KEVIN GEORGE MILLER

(917) 836-4954 | 112 Smith Street #5, Brooklyn, NY 11201 | kevin.g.miller@gmail.com

PROFESSIONAL EXPERIENCE

ChargePoint, Campbell, CA — 2016 – Present
Director, Public Policy

- Plan, direct and implement state policy advocacy focused on company priorities.

Executive Office of Energy and Environmental Affairs (EEA), Boston, MA — 2014 – 2015
Acting Chief Financial Officer

- Lead for fiscally related issues to Governor's Office and House/Senate Ways and Means committees.
- Senior advisor to Cabinet Secretary on policies of seven agencies, 2,600 FTEs, and $500M+ annual spending.

Executive Office of Energy and Environmental Affairs, Boston, MA — 2012 – 2015
Director of Capital and Federal Finance

- Developed and managed $250M+ in annual capital investment programs to support the Commonwealth's energy and environmental priorities.
- Oversaw the Commonwealth's federally-funded initiatives related to energy and the environment.

Executive Office for Administration and Finance, Boston, MA — 2011 – 2012
Fiscal Policy Analyst

- Analyst in charge of $2.6B portfolio for Governor's budget office including statewide collective bargaining, Environmental Affairs, Public Safety, Sheriffs, and Health and Human Services agencies.
- Appointed Secretary's designee on the Regional Greenhouse Gas Initiative Auction Trust Committee.

Office of State Senator Marian Walsh, Boston, MA — 2006 – 2008
Press Secretary and Campaign Strategist

- Responsible for campaign messaging, public strategy, and stakeholder engagement.

UTILITY REGULATION & GOVERNMENT APPOINTMENTS

Utility Regulation – Testimony & Expert Witness

- Connecticut PURA: Docket No. 16-07-21 – EV TOU Rates for Residential and Commercial Customers
- Massachusetts DPU: Docket No. 18-150 – National Grid Phase II Electric Vehicle Charging Program
- New York PSC: Case Nos. 19-065 and 19-E-0378 – ConEdison and NYSEG/RGE EV Charging Programs
- Rhode Island PUC: Docket Nos. 4770/4780 – National Grid EV Charging Program

Statewide Commissions and Working Groups

- Member Representative, New Hampshire Electric Vehicle Charging Infrastructure Commission
- Infrastructure Co-Chair, Massachusetts Zero Emission Vehicle Task Force
- Infrastructure Co-Chair, Drive Electric Pennsylvania
- Infrastructure Expert Member, National Zero Emissions Vehicle Strategy Working Group (Canada, Federal)

EDUCATION

Harvard Kennedy School of Government, Cambridge, MA — 2011
Master of Public Policy - International Trade and Finance

Tufts University, Medford, MA — 2005
Bachelor of Arts (Political Science and Drama), *cum laude*

United Nations International School, NY, NY — 2001
International Baccalaureate Diploma

WHITE PAPER

Exhibit CP-KGM-2

Analytical White Paper: Overcoming Barriers to Expanding Fast Charging Infrastructure in the Midcontinent Region

Analysis conducted by the Great Plains Institute for the Midcontinent Transportation Electrification Collaborative

JULY 2019

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About the Great Plains Institute (GPI)

GPI is a nonpartisan, nonprofit organization transforming the energy system to benefit the economy and environment. GPI works on solutions that strengthen communities and provide greater economic opportunity through creation of higher-paying jobs, expansion of the nation's industrial base, and greater domestic energy independence while eliminating carbon emissions.

About the Midcontinent Transportation Electrification Collaborative (MTEC)

MTEC is composed of representatives from automakers, state government, electric utilities and cooperatives, charging companies, and environmental organizations. MTEC coordinates regionally in the Midcontinent region to increase electric vehicle (EV) use, decarbonize the transportation sector, improve air quality, improve electric system efficiency, provide a great customer experience, and build infrastructure to support EV travel throughout the Midcontinent region. The group aims to inform decision-makers' thinking around policies and initiatives to speed the electrification of transportation in the region. The group carries out collective research, develops white papers and policy recommendations, and hosts public workshops for policymakers and stakeholders in the Midcontinent region. MTEC is co-convened by the Midcontinent Power Sector Collaborative and the Charge Up Midwest coalition. GPI convenes the Midcontinent Power Sector Collaborative and MTEC and is a member of the Charge Up Midwest coalition.

MTEC published a white paper entitled, "Electric Utility Roles in the Electric Vehicle (EV) Market: Consensus Principles for Utility EV Program Design," in April 2018 and "A Road Map to Decarbonization in the Midcontinent: Transportation Electrification," in January 2019.

Authors

This report is by Dane McFarlane, Matt Prorok, Brendan Jordan, and Tam Kemabonta.

Acknowledgments

Thank you to the Midcontinent Power Sector Collaborative participants for their feedback on this report and analysis.

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Contents

Executive Summary

Increased adoption of electric vehicles (EVs) has the potential to significantly and positively impact the electric utility sector and its customers. EVs offer utilities load growth opportunities without necessarily increasing coincidental load peaks. They can also help minimize new investments in generation and distribution infrastructure and actively match load with expanding renewable generation. Studies have shown that for EV owners with access to home charging configurations, most EV charging will occur at home which presents opportunities for load management over longer charging periods.[1] Outside of the home, public charging remains a crucial enabling factor for significant adoption of EVs. In particular, strategically located direct current fast charging (DCFC) will enable longer trips, higher mileage-per-day usage, and charging by people without access to home or workplace charging.

Numerous studies demonstrate the importance of public DCFC in enabling higher rates of EV adoption.[2 3 4 5 6] However, a study by the National Renewable Energy Laboratory (NREL) found that the Midcontinent region, and the US in general, has far less public charging infrastructure than what is required to achieve greater levels of EV adoption.[7] The region currently has 425 DCFC plugs at charging stations and NREL's analysis indicates that 4,020 plugs will by needed by 2030. This suggests a gap of 3,595 dedicated DCFC plugs at public charging stations. At \$60,000-\$100,000 per plug, this would require an investment between \$215-\$360 million over the next 11 years. In addition to capital and construction costs, the NREL analysis found that operating costs, including the costs of electric demand, present a huge barrier to the economic feasibility of DCFC stations.

This white paper is intended to study a specific barrier to providing adequate DCFC services in the Midcontinent region and nationwide: electric utility demand charges. For most utilities, the demand charge is based on the demand (kW) measured for a billing month that is required to supply the maximum 15 minute-average amount of energy used by the customer in a billing month.

In terms of high wattage (50 kilowatts and above) electrical equipment, DCFC is a unique use-case characterized today by relatively high-power capacity and low-energy utilization. This means that the operating cost incurred through capacity or demand charges often can far exceed the cost for energy usage. As the analysis in this white paper demonstrates, this situation can lead to operating costs that far exceed the revenue these chargers can receive from customer payments. Importantly, it is clear from the results of GPI's analysis that demand charges are a primary factor in DCFC station economics, representing the majority of costs in most scenarios studied here.

GPI investigated the economics of operating a DCFC station along a specific highway corridor along Interstate 94 from Minnesota to Michigan, passing through the service territories of many electric utilities. The analysis presented here demonstrates that there is a high degree of variability from one utility service territory to the next. In some service territories, it is possible to economically operate a DCFC station today with the current rate tariffs, even with low utilization. In some territories, because of tariff structures designed for conventional commercial and industrial equipment, it may never make economic sense, even with very high utilization. As the market demands higher capacity DCFC, moving from 50 kilowatt (kW) to 150 kW and higher to enable faster charging, the economic challenges presented by utility demand charges are further exacerbated.

Addressing this issue is complicated. Demand charges exist for a reason and are based on a "cost-of-service" philosophy, which asserts that electricity system users should pay for any costs they impose on the system. Every utility has a different system and customer base and will approach this challenge in different ways. At the same time, analysis suggests both that DCFC is a critical element in enabling EV adoption and that managed Level 2 charging at home and the workplace offers significant benefits to the electric system. There is clearly a balance to be struck between possible costs imposed by DCFC in certain settings, and considerable benefits from the increased EV adoption it can enable.

This white paper highlights the main considerations in designing a demand charge tariff structure that is suitable for encouraging DCFC investment, highlights approaches taken by some utilities, and presents information for utilities and regulators to consider as they are seeking their own solutions to this problem.

1 "Plugged In: How Americans Charge Their Electric Vehicles," Idaho National Laboratory, 2015, https://avt.inl.gov/sites/default/files/pdf/arra/ARRAPEVnInfrastructureFinalReportLqltySept2015.pdf. (accessed November 2018).

2 Li, Shanjun; Tong, Lang; Xing, Jianwie; Zhou, Yiyi, "The Market for Electric Vehicles: Indirect Network Effects and Policy Design," *Journal of the Association of Environmental and Resource Economists* 4, no. 1 (March 2017).

3 Vergis, Sydney; Chen, Belinda, "Understanding Variations in U.S. Plug-In Electric Vehicle Markets," Institute of Transportation Studies, University of California – Davis, Research Report UCD-ITS-RR-14-25, November 2014.

4 Tietge, Uwe; Mock, Peter; Lutsey, Nic; Campestrini, Alex, "Comparison of Leading Electric Vehicle Policy and Deployment in Europe," International Council on Clean Transportation, May 2016.

5 Bakker, Sjoerd; Trip, Jan Jacob, "Policy options to support the adoption of electric vehicles in the urban environment," *Transportation Research Part D* 25 (December 2013):18-23.

6 Searle, Stephanie; Pavlenko, Nikita; Lutsey, Nic, "Leading Edge of Electric Vehicle Market Development in the United States: An Analysis of California Cities," International Council on Clean Transportation, September 2015.

7 Wood, Eric; Rames, Clement; Muratori, Matteo; Raghavan, Sesha; Melaina, Marc. "National Plug-In Electric Vehicle Infrastructure Analysis," National Renewable Energy Laboratory, September 2017.

