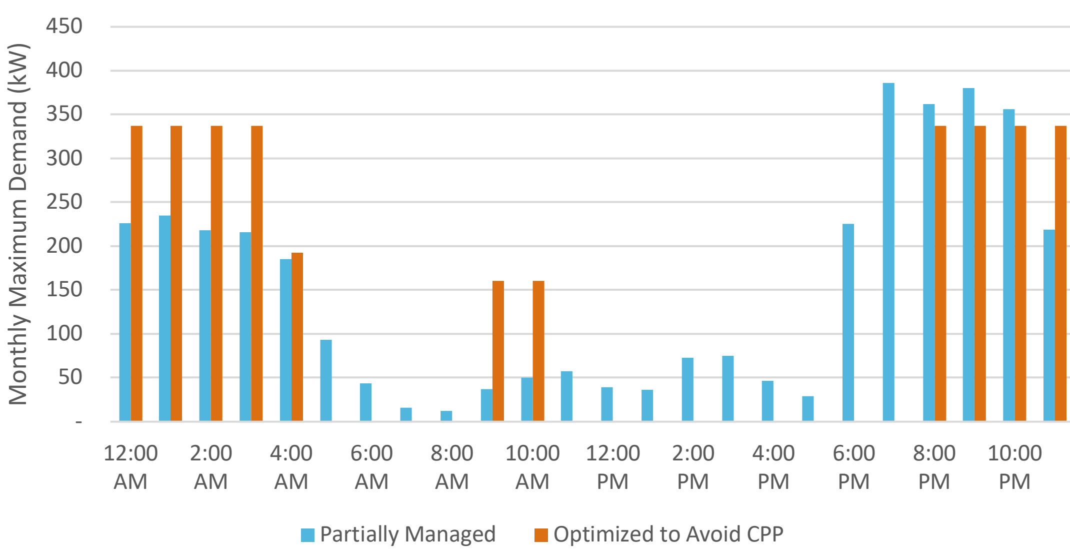
For reasons we explain below, we modeled the bus depot load profile only at a 30% utilization rate.

FIGURE 6: LOAD PROFILE FOR BUS DEPOT



To determine demand charges, we used the actual observed 15-minute peak demand intervals in the RTD data.

FIGURE 7: DEMAND-CHARGE MODELING FOR BUS DEPOT



TARIFFS

Xcel Colorado's S-EV tariff

We modeled Xcel's S-EV tariff without modification under the load profiles and utilization rates explained above.

To determine the cost impact of the CPP adder in the worst-case scenario, we used a random number generator to distribute the maximum of 15 CPP events over the course of the summer months. This produced five CPP events in June, seven CPP events in July, and three CPP events in August. We then modeled July as the worst-case monthly bill.

PG&E's EV-Large S commercial EV tariff

Because energy prices are different in California than they are in Colorado, we retained the form of the PG&E tariff but adjusted the prices of its components to reflect the Colorado context for the purposes of comparing the tariffs. We did this by calculating the difference between the average cost of electricity in California ($0.199/kWh) and Colorado ($0.123/kWh)[3] and adjusting each component of the PG&E tariff by that factor. We then used the modified (price-adjusted) PG&E tariff for comparison with the Xcel tariff and the RMI tariff.

RMI tariff

The chief distinguishing feature of our tariff is that it allows volumetric energy charges and demand charges to slide as a function of the utilization rate. There are no firm guidelines as to the upper and lower boundaries of the scale for either charge, but in practice, we would advise allowing the energy charges and demand charges to slide between 3% and 30%, with no further increase of demand charges or decrease in energy charges above 30% utilization. This is because above 30%, charging stations should be able to generate enough revenue to tolerate the equivalent of a conventional demand rate. However, it would be best to test these assumptions using empirical field data because tariffs and costs can vary so widely from place to place.

Public DCFC modeling under the RMI tariff

To model the RMI tariff, we needed to choose appropriate prices for both energy and demand. To do this, we calculated the revenue that would accrue to Xcel under its proposed S-EV tariff over 10 years of operation as follows:

1. A 5% utilization rate for the first three years
2. A 10% utilization rate for the following three years
3. A 30% utilization rate for the final four years

Because there are no generally accepted forecasts for EV adoption or utilization rates on a public DCFC over the next decade, we selected these utilization rates to try to model what future demand might look like in our informed estimation. However, other modelers might make different assumptions.

After calculating the revenue that Xcel would earn under these assumptions, we then determined the prices for energy and demand in our tariff such that it would produce roughly the same revenue over 10 years, but would do so in a way that resulted in a flatter, more consistent utility bill for charging station network operators as the utilization rate changes.

Bus depot modeling under the RMI tariff

For the bus depot modeling, unlike for the public DCFC sites, we expect the load to be very consistent over time, because we assume the bus fleet managers will be charging roughly the same number of buses the same way every day. We also determined that the current utilization rate on RTD's existing chargers is around 45%—above the upper bound of the sliding scale in our tariff design. We would expect a fully electrified bus fleet with mature operational strategies to see even higher utilization rates, because we would expect fleet managers to use the smallest practical number of chargers to recharge their bus fleets, and run them at high utilization rates.

Therefore, we modeled the bus depot charging for the RMI tariff at a flat 30% utilization rate, which is the upper bound of the sliding scale in our tariff. Higher utilization rates would produce the same cost outcomes for the bus fleet operator. Because the utilization rate is only an operative feature of the modeling under the RMI tariff, and because the sliding-scale characteristic of our tariff is not useful to a bus fleet with a constant utilization rate, a more conventional tariff design may be more appropriate for RTD.

RESULTS

The results of our modeling are as follows.

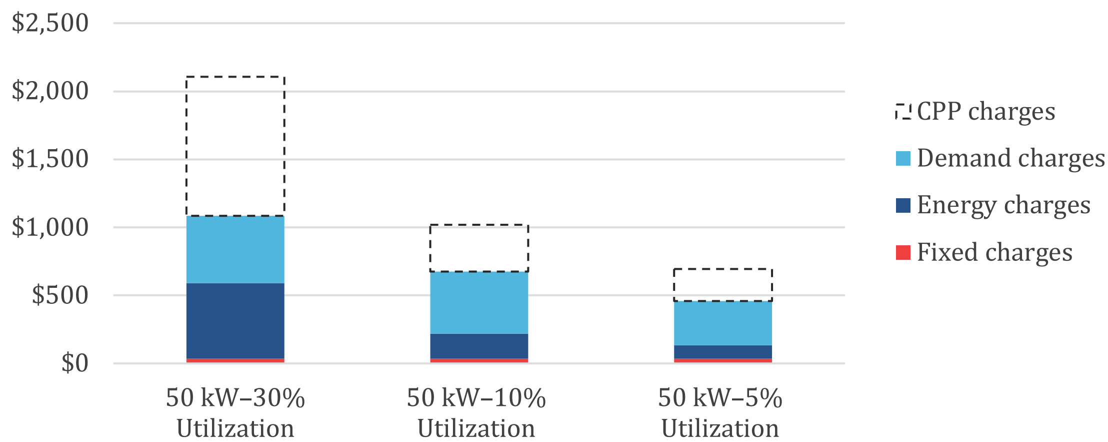
Monthly Utility Bills for Public DCFC

We calculated the monthly bills that would result from the set of public DCFC charging scenarios described above. This way of looking at the results is helpful in understanding the total cost of operation that a charging station owner is likely to incur.

XCEL TARIFF

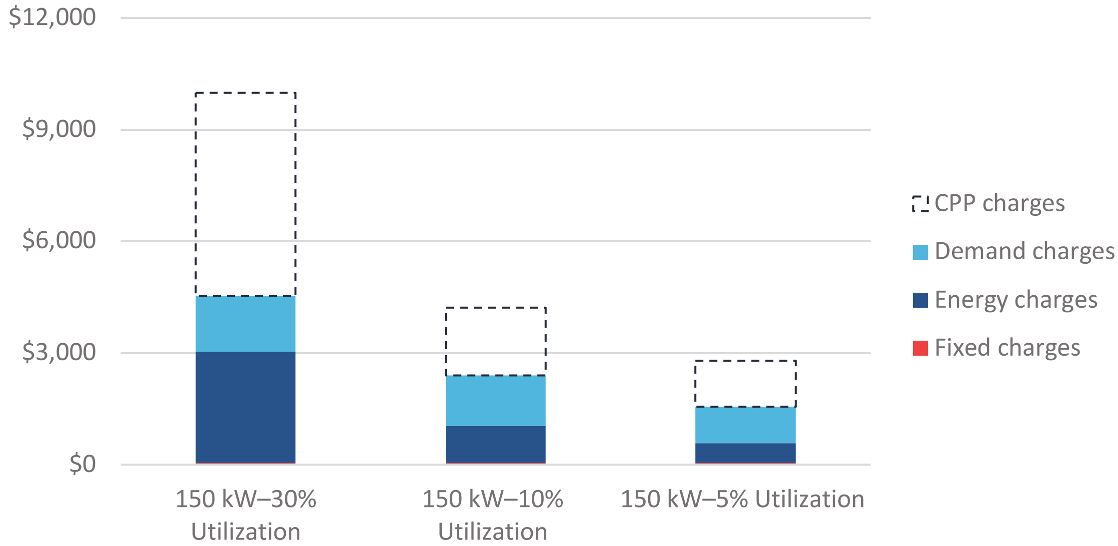
For the 50 kW chargers, the impact of the CPP charges on the monthly bills under the Xcel tariff can be quite significant, and that impact increases with the utilization rate. This chart shows what the bills might look like for the month of July, with charges for the seven CPP events shown in dotted outline.

FIGURE 8: MONTHLY UTILITY BILL FOR A 50 KW CHARGER ON THE XCEL TARIFF



For the 150 kW chargers, the impact of the CPP charges scales proportionally, reflecting the proportional scaling that we did to model the 150 kW load profile, as explained in the “Methodology” section above.

