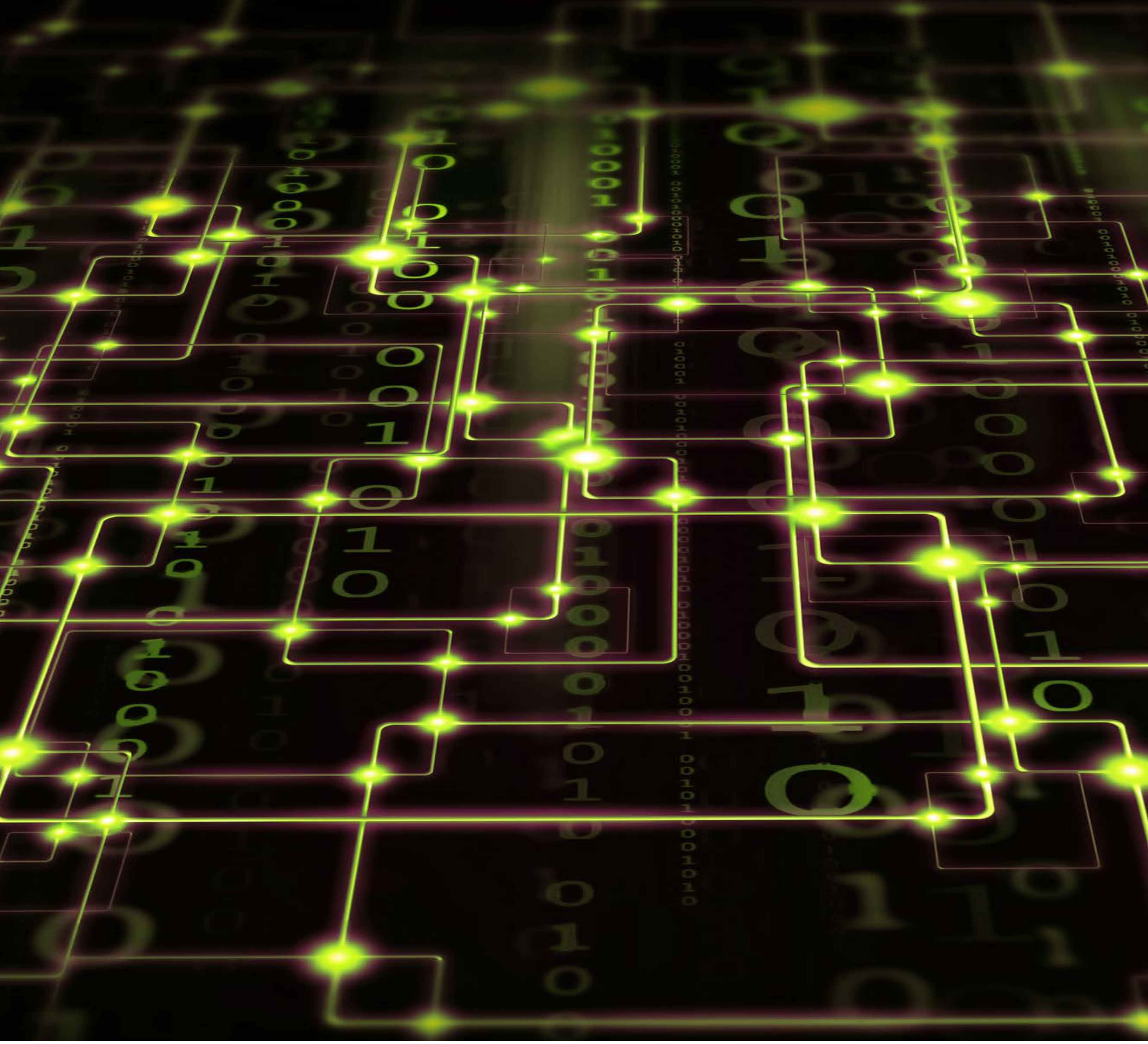

LET'S GET FLEXIBLE

Considerations for Unlocking Grid Capacity Using Flexible Interconnection

Environmental Defense Fund

LET'S GET FLEXIBLE

Considerations for Unlocking Grid Capacity Using Flexible Interconnection

Authors
Casey Horan
Michael Zimmerman
Cole Jermyn
Dakoury Godo-Solo

Published February 2025

Acknowledgments
The authors would like to thank the following individuals for providing feedback on this whitepaper. Organizational affiliations are listed for identification purposes only.

The opinions expressed in this whitepaper do not necessarily reflect those of the individuals who reviewed it. EDF bears sole responsibility for the whitepaper's contents.