Summary of Analytical Methodology

Many analyses demonstrate the potential benefits for utilities and utility customers from home and workplace EV charging. According to a previous MTEC white paper:

> "Electric vehicles offer the potential for benefits to the electric system, for electricity consumers, and for utilities themselves. Increased revenue from growth in transportation electrification can supply necessary investments to enable the transition to a modern system, while turning the conventional wisdom about stagnant load growth on its head. Electric vehicles can add a significant additional load without an equivalent increase in peak demand, thus improving the utilization of existing infrastructure and avoiding the need for significant new investment…EV charging at night can increase load while only minimally increasing the daily peak of the system, thereby avoiding the need for new infrastructure investment."[8]

Even though most charging load is likely to be home or workplace Level 2 charging that is suitable for managed charging, DCFC will be a critical enabler of increased EV adoption and must be supported even if managed charging is not possible or desirable in every setting.

This paper analyzes the readily available information on costs for the installation of a DCFC station, explains the typical business model of a DCFC investor/owner, and suggests rationale and opportunities for utilities to modify their rate structure to ensure DCFCs are viable business ventures. GPI staff conducted analysis for MTEC to evaluate the economics of operating DCFC today in the Midcontinent region. The analysis focused on potential DCFC infrastructure operated along the I-94 corridor from Minnesota to Michigan. Researchers gathered assumptions about the following:

- capital and operating costs for DCFC
- typical utilization rates and revenues
- actual utility rates that would be paid by DCFC operators in utility service territories across the region

Information was collected on 57 rate schedules for commercial and small industrial customers across 30 utilities. A total of 165 charging scenarios were created through a combination of three variables:

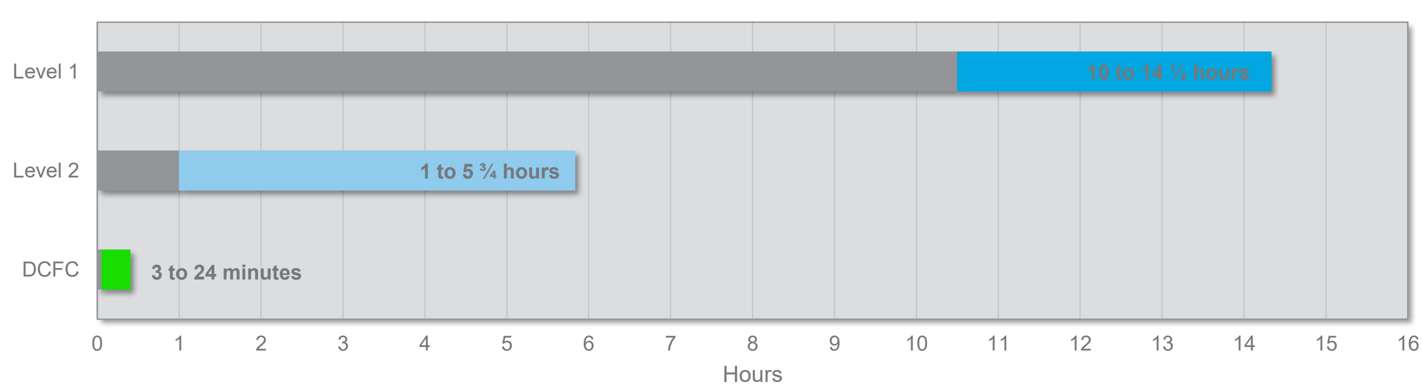
- demand level (wattage)
- utilization (charges per day)
- energy use (kWh) per charging session

Demand levels reflect typical combinations of one to three DCFC plugs: 50kW, 100kW, 150kW, 350kW, and 450 kW. Utilization was varied from 0.5 to 10 charges per day. Using utility rate information and assumptions about capital and operating costs, revenues from users, and utilization rates, an annual cash flow analysis was performed. Sensitivity analyses were run on key variables.

Results for annual cash flow in over five thousand economic scenarios and configurations (165 charging scenarios across each utility rate schedule) were calculated according to costs from volumetric, demand, customer, and facilities charges for each of the utility rates for which data was collected. The results demonstrate generally difficult economics for DCFC station operation at currently expected utilization rates and with current demand charge tariffs.

8 Great Plains Institute and Midcontinent Transportation Electrification Collaborative, "Electric Utility Roles in the Electric Vehicle (EV) Market: Consensus Principles for Utility EV Program Design," April 2018, https://www.betterenergy.org/wp-content/uploads/2018/04/MTEC_White_Paper_April_2018-1-1.pdf. (accessed November 2018)

Figure 1. Charging time required for 80 miles of range



Primary Findings

This analysis found that demand charges are one of the most significant cost factors in DCFC operation. Most utilities in the region base their demand charge on the demand (kW) measured for a billing month that is required to supply the maximum 15 minute-average amount of energy used by the customer in a billing month. As seen in figure 6 later in this paper, DCFC economics are challenging at higher power levels such as 350 kW and 450 kW, where nearly all stations that break even or generate profit are those operating in utility territories where there is no demand charge. Demand charges represented the majority of costs in most scenarios studied by this analysis. As a result, the demand charges present in utility rate schedules are a key determining component of a DCFC station's ability to break even or generate profit.

With lower-capacity DCFC (50kW), profitability is linked with utilization rate and is highly variable based on demand charge tariffs. DCFC stations of 50 kW would not operate profitably in any of the utility service territories at 1 charge per day but would be profitable in all of them at 10 charges per day. Because we expect charger utilization to be low in early years, and higher in the future, you can argue that for 50kW DCFC, higher utilization eventually solves the market failure for DCFC. This may or may not be sufficient to result in third-party investment in 50 kW DCFC. The fact that 50 kW DCFC is not profitable in every utility service territory and at all levels of utilization will make it difficult to build a truly comprehensive DCFC network and make a more fragmented network more likely.

Demand charges are more of a barrier for higher-capacity DCFC, which many industry experts expect will be needed in the future to allow for faster charging rates. For 150 kW, 350 kW, and 450 kW DCFC, a minority of utility demand charge tariffs allowed for profitable operation, even at utilization levels as high as 10 charges per day.

Our analysis makes clear that demand charges are a barrier to the widespread availability of DCFC. It also makes clear that this is not simply a chicken and egg problem that will be solved when there are more EVs and higher levels of utilization at the chargers; demand charges are higher still for higher-capacity DCFC and challenge the economics of operating these chargers even at higher levels of utilization.

Figure 2: The Minnesota to Michigan corridor segment of the I-94 highway that was the focus of the data analysis discussed in the analysis section of this white paper

Literature Review

The literature presents a strong argument that the availability of adequate public charging is a pre-requisite for increased EV adoption and a lack of adequate charging can halt further advances. Although studies demonstrate that a high percentage of charging occurs at home during the night or during the day at work when workplace charging is available, there will still be a need for public charging for certain types of driving and the preferences and needs of certain drivers. This might include those without access to home or workplace charging, people who are able to charge in a garage but occasionally take a longer road trip and must charge along the way, and fleet operators who drive too many miles in a day to rely only on Level 2 charging.

A study by Idaho National Laboratory evaluated the charging habits of people driving 8,300 EVs over three years and found that typical EV drivers charged at home 84-87 percent of the time.[9] Drivers with access to charging at their workplace (a small percentage of the overall sample) charged at work between 32-39 percent of the time. Although most EV drivers charged mostly at home, only a small percentage of EV drivers (5-13 percent) charged solely at home. This implies that public charging is infrequently used but its availability is still desired by most EV drivers. In particular, it appears that DCFC is critical for enabling trips further from home or work, as the study found that DCFC stations were used much more frequently than typical public Level 2 stations. The most highly utilized DCFC stations tended to be located close to interstate highway exits, suggesting that they are being used to enable longer-distance travel. Anecdotal evidence from charging station operators suggests increased utilization of DCFC by ride-hailing (e.g. Lyft, Uber) drivers converting to EVs and needing DCFC to extend a working shift. DCFC can also be part of the solution for offering charging to multi-unit dwellers.

Many analyses demonstrate the potential benefits for utilities and utility customers from home and workplace EV charging and generally focus on Level 2 charging. According to a previous MTEC white paper:

> "Electric vehicles offer the potential for benefits to the electric system, for electricity consumers, and for utilities themselves. Increased revenue from growth in transportation electrification can supply necessary investments to enable the transition to a modern system, while turning the conventional wisdom about stagnant load growth on its head. Electric vehicles can add a significant additional load without an equivalent increase in peak demand, thus improving the utilization of existing infrastructure and avoiding the need for significant new investment… EV charging at night can increase load while only minimally increasing the daily peak of the system, thereby avoiding the need for new infrastructure investment." [10]

That paper also discusses the importance of "designing technological or behavioral programs to enable optimal EV charging." It further reviews multiple studies demonstrating benefits for utility customers from increased EV adoption, with enhanced benefits from managing EV charging load through technological or behavioral programs. The majority of EV charging load today occurs in home or workplace settings and is either Level 1 or 2. Home and workplace Level 2 lends itself well to managed charging through behavioral or technological programs due to the likelihood that cars will park in those settings for longer than their required charging time. Managed charging options, whether they are time-of-use rates or chargers with load control capabilities, are generally low cost to implement. Not all charging settings are conducive to managed charging. DCFC, in particular, lends itself less well to the managed charging paradigm, especially when prioritizing a positive customer experience. DCFC customers are more likely to require an immediate charge and less likely to tolerate delays or curtailments. Managed charging strategies may be possible with certain uses of DCFC such as night-time charging of transit buses and school buses. Some utilities, like Pacific Gas and Electric, are trying to strike a balance by creating DCFC rate structures that have some differentiation based on time-of-day. A variety of managed and unmanaged charging strategies will be necessary to serve all users of DCFC.