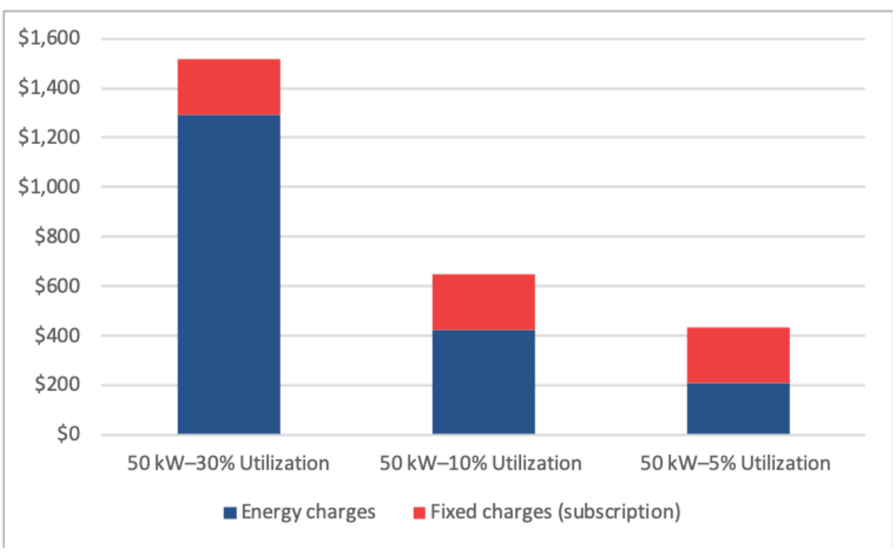
FIGURE 9: MONTHLY UTILITY BILL FOR A 150 KW CHARGER ON THE XCEL TARIFF



PG&E TARIFF

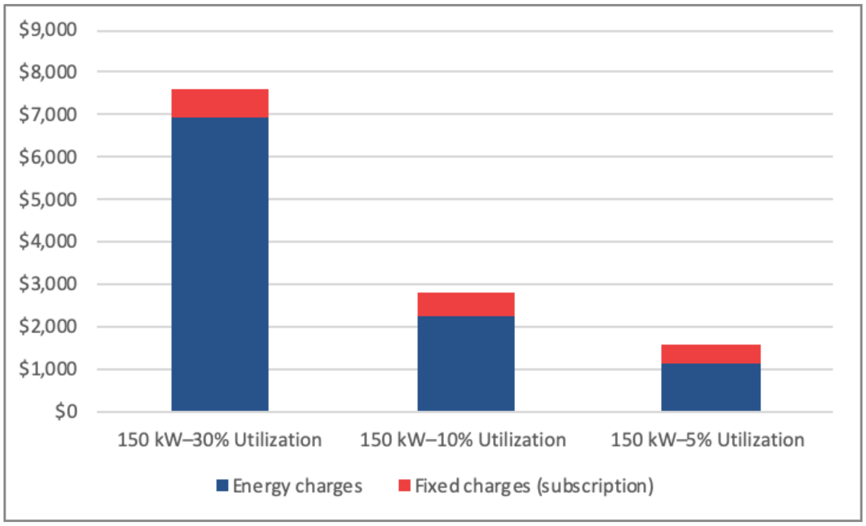
For the 50 kW chargers, the fixed charges make up a shrinking share of the total monthly bill as the utilization rate increases.

FIGURE 10: MONTHLY UTILITY BILL FOR A 50 KW CHARGER ON THE PG&E TARIFF



For the 150 kW chargers, the share of fixed charges shrinks even more as utilization increases, indicating that the tariff will scale well as utilization and power levels increase.

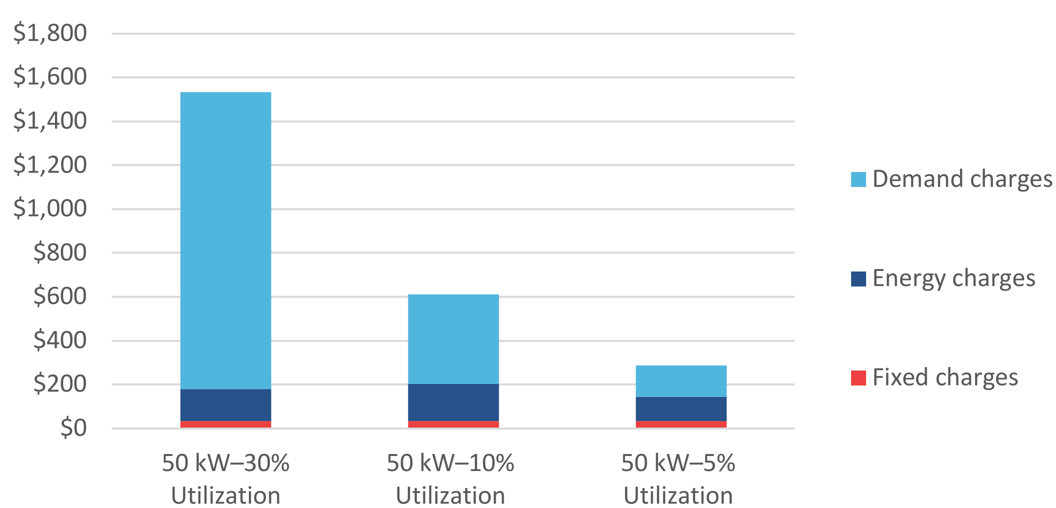
FIGURE 11: MONTHLY UTILITY BILL FOR A 150 KW CHARGER ON THE PG&E TARIFF



RMI TARIFF

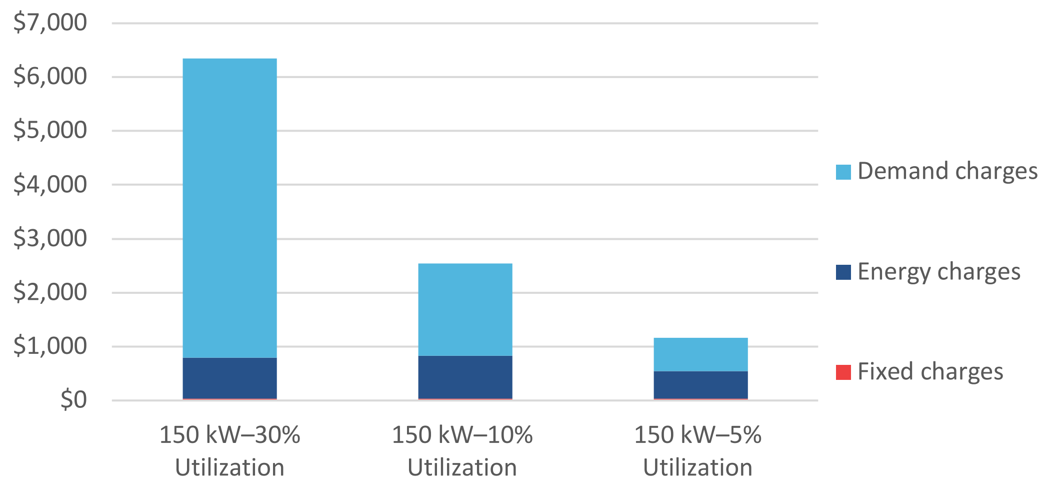
For the 50 kW chargers, demand charges make up a growing share of the total bill as utilization increases, in accordance with the sliding nature of the rate design.

FIGURE 12: MONTHLY UTILITY BILL FOR A 50 KW CHARGER ON THE RMI TARIFF



For the 150 kW chargers, the share of fixed charges becomes trivial, whereas demand charges and energy charges retain roughly the same proportional share of the monthly bill as they do with the 50 kW chargers.

FIGURE 13: MONTHLY UTILITY BILL FOR A 150 KW CHARGER ON THE RMI TARIFF



Per-Mile Costs for Public DCFC

We also calculated the per-mile costs of providing charging service under each of the public DCFC charging scenarios. This way of looking at the data is helpful in understanding what charging network operators have to work with as they try to compete with the cost of refueling using gasoline or diesel. Although the cost of gasoline and diesel varies considerably from place to place across the country, we suggest that charging networks can consider $0.09/mile as the price of conventional refueling that they need to meet or beat.[iii] This suggests that after allowing a 10% profit margin, a charging station operator would need a cost of roughly $0.08/mile or less. However, some charging network operators may need a significantly larger profit margin than 10%, depending on the nature of their financial backing.

XCEL TARIFF

For the 50 kW chargers, the cost per mile of operation under the Xcel tariff will not leave much room for profitability when the market is young and chargers have low (5%) utilization if there are no CPP events, and it will not leave any room for profitability under our worst-case model of a July with seven CPP events. However, the costs are quite manageable when the market matures and utilization rates rise to 30%, if CPP charges can be avoided.

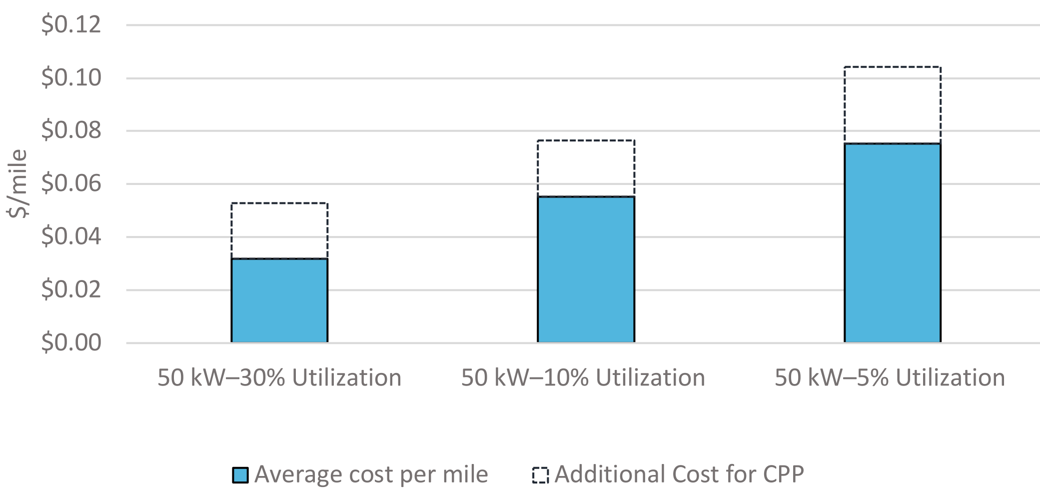
The costs of electricity for a 50 kW charger under the Xcel tariff are as follows:

- At a 5% utilization rate without CPP charges, about $0.075/mile, and about $0.104/mile with charges for seven CPP events.
- At a 10% utilization rate without CPP charges, about $0.055/mile, and about $0.076/mile with charges for seven CPP events.

[iii] We use the top-selling mid-size car in the US—the Toyota Camry with 29 mpg fuel efficiency in the city—as a proxy for the typical internal-combustion vehicle in the US. (source: Focus2Move, https://focus2move.com/usa-best-selling-cars/.) At the current average national cost of gasoline of $2.70/gallon, and the current average cost of gasoline in Colorado at $2.62 (source: AAA, https://gasprices.aaa.com/), the cost per mile for fuel is $0.09/mile.

- At a 30% utilization rate without CPP charges, about $0.031/mile, and about $0.052/mile with charges for seven CPP events.

