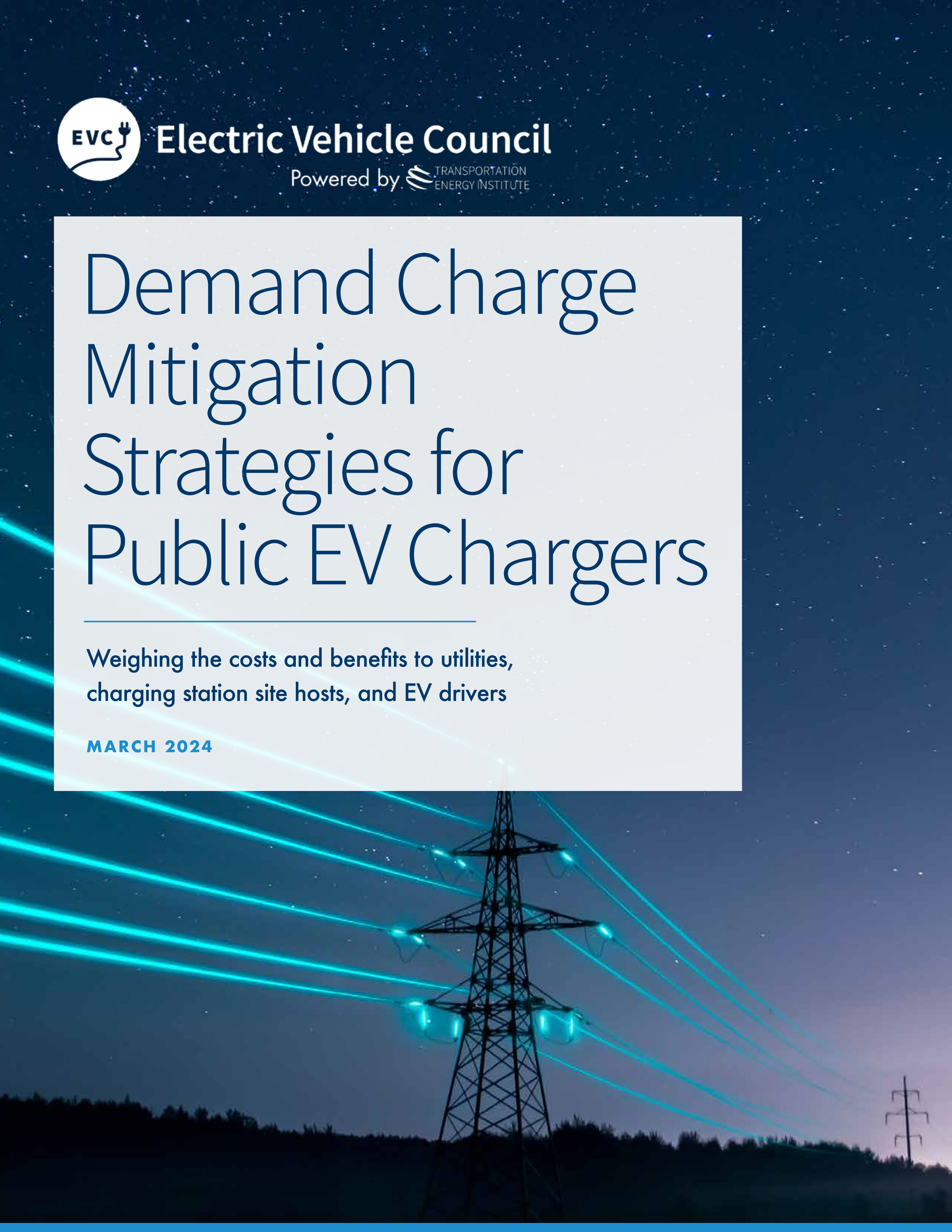

Electric Vehicle Council
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Demand Charge Mitigation Strategies for Public EV Chargers

Weighing the costs and benefits to utilities, charging station site hosts, and EV drivers

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Prepared for:
The Electric Vehicle Council of the Transportation Energy Institute

Prepared by:
E Source

Originally founded as part of the Rocky Mountain Institute (RMI), E Source has been supporting the electric, gas, and water utility industries with research, advising, consulting, and data-science services for nearly 40 years. E Source helps more than 600 utilities - that in turn serve more than 90% of the populations in the U.S. and Canada - to deliver best-in-class decarbonization and resource-efficiency programs, grid-modernization projects, and asset-management and operations optimization.

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EXECUTIVE SUMMARY

Demand Charge Mitigation Strategies for Public EV Chargers

Electric utility demand charges can have significant impacts on the business model of electric vehicle (EV) charging stations. Demand charges are fees levied by utilities on commercial and industrial (C&I) customers based on their highest level of electricity demand during a specified billing period, usually one month. They are designed to recover the cost of delivering power at times of peak-power demand on the electric grid to existing electric utility customers (e.g., commercial buildings, manufacturing facilities).

For example, an electric utility customer that installs four 150kW EV chargers would require an additional 600kW of service to deliver peak-power demand to the facility. The demand charges for this facility would be calculated based upon a demand charge rate (expressed in terms of $/kW) multiplied by the highest level of demand recorded over a period of time, often over a period of 15 minutes in a given month. Demand charges can represent a significant portion of a business customer's electricity bill, depending on how and when they use energy. (For more details about utility terms, concepts, rates and demand charges, see Appendix A beginning on page 51.)

For EV fast-charging stations—which primarily employ direct-current fast charger (DCFC) technology—demand charges can be particularly challenging, as these stations often have a high peak demand relative to their total energy consumption. The operating characteristics of public-access DCFCs—having variable and uncertain utilization characteristics—can lead to high operating costs relative to revenues, making it difficult for charging station site hosts to recover costs or operate profitably. For the purposes of this study, we are focused solely on operating costs for public-access DCFC stations used by light-duty consumer EVs.

To address these financial challenges, utilities, solution providers, and charging station hosts are all exploring different mitigation strategies to help lower operating costs. These include a variety of approaches for controlling and managing electricity demand, managing demand charges, experimenting with new utility rate structures, identifying new revenue streams and business models, and generally seeking alternatives for the profitable operation of EV charging stations. For example, DCFC station hosts may choose to offer pricing discounts during off-peak demand periods or to use a battery energy storage system (BESS) to store electricity for use during peak-demand periods. Where such options exist, they may also be able enroll in demand response (DR) or other utility programs to help manage peak demand, deliver grid services, reduce energy expenses, and lower total station operating costs.

TABLE ES-1: QUALITATIVE SUMMARY OF NET COST OR BENEFIT OF EACH MITIGATION STRATEGY BY STAKEHOLDER GROUP

STRATEGY	ELECTRIC UTILITIES	STATION OPERATORS	EV DRIVERS
Eliminate demand charges	–	+	+
Cap energy costs	–	+	o
Co-locate BESS	o	o	+
Manage charging	+	o	–

For each of the four demand charge mitigation strategies evaluated in this study, we summarize here the anticipated net impact to each stakeholder group. A "+" sign represents a net increase in benefits and/or decrease in costs, relative to baseline conditions (i.e., no mitigation). A "-" sign represents a net decrease in benefits and/or increase in costs, and a "o" sign represents no impact or costs and benefits that are more-or-less balanced. For example, for managed charging we can see that the utility benefits overall (lowered grid impacts/cost to serve), the station host experiences balanced cost-benefit outcomes (lower energy costs but also potential customer satisfaction concerns), and the EV driver generally experiences a decrease in benefits (longer wait times or reduced battery charge per session).

Source: E Source

The Transportation Energy Institute's Electric Vehicle Council commissioned this study to evaluate the potential effects of different demand charge mitigation strategies on various stakeholders. The intended audiences for this study are stakeholders operating in the electric vehicle market, including electric utilities, EV charging station site hosts and EV drivers. The intended outcome is to articulate how various demand-charge mitigation strategies are expected to impact costs and benefits to key stakeholder groups as EV markets evolve. As will be demonstrated, different strategies affect stakeholders differently; consequently, this report is not intended to identify a preferred strategy. Though myriad possible strategies exist, below are summaries of the most-common types of mitigation strategies we identified through our research. As shown in Table ES-1, each strategy carries with it a mixture of positive, neutral, or negative implications for the affected stakeholder groups:

1. **Reduce or eliminate demand charges for DCFCs.** This mitigation strategy involves creating special rate tariffs or "holiday" periods for DCFCs that reduce or remove demand charges in the rate structure. This can be an effective strategy for mitigating the negative financial impacts of demand charges to DCFC station hosts in the near term.
    - **Utilities.** This is how some rate tariffs for utility owned DCFCs are currently structured, leading to an uneven playing field for third-party

stations hosts and operators. Utilities may lose revenue if this strategy is broadly applied to all DCFCs. However, they may also attract more station development, projects, and load to their service territory when engaged in active rate reform, with growth in revenues over time. This option may place additional financial burden on utility customers in the near term, if the realized costs associated with serving DCFC stations are passed along to the ratepayers. Utilities should also consider testimonials and hearings which call into question coincident-peak impacts of DCFC station operation and the actual costs incurred on the grid.

- **Station hosts.** In most cases, eliminating demand charges would reduce energy costs for EV charging station site hosts immediately, lowering the cost to operate these stations, improving their margins, and eliminating the need to implement other demand-charge mitigation strategies. Under ideal conditions, this may encourage broader investments in infrastructure from the private sector.
- **EV drivers.** To the extent that lowering or eliminating demand charges encourages greater investments in EV charging infrastructure, EV drivers will benefit from such investments. In the future, lower energy costs to site hosts could also theoretically be passed along to EV drivers in the form of competitive pricing. In the near term these same drivers may experience increased energy costs overall, where utility operating costs are passed along to the rate base, since all EV drivers are also electric utility customers and therefore rate payers. This approach may also limit the need for alternative strategies such as charge management/demand controls that impede the rate of EV charging, thereby improving EV drivers' experience.

2. **Cap the total per-kWh monthly energy costs for low-use stations.** This mitigation strategy involves setting a maximum monthly energy cost for DCFC hosts, typically based on how much energy is consumed in total per month (i.e., maximum $/kWh). It eliminates the possibility of massive monthly bills, helping to make energy costs for DCFC station site hosts more predictable and stable.

- **Utilities.** This strategy limits revenue loss for utilities, relative to eliminated demand charges. However, some of the cost burden associated with serving DCFCs may still reside with utilities and/or be passed along as rate increases to all utility customers. Implicit in this strategy is an assumption that as utilization rates increase, demand-based pricing will be reintroduced, and caps may be scaled relative to utilization or removed altogether.
- **Station hosts.** This strategy helps to de-risk DCFC investments in the near term by lowering monthly energy costs and making them more predictable and stable. This will help to improve the margins associated with DCFC station operation.
- **EV drivers.** With improved economics for site hosts, EV drivers may experience ancillary benefits, such as more installed DCFC infrastructure, better network coverage, and improved reliability.

3. **Install co-located batteries to help manage peak demand.** This mitigation strategy involves installing an on-site BESS at DCFC stations. Predictive analytics and controls are also needed to manage peak station demand and power flow mix from distributed energy resources (DERs). Continued use of BESS as a DCM strategy over time, however, will likely necessitate continuous upgrades and scaling to keep pace with increasing DCFC charge rates, utilization rates, and other technological advancements.

    - **Utilities.** DERs such as batteries can reduce the need for distribution system capacity upgrades and line extensions in some cases, depending on site characteristics. Batteries may also be used to help manage peak monthly demand, and to ensure agreeable power quality characteristics during DCFC operation. Utilities may lose revenues associated with monthly demand charges, but their cost to serve DCFC loads will be lowered as well.
    - **Station hosts.** Can save money via demand-charge management, depending on local utility rates. Where batteries are used to avoid grid service upgrades, project timelines can be accelerated. DERs may help improve station reliability, lower carbon intensity (depending on local grid mix), and improve the site host's ROI if and where excess power can be sold as export back to the grid. Grid interconnection requirements for DERs may also delay project timelines in some cases (e.g., when exporting power back to the grid). These systems also become less effective at managing demand as station utilization increases over time.
    - **EV drivers.** Where utility grid services are limited, an EV may still be able to receive a fast charge where co-located batteries are used, even during times of localized grid constraints, disturbances, or outages. This strategy may also deliver lower-carbon electricity for EV charging, depending on the local utility grid mix (e.g., when paired with renewable generation). However, during periods of high station utilization, the battery can be drained and the EV driver will experience a slower charge if the site has insufficient grid capacity.

4. **Manage EV charging during peak periods.** This mitigation strategy involves limiting or reducing the power draw for one or more vehicles charging at a DCFC station. Charging can be controlled by the utility, station host, or a third party, relative to station demand (e.g., number of vehicles charging simultaneously), grid demand, or both.

   - **Utilities.** The ability to make DCFCs a controllable load helps utilities to better plan for and manage the grid. Actual impacts of controllability will vary depending on how, when, where, and how quickly DCFCs can be controlled. Most of the prior studies we reviewed suggest that utilities desire controllable DCFCs.
   - **Station hosts.**By managing peak demand, station hosts may be able to lower their monthly bills (e.g., demand charges) and could potentially be paid to participate in EV managed charging or demand response (DR) programs and events, though these remain relatively rare so far. The practice of limiting total station power during times of peak utilization is already common among station hosts.
   - **EV drivers.** Drivers will most likely experience charging delays and reduced level of service when EV charging is managed. However, drivers may also be compensated for this inconvenience with discounts, payments, or other perks.

To ensure the long-term financial viability of DCFC stations, it is important that station hosts site and size charging equipment and stations with the intention of maximizing utilization. Utilities will always attempt to recover costs on both the energy delivered (consumption) and maximum power available (capacity). Building larger stations enables more throughput, but also requires higher utilization to cover demand charges. For stations with limited utilization – such as those located far from urban areas or major corridors – a rate tariff with a reduced demand charge, eliminated demand charge, or one with capped maximum monthly energy costs will tend to offer better financial returns than standard C&I customer rates that include demand charges. Where demand charges remain high and monthly energy costs are not capped, a co-located BESS could provide more-favorable operating costs relative to baseline conditions (i.e., unfavorable utility rate options).

Contents

List of Acronyms

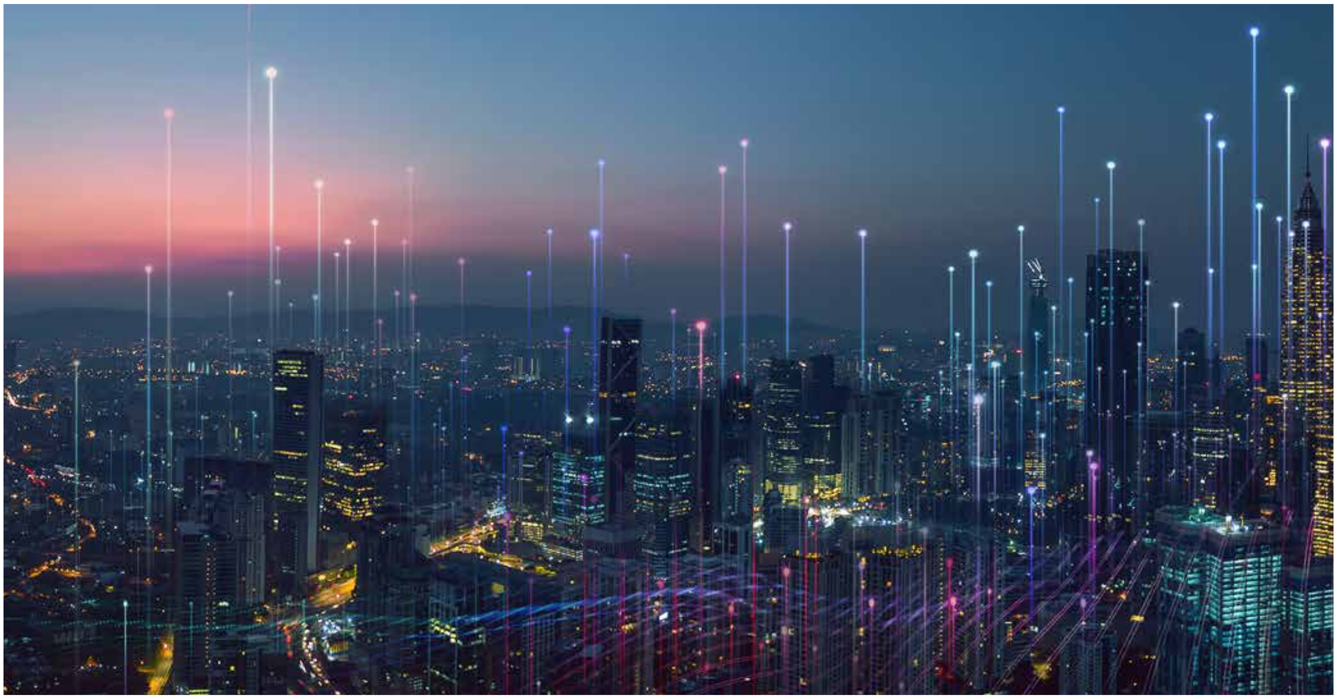
AFC	alternative fuels corridor; designation by the US Federal Highway Administration (FHWA)
BESS	battery energy storage system; any battery-based energy storage technology
DCFC	direct-current fast charger; high-power chargers used for faster charging of EVs and/or for charging large vehicles
DCM	demand-charge management; actively limiting the monthly utility demand charge
DER	distributed energy resource; a grid-connected device that can be called upon as a grid resource to produce, store, or modulate the use of electricity
DR	demand response; reducing electricity demand during critical grid events
EMC	electric membership cooperative; a member-owned, non-profit enterprise acting as an electric utility
EV	electric vehicle; refers generally to any vehicle that can plug in and draw electrical power from a grid
EVSE	electric vehicle supply equipment; a general term for EV-charging equipment
EVSP	electric vehicle service provider; a vendor offering EV-charging services
IOU	investor-owned utility; a privately owned enterprise acting as a public utility
kW	kilowatt; 1,000 watts (unit of power)
LF	load factor; ratio of energy delivered to total potential energy delivery
MW	megawatt; 1 million watts, or 1,000 kW
PPU	public-power utility; a non-profit enterprise acting as a public utility
PUC	public utilities commission; quasi-governmental bodies regulating public utilities
RDR	reverse demand response; increasing electricity demand during times of excess renewable energy generation
RTP	real-time pricing; time-varying pricing that more-or-less reflects real energy costs
TE	transactive energy; a system for the direct buying and selling of electricity between end users on a spot market, including real-time price signals
TOU	time-of-use; in reference to time-varying energy pricing
UF	utilization factor; ratio of time electrical equipment is used versus not used

INTRODUCTION

The cost of electricity reflects the price of generation and delivery to end-use customers, but the exact relationship between cost and energy pricing is complicated. Unlike other commodity markets – including liquid petroleum fuels – the price paid for electricity at any given moment in time does not accurately reflect the actual cost of delivering it to market.

Various "real time pricing" (RTP) and transactive energy (TE) solutions have been postulated, proposed, and even piloted by electric utilities and research organizations, but so far, such approaches are not widely adopted. To compensate for the mismatch in spot-market energy costs and prices – and to comply with state and local regulations and market requirements – utilities have tended to design ever-more diverse and complex rate tariffs over time. This serves the purpose of spreading the cost of operating and maintaining the electric grid evenly over time and the entire "rate base" (utility customers), and also comply with their obligation to serve all customers.

In 2022, electric vehicle (EV) new car sales surpassed 5% of market share in the US for the first time, and this trend in transportation electrification is only expected to accelerate in the coming years. It is particularly important for stakeholders in the US to develop a shared understanding of related needs and issues as the federal government implements its National Blueprint for Transportation Decarbonization and allocates large sums of money to both public and private efforts to electrify transportation systems.



SITING AND OPERATING FAST CHARGING STATIONS

While federal and state governments have been partnering with and funding EVSPs to deploy DCFCs across the US for more than 10 years already, there continues to be a lot of variability when it comes to station siting, sizing, cost, design, layout, access, uptime, and level of service across different networks. Tesla's Supercharger network stands out as the clear market leader in terms of size, level of service, and cost to deploy, according to financial reports and public records (e.g., Plug in America, 2022).

Roughly 60% of all fast chargers in the US are owned and operated by Tesla, and Tesla drivers report higher uptimes and lower incidence of "major difficulties" when attempting to charge (e.g., 4% for Tesla vs. 25% for non-Tesla charging stations in California). Tesla has also started to open up its charger network to non-Tesla vehicles through its Non-Tesla Supercharger Pilot in countries outside of the US, and has reported it plans to also open up access to 7,500 Superchargers in the US by the end of 2024. As a result, more than half a dozen automotive manufacturers and several charging station operators and manufactures have announced they will now comply with the Tesla charging specification, commonly referred to now as the North American Charging Standard (NACS; see North American Charging Standard).

In discussions on federal funding to expand DCFC networks along US Alternative Fuels Corridors (AFCs), the issue of what constitutes an appropriate "minimum distance" between charging stations has been discussed at length. Of course, it is difficult to plan for an optimal spacing of stations when charger reliability remains low for some locations, but the current goal set by the Biden Administration is a minimum spacing of 50 miles between charging stations. For DCFC projects to be eligible for federal funding as part of NEVI in support of the AFC program, they must meet higher minimum nameplate and operational power output requirements. Whereas many early-generation DCFCs operated at 50 kW maximum power output, the new minimum threshold has been set at 150 kW or more per DCFC unit and 600kW or above per DCFC charging station site to receive funding through NEVI in support of the AFC program (see National Electric Vehicle Infrastructure Standards and Requirements).

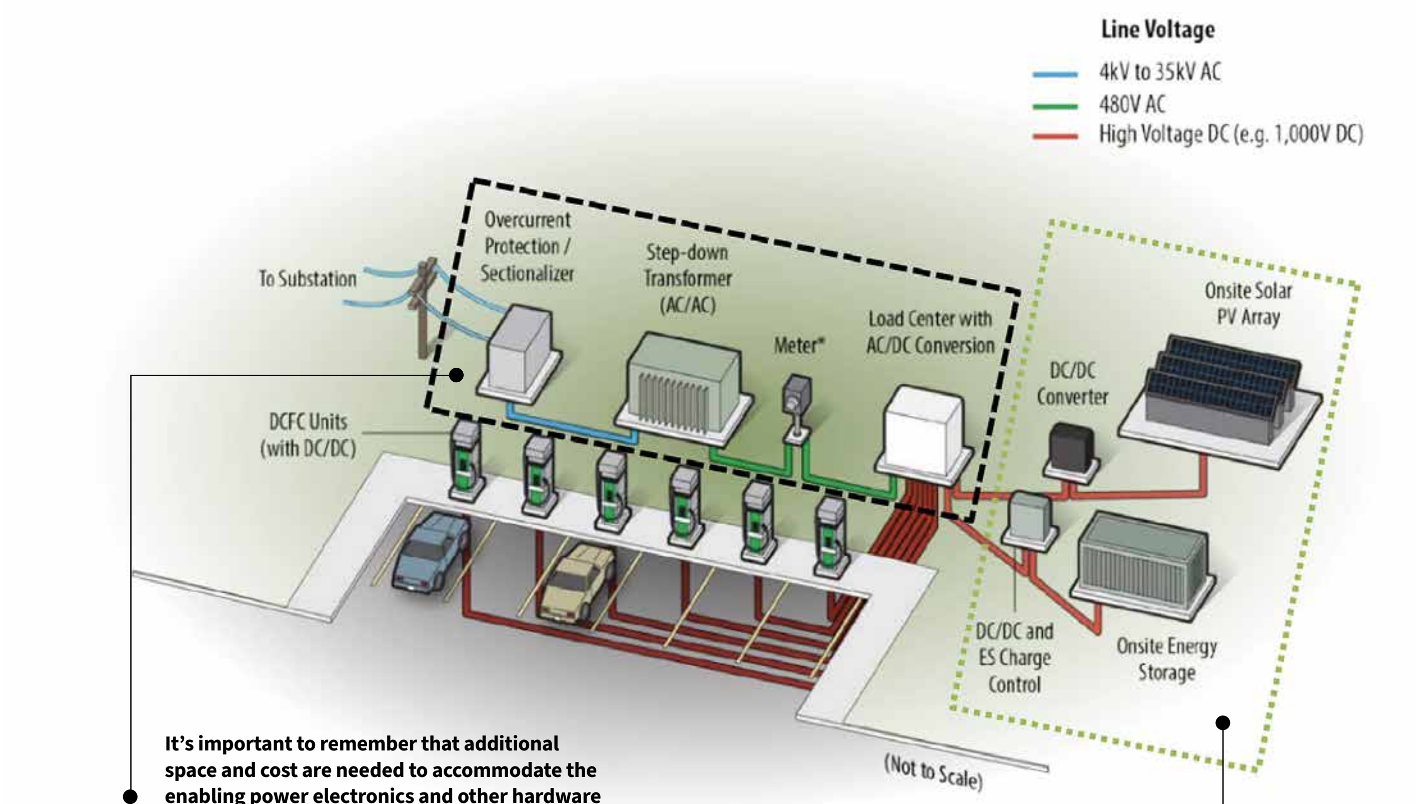
SITING NEW DCFC STATIONS

Through our conversations with EVSPs and other DCFC station hosts, we've learned that the siting criteria used for DCFC deployment are similar across organizations. These companies seek high traffic volumes along major routes, often within or connecting urban centers. This can lead to multiple

EVSPs competing for space and grid capacity at the same locations, in what some of these companies have self-described as a “land grab.” From a utility perspective this is not ideal, since the optimal location for siting a DCFC for drivers is not always co-located with available grid capacity or ease of service upgrades. Usually, EVSPs are forced to queue in a first-come, first-served fashion, just as any other utility customer must typically do when requesting a new, upgraded, or extended service. Some utilities like Pacific Gas and Electric (PG&E) offer decision support tools for station operators and site hosts and provide information resources on their websites (e.g., Site information for electric vehicle Direct Current Fast Chargers).

