Electricity Markets & Policy
Energy Analysis & Environmental Impacts Division
Lawrence Berkeley National Laboratory

Snapshot of EV-Specific Rate Designs Among U.S. Investor-Owned Electric Utilities

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April 2023

This work was supported by the U.S. Department of Energy's Office of Electricity under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

A Snapshot of EV-Specific Rate Designs Among U.S. Investor-Owned Electric Utilities

Prepared for the
Office of Electricity
U.S. Department of Energy

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April 2023

The work described in this study was funded by the U.S. Department of Energy's Office of Electricity under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

Acknowledgements

The work described in this study was conducted at Lawrence Berkeley National Laboratory and supported by the U.S. Department of Energy's Office of Electricity under Contract No. DE-AC02-05CH11231.

The authors would like to thank Chris Irwin (DOE OE) for his support of this research.

The authors thank the following experts for reviewing this report (affiliations do not imply that those organizations support or endorse this work):

Tanya Burns	Arara Blue Energy Group, LLC
Galen Barbose	Berkeley Lab
Garrett Fitzgerald	SEPA
Michelle Levinson	World Resources Institute
Jeff Loiter	National Association of Regulatory Utility Commissioners
Julie Peacock	Pacific Northwest National Laboratory
Kara Podkaminer	Department of Energy
Melissa Whited	Synapse Energy

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Acronyms and Abbreviations

DCFC	Direct Current Fast Charger Equipment
DER	Distributed Energy Resource
DOE	Department of Energy
EV	Electric Vehicle
EVSE	Electric Vehicle Supply Equipment
IIJA	Infrastructure Investment and Jobs Act of 2021
IRA	Inflation Reduction Act of 2022
IOU	Investor-Owned Utility
L1	Level 1 Electric Vehicle Charger Equipment
L2	Level 2 Electric Vehicle Charger Equipment
TOU	Time-of-Use Rate Design
RTP	Real-Time Pricing Rate Design
PUC	Public Utilities Commission
PURPA	Public Utility Regulatory Policies Act of 1978

Executive Summary

There are now more than 1.7 million registered electric vehicles (EV) in the U.S., and this number is expected to grow to over 26 million by 2030 (EEI, 2022). Several factors are driving this growth. EV aesthetics and functionality are rapidly evolving to support and promote changes in consumer preferences, and auto manufacturers now offer more EV models to satisfy consumer demand. A variety of federal and state policies are further driving EV adoption and deployment by seeking to reduce the upfront capital cost and ongoing operating expense. However, EV-specific electric utility rates have a profound effect on the underlying economics that drive EV adoption. State utility regulators and electric utilities play a critical role in approving and designing EV-specific rates, respectively. Given the nascence of the EV industry coupled with regulators' and utilities' very limited experience with EV-specific rate designs suggests there could be substantial benefit from efforts intended to provide a better understanding of how EV-specific rates are actually being designed presently in the United States.

To meet that need, we developed a database of piloted, proposed, and offered rates among U.S. investor-owned utilities (IOUs) between 2012 and 2022. The database is comprised of 217 electric utility retail rates from IOUs in 37 states and the District of Columbia that either required proof of EV ownership or were otherwise designed for the purposes of reselling energy for use in EV charging (i.e., EV-specific rates). Although the database may not contain the full population of EV-specific rate filings, we believe it captures nearly all publicly available regulatory filings of EV-specific rate offerings, and is therefore sufficiently representative of the entire investor-owned electric utility industry.

Of the 136 active or approved (i.e., offered) rates during our study period, we were able to identify some broad themes around rate design for residential[1], commercial[2], and utility-owned[3] classes as follows:

1. **Residential Customer Rates (n=54)**: Although nearly every single residential EV-specific rate in our database included a time-of-use (TOU) design, the dominant design comprising half of these also included eligibility or a requirement for some form of dedicated metering of the EV charging load while the remainder applied to the whole home either explicitly or implicitly. A little less than a third of the TOU rates with some form of dedicated metering also seasonally differentiated the period definitions and/or rate levels. Overall, the TOU rates primarily relied on a two-part TOU rate design (i.e., on-peak vs off-peak rate periods). However, some rates incorporated a third period, as either a mid-peak set at a price level between the on-peak and off-peak, a super-off peak set at a price level below the off-peak, or some other rate variance in pricing per kWh. Only two of the TOU rate offerings with dedicated metering included a

1 Intended for use by typical residential class customers, including multi-family

2 Intended for use by commercial, industrial, or general service classes of customers, as well as those who were not included in any other category.

3 Intended for use at utility-owned charging equipment that is primarily deployed for public use, although examples at private multi-unit dwellings do exist.

demand charge, which utilized a traditional non-coincident design, and only one of those applied a holiday period (during which the demand charge was suspended).

2. **Commercial Customer Rates (n=48)**: The dominant commercial EV-specific rate offering, comprising a little less than half of our sample, included both a TOU rate design, of which well more than half incorporated some form of seasonality, and some form of a demand charge, of which more than half applied a demand charge alternative or holiday (e.g., demand charge discounts, demand charge discounts tied to load factor, demand charge discount sunsets or other reforms to address the viability of direct current fast charging (DCFC)). Every single one of these TOU and demand charge rates offered to commercial customers required a secondary meter to exclusively measure the EV charging load, while almost half specifically applied to DCFC chargers. Roughly one-third of the rates in our database offered to commercial customers used a TOU design without the application of a demand charge, most of which required a dedicated second meter. Only a handful of these rate offerings expressly mentioned charging technology, where either Level 2 (L2) or DCFC applied.
3. **Utility-Owned Charging Rates (n=27)**: Almost 80% of these utility-owned charging rates were applicable to DCFC and nearly half applied to L2 chargers, although a handful of these rates applied jointly to both types of charging technology. Utilities employed different volumetric energy charges as part of the overall rate design. Only a third of the offered rates employed TOU design which were mostly determined from a "cost-based" perspective, considering T&D costs and other energy, delivery, and ancillary components, that typically differentiated by season. However, a handful employed a "market-based" methodology for setting these prices, looking at the cost of fueling gasoline and/or at the private market's pricing of its DCFC stations. A small number of utilities alternatively offered a flat energy fee for charging, with varying limiters, riders, and adjustments depending on the utility.[4] Not a single offered rate for utility-owned infrastructure included a demand charge.

We were able to organize 41 of the 54 pilots into one of five categories as follows[5]:

1. **Commercial Customer Rates (n=14)**: These rate pilots generally included TOU rate designs, although a few sought to evaluate the viability of more temporal differentiation; one, for example, utilized an RTP design based on real-time hourly integrated wholesale market prices. Several rate pilots incorporated varying applications of demand charge alternatives, inclusive of demand charge limits or discounts. Many appeared to generally include DCFC infrastructure, but in a few instances pilot EV rates also applied specifically to L2 charging equipment.
2. **Residential Customer Rates (n=13)**: These rate pilots also generally included TOU rate designs, but relied on varying ratios of peak to off-peak charging rate levels.[6] A few were focused on testing customer acceptance and measuring charging load in response to rates whose

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[4] For example, Rocky Mountain Power in Utah has a credit for both off peak charging and for rate-paying customers.

[5] The other 13 pilots covered more miscellaneous topics that could not readily be grouped with one another.

[6] The ratios of on-peak vs off-peak periods vary across service territories and further research would need to be conducted to determine what is driving differences in those ratios. Presumably, these are a function of local system conditions, with variables (e.g., generation mix) that may not be directly comparable from one service territory to the next, as well as policy preferences that may affect cost allocation for recovery in the different rate periods.

volumetric energy charges differed due to different metering configurations. One pilot was restricted to only those with L2 or DCFC chargers and applied an on-peak-only demand charge exclusively to the EV charging load.

3. **Utility-owned Charging Station Rates (n=10)**: As more utilities apply for self-owned charging stations, the rates that they initially offer at these stations are rolled out on a pilot basis but exhibit many of the same design elements of established “offered” rates at utilities with more established charging stations. These rate design elements commonly include: discounts for customers charging in the service territory, rates set at a "market rate" or with requirements that charging stations be located in underserved communities or within certain charging corridors that otherwise lack investment from the private market. In certain cases the rates are offered as pilots to give the utilities more experience and the opportunity to apply learnings from offering charging services.
4. **Commercial Fleet Rates (n=2)**: These rate pilots were only available to commercial fleet operators who relied on L2 or DCFC chargers. One largely focused on utility control and optimization of the charging load, while the other sought to test the viability of rate designs more consistent with the general status quo (i.e., TOU rate design and a demand charge, both with seasonal variation).
5. **School Bus Fleet Rates (n=2)**: These rate pilots were only available to customers with fleets of school buses, and both included simple TOU rate components.

Based on these observations for both offered and piloted EV-specific rates, we can infer a number of policy-driven objectives. First, utilities and regulators may be highly motivated to promote EV adoption through simple rate designs while seeking broad management of grid impacts from the additional electric demand associated with charging loads (e.g., by encouraging off-peak charging). Second, the absence of highly dynamic temporal or locational rate designs suggests that, as in other utility applications, achieving the greatest level of economic efficiency is likely not as high a priority at the present time as other issues or may not be feasible or cost-effective due a variety of reasons (e.g., the existing metering infrastructure is too limited or nonexistent). Third, a small handful of rate pilots suggests utilities may be motivated to simply gain experience with new customers and presumably new electricity demand patterns (e.g., third-party or utility charging stations, commercial or school bus fleets), but again the historical record of pilots leading to full rollouts is dubious at best.

As we have noted, utility regulators have a central role to play in the development of the EV future, including seeking solutions to encourage EV adoption, integrate EVs and charging technologies into the electric system, and ensure that benefits are shared equitably by all. The research provided here addresses the critical role that rate design can play, but also suggests a number of near-term considerations for regulators and policymakers and some areas of potential future research.

