Alliance for Transportation Electrification

Energizing EV Charging Stations

New and Flexible Approaches to Capacity Constraints

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Steering EV Policy in the States

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About ATE

The Alliance for Transportation Electrification (ATE) is North America's largest 501(c)(6) EV trade association representing over fifty member companies dedicated to expanding safe, dependable, affordable, and accessible electric transportation technology.

Attributions

This paper was supported and informed by members of the ATE Interconnection Task Force. The task force consists of over seventy members representing industry stakeholders with expertise in utility service connection processes. The Interconnection Task Force was formed to examine the process for connecting new EV load to the grid and explore and share innovation in this process from the utility, customer, and stakeholder perspectives.

Co-Chairs:

- Kathy Knoop, General Motors
- Rosalie Barcinas, Southern California Edison

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Executive Summary

Utilities have an obligation to deliver electricity to all customers within their service area who request service, as well as maintain high grid reliability in the distribution grid and charge affordable rates. When customers request a new service connection or an upgrade to an existing connection, utilities determine whether distribution system capacity exists at that location—and if not, they build sufficient capacity to serve that customer, typically without regard to customer load management or distributed energy resources.

Between electrification (including transportation electrification) and data centers, new loads are lining up rapidly to connect to the grid. Between the lengthy service connection queue and the distribution system upgrades that may be necessary to serve these loads, utility service connection timelines in many jurisdictions are stretching, delaying energization. Meanwhile, the investment forecasts associated with upgrading the grid over the next decades are beginning to mount.

This paper explores a range of solutions that utilities are pursuing to address these two challenges—the **time** and **cost** required to upgrade the distribution grid to serve a new customer.

Figure 1 shows the set of solutions explored in the paper.

Figure 1: New and Flexible Approaches to Capacity Constraints

Case studies highlight these solutions in action: tools, programs and offerings from utilities across the country, including Dominion Energy, Portland General Electric, National Grid, Southern California Edison, and Pacific Gas and Electric.

The paper concludes with recommendations for how utilities, and the Public Utility Commissions (PUCs) that regulate them, can explore and implement these solutions in their own jurisdictions. Figure 2 gives an overview of these recommendations.

Recommendations for Utilities

- Identify specific challenges
- Develop tailored solutions
- Evolve technologies, analysis and operational readiness
- Consider necessary tariff and rule changes
- Design for success
- Share data and learnings

Recommendations for Public Utility Commissions

- Proactively address the topic
- Accelerate your process and be flexible
- Support utility research and development
- Address cost allocation and recovery
- Obtain data and learnings
- Consider cost-effectiveness

Figure 2: Recommendations for Utilities and Public Utility Commissions

The Energization Challenge

Per the regulatory compact under which they operate, electric utilities are monopoly providers to an established service area, within which they are obliged to serve all customers. This obligation to serve means that utilities must build the electric grid to deliver the energy that customers require, along with any associated upstream grid investments such as distribution transformers, primary feeders, or substations. Another aspect of the regulatory compact is the responsibility to keep high reliability in the distribution network—making the engineering associated with such grid upgrades of utmost importance. Meanwhile, the role of regulation is to ensure that all of this happens in a way that manages costs to keep rates low for customers.

Figure 3 outlines, at a high level, the typical process that utilities follow to connect new or upgraded service for a particular customer. Figure 3 is a shorthand diagram that elides significant details in the energization process; for more information, see ATE's recent papers on this topic.[1]