Important siting criteria include the proximity and location of utility high-voltage service (e.g., 400- or 480-volt), the configuration of the lot or rest area, existing distribution grid capacity constraints, and trenching distances. These site-specific factors can drive up project costs and extend development timelines significantly, making it difficult to estimate average costs for DCFC installation across multiple locations without a site visit and capacity assessment. And while the chargers themselves are the piece of equipment that is seen and used, additional make-ready infrastructure is needed to deliver power safely from the utility service drop point to the vehicles (Figure 1).

FIGURE 1: A DCFC STATION REQUIRES HIGH-POWER, MAKE-READY EQUIPMENT TO OPERATE



It’s important to remember that additional space and cost are needed to accommodate the enabling power electronics and other hardware at a DCFC station. In many cases, this “make-ready” equipment (designated by black-dashed box) can cost more and require longer lead times to procure than the charging equipment itself.

Establishing easement agreements can also require a lot of time and effort, sometimes delaying project completion. Co-located storage and/or generation may also deployed (designated by green-dotted box), but these equipment are not necessarily required for station operation. (adapted from Francfort et al., 2017)

*Meter may be located on the other side of the transformer

Source: Francfort, J., Shawn Salisbury, John Smart, Thomas Garetson, and Donald Karner (2017, May). Considerations for Corridor and Community DC Fast Charging Complex System Design. Retrieved from: https://avt.inl.gov/sites/default/files/pdf/reports/DCFCChargingComplexSystemDesign.pdf

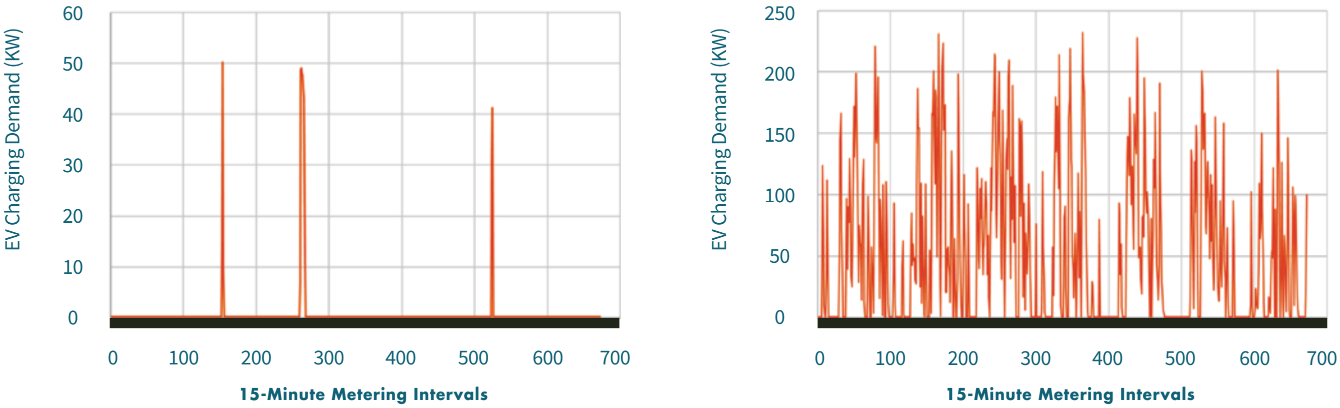
Even the most helpful and cooperative utilities may struggle to adequately support planning and meet anticipated timelines on DCFC projects.

GRID CAPACITY AND STATION UTILIZATION CONSIDERATIONS

Unfortunately, there is usually no single or perfect source of information about the state of the grid in many utility service territories, especially for large systems. Even the most helpful and cooperative utilities may struggle to adequately support planning and meet anticipated timelines on DCFC projects. For example, we mentioned earlier that PG&E is a leader among utilities when it comes to supporting DCFC deployments. At the same time, it is one of the largest electric utilities serving a sprawling service territory of 5.5 million electric customers. Even in Northern California, it can take 3 years (or longer) from the point of project initiation to completion and commissioning of a DCFC station. Some of the best-available public guidance PG&E offers its business customers comes from a study conducted in 2015 and 2016 and a corresponding micro-siting tool developed as part of that effort (Direct Current Fast Charging Mapping). While many of the findings and recommendations from this large joint study are still valid and its forecasts extend out to 2025, information about the state of PG&E's grid and locational capacity constraints probably aren't very useful at this point.

In some instances, utilities may maintain so-called "hosting capacity" maps online to illustrate approximate localized grid capacity availability in their service territories. You can think of it as the utility's way of communicating how able their distribution grid is to "host" new power demand or supply locally. Similar maps were first generated in response to the needs of distributed solar installers and customers installing on-site solar power, and more recently we're seeing maps made available to support building and transportation electrification objectives (e.g., for siting EV charging stations). Unfortunately, most utilities do not publish hosting capacity maps online, but increasingly we see the need for more transparency when it comes to comparing current and forecasted demand for EV charging with locational grid-capacity information. As just one example, regulated utilities operating in the state of New Jersey are required to publish capacity maps and you can find some of them online (e.g., see PSE&G's EV Hosting Capacity Map).

FIGURE 2: UTILIZATION RATES CAN VARY SIGNIFICANTLY AMONG DCFCS, EVEN AT NEIGHBORING STATIONS



Two DCFC stations located along the same major corridor in a relatively remote area, operated just a few miles apart from each other, with drastically different utilization rates (e.g., < 1% vs. > 30%). Part of this might be explained by site-specific characteristics, but much of the difference has to do with station performance and which EV drivers have access to these stations.

Source: Confidential; utility customer AMI meter data from anonymous utility and customers

In addition to considering site-specific factors, actual station utilization can vary to a large extent based on charging station brand and the specific end-use customer populations being served. For example, we've observed two DCFC stations located along the same major corridor in a relatively remote and rural area, operated just a few miles apart from each other, with drastically different utilization rates. Part of this might be explained by site characteristics, but much of it likely has to do with which drivers are using these stations. In Figure 2 you can see weekly load profiles for these two public-access DCFC stations.

The load profile on the left is for a 50kW, non-Tesla legacy station, which serves mostly non-Tesla vehicles. The load profile on the right is for a Supercharger station with multiple DCFCs that each can deliver up to 150kW (though combined maximum power is limited), used only by Tesla EV drivers. Due to their larger batteries and longer driving ranges, Tesla vehicles are more likely to make longer road trips, even to relatively remote parts of the country. Meanwhile, the non-Tesla station is likely mostly used by local EV drivers, and obviously infrequently. While the utilization rate of the non-Tesla station is around 1%, the utilization rate for the Supercharger station is closer to 30%. Because of this, a standard rate with a demand charge may be perfectly reasonable for the Tesla station, but for the non-Tesla station is could be prohibitive.

CUSTOMER EXPERIENCE, EXPECTATIONS, AND CHARGING BEHAVIOR

Dating back to the EV commercialization efforts of the 1990s, public EV charging station reliability has been a weak link in the effort to electrify transportation. More recently, independent studies of DCFC up-time and operability indicate that on the order of 1 in 4 existing DCFC stations are not available for use by EV drivers at any given time (see the DCFC reliability, utilization, and grid impacts section of this report for more details). Much like utilization rates, it has also been observed that Tesla Superchargers have significantly higher reported levels of both uptime and customer satisfaction (Plug in America, 2022).

In general, customers find EV public charging rates to be confusing and inconsistent. EV drivers rarely understand why differentials exist in pricing for DCFCs in different locations or used at different times. When pricing is confusing to customers, it can be very challenging to send an effective price signal to influence their charging behavior or purchase decisions. Customers are also accustomed to gas prices that fluctuate daily or weekly, whereas the marginal cost to deliver electrical power fluctuates hourly. When customers are charged more without explanation for what they view to be the same level of service, customer satisfaction and brand loyalty will tend to suffer.

This same observation – that individual customers don’t like to be charged more when they don’t feel like they are receiving more value – can just as easily apply to station site hosts, as customers of electric utilities. Due to the confusing nature of utility rate tariffs, station hosts may not understand why they are being charged more or how to effectively make operational adjustments that will save them money, assuming such options exist.

Evidence from early EV adopters suggest that acceptable EV recharge times are entirely dependent on where the vehicle is located and what the driver is doing while the vehicle charges. For example, if the driver is waiting in a hot dusty parking lot with nowhere else to go and nothing else to do, recharge times should be as fast as possible. But if the vehicle will be parked for long periods anyway, or drivers have desirable ways to spend their waiting time, then the speed of the charging session may become less important (e.g., see the Forbes article series on It’s Not Where You Charge An EV, It’s What You Do While Charging).

TYPES OF UTILITIES, THEIR SIMILARITIES, AND DIFFERENCES

When engaging with a new utility – and especially when attempting to interface with multiple utilities at once to negotiate tariff agreements – it is helpful to understand each individual utility's structure and function. Knowing at least a little about how utilities operate can make it easier to understand how their businesses operate to get a better view of the role they play in local markets and communities.

In many states, there have been debates over whether it should or should not be legal for non-utilities to resale electricity to customers while not being regulated as an electric utility themselves. The consensus is that EV charging shall be exempted from broader utility regulation, with only a hand full of state exemptions (i.e., Montana, Nebraska, Tennessee, and Wisconsin do not allow non-utilities to sell electricity directly to consumers).

INVESTOR-OWNED UTILITY (IOU)

As for-profit businesses, the IOUs are similar in some ways to other for-profit businesses. However, as "regulated monopolies" these utilities are subject to stringent state and federal regulations. While IOUs may offer various utility services – be they electricity, natural gas, water, wastewater, or solid waste – most IOU business is related to energy (e.g., electricity and natural gas). If a utility has a parent or holding company, it is probably an IOU. These utilities come in many flavors and sizes and can be quite complex in construction. An IOU could be anything from a small local legacy "electric and light" company owned by a larger holding company, all the way up to a massive multi-national conglomerate, composed of multiple holding companies serving different states and regions. The very largest utilities in the US are IOUs, and even though they make up the smallest fraction in total numbers, IOUs serve the majority of the US population (e.g., about 2/3 of all electric customers are served by IOUs).

Since they are heavily regulated by state and federal governments, IOUs are held accountable for their spending and have rigorous reporting requirements. In this way, IOUs may sometimes act as if they are an extension of state and federal government, even though they are private enterprises. They also may view the regulator with disdain, as changes in state policy and decisions made by the utility commissions can cost them very large sums of money and complicate their business models in new and painful ways. But this is all part of the process. For regulated utilities, cost-recovery and cost-causation are viewed as vital to IOUs and their investment and business decisions. Or at least, that is the intention behind their “regulated monopoly” business model; in practice, the degree to which IOUs are effectively held accountable for their spending is regularly called into question. Some states have enacted varying degrees of utility “deregulation,” meaning that some or all IOU activities don’t require as much rigorous oversight and scrutiny.

All IOUs are driven by profitability and shareholder returns, with varying degrees of success (e.g., electric utility stocks are sometimes considered longer but safer investments). Private ownership is sometimes touted as a benefit that enables the IOU to focus more on innovation and progressive business investments rather than solely offering egalitarian service to the community or member-owners, though this certainly varies from one jurisdiction to the next. Deregulated utilities and the deregulated divisions of regulated IOUs tend to be more aggressive when it comes to profitability goals, business growth, and seeking opportunities to enter new markets. This may be helpful to keep in mind when considering exactly what role a given utility plays in the local markets, and potentially what role it may seek to play in the future.

It’s also important to keep in mind that utility regulations are not all fixed in stone, and that over time some utility activities that were forbidden may eventually be allowed or even encouraged by their regulators (or vice versa). A classic example can be seen in California where the public utilities commission (PUC) forbid utilities from owning and operating EV charging equipment for some time, to prevent the IOUs from establishing a market monopoly over electric fueling. However, the PUC later determined that the EVSE market was stagnating and that the IOUs there could fill an important market gap, eventually allowing the IOUs to recover the costs from investing in EV chargers from their respective rate bases (customers). By comparison, Illinois and other states are currently in the same position that California was in 10 years ago, and the regulators in these states are concerned about unduly burdening rate payers with the cost of deploying EV charging infrastructure.

Because of their larger size and the fact that they may have expanded over time to include/absorb multiple legacy utilities, some IOUs continue to maintain old and aging grid assets, serve very diverse populations, and generally have a more-difficult time expanding and upgrading their grid and services. IOUs are more likely to have complicated rate tariffs and a wider selection of different rate tariffs from which to choose (for better or worse). Also due to their larger size, IOUs may be better at serving large utility customers (i.e., key accounts) but have relatively little engagement with, or detailed knowledge of, their smaller customers.

PUBLIC-POWER UTILITY (PPU)

Also sometimes referred to as "municipal utilities," PPUs are commonly associated with a city, town, village, borough, or other local governmental body. A PPU is a non-profit enterprise, owned by the community they serve. PPUs emphasize their community focus and localized benefits, and in this vein have some of the strongest marketing and branding of any utility type (and some PPUs also maintain very high customer-satisfaction rates, to match their marketing). Though not universally true, if the utility's name includes the name of a city or town, there's a good chance that it's a municipal utility. The largest PPU in the US is Los Angeles Department of Water and Power (LADWP), serving 1.4 million electric customers and 4 million water customers.

PPUs are typically governed by a utility board that oversees and directs their actions, but ultimately these utilities answer to the populace of the municipality they serve. Generally speaking, PPUs and their actions can be viewed as existing in something of a "middle ground" between entirely for-profit utilities and non-profit cooperatives; PPUs tend to be more careful and conservative in some ways than IOUs but more growth-oriented than cooperatives. All utility types have strengths and weaknesses and have proven their abilities at innovating on specific issues and technologies. But thanks to their close alignment with local government, PPUs have the potential to scale innovative changes across their service territories relatively rapidly.

Like any other local government agency, PPUs run into the same issues and face the same challenges that any city government might face. Since the city government and the electric utility are essentially the same entity, it may be easier to engage with PPUs on projects or agreements requiring alignment of both stakeholders. At the same time, PPUs tend to be more political and bureaucratic by their very nature, which can lead to "siloing" of business functions, difficulty coordinating across various business units, and extra processes or red tape that some business customers may view as unnecessary or inefficient.

At the same time, PPUs are often great partners on new projects and some of the most innovative and progressive utilities in the US are municipalities. While most utilities typically have a working understanding of and degree of influence over local building codes and standards (C&S), some PPUs coordinate closely with other local government departments on C&S issues. This can be helpful when seeking utility input or related technical services on a new project, e.g., establishing realistic expectations of project scope, cost, and timeline.

ELECTRIC MEMBERSHIP COOPERATIVE (EMC)

The last of the three most-common utility types is the cooperative, sometimes referred to as an EMC, power association, electric co-op, and/or member corporation. Co-ops are also sometimes associated with the local counties they serve (e.g., the name of the county is in the name of the co-op). Cooperatives tend to be small but they are mighty in number; they have by far the largest total number of individual utilities operating in the US and also serve the largest total land mass, of the three major utility types. While cooperatives can theoretically be located anywhere, they tend to serve smaller and more-rural communities. There may be the presumption that cooperatives are only located in the Midwest – and there certainly are many that operate there – the reality is that cooperatives are abundant in the rural parts of all states, including California and New York. The one major exception is Hawaii, which only has one electric cooperative operating on the small island of Kauai. Pedernales Electric Cooperative in Central Texas is the largest utility of its type in the US, serving 345,000 customers.

Since cooperatives are non-governmental, non-profit, and member-owned organizations, their actions are obviously dictated to a large degree by member needs and priorities. In structure and function, this is perhaps the furthest model from a growth-oriented, profit-driven company, though the cooperative model is long-tested and continues to thrive after all these years. As you might imagine, cooperatives and their members tend to be both culturally and fiscally conservative and cost-conscious. Projects and investments that serve broad member needs and interests and help to place downward pressure on member rates will tend to be favored over those that do not.

Due to their rural, stable, and conservative nature and model, cooperatives may be more difficult to engage than other utility types when it comes to deploying a large EV-charging infrastructure project. This is of course not universally true, and some cooperatives may be "long on generation" and in search of new and viable load-growth revenue opportunities. Some cooperatives are also quite innovative; they were among the first utilities to offer direct rebates for EVs to their customers, and in some cases are the first to embrace and deploy new and emerging technologies. In any case, most cooperatives don't have much prior experience with large EV grid-integration projects, so they may require more time, patience, and close coordination to help them understand the nature of a project, the business opportunity it presents for them, and how to adjust their overall resource and capacity planning accordingly.

Most cooperatives don't have much prior experience with large EV grid-integration project, so they may require more time, patience and close coordination.

RATE TARIFFS, DEMAND CHARGES, AND MITIGATION STRATEGIES

While utility rate structures may seem straightforward for energy industry professionals accustomed to work with them, for non-utilities they can be quite confusing.

A rate tariff is an electricity pricing agreement made between a utility and its customers; for regulated utilities, these tariffs are reviewed and approved by state regulators. All details of how the customer will be charged by the utility for energy services – including who qualifies for the rate, service capacity ranges, energy blocks or pricing tiers, usage or timing variations, and other variables impacting energy costs – are included in the tariff. A typical tariff is between 2 and 10 pages long, though some may be even longer, and they often contain specialized industry language.

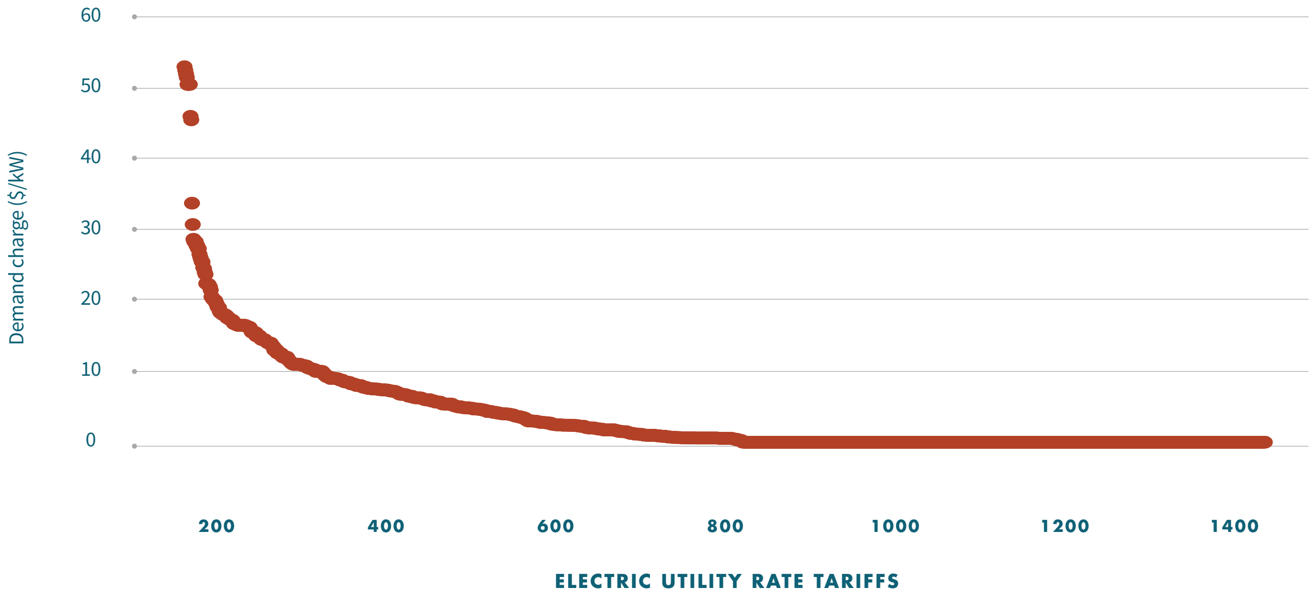
A demand charge is the part of the rate tariff that compensates utilities for maintaining and reserving sufficient grid capacity to serve the customer (and all customers). While demand charges and other capacity-based rate elements can take many forms, the simplest and most-common approach is to charge the customer a set dollar amount per unit of power demand (kW), based on the maximum power draw for the month. For example, if the demand charge for a given rate tariff is $10/kW and the customer's peak demand is 600kW, the demand charge for that customer for that month will be $6,000. The rate tariff – including the demand charge – is typically set when the customer establishes service with the utility, and in some cases the customer may have the option to select a different rate schedule (for more details on how utility rates are structured and how customers are billed, see Appendix A – Background information).

It can also be tempting to treat utilities as a monolith – assuming that they are all alike – and come to expect the same things when interacting with each utility. In operation, however, utilities can be quite unique from one region, state, or service territory to the next. Generalizing even within groups of utilities (e.g., all IOUs, co-ops, or munis) or by region can be potentially misleading. For example, our rate analysis for utilities operating in the Midwest shows that they have some of the lowest demand charges on average, as some might tend to expect. However, they also have rate schedules that include some of the highest demand charges overall (see Figure 3). In Appendix A, we also describe some of the attributes of the three major utility types and how they are similar and different in certain ways.

The purpose of doing this was to explain the conditions and constraints under which these organizations and their employees operate, in order to help the reader better understand and communicate with them.

When it comes to rates – and especially demand charges – we found that utility type is not necessarily a good indicator of rate structure or energy costs, in and of itself (for more details and results of our rate analysis, see Appendix C – Rate analysis). We reviewed nearly 7,500 C&I customer rate tariffs from 329 different utilities, using data sourced from the Utility Rate Database (URD) of the Open Energy Information (OpenEI) wiki, hosted by NREL. While this database is not as up-to-date as some paid

FIGURE 3: DISTRIBUTION OF MIDWEST UTILITY DEMAND CHARGES FOR BUSINESS CUSTOMER TARIFFS



If we consider only the average cases, our observations may match stereotypes and expectations about relative electric rates by utility type or region (e.g., California = expensive, public power = affordable). **But when we look across the entire US and a large sample of utility business customer rates for all regions and utility types, we see that stereotypes do not always hold true.** In the example pictured above, we compared all tariffs for utilities operating in the Midwest, and found examples of some of the highest demand charges in the country (e.g., up to $53/kW). On average though, this region has among the lowest demand charges (e.g., $7/kW).

Source: E Source; data from National Renewable Energy Lab [NREL] (2023, February). Utility Rate Database, OpenEI. Retrieved from: https://openei.org/wiki/Utility_Rate_Database services – like those made available by Arcadia Power and GridX – it is sufficiently large and publicly accessible, making it a useful resource that can be cross-referenced and compared across multiple studies. This is helpful in understanding general market and utility trends and validating findings. For anyone intending to make large investments in DCFC – and particularly for those who expect to install and operate hundreds or even thousands of chargers – we would recommend considering a paid data service for comparing and tracking the latest updates to electric utility rates.

We did not review every utility in the US, nor did we include every rate tariff listed in OpenEI. Our sampling is generally representative of non-residential utility rate options and includes utilities operating in all 50 states. We had no similar dataset for utility rates in Canada, and so our analysis is confined only to the US. We're also aware of those utilities experimenting with new rate designs that are not reflected in the UDR dataset, some of which have few or no customers enrolled so far (e.g., capacity-only rates, export rates). We will address these rate tariffs in the following sections. Consider also that most utilities are conservative by nature and do not make changes quickly nor hastily, and that the rate-making process tends to be long and arduous. With this in mind, we think the observations made here are likely still representative of most US utilities, C&I rate tariffs, and demand charges.

We are aware that utility rates in many parts of the US have risen in recent years, and that the corresponding rise in end-user energy costs is not necessarily reflected in the data we've pulled from the URD. To better account for inflation, economic downturn, and utilities passing on the increases in marginal cost to deliver electricity to the end consumer, we have spot-checked several utility rate schedules with an emphasis on experimental, pilot, and other DCFC-specific rates.

REVIEW OF UTILITY DEMAND CHARGES ACROSS THE US

Below are some general findings from our independent rate analysis (additional details and statistics can also be found in Appendix C). Note that tariffs with no demand charges (listed or otherwise) were not included in our statistical comparisons:

- **IOUs typically have the largest number of C&I rate tariffs.** This means there are more options to choose from, but not all tariffs are open to all customers, and they can also be more complex than those of other utility types. For example, the largest IOUs can have hundreds of business customer rates, each of which includes numerous rate-design features and agreement clauses that are updated and changed periodically.
- **The highest demand charges we found were around $50 per kW.** Regardless of utility type or region of the US where they operate, the maximum demand charges we found across all utilities and rates were around $50/kW, and only a small hand full of tariffs (utility rate schedules) included demand charges this high.
- **Rate tariffs with higher demand charges are also more likely to include tiers.** While this is far from a universal rule, we found that tariffs with higher demand charges often tier them – either increasing or decreasing the charge according to certain qualifiers – whereas tariffs with low demand charges are less likely to include tiers. However, we also identified quite a few rate tariffs that have $0/kW initial demand charge but apply a demand charge if the customer meets specific load factor (LF) or consumption threshold criteria (for a more-detailed definition and examples of LF, refer to Appendix A).
- **More than 40% of the non-residential rate tariffs we reviewed have no demand charges.** While it is possible that this is an artifact of the dataset we retrieved from the URD, we found that around 43% of all the non-residential rate tariffs we

reviewed had no demand charge listed or the value was listed as $0/kW. This is consistent with reports on NREL rate modeling and analysis (e.g., Muratori et al., 2019b).