First, it is important to consider implications of EV rate design objectives vis-à-vis other distributed energy resources (DERs), especially because states typically have different rate designs and policies or goals for individual DERs. The importance of the specifics of any particular rate design in assessing the potential impact on DER deployment more broadly cannot be overstated. For example, EV rate designs,

and the trend towards rates that encourage load shifting more generally, will likely benefit more flexible DERs as opposed to DERs like energy efficiency and distributed solar photovoltaic systems with largely uncontrolled load shapes (Satchwell et al., 2019). States also have considerably more experience with rate offerings for more traditional forms of DERs than EVs, so there may be opportunities to leverage that experience to design better and more effective EV-specific rates.

Second, regulators and utilities should consider the frequency with which EV-specific rate designs are updated or altered to reflect changing grid, economic and/or environmental conditions. Many current EV rates encourage charging during nighttime hours, yet it may not always be the case for certain power systems that nighttime will be identified as off-peak. In fact, greater EV charging during nighttime hours could conceivably result in a new peak, which would necessitate establishing new peak and off-peak rate periods and price levels (Satchwell et al., 2023). Furthermore, there is an increasing number of electricity systems where surplus renewable power supply exists in daytime hours, which would suggest that EV rates might better achieve decarbonization goals by focusing on daytime charging.

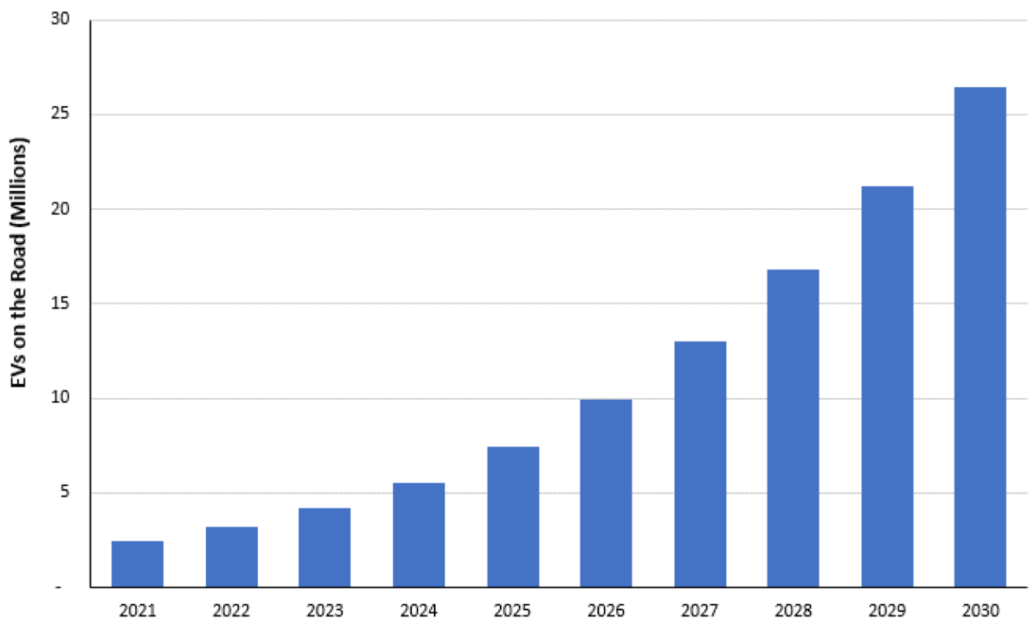
Third, as EV deployments increase, it will be important to revisit EV rate designs in terms of their effectiveness in achieving the stated (or, more likely, implicit) objective – not unlike the net energy metering reforms that occur as distributed PV deployments increase and their marginal system value changes. The power sector is undergoing a significant transition to higher renewable energy deployments and increasing load from electrification. As such, the value of EV charging may shift to different periods of the day and year, which would necessitate altering EV rate designs accordingly.

Finally, this research effort was designed to characterize recent EV-specific rate designs in the investor-owned electric utility industry. It was not designed to assess *why* those particular rate design elements were proposed and approved, or *why* others were not. A research effort seeking to characterize the *why*, beyond the *what*, could help assess where the industry may be truly headed, what barriers impede more innovative and dynamic rate designs, and what opportunities exist to overcome those barriers. Additionally, there is very little public and easily accessible information about the enrollment levels for the offered EV-specific rates. Collecting and analyzing such information for each of the rates in our database could provide valuable insights concerning the scale, impact and effectiveness of individual and collections of different rate design elements. Furthermore, the federal government has taken certain specific actions that are directly relevant to state-level rate design. For example, recent legislation over the past two years, including the IIJA (U.S. Congress, 2021) and the Inflation Reduction Act of 2022(U.S. Congress, 2022), included important provisions for transportation electrification overall. The IIJA also included provisions that encourage states to seek reform of existing demand charges. Understanding at a much more granular level of detail how these federal statutes and provisions are affecting rate design could be useful for future federal and state policymaking efforts, as well as for state regulators still determining how to best react to these new federal policies. Lastly, while it is clear that rates are a critical component of achieving regulatory objectives, rates are not the only tool available to regulators. In fact, rates are more often coupled with incentives and other programs, which are usually designed to establish an ecosystem of enabling communication and control

technologies to promote managed charging or vehicle-to-grid initiatives, among others. Understanding the types and frequency of program design elements offered by utilities as well as those being piloted could augment this report by providing a comprehensive snapshot of the current and potential future EV-specific programs in the U.S. electric utility industry.

1. Introduction

Electric vehicle (EV) adoption in the U.S. has reached notable levels and is expected to increase significantly through the current decade. There are now more than 1.7 million registered EVs in the U.S., and this number is expected to grow to over 26 million by 2030 (see Figure 1) (EEI, 2022). Several factors are driving this growth. EV aesthetics and functionality are rapidly evolving to support and promote changes in consumer preferences, and auto manufacturers now offer more EV models to satisfy consumer demand. Ten years ago, major manufacturers offered fewer than 10 EV models for sale to U.S. consumers (AFAI, 2022a); by the second quarter of 2022, that had grown to over 80 models, and EVs accounted for 6.6% of all U.S. light-duty vehicle sales (AFAI, 2022b). Further, corporate investments in public charging infrastructure are also increasing, as evidenced by the 5.1% growth during the second quarter of 2022 in EV supply equipment (EVSE) ports (Brown et al., 2022) meant to address range anxiety for would-be EV customers and provide more options to current EV owners.



Source: EEI (2022)

Figure 1. Forecast of EVs on the Road in the U.S.

In addition to evolving customer preferences and advances in auto manufacturing, several federal and state policies are driving EV adoption and deployment by seeking to reduce the upfront capital cost and ongoing operating expense. Many states and the federal government offer sizable subsidies to reduce the upfront purchase price of EVs, while 26 states plus the District of Columbia have some form of tax incentive or rebate for the purchase of a light-duty electric vehicle (EnergySage, 2022).[7] The Inflation Reduction Act of 2022 provides an additional $7,500 federal tax credit for income-eligible individuals purchasing an eligible new electric vehicle, and up to $4,000 (or 30% of the sales price) for income-

[7] States have different definitions of what qualifies for incentives or rebates. For example, California includes electric, plug-in hybrid electric, and fuel-cell vehicles in their program (CACVRP, 2022), whereas New Jersey excludes plug-in hybrid electric vehicles (DOE AFDC, 2022).

eligible individuals purchasing an eligible used electric vehicles (SAFE and EC, 2022). Because of state and federal subsidies, the upfront cost of EVs, especially light duty vehicles, may be comparable in cost, or even cheaper than, their gas-powered counterparts presently (Orvis, 2022). As a more far-reaching measure to promote EV adoption, California, Oregon, and Washington banned the sale of gas-powered passenger vehicles by 2035, and other states, such as New York and Massachusetts, are expected to follow suit (Gitlin, 2022; Steves, 2022).

In addition to state and federal policies, EV-specific electric utility rates have a profound effect on the economics that drive EV adoption, as well as the ability of EVs to realize broader power system and societal benefits (Satchwell et al., 2019). State utility regulators and electric utilities, among others, play a critical role in achieving these outcomes given their role in approving and designing EV-specific rates, respectively. However the nascence of the EV industry coupled with regulators' and utilities' very limited experience with EV-specific rate designs suggests there could be substantial benefit from efforts intended to provide a better understanding of how EV-specific rates could be designed more broadly and how they are actually being designed presently in the United States.

To meet that need, this study presents a framework for identifying the design elements of EV-specific rates, previously developed in Cappers and Satchwell (2022) but reprinted here, and then applies that framework to a database of piloted, proposed, and offered rates among U.S. investor-owned utilities (IOUs) between 2012 and 2022. Through this research, we are able to describe and characterize the current landscape of EV-specific rate designs across the country in a more organized fashion. We conclude this study by discussing broader aspects of rate design that may have implications for the achievement of EV objectives and realization of societal benefits.

We organize this report as follows. In Chapter 2, we present a framework for organizing EV-specific rate designs. Chapter 3 discusses the data collection methods we used to produce our database of EV-specific rates. In Chapter 4, we apply the framework and summarize the results of our analysis of the EV-specific rates in our database. Chapter 5 provides our key conclusions from the analysis, as well as their implications.

2. Organizing Framework

Retail rates are designed based on two broad concepts. First, approved retail rates must recover a utility's costs (i.e., revenue requirement) and be deemed by regulators to be just and reasonable based on ratemaking principles. Second, rates must satisfy certain policy and/or market objectives that can vary based on a state's distinct rules, regulations, and policies, as well as different stakeholder motivations. Because utilities and regulators have begun to design and approve retail rates specific to EVs, the cost recovery and especially the policy/market objectives may be somewhat different from rates that apply more broadly (Satchwell et al., 2019). In turn, the resulting rate designs and the particular elements incorporated into EV-specific rates may differ from those traditionally used.