A range of studies attempts to establish a causal relationship between DCFC availability and EV adoption. Searle et al. conducted regression analysis on a range of variables and found that total EV sales share was positively correlated with EV model availability, public charging availability per capita, and median household income and found that the correlation was statistically significant.[11] Other studies (Bakker et al. 2013[12]; Tietge et al. 2016[13]; Lutsey et

9 Idaho National Laboratory, "Plugged In: How Americans Charge Their Electric Vehicles," 2015, https://avt.inl.gov/sites/default/files/pdf/arra/ARRAPEVnInfrastructureFinalReportLqltySept2015.pdf.

10 Great Plains Institute and Midcontinent Transportation Electrification Collaborative, "Electric Utility Roles in the Electric Vehicle (EV) Market: Consensus Principles for Utility EV Program Design," April 2018, https://www.betterenergy.org/wp-content/uploads/2018/04/MTEC_White_Paper_April_2018-1-1.pdf. (accessed November 2018)

11 Searle, Stephanie; Pavlenko, Nikita; Lutsey, Nic, "Leading Edge of Electric Vehicle Market Development in the United States: An Analysis of California Cities," International Council on Clean Transportation, September 2015.

12 Bakker, Sjoerd; Trip, Jan Jacob, "Policy options to support the adoption of electric vehicles in the urban environment," *Transportation Research Part D* 25: 18-23 (December 2013).

13 Tietge, Uwe; Mock, Peter; Lutsey, Nic; Campestrini, Alex, "Comparison of Leading Electric Vehicle Policy and Deployment in Europe," International Council on Clean Transportation, May 2016.

al. 2016[14]; Vergis and Chen, 2014[15]; Li et al., 2017[16]) have similarly found that although home charging is more heavily utilized, EV adoption and public charging infrastructure are still linked. Searle et al. postulate that infrequent convenience charging “is still important, as it can increase the functional range, and, even when seldom used, increase electric vehicle driver confidence to use the full existing range. Another interpretation is that the charging network increases general awareness, understanding, or comfort about the visibility of the electric vehicles among prospective new buyers.”

NREL offers the most comprehensive attempt to quantify the “charging gap” around the country.[17] NREL analyzed the level of charging needed to support higher levels of EV adoption—modeling linear growth from today’s level of EVs on the road to 15 million light-duty EVs by 2030, translating to 2 percent of light-duty vehicle sales. This includes a mixture of plug-in hybrid and full battery EVs with various ranges. The study assumed that 88 percent of charging occurred at home. Results indicated that 27,500 DCFC plugs (at 8,500 stations) will be needed, including 19,000 in cities, 4,000 in towns, 2,000 in rural areas, and 2,500 along interstate corridors. For Level 2 charging, 601,000 plugs will be needed, including 451,000 in cities, 99,000 in towns, and 51,000 in rural areas. According to NREL, there were 3,383 DCFC plugs nationwide and 36,339 Level 2 plugs as of the publishing date. This understates the infrastructure gap for the Midcontinent region because the vast majority of US public charging infrastructure is on the coasts. Tesla’s proprietary chargers are not included in these numbers because they can only be used by Tesla vehicles.

The NREL analysis goes into great detail on considerations for DCFC corridor planning, including mapping traffic volumes and trips to designated corridors, evaluating the distance to substations to ensure adequate electricity infrastructure to support DCFC, land availability for new DCFC, and other considerations. NREL’s state-by-state results are included in table 1. Comparing these numbers to current levels clearly show the gaps in the Midcontinent region. In the region, there are currently 425 public DCFC plugs and NREL’s analysis indicates that 4,020 will be needed by 2030. That is a gap of 3,595. A rough estimate of $60,000-$100,000 per plug suggests an overall investment need of $215-360 million over the next 11 years.

14 Lutsey, Nic; Slowik, Peter; Jin, Lingzhi, “Sustaining Electric Vehicle Market Growth in U.S. Cities,” International Council on Clean Transportation, October 2016.

15 Vergis, Sydney; Chen, Belinda, “Understanding Variations in U.S. Plug-In Electric Vehicle Markets,” Institute of Transportation Studies, University of California – Davis, Research Report UCD-ITS-RR-14-25, November 2014.

16 Li, Shanjun; Tong, Lang; Xing, Jianwie; Zhou, Yiyi, "The Market for Electric Vehicles: Indirect Network Effects and Policy Design." *Journal of the Association of Environmental and Resource Economists* 4, no. 1 (March 2017).

17 Wood, Eric; Rames, Clement; Muratori, Matteo; Raghavan, Sesha; Melaina, Marc, “National Plug-In Electric Vehicle Infrastructure Analysis,” National Renewable Energy Laboratory, September 2017.

Table 1. Plug-in Electric Vehicles (PEVs) and Charging Plugs by State: NREL 2030 Projections

State	Total PEVs today[18]	Total PEVs projected, 2030	% PEV projected, 2030	Workplace L2 plugs, 2030	Public L2 plugs, 2030	Public DCFC plugs, 2030	Public L2, today	Public DCFC, today[19]
AR	889	68,000	33%	2,300	1,800	140	52	10
IA	2,111	99,000	30%	3,500	2,500	170	164	2
IL	17,336	555000	51%	16,600	8,700	880	816	71
IN	4,638	210000	37%	6,700	4,700	410	270	30
KS	1,992	98000	39%	2,900	2,000	160	664	20
LA	1,304	70,000	44%	2,000	1,600	170	84	7
MI	16,444	258,000	20%	9,700	6,700	290	749	39
MN	6,902	228,000	43%	6,600	4,500	370	440	53
MO	5,052	201,000	43%	5,900	4,100	370	1410	58
MS	542	46,000	44%	1,400	1,100	130	30	7
ND	226	13,000	26%	500	400	20	20	0
NE	1,459	53,000	37%	1700	1100	100	119	2
OH	10,604	393000	38%	11,900	8,000	690	490	95
SD	335	21,000	28%	800	600	40	11	0
WI	6,967	243,000	36%	7,800	5,500	450	227	31

18 Atlas Public Policy, “EV Hub,” July 2017, https://atlaspolicy.com/rand/ev-hub/. (accessed November 2018)

19 Atlas Public Policy, July 2017.

DCFC Economics: GPI's Analysis

To investigate the impact of utility demand charge tariffs on the economics of DCFC, the analysis focused on a specific corridor—the M2M (Moorhead, MN, to Port Huron, MI) corridor along Interstate 94. This corridor was designated as an alternative fuel corridor by the Federal Highway Administration. Through a US Department of Energy grant administered by the Clean Cities Coalition, a collaborative group is currently working to plan and build DCFC along this corridor. This analysis has already been used by project partners in conversations with utilities about potential projects in their service territories.

Cities and towns of interest along the M2M part of the I-94 corridor were considered, with a focus on identifying towns roughly 50-70 miles apart. These cities include Fergus Falls, Saint Cloud, and Alexandria in Minnesota; Hudson, Eau Claire, Tomah, and Wisconsin Dells in Wisconsin; and Kalamazoo and Ann Arbor in Michigan. Major cities like Minneapolis, Saint Paul, Milwaukee, Chicago, and Detroit were not considered as these cities already have multiple DCFC stations available for EV charging (figure 3). For this study, we only looked at DCFC stations that are compatible with all EVs and thus excluded Tesla superchargers that are only compatible with Tesla automobiles.

A 10-mile buffer around each of the cities being considered was used to identify utilities with service territories along the I-94 corridor. The electric rate schedules of these utilities were then compiled, as discussed further below.