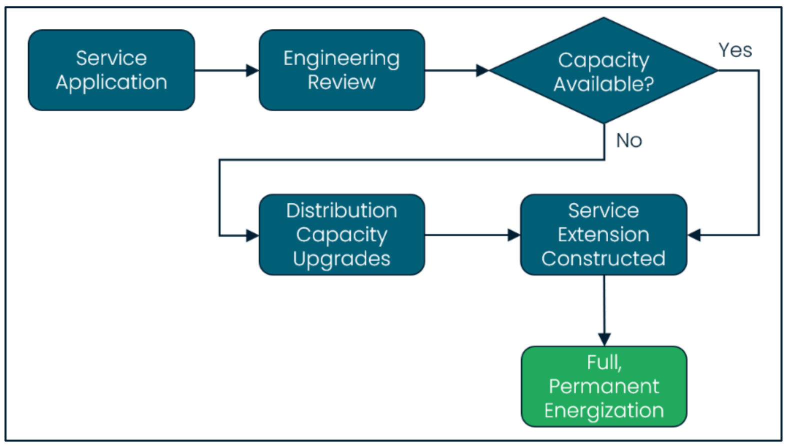

Figure 3: Typical Utility Service Connection Process

Following a service application by the customer, the utility conducts an engineering review to determine whether grid capacity exists at the location where the customer wishes to connect. If grid capacity exists, a service extension is constructed—a process that can take some time—and the customer's site is energized.

If grid capacity does not exist—due to a constrained substation, feeder or circuit, for example—then the utility must plan to upgrade these distribution system assets. This process can take from one to ten years, depending on the asset in question, and can cost several million dollars. Importantly, utilities across the country use different approaches to allocating the costs of service extensions and any associated grid upgrade costs between the connecting customer and all ratepayers. As will be discussed, these differences have

[1] Alliance for Transportation Electrification. Energizing EV Charging Stations: Overview of the Interconnection Process. March 2023. https://ate-ev.org/wp-content/uploads/2025/07/2023_ATE_Interconnection-Energization-Part-1_Overview.pdf

significant implications for the economic costs and benefits of the solutions discussed herein for connecting customers, the utility, and ratepayers.

Meanwhile, utilities and customers across the country are finding that the business-as-usual approach to connecting new load is increasingly insufficient in an era of rapid load growth, particularly for electric vehicle (EV) charging sites. Transportation electrification load differs from other load in several key ways that impact energization timelines:

- It can be power-dense (amount of capacity requested, as compared to site size);
- It can have a low load factor (average demand, as a percentage of maximum demand or nameplate capacity); and
- It often materializes on a much shorter timeline than similar amounts of building load, as it is faster to install EV chargers or procure EVs than it is to build a large new apartment complex, sports stadium, big-box store, or similar structure.

Increasingly, service connection timelines are a major impediment to transportation electrification. Accordingly, utilities are addressing more straightforward service extension delays through process improvements, stronger customer communication, and other solutions—and these approaches have a material impact. However, in areas where distribution grid capacity is constrained, some EV customers continue to face lengthy service connection timelines that do not meet their operational needs.

Table 1 shares some examples of constraints, triggering conditions, and potential solutions for each type of energization delay.

Table 1: Comparing Reasons for Lengthy Energization Timelines in Utility Service Connection Processes

	Distribution System Capacity Upgrades	Service Extension Construction
Purpose of Process	• Prepare to Serve Load	• Connect Load
Constraint Examples	• Substation Capacity • Feeder Capacity	• Transformer Availability[2] • Utility Personnel Bandwidth • Local Permitting Timelines
Triggering Conditions	• Energy-Dense Requests • Short Customer Timelines	• High Volume of Applications • Short Customer Timelines
Possible Timeline	• 1-10 years	• Up to 2 years
Potential Solutions	• Proactive Investment • Decision Support Systems • Bridge-to-Wires Solutions • Long-Term Load Flexibility	• Process Improvements • Pre-Ordering Equipment • Additional Personnel • Local Permitting Reform

[2] Alliance for Transportation Electrification. *Energizing EV Charging Stations: Supply Chain Delays and Utility Best Practices*. October 2023. https://ate-ev.org/wp-content/uploads/2025/07/2023_ATE_Interconnection-Energization_Part-2-Supply-Chain.pdf

Energization timeline delays carry risks for utilities, customers, and policymakers, as outlined in Table 2:

Table 2: Energization Risks for Utilities, Customers and Policymakers

Utility Risks	Customer Risks	Policymaker Risks
• Unmet customer expectations • Potential for canceled or lost projects, resulting in lost revenue	• Higher uncertainty and complexity • Rising soft costs (estimates are no longer valid, cost of materials change, projects may have to be rebid)	• Missed opportunity for downward rate pressure[3] • Weakened economic development • Slow electrification, potentially affecting state energy policy goals

In addition to timeline delays, when distribution system capacity is limited, utilities and their customers are faced with the costs it takes to construct the necessary upgrades. In recent analysis from the California Public Advocates Office, grid upgrades to support transportation and building electrification are estimated to cost at least $25 billion by 2040 in the service areas of California's three largest investor-owned utilities.[4] The study finds that the overall effect of electrification will put downward pressure on rates, but the volume of these costs—and the disparity in the managed versus unmanaged scenarios—highlight the importance of addressing costs in the distribution system and managing EV load.

[3] Alliance for Transportation Electrification. *Making Electricity More Affordable with EVs*. July 2025. https://ate-ev.org/wp-content/uploads/2025/07/ATE_Making-Electricity-More-Affordable-with-EVs_FINAL.pdf

[4] Public Advocates Office. *Distribution Grid Electrification Model 2025 Study and Report*. October 2025. https://www.publicadvocates.cpuc.ca.gov/-/media/cal-advocates-website/files/press-room/reports-and-analyses/251030-public-advocates-office-distribution-grid-electrification-model-2025.pdf

A NOTE ON PROACTIVE INFRASTRUCTURE INVESTMENT

Proactive infrastructure investment is an emerging approach whereby the utility proactively builds distribution grid capacity in areas that are forecast to see rapid load growth within a given time horizon. This approach—and regulatory frameworks to govern its use—is under exploration in states such as Minnesota and Colorado, with proactive utility investments recently authorized by Commissions in California, New York, and Massachusetts.

Proactive investments allow the utility to build out the grid ahead of need, and these investments are based on robust analysis and forecasting to protect ratepayers from the risk of stranded assets. Utilities proposing proactive investments engage in extensive, bottom-up electrification load forecasting and scenario planning, along with a rigorous approach to knitting known or projected customer loads into the existing top-down forecasts that are used in traditional system-wide resource planning. This process helps identify least-regrets investment areas.

In addition to helping alleviate the timeline delays increasingly associated with the reactive grid construction approach, proactive infrastructure investment has the potential to address some of the costs associated with developing the grid. For example, research by the Environmental Defense Fund (EDF), drawing on detailed data from CenterPoint Energy in Texas and Con Edison in New York, projected that a reactive, piecemeal distribution grid upgrade approach will result in higher long-term costs for ratepayers than well-planned, deliberate, and proactive investment.

But proactive infrastructure investment is designed to mitigate tomorrow's problems; it does not address distribution capacity constraints that affect customers currently in the service connection queue. Proactive infrastructure investment is a complementary approach to the solutions explored here, which address the challenges of time and cost of distribution capacity upgrades at the time of a service application from a customer.

Solution Overview

Fortunately, while load growth is increasing, technology is changing to give utilities and their customers better forecasting of, insight into, and control over real-time site and grid conditions. Because of this trend, there are many emerging and potential utility solutions to these two challenges of the energization process: the **time** and **cost** required to upgrade the distribution grid to serve a new customer.

Solution Categories

Broadly, utility solutions fall into three categories, which are described briefly here and then in more depth in subsequent sections:

Decision Support Systems

This category contains customer-facing and/or analytical tools that can help utilities and their customers more quickly, precisely and affirmatively answer the question of whether grid capacity is available at a site:

- **Hosting capacity maps** can help customers find places on the grid that have existing capacity, potentially guiding their operational planning and service applications.
- **Advisory services**, especially with fleet customers who are seeking to electrify, can open lines of communication early and help customers find good locations and right-size their service applications to the actual operational capacity they will need.
- **Capacity checks** are pre-application, fee-based engineering reviews that utilities can perform to help a customer understand existing grid capacity before they complete the design and engineering work required to submit a service application.
- **Service sizing refinements** leverage new data and analytics to adjust some of the assumptions that are used in the engineering and design process, increasing the likelihood that grid capacity is determined to be available.