In this chapter, we describe a framework for identifying and characterizing the key elements of EV-specific retail rate designs. Although this framework was previously presented in Cappers and Satchwell (2022), we reintroduce it here to provide sufficient background for our subsequent analysis of current and proposed EV-specific rate design elements that heavily relies on this framework. Importantly, the rate design elements described below should ultimately be connected to the policy and/or market objectives, including rates to promote EV adoption, for grid management, to increase system economic efficiency, to achieve decarbonization goals/targets, and to equitably share the benefits of EVs across all customers.

2.1 EV Consumption Measurement and Metering Configurations

One of the primary rate design decisions a utility makes is about what and how to measure and meter electricity consumption. Utilities typically measure parts of or the entire premise's electricity consumption by either utilizing the existing utility meter or requiring the customer to install a utility-provided alternative meter that accurately measures a number of additional elements required by the rate design (e.g., interval meter to measure time-differentiated electricity consumption, demand meter to measure maximum electricity consumption). Because EVs represent one of, if not the, biggest end-use load at a premise, utilities have begun to consider if these historical approaches to measurement and meter configurations are still applicable for EV-specific rate designs, or if alternatives are more appropriate.

The simplest and cheapest approach is to measure the customer's EV charging load combined with all other loads at the home or workplace. Such configurations are often called "whole-house" or "whole-premise" because they encompass all of a customer's electricity consumption at the home or workplace, regardless of its source, and rely on the existing account meter.

Alternatively, a rate could measure only the EV charging load. In such cases, the utility has a few options for how to measure it. First, the rate could require two revenue-grade meters: one to solely measure the EV charging and a second to measure the electricity consumption for all other loads. Although EVs themselves measure electricity usage, the internal meter is not typically considered revenue-grade because they either do not currently meet accuracy standards and/or have not gone through the certification process, broadly speaking. Second, for a utility seeking a less expensive but still accurate metering technology for EV charging load, a dedicated submeter for the EV that sits between the main revenue-grade meter and the EV supply equipment (EVSE) is an option.

For those tariffs that require a dedicated second account meter to specifically measure the EV charging load, a number of additional issues must be addressed. First, the matter of who pays for the additional meter must be decided. Some utilities increase the ongoing monthly customer charge or apply an up-front meter fee at the time of installation. Second, the costs associated with the installation of this dedicated meter, along with a meter socket, lever bypass, conduit and wiring of a dedicated circuit, must also be incurred and potentially recovered by the utility. In some cases, the customer is responsible for paying a licensed electrician to perform this work; but utility or state energy office

financial assistance programs could be implemented to help offset some or all of these costs.
The alternative approach for specifically measuring EV load, which relies on submetering, would require a similar set of design issues to be decided while also determining what qualifies as a submeter. Currently there are several technology options being considered by utilities. First, a stand-alone revenue-grade sub-meter, similar to what is used in multi-family dwellings, could be specified in the rate. Second, and as an alternative, the utility could require a submeter that is integrated into the EVSE. Third, the EVs on-board computing capability could be used by allowing an external device to be plugged into the car's on-board diagnostic port. The first two submetering technology options would incur an additional cost for installation as they require a licensed electrician. The last option would require some form of internet access (e.g., cellular, WiFi) to transmit the meter data back to utility directly or via some authorized third-party vendor.

2.2 Temporal Differentiation in Volumetric Energy Charges

Electric utilities often consider the merits of introducing some form of temporal differentiation into the volumetric energy charge (cents/kWh) that reflect variation in the underlying cost to serve. Rate designs with temporal differentiation can range from multi-hour periods each day to sub-hourly intervals, as well as different rates each season (e.g., winter vs. summer). EV-specific rates are no different and may suggest, given the size of EV charging load, even greater applicability of temporal differentiation.

Time-of-Use (TOU) rate designs introduce temporal variation in volumetric energy charges during broad, fixed time periods each day with static rate levels. When first introduced over 60 years ago, TOU rates were generally designed to coincide with longer-term forward market wholesale power contracts that had two periods: a peak period, which was defined with a 16-hour window (6:00 a.m.–10:00 p.m.) on weekdays and an off-peak period covering the remaining 8 hours of the weekday and all hours on the weekend. More recently, many utilities have shortened the peak period to more accurately reflect when marginal electricity generation costs are at their highest, but have also allowed the definition of that period to change seasonally (e.g., summer vs. non-summer months). In addition, some utilities have further broken up the daytime into two sub-periods: (1) a more narrowly defined peak period often covering just the afternoon hours, and (2) a shoulder or mid-peak period that encompasses the morning and early evening hours. A handful of utilities have also broken out the overnight hours into two subperiods, with one of them having the rate set very low (e.g., super off-peak). The ratio of the peak to the off-peak volumetric energy charge can generally range from 1.2:1.0 to 4.0:1.0.

Critical Peak Pricing (CPP) introduce temporal variation in volumetric energy charges during infrequent but fixed time periods with static rate/rebate levels. Often, these rates apply only seasonally (e.g., summer), instead of year-round. They are generally overlaid on top of either flat, block, or TOU rates and are designed to infrequently but dramatically, elevate the volumetric energy charge (or provide a substantial volumetric energy rebate) to compel load reductions (e.g., deferred EV charging) during times of exceptionally high electricity demand or high wholesale market prices. Customers often receive between 2- and 24-hour advance notice of such events, which is communicated to them by the

utility via email, text, phone, or even a dedicated web application. The ratio of the critical peak to the otherwise applicable volumetric energy charge in that period can generally range from 5.0:1.0 to 12.0:1.0.

Variable Peak Pricing (VPP) introduces temporal variation in volumetric energy charges during broad, fixed time periods with dynamic rate levels. They are a more variable version of TOU with a CPP overlay, as they can assign a different rate level during the peak period each day, depending on system and wholesale market conditions. In contrast to a standard TOU rate, the VPP design is advantageous when system conditions vary considerably from day to day. Such rates often have a seasonal component as well, where the period definition can change (e.g., summer vs. non-summer months). The ratio of the peak to the off-peak volumetric energy charge can generally range from 1.2:1.0 to 12.0:1.0, depending on the rate level applied in the peak period.

Real-Time Pricing (RTP) introduces temporal variation in volumetric energy charges during short time intervals with dynamic rate levels. They are generally designed to pass the wholesale price of electricity (or some proxy of it) directly on to customers, instead of setting the hourly rate level during a general rate case. This is overwhelmingly done presently by providing customers with volumetric energy charges that differ at the hourly level, which are usually based on day-ahead unit commitment or market outcomes (RTP-DA) but can also be derived from a weighted average of 5–15 minute dispatch or real-time market outcomes (RTP- RT). Some utilities also allocate wholesale capacity and/or ancillary service costs to some subset of the highest priced intervals each year. The most extreme form of RTP is characterized as transactive energy, where a customer provides both a demand for all grid services but also a bid to supply grid services from a portfolio of highly interactive and controllable electric loads (including EV charging load) into a highly dynamic and interactive market that produces a price signal on a sub-hourly basis (e.g., every 5-15 minutes) from a market clearing process.

2.3 Locational Differentiation in Volumetric Energy Charges

Utilities have not historically reflected geographic cost differences in rate designs because, in large part, of the challenges associated with accurately measuring and allocating those costs, as well implementing rates that are more complex. However, the unique engineering challenges imposed on the distribution grid from the additional load and maximum demand associated with EV charging loads differs dramatically from one location to another, which ostensibly could impose substantially different costs on the system that warrant the introduction of additional complexity into the rate design. Utilities could represent these different costs and grid challenges (including emissions) into the volumetric energy charge by differentiating it on a locational basis. Specifically, EV tariffs could incorporate some form of locational differentiation into the volumetric energy charge (cents/kWh) which could be applied at either the bulk power system level (e.g., pricing zone, climate zone) or at the distribution system level (e.g., substation, feeder). Or, to a lesser extent and in the context of emissions, at a site-level (e.g., home or workplace).

2.4 Demand Charge Rate Designs

Aside from the volumetric energy charge, a utility also can incorporate a charge into the tariff based on the customer's maximum demand of electricity (i.e., demand charge or $/kW-month). This maximum demand is measured over some period of time, typically a month, where the level of that demand can be set any time by each customer independent of other customers (i.e., non-coincident peak demand), when the bulk power or distribution system in aggregate reaches its maximum level (i.e., coincident peak demand), or when each customer's maximum demand occurs during a pre-defined set of hours (e.g., peak period) each month (i.e., billing demand). The time interval for measuring the maximum demand can range from 15-minutes to an hour. In addition, the utility could measure demand each month, independent of any previous measurements, or could maintain a level of measured demand for some period of time into the future (e.g.,12 months) in order to take a longer-term view of maximum demand (i.e., demand ratchet). Utility tariffs can also differ in the level of the charge applied to that measured demand. The demand charge ($/kW-month) may be the same all year or can vary seasonally (e.g., summer vs. non-summer months).

2.5 EV Charging Controls

Aside from volumetric energy charges and demand charges, a utility can use control technology as a means for supporting efforts to more directly manage the charging loads from customers' EVs. Design decisions on this issue determine whether the customer must have some form of connection to the utility with which to communicate its charging status (one-way or two way) as well as whether the utility or the customer may control EV charging patterns.