Figure 3: Cities of interest with 10-mile buffers

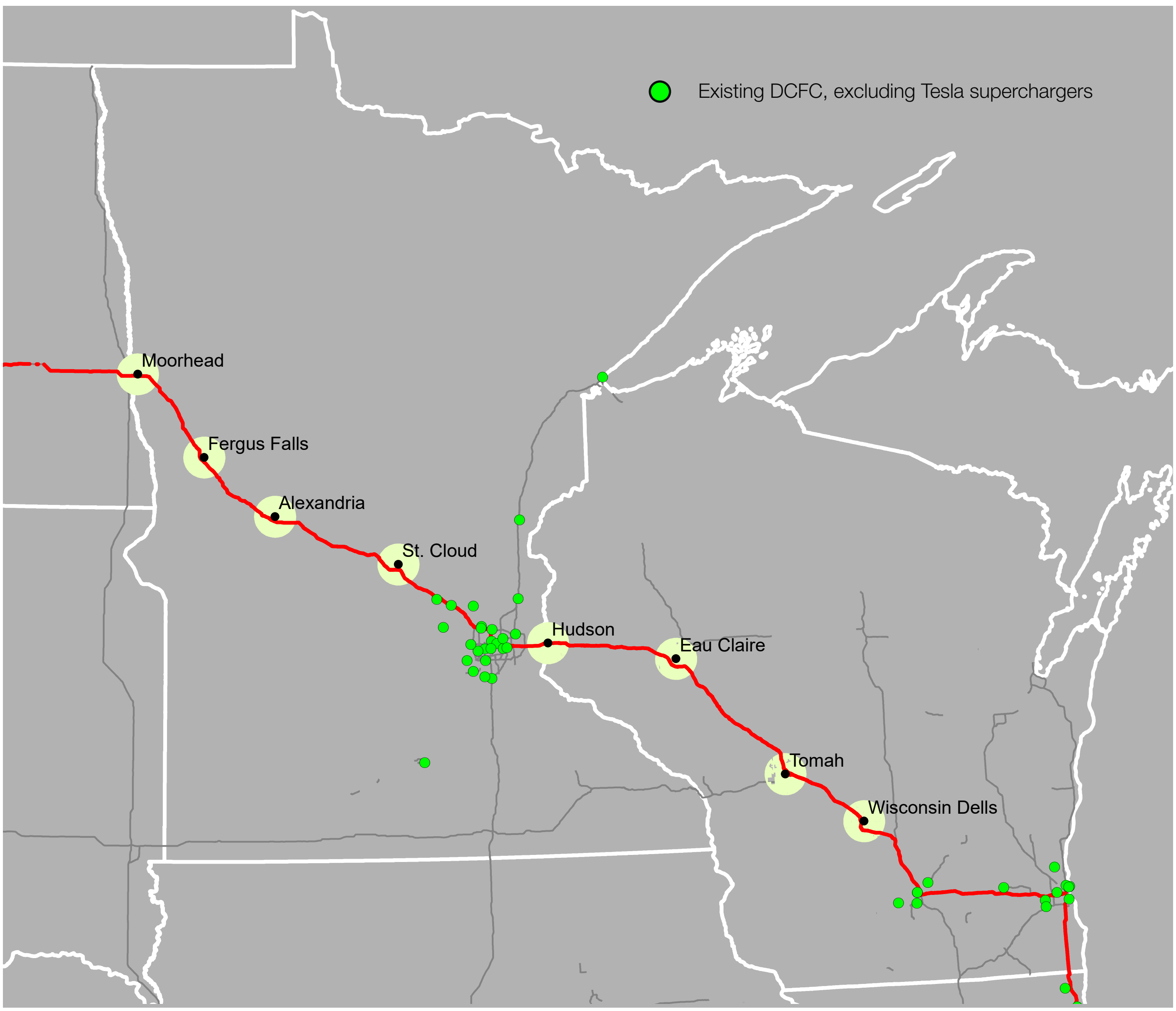
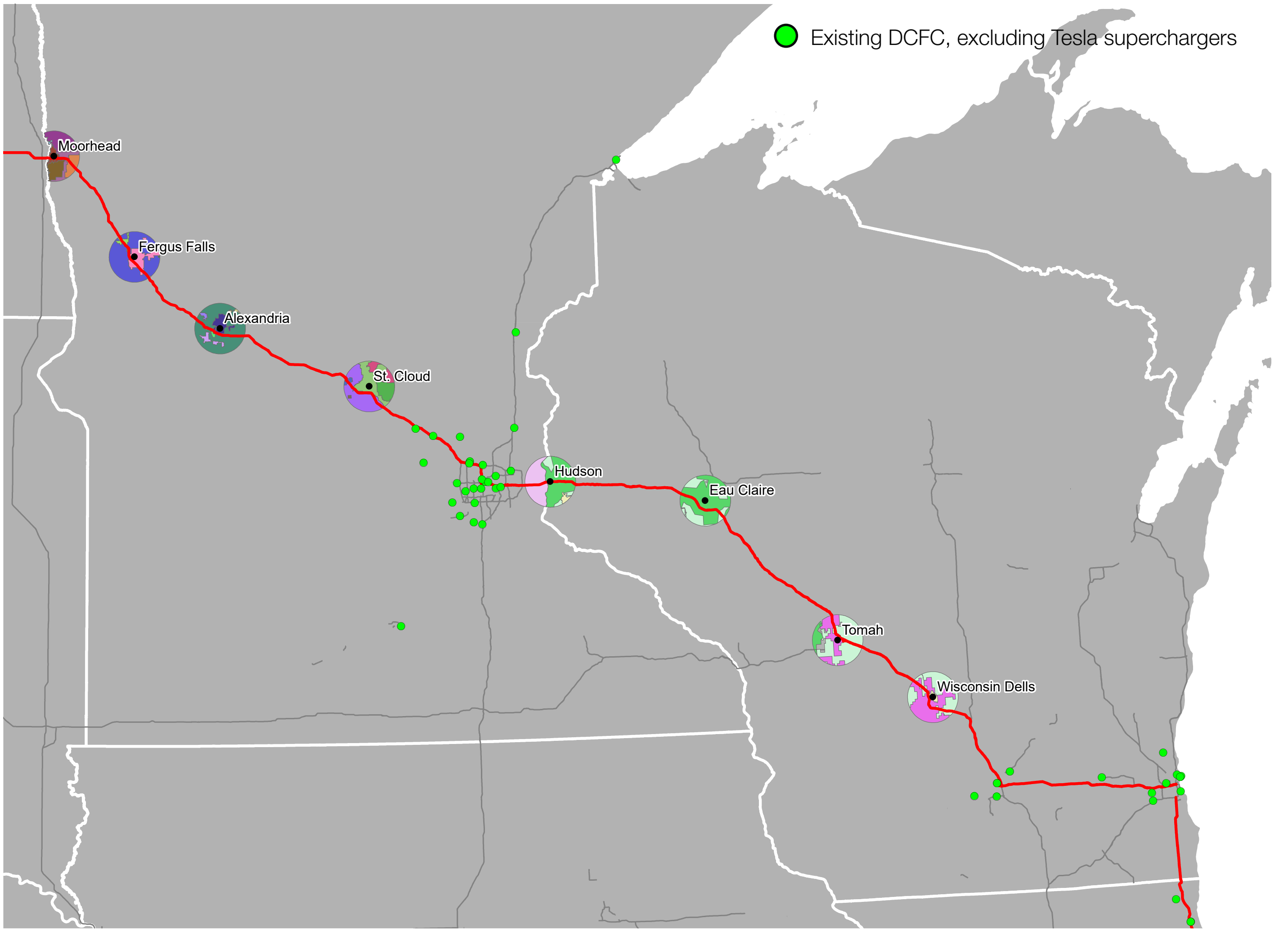


Figure 4: Cities of interest and utility territories within a 10-mile buffer



Data collection

Information was collected for 57 electric service rate schedules for commercial and small industrial customers across 30 utilities along the M2M corridor. Rates were classified by applicable demand levels representing various levels of DCFC capacity currently on the market or expected to be in the near future: 50kW, 100 kW, 150kW, 350kW, and 450kW or above. It is assumed that high-capacity charger levels are an adequate representation of co-located chargers. For example, a level of 150kW could represent either a single charger or three co-located 50kW charges.

For each applicable rate schedule, the following information was collected:

- minimum and/or maximum demand level—kW
- customer/facilities charge—$
- energy charge (summer, winter, shoulder as applicable)—$/kWh
- demand charge (summer, winter, shoulder as applicable)—$/kW
- periodicity of each rate component (i.e., monthly, annual, etc)

While most utilities base their demand charge on the demand (kW) measured for a billing month that is required to supply the maximum 15 minute-average amount of energy used by the customer in a billing month, some, but not all, utility rates vary across the seasons of the year. A rate may include a summer season, winter season, shoulder season, or combination of the three. This information was captured and compiled into a database.

Charging Scenarios

A total of 165 charging scenarios were created, varying three variables: demand level (kW), utilization (charges per day), and energy use (kWh) per charging session. Demand levels reflect typical combinations of one to three DCFC plugs: 50kW, 100kW, 150kW, 350kW, and 450 kW. Utilization was varied from 0.5 to 10 charges per day. This time-agnostic approach enables this study to examine both near-term and long-term economic viability of DCFCs as utilization rates are currently low but expected to increase as EV penetration increases throughout the region. Energy usages of 12, 14, and 16 kWh per charging session were also modeled.

Modeling Assumptions

In addition to the variables used to define the scenarios used in this study, other operating assumptions were needed to perform an annual cash flow analysis. The non-electrical costs associated with operating a DCFC in the Midcontinent region were held constant across all modeling scenarios to isolate the effects of variation in utility rate design on DCFC economic viability. These assumptions are:

- annual scheduled maintenance: $2,200/year
- insurance: $300/year
- cellular fees: $150/year
- networking fees: $300/year
- capital cost: $1000/kW of installed DCFC capacity

Note that capital cost was varied in a sensitivity case to explore the impact on project viability of policy options to lower or eliminate the capital cost born by project developers. To amortize capital costs, we assumed a 10-year period and a 3 percent annual interest rate.[20]

The model also includes income assumptions that are separate from the electrical cost assumptions to reflect the fact that many states do not allow the sale of electricity by non-utilities and require that DCFC developers instead sell "charging time." These income assumptions include:

- connection fee: $3/charging session
- per-minute charging time fee: $0.20/minute of charging

In reality, the operator of a charging station will charge rates depending on their own business model. These example rates are meant to represent a generalized Midwestern charging station and are not meant to reflect any particular charging operator. An average connection length of 17 minutes was assumed for all examined scenarios. These values were also held constant across all scenarios modeled to isolate the effects of variance in utility rate design on DCFC economic viability.

20 Johnson, Charlie. Walker, Jonathan, "Peak Car Ownership: The Market Opportunity of Electric Automated Mobility Services," 2017, https://www.rmi.org/wp-content/uploads/2017/03/Mobility_PeakCarOwnership_Report2017.pdf. (accessed November 2018)

These economic modeling assumptions represent a generalized or average business model for a typical charging station operator, but costs and rates charged to customers do vary. GPI has built an interactive web tool that allows any user to set their own rates and view model results in real time. Please contact the study authors if you are interested in using this tool.

Model Calculations

An annual cash flow was calculated that included annual electrical costs and revenue driven by assumed charging behavior, and non-electrical costs associated with operating and maintaining the charger. Equation 1 below describes the summation used to calculate annual cash flow, where *CF* is the annual cash flow, *I* is annual income, *EC* are the various electrical costs, *CC* is the amortized annual capital cost, and *OOC* is the annual operating costs not included in the electrical costs.

Eq 1. $$CF = I - EC - CC - OOC$$

Eq 2. $$I = [(cpd * f) + (cpd * mf * t)] * 365$$

Equation 2 describes the annual income of the DCFC where *cpd* is the number of charges per day at the modeled DCFC, *f* is the connection fee, *mf* is the per-minute charging fee, and *t* is the charging time. These revenue components are multiplied by 365 to determine annual income.