Alex Collins, PG&E
Samantha Houston, Union of Concerned Scientists
Sean Morash, Telos Energy

Environmental Defense Fund
Guided by science and economics, Environmental Defense Fund (EDF) tackles our most urgent environmental challenges with practical solutions. EDF is one of the world's largest environmental organizations, with more than 2.5 million members and a staff of 700 scientists, economists, policy experts, and other professionals around the world.

TABLE OF CONTENTS

ACRONYMS

ADMS	Advanced Distribution Management System
ALM	Automated Load Management
DER	Distributed Energy Resources
DERMS	Distributed Energy Resources Management System
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
HCA	Hosting Capacity Analysis
kW	Kilowatt
LCMS	Load Control Management System
LGP	Limited Generation Profiles
MHDV	Medium- and Heavy-duty Vehicles
MW	Megawatt
PG&E	Pacific Gas & Electric
PUC	Public Utility Commission
SCE	Southern California Edison
VGI	Vehicle-Grid-Integration
V2G	Vehicle-to-Grid

INTRODUCTION

As states progress toward widespread transportation electrification, the need to prepare the grid to serve growing electricity demand from electric vehicle charging is increasingly salient. Several states have adopted policies aimed at accelerating EV deployment, both for light-duty passenger vehicles as well as medium- and heavy-duty vehicles, but even outside those states, electric MHDVs are increasingly becoming a lower-cost alternative to fossil fueled MHDVs.[1] Electrification can be particularly impactful, as these vehicles make up a small percentage of vehicles on the road but are disproportionately responsible for both local air pollution and greenhouse gas emissions.[2] Manufacturers are responding by producing increasing numbers and types of electric MHDVs, and today a fleet operator can often take delivery of one of these vehicles in a matter of months. A fully electrified MHDV fleet, however, can be a significant consumer of electricity, and connecting the necessary charging infrastructure to the grid can often require distribution grid upgrades that take longer than receiving the vehicles. Therefore, policies that can shorten the timeline to interconnect MHDV fleets' chargers to the grid can provide significant benefits, both economic benefits to the fleet that can put its newly acquired vehicles and chargers to work, and societal benefits where these electric trucks and buses are displacing fossil fuel vehicles earlier than otherwise possible.

This growing electricity demand from EV charging is happening within a broader electric sector transition of quickly increasing demand after many years of slower, incremental load growth.[3] Other electrifying end uses, such as buildings' space and water heating, along with new load sources like data centers, are all putting new demands on utilities.[4] The speed at which new demand for electricity is increasing requires consideration as to how utilities and the grid should evolve to better serve a quickly changing energy landscape.[5] As one part of this, utilities, decision-makers and customers should re-evaluate the traditional model for the interconnection agreement (the contract between the customer and the utility) which governs the conditions under which the customer's load can be interconnected. Flexible interconnections, an emerging[6] option for customer interconnection agreements, will be increasingly valuable to utilities and customers alike due to their potential to offer sustainable, scalable strategies for meeting demand without sacrificing grid reliability.

This paper discusses three key program design questions utilities and policymakers will need to address in advancing flexible interconnection programs. While focused on flexible interconnection in the context of MHDV electrification, much of the discussion will be applicable to customers with other types of load requesting new or upgrading interconnections as well.

What are flexible interconnections?

The term "flexible interconnection" refers to a range of methodologies for optimizing use of existing grid infrastructure when connecting customers to the grid. In the context of EV fleets, flexible interconnection or energization[7] is best understood as limiting the amount of peak power drawn from the grid by the fleets' chargers to avoid exceeding the capacity limits of the associated utility-side and/or customer-side electrical infrastructure. Flexible interconnections can be achieved through: (i) hardware, where physical infrastructure is put in place to limit a customer's maximum demand; and/or (ii) software, which relies on digital controls on the customer's load and can adapt power output dependent on need and/or constraint. Different flexible interconnections may rely predominantly on hardware, software or a combination of both depending on the complexity of the system.[8]

Traditionally, most utilities wait to interconnect customers' new or upgraded loads until after completing any distribution system upgrades needed to serve that customer's maximum anticipated demand. For EV charging, utilities tend to use a more conservative approach by building to meet maximum theoretical demand, combining the cumulative nameplate capacity of the customer's load.[9] For example, a customer installing five EV chargers, each with a maximum demand of 100 kilowatt, would need 500 kW of grid capacity before interconnecting. This customer, however, may not need the full 500 kW of grid capacity, and the grid may be fully capable of supplying sufficient energy to meet the customer's actual day-to-day needs. In this scenario, a flexible interconnection agreement can serve as a "bridge-to-wires" solution while the utility works to complete upstream upgrades. For example, this customer may only need 250 kW of grid capacity to start, perhaps because they only recently transitioned a small portion of their fleet to EVs, and it will take a few more years to fully transition the entire fleet. If the grid can safely supply 250kW capacity at peak for at least the next year, and the customer's energy needs are met, why should a utility wait to interconnect the resource?