FIGURE 14: PER-MILE COST FOR A 50 KW CHARGER ON THE XCEL TARIFF

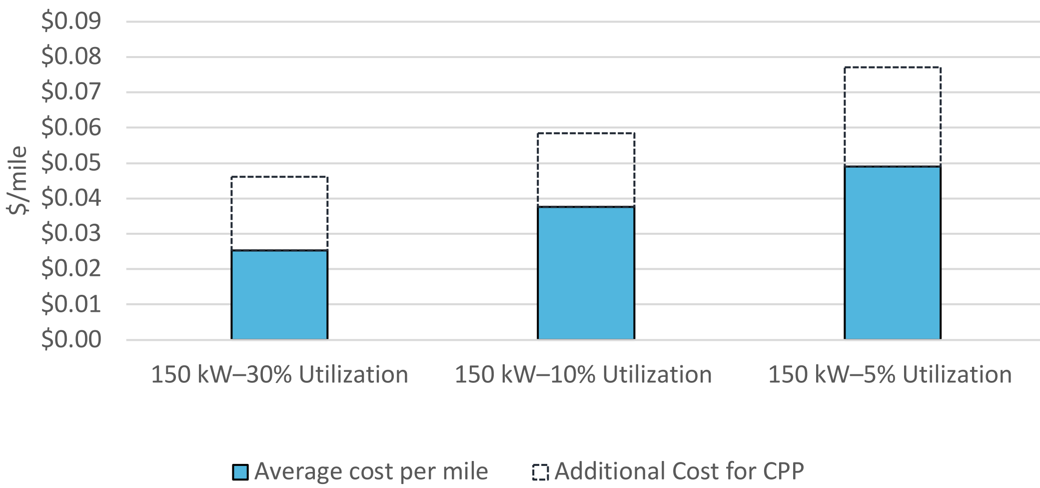


For the 150 kW chargers, the cost per mile of operation under the Xcel tariff should be tolerable for a charging station operator once utilization rates rise above 10%, even in our worst-case model of a July with seven CPP events. However, costs are still challenging when the utilization rate is at 5% and there are seven CPP events. If a charging station operator were able to avoid CPP events entirely, the Xcel tariff would be affordable for 150 kW chargers.

The costs of electricity for a 150 kW charger under the Xcel tariff are as follows:

- At a 5% utilization rate without CPP charges, about $0.049/mile, and about $0.077/mile with charges for seven CPP events.
- At a 10% utilization rate without CPP charges, about $0.038/mile, and about $0.057/mile with charges for seven CPP events.
- At a 30% utilization rate without CPP charges, about $0.025/mile, and about $0.045/mile with charges for seven CPP events.

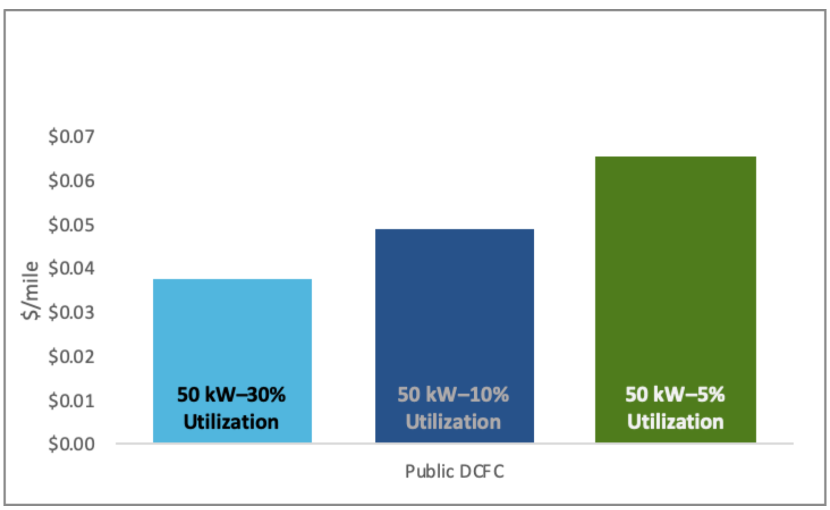
FIGURE 15: PER-MILE COST FOR A 150 KW CHARGER ON THE XCEL TARIFF



PG&E TARIFF

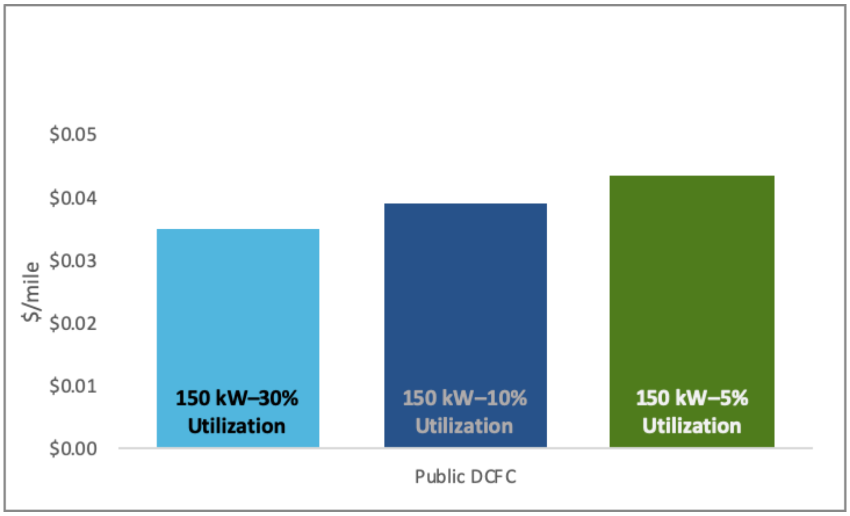
For the 50 kW chargers, the cost per mile under all utilization rates appears to present a reasonable profit opportunity for a charging station operator. The cost of electricity is about $0.065/mile at a 5% utilization rate, about $0.049/mile at a 10% utilization rate, and about $0.038/mile at a 30% utilization rate.

FIGURE 16: PER-MILE COST FOR A 50 KW CHARGER ON THE PG&E TARIFF



For the 150 kW chargers, the cost per mile under all utilization rates appears to present a reasonable profit opportunity for a charging station operator. The cost of electricity is about $0.043/mile at a 5% utilization rate, about $0.039/mile at a 10% utilization rate, and about $0.035/mile at the 30% utilization rate.

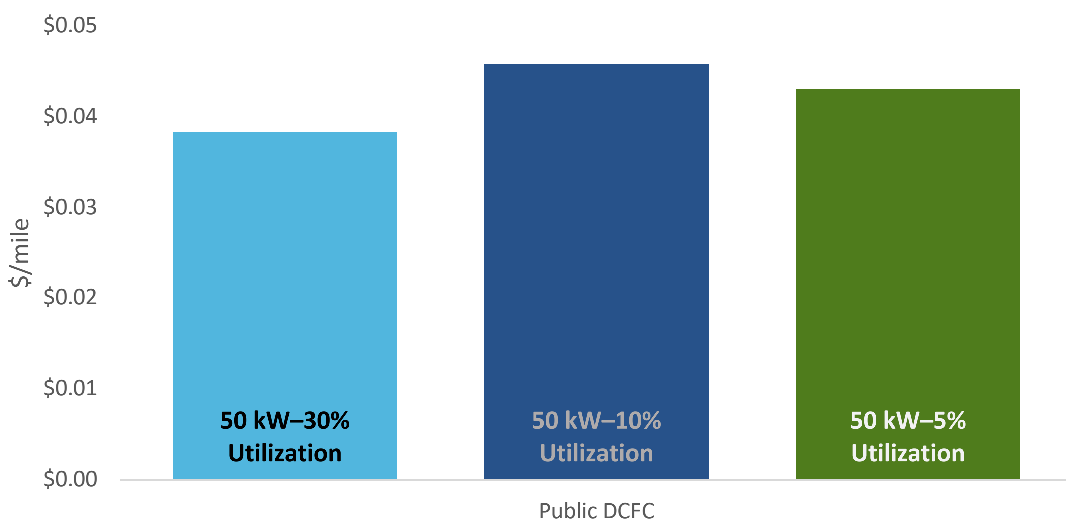
FIGURE 17: PER-MILE COST FOR A 150 KW CHARGER ON THE PG&E TARIFF



RMI TARIFF

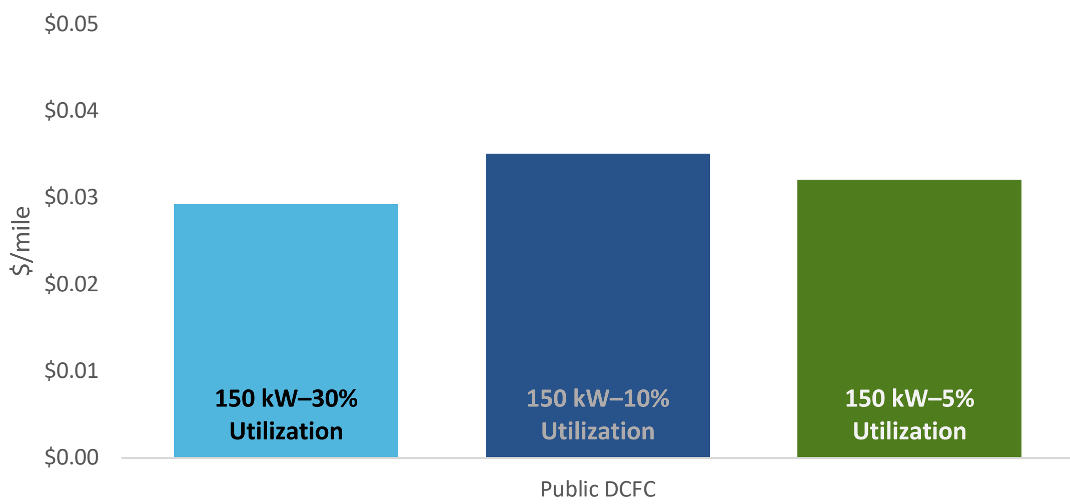
For the 50 kW chargers, the cost per mile under all utilization rates appears to present a reasonable profit opportunity for a charging station operator. The cost of electricity is about $0.043/mile at a 5% utilization rate, about $0.045/mile at a 10% utilization rate, and just under $0.04/mile at the 30% utilization rate.

FIGURE 18: PER-MILE COST FOR A 50 KW CHARGER ON THE RMI TARIFF



For the 150 kW chargers, the costs per mile show a broadly similar distribution across the utilization rates as compared to the 50 kW chargers. The cost of electricity is about $0.032/mile at a 5% utilization rate, about $0.035/mile at a 10% utilization rate, and about $0.029/mile at the 30% utilization rate.