The simplest design approach uses a very indirect control strategy that allows customers to retain complete control over their charging behavior while integrating financial or other interventions. The customer would leverage their EV's onboard controls or the apps provided for their vehicle to pre-program a charging strategy in response to a predefined and static price signal, without any obligation to maintain an electronic connection between the charger and the utility. However, a customer could elect to have its Level 2 (L2) or direct current fast charger (DCFC) receive price signals from the utility (e.g., via its charge management system) in order to more easily respond to the utility's chosen rate design. A customer would need to incur the additional equipment and installation costs for these types of chargers.

Alternatively, the utility could pursue a more direct strategy requiring that the customer grant control over their EV charging behavior to the utility, enabling the utility to manage the electricity draw of the EV when connected. The L2 or DCFC could be controlled directly by the utility or managed by a third-party that serves as an intermediary between the customer and the utility. In either case, technology that can support two-way communication between the entity providing the control and the EV is required, whose cost is likely borne by the customer. In exchange, the customer faces a lower rate. The level of this rate discount is often predicated on the ability of the customer to override the charging control signal - having more firm control over EV charging patterns is worth more to the utility than the

alternative resulting in a deeper discount. The utility usually specifies in the rate's terms and conditions the limitations of their ability to control the customer's EV charging load.

3. Data Collection

A primary objective of this research was to develop a comprehensive and representative database of existing rates found in EV-specific tariff offerings by investor-owned electric utilities. The research leveraged E9 Insight's database of ongoing and recent regulatory proceedings at state public utility commissions. This existing information was supplemented by targeted research using publicly available sources (e.g., state public utility commission dockets, utility websites, etc.) to identify rates and programs that were specifically implemented for all types of EVs and EVSE. Specifically, the research collected IOU[8] tariff filings with or decisions by state regulatory commissions between 2012 and 2022, but the overwhelming majority of rates (~90%) dated from 2018-2022. A goal of the research was to both aggregate and evaluate EV-specific retail rates. Although the database includes rates that were coupled with other program incentives (including EV rebates, tax/bill credits, and other financial incentives), we exclusively focus on rate design elements for the purposes of this study.[9]

Rates available for electric service that either did not require proof of EV ownership or were not otherwise designed for the purposes of reselling energy for use in EV charging were excluded from our database.[10] For example, a rate available to residential customers with or without an EV was excluded; similarly, a general commercial service rate that was available for, but not limited to or designed for, EV charging was not included.

The database comprises 217 EV-specific retail rates from IOUs in 37 states and the District of Columbia. It may not contain the full population of EV-specific rate filings, but we believe it captures nearly all publicly available regulatory filings of EV-specific rate offerings, and is therefore sufficiently representative of the entire investor-owned electric utility industry.

[8] Our research did not examine rates available from energy marketers or municipal, cooperative, or other public utilities. This was due to several factors, including less publicly available information and the limited interactions these entities have with the state regulatory bodies overseeing larger, investor-owned utilities.

[9] We differentiated rates and programs according to whether the charge was directly or primarily based on kWh consumption. Programs included a broader range of rebates, credits, and other incentives that were not primarily based on kWh consumption. For example, bill credits applied for participating in a demand response program via telematics are out of scope.

[10] Notably, as this study examined utility rates that either required proof of EV ownership or were otherwise designed for the purposes of reselling energy for use in EV charging, in order to take service under the rate class, a large set of otherwise applicable commercial rates were not included. This is because in certain instances, electric vehicle service providers may take service under general commercial service classes more favorable to their business model, however not necessarily specifically designed for commercial EV charging purposes. Additionally, many of the reforms taking place to address the barriers that demand charges pose to commercial EV charging are otherwise applied to existing EV rates via utility "programs" (e.g., demand charge credits) and thus do not qualify as an "rate."

We categorized EV-specific rates in the database by their status, as follows[11]:

- **Active:** Rates that were widely available to all EV customers in the relevant customer class
- **Approved :** Rates that were approved by regulators but not yet in service
- **Proposed**: Rates that had been filed and awaited decision by the PUC
- **Piloted:** Rates where a small number of customers took service provisionally and/or where service is available over a specified or limited time
- **Inactive**: Rates that were no longer active either because they had sunset or were no longer available to new enrollees.[12]

Our research identified 131 EV-specific rates that were Active at the time of our analysis offered by 55 unique IOUs, along with five that were Approved but not yet active offered by 4 unique IOUs, 12 that were Proposed by 8 unique IOUs, 55 that were being Piloted by 24 unique IOUs, and nine that were Inactive at 5 unique IOUs.

For subsequent analytical purposes, we further group rate filings in our database by status to infer emerging designs as follows:

- **Offered (n=136)**: Rates identified as either Active (n=131) or Approved (n=5) represent those that are or will soon be offered to EV-owners, and may represent slightly older rate design preferences given the length of regulatory review
- **Proposed (n=12)**: Rates identified as Proposed (n=12) may represent more timely preferences of IOUs for alternative rate design elements that differ from the status quo (i.e., current EV rates)
- **Piloted (n=54)**: Rates identified as Piloted (n=54) may represent longer-term preferences of either IOUs and/or regulators for alternative rate design elements that differ from the status quo; however, the electric utility industry has a long history of piloting alternative rate designs without a subsequent full-scale offering (due to insufficient achievement of pilot objectives, evolving rate objectives, or other reasons)

4. EV-Specific Retail Rate Snapshot

In this chapter, we provide a snapshot of EV-specific retail rates that were either offered, proposed or piloted during our analysis period. First, we report how many of these rates contained in our database are associated with each customer class or type of EV-charger across the three different rate statuses (i.e., offered, proposed, piloted). Then, we directly apply the framework discussed in Chapter 2 to the EV-specific retail rates contained in the database described in Chapter 3. Accordingly, we first independently tally and report the number of EV-specific rates associated with the levels of each retail rate design element described in the framework across the three different rate statuses, assuming

[11] Rates filed by utilities but rejected by regulators were not included in our database.
[12] The motivation behind the decision to make these rates inactive was not examined.

higher frequencies suggest greater emphasis and/or interest by utilities and regulators.[13] Afterwards, we treat each rate as a portfolio of its component rate design elements to identify more comprehensive and holistic groupings of offered and piloted EV-specific retail rates.[14]

4.1 General Categorization

4.1.1 Customer Classes

A utility typically assigns each retail rate to a specific customer class based on their physical characteristics (e.g., level of maximum energy demand, apparent power, or phase of service). With respect to EVs, customer classes may be further defined by the type of vehicle or owner of the charging equipment. EV-specific rates were organized in the database by the following customer classes:

- **Residential**: Intended for use by typical residential class customers, including multi-family
- **Commercial[15]**: Intended for use by commercial, industrial, or general service classes of customers, as well as those who were not included in any other category
- **Mixed**: Included a combination of residential and commercial customers
- **Utility-owned**: Intended for use at utility-owned charging equipment that is primarily deployed for public use, although examples at private multi-unit dwellings do exist
- **Fleet**: Intended for specific use by public or private fleets (e.g., commercial fleets, school bus fleets)

Among 136 offered EV-specific retail rates, 40% (54) applied to residential EV customers (see Figure 2). A little over one-third of the rates (48) identified were for commercial customers. A handful of rates (3) applied to both residential and commercial customers. Twenty percent of the rates (27) identified applied to utility-owned EV chargers. Only a small number of rates (4) explicitly applied to non-utility fleet operators.[16]

The 12 proposed EV-specific rates applied to residential or commercial customers, although the vast majority were for commercial customers (10). Our research did not find any proposed EV-specific rates for utility, fleet, or mixed customer classes.

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13 A rate could be explicitly applicable to more than one level of a particular rate design element. For example, a rate could include both seasonal and period-based temporal differentiation, or apply to load demanded by just the EV or by the whole premise. When such cases occurred, we coded the database to reflect all applicable rate design element.

14 We chose not to do a similar aggregated analysis of the "proposed" rates given the very limited small sample of 12 rates.

15 We acknowledge that commercial EV rate design is a priority of the Biden Administration, as codified in Section 40431 of the IIJA amending Section 111(d) of PURPA, and that over the course of this study several state public utility commissions (PUCs) either opened proceedings, or issued decisions, regarding issues material to rate design. Notably, as this study examined utility rates that either require proof of EV ownership, or are otherwise designed for the purposes of reselling energy for use in EV charging, in order to take service under the rate class, a large set of commercial rates, particularly those that may be taken service under to provide DCFC were not examined.

16 Fleet specific EV rates are infrequent and or in the early stages of development. Given this, we assume that fleet operators would take service under the otherwise applicable commercial rate class.

In contrast, pilots for EV-specific rates applied across all five customer classes, and primarily for residential or commercial customers.

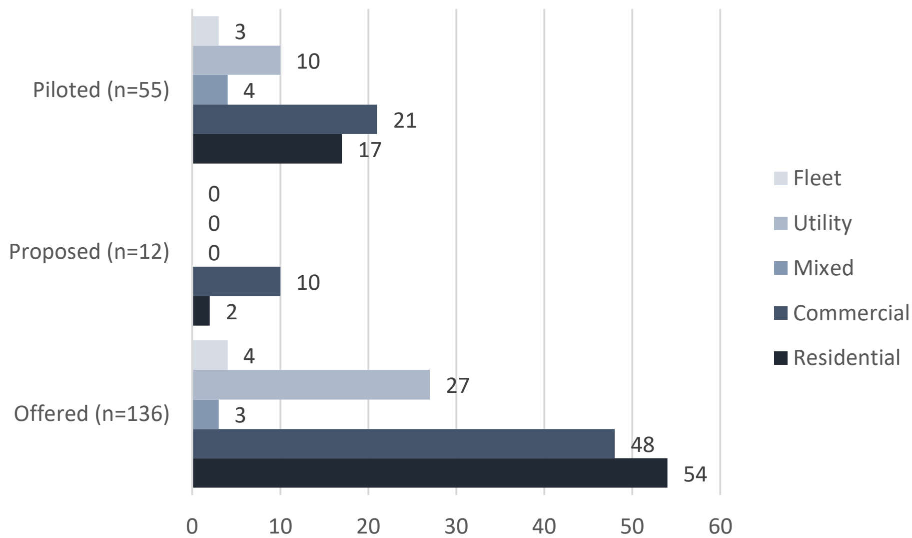

Figure 2. Count of EV-Specific Rates by Status and Customer Class

4.1.2 Charger Type

Customers can choose how fast they want to charge their EV based on the type of charger they use. Benefits of faster charging include a greater ability to respond to shorter off-peak pricing periods, and longer EV range per hour of charging. However, all else being equal, faster charging places a higher demand on the electric grid over a shorter period of time. Some rates may differ by charger type to reflect the costs that higher-demand charging may impose on the grid.