Alternatively, the customer may plan to use all of their chargers from the start, but won't contribute to peak demand because they can do all of their charging during the overnight off-peak period. This customer may be able to avoid triggering a distribution grid upgrade indefinitely, and get faster interconnection, in exchange for agreeing to control their cumulative demand, making the flexible interconnection a long-term solution. Regardless, flexible interconnection can benefit fleets by shortening interconnection timelines, benefit ratepayers and society by facilitating greater end-use electrification and potentially mitigate or delay the need for upstream upgrades.

In practice, there is no one-size-fits all flexible interconnection regime, and programs can be adapted to accommodate any given number of operational, technical and legal limitations. At its core, a flexible interconnection agreement is an arrangement governing the terms of energy use, and both the customer and the utility have some agency in determining the best configuration. The customer must determine whether the value they receive in terms of faster energization justifies the potential cost and operational complexity of the system, which they can balance with

> **There is no one-size-fits all flexible interconnection regime, and programs can be adapted to accommodate any given number of operational, technical and legal limitations.**

The three questions discussed here are foundational questions meant to aid utilities, customers and other stakeholders at the initial stage of designing flexible interconnections.

other factors such as potential participation in bidirectional charging, demand response programs, etc. Still, some choices that affect the benefits and drawbacks of the program will be left exclusively to the utility, and process uniformity can make these arrangements more readily scalable.

This paper explores three crucial questions that will need to be answered to build a successful flexible interconnection program:

(1) Structure, or how the customer's energy use is limited in practice;

(2) Communication, the technologies used to manage the customer's energy limit; and

(3) Enforcement, the mechanisms used to dissuade the customer from exceeding the limit.

There are several other considerations not included in this paper that will also need to be answered in the development of flexible interconnection programs, such as those applicable to agreement form and scope, liability, distribution planning, technical requirements, customer-utility engagement, customer compensation and cost-sharing. The three questions discussed here are foundational questions meant to aid utilities, customers and other stakeholders at the initial stage of designing flexible interconnections. Importantly, the questions discussed here are not intended to yield binary answers, but rather a range of potential solutions along a spectrum of complexity that can be mixed and matched to create an array of flexible interconnection program designs.

STRUCTURE: HOW DYNAMIC IS THE LIMIT?

FIGURE 1

Spectrum of flexible interconnections

Less complex → **More complex**

Static load limits | Seasonal load limits | Fixed-schedule limits | Day-ahead limits | Real-time limits

The first question utilities need to answer for customers served under flexible interconnection agreements is how frequently the customer's maximum allowable demand will change, resulting in a range of possible options along a spectrum of complexity. Where utilities fall on the spectrum of what they can offer between a simpler, static limit and a more sophisticated dynamic limit will depend on the utility's circumstances, including their distribution system needs and their visibility into the system. Dynamic limits may require additional investment in granular data and more sophisticated technology to manage load and ensure reliable communication and grid safety, which will increase costs. However, a more dynamic limit can yield significant benefits by unlocking grid capacity and increasing system efficiency and optimization. Moreover, the optimal structure will ultimately depend on what the customer is willing to accept, i.e., how much to limit energy usage and for how long, and how worthwhile it is based on the upfront costs and associated trade-offs. Both utilities and customers therefore must work closely to find a structure that suits all parties involved.

The simplest answer to the question of how often the load limit should change is, never. A static upper load limit is one that does not change in response to external signals like real-time grid conditions. A static limit is the simplest option to put into practice and could best suit those utilities with the least visibility into their systems. For example, a customer with EV chargers with a cumulative nameplate capacity of 500kW could agree to limit load to 250kW maximum demand, year-round.

A static load limit could also suit situations where utilities are building, or are planning to build, upstream upgrades to meet new electric load demand and the flexible interconnection is an interim, bridge-to-wires solution. Once upgrades are complete, the utility can raise the customer's limit to reflect newly available capacity, until the customer's full nameplate capacity is reached. This type of static limit is also sometimes referred to as "ramped" or "phased" connection. In the United Kingdom, ramped connections are already being used to address interconnection delays brought on by capacity constraints.[10] Similarly, many U.S. utilities already offer some form of ramped connection called "construction service," where construction projects receive partial energization prior to completion, which is increased at a later date.[11] In sum, the simplest static load limit structures might represent the easiest lift for both utilities and customers, cost less install and offer a pathway to begin alleviating delays for EV charging deployments immediately.