- **Relatively few rates include demand-charge TOU elements or tiering.** While some C&I customer rate tariffs have complicated structures, including multiple tiers of demand charges that can vary by capacity, consumption, time-of-day, seasonally, or other factors, most rates are less complicated.
- **IOUs had the lowest average and maximum demand charges in our review.** The cooperative utilities we surveyed had the highest average demand charge at $9.60/kW, and the highest overall demand charge we found was for an industrial rate tariff offered by a public-power utility, at $53/kW. IOUs had the lowest average and maximum demand charges for those tariffs we reviewed in our analysis.
- **Utilities operating in the Northeast had the highest average demand charge.** Average demand charges were lowest and almost identical in the South and Midwest (~$7.25/kW). Average demand charges in the West were higher ($9.40/kW), but they were highest among the Northeast utilities we reviewed, at $10.67/kW.

EXPERIMENTAL RATES, PILOT TARIFFS, AND RECOMMENDED SCHEDULES FOR DCFCS

As we mentioned previously, it is within the electric utility's best interest to balance cost recovery with the business viability of DCFC operations. To that end, they are exploring new rate designs that are more appropriate for DCFCs in different applications. In the near term when station utilization is low and so are customer load factors, we're observing different strategies to essentially do the same thing; lower or cap monthly energy costs to make them more manageable and predictable for DCFC hosts. Below are some of the ways we've observed utilities making adjustments to demand-based charges:

- **No demand charges.** The rate tariff simply does not include demand charges (e.g., utility-owned DCFCs have been placed on special rate tariffs without demand charges)

- **Eliminated demand charges.** The rate tariff normally does include a demand charge, but the demand charge has been removed (for either an explicit or indefinite period)
- **Reduced demand charges.** Lowered per-kW demand charge for EV-specific rates
- **Offer demand-charge holidays.** Removing demand charges at specified dates or times
- **Offer demand-charge grace periods.** Allow customers to operate without incurring demand charges for a limited initial period
- **Phase in demand charges.** Low-to-no demand charges initially, with demand charges increasing over time (e.g., with a corresponding decrease in volumetric charges)
- **Cap demand charges.** Setting a maximum per-kWh cost cap
- **Load-factor based adjustments.** A cap on monthly costs for low-LF customers
- **TOU demand charges.** Lowering demand charges at off-peak times
- **Seasonal demand charges.** Lowering and raising demand charges seasonally

It is so far not necessarily clear which, if any, of these rate-reform strategies best reflect actual cost causation and cost-to-serve for DCFC loads from the utility perspective. Some of these strategies are likely to be more feasible in the near term (e.g., reduce or eliminate demand charges), while others could deliver more long-term benefits (e.g., load-factor based adjustments). Most of these approaches are generally often viewed as short-term solutions to the problem of high DCFC operating costs. For a list of utility experimental, pilot, and suggested rate schedules for DCFC customers, refer to Appendix C (Table C-1).

INFLUENCE OF ON-SITE STORAGE, GENERATION, AND LOAD-CONTROL

Generally speaking, there are three fundamental approaches taken to reduce or manage energy costs associated with DCFC operation:

1. **Select the best utility rate relative to your unique energy-use characteristics;**
2. **Apply load-management control technologies and techniques; and,**
3. **Offset or supplement grid demand using power from on-site sources.**

While it's certainly possible to apply all three approaches to help lower the operating costs of DCFC stations, these are listed in order of lowest-to-highest complexity. The low-lift option is to simply dial in the best-possible rate for your station, then "set it and forget it" (i.e., don't manage or supplement grid power demand). In general, this is the easiest approach and preferred by station hosts.

While option #1 may be perfectly acceptable for some DCFC station hosts, others may wish to employ more-sophisticated techniques and capture greater cost savings or other benefits. In general, approaches #2 and #3 tend to be synergistic, i.e., implementing controls + on-site electricity storage, generation, or both can deliver greater and more-diverse benefits than applying either in isolation.

While it's sometimes helpful to talk about on-site storage and generation collectively as DERs (distributed energy resources), for the sake of this discussion it is more valuable to consider them as distinct and separate technologies. There are different types of generation and storage technologies, each with their own unique operational, cost, and benefit characteristics.

DERS THAT SUPPORT DEMAND MANAGEMENT

- **Battery energy storage system (BESS).** A BESS tends to be a desirable form of energy storage because it is a flexible DER that can be charged and discharged rapidly and frequently as needed. As such, it is currently the only in-market, viable DER solution for managing DCFC station demand. BESS technology also operates in relative silence (though cooling fans can be heard on larger systems), and it can be deployed in a wide range of operating conditions and applications. BESS technology can be used to effectively manage demand and demand charges, though this requires precise controls, predictive analytics, and sizing. Charging and discharging batteries introduces energy losses, especially at high power rates, and this should be considered during system design. However, for larger DCFC stations and stations that are more-highly utilized, it is more difficult to make the case for using BESS as a reliable DCM strategy.

OTHER DERS

- **Solar photovoltaics (PV).** Solar PV tends to be a desirable generation option because it is relatively low cost, silent in operation, easily co-located with buildings (e.g., rooftop installations), and requires relatively little maintenance. PV is effective at helping to lower energy-related charges by reducing grid power consumption and in some cases, exporting power back onto the grid with reimbursement from the grid operator (e.g., through a feed-in tariff). PV alone is not effective at managing peak demand or demand-related charges, since solar availability is intermittent and solar arrays would need to be very large to power a typical DCFC station. However, when paired with BESS, they may offer some desirable benefits for station hosts and EV drivers (e.g., energy decarbonization, lower monthly energy bills).

> **The low-lift option is to simply dial in the best-possible rate for your station, then "set it and forget it".**

- **Wind generators.** Similar to solar, wind generation tends to be desirable because it produces no emissions while operating and can be quite cost-effective relative to other energy resources. However, wind power is very site-dependent and not every location will have adequate wind resource. The best-quality wind resource also tends to be relatively high off the ground and away from buildings, making it even more difficult to site and co-locate with existing buildings. While it's certainly possible to install on-site wind in support of DCFC operations, it is usually not the most-practical option. Wind generation alone – not paired with energy storage – is also not effective for managing peak demand.
- **Fossil-fueled generators.** The most well-established DER technology is the fossil-fueled generator. Often powered by natural gas, diesel, or propane fuels, generators are common, easily procured, and relatively low cost. More so than the other DER technologies mentioned so far, generators have well-established distribution channels, parts suppliers, and technicians familiar with their repair and maintenance. For emergency backup power, generators remain the go-to option for most applications. However, generators also have the worst emissions profile and carbon footprint of the technologies in this list, which is a big reason the other alternatives are being developed and promoted much more aggressively in recent years. They are not an appropriate option for daily use where environmental, health, or carbon restrictions apply.
- **Fuel cells.** Fuel cells are like a mix between a battery and a generator. As their name implies, some form of fuel is fed into the unit and used to generate electricity. The most common fuel types include methane (natural gas), hydrogen, and air. Fuel cells have an advantage similar to that of fossil-fueled generators, that they can operate grid independently as long as there is stored fuel available and are not subject to the same recharge limitations or state-of-charge (SOC) restrictions experienced by batteries. However, similar to batteries and in some cases more significantly, energy losses and costs are associated with producing, transporting, compressing, storing, and using the fuel.
- **Microgrids.** A grid is any conductive network connecting an electric source with one or more loads. The prefixes "micro" and "nano" can be confusing but are simply intended to denote an electric grid that can operate independently, in electrical isolation from the larger utility grid. What distinguishes a backup generator or stationary battery powering an emergency circuit from a full microgrid usually comes down to level of performance. A microgrid is often designed for resilience, with the intention of riding through multi-hour or even multi-day power outages on the utility grid. This added performance adds cost and complexity and is typically only worth the cost where site-specific factors dictate the need (e.g., operating mission-critical equipment, offering community resiliency services).

Of all the DERs, batteries are the technology class with the greatest demonstrated technical and economic performance and near-term potential for pairing with DCFCs to lower operating costs and improve performance (e.g., power quality). Adding BESS to a project can add cost, complexity, and time (e.g., for grid interconnection agreements), though in some circumstances it may help to reduce project timelines (e.g., with DCFC-integrated batteries, where utility grid service is currently insufficient to meet station kW demand). A few studies have been conducted to assess the viability of installing batteries to specifically improve DCFC performance and lower costs. Like other studies on the benefits and opportunities associated with grid-tied BESS, they generally point to the conclusions: that distributed batteries are a low-cost option when compared to increasing grid capacity at the grid edge where there is no three-phase power available (e.g., CEO, 2021).

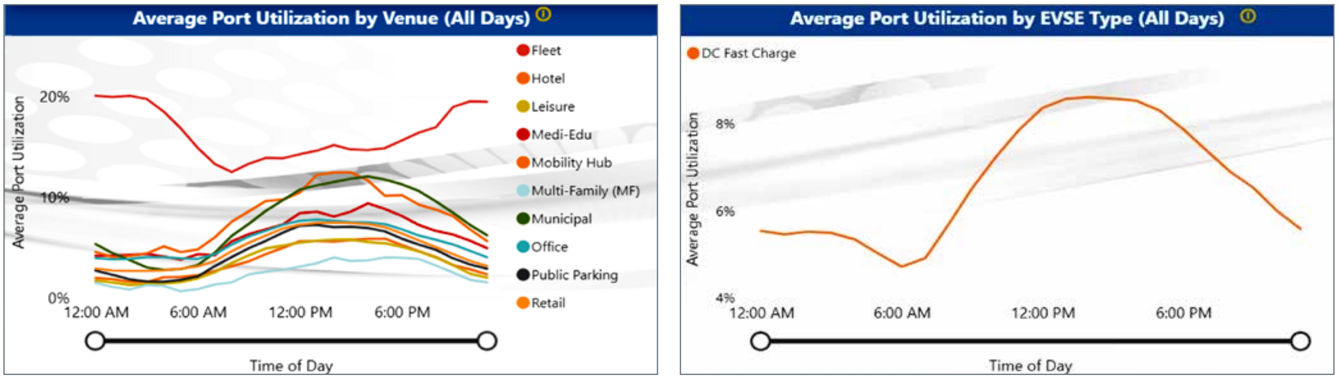
ENERGY AND ECONOMIC MODELING RESULTS

To better understand the financial implications of the most-popular demand mitigation strategies for utilities, site hosts, and EV drivers, we combined real-world DCFC session data and simulated energy systems to benchmark relative financial performance.

Our primary focus is to model the five main mitigation strategies outlined in the executive summary: *(1) remove demand charge; (2) cap max energy costs; (3) co-locate battery storage; (4) manage EV charging; and, (5) increase utilization and move to a capacity-based rate.*

As inputs for our modeling, we utilized loading and utilization data from EV WATTS, as well as anonymous data provided directly from electric utilities. These data represent the operation of more than 4,900 DCFC station connectors, as well as charging session data spanning more than three years (2019 – 2022). Station- and session-level data was made publicly available by Energetics for “corridor” and “undesignated” charging applications, while data for specific site types like retail and fleets are also provided but only in the aggregate (e.g., average over large regions). Figure 4 depicts average daily DCFC utilization rates by location type (left) and overall (right) from the EV WATTS dataset. Average DCFC port utilization was found to be around 7% across all venue types, while LF values as of fall 2022 were around 2% on average for monitored station sites located all across the US (Figure 5).

FIGURE 4: DCFC UTILIZATION RATES REMAIN LOW FOR MOST APPLICATIONS EXCEPT FOR FLEETS



Of the nearly 5,000 DCFC ports tracked as part of the EV WATTS project, most show a similar load pattern with lower utilization at night and peak utilization in the afternoon. This corresponds well to solar generation availability and supports the case for increased priority of solar-sourced charging for DCFCs. The one exception is fleet charging, which on the whole demonstrates higher utilization rates at night – while vehicles are presumably parked charging at a centralized fleet depot – and relatively lower utilization rates in the middle of the day. Note also that these port utilization rates are time-based rather than energy-based, reflecting the amount of time vehicles spend plugged in vs. how much energy each EV received.

Source: Energetics (2022, June). EV WATTS. Retrieved from: https://www.energetics.com/projects/electric-vehicle-widescale-analysis-for-tomorrows-transportation-solutions

FIGURE 5: APPROXIMATE LOCATIONS OF EV CHARGING STATIONS PARTICIPATING IN THE EV WATTS PROJECT

While the EV WATTS data does not represent EV charging in every state, it provides better coverage and representation of real-world station operation than any other public dataset available in the US so far. **You can see by the relative size of the blue bubbles in this map that sampling is concentrated in the Northeast, with additional pockets in Oregon, Colorado, Texas, and Michigan and more-scattered sampling elsewhere**. About 13% of the total number of ports tracked were at DCFC stations, while the remaining are Level 2 chargers (note: for this study, we only considered the DCFC stations, ports, and sessions in our analysis).

Source: Energetics (2022, June). EV WATTS. Retrieved from: https://www.energetics.com/projects/electric-vehicle-widescale-analysis-for-tomorrows-transportation-solutions

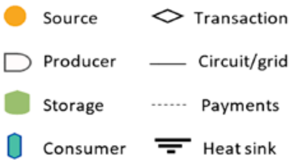
MODELING APPROACH

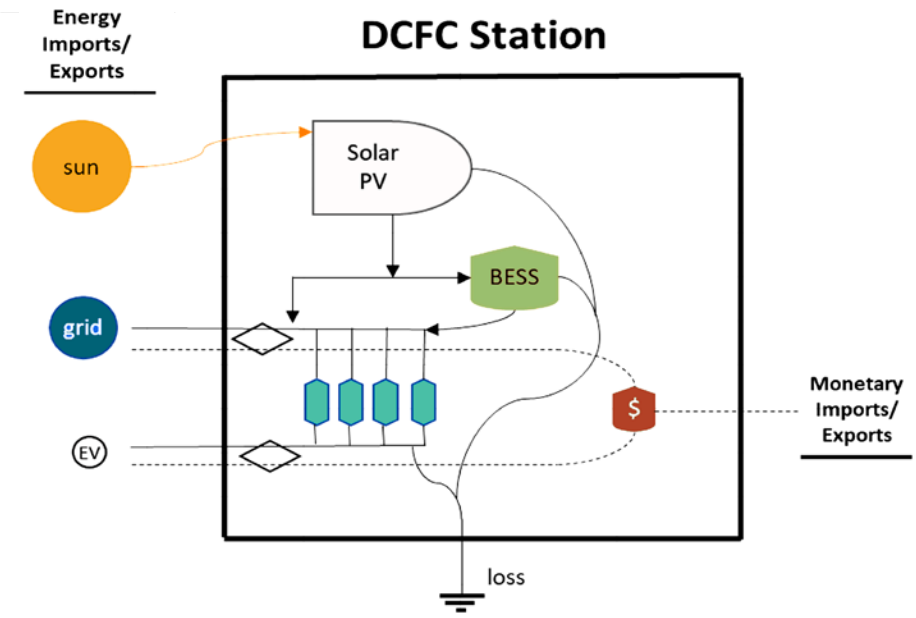
To evaluate DCFC economic viability in the absence of data provided directly by EVSPs, we built a dynamic systems model using a combination of real-world public data, proprietary algorithms, and industry expert survey feedback (Figure 6). We ran simulations using NREL's REOpt to produce accurate BESS load profiles, and paired these with the outputs from our own proprietary DCFC demand-charge management and mitigation model. We did not consider potential resiliency benefits in this analysis, nor possible revenue streams from delivering other grid services. This is mostly because these value streams are difficult to quantify and/or are not available in all markets; market access for small DERs and energy consumers/producers (or so-called prosumers) remains quite limited so far.

COMPARING COMMON MITIGATION STRATEGIES

Through our modeling, we investigated the relative impacts of common demand-charge mitigation strategies on utilities, DCFC station hosts, and EV drivers. We found that these mitigation strategies have the largest impacts on relative revenues realized by either utilities or station hosts in inverse amounts, while EV drivers tend to be less directly affected. In general, impacts to EV drivers are more-or-less at the discretion of utilities or station operators, to the extent that they choose to pass on costs or savings, manage charging, or install on-site DERs to supplement power and/or improve overall station performance.

FIGURE 6: DYNAMIC SYSTEMS MODEL OF ENERGY AND MONETARY FLOWS FOR DCFC WITH SOLAR + STORAGE



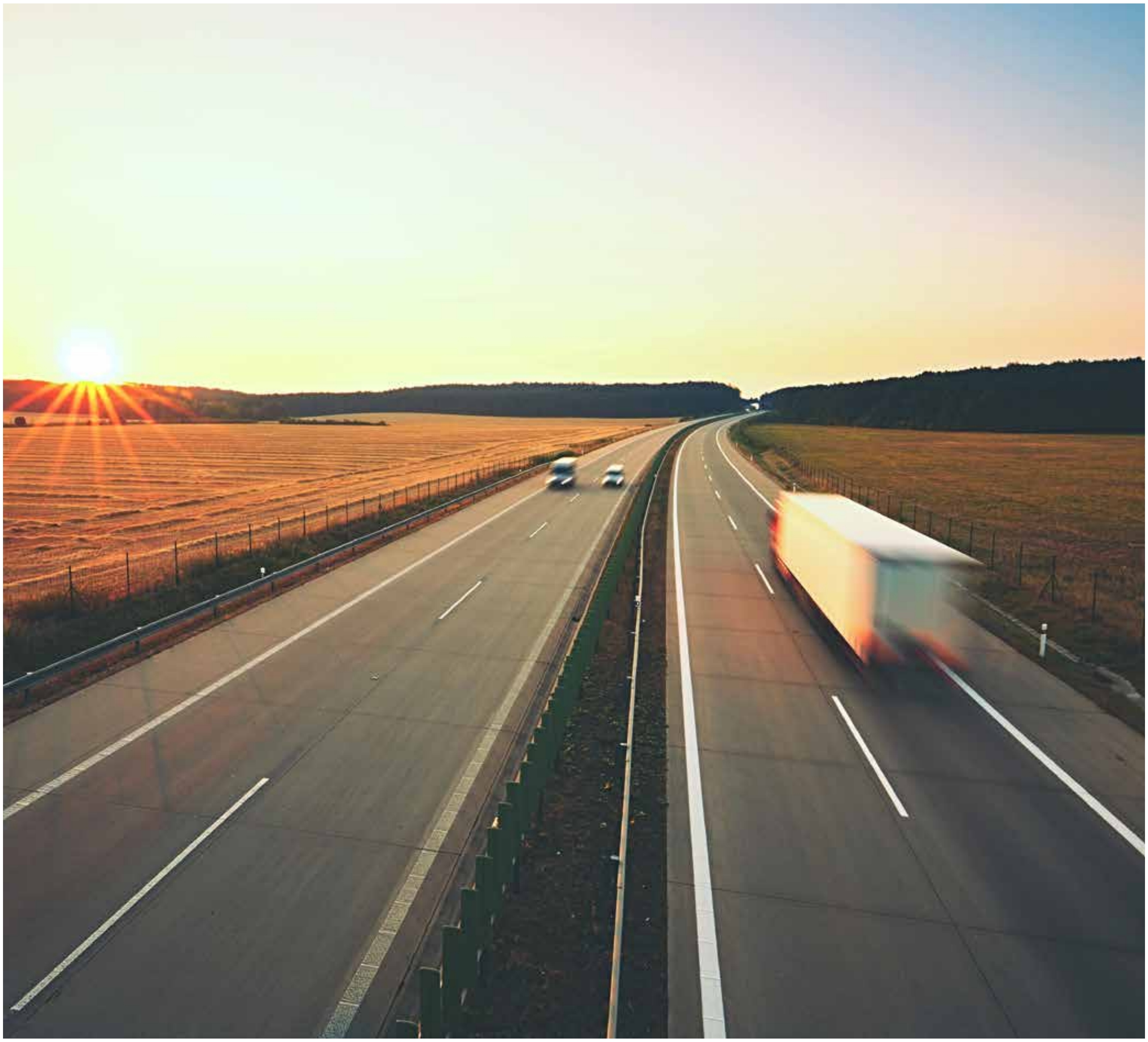


E Source built a custom model for this study, to simulate power and dollar flows between customers, DCFC station hosts, and electric utilities. Through station simulation, we tested different sizing and pricing scenarios to assess relative viability under varying site-specific conditions and utilization rates. While it was neither practical nor useful to attempt to model all potential system configurations and operating conditions, we selected likely scenarios based on real-world data in order to compare common demand-charge mitigation strategies.

Source: E Source

REDUCE OR ELIMINATE DEMAND CHARGES

We found that lowering or removing demand charges can be an effective way to improve DCFC station financial viability for station site hosts. This is already a strategy used by some utilities and may be referred to as a "demand charge holiday" where the site host's tariff temporarily has the demand charges lowered or removed (e.g., when station utilization is low). We found that operating costs are more likely to be lower than the station revenues when the utility rate tariff includes no demand charge (e.g., assuming charging session pricing is based on price parity with average per-mile gasoline prices). However, if the utility significantly increases volumetric charges – in order to compensate for revenue loss associated with removing demand charges – this may negate the benefits, depending on the local pricing for DCFC station charging sessions. This strategy represents a viable near-term solution, as evidenced by utility-only rates that do not include demand charges. However, in the mid-to-long term, reducing the utility revenues associated with demand charges could lead to a transfer of financial obligation to other stakeholders (e.g., through alternate cost-recovery mechanisms, such as higher general customer rates).



CAP MAXIMUM ENERGY COSTS

We found that the most-common, rate-based mitigation approach taken by utilities thus far involves some form of cap placed on the maximum monthly energy costs a DCFC station host will incur. For low-utilization stations, this often takes the form of a two-part tariff: (1) either the station host pays the EV-specific rate, having both a demand and energy component; or, (2) the station host pays a set per-kWh amount for all energy consumed, whichever is lower. This approach serves as a useful near-to-mid term strategy for limiting the operating costs for DCFC station hosts and also helping to make energy costs more predictable from month to month.

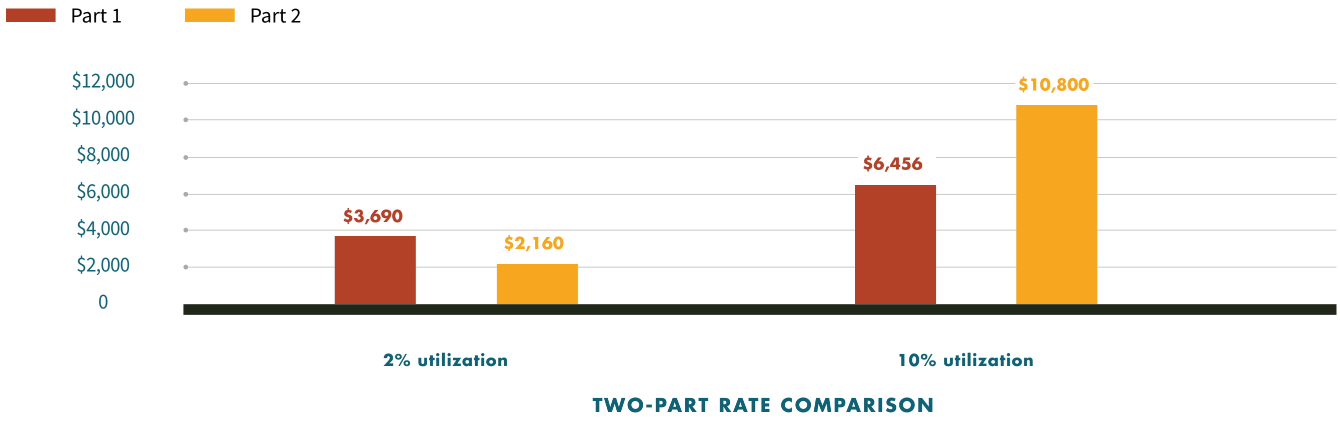
Consider a hypothetical example of a utility rate tariff having the following two-part structure:

1. **Station site host pays an energy charge of $0.08/kWh plus a demand charge of $5/kW; or,**
2. **Station site hosts pays an energy charge of $0.25/kWh and no demand charge.**

The site host will pay the same fixed charges, including delivery fees, fines, etc. We assume here that the DCFC charging station has the same peak monthly demand of 600kW but different utilization rates in each scenario: 2% utilization vs. 10% utilization (Figure 7).

Another way to think about this type of two-part tariff is in terms of load factor (LF). The LF is a measure of how much energy an electrical device consumes relative to how much energy it would consume if it were operated continuously, 24/7. So for a DCFC unit, the LF is the ratio of energy dispensed to EVs over the total amount of energy the DCFC could have dispensed if it were operated around the clock. The LF reflects the reserved capacity needed to serve an end-use customer's electrical loads from the grid operator's perspective, relative to how much revenue they bring in from actually delivering electricity to that load. Below you can see a graphic of cost-per-unit of energy delivered to the customer versus LF. When LF is low, the customer pays more per unit of energy consumed.