FIGURE 19: PER-MILE COST FOR A 150 KW CHARGER ON THE RMI TARIFF



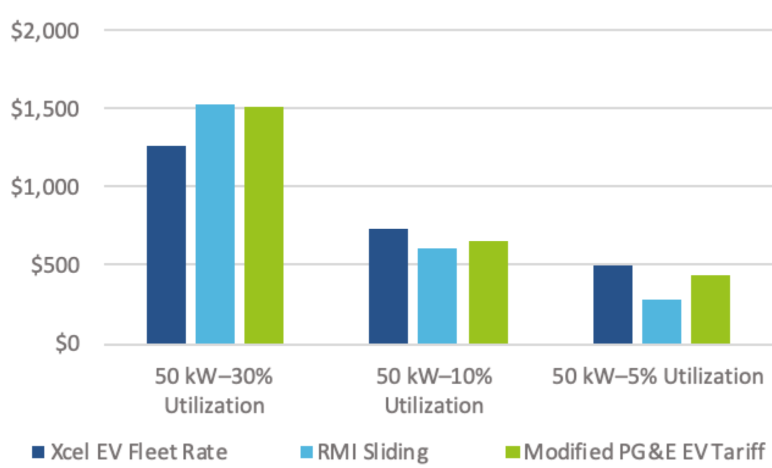
Tariff Comparison for Public DCFC

Here, we compare the three tariffs we analyzed for the public DCFC charging scenarios.

PUBLIC 50 KW CHARGER

For a 50 kW charger, the RMI tariff produces the lowest monthly bill at low utilization but the highest cost at high utilization, just edging out the PG&E tariff.

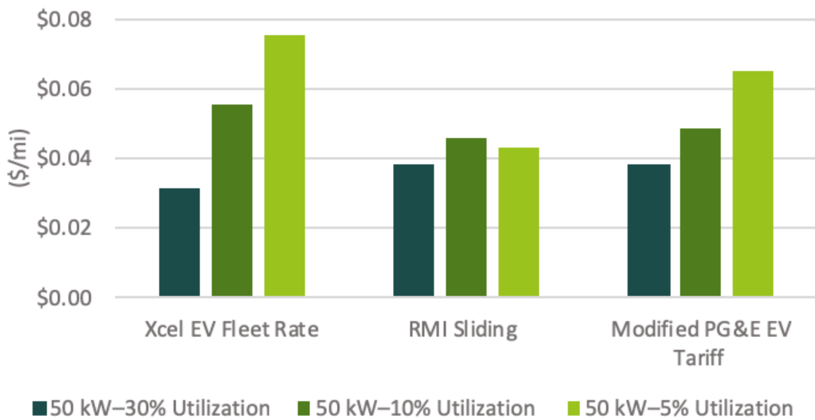
FIGURE 20: MONTHLY BILLS UNDER EACH TARIFF FOR A 50 KW CHARGER



On a per-mile basis, the RMI tariff results in the lowest and most consistent cost per mile for all utilization rates of 50 kW charging stations, although the PG&E tariff produces broadly similar costs. By contrast, the Xcel tariff results in higher costs at the 5% and 10% utilization rates and lower costs at the 30% utilization rate. (In Figure

21, the Xcel costs include the cost of 15 CPP events per year amortized across the year. Under our worst-case scenario of seven CPP events in a single month, as shown in Figure 14, the costs under the Xcel tariff would be significantly higher than they would be under the other two tariffs.)

FIGURE 21: PER-MILE COSTS UNDER EACH TARIFF FOR A 50 KW CHARGER



Note: The Xcel tariff includes costs for 15 CPP events, spread across one year.

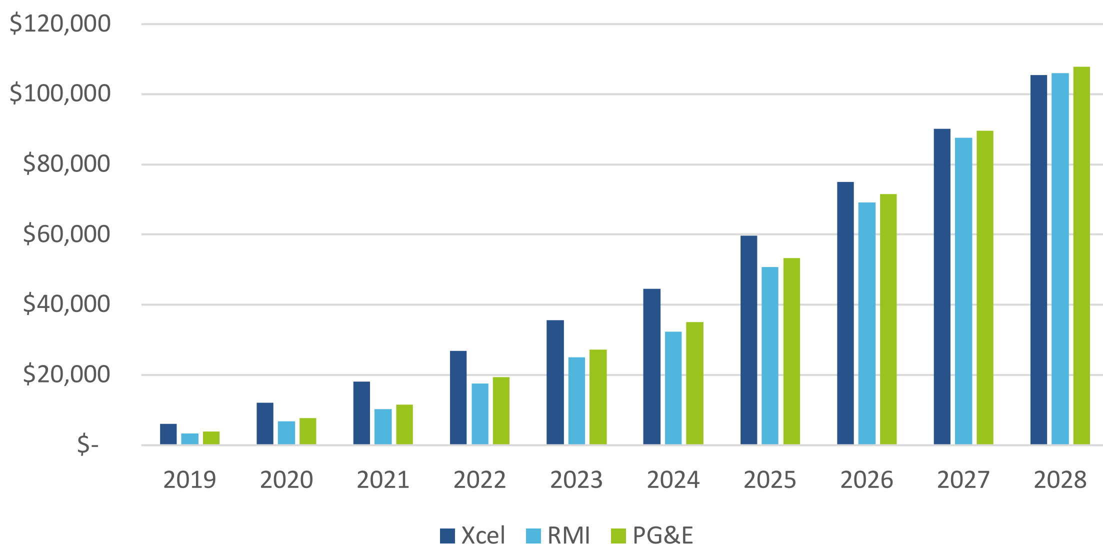
Despite these differences, all three of the tariffs produce very similar revenue over the 10-year modeling period.

TABLE 7: TOTAL REVENUE FROM ALL THREE TARIFFS OVER 10 YEARS FOR A 50 KW STATION

	Total revenue over 10 years
Xcel	$ 105,451
RMI	$ 105,960
PG&E	$ 112,009

The Xcel tariff produces more cumulative revenue than the RMI tariff or the PG&E tariff in each year of the modeling period, until the cumulative revenue from all three tariffs converges in the tenth year.

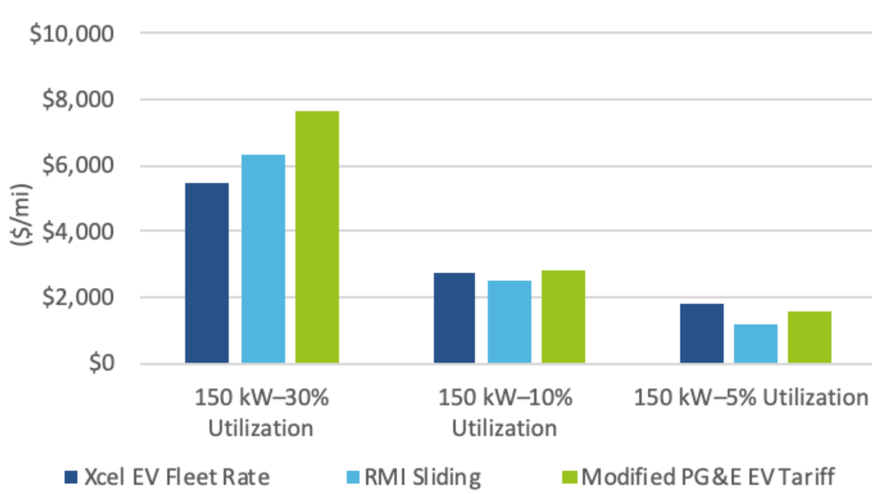
FIGURE 22: CUMULATIVE REVENUE BY YEAR FROM ALL THREE TARIFFS OVER 10 YEARS FOR 50 KW STATIONS



PUBLIC 150 KW CHARGER

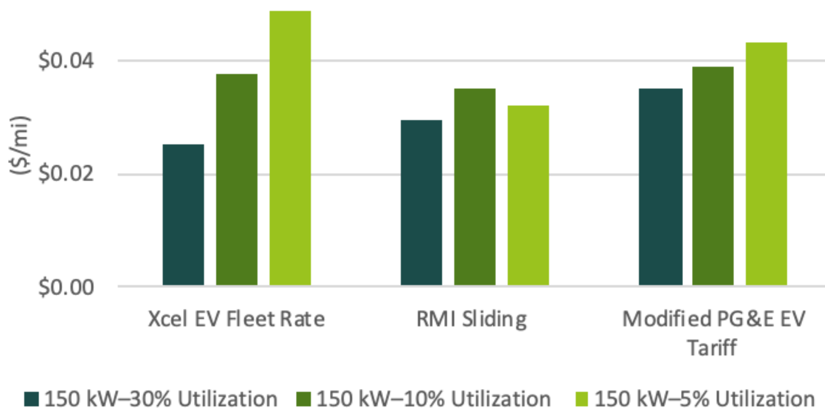
For a 150 kW charger, the RMI tariff produces the lowest monthly bill at low utilization rates. At high utilization, the Xcel tariff produces the lowest monthly bill.

FIGURE 23: MONTHLY BILLS UNDER EACH TARIFF FOR A 150 KW CHARGER



On a per-mile basis, the RMI tariff again produces the most consistent cost per mile for all utilization rates of 150 kW charging stations, as well as the lowest cost for the 5% and 10% utilization rates. At the 30% utilization rate, the Xcel tariff produces the lowest cost, at $0.025/mile, with the RMI tariff a close second at $0.029/mile. (In Figure 24, the Xcel costs include the cost of 15 CPP events per year amortized across the year. Under our worst-case scenario of seven CPP events in a single month, as shown in Figure 15, the costs under the Xcel tariff would be significantly higher than they would be under the other two tariffs.)

FIGURE 24: PER-MILE COSTS UNDER EACH TARIFF FOR A 150 KW CHARGER



Note: Xcel tariff includes costs for 15 CPP events, spread across one year.