Dynamic limits

Dynamic limits represent a more sophisticated method to determine available limits for an EV charging site, and there are benefits and tradeoffs to selecting a more dynamic structure. For example, dynamic limits best suit utilities with greater visibility into their distribution systems, such as those that have deployed some form of a distributed energy resource management system, and those that have established granular hosting capacity analyses and forecasting methods for expected electric loads like EVs, buildings and data centers. Such system investments can be costly, but improved grid visibility also unlocks significantly more grid capacity and increases overall system efficiency and optimization. In contrast, a less sophisticated system tends to require more conservative load assumptions to avoid risk of running up on grid constraints. Utilities can theoretically implement some types of dynamic flexible interconnections without a sophisticated DERMS, however, a DERMS is necessary where the utility requires operational grid visibility, e.g., real-time or day-ahead signaling.[12]

At the less sophisticated end of the spectrum, dynamic limits can be established as upper and lower bounds for a given time interval, e.g., time of year. For example, in a place like Arizona, there might be more distribution grid capacity available during the winter than during the summer simply because fewer people are using air conditioning. So, during the winter, the customer's charging limit could be stepped up from 250kW to 500kW, and vice versa. It is unlikely that such a step-up in complexity would require additional insight or investment into real-time grid conditions, and it might benefit an MHDV EV charging customer who needs to charge more often in colder weather.

To go one step further, a customer's load limit could be set to vary over the course of a day based on a fixed schedule.[13] This type of structure might be based on more predictable, forecasted conditions and anticipated constraints, such as planning to reduce charging during peak demand. For example, an EV charging site could be limited to 250kW peak charging during the hours of peak demand on the local distribution infrastructure (for example, 5pm and 11pm every day), and 500 kW at all other times. A utility would still need to conduct distribution planning analyses to identify what the actual limits should be, but this could be largely based on regular forecasting assumptions, such as those based on historical or probabilistic data, rather than highly granular real-time conditions.

At the more sophisticated end of the spectrum, upper load limits can be tied to more variable factors, such as day-ahead forecasts or real-time grid conditions. In addition to requiring more robust hosting capacity analysis that reflects grid conditions, a dynamic approach would require more advanced technology to ensure reliable communication between the customer and the utility. Customers would therefore need to install load control management systems[14] capable of both (i) receiving signals about changing limits from the utility; and (ii) effectively communicating those limits to the customer. The various technical and operational considerations surrounding LCMS will be discussed in more detail later.

To date, few utilities have implemented flexible interconnection programs with dynamic limits for load.[15] This could be partially due to the advanced technical and operational requirements that make dynamic limits feasible only for utilities that have invested in more sophisticated grid planning and DERMS systems. California utility Pacific Gas & Electric recently began its FlexConnect pilot, which operates on a day-ahead schedule.[16] Day-ahead forecasting is approaching the more complex end of the spectrum, where customers receive updated load limits 24 hours ahead of time. Currently, the pilot is only offered to a select few customers subject to extended interconnection wait times.

The concept of dynamic limits generally, which make use of the grid's changing ability to transfer power, are already being put into practice in one form or another at both the transmission and distribution level.[17] For example, the Federal Energy Regulatory Commission required ambient adjusted ratings for transmission lines to increase overall power flows on transmission lines by accounting for ambient conditions rather than static assumptions.[18] State regulators and utilities can design similar structures for flexible interconnections that work for different localities. Dynamic limits have also already been established at the distribution grid level for energy export in California. In March 2024, the CPUC issued a decision allowing "Limited Generation Profiles"[19] of renewable energy systems to flexibly interconnect to the distribution grid.[20] LGPs specify the maximum amount of energy that can be exported to the grid throughout the year based on grid conditions. And in Europe, a utility-controlled dynamic load limit rule in Germany requires

that distributed energy resources above a certain kW threshold must be controllable, wherein DERs are allowed to connect under the condition that loads can be curtailed by the distribution system operator at any time to address grid constraints.[21]

In sum, flexible interconnections with static limits will likely be simpler to implement, while dynamic load limits require more technical consideration and investment but can unlock more unused grid capacity. The more complex the system, the more likely benefits will flow from higher load factor, such as reduced energy costs. Utilities and customers must carefully weigh the costs of participating in a more complex program, such as grid visibility and advanced technical and operational standards that would need to be met to ensure safety and reliability. However, investing in a more sophisticated system could be well worth it for those utilities already pursuing other grid modernization and optimization efforts.

Hosting capacity analyses

A hosting capacity map is a visualization of the available capacity for connecting new load and/or generation. Robust, granular hosting capacity analyses and publicly hosted maps can help utilities, customers, and regulators anticipate where need will arise and plan for flexible interconnections. Publishing findings in map form can help both utilities and customers identify where DERs might alleviate or aggravate grid constraints, meaning they can help businesses like EV charging companies identify where there is available capacity on the electric grid to connect new chargers.