Eq 3. $$EC = (cpd * epc * vr) * d + [(dl * dr) + fc + cc] * m$$

Equation 3 describes the annual electrical costs of operating the DCFC where *epc* is the energy use per charging session (in kWh), *vr* is the volumetric rate ($/kWh), *dl* is the demand level of the DCFC (in kW), *dr* is the demand charge rate ($/kW), *fc* is the annual facilities charge, and *cc* is the annual customer charge. Volumetric charge costs are incurred daily (*d*) while demand charge costs are incurred monthly (*m*). Note that the appropriate volumetric and demand rates are applied in the model within this summation for summer, winter, and shoulder periods for each utility. The periods are then summed to calculate annual costs.

Eq 4. $$CC = (dl * C * s) * \left[i + \left(\frac{i}{1+i^{(n-1)}}\right)\right]$$

Equation 4 describes the amortized annual capital cost incurred by the project developer, where *C* is the assumed all-in capital cost of a DCFC per kW of installed capacity, *s* is the share of the capital cost the project developer is responsible for,[21] *i* is the assumed interest rate, and *n* is the assumed amortization period. Note that *s* is held constant at a value of 1 except in the sensitivity cases.

Eq 5. $$OOC = sm + I + cf + nf$$

Equation 5 describes the annual operating costs for the DCFC where *sm* is the annual scheduled maintenance cost, *I* is the annual insurance cost, *cf* is the annual cellular fee, and *nf* is the annual networking fee.

21 This parameter allows the model to explore policy options for capital cost sharing between multiple engaged entities.

Results

Results for annual cash flow in over five thousand scenarios and configurations (165 charging scenarios, across many utility rate schedules) were calculated according to costs from volumetric, demand, customer, and facilities charges for each of the utility rates for which data was collected. The results demonstrate generally difficult economics for DCFC station operation at current utilization rates. Cash flow to the station operator positively increases with greater utilization levels, as usage increases from one charge per day to 5 or 10 charges per day. Costs, however, are highly sensitive to charging level (50 kW, 150 kW, 350 kW, and 450 kW) and the resulting demand charge from the utility. Increased charging levels provide significantly faster charging times while delivering the same amount of energy. Most utility rate schedules considered in this study incurred both demand charges (per peak kW) and energy charges (per monthly kWh) at power levels of 50 kW and above.

Figure 5 demonstrates the impact of utilization rates at 50 kW DCFC stations operating throughout the study area. Each circle represents a unique utility rate schedule, where the size of the circle represents the cost incurred through customer and facility charges, which are placed along the axis according to their energy charge (vertical axis) and demand charge (horizontal axis). Green circles represent a DCFC station that can break even or profit under their particular utility rates at each chart's power level (kW) and utilization rate (charges per day). Red circles represent stations where costs exceed revenues and thus operate at a loss.

As seen in figure 5, low-utilization rates present challenging economics for DCFC operators. As utilization increases, more stations begin to break even or make a profit. At 5 charges per day, about half of the utility rate schedules in this study provide favorable economics for DCFC operators at the 50 kW demand level. Those utilities which have higher than average demand charges (above $6 / kW) still present challenging economics until higher utilization rates. At charging levels of 50 kW, DCFC stations at all utilities in this study would break even or profit at 10 charges per day.

Figure 5. Break even performance of 50 kW DCFC stations under each utility rate schedule with increasing utilization (charges per day). Red circles are stations where incurred annual costs are greater than revenues. Green circles are stations that break even or profit.

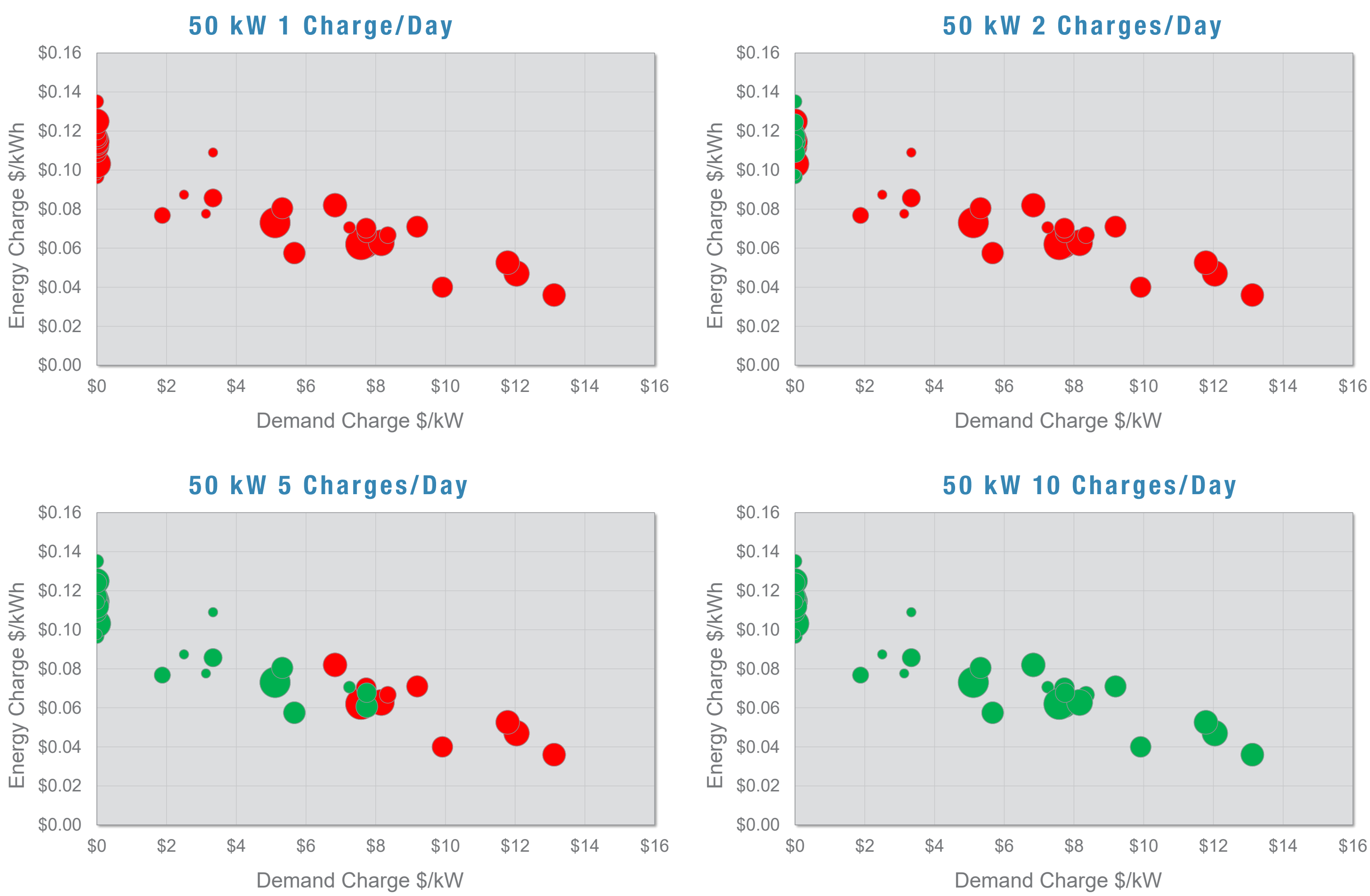
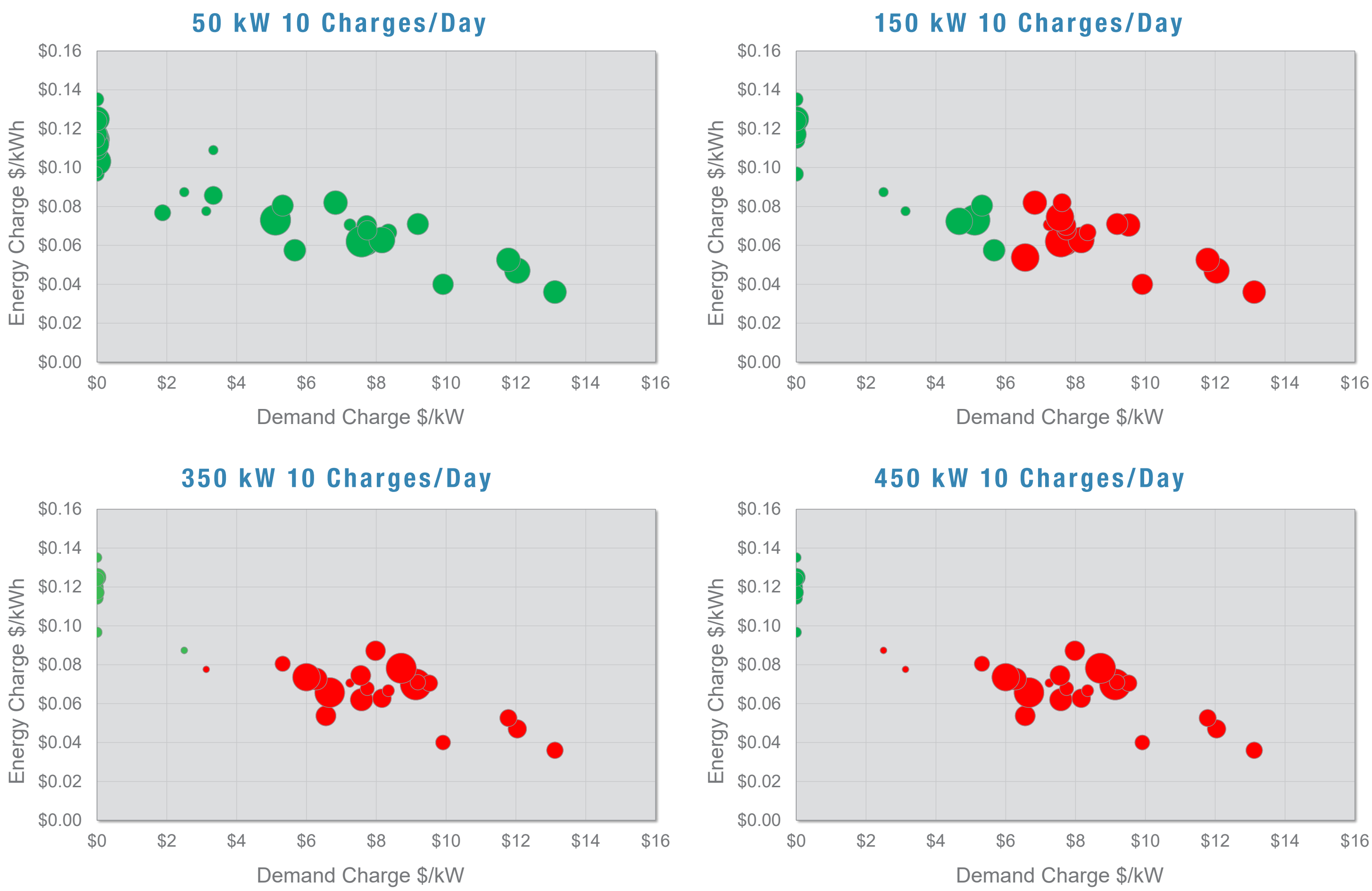