If EV-specific rates included specific provisions or eligibility requirements by charger type, they were categorized as follows[17]:

- **Level 2 (L2)**: Applicable only to those customers using an L2 charger
- **Direct Current Fast Charging (DCFC)**: Applicable only to those customers using DCFC

The majority (62%) of offered EV-specific rates (84) did not specify a charger type (see Figure 3), suggesting that they applied to all charger types consistent with any of the other rate design

[17] We did not categorize Level 1 (L1) chargers because they deliver a standard ~1.2kW demand and all are the default charger for all light-duty EVs can utilize them without any incremental cost to upgrade the EVSE at a premise. L2 chargers typically deliver between 6.2 and 19.2 kW, use a 208-240v power source and a dedicated circuit that can range between 32-60 amps. DCFC typically deliver between 15 to 350 kW through a commercial-grade three-phase connection providing 200 to 1000 volts.

requirements.[18] When a charger type was specified, utilities were more likely to implement rates focused on DCFC (42) over L2 (29) chargers, likely due to the much higher demand DCFC place on the grid and the greater ease of integrating L2 charging demands . Note that some EV-specific rates explicitly identified more than one charger type.

Among proposed rates, our analysis shows that IOUs were more likely to specify a charger type than to make the rate applicable to all chargers. Seventy-five percent of the 12 L2 proposed EV-specific rates only applied to DCFC (9), while 50% applied only to L2 chargers (6). Five of the 12 proposed rates applied to either DCFC or L2 chargers.

In contrast, only a minority of rate pilots appeared to include charger types. Of the 54 EV-specific rate pilots that explicitly applied to a charger type, 30% mentioned DCFC (16) and just under 20% referred to L2 chargers (9).

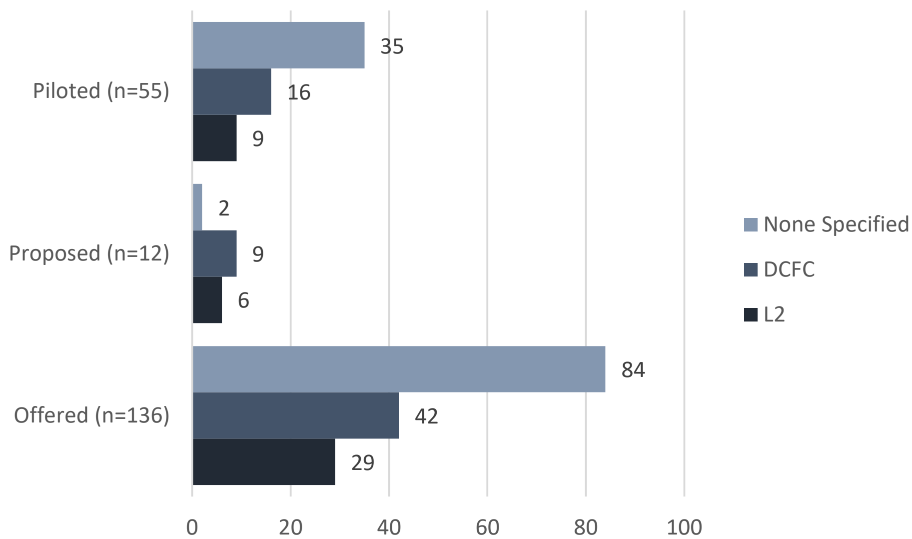

Figure 3. Count of Current EV-Specific Rates by Status and Charger Type

4.2 Rate Design Element Framework Categorization

4.2.1 Metering Configurations

One of the basic EV-specific rate design choices is whether to meter EV charging load separately or aggregate it with other home or business electric loads. Generally, the tradeoffs between choices are based on costs for additional equipment to submeter EV charging loads, simplicity of customer bills, and reflecting EV-specific costs (Satchwell et al., 2019).

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18 Some EV-specific rate offerings may only apply to certain voltage or peak demand (kW) levels, as well as customer classes, which themselves may be defined in terms of certain voltage or peak demand levels, would indirectly limit the use of certain charger types (e.g., lower voltage or peak demand level requirements would exclude DCFC).

Rates were reviewed for their requirements or options with regard to metering configuration, which comprised two categories. First, meter coverage was defined as follows[19]:

- **Whole Premise**: The meter measured electricity consumption for the entire premise
- **Dedicated EV**: The meter measured electricity consumption strictly for the EV

Investor-owned utilities seemed generally split between simply measuring the entire premise load as a component of the rate design or explicitly measuring the EV charging load (see Figure 4). Twenty-two percent of the 136 currently offered EV-specific rates explicitly measure the entire premise load (30), while another 33% did not specify any meter coverage (45), which likely means they also measured the entire premise load. But about half of utilities did design their rate offerings to apply to EV charging load[20]: 73 of the 136 current rate offerings (54%).

A similar dynamic plays out when looking at proposed or piloted EV-specific rate filings: the majority either required or afforded the option to measure the electricity needs of the EV separate from the rest of the premise. Of the 12 proposed rates in our database, 75% applied to the EV charging load, although two of nine of these could also apply to the whole premise. Twenty-five percent didn't specify any particular meter coverage (3). Fifty-seven percent of the 55 rate pilots explicitly included a meter configuration for measuring the electric charging needs of the vehicle (31). Of the six pilots that mentioned whole-premise metering, one gave customers the option to choose between the two metering configurations.

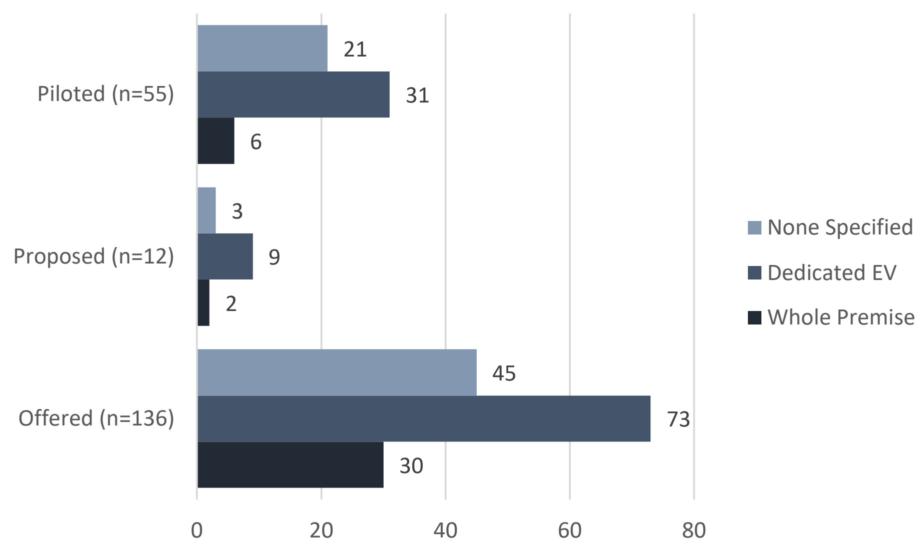

Figure 4. Count of Current EV-Specific Rates by Status and Meter Coverage

[19] A rate could be explicitly applicable to more than one type of metering configuration and so was coded in the database as such.

[20] It is worth noting that in some cases, the rate does explicitly measures additional but minimal ancillary loads (e.g., lighting for charging stations).

There are several options for measuring and recording the specific EV charging load. Each option differs primarily in terms of costs to the customer and/or utility, but design choices may also be driven by additional considerations about whether meters are eligible for customer billing under state rules.

Where there was a requirement or option for a dedicated EV meter, the utility would identify the type that was required, which we categorized as follows:

- **Utility Meter**: An additional utility-grade meter was used to measure EV charging load
- **Telematics**: The EV's own internal telematics were used to measure EV charging load
- **EVSE**: The EV supply equipment's internal measurement capabilities were used to measure charging load

Our analysis of currently offered EV-specific rates found that only a handful used a dedicated EV measurement device other than the meter provided by the utility. Only 4% of the 73 rates explicitly mentioned measuring the charging load via EVSE, and not one relied on the vehicle's telematics (see Figure 5). No utility proposed rates utilizing EVSE or EV telematics for metering. However, we identified one utility pilot rate that used vehicle telematics and three more pilot rates that leveraged the EVSE's measurement capabilities. Given the extremely limited number of EV-specific rates that include any form of EVSE or EV telematics, it appears that, to date, utilities and their regulators may be been reluctant to rely on something other than the utility's own meter to accurately measure electricity consumption for billing purposes. However, the fact that a least a few utilities were piloting this technology does suggest some interest, either by regulators, utilities, or both, to consider the viability of alternative metering technologies.