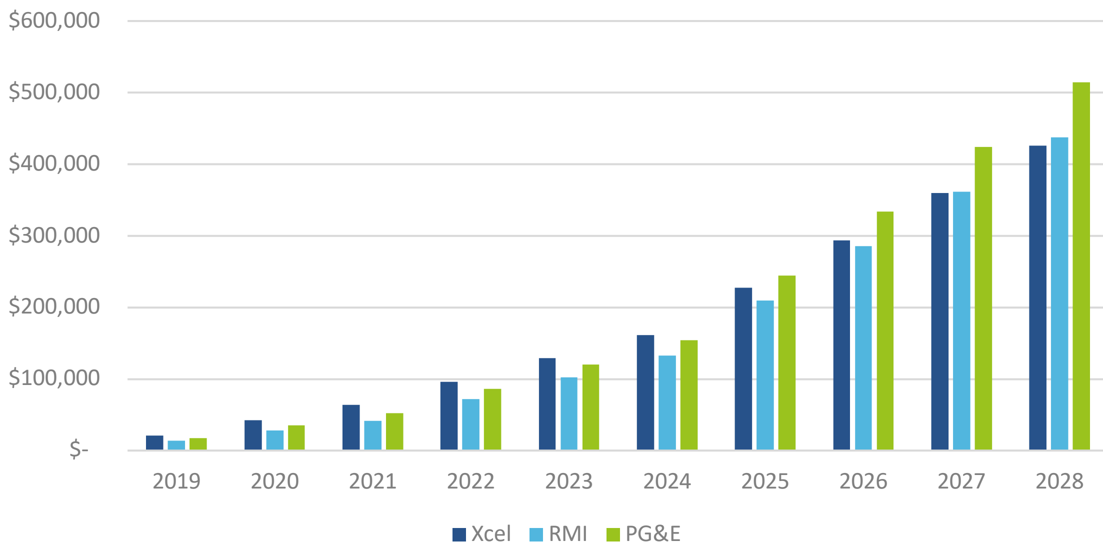
As we explained above, the Xcel and RMI tariffs produce roughly the same total revenue over 10 years because we have designed the RMI tariff to do so, but the PG&E rate produces about 15% more revenue over the modeling period.

TABLE 8: TOTAL REVENUE FROM ALL THREE TARIFFS OVER 10 YEARS FOR 150 KW STATIONS

	Total revenue over 10 years
Xcel	$ 425,556
RMI	$ 437,856
PG&E	$ 523,964

The Xcel tariff produces more cumulative revenue than the RMI tariff or the PG&E tariff each year until the utilization rate goes to 30%, starting in the seventh year of our modeling period, when the cumulative revenue from the PG&E tariff pulls ahead, primarily due to its higher energy charges.

FIGURE 25: CUMULATIVE REVENUE BY YEAR FROM ALL THREE TARIFFS OVER 10 YEARS FOR 150 KW STATIONS



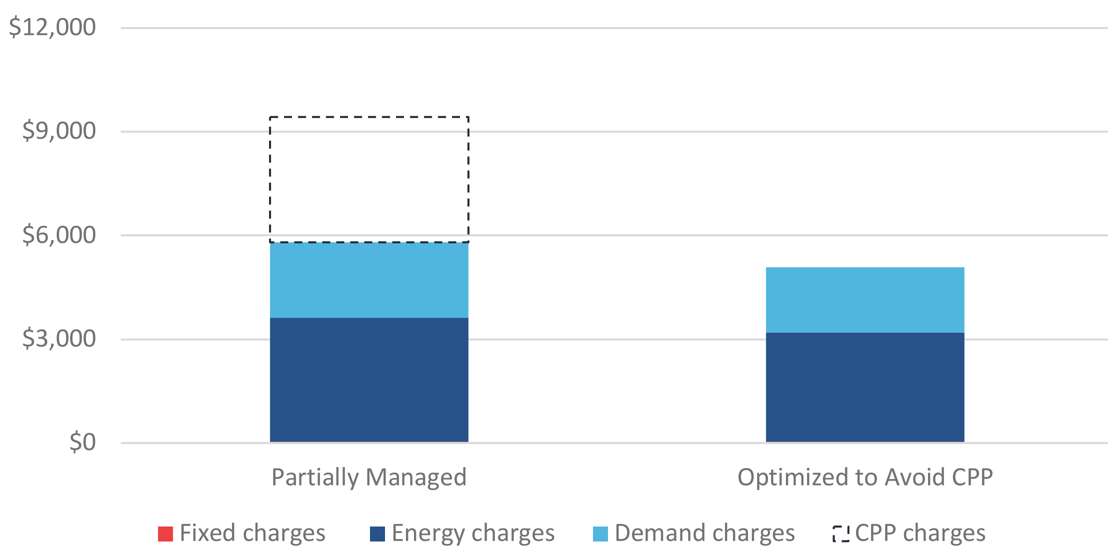
Monthly Bills for Bus Depot

The monthly bills that would result from the three tariffs we analyzed are as follows for the bus depot charging scenarios.

XCEL TARIFF

For the bus depot charging scenarios, the CPP charges on the Xcel tariff have the potential to increase the monthly bill by about one-third. However, the bus transit agency may be able to avoid the CPP adder by never charging between noon and 8 p.m.

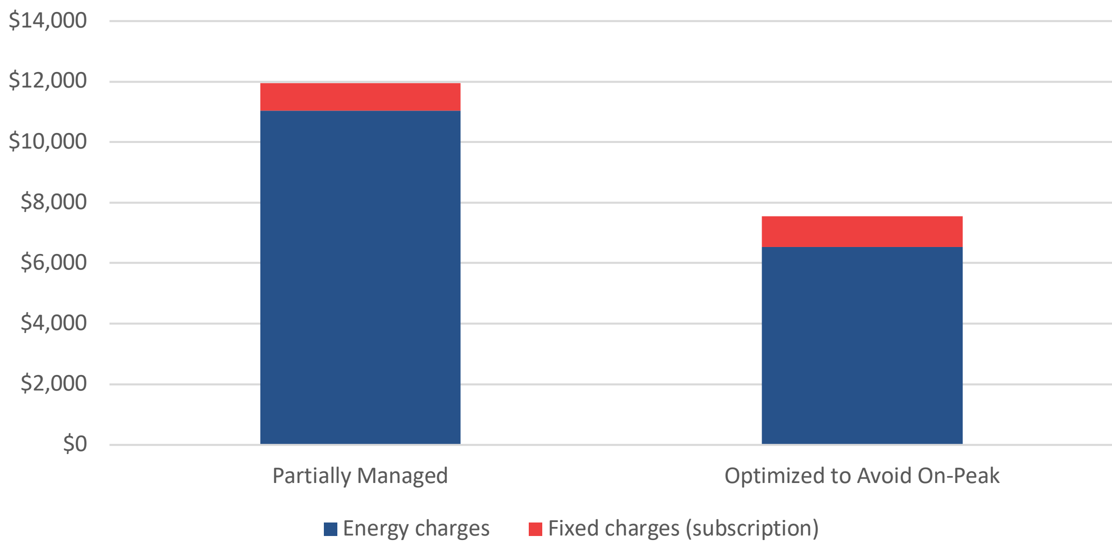
FIGURE 26: MONTHLY BILLS FOR BUS DEPOT ON THE XCEL TARIFF



PG&E TARIFF

For the bus depot charging scenarios, the higher ToU costs for energy on the PG&E tariff will produce a larger monthly bill than under the optimized Xcel tariff with no CPP charges.

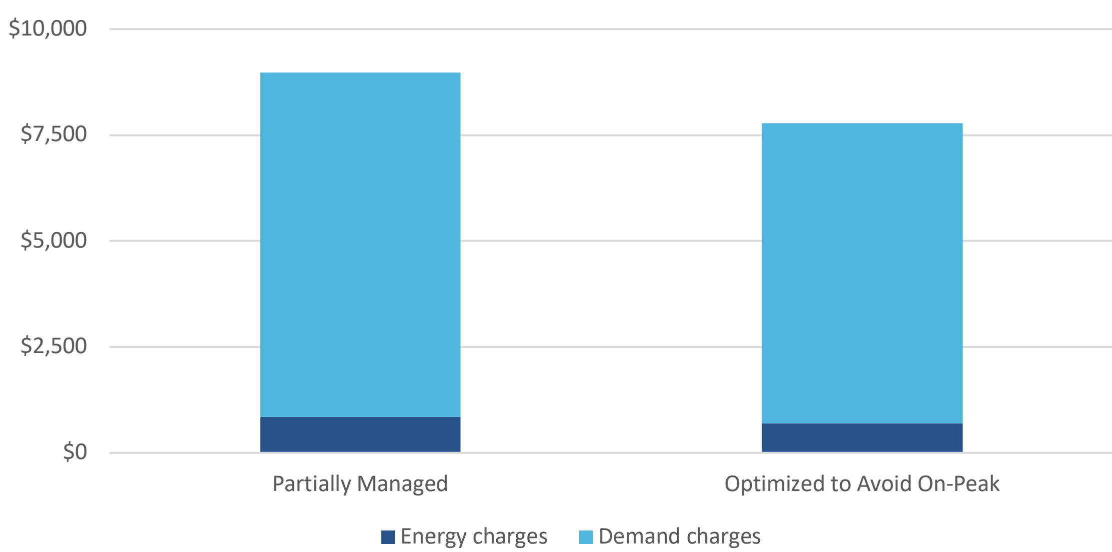
FIGURE 27: MONTHLY BILLS FOR BUS DEPOT ON THE PG&E TARIFF



RMI TARIFF

For the bus depot charging scenarios, the RMI tariff would produce a monthly bill that is similar to what the PG&E tariff would produce under an optimized charging regime.

FIGURE 28: MONTHLY BILLS FOR BUS DEPOT ON THE RMI TARIFF



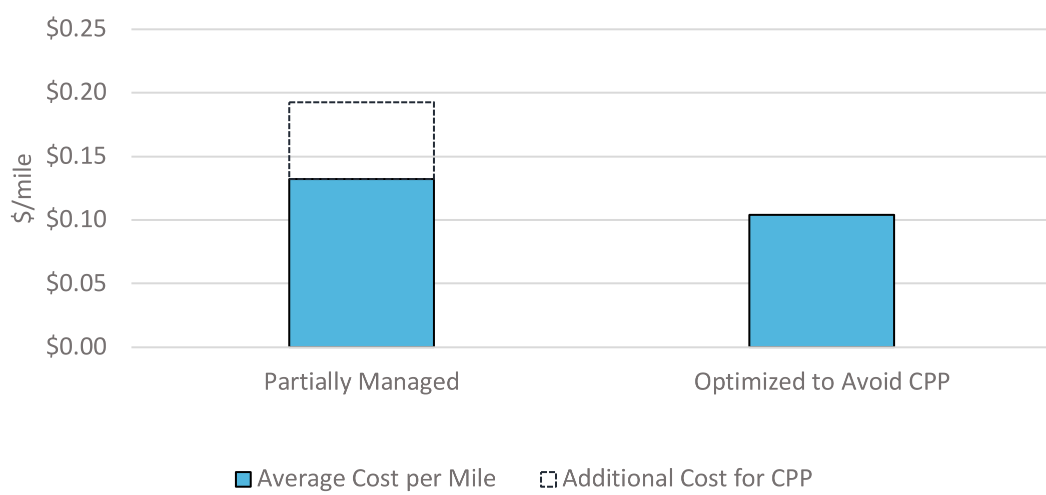
Per-Mile Costs for Bus Depot

The per-mile costs that would result from the three tariffs we analyzed are as follows for the bus depot charging scenarios.