COMMUNICATIONS:HOW SOPHISTICATED IS THE LOAD CONTROL MANAGEMENT SYSTEM INTERFACE?

How should the utility communicate signals pertaining to the customer's maximum allowable demand? The communication interface style between the customer and the utility, whether autonomous or communications-based, will largely determine the bounds of a flexible interconnection's sophistication. The most basic solution could be fully autonomous (or "set it and forget it"), meaning there is no ongoing communication between the utility and the customer's equipment once the interconnection limits are set. But the more complex the structure of the flexible interconnection, the more likely that the customer will need some sort of communications-based LCMS to relay signals about changing limits between the utility and the customer. A communications-based system could be a larger upfront investment, both for customers and utilities, but it may unlock more grid services, better optimize local grid assets, and enable grid orchestration.[22] Southern California Edison's LCMS Pilot is designed to eventually offer both of these options by allowing the customer manage their electrical demand and EV charging stations within specific parameters set by SCE either: (1) without real-time external communication (autonomous); or (2) with utility-based communication.[23] Regardless, both types of configurations come with safety backstops to ensure grid safety and security.

Autonomous load limits

A flexible interconnection agreement with an autonomous load limit would mean the customer's LCMS would be pre-programmed around the limits set out in the agreement, including any variance related to seasonality, time-of-day or voltage limitations.[24] For the customer, the benefits of such an agreement would be (i) lower upfront costs, as the LCMS does not need to be communications-capable; (ii) greater predictability, because load limits are known well in advance; and (iii) less contingency planning such as setting backstop limits in the event of a communications disruption between the LCMS and utility. The downside of autonomous load limits is forfeiting the potential added benefits of a fully dynamic load limit, namely access to additional grid capacity during more hours of the year, which is only feasible with a communications-capable LCMS in place and a flexible interconnection agreement that leverages those capabilities. From the perspective of the utility, autonomous load limits may be easier to implement, as they do not require a DERMS or alternative method of reliability communicating limits to the customer's LCMS. And, an autonomous limit may avoid the added complexity and risk of relying on customers' LCMS to safely and reliably switch to backstop limits during communications outages.

In the case of the SCE pilot, the localized autonomous LCMS operates independently without real-time external communication, using pre-programmed limits to manage power usage. Utility personnel and approved third-party contractors can program the customers' LCMS locally to implement the SCE-provided limits, or it can be programmed remotely via approved communications.[25]

Communications-based load limits

Flexible interconnections can take advantage of a range of options for systems that communicate between the utility and the customer's LCMS, through hardware and/or software, to adjust the charging rate and timing of the interconnection based on grid conditions. To date, there is little consensus among utilities or their regulators regarding the operational and technical LCMS standards deemed necessary to ensure grid safety and reliability.[26] While progress to develop uniform standards is steady, utilities and technical experts may be able to help speed the development of these standards through increased participation in decision-making process. In the meantime, decisionmakers can ensure progress on basic load flexibility policies while regulatory and standard-setting bodies debate cybersecurity and communications rules for more sophisticated configurations. As utilities move forward, they should also consider how a potential communications-based LCMS might integrate with future vehicle-grid integration programs, including managed charging and vehicle-to-grid programs.

For utilities with more advanced grid operations, communication-based technologies may be a natural extension of existing capabilities. For example, PG&E's FlexConnect pilot referenced in the above section utilizes such communications-based technology.[27] PG&E previously invested in a sophisticated DERMS that allows the utility to collect real-time customer DER data and improve grid efficiency and system visibility. This allows PG&E to relay adjusted load limits to FlexConnect customers 24 hours ahead of time. PGE&E must rely on the communications interface in the LCMS technology to reliably convey the load limit notification, to which the customer's LCMS will respond automatically. The combination of a sophisticated DERMS and a communications-based flexible interconnection program like FlexConnect could help utilities with broader grid modernization and orchestration efforts.[28]

Additionally, SCE is currently exploring a communications-based pathway to implement in its LCMS Pilot involving its Advanced Distribution Management System, which is able to determine site limits dynamically based on local grid conditions and send those limits to the customer's communication interface via IEEE 2030.5 protocol.[29] Communications can be implemented either via cloud-based services or through direct communication gateways at the customer's facility. Communication between SCE and the customer's LCMS is accomplished using utility-specified cybersecurity protocols to protect against unauthorized access and potential cyber threats. These communications protocols and the hardware solutions that accompany them are a complex, evolving field, and additional utility pilots would be beneficial to determine which combinations are most useful and cost-effective. But, as the ongoing California pilots demonstrate, these technologies are sufficiently developed to allow utilities to deploy at least some forms of communications-based flexible interconnection options for customers.