Bridge-to-Wires Solutions

Bridge-to-wires solutions, currently piloted in a handful of jurisdictions, are solutions that support partial or temporary energization of a site while the utility builds longer-term grid infrastructure:

- **Mobile assets**, such as utility-owned mobile batteries or mobile substations, can be deployed to customer sites as needed on a temporary basis while permanent grid infrastructure is sited and deployed.

- **Phased service connection** is a project management approach where the service connection increases stepwise over time as the utility builds grid capacity and the customer installs incremental chargers.
- **Static flexible service connections** offer the customer schedule-based capacity limits during the bridging period. The customer can implement behind-the-meter solutions, including distributed energy resources (DERs) to remain within the limits and still meet their business needs.
- **Dynamic flexible service connections** use a more granular approach to establishing operating limits—such as sending day-ahead signals to the customer with hourly limits.

Long-Term Load Flexibility

Long-term load flexibility includes static and dynamic approaches that are implemented over the long term, which can help the utility and participating customers maximize use of the existing grid, deferring both the need for specific grid upgrades and the costs associated with them. While these approaches are not yet offered in the U.S. market, and individual customers' interest in participating in them may vary, many parties envision a future where they are routinely offered as an option to customers, with compensation for participation.

Comparing Solutions

It is important to bear in mind that these solutions are not created equally: they are designed to address different challenges, are at varying levels of market maturity as utility offerings, and have different costs and risks associated with implementation.

In addition to implementation costs, grid upgrade cost allocation methodology differences between utilities have an impact on how these offerings will be received by customers. The primary motivation for a connecting customer to opt into a bridge-to-wires solution is a faster energization timeline, and the value of the faster timeline must outweigh the costs of the on-site solutions and operational impacts of participating. For long-term load flexibility in jurisdictions where distribution system upgrade costs are allocated primarily to the connecting customer, that customer may be highly motivated to consider a long-term load flexibility solution that reduces their costs—so long as it meets their operational needs—or they may need an incentive to reconcile the economics. Jurisdictions where upgrade costs are more socialized among ratepayers may need to provide higher incentives for long-term load flexibility, to compensate for the on-site technology costs and the loss of operational flexibility. In all cases, utilities should acknowledge that some customers will never be interested in these approaches due to their operational impacts, and offer them as options, considering both value and compensation for the customers who opt into them.

To navigate this landscape, utilities and regulators must define the challenges they're trying to solve as well as the costs and risks they are willing to take on to solve them; consider value for the grid and the customer; and remain mindful of the potential complexity of implementing utility program solutions that are not yet market-tested at scale. Table 3 shows the differences between these solution categories, and these differences will be explored further in subsequent sections.

Table 3: Comparison of Capacity Constraint Solution Categories

	Decision Support Systems	Bridge-to-Wires Solutions	Long-Term Load Flexibility
Speeds Energization Timeline	●	●	●
Avoids Utility Implementation Costs	◕	◑	◔
Avoids Customer Implementation Costs	●	◑	◑
Reduces Capacity Upgrade Costs	◔	○	●
Market Maturity	●	◔	○

Fortunately, these solutions are not mutually exclusive, and utilities can start with easier solutions while endeavoring to move up the maturity curve to more sophisticated approaches. Many customers taking advantage of the most advanced options have also been beneficiaries of the most basic options. Addressing the costs and timelines associated with building a connected, dynamic grid to support an electrified future will require an all-of-the-above strategy.

A NOTE ON CUSTOMER-SITED DISTRIBUTED ENERGY RESOURCES

In addition to the utility-offered solutions discussed above and explored further throughout the paper, customer-sited DERs can mitigate the risks associated with long energization timelines, providing resilience and reliability for customers while supporting grid reliability. This solution can serve a dual purpose of speeding energization and helping lower the overall burden on the grid and adding high-value local generation to the supply stack, contributing to energy affordability. This solution is applicable both as a bridge-to-wires solution and as an approach that supports long-term load flexibility. If used as a bridge-to-wires solution, once the customer is fully energized the DER may become a valuable resiliency solution for the facility that can provide services back to the grid.