Figure 6 compares the performance of varying charging levels at higher utilization rates. The 50 kW DCFC stations break even or achieve profit at 10 charges per day under all utility rate schedules considered by this study. Higher power levels (faster charging) present more difficult economics under the current rate design paradigm. Upgrading from 50 kW to 150 kW results in DCFC stations no longer breaking even in more than half of utility rate schedules. The number of utility rates that offer favorable economics continues to decline at 350 kW and 450 kW. This is a result of demand charges, which are determined by the peak demand seen at the facility for each month, typically measured across a single 15-minute interval. A single charger operating at its full capacity of 50 kW will incur a corresponding demand charge (between $2 and $14 per kW) for 50 kW each month.

This analysis found that demand charges are one of the most significant cost factors in DCFC operation. As seen in figure 6, DCFC economics are challenging at higher power levels such as 350 kW and 450 kW, where nearly all stations that break even or profit are those operating in utility territories where there is no demand charge.

To determine the relative impact of each cost component, the volumetric energy costs, demand charge costs, and fixed costs were calculated for up to 10 charges per day at each power level.

Figure 6. Break even performance of DCFC stations under each utility rate schedule at 10 charges per day with increasing charging levels (50 kW, 150 kW, 350 kW, and 450 kW). Red circles are stations where incurred annual costs are greater than revenues. Green circles are stations that break even or profit.



Figures 7 and 8 present the resulting cost components. In each case of charging level, demand charges remain constant across all utilization levels while volumetric charges grow with increased utilization. Assuming that charging station operation would not exceed the total power capacity of the charger, a 50 kW charger would not incur demand charges (per kW) that exceed the 50 kW demand level. Growing utilization does increase the amount of energy that is delivered to customers, however, and thus the volumetric energy charge (per kWh) also increases.

A 150 kW or 350 kW DCFC station may deliver the same amount of energy over a time period as a 50 kW DCFC station. Thus, volumetric energy charges are not correlated with charging power levels and remain flat as charging level increases to 150 kW, 350 kW, 450 kW, and so on. Demand charges, however, are intrinsically correlated with charging power levels, resulting in significantly increased demand charges with upgraded power levels. A comparison of the annual electrical costs charts in Figures 7 and 8 shows that while volumetric energy charges can be seen increasing with utilization rates, the increased demand charges are of much higher magnitude as the power level is increased.

The share of costs charts in figures 7 and 8 also report the share of fixed costs, which include the non-electrical costs of running a DCFC station (such as payment system software and communications). For lower-power levels such as 50 kW, fixed costs do represent a significant portion of overall costs. As utilization increases, however, costs incurred by volumetric energy charges outpace fixed costs. Additionally, as power levels increase to 150 kW, 350 kW, and 450 kW, the costs incurred by demand charges represent by far the largest share of the total cost.