FIGURE 7: RATES WITH CAPPED ENERGY COSTS CAN LOWER OPERATING COSTS FOR SITE HOSTS

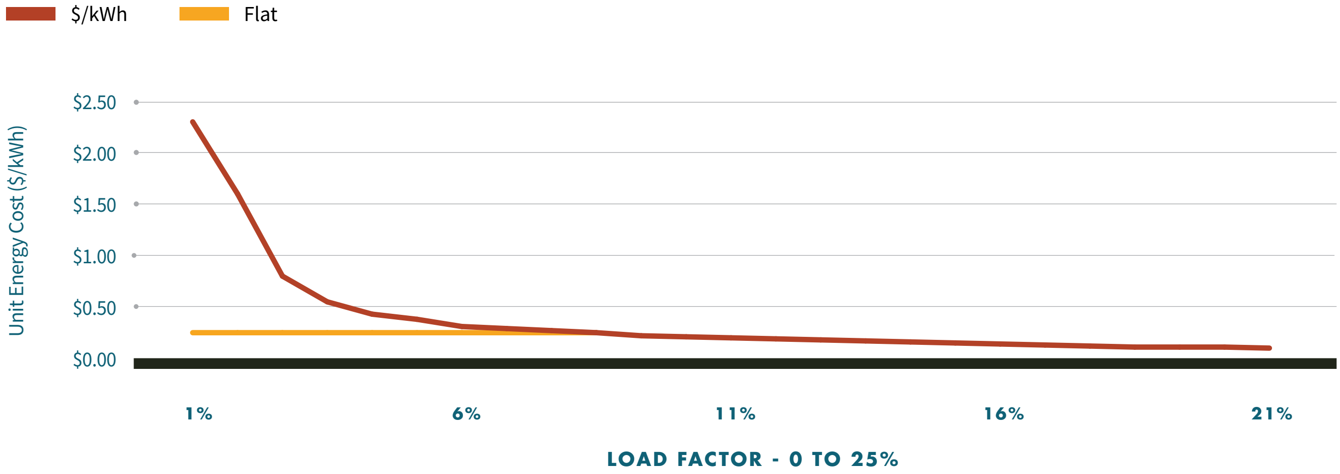


For this hypothetical two-part rate tariff, we can see that for 2% station utilization, the capped energy charge of $0.25/kWh represents the lower monthly cost and an energy cost savings of about $1,500 per month, relative to rate with demand charge. However, at 10% station utilization, the EV-specific rate with a lower energy charge + demand charge represents a lower monthly energy cost and about $4,300 cost savings relative to the energy-only rate. Of course, if we change the relative magnitude of either the energy or demand charges, or assume differences in monthly peak demand, we will produce difference outcomes for these scenarios.

Source: E Source

When the LF is higher, the customer pays less. By capping the per-unit energy costs for low-LF station operation, the utility limits the risk to the customer that would normally be present in a standard tariff with a demand charge (Figure 8).

FIGURE 8: A TWO-PART TARIFF, DEPICTED IN TERMS OF LOAD FACTOR (LF) VERSUS ENERGY COSTS



While this rate structure can take many forms and include numerous variations in tariff detail, the intent and approach are generally the same: limit operating costs for low-use DCFC stations. Pictured here we have a special tariff designed for DCFC hosts, where below 10% utilization the per-unit costs are capped at $0.25/kWh and no demand charge is applied. At higher station utilization (> 10%), the rate reverts to a standard consumption + demand tariff that demonstrates a lower monthly energy cost, relative to the flat per-kWh rate (as shown in Figure 7). The area between the rust-red and yellow lines represents potential cost savings to the site host for this two-part, LF-based rate, relative to the standard tariff.

Source: E Source; adapted from https://media.ktoo.org/wp-content/uploads/2022/02/AELP-TA504-1-Experimental-High-Power-Electric-Vehicle-Charging-Final-1-24-22-w-Attachments.pdf

CO-LOCATE BATTERY STORAGE

It is tempting to assume that “batteries charging batteries” will alleviate all woes when it comes to grid upgrades and DCFC operational cost management. While this may someday be the case, batteries remain relatively expensive and in high demand due to limited manufacturing supply volumes and critical materials constraints. While this may eventually change at the federal level in the US – as the domestic supply chain for batteries and EVs continues to mature – battery cost and availability remains a limiting factor when implementing this strategy. For critical station locations where utilization is unlikely to grow in the near term – including remote corridors, destination chargers, and sites with constrained utility serviced capacity – the case for co-located batteries is strengthened.

Demand-charge mitigation is currently the most universally viable value proposition for co-located (or internally integrated) batteries at DCFC stations. The cost-savings potential for demand-charge management is limited by the magnitude of the demand charge, which means this strategy cannot effectively be paired with the previous strategy (i.e., lowering or eliminating demand charges). The monthly peak demand for a

DCFC will likely be similar from one month to the next, i.e., the maximum rated output of the DCFC, the combined station power, or the utility service limit, based on available service capacity.

For stations that have high demand charges and low utilization, a co-located battery could help to make station operation more economically feasible. But for stations with standard demand charges – on the order of $5 to $15 per kW – the upfront cost of the battery system will likely be prohibitive relative to the cost-savings potential of DCM, especially if station utilization increases rapidly.

MANAGE EV CHARGING

Though EV managed charging is an increasingly popular topic within the energy industry, most EV charging remains unmanaged today. Controlling EV charging is theoretically a straightforward demand-mitigation strategy, but there are a number of complicating factors that prevent widespread adoption of this technique:

- **Competing priorities.** Where EVs and DCFCs are owned and operated by private individuals or organizations, managing these resources in response to real-time grid conditions is a challenge. Unless grid-responsiveness can somehow be made top priority, the ability to realize benefits from managed charging remains low.
- **No mechanism.** EV-specific rates don't require that EV charging is managed in order to enroll. And so far, utility managed-charging pilot programs have not settled on a preferred approach from signaling and controlling EV charging.
- **Managing premise vs. system peaks.** If utility customers are already engaged in demand-charge management to lower their own monthly energy costs, they are less likely to respond to signals related to their demand coincident the system grid peak (e.g., demand response program notifications). Customers will optimize the use of a BESS to meet their own primary objectives and deliver the greatest benefit to themselves, as opposed to providing societal or system-wide benefits. We have observed this behavior in multiple BESS pilots and DR program evaluations.

A major competing priority for public-access DCFCs is the need to meet customer expectations and maintain high customer satisfaction with timely charging. If site hosts attempt to slow or stop charging sessions in response to grid needs, they may lose customer loyalty and revenues. While it is theoretically possible to manage charging at any level, from zero to maximum rated power draw, we've seen no evidence so far that would indicate what an "acceptable" level of management looks like for public charging stations, and therefore this strategy remains difficult to evaluate realistically without more site- or customer-specific information. Also, there are now examples of state utility commissions expressly stating that EV managed charging and public DCFC stations for light-duty EVs are incompatible (e.g., see New York State Department of Public Service's CASE 22-E-0236 – Proceeding to Establish Alternatives to Traditional Demand-Based Rate Structures for Commercial Electric Vehicle Charging).

COMPARING COMMON DCFC STATION VENUES

Most of the data that has been made publicly available for DCFC stations so far is for older/legacy stations with limited charging capacity (e.g., 50kW). The available evidence suggests that EV drivers prefer to charge at higher-power DCFC stations over lower-power stations and are more likely to use them wherever possible. As such, we would generally assume that utilization of newer and higher-power stations will tend to be higher than what we observed in the historical data, which was also impacted by COVID-19.

While DCFC sizes and configurations tend to be relatively similar and can be categorized based on a relatively small subset of equipment groupings, venues for DCFC stations can be quite different. For the EV WATTS project and publicly-reported analysis, public-access stations were grouped by venue into one of 8 categories: *office, retail, municipal, medical/educational, parking lot/garage, leisure, transit,* and *hotel.* Private fleet DCFC stations were also grouped separately.

While some differences were observed between venue types in terms of daily load profiles and utilization rates, the biggest difference observed was between fleet and non-fleet stations (e.g., see Figure 3). Here, we consider two DCFC station venue types and applications: *gasoline refueling stations* and *corridor stations*.

GASOLINE REFUELING STATIONS

Some fuel retailers are deploying DCFCs at existing refueling station locations. As just one example, announced mid-year 2022, GM is partnering with EVGo and Pilot/Flying J to deploy DCFCs at 500 travel centers across the US (see [EVgo Announces EVgo eXtend Project to Deploy High Power Fast Charging Access to Drivers Across the US]()). Similar to this DCFC application, we considered the installation of two, 350kW DCFCs at existing gas refueling stations with co-located BESS.

In this scenario, a BESS can reduce demand under ideal system conditions and significantly reduce total grid energy consumption overall. However, this assumes optimal battery performance under ideal conditions, which is unlikely to materialize under real-world conditions. Assuming station utilization increases over time, a co-located BESS will tend to deliver more value in the early years of station operation and less value in the future, though this may be favorable from host's perspective (e.g., improving rate of return with early-year savings). A co-located solar PV system delivers relatively less benefit relative to project cost, and is therefore less likely to be worth installing at a DCFC station.

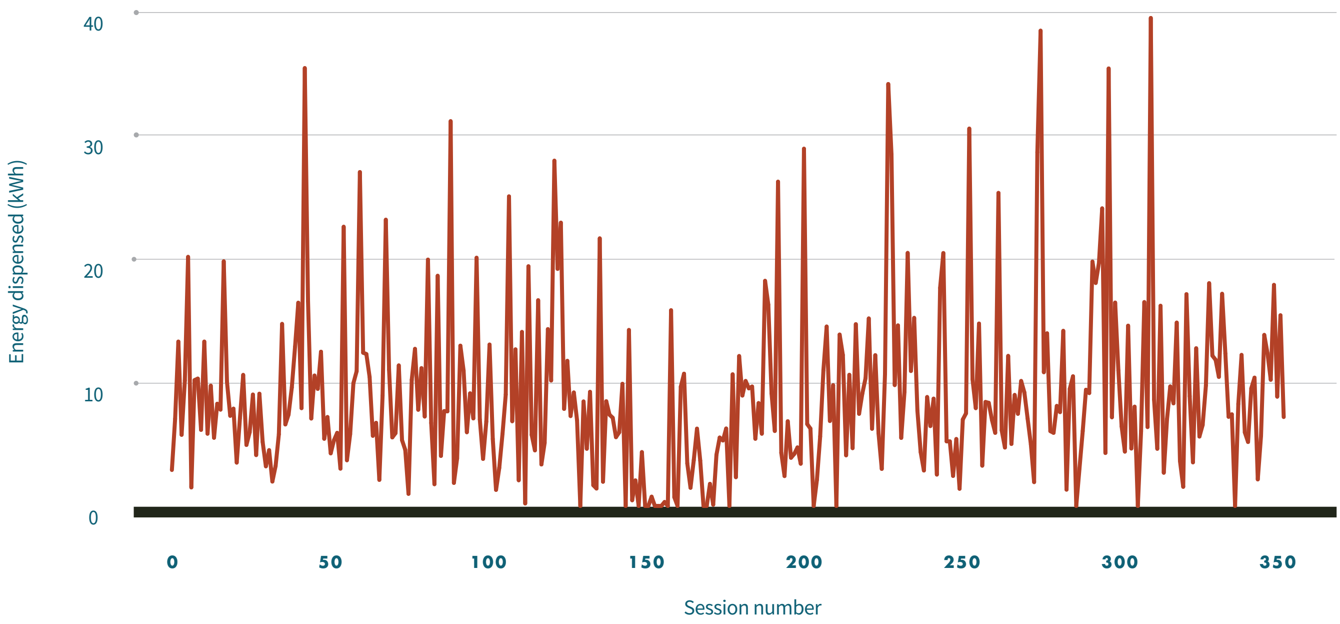
CORRIDOR DCFC STATION

With guidance from the US federal government, the new minimum standard DCFC power rating for corridor charging stations is 150 kW per unit, or about three times larger than the previous standard DCFC size (i.e., 50 kW). Installing four of these units at a single location is equivalent to an aggregate maximum station demand of around 600 kW. This is similar to the refueling station scenario in terms of total station power demand (i.e., 600 kW vs. 700 kW), though with 4 chargers and up to 8 charge ports, low-to-moderate utilization stations will not reach peak demand as frequently as we see with the larger DCFC units.

While we have relatively little data on 150kW DCFC stations in operation so far, we do have data on stations with the equivalent power draw (e.g., 50 kW x 3 DCFCs). We analyzed real-world utilization data for one such station from the EV WATTS dataset for a corridor DCFC station in the Boulder, CO metro area. In spite of being in an EV early-adopter market and densely populated region, utilization over the three-year period of observation was relatively low (e.g., 1 to 5 daily charging sessions on average). Only rarely were two or more EVs plugged in at this station at the same time. Total energy dispensed per charging session on average was 18 kWh (Figure 9).

At this rate of station utilization and energy sales, a 200 kWh battery could serve most daily energy needs at this station relatively effectively. However, the number of charging sessions occurring daily at this station is trending upward. This may simply be a rebound effective post-COVID, or it may be an indication that station utilization will continue to increase over time, in which case the relative value of a co-located battery system would tend to diminish over its useful life, without some "future-proofing" measures applied (e.g., adding additional battery modules over time, creating new value streams).

FIGURE 9: ENERGY DISPENSED AT A DCFC CORRIDOR STATION IN THE BOULDER METRO AREA

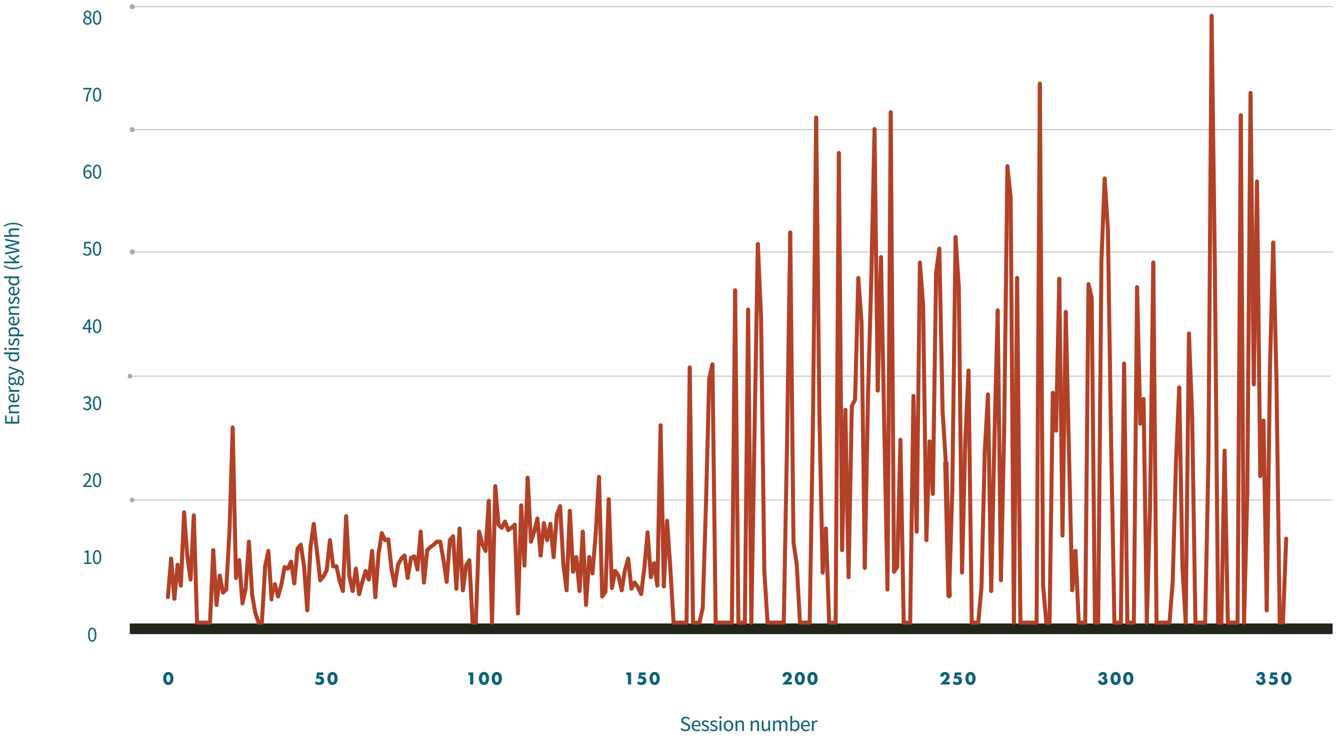


This corridor DCFC station in the Boulder metro area has two DCFC units, each having two charge ports. Daily station utilization rates for this station over the three-year period of observation remained low, at around 2%. Energy dispensed per charging session at this station, as well as duration of charging sessions, remained relatively small over the period of observation. Station utilization rates are consistent with the average observed for all DCFCs participating in the EV WATTS study across the U.S., even though we might expect it to be higher considering this is an urban station in an area we might expect to demonstrate higher level of EV ownership and station use.

Source: E Source; data from EV WATTS project

We also analyzed charging session data for a 50kW DCFC operating at a corridor location in the Dallas-Fort Worth metropolitan area over the same three-year period (2019 – 2022; Figure 10). Overall, utilization of this station was very low, logging only about 10% of the charging sessions observed at the Boulder station (i.e., << 1% utilization). While we don't know the exact reason for this, a number of factors may be contributing, including lower levels of local EV adoption, inconvenient station siting, and lower desirability of the location and/or charger capability (e.g., just one 50kW DCFC offering limited EV charging capability and performance).

FIGURE 10: ENERGY DISPENSED AT A CORRIDOR DCFC STATION IN THE DALLAS – FORT WORTH METRO AREA



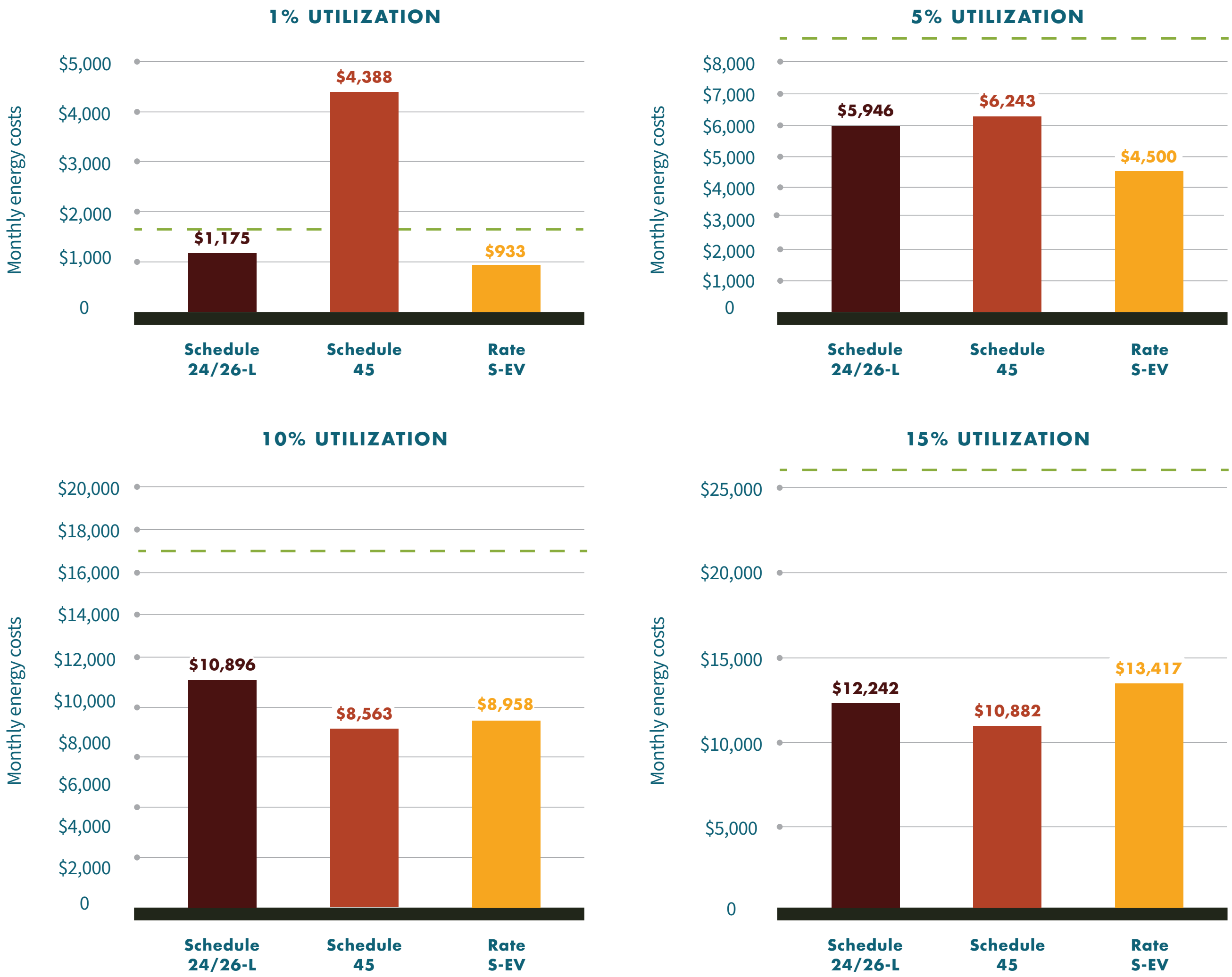
This public station has one DCFC unit with one charge port. We observe the trend that more energy is being dispensed per charging session over time. This is likely due to the wider availability of longer-range EVs with larger batteries in recent years. However, what we do not observe at this station is the trend toward increased number of charging sessions per day, as we saw at the Boulder location. In general, station utilization at this site remained very low for the entire three-year period. Assuming that station utilization does not increase over time, it will be difficult to operate this station profitably as a standalone business without a secondary motive (e.g., as a loss-leader that attracts customers for some other business purpose, or to provide greater connectivity in a broader network consisting of other highly-utilized stations). However, for larger stations (e.g., 150kW DCFCs) and in post-COVID conditions, we expect to see more-favorable usage patterns in the future

Source: E Source; data from EV WATTS project

IMPLICATIONS OF TARIFF DESIGN

Some stakeholders in the EV industry are calling for utility rate reform to better support EV charging – and DCFC station operation in particular – and in response some utilities have been experimenting with a number of alternative rate designs. We discussed these general alternatives previously in this report (see Rate tariffs, demand charges, and mitigation strategies). We modeled a few of the actual utility rates for a 600kW DCFC station under varying station utilization rates. We demonstrate that some rates are more effective than others in terms of lowering site hosts monthly energy costs under low-utilization conditions (Figure 11).

FIGURE 11: IMPACT OF RATE TARIFF AND UTILIZATION ON MONTHLY DCFC STATION ENERGY COSTS



Here we compare three rate tariffs that might apply to a 600kW DCFC station host: one with a demand charge of $6.35/kW (Schedule 45), one with no demand charge at low load factor (Schedule 26-L) or a demand charge of $13.85/kW at higher load factors (Schedule 24), and one with no demand charge but a consumption charge of $1.44/kWh during critical peak periods (Rate S-EV). The bars depict DCFC station host monthly energy costs (paid to the electric utility). If we assume peak season (summer) and peak-time consumption rates – with most charging (90%) occurring outside of critical peak periods for Rate S-EV – we observe that energy costs are below revenues (green dotted line) for most rates across the utilization scenarios. The one exception is observed at low station utilization (1%) for Schedule 45 where a demand charge is applied; energy costs in this case far exceed anticipated revenues, where we assume flat pricing of $0.40/kWh by the station host to the EV drivers for their charging sessions. We see that the cheapest rate for the site host at low utilization (Rate S-EV) is the most-expensive rate at the highest utilization level considered here. For more details on each of these tariffs, refer to Table C-1 in Appendix C – Rate analysis.

Source: E Source; data from utility rate tariffs

ADDITIONAL CONCERNS AND CONSIDERATIONS

We've discussed the cost and grid-capacity concerns associated with DCFC operation at great length throughout this report, but those are not the only issues worthy of consideration. While DCFCs deliver concrete and indisputable value for EV drivers – helping to assuage their range anxiety and enable long-distance travel – there are also non-financial concerns that should be addressed or at the very least considered. We discuss some of them here and highlight opportunities to potentially address these concerns in the future.