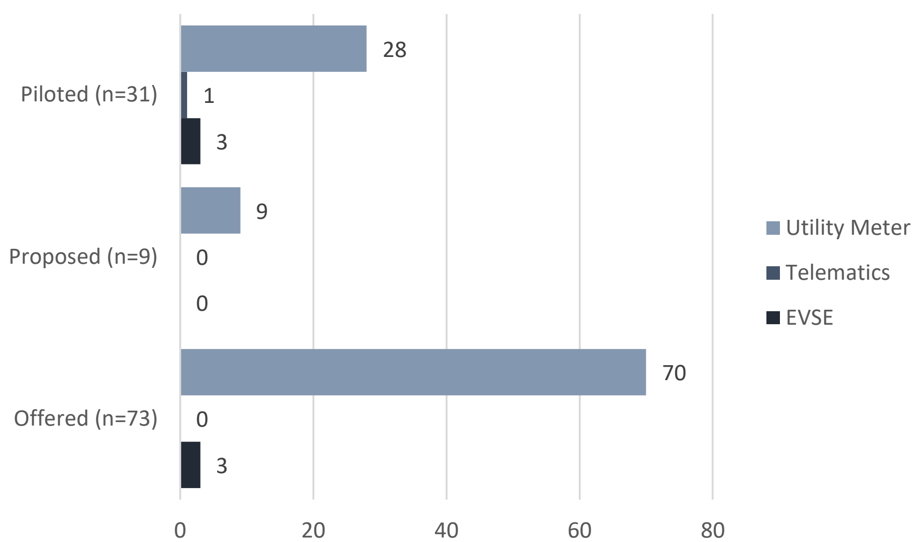

Figure 5. Count of Current EV-Specific Rates by Status and Dedicated EV Meter Technology

4.2.2 Temporal Differentiation

Power system costs vary temporally to serve electricity demand that changes by minute, hour, and season. Temporal differentiation in the volumetric energy charges of EV-specific retail rates are

intended to better match the timing of EV charging demand with system costs. Temporal pricing has been offered to commercial and residential customers for several decades to promote improvements in system load factors, encourage reductions in extremely high system costs during narrow time periods, and incentivize shifting load from high- to low-cost periods.

Rate designs that integrated temporal differentiation were assigned as follows:

- **Seasonal**: Rate schedules that differed by season (e.g., summer and non-summer)
- **Period**: Rate schedules that varied according to two or more multi-hour periods of the day (e.g., TOU rates)
- **Hourly**: Rate schedules that varied according to the hour of the day (e.g., RTP)
- **Other**: Rate schedules that varied temporally in any other way (e.g., as monthly load factors increase the cost per kWh charge decreases, critical peak energy charge overlay)

The single most common rate design element in currently offered EV-specific rates appeared to be the application of period-based temporal differentiation. Seventy-five percent of the current EV-specific rates in the database (102) utilized a period-based (i.e., TOU) design, while 70 changed seasonally (see Figure 6). Two EV-specific rates utilized more granular temporal differentiation, RTP. A little less than one-quarter of currently offered rates (30) do not include any temporal differentiation.

We identified a few examples of proposed or piloted rates that utilized more granular time-differentiated EV-specific rate designs than those currently being offered. Of the 12 EV-specific rate proposals, four utilized some form of period-based design while five allowed rates to change seasonally. Likewise, thirty-seven (37) of the 55 piloted rates relied on a TOU design, while 21 of the rate pilots utilized some form of seasonal rate. However, our research identified two piloted EV-specific rate offerings utilizing an RTP design.[21] This suggests that there may be a small but growing interest in offering EV owners rates with greater temporal granularity.

[21] More broadly, RTP is very uncommon. When utilities do implement it, such designs often strictly apply to supply costs for larger commercial and industrial customers.

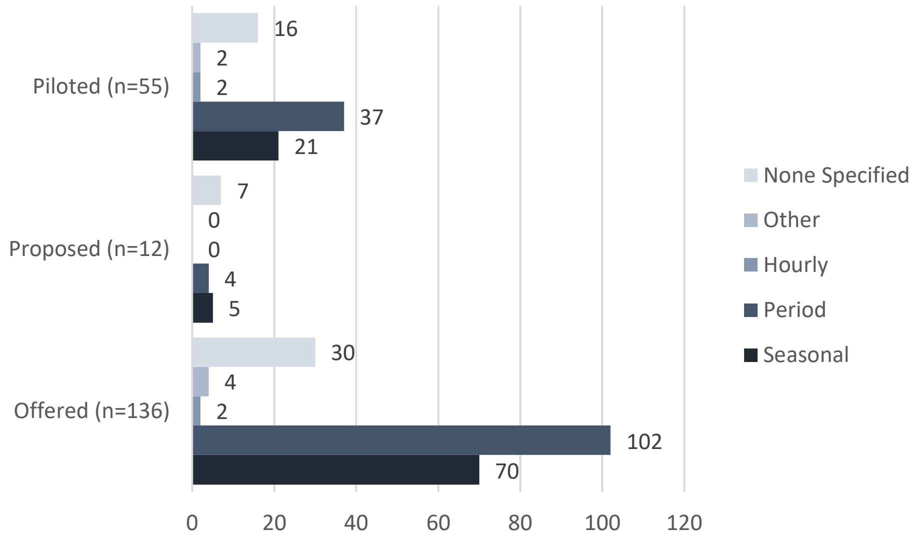

Figure 6. Count of EV-Specific Rates by Status and Temporal Differentiation

4.2.3 Locational Differentiation

Similar to temporal differences in costs, in certain markets there may be differences in costs to consumers based on locational considerations on the bulk power system (e.g., zonal pricing) and/or distribution system (e.g., feeder level). Rate designs with locational differentiation can be as simple as volumetric energy charges that vary by location on the subtransmission (e.g., 34.5-69.0 kV) grid, or more complex differential coincident peak demand charges that are based on congestion of local distribution lines (e.g., below 34.5 kV). For this analysis, rate levels reflective of cost differences at the bulk power system (e.g., above 69 kV) were not considered to have any locational differentiation. Although not a single currently offered or proposed EV-specific rate in the database incorporated any locational differentiation in the design, there was a single rate pilot that did[22] (see Figure 7).

[22] This rate pilot was San Diego Gas & Electric's Power Your Drive, which included differential locational prices for accessing the utility's charging infrastructure.

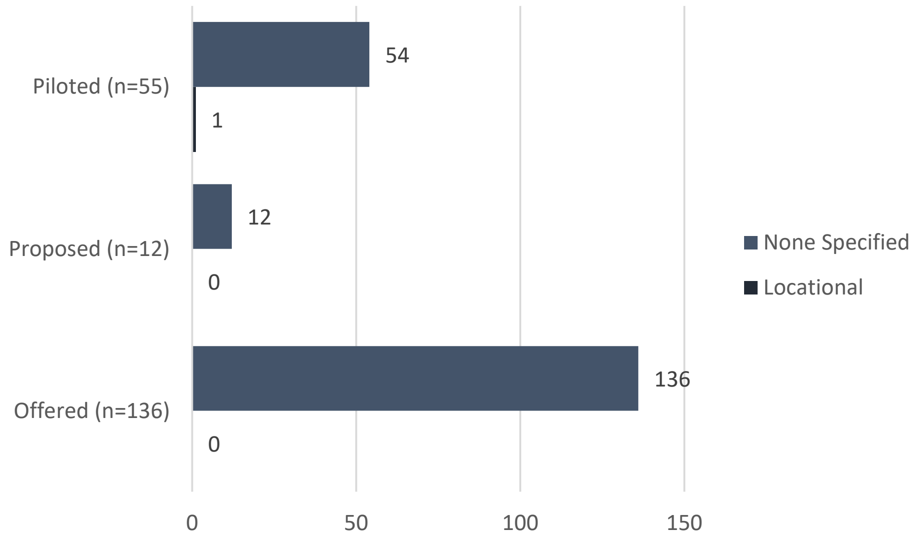

Figure 7. Count of EV-Specific Rates by Status and Locational Differentiation

4.2.4 Demand Charges

The underlying utility cost structure includes many investments in grid infrastructure needed to serve customers' maximum demand. For example, sufficient electricity supply must exist to meet the highest annual demand plus contingencies, and distribution transformers are sized to meet maximum load and potential future load growth. Demand charges have historically been included in many retail rate designs to recover some or all these demand-driven costs, particularly from commercial and industrial customers who generally have much higher demand levels or lower load factors than residential customers on a per-customer basis.[23] Demand charges for EV charging load are similarly intended to recover demand-driven costs, especially for DCFC chargers that have substantially higher demand levels than L2 chargers, but they may also impose prohibitively high costs on EV customers and DCFC station operators (Tucker and Snyder, 2021). To address this concern, Congress included amendments to the Public Utility Regulatory Policies Act (PURPA) (U.S. Congress, 1978) in the Infrastucture Investment and Jobs Act (IIJA) (U.S. Congress, 2021) which established a specific directive to the nation's utility regulators to consider rates that "promote greater electrification of the transportation sector."[24] In response to these new directives, several states decided to initiate regulatory proceedings which resulted in the approval of new commercial rate designs that implemented a variety of what we are calling Demand Charge Alternatives (described in more detail below). As such, regulators and utilities

[23] Notably, there has been increasing interest in and approval of residential customer demand charges over the past decade or so (e.g., Hledik, 2014; Hledik and Faruqui, 2016; Satchwell et al., 2019).

[24] The amendments to PURPA directed utility regulators in every state to begin proceedings before November 2022 to consider measures including the establishment of new, EV-specific rates that: 1. Promote affordable and equitable EV charging options for residential, commercial, and public EV charging infrastructure; 2. Improve the customer experience associated with EV charging, including by reducing charging times; 3. Accelerate third-party investment in EV charging; and 4. Appropriately recover the marginal costs of delivering electricity to EVs and EV charging infrastructure (U.S. Congress, 2021).

are clearly exploring a variety of approaches to demand charge designs, which seek to address these challenges in a balanced way.