XCEL TARIFF

For the bus depot charging scenarios, the per-mile cost of charging is about $0.10/mile without any CPP charges, and about $0.19/mile under the existing charging regime with seven CPP events in a month. However, the bus transit agency may be able to avoid the CPP adder by never charging between noon and 8 p.m.

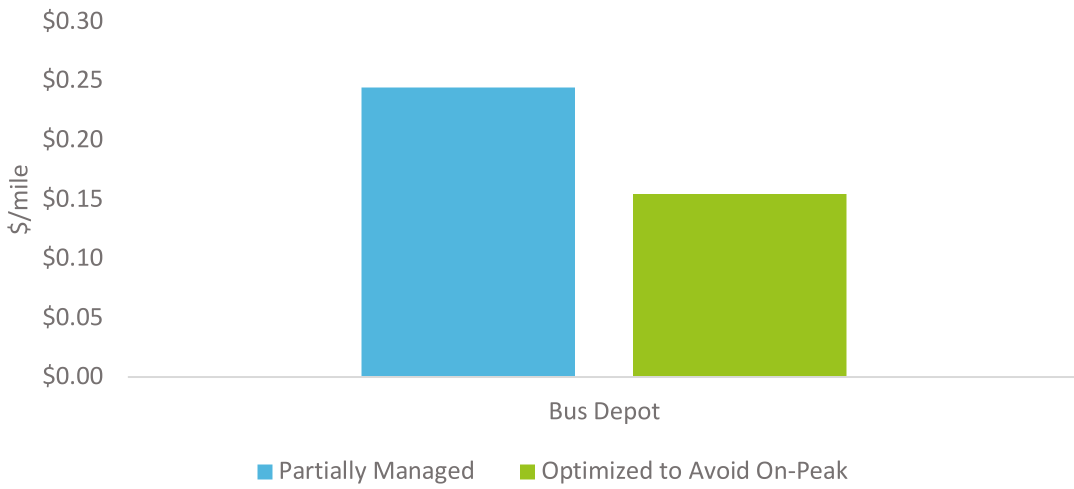
FIGURE 29: PER-MILE COST FOR BUS DEPOT ON THE XCEL TARIFF



PG&E TARIFF

For the bus depot charging scenarios, the per-mile cost of charging is about $0.15/mile if charging can be optimized to avoid the expensive on-peak hours of the ToU rate and about $0.24/mile under RTD's existing charging regime, which is not optimized for the proposed PG&E tariff.

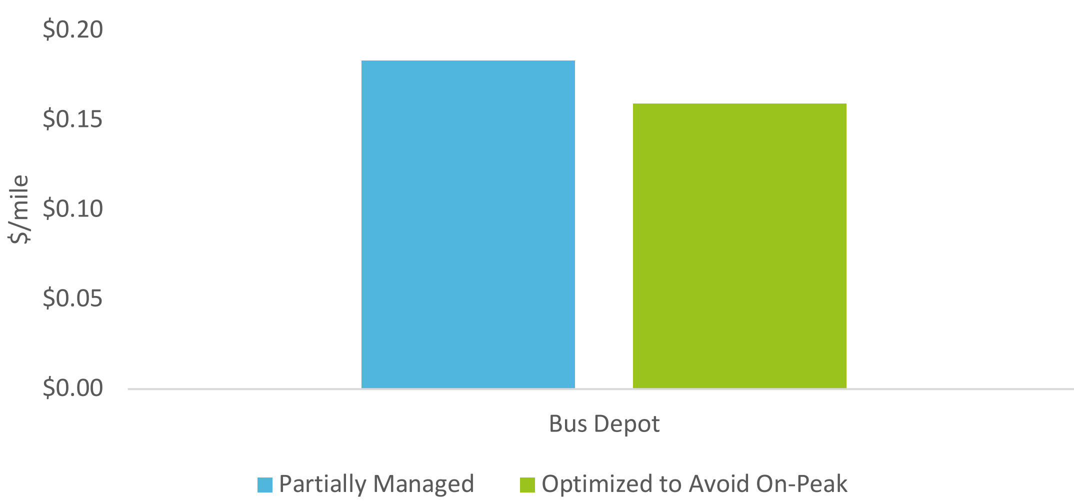
FIGURE 30: PER-MILE COST FOR BUS DEPOT ON THE PG&E TARIFF



RMI TARIFF

For the bus depot charging scenarios, the per-mile cost of charging is about $0.16/mile if charging can be optimized to avoid the expensive on-peak hours of the ToU rate and about $0.18/mile under RTD's existing charging regime, which is not optimized for the proposed RMI tariff.

FIGURE 31: PER-MILE COST FOR BUS DEPOT ON THE RMI TARIFF

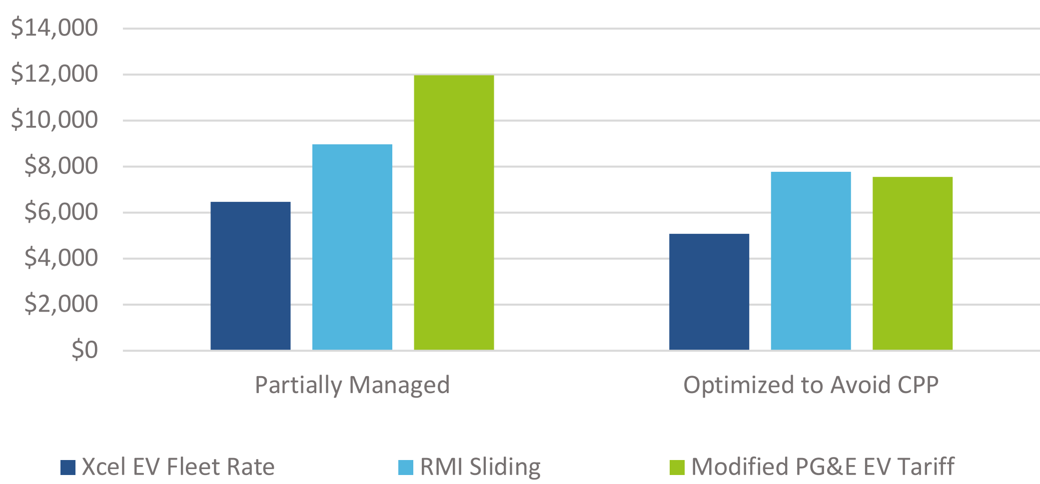


Tariff Comparison for Bus Depot

Here, we compare the three tariffs we analyzed for the bus depot charging scenarios.

The monthly bill for RTD would be lowest under Xcel's proposed tariff for both the existing partially managed charging scenario and for the optimized charging scenario designed to avoid CPP charges. The monthly bills would be quite similar for the optimized scenario under the PG&E and RMI tariffs.

FIGURE 32: MONTHLY BILL COMPARISON FOR BUS DEPOT



On a per-mile basis, the cost of charging buses will again be lowest under the proposed Xcel tariff for both the partially managed and optimized scenarios, and would be very similar for the optimized scenario under the PG&E and RMI tariffs.

FIGURE 33: PER-MILE COST COMPARISON FOR BUS DEPOT

RECOMMENDATIONS

We believe that the most important metric by which to judge these three tariff designs is the cost per mile, because charging network operators will have to meet or beat the cost of refueling a conventional petroleum-powered vehicle. If charging a vehicle at a high-speed public charging station is more expensive than refueling with gasoline or diesel, it is unlikely that widespread consumer adoption of EVs will materialize, because only about one-third of US residents live in single-family homes,[4] and not all of them have a suitable location (such as a garage) for charging an EV overnight. Although we unreservedly advocate EV charging on slower Level 1 or Level 2 chargers wherever practical, high-speed public DCFCs must be at least as available as filling stations are today before many consumers will be comfortable making an EV their primary vehicle.

Therefore, operators of public high-speed charging stations must be able to deliver a cost per mile for charging at or below roughly $0.09/mile—the equivalent cost of gasoline for a 2019 Toyota Camry—while still having some profit margin.[iv] As explained above, assuming a 10% profit margin, operators of DCFC charging networks must, on average, see a cost of delivered electricity no higher than $0.08/mile. While we recognize that electricity, gasoline, and diesel costs and the fuel efficiency of both conventional vehicles and EVs all vary considerably from place to place and model to model, we believe that $0.09/mile is a reasonable general maximum limit for the purpose of evaluating EV tariffs.

As our analysis shows, the RMI tariff design results in the most consistent cost per mile for all utilization rates of both 50 kW and 150 kW public DCFC charging stations, which is due to its sliding-scale design. The RMI tariff also delivers energy at the lowest cost on a per-mile basis for public DCFC stations at the 5% and 10% utilization rates. Even in the worst-case example for the RMI tariff (10% utilization), it delivers energy at a cost of $0.046/mile for a 50 kW charger and $0.035/mile for a 150 kW charger (see Figure 21 and Figure 24), which is well below the design limit of $0.09/mile.

Because the RMI tariff results in the lowest cost of energy at the 5% utilization rate—which, of the utilization rates we modeled, is the closest to typical real-world experience—we believe it should be given due consideration. It is vital, while EV adoption is still in its early days and utilization rates on public DCFCs are low, that costs are low enough to encourage charging station operators to continue to deploy more public charging stations. We remind the reader that even though it produces the lowest cost at low utilization rates, the RMI tariff is designed to generate the same revenue as Xcel would receive under its own tariff design over 10 years in our modeling.

We also remind the reader that the precise costs we have assigned in this model to the fixed charge, energy charges, and demand charges in the RMI tariff are all selected to match the Colorado utility ratemaking context using Xcel Colorado's proposed tariff and contemporary charges as a proxy. Were another utility or state to implement the RMI tariff design, it may very well use different prices for each of the charges. The relevance of our tariff is not in the specific costs assigned to each of its components, but rather its sliding-scale design.

The PG&E tariff produces results for public DCFCs that are quite similar to those for the RMI tariff, reflecting the fact that it was designed to deliver fairly stable prices for DCFCs in particular. Recognizing that we adjusted the components of the PG&E tariff so that it would reflect typical energy costs in Colorado, one might reasonably ask whether our adjustments were accurate enough to lend significance to the difference between the results of the PG&E and the RMI modeling.