"These communications protocols and the hardware solutions that accompany them are a complex, evolving field, and additional utility pilots would be beneficial to determine which combinations are most useful and cost-effective.

ENFORCEMENT: HOW STRICT IS THE LOAD LIMIT?

Utilities and customers have a range of choices in technology.

The flexible interconnection agreements' upper load limit will necessarily be subject to enforcement, as the requirements of an agreement are only as useful as the mechanisms used to enforce them. If there is a lack of enforcement when customers exceed their limits, then utilities may not be able to rely on them to consistently operate within grid constraints. On the other hand, if penalties are excessively harsh, customers may be deterred from engaging in a program at all. These considerations are particularly important for scaling these programs beyond the pilot stage, as it is much simpler for a utility to work with a handful of trusted customers to ensure compliance than it will be to maintain that compliance when these programs are widely available. Utilities will need to carefully consider the implications of enforcement mechanisms in order to ensure the right balance between encouraging participation, realizing benefits and protecting grid infrastructure.

In addition, utilities and customers have a range of choices in technology — whether hardware-based, software-based or a mix of both — that can be used to enforce flexible load limits. Options range from simple hardware-based technology, such as a current limiter, which could physically prevent a customer from exceeding their agreed-upon limit. Under a static limit, this could mean that a customer's EV charger could prevent additional charging once the customer reaches their peak. Alternatively, software-based options can serve the same purpose and might provide more long-term flexibility to implement dynamic limits or alter other program parameters. As a threshold matter, however, utilities will need to decide on what exactly they mean by load limit.

Hard cap

Under a "hard cap," the customer could agree to a guaranteed upper load limit and would not be able to exceed the limit without being subject to an enforcement action by the utility, such as cancelation of the flexible interconnection agreement. For example, the utility could require an EV charging customer with a static limit of 250 kW to install a hardware or software solution meeting certain specifications to guarantee that limit won't be exceeded. The interconnection agreement may also specify penalties for exceedance, such as a new, lowered limit, or outline a three strikes policy before cancelation of the agreement. A hard cap might be preferable where the distribution system assets upstream from the customer are at capacity, and any demand overage by the customer is virtually guaranteed to exceed the asset's capacity. Whereas, if the capacity constraint is further upstream on assets that are shared by a greater number of customers, then any given customer overage is less likely to trigger a capacity exceedance. In such situations, a soft cap could give customers permission to occasionally exceed limits.

Soft cap

Under a soft cap, the customer could agree to a target import limit for the flexible interconnection that the customer could be allowed to exceed under certain conditions subject to disincentives. For example, the EV charging customer who exceeds their 250 kW limit could be subject to higher demand charges on their next bill for every kW over the limit. The use of a soft cap would not necessarily need to physically constrain the customer's load if constructed like a time-of-use rate or demand charge to incentivize good charging behavior. Regardless, such a policy may be useful in instances where excess grid capacity exists today that would allow a customer to exceed their limit without damaging grid assets or causing an outage, but the utility anticipates additional load growth that will use up that capacity in the near future. The utility may plan to rely on flexible interconnection agreements with multiple customers to avoid a grid upgrade need, and a soft cap arrangement will allow for customer flexibility while still encouraging grid beneficial charging behavior. These types of arrangements could look similar to standby rate arrangements, where a rate is paid by an electric utility customer who is served in part by on-site generation and in part by services delivered through the electric grid.[30] Some standby rate structures require customers to pay a penalty if they exceed a soft kW cap. Going forward, soft caps could be paired with dynamic price signals, that include both generation and infrastructure considerations.[31]

TABLE 1

Comparison of different possible flexible interconnection structures and considerations.

Interconnection structure	Use case	Suitability criteria
Static hard cap autonomous	250 kW charging limit always, customer cannot exceed limit or LCMS curtails charging. Customer-side hardware is configured to automatically limit the customer's energy usage by shutting off when the limit is reached.	Where local assets immediately upstream of customer meter are at or near capacity and utility lacks DERMs and/or the customer is not able to install LCMS.
Dynamic soft cap autonomous	250 kW charging limit during the day, during evenings the limit increases to 500 kW. Customer can exceed limit subject to additional fee. LCMS is pre-set to adjust limit from day to night.	Where local assets immediately upstream are limited to an extent during peak demand periods. Customers must be willing and clearly understand pricing structure if able occasionally exceed the limit.
Semi-static hard cap autonomous	250 kW during summer, raised to 500 kW during winter, repeating limits until grid upgrades are complete.	Where local assets immediately upstream are limited to an extent during peak demand periods. Customers must be willing and clearly understand pricing structure if able occasionally exceed the limit.
Dynamic hard cap communication-based	Upper load limit varies between 250-500 kW depending on grid conditions. Utility sends signals to customer on day-ahead schedule communicating changing limits to LCMS. Customer can manage their load under the cap or hardware will limit power.	Where local assets immediately upstream are limited by a thin, variable margin with a sophisticated DERMS, customer-side communications-based LCMS that can reliably interface with customer and has backstop for grid security.