Solution Deep Dive: Decision Support Systems

The most straightforward opportunities for utilities to pursue are tools and systems that help utilities and their customers work together to more quickly, precisely and affirmatively determine whether grid capacity is available at the customer's desired location. Several of these approaches have been covered in prior ATE papers,[5] along with recommendations for other entities that are part of this process, such as customers, developers, regulators and local governments. The Electric Power Research Institute (EPRI) also recently issued a paper focused on EV charging for small fleets and multifamily housing, which proposed forty-four solutions to help enable an accelerated service connection process for smaller customers, some of which are also captured here.[6]

Hosting Capacity Maps

Publicly available hosting capacity maps provide information to potential developers and site hosts on where grid capacity is available to host charging stations, to help in the site selection process. These maps, offered by many utilities around the country, visually demonstrate with color coding the areas where analysis indicates capacity is either available or limited. Because use of the grid changes rapidly, hosting capacity maps are a snapshot in time. This means they must be updated on a regular schedule, and they should not be the basis for final customer decisions.

Some utilities are reluctant to offer such maps, because they are costly to maintain; can become outdated quickly; can be misinterpreted; and have the potential to present security risks. Most hosting capacity maps were developed to support interconnection of DERs and lack insight into the load queue, meaning they are less well-suited to forward-looking evaluation of load additions. And hosting capacity maps are not a replacement for tailored advisory services or a more detailed engineering review. Yet with these caveats and appropriate security safeguards, more utilities are beginning to make these maps publicly available. EPRI offers eRoadmap, a public-facing tool that integrates vehicle demand forecasts with hosting capacity data from utilities around the country.[7] And Atlas Public

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[5] Alliance for Transportation Electrification. *Energizing EV Charging Stations: The Pre-Planning Process*. March 2024. https://ate-ev.org/wp-content/uploads/2025/07/2024_ATE_Interconnection-Energization-Part-3_PrePlanning.pdf

[6] Electric Power Research Institute. *A Grid Connection Roadmap for Utilities to Support Small Electric Vehicle (EV) Customers*. April 2025. https://www.epri.com/research/products/000000003002031160

[7] Electric Power Research Institute. *eRoadMAP*. Accessed October 2025. https://eroadmap.epri.com/

Policy has summarized best practices in hosting capacity maps for utilities, such as including available capacity for on- and off-peak demand periods.[8]

Case Study: Dominion's EV Capacity Map (VA and NC)