[iv] We use the top-selling mid-size car in the US—the Toyota Camry with 29 mpg fuel efficiency in the city—as a proxy for the typical internal-combustion vehicle in the US. (source: Focus2Move, https://focus2move.com/usa-best-selling-cars/.) At the current average national cost of gasoline of $2.70/gallon, and the current average cost of gasoline in Colorado at $2.62 (source: AAA, https://gasprices.aaa.com/), the cost per mile for fuel is $0.09/mile.

If all CPP charges can be avoided, the Xcel tariff could deliver the lowest costs once the market matures. However, the Xcel tariff will leave very little room for profitability when the market is young and chargers have low utilization, even when there are no CPP events, and it will not leave any room for profitability under our worst-case model of a July with seven CPP events. Therefore, we cannot recommend the Xcel tariff for public DCFCs.

Given these results, of the three tariffs we analyzed, we believe the RMI tariff strikes the best balance for public DCFC installations. By varying charges as a function of utilization, it is possible to satisfy three key objectives simultaneously: creating an attractive business opportunity to charging network operators, keeping the cost of charging at or below the equivalent cost of refueling a conventional gasoline or diesel vehicle, and permitting an appropriate level of cost recovery for the host utility.

For the bus depot, our analysis shows that the average cost per mile is lowest under Xcel's S-EV tariff for both charging scenarios we analyzed. Accordingly, we recommend Xcel's tariff as the optimal one for the public bus transit agency. As discussed above, the chief advantage of the RMI tariff is its ability to scale with utilization, but utilization will be more or less constant for any given number of buses being recharged at a bus depot. Therefore, the sliding-scale feature of the RMI tariff isn't advantageous for a bus depot use case, where the higher demand charges in the RMI tariff would impose higher costs on the transit agency. The Xcel tariff will be particularly desirable for the bus transit agency if the fleet managers can avoid the CPP adder on the Xcel tariff by never charging between noon and 8 p.m.

As a general matter, cost causation—the core principle of rate design—still needs more empirical support where DCFCs are concerned.

Conceptually, the CPP approach of the Xcel tariff is sound in that it specifically targets the recovery of high marginal costs when system capacity is constrained, and it affords at least the possibility that a DCFC operator might attempt to avoid those charges. However, if the CPP charges cannot be avoided for public DCFC stations, the Xcel tariff will be too expensive to encourage charging network operators to deploy more chargers. And, to the best of our knowledge, none of the public DCFC station operators offer price signals, or other incentives or disincentives, that would cause their users to avoid using the stations during high-cost hours, so they would be unlikely to be able to avoid CPP charges that way. (It may be economically sound for them to use on-site battery storage to avoid incurring CPP charges, but determining that is a study in itself.)

Equally, one might reasonably ask whether the high fixed charge in the PG&E tariff, or the high demand charge incurred at high utilization in the RMI tariff irrespective of coincidence with system peaks, appropriately recover the costs of providing service to a DCFC under those tariffs. One might also interrogate whether the costs recovered are strictly limited to costs the utility incurs at the DCFC's interconnection point, which would justify recovering those costs from the operator of the DCFC, or whether the costs incurred are somewhere upstream from the interconnection point and therefore should be more broadly socialized. Accordingly, we recommend that regulators ask utilities to demonstrate in detail the actual costs that DCFC stations impose on their systems, in order to develop an accurate understanding of those costs and to evaluate whether recovering those costs through a DCFC-targeted tariff is warranted.

ENDNOTES

[1] Garrett Fitzgerald and Chris Nelder, *EVgo Fleet and Tariff Analysis*, RMI, March 2017, www.rmi.org/wp-content/uploads/2017/04/eLab_EVgo_Fleet_and_Tariff_Analysis_2017.pdf

[2] Colorado Public Utilities Commission Proceeding Number 19AL-0290E https://www.dora.state.co.us/pls/efi/EFI.Show_Filing?p_fil=G_755521&p_session_id=

[3] Prices for June 2018. ElectricChoice (last updated March 2019), www.electricchoice.com/electricity-prices-by-state

[4] National Multifamily Housing Council, www.nmhc.org/research-insight/quick-facts-figures/quick-facts-resident-demographics

22830 Two Rivers Road
Basalt, Colorado 81621 USA
www.rmi.org

The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 20-69 July 2, 2020

Investigation by the Department of Public Utilities on its own Motion into the Modernization of the Electric Grid – Phase Two.

VOTE AND ORDER OPENING INVESTIGATION

I. INTRODUCTION

On May 10, 2018, the Department of Public Utilities ("Department") issued an Order approving the first Grid Modernization Plans for Massachusetts Electric Company and Nantucket Electric Company, d/b/a National Grid ("National Grid"), Fitchburg Gas and Electric Light Company d/b/a Unitil ("Unitil"), and NSTAR Electric Company d/b/a Eversource Energy ("Eversource")[1] (collectively, "Companies"). Grid Modernization, D.P.U. 15-120/D.P.U. 15-121/D.P.U. 15-122 (2018) ("Grid Modernization Order"). The Department preauthorized several grid-facing investment categories, subject to a company-specific budget cap, for a three-year investment term from 2018 through 2020.[2] D.P.U. 15-120/D.P.U. 15-121/D.P.U. 15-122, at 107-108, 113-114. The Department declined, however, to preauthorize the Companies' proposed customer-facing grid modernization investments because our review of the business cases for full deployment of advanced metering functionality showed that the anticipated benefits of these investments did not justify the substantial costs. Grid Modernization Order at 117-135.

---

1 A Grid Modernization Plan was filed in D.P.U. 15-122 by NSTAR Electric Company and Western Massachusetts Electric Company. Subsequently, in NSTAR Electric Company and Western Massachusetts Electric Company, D.P.U. 17-05, at 36-55 (2017), the Department approved the corporate consolidation of Western Massachusetts Electric Company with and into NSTAR Electric Company pursuant to G.L. c. 164, § 96.

2 On May 12, 2020, the Department extended the current three-year Grid Modernization Plan investment term through 2021 and established a revised filing date for the subsequent grid modernization plans of July 1, 2021. Grid Modernization, D.P.U. 15-120-D/D.P.U. 15-121-D/D.P.U. 15-122-D at 7 (2020).

In particular, the Department found that the substantial operational savings previously achieved by the Companies through the automated meter reading ("AMR") meters already in use in the Commonwealth, combined with the significant stranded costs that would be incurred to replace these AMR meters prematurely, made full deployment of advanced metering infrastructure difficult to achieve in a cost-effective manner. Grid Modernization Order at 121-124. Also, the Department determined that the costs to upgrade a company's billing and meter data management systems to accommodate deployment of advanced metering functionality further complicated the cost equation. Grid Modernization Order at 121-124.

In addition, the Department determined that customer participation in time-varying rates ("TVR") or other dynamic pricing programs was needed to maximize the benefits of advanced metering functionality. Grid Modernization Order at 133, 136. The Department questioned the reliability of the Companies' customer participation rate assumptions, which added to the uncertainty of the likely benefits from proposed customer-facing grid modernization investments. Grid Modernization Order at 129. The Department found that the increasing number of customers on competitive supply, especially as a result of the recent growth of municipal aggregation in the Commonwealth, further reduced the anticipated benefits of a full deployment of advanced metering functionality as it could significantly curtail the number of customers that can participate in TVR. Grid Modernization Order at 125.

Finally, the Department determined that price fluctuations in the forward capacity market added further uncertainty in achieving anticipated benefits from peak demand reduction. We determined that the forecast of forward capacity market prices used by the Companies to monetize the benefits of peak demand reduction achieved through TVR was not reflective of actual forward capacity market conditions. Grid Modernization Order at 131-132.

In sum, the Department concluded that the anticipated benefits of the Companies' proposed customer-facing investments in advanced metering functionality did not justify the substantial costs. Grid Modernization Order at 134. Our inquiry into advanced metering functionality, however, does not end there. In the Grid Modernization Order, at 135-137, we identified several issues concerning deployment of advanced metering functionality appropriate for further investigation. The Department now opens this second phase of our grid modernization investigation to consider the next appropriate steps for deployment of advanced metering functionality in the Commonwealth.

II. SCOPE OF INVESTIGATION

In the Grid Modernization Order, at 3, 124-135, the Department found significant barriers to a full deployment of advanced metering functionality and indicated that we would consider whether a targeted deployment of advanced metering functionality to certain customer groups would yield benefits that justify the costs. In this proceeding, the Department will explore whether a targeted deployment of customer-facing technologies to electric vehicle ("EV") customers, including residential customers, low-income customers, commercial and industrial ("C&I") customers, and EV charging site hosts, is appropriate.

EV customers currently are a small, but rapidly growing, subset of electric customers in the Commonwealth.[3] And, importantly, EV-charging load has the potential to be significant.[4] Continued growth in the EV sector will be critical to the achievement of the

---

[3] For example, the Department of Energy Resources recently expanded the MOR-EV rebate program for the purchase of electric vehicles to include commercial and nonprofit fleets as well as passenger vehicles. See Baker-Polito Administration Expands Electric Vehicle Program to Include Commercial and Nonprofit Fleets, available at: https://www.mass.gov/news/baker-polito-administration-expands-electric-vehicle-rebate-program-to-include-commercial-and (June 25, 2020). Since the program first launched in June 2014, over 16,000 EVs were purchased in Massachusetts with rebates through the MOR-EV program. See Massachusetts Offers Rebates for Electric Vehicles, MOR-EV Program Statistics, available at: https://mor-ev.org/program-statistics (last updated June 23, 2020).

[4] The Smart Electric Power Alliance reports that, in addition to increases in volumetric electric loads, a typical EV charger consumes approximately 3.3 to 10.0 kilowatts ("kW") of demand, which can exceed the total peak demand of a home. In addition, charging loads for vehicles with larger batteries can be up to 20 kW. Smart Electric Power Alliance, A Comprehensive Guide to Electric Vehicle Managed Charging, at Table 1 (2019).

Additionally, the U.S. Department of Energy estimates that a typical EV can require approximately 24 to 50 kW-hours of electricity to drive 100 miles. See U.S. Department of Energy, Power Search, available at: https://www.fueleconomy.gov/feg/powerSearch.jsp (sorted by "Model Year 2020-2021" and "Vehicle Type All Electric") (last visited July 1, 2020). Based on the average annual vehicle miles driven per capita in Massachusetts (i.e., 9,100 miles), a typical EV may consume between 2,184 and 4,550 kW-hours of electricity annually in the Commonwealth. See Office of Energy Efficiency & Renewable Energy, FOTW #113, December 23, 2019: Average Annual Highway Vehicle Miles Traveled Per Capita Varies by State, available at: https://www.energy.gov/eere/vehicles/articles/fotw-1113-december-23-2019-average-annual-highway-vehicle-miles-traveled (2019).