Figure 7. DCFC station costs by charges per day: 50 kW and 150 kW chargers

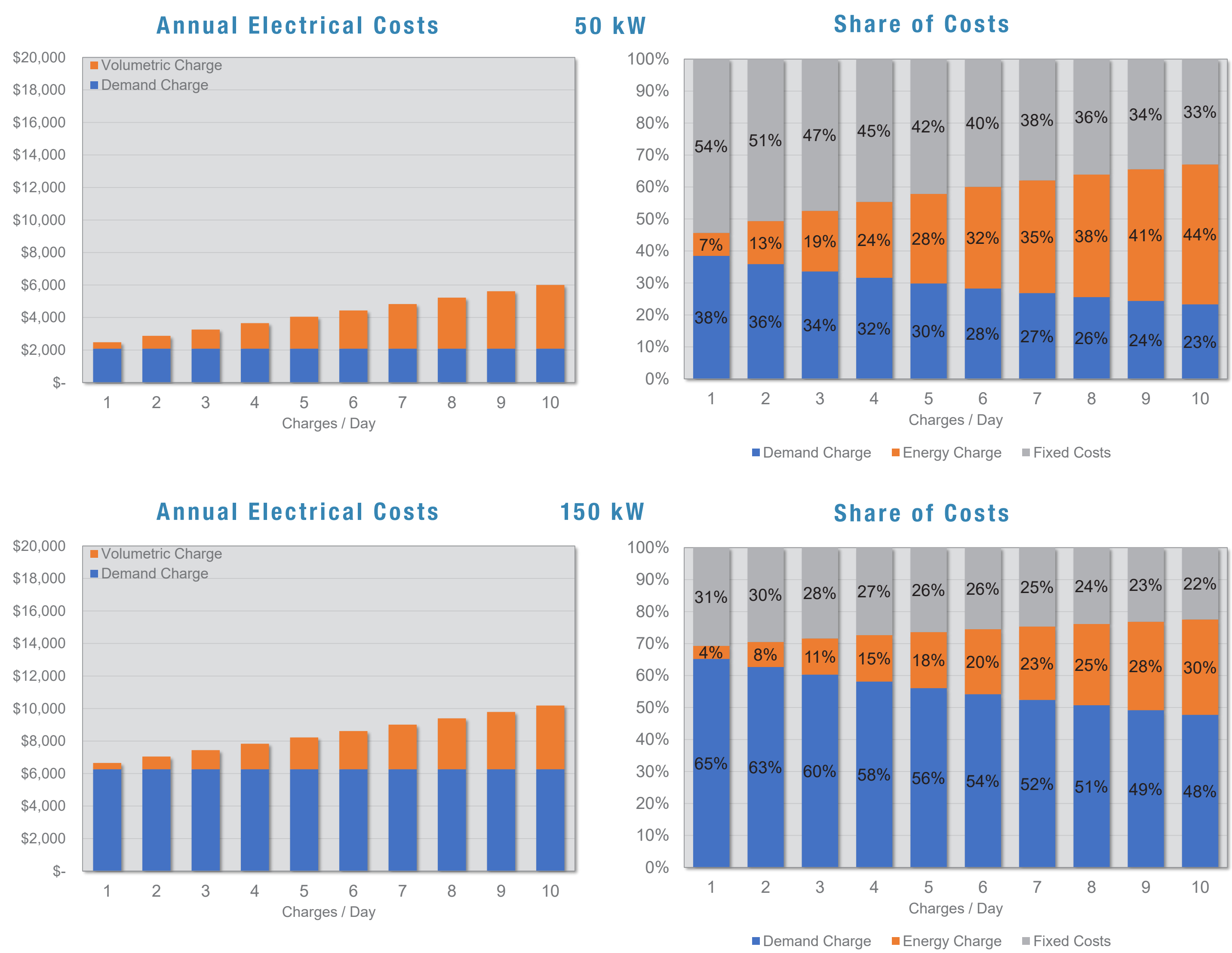


Figure 8. DCFC Station costs by charges per day: 350 kW and 450 kW chargers

Figure 9. Demand charge share of DCFC station costs across kW power levels

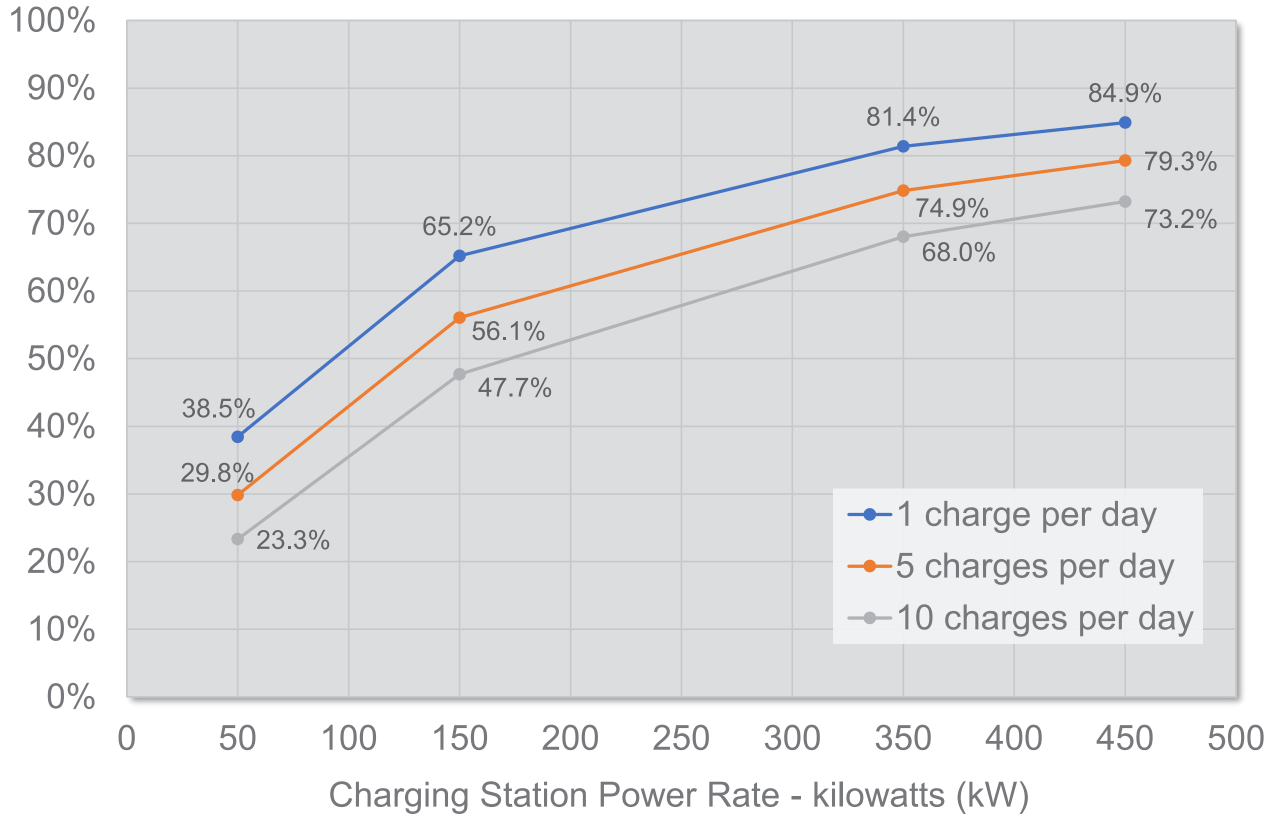


Figure 9 demonstrates the impact of both increased utilization and increased charging rate power levels on the demand charge share of DCFC station costs. In all power levels, increased utilization will decrease the share of demand charge costs as the amount of energy supplied by the DCFC increases. At 50 kW, increasing utilization by a factor of 10 from one charge per day to 10 charges per day will decrease the demand charge share by about 15 percent from 38.5 percent of total costs to 23.3 percent. At 450 kW, the share is reduced by only about 12 percent, from 84.9 percent to 73.2 percent. Meanwhile, upgrading charging power levels from 50 kW to 450 kW (by a factor of 9) results in significantly greater growth in demand charge share of total costs. At a low utilization rate of 1 charge per day, the demand charge share increases by 46 percent from 38.5 percent at 50 kW to 84.9 percent at 450 kW. At higher utilization rates, a similar increase of about 50 percent is seen, with the demand charge share of total costs of 23.3 percent at 50 kW growing to 73.2 percent at 450 kW.

It is clear from these results that demand charges are a primary factor in DCFC station economics, representing the majority of costs in most scenarios studied by this analysis. As a result, the demand charges present in utility rate schedules are a key determining component of a DCFC station's ability to break even or generate profit. Figure 6 above demonstrates that the only DCFC stations able to break even at higher charging rate power levels are those that are subject to utility rates with reduced or no demand charges.

Figure 10 illustrates the break-even threshold of DCFC stations at utilization rates between 2 and 10 charges per day. The horizontal axis reports feasible demand charges along the breakeven threshold lines, while the vertical axis reports feasible energy charges. At each utilization rate, a DCFC station would be expected to break even at energy and demand charges anywhere along that line. The average of energy and demand charges rate (about $0.07 / kWh and $6.6 / kW) studied in this analysis along the M2M corridor is shown as a red dot. According to the placement of the average rate schedule, a 150 kW DCFC station operating in the M2M Corridor region would need a utilization rate between 7 and 8 charges per day to economically break even.

Figure 10: Break-even thresholds by utilization rate at 150 kW

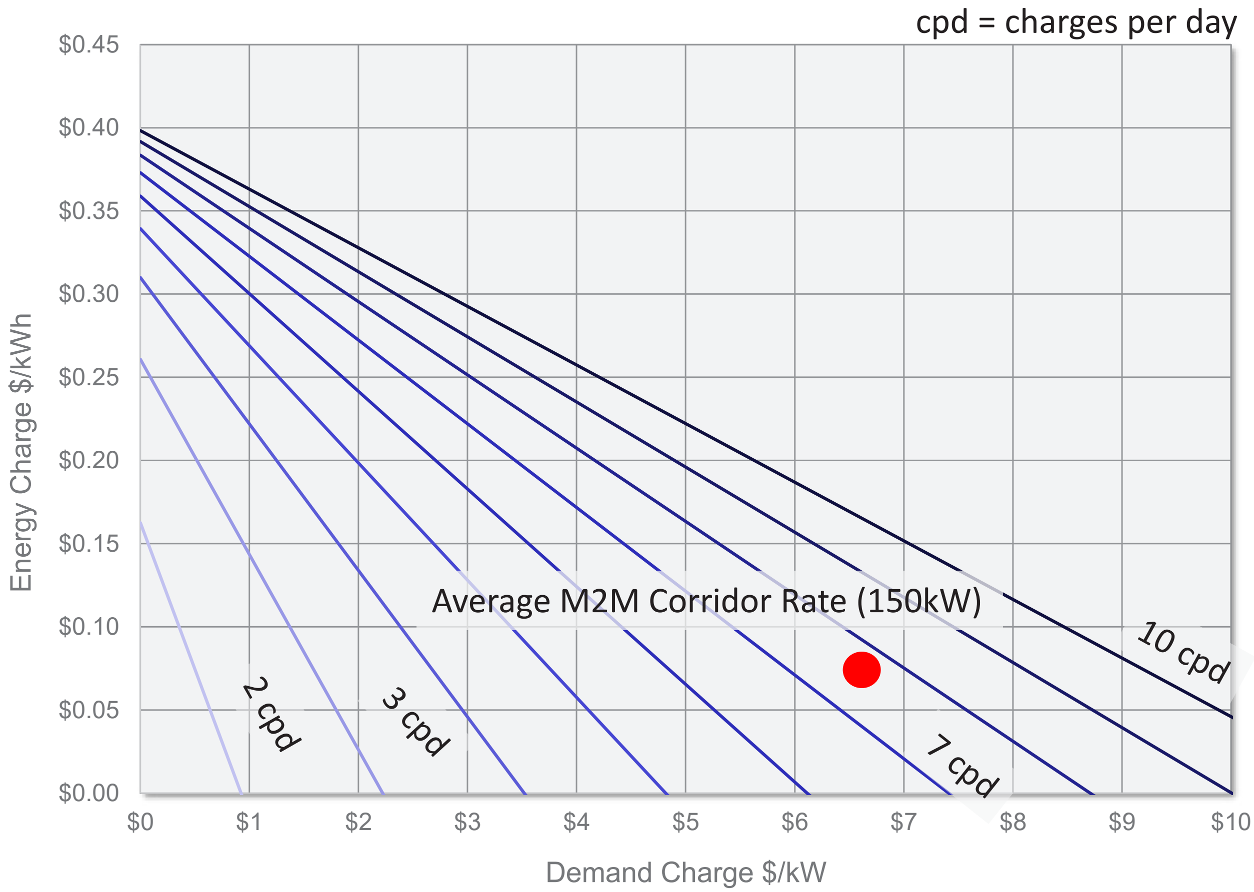


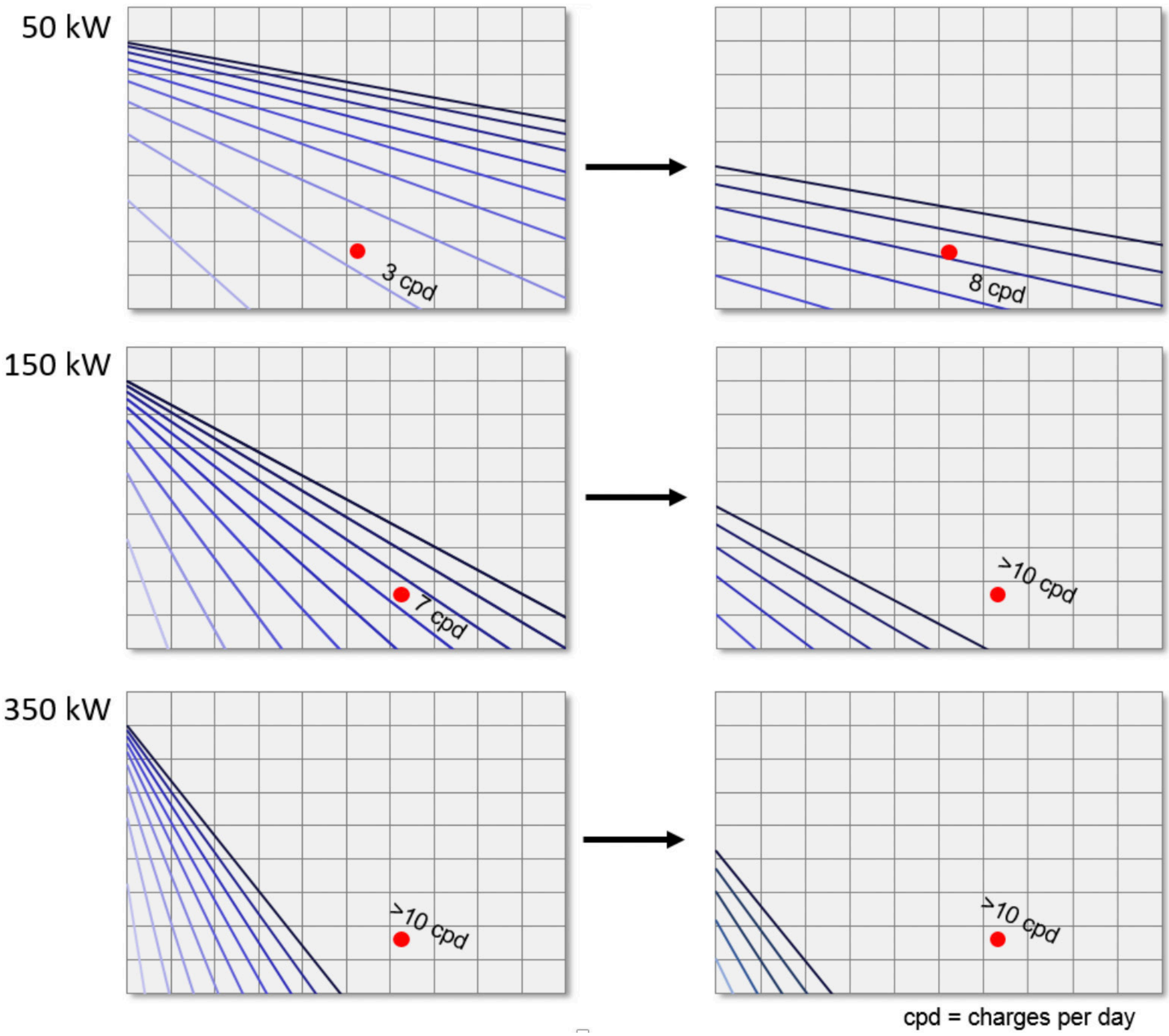
Table 2: Charges per day needed to break even with and without capital costs