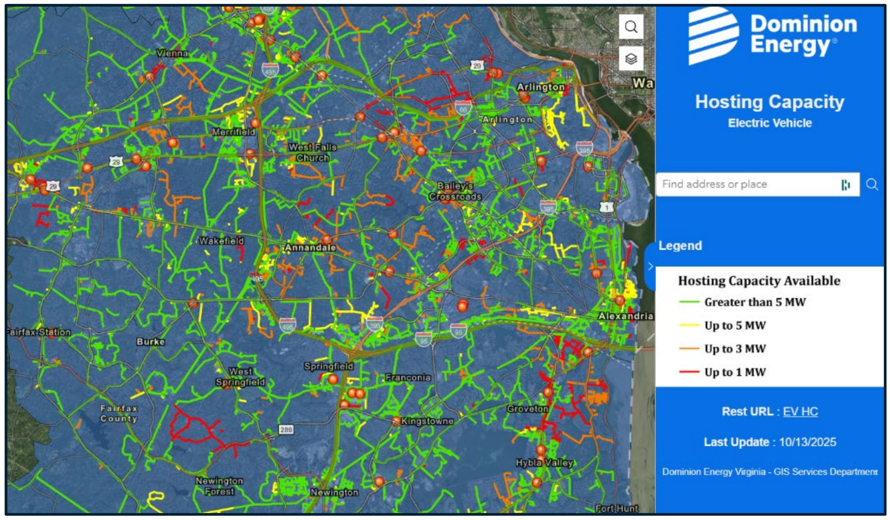

Figure 4: Dominion Energy - EV Capacity Map

Dominion Energy had hosting capacity maps for customers to assess sites for additions of residential and utility-scale solar, but the team recognized that these tools weren't well-suited to additions of load. They leveraged their prior experience to proactively develop an EV capacity map[9] that helps customers select appropriate sites with sufficient capacity for EV load. They worked with their internal asset management and GIS teams to collect data sets on distribution system assets such as substations, feeders and circuits. Dominion included layers for Alternative Fuels Corridors and existing DC fast charging sites (to support customers in selecting National EV Infrastructure [NEVI] sites) and environmental justice layers (to help customers understand which sites are eligible for enhanced EV program incentives from the utility). Dominion can also pull in public GIS layers from elsewhere, adapting the map to their customers' evolving needs. Importantly, the map displays a forecast of capacity that includes data and projects from Dominion's energization queue—avoiding a common concern with hosting capacity maps, which is that they may display capacity that is already "reserved" by a queued customer. Updating the EV capacity map is a significant undertaking—the data processing alone takes 15 days—so Dominion updates the map quarterly. Overall, the EV capacity map helps Dominion share more granular information tailored to EV charging, proactively engaging with their customers to help guide decision-making and identify areas of capacity where EV charging could be most cost-effectively integrated to the grid.

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[8] Atlas Public Policy. *Hosting Capacity Maps for EV Charging*. December 2024. https://www.atlasevhub.com/wp-content/uploads/2024/12/Final-Report-Hosting-Capacity-Maps-for-EV-Charging-1.pdf

[9] Dominion Energy. *Electric Vehicle (EV) Capacity Map Tool. Accessed October 2025*. https://www.dominionenergy.com/about/delivering-energy/electric-projects/ev-capacity-map

Advisory Services

Increasingly, utilities offer advisory services to customers that seek to install EV charging.[10] This offer is typically directed at vehicle fleets in the utility service area, but other customers (multifamily dwellings, commercial charging providers, etc.) may also want to take advantage of such services. Consultations typically take place prior to a customer submitting a service application, but utilities should also structure their offerings to take place afterward, if needed.

These consultations typically include assessments of infrastructure needs, financial analyses including bill impacts, and incentive opportunities. For fleets, advisory services can include assessments of vehicle type and use case, total cost of ownership, and charging infrastructure optimization.

Offering advisory services helps utilities maximize use of the existing grid and streamline customer service connections. Utilities can support customers in assessing their overall site capacity needs—which may be far less than the summed nameplate capacity of the EV chargers they plan to install—and help walk through the pros and cons of options such as automated load management, on-site DERs, or flexible service connections. These discussions may guide a customer toward on-site solutions that obviate the need for a grid capacity upgrade. Even absent a grid constraint at the customer's location, these options may help customers mitigate the impact of demand charges or optimize their charging to a time-of-use rate schedule, keeping their overall bill lower. Utilities can identify candidates for these services through channels such as EPRI's GridFAST tool, a central portal to connect businesses and utilities early to help proactively plan and accelerate EV charging projects.[11]

Advisory services also help utilities pinpoint new load and forecast where and when it will arrive, supporting overall planning efforts. In some jurisdictions, utilities formally integrate customer-specific data into their planning prior to a formal service application, either as incremental load or as a way of disaggregating existing load forecasts (or both). With appropriate scenario planning and other guardrails, this bottom-up approach can support proactive infrastructure investment.