BATTERY LIFE AND DEGRADATION

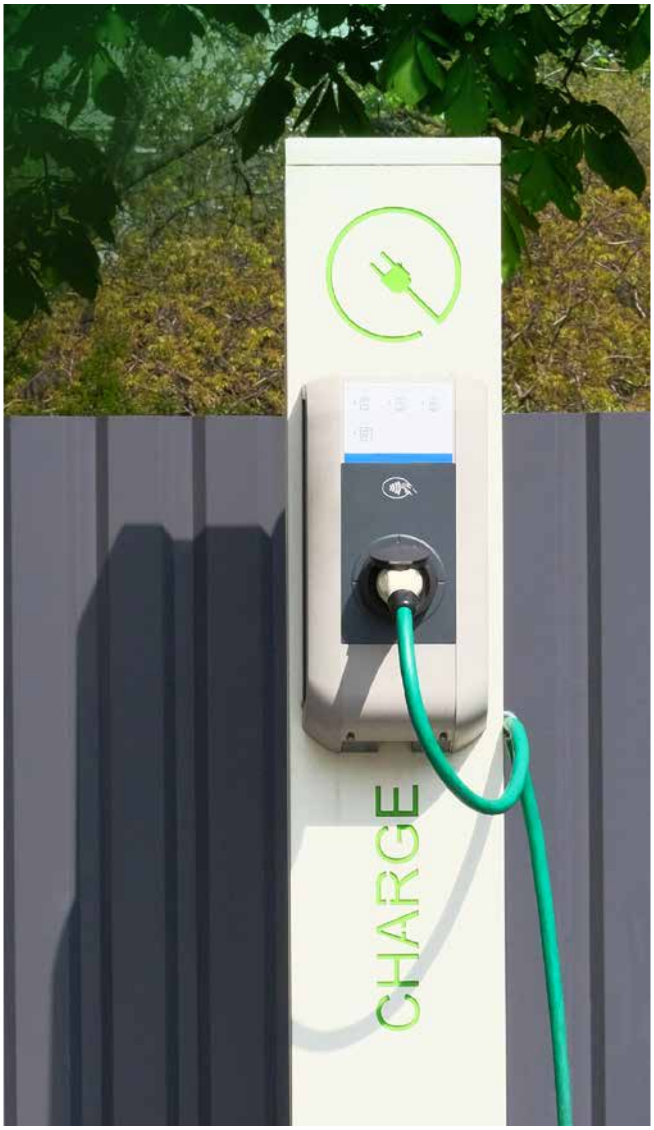
Most EV charging events occur at Level 1 or Level 2 rates so far. This commonly occurs in the home, at the workplace, or in a fleet depot. The fundamental nature of most battery chemistries dictates that the faster you recharge them, the faster you will degrade those batteries and shorten their useful life, due to internal resistance and heating that tends to break down their materials. While EV battery technology continues to improve year over year, there remains the non-trivial issue of accelerated battery degradation due to frequent fast charging. While there has been much concern voiced over the impacts associated with vehicle-to-grid (V2G) functionality on EV battery life, EV drivers seem generally less concerned about fast charging. However, there is growing evidence to suggest that regular DCFC use will reduce the useful life of an EV's batteries (e.g., see What 6,000 EV battery lives tell us about EV battery health).

EQUITY AND ACCESS

Some EV owners are unable to recharge their vehicles at home because they live in an apartment, don't have off-street parking, or otherwise don't have regular and reliable access to EV charging at home. For these drivers, workplace and public-access EV charging are critical. It's important that we help to maintain affordable refueling options for these individuals, even as levels of service and rate of recharge continue to go up in response to popular demand. For example, EV drivers in the San Francisco Bay Area who live in apartments and cannot charge at home have reported to us that they pay more to use public-access DCFCs in the city than they would be paying to refuel a conventional car with gasoline (even at relatively high Bay Area gas prices). This is at least in part due to the high energy costs paid by site hosts in that area, and these equity concerns have been reported on by station hosts as well (e.g., see recent comments made in federal proceedings to the US Environmental Protection Agency).

BATTERY SWAPPING

While battery swapping was a popular concept several years ago that seemed to have gone the way of the dodo bird when Better Place went out of business, it is currently experiencing a revival in interest. If EV battery swapping became popular, it could help to limit the need for DCFCs and corresponding grid strain. By swapping out a discharged battery with a recharged one, the discharged batteries can then be recharged more slowly before being swapped back into another vehicle. This in turn could impact future expectations for DCFC utilization and overall economic viability. It remains to be seen if battery swapping will succeed in the market, but from a grid operator's perspective it may be a more desirable option relative to serving DCFC loads.



SECOND-LIFE BATTERY APPLICATIONS

There is also significant interest in using aged EV batteries as stationary energy storage, including for DCFC applications. The irony here is that the more frequently an EV uses a DCFC during its useful life, the less likely its battery will be in sufficiently good condition at end of life to be used for a secondary application. New technologies are being advanced to help gauge the remaining useful life of used EV batteries and determine what second-life applications are likely to make the most sense for each pack (e.g., Montes et al., 2022).

SOLID-STATE POWER ELECTRONICS

New technologies are being commercialized today that have the potential to introduce real step-changes in electrification. Solid-state technologies are among the most promising. From solid-state transformers to circuit breakers and even battery storage, this is a rapidly-evolving area of development that will significantly impact EVs, EV charging, and grid operations. As one manufacturer recently reported to us "We've literally run millions of cycles on our new solid-state units, and have observed no obvious signs of degradation. So far, we still have no idea how this equipment will degrade over time or what the failure modes will actually look like, or when those might occur." These technologies generally help to reduce space needs, expand manufacturing capacities, increase power capacities, improve responsiveness, reduce latency times, and make power electronics far more controllable in general. While we think it's still too early to promote any of the vendors in this space, we are actively tracking new developments and demonstrations.

DEMAND RESPONSE

We read in multiple prior studies that utilities report a desire for demand response (DR) capabilities for DCFCs, but so far we have not observed much movement on this issue. DR involves reducing the power draw from electrical equipment (such as a DCFC unit) during a peak demand period on the electrical grid (e.g., a hot summer day when air conditioning use is high). Most EVs enrolled in DR programs are light-duty vehicles charging at home using Level 2 equipment. It is not obvious to us that it even makes sense to enroll a public-access DCFC into a utility DR program, just as EV managed charging and DCFC stations may be incompatible. Only stations with co-located BESS may be able to participate in such programs without negatively affecting the customer experience. Technically speaking, it may not be difficult to control a DCFC to respond to a DR signal or event, but logistically this use case has not been proven out yet.

COMMUNICATIONS NETWORKS

Another issue that does not get nearly enough attention is that of communicating with DCFC equipment and having adequate communications infrastructure in place to serve this equipment. For any project where the DCFC station and/or on-site DERs will be operated to deliver secondary benefits – such as in the service of DR programs, managed-charging programs, frequency-regulation markets, emergency backup power, or other services – low-latency communications are critical to effective resourcing. Some efforts are now under way to coordinate across industries to help lower costs and improve outcomes, e.g., through so-called "dig once" initiatives to bury new power lines and fiber optics cables at the same time and place. But so far, communications needs tend to be underappreciated, undervalued, and deficiencies tend to be discovered too late to effectively address performance concerns.

CONCLUSIONS AND RECOMMENDATIONS

Installing a DCFC station is a larger undertaking than many people realize; it's a civil engineering project with significant electrical requirements. These stations tend to be expensive to install and operate, so it's important to carefully consider all aspects of station design, sizing, and utilization before making the investment.

Choosing the right electric rate tariff is just one of many considerations, but it is an important one (for more details on choosing the right tariff, see Appendix A – Background Information). It's also important to keep in mind that the best rate tariff for operating a DCFC station today is likely to change over time.

It's important to consider the tradeoffs between faster charging and cost to serve EV loads. DCFC station utilization so far remains very low at most station locations and for most brands, and we have no certainty about exactly how utilization rates will grow over time and space. While some customers may be willing to pay more for faster charging in some cases, not all customers will be willing or able to pay for premium EV-charging services and experiences (e.g., low-income customers). Many customers may also expect to pay less to charge their EV than what it costs to refill a gasoline vehicle (e.g., ~ $0.50 per kWh equivalent), so it's important to consider the retail cost of gasoline and diesel fuel relative to electric fuel pricing.

RELATIVE EFFECTIVENESS OF COMMON MITIGATION STRATEGIES

Through the course of this study, we identified several strategies that can be used to mitigate high demand charges from electric utilities for DCFC operation, with varying degrees of effectiveness:

1) **Eliminate demand charges**. This is likely the simplest and most-effective way to make DCFC stations more cost-competitive, but may only be a viable mitigation strategy in the near term. The fact that utility-owned DCFC rate tariffs so far do not include demand charges is telling. For stations with low utilization (e.g., < 10%), demand charges make it infeasible to operate stations profitably. This also alleviates the need for station hosts to deploy additional hardware or software, including expensive co-located DERs, load control, and predictive analytics. While this is only a near-term strategy, it should be seriously considered in the interim as the nascent EV market grows and matures. However, this strategy may also require utilities to recover costs by passing along costs to customers in the form of general rate increases, which are rarely popular. Or, utilities may attempt to recover costs through other means (e.g., delivery charges based on total service capacity vs. energy consumed). Eliminating demand charges without instituting other cost-recovery mechanisms will present challenges for utilities with respect to operating the grid cost-effectively and could eventually lead to unexpected rate increases.

2) **Cap monthly energy costs.** While this mitigation strategy is more complicated to implement (e.g., with added utility backend billing requirements), it produces a similar outcome to the near-term elimination of demand charges. However, this approach is more flexible than simply eliminating demand charges, in that it makes room for the possibility of higher utilization rates (and load factors) where rates with demand charges can produce lower monthly energy costs for the station host, relative to the fixed per-kWh cost cap. Where station utilization fluctuates significantly from one month to the next, this may be a preferred option for station hosts. However, this is still a near-to-mid term strategy, and over time as station utilization rates increase, this approach may no longer be warranted. This approach limits financial risk to both utilities and station hosts.

3) **Install co-located energy storage.** The major brands of EVSPs and station hosts have already begun deploying co-located BESS at DCFC stations across the US. Multiple EVSPs have reported to us that this is largely for the purposes of managed demand and reducing demand charges. Roundtrip BESS efficiency should also be considered as these losses may offset the benefits in some cases. There is little evidence so far to suggest that co-located (or embedded) batteries improve overall DCFC station economics over the long term, relative to competitive utility rates; they are merely the best option available where utility rates are unfavorable for station operation. Without significant outside subsidies or additional revenue streams for delivering grid services, the business case for co-located batteries at DCFC stations remains challenging.

4) **Manage EV charging during peak periods.** While there is some concern among site hosts and EVSPs that slowing EV charging during station or grid peak demand will be unacceptable to customers, we know that this strategy is already widely used. In some cases this is due to limited electric service capacity relative to total maximum station demand, and in other cases this is a cost-saving strategy. In any event, it is used because it is an effective means of managing total power demand and operating costs. Sophisticated controls may even be used to predict peak-power events and minimize DCFC de-rating to the extent possible, or adjust charge rates based on user feedback. This is also one of the lower-cost options for the site host, and when coordinated with the electric utility can deliver benefits to both the host and the grid system. Impacts to the customer are largely viewed as negative, but the magnitude of these impacts and implications can vary significantly.

OBSERVED DIFFERENCES BY UTILITY TYPE AND US REGION

Through our analysis of utility rate structures and DCFC operating conditions across the US, we found conditions to generally be similar across the board. Demand charges from utilities operating in the Northeast and West are somewhat higher on average – on the order of $10/kW – while demand charges from utilities operating in the Midwest and South are somewhat lower on average (e.g., $7/kW). Observed differences by utility type were less pronounced, though we were surprised to see that average demand charges were actually the highest for the cooperative utility rates we analyzed (i.e., $9.60/kW), while the IOUs had the lowest average demand charges (i.e., $8.34/kW). However, these differences are relatively small, and overall will tend to have similar negative impacts on the financial viability of low-utilization DCFCs.

When it comes to rate options, IOUs have by far the most options to choose from, and these utilities also have the largest number of EV-specific proposed, piloted, and experimental rate tariffs. At the same time, IOU tariffs tend to be the most confusing and difficult to decipher and track, as they are also changed and updated continuously. While all utilities are compelled to recover the costs associated with operating and maintaining the grid through rates, some utilities are more likely to make near-term exceptions to help support and enable electrification, based on company goals and priorities. This is not isolated to any particular utility type, and we have observed IOUs, public power utilities, and cooperatives that are all taking meaningful steps to enable transportation electrification in early markets.

We also did not observe strong correlations in the DCFC station data between utilization and location. Stations located in early EV markets did tend to be utilized more heavily, though this was not universally the case. For example, in the Colorado data we would have expected to see stations in Boulder and Denver be highly utilized. Instead, the most-heavily utilized DCFC station was actually in Longmont (CEO, 2021), demonstrating similar utilization levels as high-traffic stations located in California. Urban vs. rural siting is also not necessarily an indicator of high utilization, and we observed numerous urban DCFC stations with very low utilization rates.

However, some patterns in station utilization were observed that confirm our intuitive expectations. All DCFC stations located at all venue types experience higher levels of utilization during the weekends vs. weekday, though the general load profiles remain similar (i.e., peaking in the afternoon). Venues associated with travel and leisure – including hotels, resorts, parks, and other destinations – similarly demonstrate higher weekend use. And fleet DCFC stations demonstrate higher nighttime utilization and lower daytime utilization, and higher use during weekdays than weekends but overall, significantly higher utilization at all times, relative to public-access DCFC stations.

RELATIVE COSTS AND BENEFITS TO STAKEHOLDERS

In general, we find that any demand-charge mitigation strategy that benefits one stakeholder group is likely to come at a cost to one or more of the other groups. For example, by either eliminating demand charges or managing them with an on-site BESS, the station host will save money at the expense of revenues to the utility. Similarly, if the utility managed EV charging during periods of peak system demand on the grid, the benefits experienced by the grid may come at the expense of benefits to the EV driver (i.e., a rapid recharge). However, in some cases there are measures that deliver benefits to multiple groups at once, such as managed charging (Table 1).

TABLE 1: QUALITATIVE SUMMARY OF NET COST OR BENEFIT OF EACH MITIGATION STRATEGY BY STAKEHOLDER GROUP

STRATEGY	ELECTRIC UTILITIES	STATION OPERATORS	EV DRIVERS
Eliminate demand charges	-	+	+
Cap energy costs	-	+	o
Co-locate BESS	o	o	+
Manage charging	+	o	-

An explanation for the costs and/or benefits of each mitigation strategy presented in Table 1 is provided in the Executive Summary starting on page 4.

For each of the four demand charge mitigation strategies evaluated in this study, we summarize here the anticipated net impact to each stakeholder group. A "+" sign represents a net increase in benefits and/or decrease in costs, relative to baseline conditions (i.e., no mitigation). A "-" sign represents a net decrease in benefits and/or increase in costs, and a "o" sign represents no impact or costs and benefits that are more-or-less balanced. For example, for managed charging we can see that the utility benefits overall (lowered grid impacts/cost to serve), the station host experiences balanced cost-benefit outcomes (lower energy costs but also potential customer satisfaction concerns), and the EV driver generally experiences a decrease in benefits (longer wait times or reduced battery charge per session).

Source: E Source

RECOMMENDATIONS AND SUGGESTIONS FOR STAKEHOLDERS

The only mitigation strategy we found to be 100% effective at mitigating demand charges – at least from the EV charging station host's perspective – is the elimination of demand charges from the rate tariff. This is how rates are currently structured for utility-owned DCFC stations. This is not a long-term strategy, and may only be viable for a few years, while station utilization rates remain low. This strategy requires no additional upfront costs but does require utilities to experience reduced revenues in the near term. By comparison, the strategy of using a co-located BESS for DCM can reduce utility revenues and add upfront costs and risks to DCFC station projects. Many utility rates – including time-varying rates and those with demand charges – do not support the financial viability of DCFC station operation in the near term.

THERE ARE NO SILVER-BULLET SOLUTIONS, ONLY MORE-APPROPRIATE STRATEGIES

In addition to energy costs, station utilization is one of the most-important factors in overall DCFC financial viability. We found that a significant inflection point exists for some utility rate tariffs, relative to the impact on DCFC cost-effectiveness. It is more difficult for utilities to recover costs associated with serving low-LF loads, and this is reflected in either the demand-related or capacity-related elements of non-residential customer rate tariffs. Rather than attempting to install DCFCs everywhere, as fast as possible (as some EVSPs are reportedly attempting to do), siting DCFC stations to maximize utilization is more financially sound and grid efficient.

It is worth considering the installation of a BESS at DCFC stations to help lower costs and potentially deliver additional benefits, especially where station utilization is low and/or future demand remains uncertain. However, it's important to consider that this is typically a less-favorable strategy, relative to utility grid services with competitive rates. If tariff choices exist, consider each carefully before initiating service. Batteries can help to improve the “grid friendliness” of DCFCs by lowering the harmonic emissions associated with station operation. Co-located DERs can also help to reduce project costs for rural or remote stations where grid services do not exist, grid capacity is already constrained, and/or the cost to upgrade or extend services is prohibitively expensive (e.g., where three-phase power is not currently available).

SUGGESTIONS FOR UTILITIES

What remains largely missing from the conversation on appropriate ratemaking for DCFCs is a careful consideration of cost causation and impacts to distribution grids. While utility industry representatives have expressed concerns surrounding the potential costs and impacts associated with EV fast-charging for decades, we still have no shared consensus on what these are. And as long as these real costs remain unknown or esoteric knowledge, the EV industry as a whole will remain at odds on this issue.

Utilities have generally done a poor job when it comes to effectively communicating and justifying rate design for DCFCs, failing to provide more details on what it costs to serve these loads. It is not surprising that DCFC station hosts are unhappy about utility rate design and tariff options, especially when it is unclear how tariffs are designed or why certain elements apply to DCFC operation. This problem is further exacerbated by the fact that rates for utility-owned DCFCs are not the same as those applied to non-utility station hosts, and universally appear to be more favorable to the utility. These discrepancies remain unexplained and unjustified so far.

Utilities should work with DCFC station hosts and other stakeholders – including the national laboratories and industry research organizations – to understand what the real costs and impacts are to the grid, relative to DCFC operation in common applications. Once a shared baseline is established for how DCFCs impact grid operations, system upgrade requirements, accelerated equipment degradation, and subsequent utility costs, then we will be in a better position to understand the “why” behind appropriate ratemaking and different strategies for mitigating grid impacts and recovering costs.

SUGGESTIONS FOR STATION HOSTS

It's important to remember that EV charging stations fill a unique role in the energy landscape. Even though they are not regulated in the same way as electric utilities, EVSPs participate as intervenors in utility regulatory proceedings and have influence on utility commissions as they set state policies. They advocate to state regulators and government officials in favor of their business interests as they relate to electricity delivery and sales for the purposes of transportation fueling. They are among the only non-utility business type granted special designation and allowance to resell electricity in retail markets, and this is unlikely to change any time soon.

A common complaint made by EVSPs is that the electric utilities as regulated monopolies have unfair advantages in EV-charging markets where they are permitted to engage directly. While this may or may not be the case in all situations, the argument being made remains more-or-less the same: regulators should act to limit utility involvement in these markets to promote competition, innovation, consumer choice, affordability, and so on. And by limiting utility activity in the EV market, regulators may also help to limit the economic burden associated with electrifying transportation that is placed on utility ratepayers.

For station hosts to experience the best outcomes, we think it's important that utilities and EVSPs view one another as partners. Electric utilities as heavily regulated entities don't have a choice in which customers they serve, as they have an obligation to serve all customers. But in certain circumstances they may prioritize projects and/or partnerships that they expect to deliver the greatest societal benefits and help them meet their overarching TE goals and objectives. As we have observed in reports from past studies of DCFC deployments, utility cooperation (or lack thereof) can mean the difference between a fast and affordable install, and one that's over schedule and over budget.

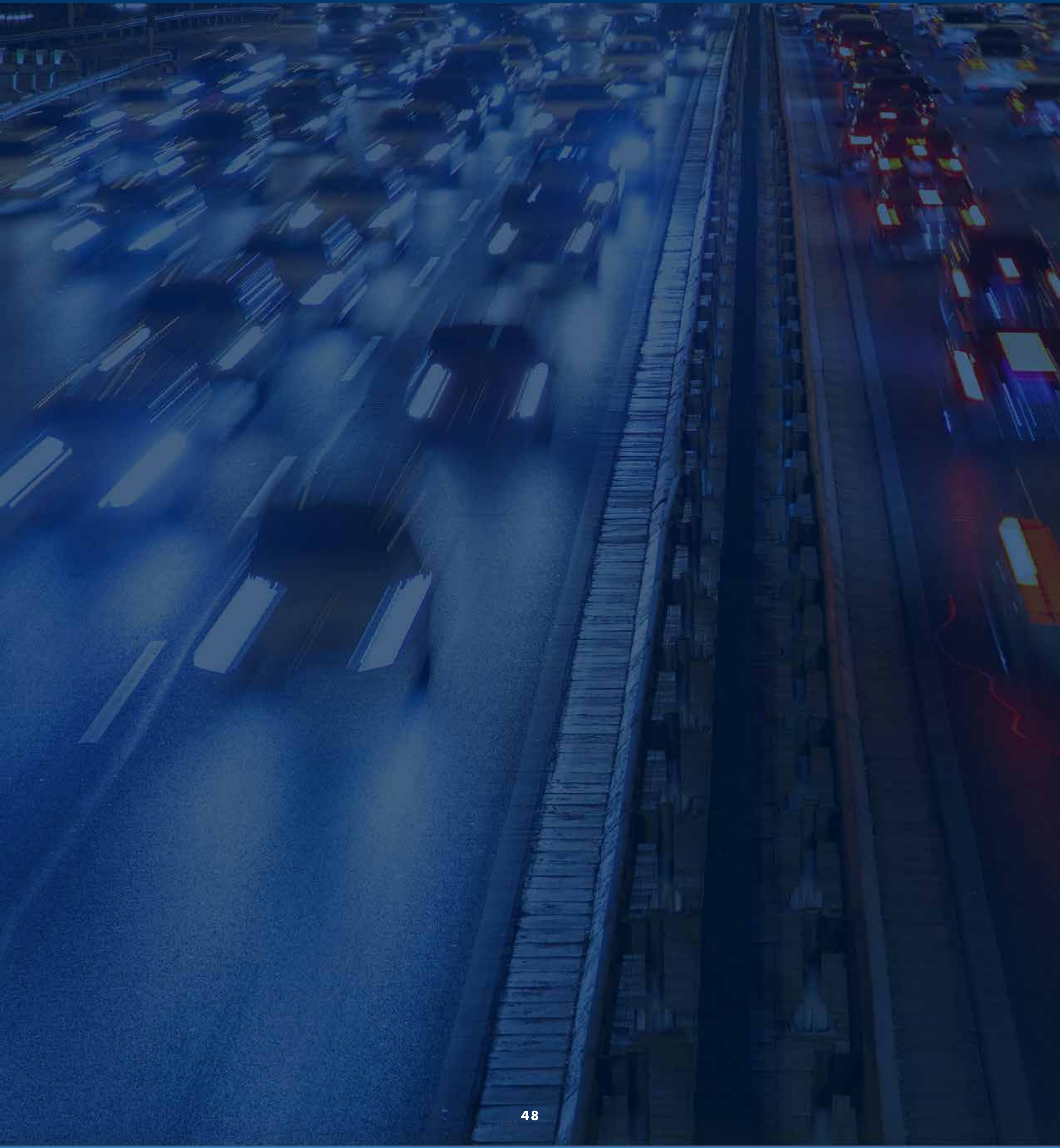
SUGGESTIONS FOR EV DRIVERS

Although DCFC stations play an important role in enabling transportation electrification, EVs should be charged at slower rates (Levels 1 or 2) for the benefit of the grid, natural resources, the consumer's pocketbook, and vehicle battery life whenever practical. Fast charging should be used as needed, for enabling things like long-distance travel or emergency charging. If consumer expectations and behaviors don't evolve beyond classic "gasoline thinking," then we can expect the energy transformation to take longer and cost more than it otherwise should.

Part of this evolution will require the reconciliation and balancing of personal and societal costs and benefits. Modern industries and economies were built upon the twin fundamentals of internalized gains and externalized impacts. As we attempt to internalize negative impacts and share economic benefits more broadly across our society, old habits will need to be challenged and adjusted. Otherwise, clean technologies will fail to live up to their theoretical potentials, leading to unnecessary excesses and waste that do not support our best interests or goals.

In addition to adopting "triaged charging" behavior, EV drivers should also consider buying smaller vehicles and vehicles with smaller batteries wherever these meet their mobility needs. Worst-case emotional purchase behavior leads to additional resource inefficiencies and cost overruns that are not needed. Commuting daily in an oversized electric truck with an oversized battery is arguably not a huge improvement over making that same commute in a small conventional vehicle (especially in regions where the electric grid has yet to be decarbonized).

APPENDIX, GLOSSARY, AND BIBLIOGRAPHY



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APPENDIX A

Background information

In this appendix, we attempt to explain how utilities bill their business customers, why they structure rates the way that they do, and how this affects the cost to charge an EV and to operate DC fast-charging equipment.

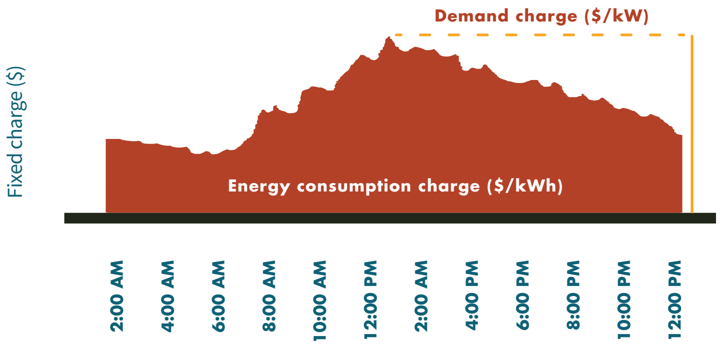
COMMON ELECTRIC UTILITY CONCEPTS

Grid. This is a term that most people are probably already familiar with since the popular media regularly reports on the state of the grid (often with dire warnings). An electric grid in the simplest terms is any network of conductive material that can carry electricity from source to sink. But for the purposes of this study, when we refer to "the grid" we're generally referring to the network of "poles and wires" that moves electricity from source to consumer, and includes a dizzying, complex array of generation, transmission, and distribution (GT&D) assets. We'll also discuss smaller grids of the "micro" and "nano" varieties, but they all essentially do the same thing: move electricity.