Commonwealth's statewide goal of lowering carbon emissions 80 percent by 2050.[5, 6] In addition, EV-charging load is both discrete and controllable, and EV customers are likely to be motivated to manage their charging behavior if they are given appropriate price signals or

---

5 The Global Warming Solutions Act ("GWSA") requires the Commonwealth to reduce its greenhouse gas emissions by at least 80 percent below 1990 levels by 2050. St. 2008, c. 298, § 3. Further, pursuant to the GWSA, on April 22, 2020, the Baker-Polito Administration established a statewide net zero emissions limit for 2050 as "necessary to adequately protect the health, economy, people and natural resources of the Commonwealth...." Executive Office of Energy and Environmental Affairs, Determination of Statewide Emissions Limits for 2050, available at: https://www.mass.gov/doc/final-signed-letter-of-determination-for-2050-emissions-limit/download (2020).

6 The Executive Office of Energy and Environmental Affairs ("EEA") has estimated that the transportation sector will account for more than 40 percent of all greenhouse gas emissions in 2020. Executive Office of Energy and Environmental Affairs, Massachusetts Clean Energy and Climate Plan for 2020, at 86, available at: https://www.mass.gov/files/documents/2017/12/06/Clean%20Energy%20and%20Climate%20Plan%20for%202020.pdf (December 31, 2015). To address these emissions levels, in December 2018, the Commission on the Future of Transportation in the Commonwealth recommended that Massachusetts (1) develop standards for EVs to charge during off-peak hours and be available to deliver energy to the grid during peak hours, and (2) establish a goal that all new cars, light duty trucks, and buses sold in Massachusetts be electric by 2040. Commission on the Future of Transportation in the Commonwealth, Choices for Stewardship: Recommendations to Meet the Transportation Future (Executive Summary), at 8, available at: https://www.mass.gov/doc/choices-for-stewardship-recommendations-to-meet-the-transportation-future-executive-summary/download (last visited July 1, 2020). In addition, EEA has stated that it intends to release its 2050 Decarbonization Roadmap Report and 2030 Clean Energy and Climate Plan before the end of 2020. Executive Office of Energy and Environmental Affairs, MA Decarbonization Roadmap, available at: https://www.mass.gov/info-details/ma-decarbonization-roadmap (last visited July 1, 2020).

incentives.[7] For these reasons, the Department will investigate the targeted deployment of advanced metering functionality to EV customers.

Advanced metering functionality includes a broader range of technology than just advanced metering infrastructure ("AMI") or "smart meters." Accordingly, the Department's investigation will include a full range of cost-effective options in addition to standard AMI technology. The Department expects that, at a minimum, a targeted deployment of advanced metering functionality to basic service EV customers will help establish the groundwork for future deployment of advanced metering functionality to other customer segments.

An investigation into a targeted deployment of advanced metering functionality to EV customers necessarily involves the exploration of TVR designs and other dynamic pricing options[8] that would enable these customers to take advantage of the benefits of advanced metering functionality. TVR should provide effective price signals to customers so that they can take actions that will contribute to reducing system peak demand. In this proceeding, the Department will investigate potential TVR designs for EV customers receiving basic service. Further, the Department will consider whether TVR options for these customers should

---

7 For example, research has found that, for utilities that adopted off-peak EV charging rates, 90 percent of customers responded to the price signals. Smart Electric Power Alliance, Residential Electric Vehicle Rates That Work, at 11 (2019).

8 The Department's use of the term "TVR" in this Order includes the full range of dynamic pricing options for EV customers. As part of this investigation, the Department will consider any implementable TVR design or other dynamic pricing options that are expected to deliver benefits to customers.

include both supply and distribution rates. Although the Department's primary focus will be on basic service EV customers, the Department will also consider what requirements must be met to allow EV customers on competitive supply (and, in particular, EV customers that are in a municipal aggregation program) to participate in TVR to achieve the benefits of advanced metering functionality.

In the Grid Modernization Order, at 121-124, 133-134, the Department determined that the costs associated with necessary upgrades to the Companies' various systems to support advanced metering functionality was a factor that weighed against full deployment. Accordingly, the Department will also investigate the current capabilities of each company's systems to support advanced metering functionality for EV customers. Specifically, the Department will investigate the current status, constraints, and flexibility of each company's metering, data management, communications, and billing systems as they relate to incorporating advanced metering functionality.

Additionally, in the Grid Modernization Order, at 136, the Department noted that alternative metering solutions may exist to enable a cost-effective deployment of advanced metering functionality without resorting to a costly early replacement of AMR meters. In the context of examining a targeted deployment of advanced metering functionality to EV customers, the Department will explore whether any alternative solutions may be compatible with the Companies' current communications, data management, and billing systems to allow each company to collect and communicate interval data without prematurely retiring existing AMR meters.

Last, as we noted in the Grid Modernization Order, at 121-122, 133-134, the potential for stranded costs is a significant impediment to a full deployment of advanced metering functionality. Accordingly, the Department will examine end-of-life meter replacement strategies[9] that will support our grid modernization objectives[10] and limit or avoid stranded costs.

The Department expects that this proceeding will inform the customer-facing investments that the Companies will incorporate into their future grid modernization investment plans. In order to facilitate the conduct of the investigation in an efficient manner, the scope of the proceeding will be limited to the issues identified above.

III. REQUEST FOR COMMENTS

To begin phase two of our investigation, the Department seeks written comments from the Companies and other interested stakeholders on the questions below. Comments should be filed no later than 5:00 p.m. on August 13, 2020.[11] Reply comments should be filed no later than 5:00 p.m. on September 4, 2020.

---

[9] The investigation will also consider cost recovery associated with end-of-life meter replacement strategies.

[10] The Department has established the following grid modernization objectives: (1) optimize system performance (by attaining optimal levels of grid visibility, command and control, and self-healing); (2) optimize system demand (by facilitating consumer price-responsiveness); and (3) interconnect and integrate distributed energy resources. Grid Modernization Order at 99-106.

[11] On March 10, 2020, Governor Baker issued a State of Emergency related to COVID-19. Ordinarily, commenters would follow Sections B.1 and B.4 of the Department's Standard Ground Rules regarding the filing of documents. See Electronic Filing Guidelines, D.P.U. 15-184-A, App. 1 (March 4, 2020). However,

1. Please discuss all factors the Department should consider when determining whether a targeted deployment of advanced metering functionality to EV customers is appropriate. As part of your response, identify any unique factors that should be considered for particular EV customer segments (e.g., residential customers, low-income customers, C&I customers, EV charging site hosts).

2. Please:

   a. describe generally what basic service supply TVR design options each company should make available to the following EV customer segments: (1) residential EV customers; (2) C&I EV customers; and (3) EV charging site hosts. Identify and discuss the basis for any differences between TVR design options for each EV customer segment;

   b. with respect to the C&I EV customer segment, discuss whether a separate TVR design option should apply to EV fleets;

---

at this time, all filings will be submitted only in electronic format in recognition of the difficulty that commenters and the Department may have filing and receiving original copies. Until further notice, commenters must retain the original paper version of all comments and the Department will later determine when the paper version must be filed with the Department Secretary.

All written comments must be submitted to the Department in .pdf format by email attachment to Peter.Ray@mass.gov, and Hearing Officers Tina.Chin@mass.gov and Sarah.Spruce@mass.gov. The text of the email must specify: (1) the docket number of the proceeding (D.P.U. 20-69); (2) the name of the person or company submitting the filing; (3) a brief descriptive title of the document; and (4) the name, title, email address, and telephone number of a person to contact in the event of questions about the filing. Importantly, all large files submitted must be broken down into electronic files that **do not exceed 20 MB**.

All documents submitted to the Department will be available on the Department's website as soon as is practicable at https://eeaonline.eea.state.ma.us/DPU/Fileroom/dockets/bynumber (enter "20-69"). Paper copies of documents will not be available for public viewing at the Department due to the State of Emergency. To request materials in accessible formats (Braille, large print, electronic files, audio format) for people with disabilities, contact the Department's ADA coordinator at DPUADACoordinator@mass.gov.

c. for each identified basic service supply TVR design option, discuss whether there should be an accompanying distribution TVR design option;

d. for each identified TVR design option in (a) through (c), discuss whether the TVR should apply only to the EV-charging portion of the customer's load or to the customer's entire load;

e. for each identified TVR design option in (a) through (c), discuss how it is designed to provide effective price signals to EV customers so that they can take actions that will contribute to reducing system peak demand; and

f. where applicable, provide citations to jurisdictions where the identified TVR design options have been applied.

3. Please discuss how municipal aggregators can facilitate the participation of their EV customers in TVR to achieve the benefits of advanced metering functionality.

4. (Companies only) Please:

a. describe the current status of your company's metering, data management, communications, and billing systems as they relate to incorporating advanced metering functionality for EV customers;

b. identify any limitations or constraints in your company's existing metering, data management, communications, and billing systems that would serve as barriers to implementing the specific TVR designs for EV customers identified by commenters in response to question 2; and

c. discuss all solutions and the associated costs that would allow your company to accommodate the TVR designs for EV customers identified in response to question 2 using its existing metering, data management, communications, and billing systems.

5. (Companies only) Please identify:

a. the maximum number of TVR customers that your company's existing billing system can accommodate; and

   b. the TVR designs that your company's existing billing system can accommodate.

6. Please describe any alternative solutions that may be compatible with the Companies' current communications, data management, and billing systems to allow each company to collect and communicate interval data without prematurely retiring existing AMR meters.

7. (Companies only) Please describe your company's current strategy for meter replacements when an existing meter reaches the end of its useful life or otherwise needs to be replaced. As part of this response, identify any situation where a new service meter would not be capable of advanced metering functionality when installed.

8. Please discuss whether the Department should require all new service meters to be capable of providing advanced metering functionality when installed to replace an existing meter that reaches the end of its useful life or otherwise needs to be replaced.

To provide further opportunity for discussion, the Department anticipates holding a remote technical conference after reply comments are filed. The Department will provide an agenda in advance of the technical conference.

IV. ORDER

Accordingly, the Department

VOTES: To open phase two of its inquiry into the modernization of the electric grid, consistent with the scope of investigation described herein; and it is

ORDERED: That the Secretary of the Department shall send a copy of this Order to each electric distribution company subject to the jurisdiction of the Department under G.L. c. 164, the Attorney General for the Commonwealth of Massachusetts, and to the service lists in D.P.U. 15-120, D.P.U. 15-121, and D.P.U. 15-122.

By Order of the Department,

Matthew H. Nelson, Chair

Robert E. Hayden, Commissioner

Cecile M. Fraser, Commissioner