CONCLUSIONS

In sum, flexible interconnections offer a tool to help overcome the challenge of meeting growing electric load demand from transportation electrification in a sustainable, scalable manner. The range of options available for utilities and customers to deploy raises the need to consider the most important pillars with which to build a successful flexible interconnection program. Understanding the implications surrounding the structure of the load limit, the communications style and enforcement mechanism will help stakeholders begin to design and test working programs. This way, states can ensure continued progress toward decarbonization and electrification goals without sacrificing the safety and reliability of the grid.

REFERENCES

1 The Advanced Clean Trucks (ACT) rule spurs deployment of MHDV EVs by requiring an increasing share of new vehicle MHDV sales to be comprised of zero- emission MHDVs. The following states adopted the ACT rule: Colorado, Massachusetts, New Jersey, New Mexico, New York, Oregon, Vermont, Washington, Maryland, Rhode Island, California. Washington, D.C., Hawaii, North Carolina, and Virginia signed a Memorandum of Understanding to work toward 100% zero-emission trucks. See Claire Buysee & Ben Sharpe, California's Advanced Clean Trucks Regulation: Sales Requirements for Zero-emission Heavy-duty Trucks (ICCT, Jul. 2020), theicct.org/publication/californias-advanced-clean-trucks-regulation-sales-requirements-for-zero-emission-heavy-duty-trucks/. See also Catherine Ledna et al., Assessing total cost of driving competitiveness of zero-emission trucks, 27 iSCIENCE (2024), sciencedirect.com science/article/pii/S2589004224006060. (Modeling the total cost of driving for all trucks Class 3-8 in the US, finding that projected zero-emission MHDV volumes demonstrate better total cost of ownership compared to internal combustion engine trucks, e.g., early markets with first- and last-mile delivery, local and regional haul, and moving toward long-haul transportation. Zero-emission MHDVs are likely to reach cost parity with internal combustion engine vehicles by 2035).

2 Larissa Koehler & Pamela MacDougall, Accelerating Electric Vehicle Infrastructure: A How-to Guide for Regulators (EDF, 2022), blogs.edf.org/energyexchange/wp-content/blogs.dir/38/files/2022/02/Accelerating_Electric_Vehicle_Infrastructure.pdf.

3 Wilson, J. ET AL., Strategic Industries Surging: Driving US Power Demand (Grid Strategies, dec. 2024), gridstrategiesllc.com/wp-content/uploads/National-Load-Growth-Report-2024.pdf.

4 John D Wilson & Zach Zimmerman, The Era of Flat Power Demand is Over (Grid Strategies, Dec. 2024), gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf.

5 Id.

6 While nascent for load, flexible interconnections see greater use today for generation. See e.g., California's "Limited Generation Profiles" (LGPs). CPUC, Resolution E-5296 (March 2024), docs.cpuc.ca.gov/PublishedDocs/Published/G000/M526/K988/526988970.PDF.

7 Throughout this paper, the term "flexible interconnection" is used to refer to connecting EVs to the grid, but some jurisdictions prefer to differentiate solar "interconnections" and EV "energizations." Functionally, the concepts discussed herein can apply to both solar and EVs.

8 Operations and customer behavior may also have a role to play in "low-tech" flexible load management structures not included in the scope of options discussed here, e.g., when the customer agrees to manually stagger charging such that they do not exceed demand.

9 Utilities tend to apply a "diversity factor" to determine maximum demand for traditional, well-known load sources, such as apartment buildings, e.g., to account for how two apartment buildings on the same block are unlikely to reach peak demand at the same time. See Jignesh Parmar, Energy Demand Factor, Diversity Factor, Utilization Factor, and Load Factor, Electrical Engineering Portal, electrical-engineering-portal.com/demand-factor-diversity-factor-utilization-factor-load-factor. However, utilities might avoid this approach with EV chargers by opting for a more conservative approach that assumes the combined nameplate capacity of all chargers, since there is higher risk that all chargers could be used simultaneously.

10 Premier Energy Utility Consultants, The Electricity Capacity Crisis – SSEN Ramped Connection, (April 12, 2023), premierenergy.co.uk/blog/the-electricity-capacity-crisis-ssen-ramped-connection/.