Demand. Electric demand reflects the power draw for a given customer, premise, meter, or end-use device (e.g., an EV charger). The magnitude of electric demand for a given customer is also referred to as that customer's "capacity" and refers to the level of grid service required to serve electrical needs at their premise. Power is theoretically measured "instantaneously" and so does not have a time element associated with it. For example, the demand of a DCFC may be rated for an instantaneous maximum power draw of anywhere between 50 kilowatts (kW) on the low end to 1 megawatt (MW) or more on the upper end. In practice, utilities often measure demand as average power draw over 15-minute intervals, since this is the level of granularity enabled by so-called "smart meters" (i.e., advanced metering infrastructure, or AMI).

Load. In transportation and logistics circles, a "load" most likely refers to the weight, volume, and/or type of materials moved as cargo. For electric utilities – and for the purposes of this report – when we refer to load, we mean an electric load, which describes some electrical end-use device, circuit, building, or premise that draws electric power from the grid in order to operate. Loads come in all shapes and sizes and are commonly characterized by so-called "load profiles" (LPs), a depiction of the load's fluctuations in power drawn over time (Figure A-1).

FIGURE A-1: ELEMENTS OF AN END-USE LOAD PROFILE AND ELECTRIC UTILITY BILL FOR A COMMERCIAL PREMISE



This graph depicts a generic load profile at a business customer utility meter, as well as the basic ways in which a customer is charged by the utility for electricity. The three fundamental aspects of the utility bill include a fixed charge (not tied to energy use), the consumption charge (based on the total volume of energy consumed), and the demand charge (based on the peak monthly power demand).

Source: E Source

Base load. A so-called "base load" is a description of power demand that is essentially constant or flat over time. In Figure A-1, the base load is the portion of the graph that is rust-red all day. For utilities, the base load is the easiest load to serve, as it does not fluctuate, is therefore easy to predict, and requires the lowest-cost generation assets to serve. For a utility business customer, if their base-load demand is high, then their energy costs per-unit of energy consumed will usually be low. This is preferable for the profitability of a business model based around high electricity use. Conversely, customers with low base load and high peak load pay more per unit energy.

Grid-friendly load. This is a less-common term, but one that is gaining in popularity within the utility industry, in response to increasing interest in electrification of buildings and transportation. A device or premise with a high base load may be grid-friendly, for example (but this is not necessarily always the case). From an electric grid operator's perspective, the "friendliest" loads (i.e., those that are the easiest for them to serve) are ones that are steady and predictable in their demand (kW), are less expensive to serve (e.g., lower marginal costs), and/or have a low likelihood of causing a significant grid disturbance. Such "friendly" loads are less expensive to serve in operation and also pose less of a risk to the expensive grid equipment that serves them.

For power engineers, there are many terms and measurements that are commonly used to quantify and describe the degree to which a given load is agreeable to serve or not. These include terms like power quality (PQ), power factor (PF), total harmonic distortion (THD), load stability, controllability, responsiveness, ride-through performance, and others. While it is not essential that the reader understand all of these concepts and how to apply them in order to get value from this report, it is helpful simply to note that grid operators have a keen interest in the "friendliness" of electric loads, at all scales.

Consumption. Electricity consumption refers to the total amount of energy used by a given customer, premise, meter, or end-use device over a given period of time. In this way, electricity is commonly viewed as a commodity that gets consumed, at least in some sense. This commodity is measured and reported in units of kilowatt-hours (kWh), i.e., kW x hrs, or the power demand over time. Utilities typically track demand (kW) in 15-minute increments and aggregate these measurements to produce fairly accurate (revenue grade) estimates of total energy consumed over a monthly billing cycle.

Rate tariff. While use of the term "tariff" may apply to taxes or other fees levied on imported or exported materials or products, in the context of utility rates it generically refers to "fixed pricing agreements" between utilities and their customers. The terms schedule, tariff, and agreement are all commonly used in conjunction and sometimes interchangeably to refer to the customer rate. For regulated utilities, a rate-case process is typically required to create a new tariff or adjust an existing one. Rate cases are commonly drawn out over months or years and may involve written and oral testimony of industry experts, utility representatives, and so-called intervenors representing various industries, consumer advocates, and others.

Rate structure. How a given rate tariff is designed – including specific pricing details, clauses, and customer requirements – are sometimes collectively referred to as its structure. For example, a complex rate structure might be something like a variable rate; one with pricing that varies seasonally, by time of day, and based on how much energy has already been consumed so far in one month (or based on historical consumption or demand patterns). The opposite of a complex rate structure is a fixed rate, or one that does not vary with time or usage.

Volumetric pricing. For those familiar with commodities markets, volumetric pricing – also sometimes referred to as energy pricing – is probably the most intuitive rate element. This refers to consumption-based pricing, usually measured in units of dollars per kilowatt-hour ($/kWh). Even though the average electricity consumer may have no idea what a kWh measures, this remains one of the more “intuitive” aspects of electricity pricing. Even where other rate elements are present, total electricity costs are often communicated in aggregate terms as $/kWh (e.g., as the price an EV driver sees at a public charging station).

Demand pricing. In the US, residential electric utility customers historically do not pay demand charges, but business customers usually do (e.g., commercial and industrial, or C&I). Demand-based pricing is often dictated by the maximum power demanded in the billing month for a given customer meter or site, stated in units of dollars per kilowatt ($/kW). Demand pricing tends to be less “intuitive” as it is less about how much energy is consumed and more about the grid capacity needed to serve the electric load(s).

Fixed pricing. Electric utilities often consider the cost to serve their customers in terms of two cost components: fixed and marginal. Fixed costs are associated with any capital or operating expenditures that are not output-dependent. That is, these costs do not change regardless of how much power is produced or consumed. For utilities to continue operating and remain solvent, they obviously must recuperate these fixed costs through charges to the rate base. At least in theory, these fixed costs should be reflected in fixed charges to the customer.

Marginal pricing. Marginal pricing is output-dependent and reflects the actual cost of serving the load based on demand and time-varying cost factors. This concept is typified by electric grid assets such as “peaker plants” or “spinning reserves” or “curtailed generation” – electricity generators that are rapidly ramped up and down or are operated without producing useable electricity for sale. These are the most-expensive assets for grid operators to maintain and also tend to deliver the least benefit in terms of meeting decarbonization goals. Marginal pricing (at least in theory) enables grid operators to account for and recover these costs more-directly.

Usage factors. There are several ways engineers commonly compare potential vs. actual usage. Capacity factor (CF) is one common term, sometimes used to describe power generation, e.g., the percent of time a powerplant is operating at maximum power output. Similar engineering terms include load factor (LF) and utilization factor (UF), and they express variations on fundamentally similar concepts. A customer’s LF value is commonly calculated by dividing monthly energy consumption (kWh) by that month’s peak demand (kW). At least in theory, the higher the LF value (closer to 1.0), the easier and more cost-effective it is for grid operators to serve the load. LF is also commonly used to describe loading on the electric grid at any scale, from distribution feeders all the way up to regional operating systems.

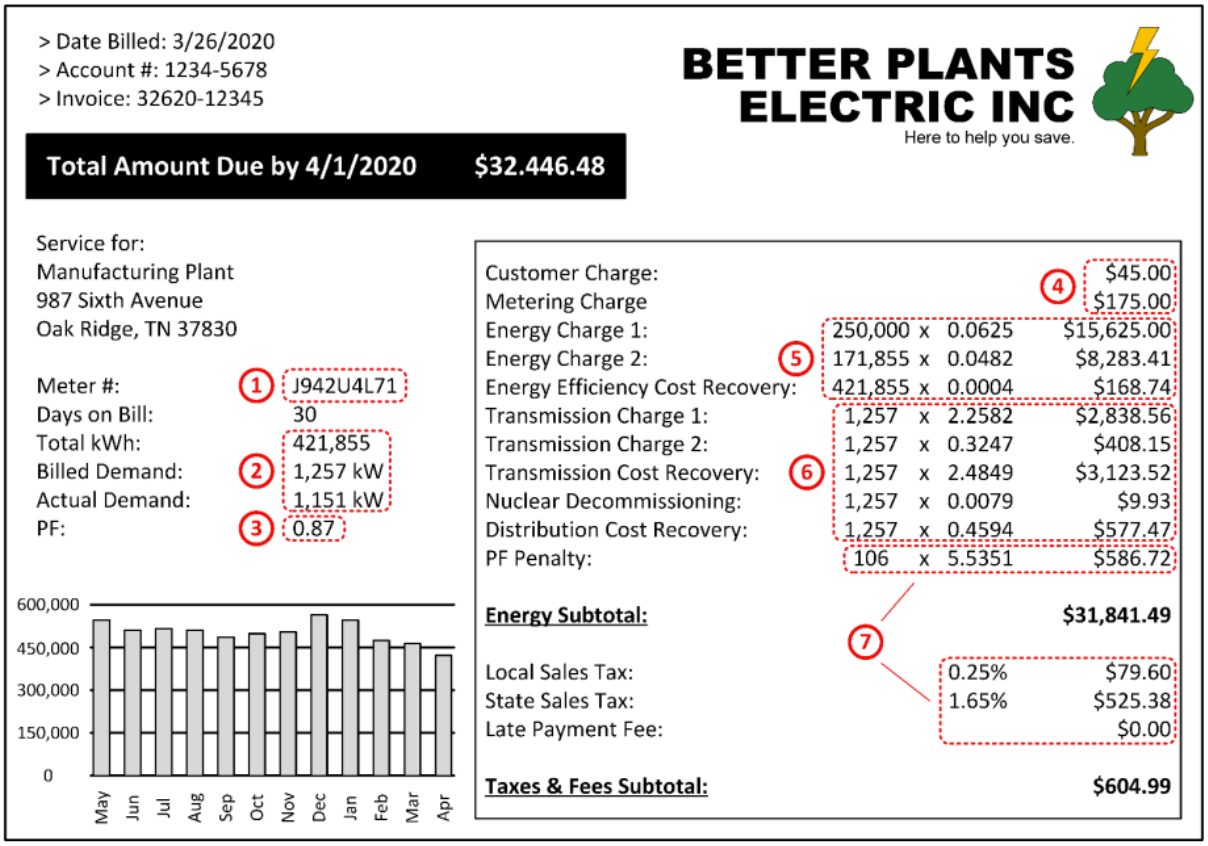
In simple terms, if an electric load runs 24/7 at maximum rated power without fluctuation, it has an LF of 100% or 1.0. So, if the peak demand of a DCFC is 350 kW and its LF = 1.0, it would consume 252,000 kWh in a 30-day billing period, assuming no variation in demand or other electrical loads or losses (i.e., 350 x 30 x 24 = 252,000). In operation, DCFCs have UFs that are much lower than 1.0, even under “ideal” conditions and relatively high usage rates. A high UF value for a typical DCFC is on the order of 0.1 to 0.3. This is why some utility rate tariffs can be problematic for DCFC operation; those favoring high loading and utilization will be more costly.

EV-charging levels. The rate at which an EV is recharged is limited either by the power supplied by the charging station or the nameplate rated power of the vehicle’s on-board battery charge controller (whichever is lower). In this report, we mostly refer to power in terms of kilowatts (kW), and this gives some sense of how fast the vehicle can be charged at a given power source (e.g., EV charging station). Another common way to refer to this is "levels" of charging. Level 1 charging involves plugging an EV into a standard electrical outlet (120 volts), with a power supply of 1.3 to 2.4kW. Level 2 charging is supplied by a 240-volt circuit (similar to a clothes dryer outlet) and can deliver between 3 and 19.2kW of power. Level 3 charging is often synonymous with DCFC (AC Level 3 is relatively rare) and typically delivers anywhere from 50 to 350kW of power in the US and Canada.

HOW UTILITIES BILL THEIR CUSTOMERS

While not every utility bill is structured in the same way, most do contain similar information. The trick is often knowing how to read and interpret what's on the bill (Figure A-2).

FIGURE A-2: DECIPHERING A TYPICAL ELECTRIC UTILITY BILL



> Date Billed: 3/26/2020
> Account #: 1234-5678
> Invoice: 32620-12345

BETTER PLANTS ELECTRIC INC
Here to help you save.

Total Amount Due by 4/1/2020 $32.446.48

Service for:
Manufacturing Plant
987 Sixth Avenue
Oak Ridge, TN 37830

Meter #:	①	J942U4L71
Days on Bill:		30
Total kWh:	②	421,855
Billed Demand:		1,257 kW
Actual Demand:		1,151 kW
PF:	③	0.87

Customer Charge:	④				$45.00
Metering Charge					$175.00
Energy Charge 1:	⑤	250,000	x	0.0625	$15,625.00
Energy Charge 2:		171,855	x	0.0482	$8,283.41
Energy Efficiency Cost Recovery:		421,855	x	0.0004	$168.74
Transmission Charge 1:	⑥	1,257	x	2.2582	$2,838.56
Transmission Charge 2:		1,257	x	0.3247	$408.15
Transmission Cost Recovery:		1,257	x	2.4849	$3,123.52
Nuclear Decommissioning:		1,257	x	0.0079	$9.93
Distribution Cost Recovery:		1,257	x	0.4594	$577.47
PF Penalty:	⑦	106	x	5.5351	$586.72
Energy Subtotal:					**$31,841.49**
Local Sales Tax:		0.25%			$79.60
State Sales Tax:		1.65%			$525.38
Late Payment Fee:					$0.00
Taxes & Fees Subtotal:					**$604.99**

Each utility bill may be structured in slightly different ways, but most contain these same elements: 1. Customer's meter number; 2. Utility readings of that meter (in aggregate kWh); 3. The customer's power factor (PF) rating; 4. Fixed charges; 5. Consumption charges; 6. Demand charges; and, 7. Taxes, fees, and penalties. For this customer, demand-related charges represent more than 20% of the monthly utility bill (DOE, 2021).

Source: US Department of Energy Better Plants Program (2021, April). Understanding your utility bills: Electricity. Retrieved from: BP Understanding your Utility Bill - Electricity_FINAL.pdf (energy.gov)

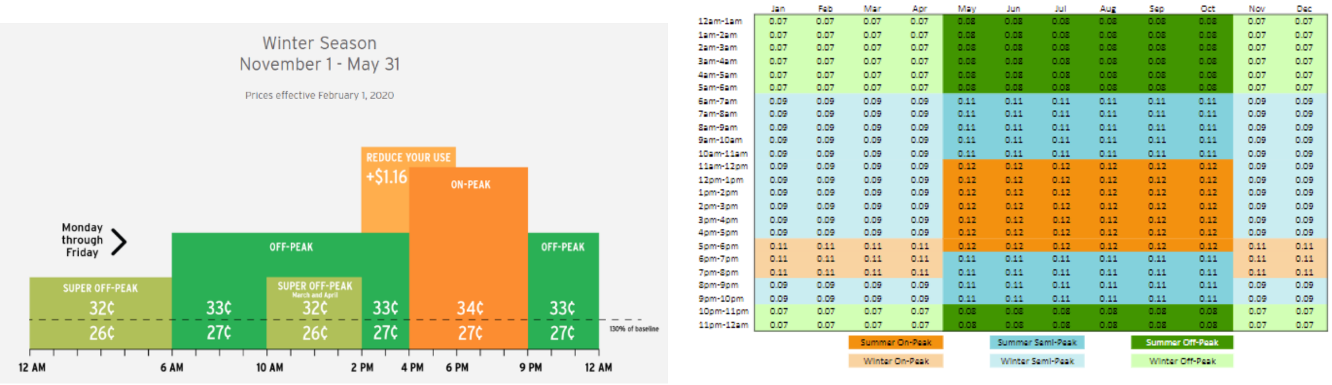
COMPARING UTILITY RATE OPTIONS

Utility rate design is a unique specialization, and the finer details of rate-making exist well beyond the scope of this report. For non-rate experts, there are a few key questions you can ask about a rate schedule that may be helpful in understanding how it was designed, how it compares to other rate options, and how that is likely to impact your energy costs over time:

- **Who is this rate designed for and who is eligible?** Some rates are narrowly restricted in terms of eligibility, while others are open to a broad range of customers. And some sectors of utility customers have more rate options to choose from than others. Knowing which rate schedules apply to your business or application is a good first step. You can learn which rate plans for which you qualify from your utility website or account manager.
- **What is your load profile like?** It's not always easy to predict what your load profile will look like in the future, especially following a retrofit project or equipment installation. Your utility may be able to provide some insight on this, in addition to monthly billed energy usage, either through EIS services, a mobile app, or custom technical services, such as an energy audit or site assessment prior to a new project. Particularly for DCFC stations metered along with the rest of the customer's facility, there may be efficiency measures and load-flexibility opportunities within existing buildings that can be pursued to lower overall demand at the customer's site.
- **Based on the load profile, what is the approximate load factor (LF)?** As mentioned previously, LF describes the amount of energy consumed relative to the maximum amount of energy that could have been consumed. If you have a high LF (i.e., a flat load profile), a capacity-based rate design (e.g., higher demand charge, low-or-no energy charge) could save you money. If your LF is low, a rate design based more on volumetric pricing with low-or-no demand charge will be a better choice (assuming such a tariff is available). You may wish to request load data from the charging equipment manufacturer before you install the DCFC to get a better sense of future energy costs.
- **Does variability in the rate design compliment (or conflict with) variability in the load?** This question can be harder to answer without having good data on hand, including the load profile and utility bill history. For example, being on a time-varying rate, a rate schedule that varies seasonally, or a tiered rate is only advantageous if you can manage your loads and shift them to lower-cost times. For a public-access EV charging station, this will be more difficult to implement. You may have no choice but to sign up for a TOU rate, but without controllability, this type of rate will make energy costs less predictable.

Let's consider the example of the following tariff from San Diego Gas and Electric (SDG&E), depicted in Figure A-3. This depicts a time-varying, winter-specific, tiered weekday rate schedule (left) as well as a fully mapped out annual schedule (right). Without some prior experience with rate design or more explanation from the utility, it may be difficult for a customer to understand how they should manage their loads or otherwise adjust behavior to respond optimally to this price signal, even though the differences in off-peak and on-peak rates may be significant. And without knowledge of how a DCFC is likely to operate, it can be relatively difficult to select the optimal rate plan for minimizing the associated energy costs. It can be worthwhile to have a conversation with both your utility and DCFC equipment or service provider.

FIGURE A-3: DAILY (LEFT) AND ANNUAL (RIGHT) RATE SCHEDULE EXAMPLES FOR A TOU RATE



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
12am-1am	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
1am-2am	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
2am-3am	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
3am-4am	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
4am-5am	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
5am-6am	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
6am-7am	0.09	0.09	0.09	0.09	0.11	0.11	0.11	0.11	0.11	0.11	0.09	0.09
7am-8am	0.09	0.09	0.09	0.09	0.11	0.11	0.11	0.11	0.11	0.11	0.09	0.09
8am-9am	0.09	0.09	0.09	0.09	0.11	0.11	0.11	0.11	0.11	0.11	0.09	0.09
9am-10am	0.09	0.09	0.09	0.09	0.11	0.11	0.11	0.11	0.11	0.11	0.09	0.09
10am-11am	0.09	0.09	0.09	0.09	0.11	0.11	0.11	0.11	0.11	0.11	0.09	0.09
11am-12pm	0.09	0.09	0.09	0.09	0.12	0.12	0.12	0.12	0.12	0.12	0.09	0.09
12pm-1pm	0.09	0.09	0.09	0.09	0.12	0.12	0.12	0.12	0.12	0.12	0.09	0.09
1pm-2pm	0.09	0.09	0.09	0.09	0.12	0.12	0.12	0.12	0.12	0.12	0.09	0.09
2pm-3pm	0.09	0.09	0.09	0.09	0.12	0.12	0.12	0.12	0.12	0.12	0.09	0.09
3pm-4pm	0.09	0.09	0.09	0.09	0.12	0.12	0.12	0.12	0.12	0.12	0.09	0.09
4pm-5pm	0.09	0.09	0.09	0.09	0.12	0.12	0.12	0.12	0.12	0.12	0.09	0.09
5pm-6pm	0.11	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.12	0.12	0.11	0.11
6pm-7pm	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
7pm-8pm	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
8pm-9pm	0.09	0.09	0.09	0.09	0.11	0.11	0.11	0.11	0.11	0.11	0.09	0.09
9pm-10pm	0.09	0.09	0.09	0.09	0.11	0.11	0.11	0.11	0.11	0.11	0.09	0.09
10pm-11pm	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
11pm-12am	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07

Summer On-Peak
Summer Semi-Peak
Summer Off-Peak
Winter On-Peak
Winter Semi-Peak
Winter Off-Peak

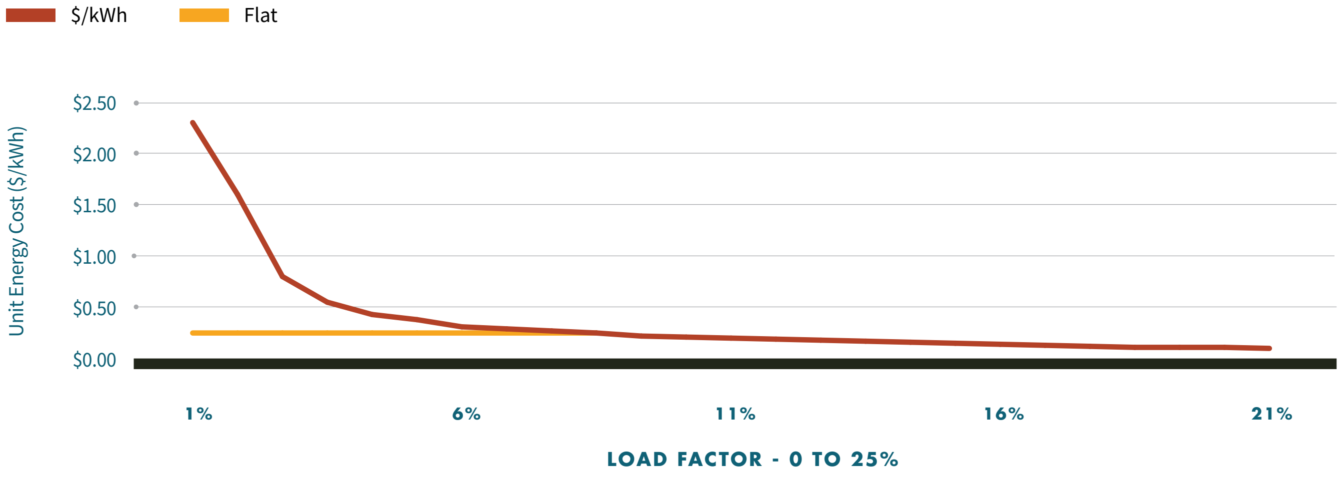
Several different rate elements are depicted in these two figures: baseline (Tier 0) versus above-baseline (Tier 1) pricing difference (denoted by dotted line on left); on- and off-peak and super on- and off-peak rate differences; and winter and summer seasonal rate differences (right). Note that this only depicts volumetric pricing differences, not demand-based variation. (E Source, 2020)

Source: E Source Companies LLC (2020, February). Behind-the-meter battery market study. Retrieved from: https://www.etcc-ca.com/reports/behind-meter-battery-market-study; tariff data from SDG&E

CONSIDERING DIFFERENT DEMAND-CHARGE APPROACHES

Utilities have experimented with a number of demand charge variations in an attempt to recover costs while also accommodating the needs of customers with high demand and relatively low volumetric consumption (i.e., low LF). DCFC operations are a textbook example of this customer class, and many electric utilities continue to explore and experiment with new and alternative rate options that make the most sense for each customer. These largely involve temporary removal of demand charges, caps on demand-based charges, adjustments for low-load factor customers, and even demand-only rates (for high-utilization customers). In general, the assumption is that eventually, station utilization will increase and so will load factor, and the relative cost of supplying power will go down (Figure A-4).

FIGURE A-4: A TWO-PART TARIFF, DEPICTED IN TERMS OF LOAD FACTOR (LF) VERSUS ENERGY COSTS



Several pilot and experimental EV-specific rate tariffs for DCFCs essentially do the same thing: for low station utilization and low load factor, the utility places a cap on the per-kWh cost the customer will pay. So, in this example, if the DCFC load factor is 10% or less, the station host pays the same amount (i.e., $0.25/kWh). If load factor increases, the cost goes down. For low load factor, the area between the rust-red and yellow lines represents potential cost savings to the site host.