Several aspects of demand charges were examined in the available tariff information. Where demand charges were present, the research noted the existence of a demand charge component of the rate as follows:

- **Traditional Only**: Rates that included a typical, traditional design for a demand charge[25]
- **Alternative Only**: Rates that only included an alternative to a traditionally designed demand charge (e.g., demand subscription model, monthly upper limits on billed demand, level of demand charge tied to monthly load factor or station utilization[26]).
- **Alternative Overlay**: Rates that under particular conditions specified in the tariff overlaid an alternative to a traditional demand charge (e.g., discounted demand charge applied as a credit, reduced demand charge for off-peak usage, phasing out the $/kW demand charge in favor of a $/kWh volumetric energy charge based on station utilization) on top of a traditionally designed demand charge, both which were included in the tariff filing[27]
- **Holiday**: Rates that included some version of a demand charge holiday, where the demand charge would be suspended for a period of time or where the holiday would otherwise be scheduled to sunset.

Our analysis found that the vast majority of currently offered EV-specific rates did not include any form of a demand charge (see Figure 8), which is consistent with the observation that demand charges are almost exclusively a component of commercial customers' rate designs. Of the 29 rate offerings that did, eight exclusively employed a traditionally designed demand charge, 13 layered an alternative design onto a traditional one, and eight used an alternative design without explicitly including a traditional design. A little more than 15% of the rate offerings with a demand charge applied a holiday, during which the demand charge was suspended (5).

Of the proposed EV-specific rates, we see increased interest from regulators and/or utilities in including some form of alternative demand charge, even if it is not applied via a holiday. Ten of the 12 proposed rates included an alternatively designed demand charge that was either overlaid onto a traditionally

[25] Traditional demand charges are designed to apply a charge (cost per kW) based on the customer's maximum demand at a particular point in time (e.g., coincident at the bulk power system's maximum demand or non-coincident at the customer's maximum demand) over a specified interval of time (e.g., one hour) (Hledik, 2014).
[26] This includes reducing the level of the $/kW charge or phasing out the $/kW demand charge in favor of a $/kWh volumetric energy charge during times when the customer has a low load factor or low station utilization rate (e.g., low amount of electricity the charging station demands from the grid per unit time), but increasing the level of the $/kW demand charge or phasing out the $/kWh volumetric energy charge in favor of the demand charge during times when the load factor or charging station utilization rate increases.
[27] In these instances, only the rate design elements described are altered, effectively replacing their counterparts in the original rate design, preserving the other elements of the rate's design (e.g., fixed charge, customer charge).

designed demand charge (8) or applied in isolation (2). All but one of these also included a provision to suspend that demand charge until certain criteria were met.[28]

Approved EV-specific rate pilots did not appear to focus on testing the application of demand charges, regardless of design. Only 14 of the 55 rate pilots included some form of a demand charge. Of those that did, three included a traditionally designed demand charge, four included an alternative to such designs, and seven overlaid an alternative design onto a traditional one. Only a single rate pilot included some sort of demand charge holiday.

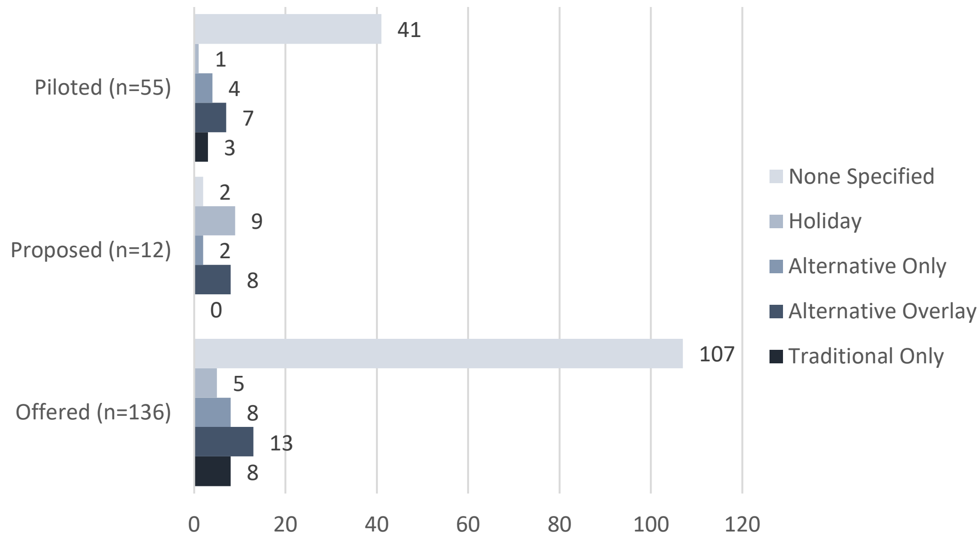

Figure 8. Count of Current EV-Specific Rates by Status and Demand Charge Type

4.2.5 Charging Controls

A number of options exist for customers to control EV charging in response to EV rate price signals, including EVSE and EV technology and software (e.g., smartphone applications). Additionally, utilities may be interested in directly controlling a customer's EV charging load to reduce or avoid charging during peak demand periods and/or to shift charging from high- to low-cost times. Where such controls were explicitly included in the rate design, they were assigned in the database based on the entity with ultimate authority to control charging as follows:

- **Utility Control Only**[29]: Rates that exclusively allow the utility to directly control the charging equipment, under specified circumstances, without the ability for a customer to override the utility control signals

[28] Typically, the criteria reflected improvements in either utilization or load factor that lead to the phase in of demand charges.

[29] The most common application of this type of control is through managed charging programs, which is excluded from this analysis, that provide a direct payment or bill credit for participation. However, in the context of rates, utilities will offer a lower rate in exchange for the right to limit EVSE output (kW or kWh) based on periods of high grid demand and/or high station utilization.

- **Customer Override**: Rates that give the customer the ability to override utility control signals, under specified circumstances
- **Customer Control Only**: Rates that exclusively give the customer the ability to directly control charging equipment

We found very few examples in the database of offered EV-specific rates that explicitly included some form of charging controls.[30] Two currently offered rates allowed customers to override a utility's control signal, and only one integrated customer control over EV charging loads (see Figure 9). No examples of rate offerings that strictly allowed utility control of EV charging were found.

Likewise, we found no proposed EV-specific rate filings with any mention of charging controls. Of the six pilots that included charging controls, five allowed customer override of a utility's control signal, and one integrated customer control of EV charging loads.

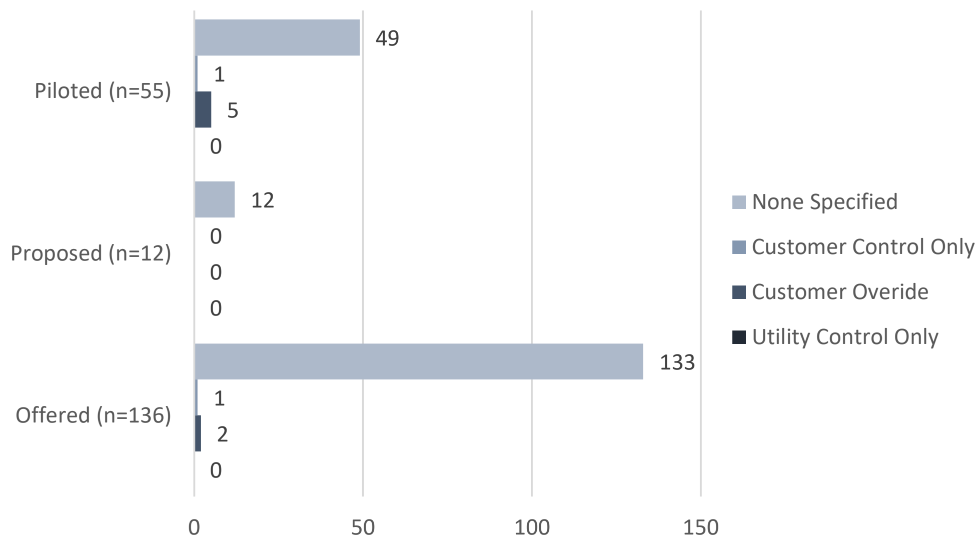

Figure 9. Count of Current EV-Specific Rates by Status and Control Source

4.3 Broader Categorization of Rate Design Elements

Of the 136 offered rates, we were able to identify some broad themes around rate design for residential, commercial, and utility-owned classes as follows:

1. **Residential Customer Rate Offerings (n=54)**: Although nearly every single residential EV-specific rate in our database included a TOU design, the dominant design comprising half of these also included eligibility or a requirement for some form of dedicated metering of the EV charging load while the remainder applied to the whole home either explicitly or implicitly. A little less than a third of the TOU rates with some form of dedicated metering also seasonally

[30] Many utility programs provide payments, rebates, or other non-rate incentives to promote more direct control of the EV charging load.

differentiated the period definitions and/or rate levels. Overall, the TOU rates primarily relied on a two-part TOU rate design (i.e., on-peak vs off-peak rate periods).[31] However, some rates incorporated a third period, as either a mid-peak set at a price level between the on-peak and off-peak, a super-off peak set at a price level below the off-peak, or some other rate variance in pricing per kWh. Only two of the TOU rate offerings with dedicated metering included a demand charge, which utilized a traditional design, and only one of those applied a holiday.