[11] See e.g., Major Utilities: CenterPoint Houston Electric, PG&E, Los Angeles Department of Water and Power.

[12] Utilities could implement dynamic load limits directly through the customer's meter (without the use of DERMS) through voltage-sensitive limits or by using time-of-use pricing to manage customer charging behavior.

[13] A dynamic load limit could be structured like time-of-use pricing but with hardware/software to guarantee customer participation.

[14] "LCMS" is used here as an umbrella term for a range of technologies that can be used to manage load.

[15] This type of flexible interconnection should not be confused with utility demand-response programs. While demand-response programs do involve utility communications to the customer and dynamically reduce the customer's load during peak periods, they are typically designed around transmission and generation conditions, rather than distribution capacity limitations. Additionally, demand-response programs are only implemented for existing customers, not as a way of getting new customers interconnected more quickly. See ENEL, The Different Types of Demand Response Programs Explained (June 26, 2024), enelnorthamerica.com/insights/blogs/types-of-demand-response-programs.

[16] See generally PG&E, PG&E FlexConnect Pilot, pge.com/flexconnect.

[17] See Federal Energy Regulatory Commission, Docket No. RM20-16-000; Order No. 881 Managing Transmission Line Ratings (Issued Dec. 16, 2021) (Requires all transmission providers, both inside and outside of organized markets, to use ambient-adjusted ratings as the basis for evaluating near-term transmission service to increase the accuracy of near-term line ratings; "FERC"). See also FERC, Staff Paper, Managing Transmission Line Ratings, Docket No. AD19-15-000 (Aug. 2019), ferc.gov/sites/default/files/2020-05/tran-line-ratings.pdf.

[18] Id.

[19] DER projects under the LGP will alter their grid injections by selecting one of three "24-value LGP configurations" options to respond to grid conditions. The three types of 24-value LGP configurations are 24-hourly, Block, and 18-23-fixed. Supra note 6.

[20] Id.

[21] German Energy Industry Act, § 14a (2011).

[22] Definitions vary, but some utilities are moving toward "orchestration" as a concept for a system that coordinates grid operation across multiple systems to manage the distribution network and optimize grid infrastructure. See e.g. PG&E Grid Modernization Progress Report (April 2024), gridworks.org/wp-content/uploads/2024/04/PGE-Grid-Modernization-Report_April-2024.pdf.

[23] SCE, Establishment of Southern California Edison Company's Customer-Side, Third Party Owned, Automated Load Control Management Systems Pilot (Advice Letter 5138-E and 5138-E-A) (January 16, 2023).

[24] An autonomous approach may not necessarily require an LCMS with a pre-programmed limit. For example, EV load limits can be modulated using voltage-sensitive EV charging or directly through the customer's meter.

[25] SCE, supra note 23.

[26] E.g., California and Colorado have specifically adopted IEEE 2030.5, Infra note 29. Most states have yet to adopt this standard or select an alternative.

[27] Both SCE's and PG&E's Pilots utilize the IEEE 2030.5 Protocol, indicating a developing set of standards for these kinds of flexible interconnection schemes. Supra note 29.

[28] According to PG&E, “The goal of PG&E’s grid modernization effort is to meet today’s challenges while also positioning the grid to meet the demands of a dynamic energy future with improved situational awareness, operational efficiency, cybersecurity, and DER integration and orchestration capabilities.” Grid Modernization Progress Report (April 2024), gridworks.org/wp-content/uploads/2024/04/PGE-Grid-Modernization-Report_April-2024.pdf[29] IEEE 2030.5, also known as Smart Energy Profile 2.0, is a communication protocol that allows electrical grid operators to connect to and manage DERs, See IEEE Smart Grid Resource Center resourcecenter.smartgrid.ieee.org/education/webinar-videos/sgweb0043#:~:text=IEEE%202030.5%20is%20a%20standard,their%20energy%20usage%20and%20generation.

[29] Many major utilities have had standby rates for customer-side generators for years. See e.g., California utilities SCE, PG&E, SDG&E; Midwest utilities Commonwealth Edison and CenterPoint Energy; Northeast utilities Con Edison and National Grid. See generally American Council for an Energy Efficient Economy, Standby Rates, database.aceee.org/state/standby-rates.

[30] The California Energy Commission is requiring electricity providers to offer dynamic pricing as an option to all California consumers by 2027 as a way to help balance supply and demand for electricity. The CPUC has directed PG&E and SCE to expand their dynamic rate pilots. See Docket R.22-07-005, Expansion of PG&E and SCE System Reliability Dynamic Rate Pilots, cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/demand-flexibility-oir/pilot-expansion-2024.pdf.