Source: E Source; adapted from https://media.ktoo.org/wp-content/uploads/2022/02/AELP-TA504-1-Experimental-High-Power-Electric-Vehicle-Charging-Final-1-24-22-w-Attachments.pdf

Note that of all the utility rates we surveyed that could theoretically be applied to DCFCs (i.e., commercial, industrial, and general-service rate schedules), rate designs appear to be split roughly evenly between those with "no demand charge" and "flat demand charge," and then there are a relatively smaller share of tariffs that include TOU demand charges. Other approaches are rare and typically remain in pilot, experimental, or proposal stages.

APPENDIX B

Prior research

Previous studies have been conducted to explore the impact of utility rates on the EV-charging business model – with a particular emphasis on DCFC operation – and identify options for improving the business case. While it is beyond the scope of this study to review them all in-depth, we've selected a few illustrative studies for consideration here. These studies were not selected at random; we include them here because they offer significant insight into the problem at hand. While other studies on this topic exist and many are included in the bibliography, they are less useful for our purposes and/or derivative in nature.

In this section, we highlight the major findings from these select studies, discuss the research and analysis conducted therein, and highlight some of their assertions, including those in need of revisiting to consider the latest-available technology, rates, and other evidence.

UTILITY RATE TARIFF ANALYSES

Electricity Rate Tariff Options for Minimizing Direct Current Fast Charger Demand Charges (2015, December; direct PDF download). Conducted by Energetics on behalf of the New York State Energy Research and Development Authority (NYSERDA) – the state energy office (SEO) of New York – this study was among the first to explore the relationship between utility demand charges and DCFC cost-effectiveness. The goals of the study were to: 1. Identify existing utility rates and demand charges that apply to DCFC operation; and 2. Identify promising alternatives to traditional utility rate design that may fit better with DCFC operation and business models.

The researchers from Energetics conducted a literature review followed by a series of interviews with utilities operating in New York and in other states, as well as other energy and EV industry stakeholders. Below are summaries of the study's key observations and findings:

- The researchers identified the following mitigation strategies but didn't address any of them directly in their study: battery storage, controls technologies, experimental rate tariffs, or some combination of the three.
- They estimated that typical DCFC revenue amounts to only about a third of station operating costs, even when the charging equipment was paid for through government grant programs.
- The authors point to three general types of rate designs that can be used for DCFC applications and may improve business outcomes for customers but are not necessarily offered by all utilities: 1. Energy-charge only with a monthly consumption threshold; 2. Energy-charge only without a monthly consumption threshold; and, 3. A rate limiter.
- They discuss utility pilots to eliminate demand charges, but point out that efforts to eliminate or reduce demand charges run counter to IOU "cost-based rate requirements and energy-saving measures."
- They profile the demand charge of nineteen utilities of different types (Table 1, PDF p. 16; mostly IOUs, eleven from New York, eight from other states).
- The authors point out that DCFC load profiles and load factors are unique, and their impacts on utility grid equipment and the need and implications for new DCFC-specific rate design remains largely unstudied and unknown.
- They mention that utilities across the board reported a desire for flexible load-management capabilities in DCFC equipment (e.g., DR-responsiveness).

- They also point out that utility-owned DCFCs might make more financial sense thanks to the utility's longer cost-recovery expectations and asset-management business model. They suggest that EVSPs are generally not in favor of this option and argue that utilities don't have experience delivering electricity as a transportation fuel.

Increasing Electric Vehicle Fast Charging Deployment (2019, January). Conducted by the Brattle Group on behalf of Edison Electric Institute (EEI), this study was published about three years after NYSERDA's study and draws from some of its conclusions. It extends and expands upon the analysis of the NYSERDA study in one key area: providing a more-detailed description of select utility rate tariffs and explaining how different elements of those rate designs can impact EV fast-charging costs. Below are summaries of this study's recommendations:

- The researchers suggest a half dozen rate-design options that utilities might consider to help *"increase DCFC deployment"* including: create a separate DCFC-specific rate class, offer more rates choices, experiment with new rate designs, limit demand charges, use volumetric charges to replace or reduce demand charges, and provide more-detailed price signals.
- They also suggest four possible options for DCFC site hosts to manage operating costs including: install energy storage, implement load-management controls, develop stations for use by a known customer category, or site charging stations behind the meter of a large electric utility customer (e.g., industrial).

A Snapshot of EV-Specific Rate Designs Among U.S. Investor-Owned Electric Utilities (2023, April). Conducted by researchers at the Lawrence Berkeley National Laboratory (LBNL), this meta-analysis of utility EV-specific rates breaks down rate tariff attributes more granularly than any previous public study of its kind. Leveraging the E9 Insights rate database, LBNL assessed EV-specific rates that apply to all EVSE applications, including utility-owned DCFCs. Below are some of the study's primary observations of EV-specific rates:

- The researchers identified nearly two dozen (22) individual EV-specific rate tariffs that apply explicitly to utility-owned DCFCs. Of these, none currently include a demand charge.
- Roughly half of all utility rates for private DCFC hosts (non-utility) were found to include some form of demand charge.
- Most EV-specific rates include peak and off-peak periods (i.e., are TOU rates). However, both temporal and spatial variations that are reflected in EV-specific rates are broadly applied across service territories and lack the granularity needed to price or value EV charging relative to the actual cost to serve.
- EV-specific rates are currently not requiring nor incorporating managed-demand software or EV managed charging options.
- While this meta-analysis provides a good overview of what utilities are doing currently in terms of designing EV-specific rates, it provides no insight into why specific rate elements exist or not. More analysis of the "why" is still needed.

COST-MITIGATION STRATEGIES

Technology solutions to mitigate electricity cost for electric vehicle DC fast charging (2019, May). Conducted by researchers from the National Renewable Energy Laboratory (NREL), this study explores the feasibility of different technical solutions for mitigating high electricity costs associated with operating DCFCs. Below are summaries of the researchers' key findings and observations:

- For the more than 7,000 rate tariffs analyzed, the researchers found that solar photovoltaics (PV) were generally effective for reducing volumetric charges, battery storage was better for managing demand charges, and the two combined (solar + storage) demonstrated synergistic effects for lowering overall operating costs.
- The researchers found that while median costs were only about $0.20/kWh, these costs varied widely and some areas experienced consistently higher energy costs. Co-locating a DCFC with solar + storage at an existing building and behind that building's utility meter demonstrated the best economic results under low-utilization conditions (but these benefits diminish as DCFC utilization increases).

Analytical White Paper: Overcoming Barriers to Expanding Fast Charging Infrastructure in the Midcontinent Region (2019, July). Conducted by researchers at the Great Plains Institute (GPI), this white paper's analysis explores the costs of operating DCFC stations in the Midwest region. The authors explore the impact of power rating and daily station utilization on operating cost, and even published an online calculator to support simple scenario analysis. Below are summaries of this study's main findings:

- The researchers suggest that low utilization in the near term equates to lower revenues, demand charges represent a large percentage of total operating costs, and higher power/faster DCFCs are the least cost-effective EV charging stations to operate under these conditions. Even at the highest utilization rates considered for their analysis (i.e., 10 charging sessions per day), high-power DCFCs delivering 450kW of charge could not be operated economically when any demand charge above $0/kW was applied.
- Utility demand charges vary considerably, many make it difficult to operate DCFCs cost-effectively under the utilization scenarios considered, but some utilities have more "DCFC-friendly" tariffs that enable DCFC systems to be operated profitably in their service territories (Xcel Energy and Pacific Gas and Electric [PG&E] are two examples given).

Electricity rates for electric vehicle direct current fast charging in the United States (2019, October). Conducted by researchers from NREL, this study analyzes more than 7,500 utility rate tariffs and the range of effects on energy costs associated with operating DCFCs across the US. Estimated energy costs had a wide range, of anywhere between less than $0.10 to more than $2 per kWh. Below are summaries of the researchers' key findings and observations:

- Low utilization of DCFCs was identified as the key driver of high energy costs, which results from a low number of charging events and limited energy delivered per event.
- As utilization of DCFCs increases, costs tend to decrease relatively quickly, and rate tariffs with demand charges can actually be advantageous for high-utilization stations.
- Managing demand at DCFC stations with multiple ports – so that the maximum total power draw is capped when multiple EVs are charging simultaneously – was identified as a viable cost-saving measure.
- They identified 45 DCFC-specific utility rate designs, most of which did not include demand charges.

DCFC-SPECIFIC RATE DESIGNS

DCFC Rate Design Study (2020, February). Conducted by researchers from the Rocky Mountain Institute (RMI) on behalf of the Colorado Energy Office (CEO), this study explores the impacts of utility rate design (and demand charges in particular) on the cost and economic viability of DCFC operation. Like the GPI study, the RMI researchers also profile the rate tariffs of Xcel Energy and PG&E, but they also compare them to a theoretical experimental tariff design they refer to as the "RMI tariff." It is an evolving experimental rate design, with volumetric charges that start out high and demand charges that are low initially, then volumetric charges decrease and demand charges increase as utilization rates increase. Over a 10-year horizon, their scenario analysis assumes a DCFC utilization rate of 5% in the first 3 years, 10% in the next 3 years, and 30% in the final four years, which they selected based on their *"informed assumption."* Below are summaries of this study's primary recommendations:

- Utility rate tariffs should be evaluated by whether or not they can "meet or beat" the cost-per-mile of refueling a gasoline or diesel vehicle, which they believe is necessary to promote widespread EV adoption. They identify a cost-per-mile threshold of $0.09/mile, and suggest that an $0.08/mile cost of delivered electricity is needed to allow for a profit margin of 10% on DCFC operation.
- They explain how both Xcel and PG&E took different approaches to cap the maximum energy costs associated with DCFC operation. In Xcel's case, they use the "Rule of 100" to effectively cap the $/kWh maximum monthly charges. PG&E's rate design applies a monthly subscription model with no demand charge.
- The RMI tariff outperforms the other two utility tariffs for public DCFC stations, delivering a cost-per-mile at around half the threshold limit in their "worst-case scenario" of 10% station utilization. This is attributed to the RMI tariff's "sliding-scale design" for adjusting volumetric and demand charges in response to station utilization rates.
- Xcel's rate design was shown to be the lowest-cost option for their bus depot charging scenario. RMI researchers recommend that Xcel choose the lowest-cost rate design for each DCFC application, to support market growth under low-utilization conditions, but also admit that utility rate cost causation for DCFC operation remains in need of "more empirical support."

Electric Transportation Rate Design Principles for Regulated Utilities (2021, July). Conducted by members of the Alliance for Transportation Electrification (ATE), this two-part working paper describes a study of rate-design principles for IOUs and the implications for EV charging. Below are summaries of this study's major recommendations:

- The authors are emphatic about the need to closely consider cost causation and recover those costs associated with serving DCFCs, especially where demand charges are lowered or removed artificially. They list several examples of possible alternatives, including demand-charge "holidays" instead of moratoriums, subscription fees with TOU rates, demand-charge waivers for low-use customers, demand limiters, exceptions for low-LF customers, demand-charge credits, and monthly cost caps.
- The authors also make recommendations about how utilities should consider energy charges to different types of DCFC hosts. For example, they suggest that EVSPs operating in all states should not be treated like regulated utilities for the resale of electricity for EV charging, but that they should receive price signals that reflect the reals costs of delivering electricity to the site. They suggest that utilities may consider surveying EVSP pricing for a given region and resetting energy pricing to reflect those averages.

DCFC RELIABILITY, UTILIZATION, AND GRID IMPACTS

Grid Impact of Electric Vehicle Fast Charging Stations: Trends, Standards, Issues and Mitigation Measures - An Overview (2021, February). Conducted by members of the Institute of Electrical and Electronics Engineers (IEEE), this paper contains a summary of findings related to DCFC impacts on grid equipment. The authors generally found that standards for measuring and reporting the power quality (PQ) performance of DCFCs is lacking. They propose an approach in this paper that could potentially be used to estimate related PQ disturbances and subsequent impacts. Below are summaries of this study's major findings:

- So-called harmonic "emissions" and distortions associated with DCFC operation – particularly high-power units and multiple DCFS operating simultaneously and switching on and off – can be significant and have the potential to pose problems.
- Ensuring that PQ standards are met and adopted broadly is one approach to reducing the risk of DCFC operation. Another is installing on-site energy storage that can be used to help buffer power fluctuations and limit harmonic disturbances.

Reliability of Open Public Electric Vehicle Direct Current Fast Chargers (2022, March). Conducted by an independent group of researchers from different organizations, this paper describes observed EV charging station reliability in the San Francisco Bay Area. This group sought to validate conflicting reports of DCFC uptime from EVSPs and EV drivers during a survey by the California Air Resources Board (CARB, 2022); EVSPs reported uptime rates in the range of 95 to 98 percent, but self-reported user experiences did not reflect this. This is particularly important for public-funded EV-charging equipment, which is required to meet minimum uptime thresholds. The findings of this group were more in line with the reports of surveyed EV drivers than those of the EVSPs, and included the following:

- The group visited 181 charging stations and tested 657 individual EVSE ports (this number would have been higher, but there were non-EVs parked in several of the adjacent stalls). All of these stations were open, public-access stations and did not include Tesla Supercharger stations. Nearly all of these stations were operated by the EVSPs Chargepoint, Electrify America, or EVGo (i.e., 97%). More than 1 in 4 charging ports was not functional for one reason or another, including 32 EVSE where the charging cable was too short to reach the vehicle's charge port.

- The researchers concluded that the public-access EVSE networks in the Bay Area do not meet the minimum 97 to 99 percent minimum uptime threshold required by public funding agencies (e.g., California, New York, or federal).

Observational Evaluation of the Maximum Practical Utilization of Electric Vehicle DCFC Infrastructure (2022, October). Conducted by researchers at the Renewable Energy Storage Laboratory (RESL) at Dalhousie University, this paper describes the analysis of 3.5 years of utilization data from 12 DCFCs. Since most EVSPs don't publicly release their utilization data and the data that has been made public so far is largely only available in aggregate (e.g., from the EV WATTS project), this type of study is valuable for the assessment of DCFC operation and utilization in real-world applications. Below are summaries of this study's major findings:

- The researchers analyzed data for 13,000 charging events on 12 DCFCs rated at 50 kW each, and located along a network having an 80 km distance between stations. They found that a 10% utilization factor (UF) is optimal for limiting the probability of EV driver queuing to wait for a charge at 10% (i.e., a 1-in-10 chance of having to wait for a port). In this case, UF is a measure of how much energy the charger delivered, divided by how much it could have theoretically delivered in a 24-hour period (e.g., 50 kW x 24 hrs = 1,200 kWh).

Public electric vehicle charging station utilization in the United States (2023, January). Similar to the NREL rate analysis, this report from researchers at NREL and Energetics sources one of the datasets we also utilized for our modeling in this study (i.e., from the EV WATTS project). Their analysis of the data is based on a subset of the total dataset (n = 629 stations), and much like our analysis there is a significant focus on how public EV charging stations are being utilized so far. Note however that their definition of "utilization" differs from the definition used in our study; they are considering the total time the EV is plugged in, rather than how much energy was delivered. Significant observations reported in this study include:

- So far, DCFC station utilization is less affected by number of available stations in the network, and more so impacted by charger rating (i.e., higher-power chargers tend to have higher utilization rates). However, it's important to note that a large majority of DCFC units evaluated in this study are rated at 50kW, while relatively few have higher power ratings (e.g., 150kW).
- While the trend in DCFC station utilization is generally on an upward trajectory, this was not consistent across station location types and at least part of this growth is due to a travel rebound following COVID-19. Some station locations were obviously impacted more so than others by COVID-19 and its travel and quarantine restrictions (e.g., offices and leisure destinations). For other station location types, impacts to station utilization were less noticeable (e.g., retail, hotels). Similarly, some location types experience more differentiation in station utilization on weekdays vs. weekends (e.g., hotels, leisure), though all venue types experienced higher utilization on weekends.

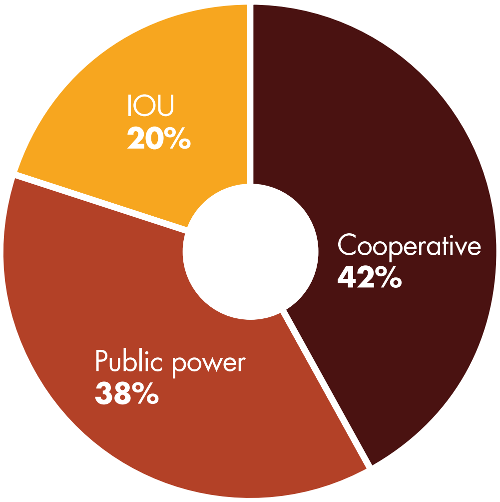
The researchers report average energy delivery for this subset of DCFC stations to be 13.5 kWh per port per day as of March 2022. From a load factor perspective, that's only about 1% utilization. The authors noted that *"Low EVSE utilization makes for challenging economics for public EV charging as a standalone business. More research is needed to assess the impacts of today's low (but possibly increasing) EVSE utilization levels on the business case and financial requirements for charging stations and the cost of charging for EV drivers."*

APPENDIX C

Rate analysis

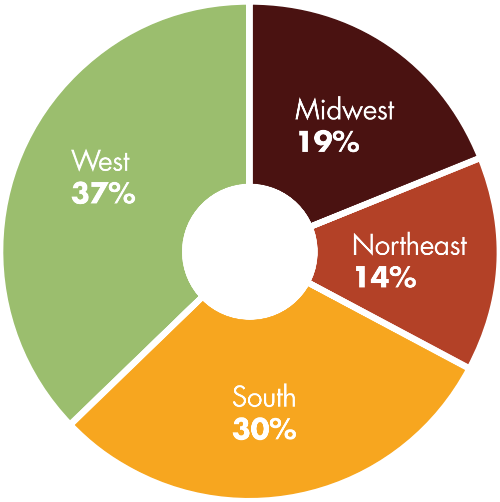
We reviewed nearly 7,500 C&I customer rate tariffs from 329 different utilities, using data sourced from the Utility Rate Database (URD) of the Open Energy Information (OpenEI) wiki, hosted by NREL. Below are some of the results from our data analysis, showing general differences in demand charges by utility type and region.

FIGURE C-1: SHARE OF UTILITIES REVIEWED BY TYPE



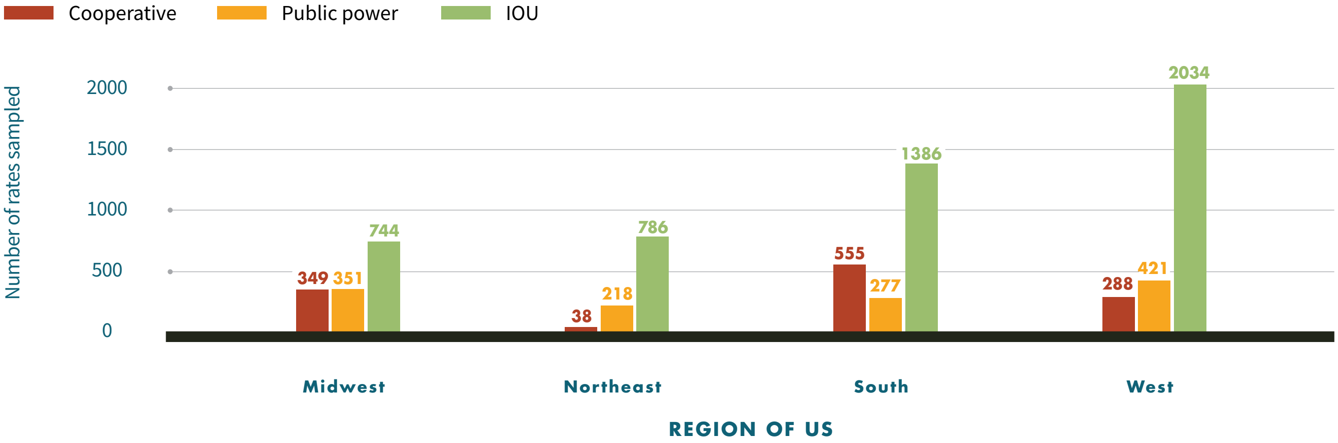
Sourc: E Source; data from OpenEI

FIGURE C-2: SHARE OF RATE TARIFFS SAMPLED BY MAJOR U.S. REGION



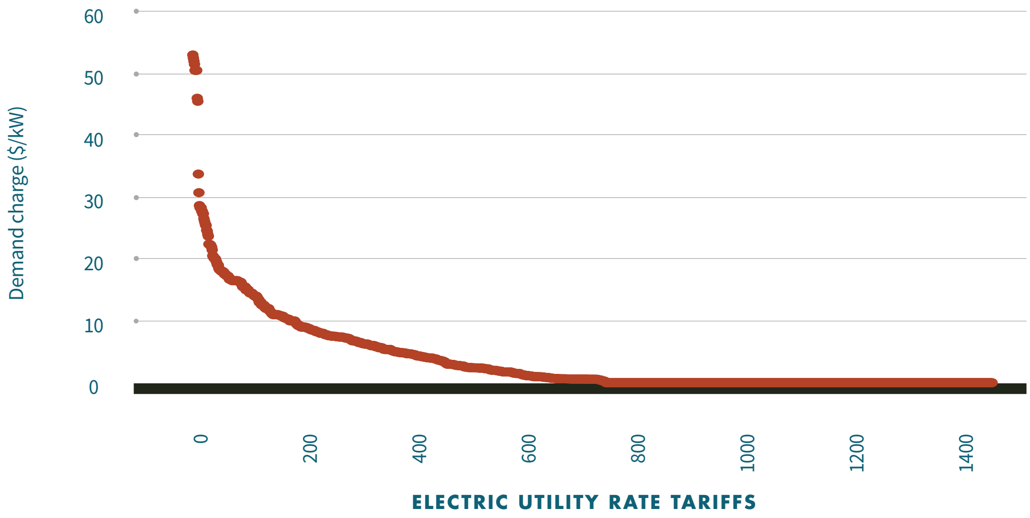
Sourc: E Source; data from OpenEI

FIGURE C-3: TOTAL NUMBER OF RATE TARIFFS SAMPLED, BY UTILITY TYPE AND REGION



E Source; data from OpenEI

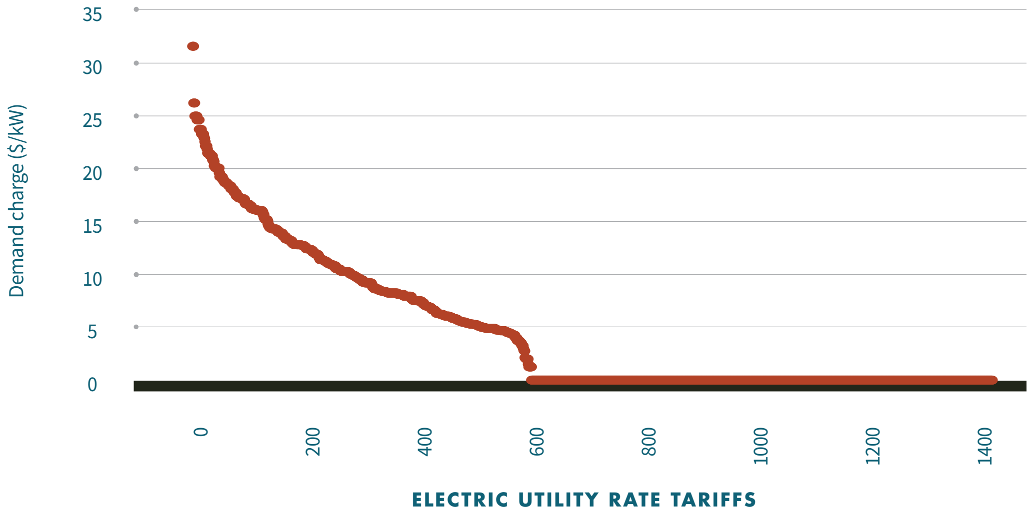
FIGURE C-4: DEMAND CHARGE DISTRIBUTION AND STATISTICS, MIDWESTERN U.S.



STATISTICS	$/KW
Mean	7.21
Median	4.90
Mode	0.59
Std-dev	7.96
Variance	63.34
Max	53.00

Source: E Source; data from OpenEI

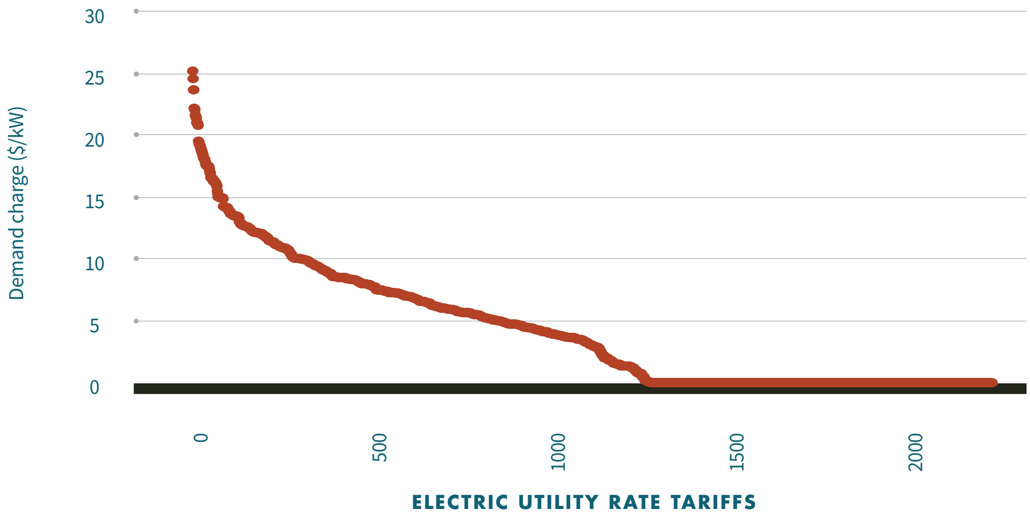
FIGURE C-5: DEMAND CHARGE DISTRIBUTION AND STATISTICS, NORTHEASTERN U.S.