Charger Level	Break Even Charges Per Day	
	Including Capital Cost	Excluding Capital Cost
50 kW	7	4
100 kW	14	7
150 kW	18	9
350 kW	40	19
450 kW	51	24

Based on modeled average rates

The capital costs of DCFC construction and installation are a significant expense. Depending on the business plan and mode of operation for a particular DCFC, capital and operation costs are often covered by two separate entities. DCFC stations considered in discussions that occurred as a part this analysis were often paid for by grants or sponsorships, or were covered by the site host while operated by an EV charging station service provider. Thus, the operational costs discussed by this paper generally do not include financed or amortized capital costs. Figure 10 illustrates the impact of including amortized capital costs in the break even considerations for 50 kW, 150 kW, and 350 kW DCFC stations, with the average M2M corridor rate schedule shown as a red circle. The overall impact of including capital costs in annual finances is an increase in the utilization rates required to break even. At power levels above 150 kW, utilization rates greater than 10 charges per day are required for positive financial performance.

Figure 11: Impact of capital cost on DCFC station break even threshold



Case Studies

This section discusses specific approaches to demand charges by different utilities that try to strike a balance between protecting the electricity system and utility customers from highly variable load, while also creating economic conditions that allow DCFC to operate and capture the benefits that result from increased EV adoption enabled by DCFC availability.

Case Study: Xcel Energy's "Rule of 100"

As noted above, DC fast chargers may often result in high peak demand (kW) due to their power level while not actually using very large amounts of energy (kWh). Under standard rates posted by most of the utilities in this study, this can result in high demand charges that make the economics of operating a DCFC station difficult until utilization levels increase. As this situation may arise at facilities in other industries or sectors, some utilities have established procedures for balancing high demand charges when usage is relatively low. The study authors spoke to Xcel Energy to hear their perspective of the need and usefulness of such demand charge adjustments.

In some areas of its service territory, including Minnesota, Xcel Energy has established a "demand limiter" provision that limits the billable kW quantity used to calculate demand charges. This provision applies when a customer has a relatively high level of peak kW demand compared to their total kWh energy usage. It functions to effectively cap monthly customer bills to an average price per kWh.

$$\begin{array}{c}\textit{demand limiter}\\ \textit{average price}\end{array} = energy\ charge + \frac{demand\ charge}{100\ hours}$$

The demand limiter provision produces a maximum average price that is simply the total of the energy charge and the demand charge divided by 100 hours. For example, with an energy rate of 5 cents per kWh and a demand rate of $10 per kW, the maximum average price is the total of 5 cents per kWh energy rate and 10 cents per kWh from the demand rate (based on $10 per kW divided by 100 hours), which is 15 cents per kWh.

$$\underbrace{\frac{\$.05}{kWh}}_{\text{Volumetric Charge}} + \left(\underbrace{\frac{\$10}{kW}}_{\text{Demand Charge}} \times \underbrace{\frac{1}{100\ hours}}_{\text{Demand Limiter}}\right) = \frac{\$.05}{kWh} + \frac{\$.10}{kWh} = \underbrace{\frac{\$0.15}{kWh}}_{\text{Effective Energy Rate}}$$

Example rates, not meant to convey actual utility rates

Prior to the demand limiter provision, a specific fixed maximum price per kWh was used. Because this required a manual reset for each change in energy or demand rates, the demand limiter provision was developed to automate the process and eliminate the need for a separate maximum price rate component. In addition to administrative simplicity, the provision also provides a directly recognizable revenue impact by its effect on historical billed demand quantities.

The relative level of peak demand and energy use is measured as "hours use" (which is the measure used in the demand limiter provision for 100 hours use) and is calculated by kWh divided by kW. Load factor is another more common measure of the relationship between kWh energy and kW demand, which is derived from the hours use measurement. For example, 100 hours use out of a total 730 hours for a month is approximately a 14 percent load factor.

Xcel's demand limiter provision provides a reasonable and practical cap on the average price per kWh, which can otherwise be excessive when customer usage at a very low load factor is applied to a demand-billed rate schedule. There is a widely recognized cost basis for the limiter provision. At the charging session lengths and utilization levels studied in the analysis for this white paper, DCFC stations load factors reached a maximum of 11.5 percent while having relatively high peak demands. As customer load factors progressively decline from an average level across the customer base, the probability of a customer peak demand occurring during a system peak times drops at a faster rate than the load factor. This relationship is known as the "Bary Curve" in the electric utility industry. This cost basis applies to generation and transmission system costs, but not to distribution system costs.

Case Study: Pacific Gas & Electric Commercial EV Rate Proposal

Pacific Gas and Electric (PG&E) is working on new commercial EV rate plans to support EV adoption. These rates propose to use a monthly subscription model while **eliminating demand charges**. PG&E is tentatively planning two commercial EVs (CEVs): CEV-Small for charging installations up to 100 kW; and CEV-Large for charging installations over 100 kW.

PG&E Commercial EV Rate Plans

CEV Small	CEV Large
Up to 100 kW	Over 100 kW
Smaller workplaces & multi-family dwellings	Fleets, large commercial spaces, fast charging
	Options for secondary and primary voltage service
Lower Cost $ / 10 kW	Higher Cost $ / 50 kW

The CEV rate includes a consistent monthly subscription charge based on the customer's chosen power (kW) level and an energy usage charge based on time-of-day pricing. Charging is actually cheapest mid-day, when renewable energy generation is at its highest on PG&E's system. Customers do pay an overage fee if their power level exceeds their subscribed level.

Replacing demand charges with a consistent monthly subscription fee can greatly alleviate many of the concerns and uncertainty with demand charges. Based on PG&E's modeling, the CEV rates provide EV charging at significantly cheaper costs than the equivalent gas or diesel prices, as well as their current commercial and industrial rates.

Note: the PG&E rates proposed here are preliminary and subject to California Public Utilities Commission review.

Discussion

According to a review of the existing literature, availability of DCFC is critical to enabling increased EV adoption. Even though the majority of charging by EV drivers is home and workplace charging, publicly accessible DCFC infrastructure is necessary for enabling adoption and necessary to allow for longer trips.

Level 2 charging at home and work offers the greatest opportunity for managed charging to offer grid benefits, for example by avoiding on-peak charging, increasing off-peak charging, and integrating off-peak generation of renewables. The benefits of managed Level 2 charging for the electric grid may not be as large without the existence of DCFC to remove a significant barrier to increased adoption.

By studying actual utility rate structures for a variety of utilities across the I-94 corridor from Minnesota to Michigan, we were able to model the likely economics of operating DCFC based on realistic assumptions about capital and non-energy operating costs and usage. We learned the following:

- Relatively low usage in the near-term translates to relatively low revenue from users.
- Demand charges are a high percentage of the overall cost of operating DCFC, as compared to energy costs and non-energy operating costs. This is exacerbated with higher-power and faster DCFC equipment.
- With lower capacity DCFC (50kW), profitability is linked with utilization rate and is highly variable based on demand charge tariffs. A 50 kW DCFC operates profitably in none of the utility service territories at 1 charge per day and all of them at 10 charges per day. Because charger utilization is expected to be low in early years and higher in the future, higher utilization could eventually solve the market failure for DCFC at 50 kW. This may or may not be sufficient to result in third-party investment. The lack of profitability of 50 kW in every utility service territory and at low to medium levels of utilization will make it difficult to build a truly comprehensive DCFC network and make a more fragmented network more likely.
- The barrier to economic feasibility presented by demand charges is greater for higher capacity DCFC, which many industry experts expect will be needed in the future to allow for faster charging rates. For 150 kW, 350 kW, and 450 kW DCFC equipment, a minority of utility demand charge tariffs allowed for profitable operation, even at utilization levels as high as 10 charges per day.
- There is a high degree of variability among utilities in terms of their demand charge tariffs. Some utilities have more “DCFC-friendly” tariffs that result in DCFC systems operating profitably across a wider range of operating conditions (see this paper’s case studies from Xcel Energy and PG&E). Many utilities have demand charge tariffs that make it difficult for DCFC to operate under many or most utilization levels.
- It is expected that DCFC systems will have low-utilization rates near term, and for utilization to increase over time as EV adoption increases (which will be enabled in part by increasing access to DCFC and network effects of building more chargers). Our analysis suggests that the conditions that are likely to facilitate increased DCFC availability in the region are a combination of reducing DCFC capital costs, which could come through state or utility cost-share in combination with private investment, and adjusting demand charge tariffs.

Demand charges exist for a reason and all utilities will have a different approach to this challenge based on their individual system and customer base. This analysis is not intended to create a “one-size-fits-all” approach, but to give utilities and regulators informational tools to address this problem in the way that works best for their system and customers.

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