2. **Commercial Customer Rate Offerings (n=48)**: The dominant commercial EV-specific rate offering, comprising a little less than half of our sample, included both a TOU rate design, of which well more than half incorporated some form of seasonality, and some form of a demand charge, of which more than half applied a demand charge alternative or holiday (e.g., demand charge discounts, demand charge discounts tied to station load factor, demand charge discount sunsets or other reforms to address the viability of DCFC). Every single one of these TOU and demand charge rates required a secondary meter to exclusively measure the EV charging load, while almost half specifically applied to DCFC chargers. In contrast to these rate offerings, roughly a third of the commercial customer rates in our database used a TOU design without the application of a demand charge, most of which required a dedicated second meter. Only a handful of these rate offerings expressly mentioned charging technology, where either L2 or DCFC applied.
3. **Utility-Owned Charging Rate Offerings (n=27)**: Almost 80% of these utility owned charging rates were applicable to DCFC and nearly half applied to L2 chargers, although a handful of these rates applied jointly to both types of charging technology. Utilities employed different volumetric energy charges as part of the overall rate design. Only a third of the offered rates employed TOU design which were mostly determined from a "cost-based" perspective, considering T&D costs and other energy, delivery, and ancillary components, that typically differentiated by season. However, a handful employed a "market-based" methodology for setting these prices, looking at the cost of fueling gasoline and/or at the private market's pricing of its DCFC stations. A small number of utilities alternatively offered a flat energy fee for charging, with varying limiters, riders, and adjustments depending on the utility.[32] Not a single offered rate for utility-owned infrastructure included a demand charge.

We were also able to organize 41 of the 54 pilots into one of five themes as follows[33]:

1. **Commercial Customer Rate Pilots (n=14)**: These rate pilots generally included TOU rate designs, although a few sought to evaluate the viability of more temporal differentiation; one, for example, utilized an RTP design based on real-time hourly integrated wholesale market prices. Several rate pilots incorporated varying applications of demand charge alternatives,

[31] The ratios of on-peak vs off-peak periods vary across service territories and further research would need to be conducted to determine what is driving differences in those ratios. Presumably, these are a function of local system conditions, with variables (e.g., generation mix) that may not be directly comparable from one service territory to the next, as well as policy preferences that may affect cost allocation for recovery in the different rate periods.

[32] For example, Rocky Mountain Power in Utah has a credit for both off peak charging and for rate-paying customers.

[33] The other 13 pilots covered more miscellaneous topics that could not readily be grouped with one another.

inclusive of demand charge limits or discounts. Many appeared to generally include DCFC infrastructure, but in a few instances pilot EV rates also applied specifically to L2 charging equipment.

2. **Residential Customer Rate Pilots (n=13)**: These rate pilots also generally included TOU rate designs, but relied on varying ratios of peak to off-peak charging rate levels.[34] A few were focused on testing customer acceptance and measuring charging load in response to rates whose volumetric energy charges were tied to different metering configurations. One pilot was restricted to only those with L2 or DCFC chargers and applied an on-peak-only demand charge exclusively to the EV charging load.
3. **Utility-owned Charging Station Rate Pilots (n=10)**: As more utilities apply for self-owned owned charging stations, the rates that they initially offer at these stations are generally rolled out on a pilot basis but exhibit many of the same design elements of offered rates at utilities with more established charging stations. These rate design elements commonly include: discounts for customers charging in the service territory, rates set at a "market rate" or with requirements that charging stations be located in underserved communities or within certain charging corridors that otherwise lack investment from the private market. Not a single pilot included the application of a demand charge. In certain cases the rates were offered as pilots to give the utilities more experience and the opportunity to apply learnings from offering charging services.
4. **Commercial Fleet Rate Pilots (n=2)**: These rate pilots were only available to commercial fleet operators who relied on L2 or DCFC chargers. One largely focused on utility control and optimization of the charging load, while the other sought to test the viability of rate designs more consistent with the general status quo (i.e., TOU rate design and a demand charge, both with seasonal variation).
5. **School Bus Fleet Rate Pilots (n=2)**: These rate pilots were only available to customers with fleets of school buses, and both included simple TOU rate components.

5. Discussion

Overall, our research found that EV-specific rate designs currently offered by investor-owned utilities in the U.S. for residential, commercial and utility customers generally included peak and off-peak period prices, often times with some form of seasonal differentiation in the period definitions or price levels, and submetering of EV charging load typically via a second utility account meter. A little less than half of the EV-specific rates offered to commercial customers included some form of a demand charge, while such were almost never included in rate offerings to residential customers or at utility-owned infrastructure. Regardless of customer type, rates basically never included locational differentiation and neither required nor integrated direct charging control technologies. The design of the 12 proposed

[34] The ratios of on-peak vs off-peak periods vary across service territories and further research would need to be conducted to determine what is driving differences in those ratios. Presumably, these are a function of local system conditions, with variables (e.g., generation mix) that may not be directly comparable from one service territory to the next, as well as policy preferences that may affect cost allocation for recovery in the different rate periods.

rates and 54 piloted rates in our database is generally consistent with these offered rates in terms of metering configuration, temporal differentiation, and locational differentiation. The general similarities between rates currently offered and those either proposed or piloted suggests limited widespread interest in moving beyond the status quo in EV retail rate design. However, a handful of the commercial rate pilots looked at either greater temporal differentiation (i.e., RTP) or a broader array of demand charge alternatives. It is worth noting that insofar as rate pilots may indicate interest notwithstanding the rather limited historical record of successful pilots transitioning to full-fledged rate offerings.

Based on these observations for both offered and piloted EV-specific rates, we can infer a number of policy-driven objectives. First, utilities and regulators may be highly motivated to promote EV adoption through simple rate designs while seeking broad management of grid impacts from the additional electric demand associated with charging loads (e.g., by encouraging off-peak charging). Second, the absence of highly dynamic temporal or locational rate designs suggests that, as in other utility applications, achieving the greatest level of economic efficiency is likely not as high a priority at the present time as other issues or may not be feasible or cost-effective due a variety of reasons (e.g., the existing metering infrastructure is too limited or nonexistent). Third, a small handful of rate pilots suggests utilities may be motivated to simply gain experience with new customers and presumably new electricity demand patterns (e.g., third-party or utility charging stations, commercial or school bus fleets), but again the historical record of pilots leading to full rollouts is dubious at best.

As we have noted, utility regulators have a central role to play in the development of the EV future, including seeking solutions to encourage EV adoption, integrate EVs and charging technologies into the electric system, and ensure that benefits are shared equitably by all. The research provided here addresses the critical role that rate design can play, but also suggests a number of near-term considerations for regulators and policymakers and some areas of potential future research.

First, it is important to consider implications of EV rate design objectives vis-à-vis other distributed energy resources (DERs), especially because states typically have different rate designs and policies or goals for individual DERs. The importance of the specifics of any particular rate design in assessing the potential impact on DER deployment more broadly cannot be overstated. For example, EV rate designs, and the trend towards rates that encourage load shifting more generally, will likely benefit more flexible DERs as opposed to DERs like energy efficiency and distributed solar photovoltaic systems with largely uncontrolled load shapes (Satchwell et al., 2019). States also have considerably more experience with rate offerings for more traditional forms of DERs than EVs, so there may be opportunities to leverage that experience to design better and more effective EV-specific rates.

Second, regulators and utilities should consider the frequency with which EV-specific rate designs are updated or altered to reflect changing grid, economic and/or environmental conditions. Many current EV rates encourage charging during nighttime hours, yet it may not always be the case for certain power systems that nighttime will be identified as off-peak. In fact, greater EV charging during nighttime hours could conceivably result in a new peak, which would necessitate establishing new peak and off-peak rate periods and price levels (Satchwell et al., 2023). Furthermore, there is an increasing

number of electricity systems where surplus renewable power supply exists in daytime hours, which would suggest that EV rates might better achieve decarbonization goals by focusing on daytime charging.

Third, as EV deployments increase, it will be important to revisit EV rate designs in terms of their effectiveness in achieving the stated (or, more likely, implicit) objective – not unlike the net energy metering reforms that occur as distributed PV deployments increase and their marginal system value changes. The power sector is undergoing a significant transition to higher renewable energy deployments and increasing load from electrification. As such, the value of EV charging may shift to different periods of the day and year, which would necessitate altering EV rate designs accordingly.

Finally, this research effort was designed to characterize recent EV-specific rate designs in the investor-owned electric utility industry. It was not designed to assess *why* those particular rate design elements were proposed and approved, or *why* others were not. A research effort seeking to characterize the *why*, beyond the *what*, could help assess where the industry may be truly headed, what barriers impede more innovative and dynamic rate designs, and what opportunities exist to overcome those barriers. Additionally, there is very little public and easily accessible information about the enrollment levels for the offered EV-specific rates. Collecting and analyzing such information for each of the rates in our database could provide valuable insights concerning the scale, impact and effectiveness of individual and collections of different rate design elements. Furthermore, the federal government has taken certain specific actions that are directly relevant to state-level rate design. For example, recent legislation over the past two years, including the IIJA (U.S. Congress, 2021) and the Inflation Reduction Act of 2022(U.S. Congress, 2022), included important provisions for transportation electrification overall. The IIJA also included provisions that encourage states to seek reform of existing demand charges. Understanding at a much more granular level of detail how these federal statutes and provisions are affecting rate design could be useful for future federal and state policymaking efforts, as well as for state regulators still determining how to best react to these new federal policies. Lastly, while it is clear that rates are a critical component of achieving regulatory objectives, rates are not the only tool available to regulators. In fact, rates are more often coupled with incentives and other programs, which are usually designed to establish an ecosystem of enabling communication and control technologies to promote managed charging or vehicle-to-grid initiatives, among others. Understanding the types and frequency of program design elements offered by utilities as well as those being piloted could augment this report by providing a comprehensive snapshot of the current and potential future EV-specific programs in the U.S. electric utility industry.

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