STATISTICS	$/KW
Mean	10.67
Median	9.49
Mode	8.23
Std-dev	5.56
Variance	30.88
Max	31.55

Source: E Source; data from OpenEI

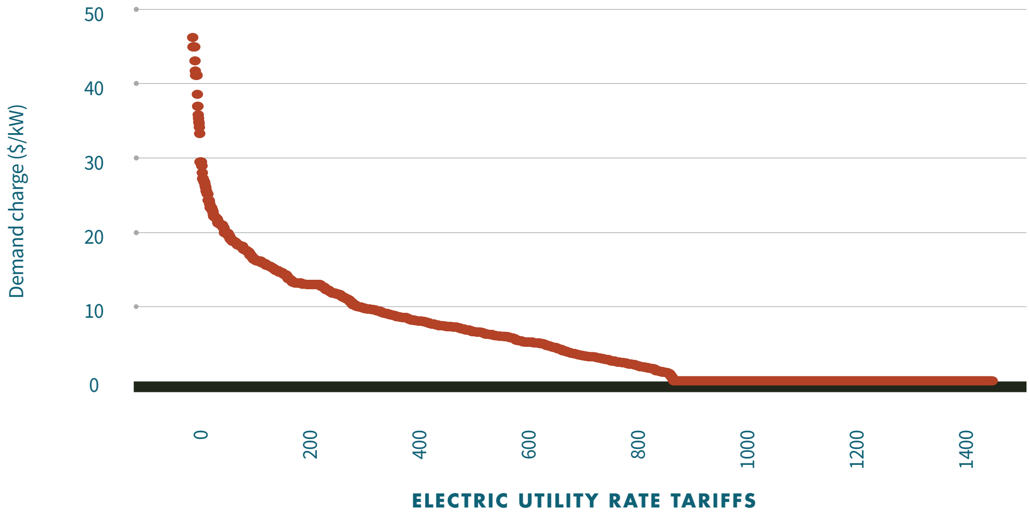
FIGURE C-6: DEMAND CHARGE DISTRIBUTION AND STATISTICS, SOUTHERN U.S.



STATISTICS	$/KW
Mean	7.37
Median	6.58
Mode	8.50
Std-dev	4.39
Variance	19.23
Max	25.20

Source: E Source; data from OpenEI

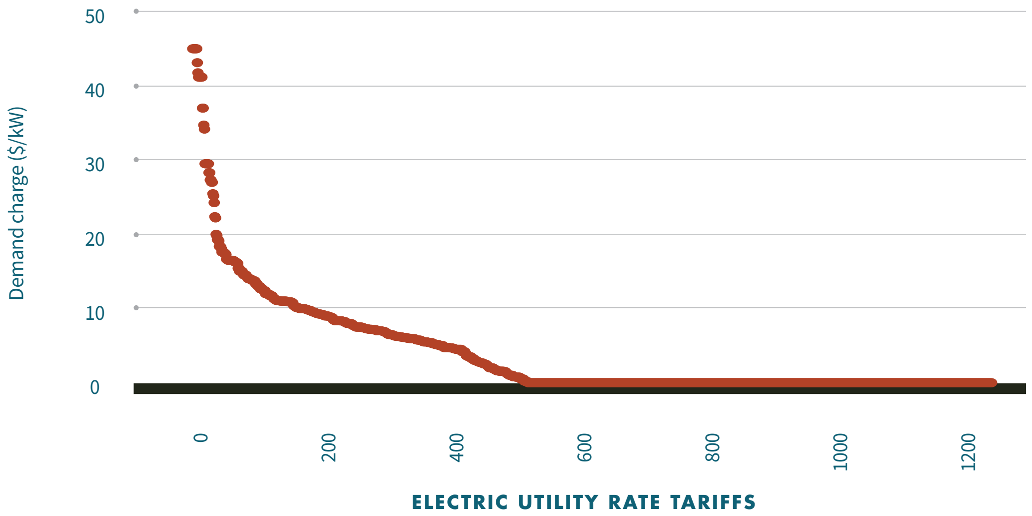
FIGURE C-7: DEMAND CHARGE DISTRIBUTION AND STATISTICS, WESTERN U.S.



STATISTICS	$/KW
9.40	10.67
7.65	9.49
13.00	8.23
7.02	5.56
49.24	30.88
46.27	31.55

Source: E Source; data from OpenEI

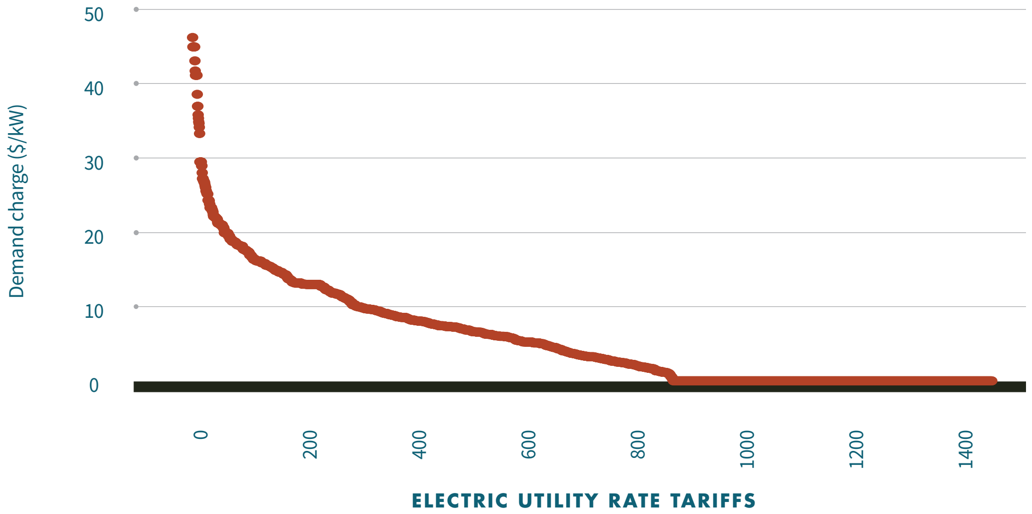
FIGURE C-8: DEMAND CHARGE DISTRIBUTION AND STATISTICS, COOPERATIVE UTILITIES



STATISTICS	$/KW
Mean	9.60
Median	7.50
Mode	11.00
Std-dev	8.40
Variance	70.45
Max	45.00

Source: E Source; data from OpenEI

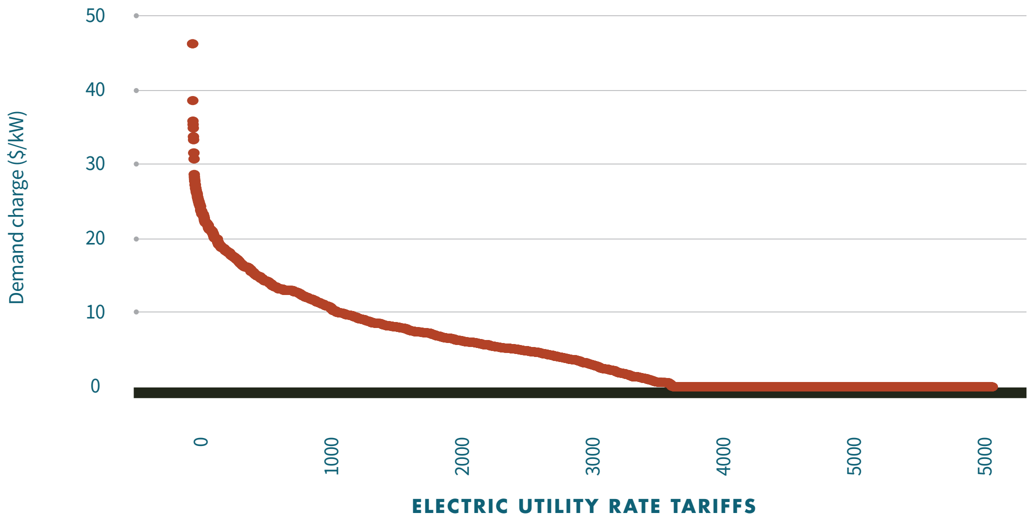
FIGURE C-9: DEMAND CHARGE DISTRIBUTION AND STATISTICS, PUBLIC POWER UTILITIES



STATISTICS	$/KW
Mean	8.99
Median	7.56
Mode	8.50
Std-dev	7.23
Variance	52.20
Max	53.00

Source: E Source; data from OpenEI

FIGURE C-10: DEMAND CHARGE DISTRIBUTION AND STATISTICS, INVESTOR-OWNED UTILITIES



STATISTICS	$/KW
Mean	8.34
Median	7.08
Mode	13.00
Std-dev	5.88
Variance	34.56
Max	46.27

Source: E Source; data from OpenEI

TABLE C-1: EXPERIMENTAL, PILOT, AND RECOMMENDED ELECTRIC UTILITY RATES FOR DCFC STATIONS

UTILITY NAME	TARIFF NAME	TARIFF NICKNAME	DEMAND CHARGE ($/KW)	ENERGY CHARGE ($/KWH)	FIXED CHARGE ($)	NOTES
Alaska Electric Light & Power	Schedule 26-L	Experimental High Power EV Charging Service	$0	$0.25 (peak season); $0.18 (off-peak season)	$96.13	Assumes > 50 kW demand; energy charge calculated based on 10% load factor (LF) assumption
Austin Energy	Fleet and Public EV Charging	Zero Energy Charge Tariff	$16.40	$0	$500	Assumes > 100 kW demand; pilot enrollment limited to 10 customers; PF-adjusted charge. Assumed fleet customer use case
Duke Energy	Rate DS	Capped Demand Charge	$7.75	$0.241 (capped)	$7.50	Assumes < 500 kW demand; if monthly bill exceeds volumetric costs equal to $0.241/kWh, the bill is calculated at the lower rate
Massachusetts **(National Grid, NSTAR, Eversource, and Unitil)**	DCA		$0/kW (for low-LF bracket)	Varies	Varies	Eliminates demand charge for lowest LF bracket (0 - 5%)
Nebraska Public Power District	General Service Demand Rate	GSDM	$0	$0.1245 (summer); $0.10 (winter)	$145	Assumes > 100 kW demand; discounts for higher usage or customers owning service equipment; for customers with relatively low load factor (e.g., < 250 kWh/kW)
New York **(Upstate and Downstate utilities)**	Targeted Adders		Up to $7.50/kW (charger nameplate)			Monthly bill adder incentives for low-LF stations; from $7.50/kW (1% LF) to $0.30/kW (12% LF).
Pacific Power	Schedule 28	General Service, Large Non-Residential	$6.35	$0.18	$114	Originally designed for services up to 200 kW, with added provisions for 200 - 300 and > 300 kW (and for DCFC when combined w/ Schedule 45)

Table C-1 Continued on next page.

Source: E Source; data from various utilty websites and tariff filings

TABLE C-1: EXPERIMENTAL, PILOT, AND RECOMMENDED ELECTRIC UTILITY RATES FOR DCFC STATIONS

Continued from previous page.

UTILITY NAME	TARIFF NAME	TARIFF NICKNAME	DEMAND CHARGE ($/KW)	ENERGY CHARGE ($/ KWH)	FIXED CHARGE ($)	NOTES
Pacific Power	Schedule 45	Public DC Fast Charger	(See schedule 28)	$0.10738 (on-peak)	(See schedule 28)	Transition rate through 2026; starts with demand-charge discount, shifts to all demand charge and no energy charge
Pacific Gas & Electric	Electric Schedule BEV-1	Business Electric Vehicles	$1.24 (in blocks of 10 kW)	$0.38 (on-peak); $0.19 (off-peak); $0.16 (super-off peak)	Calculated	Assumes < 100 kW demand; does not vary seasonally, charges $2.48/ kW overage fees
Pacific Gas & Electric	Electric Schedule BEV-2	Business Electric Vehicles	$1.91 (in blocks of 50 kW)	$0.40 (on-peak); $0.18 (off-peak); $0.16 (super-off peak)	Calculated	Assumes > 100 kW demand; does not vary seasonally, charges $3.82/ kW overage fees
Portland General Electric	Schedule 38	Large Non-Res Cost of Service	$0	$0.133 (on-peak); $0.123 (off-peak)	$25	Fixed charges may be higher (e.g., for three-phase service); rate was not designed for DCFCs
Portland General Electric	Schedule 50	Retail EV Charging	NA	$0.19/kWh (on-peak)	Flat fee: $5/session or $25/ month	Assumes > 50 kW demand; customer can pay per session or for membership subscription; on-peak charging costs $0.19/kWh extra
Portland General Electric	Schedule 83	Large Non-Res Standard Service	$5.80	$0.069 (on-peak); $0.054 (off-peak)	$30	Fixed charges may be higher (e.g., for three-phase service); rate was not designed for DCFCs
Public Service Electric & Gas Long Island	Rate 281	Self-Regulating Rate Incentive for DCFCs	?	$0.321 (capped)	?	Assumes < 145 kW demand; so-called "set point" experiment, similar to Duke Energy's rate; established based on wholesale gas prices, phases out at high LF
Xcel Energy - CO	Rate S-EV	Nonresidential Critical Peak Pricing for EV Charging	$0	$0.06935 (on-peak summer) $0.01387 (off-peak summer) $0.03467 (on-peak winter) $0.00693 (off-peak winter)	$41.13	During critical peak pricing (CPP) events (4-hour duration), customers will be notified and billed at $1.44/kWh during that CPP period

Source: E Source; data from various utilty websites and tariff filings

TABLE C-2: ADDITIONAL RATE TARIFFS IDENTIFIED BY ELECTRIFY AMERICA, GROUPED INTO "RATE DESIGN" CATEGORIES, AND DEEMED SUFFICIENT FOR DELIVERING DEMAND-CHARGE MITIGATION BENEFITS

RATE DESIGN	DESCRIPTION
Fully Volumetric Rate	The revenue requirement for a rate class is recovered through volumetric charges. (e.g., Souther California Edison's TOU-8 tariff, DTE Energy's GS-3 tariff, Rocky Mountain Power - Utah's Schedule 6A tariff, and the Tennessee Valley Authority's Electric Vehicle Charging (EVC) rates)
Low Load Factor Rate Variants	A variation on a rate schedule for low load factor customers (typically < 20%) where demand charges are reduced and usage charges are increased realtive to the parent rate. (e.g., National Grid - Massachusetts' Rate G-3 Electric Vehicle ration option, Eversource - CT's EVSE rates, and Avangrid - CT's rate GST-EV)
Demand Limiters	A rate feature where demand charges are limited for low load factor accounts based on a minimum monthly hours of use. (e.g., Xcel Energy - Minnesota's General Service A-14 tariff, Evergy - Kansas Business EV Charging Service, and Arizona Public Service's Rate Rider for DCFC)
Unit Cost Limiters	A calculation method where charges are based on the published tariff, but not to exceed a pre-defined unit cost threshold. (e.g., Dayton Power & Light Tariff D19)
Reduced Demand Charges	Demand charges are reduced to only recover local customer specific facilities-related costs (e.g., transformers), while shared distribution and generation and transmission charges are recovered volumetrically. (e.g., Xcel Energy - Colorado's Rate S-EV)
Hours of Use Tiered Charges	A rate structure where usage is grouped into tiers based on the load factor. Low load factor accounts would have usage priced in higher cost tiers with a low or no demand charge. (e.g., Georgia Power Rate PLM w/ Rider CIEV)

Source: Aaron Young, Electrify America; final comments on EVC peer-review process for the present study

APPENDIX D

Observations on international developments

In some countries outside of the US, the adoption of EVs and deployment of DCFCs have seemingly faced fewer roadblocks relative to our domestic experience. This is largely due to differences in economics and government policies that promote EV competitiveness and/or discourage the use and operation of fossil-fuel powered vehicles. Most of the lessons learned and strategies applied by other countries are not applicable or transferable to the US due to our unique market and political conditions. However, it is certainly possible that we can learn from other countries in this area. Chiefly, we can see that large, centralized DCFC stations are being deployed and operated effectively in other countries, taking advantage of economies of scale in the building and powering of stations to reduce per-unit costs. Below are some of the countries that have experienced relative success in one or more areas of transportation electrification and some of the details about the policies and conditions that enabled their successes.

NORWAY

With the highest per-capita EV ownership, highest share of new-car sales (i.e., 86% in 2021), and largest cumulative share of EVs in its nation's vehicle fleet (20%), Norway is now looked to as a world leader in EV adoption. This is not by accident; Norway established very aggressive federal goals and numerous financial incentives that strongly favored EVs. While we had just one federal tax credit for EVs in the US, Norway created a whole slew of tax exemptions, removing emissions taxes, carbon taxes, weight taxes, road tolls, and even vehicle scrapping fees. This all made it much more expensive to own and operate a gas-power vehicle relative to an EV.

Electricity also has an inherent economic advantage over gasoline or diesel as a transportation fuel. The average gasoline price in Norway is more than $8 per gallon. That's more than double the average US price. Not unlike other European countries, higher sustained gas prices lead to the adoption of smaller and lighter cars and strongly favor EVs and electrification. Norway also has excess renewable power generation from hydro power which makes up most of the country's electricity mix. This makes electricity there relatively cheap ($0.13/kWh on average) and almost carbon-free. In the US, there are those who still argue against EVs because they aren't "paying their fair share" since they don't purchase gasoline and so don't pay road taxes (even though in some states, road taxes are being levied on EVs too). But in Norway, they are essentially taxing gas-powered vehicles out of existence.

CHINA

Like Norway, much of China's success in electrifying its transportation system can be attributed to aggressive federal goals and top-down policies that strongly favor EVs. Even though China does not have the clean electric grid that Norway has – with much of its electricity still derived from domestic coal power – China's major cities have experienced horrific air quality problems over the last several decades. Similar to Southern California's experience with vehicle emissions and poor air quality (only more extreme), the desire to clean up urban airsheds has been a huge drive for EVs in China and has made it relatively easy for them to gain popular support.

As a Communist state, China's federal government generally has more autonomy when it comes to passing and implementing sweeping changes to federal policies that impact the country's economy. While some may argue that the US government has similarly far-reaching (or over-reaching) influence, there tends to be more pushback in the US through checks-and-balances. China took several proactive steps to promote EVs and fast charging beginning at least as early as 2014, with a federal goal to install nearly 5 million charging ports by 2020. Here are some of the ways China worked to achieve its goal:

- **Rate tariff reform.** Beginning in 2014, China established federal policies for pricing electricity for EV charging, which permitted DCFC station hosts to sign up for industrial rates with lower volumetric charges than commercial rates. They also exempted DCFCs from paying demand charges through 2025.
- **Scaled manufacturing.** China drove down the cost of both EVs and DCFC equipment by promoting and supporting domestic manufacturing of batteries, vehicles, and chargers.
- **Subsidized DCFC installations.** Economic incentives were also offered to help lower the upfront cost of purchasing and installing DCFCs.
- **Prioritized electrification.** High-use vehicles in urban centers like buses, taxis, and delivery vans were prioritized for electrification and provided charging to quickly grow demand for EVs and DCFCs. Also electric scooters and e-bikes were promoted and accommodated and became incredibly popular faster than anywhere in the world.

- **EVSP service fee caps.** Chinese cities set caps on the fees that service providers could charge, ensuring that EV charging remained cost-competitive with fossil fuels.
- **Utility ownership of DCFCs.** There are only two electric utilities in China and they own and operate a large number of the country's DCFCs, using "social responsibility" budgets to fund grid capacity upgrades where needed. State Grid Corporation (SCG) is one of them; it is owned by the government and is the single largest electric utility in the world. It's obviously a bit easier to adjust utility policy when the utility and the government are essentially the same entity.
- **Emphasize concentrated charging stations.** China's approach to deploying EV charging has been a bit different than what we've seen in the US. Rather than large EV hubs like the one in Barstow being an exception, this is the rule in Chinese cities. China keeps per-unit costs low by densely aggregating EV charging equipment and ports.

GERMANY

For many years, Germany has pushed hard to promote the adoption of solar power, battery storage, and other cleantech and low-carbon energy solutions. And much like China, Germany has also supported local EV manufacturing as part of its already strong automotive industry. Although German automakers were not the first to embrace EVs, the majors now all produce their own electric models, and this helped to bolster new EV sales in Germany in recent years. Germany has even done what the US has so far refused to do, in inviting Chinese manufacturer BYD into its country (note that while there are many global electric bus manufacturers, BYD is the largest and most established).

However, unlike Norway and China, it is not necessarily clear that Germany is "all in" in EVs. In addition to a slow start from its manufacturing base, recent policy changes there have retired some of the country's financial incentives and subsidies. As we saw in Georgia roughly a decade ago with the abrupt removal of state incentives, EV sales in Germany are now beginning to fall for the first time in years. Whether or not Germany will return to its place of relative dominance as a global leader in EV sales remains to be seen. And like the US, Germany still has a ways to go to support EV charging with DCFC network deployment and coverage, with a number of significant gaps still remaining (e.g., see Regional Charging Infrastructure Requirements in Germany Through 2030).

JAPAN

Electricity rates in Japan are relatively high; its average wholesale rates are equivalent to Norway's average retail rate (i.e., $0.13/kWh). Rate reform in Japan has largely consisted of bringing its rate-making policies more-or-less in line with those of US and other Western electric utilities, ensuring that the cost to serve the rate base is accurately reflected in energy pricing. But as a small island nation with limited space and resources, Japan's cost of delivering electricity can fluctuate quite a bit, and this can lead to high and unpredictable electricity pricing for customers. Also, much like Germany, the automakers in Japan are some of the biggest and best in the world, but they have been exceedingly slow to adopt all-electric vehicle technologies. For example, while Toyota led the world in commercializing hybrid technology with the Prius, the company has lagged most major global automakers in the production of all-electric cars.

Part of why Toyota, Honda, and other automakers have resisted embracing all-electric battery vehicles is that they continue to hold out hope for hydrogen and fuel cell vehicles. These companies are leaders in fuel cell technology development and it seems that scaled hydrogen-powered cars will take hold in Japanese markets sooner than in most other countries. Collectively, Japan refers to environmentally friendlier vehicles as Clean Energy Vehicles (CEVs), which includes battery-electric vehicles, plug-in hybrid vehicles, and fuel-cell vehicles. The availability of alternative fuels such as hydrogen may be a viable long-term strategy for reducing demand on the utility grid associated with DCFC operation.

UNITED KINGDOM

Much like cities in China, the drive to electrify and promote EVs in the UK was largely borne out of frustrations experienced in that nation's mega-city (i.e., London). Home to roughly 13% of the UK's entire population, the narrow, crowded streets of London are notoriously difficult to navigate and in spite of robust public transit systems, the city experiences some of the worst roadway congestion in the world. To help address congestion, low air quality, parking scarcity, and noise pollution issues in the city, London placed access fees on non-electric vehicles traveling to or through the city center and at certain times. The city also installed ubiquitous curbside charging infrastructure and offers free parking options to drivers with EVs.

The UK is also prioritizing DCFC deployment and establishing goals akin to those established in the US. Australia-based Tritium – a DCFC manufacturer – recently announced that it has plans to deploy 10,000 DCFCs across by 2030, at least in part through partnerships with British Petroleum (BP Pulse). The UK has also been a leader in demonstrating and commercializing vehicle-to-grid (V2G) technologies. There is not very much automotive manufacturing or EV-adjacent industrial activities in the UK in general, but thankfully they are within close proximity to other countries in Europe where more of these activities are taking place.

About the Electric Vehicle Council

The Electric Vehicle Council is a non-advocacy organization whose mission is to coordinate the efforts of organizations actively engaged in supporting the deployment of EV charging infrastructure. The EV Council works to distribute existing research and education materials to amplify and enhance its value to the market, as well as conducts original research to fill gaps in knowledge and further educate interested stakeholders concerning the opportunities, challenges, and successful strategies associated with the installation and operation of EV charging stations.

For more information on the Electric Vehicle Council and a current list of members,
please visit: transportationenergy.org/councils/electric-vehicle-council

About the Transportation Energy Institute

The Transportation Energy Institute, founded by NACS in 2013, is a 501(c)(4) nonprofit research-oriented think tank dedicated to evaluating the market issues related to vehicles and the fuels that power them. By bringing together diverse stakeholders of the transportation and fuels markets, the Institute helps to identify opportunities and challenges associated with new technologies and to facilitate industry coordination to help ensure that consumers derive the greatest benefit.

The Transportation Energy Institute commissions and publishes comprehensive, fact-based research projects that address the interests of the affected stakeholders. Such publications will help to inform both business owners considering long-term investment decisions and policymakers considering legislation and regulations affecting the market. Research is independent and unbiased, designed to answer questions, not advocate a specific outcome. Participants in the Transportation Energy Institute are dedicated to promoting facts and providing decision makers with the most credible information possible so that the market can deliver the best in vehicle and fueling options to the consumer.

For more about the Transportation Energy Institute visit transportationenergy.org

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