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[10] Alliance for Transportation Electrification. *Fleet Advisory Services (FAS) for Fleet Electrification: Meet Customer Needs and Provide Grid Benefits*. February 2023. https://ate-ev.org/wp-content/uploads/2025/07/2023_ATE_EC_Utility-Program-Design_Fleet-Advisory-Services-Case-Studies.pdf

[11] Electric Power Research Institute. *GridFAST*. Accessed October 2025. https://www.gridfast.com/about

Case Study: Portland General Electric's Fleet Partner Program (OR)

Portland General Electric (PGE) launched its Fleet Partner program[12] *in 2021. The program has two participation phases: a Plan phase, where PGE assists the customer with an EV feasibility assessment, vehicle operations and charging analyses, fuel cost and Clean Fuel Program analysis, design and cost estimates, and an incentive summary, delivered in a comprehensive Fleet Partner Study; and a Build phase, where PGE provides turnkey final site design and construction. As of November 2025, 99 customer sites had completed the Plan phase, and 27 customer sites had completed the Build phase. Evaluation reports reveal that participants highly value the "one-stop shop" aspect of the technical assistance provided by the program.*[13]

The data that PGE has access to through Fleet Partner—including nearly 400 ports' worth of charging session data—is valuable, as well. The utility can assess charging load shapes for a variety of fleet and vehicle types. These load shapes are being used to update PGE's EV load forecasting model, and available information about potential fleet electrification plans is formally used as an input the company's DER forecasting model (AdopDER), which informs distribution system planning.[14]

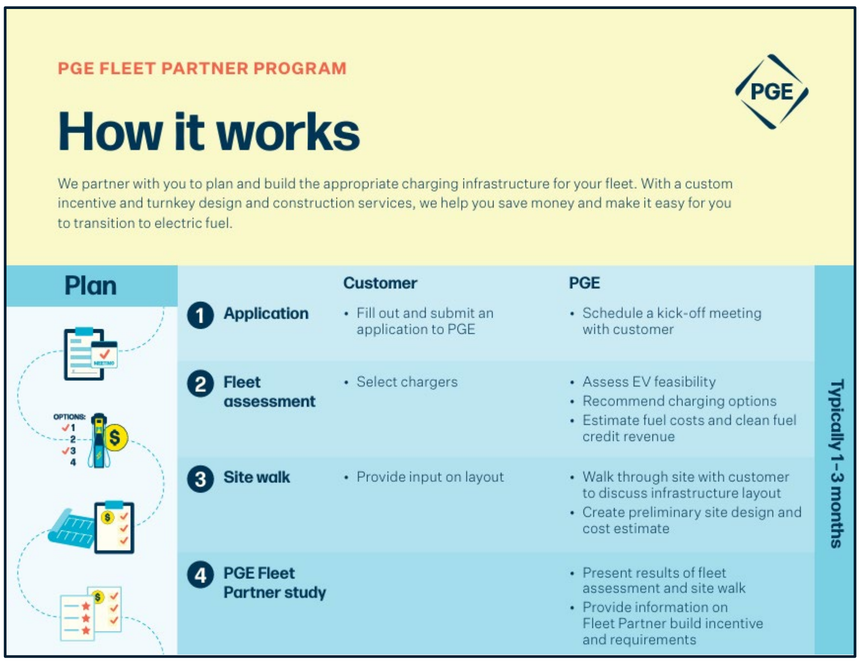

Figure 5: Portland General Electric - Fleet Partner Plan Phase

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[12] Portland General Electric. *PGE Fleet Partner Program*. Accessed October 2025. https://portlandgeneral.com/energy-choices/electric-vehicles-charging/business-charging-fleets/fleet-partner

[13] Portland General Electric. *2024 Transportation Electrification Plan Report*. May 2025. https://edocs.puc.state.or.us/efdocs/HAQ/um2033haq336533034.pdf

[14] Portland General Electric. *Distribution System Plan*. December 2024. https://downloads.ctfassets.net/416ywc1laqmd/6fsVybjYRmGNV4M7PwBOl2/c9ffcaa9e432ea82d67e6359c24c76ac/2024_PGE_DSP_2024_12_18.pdf

Capacity Checks

Even in jurisdictions with hosting capacity maps and advisory services, evaluating the grid capacity at a specific site requires a detailed utility engineering review. This is costly and time-consuming for the utility, so it is typically only conducted after a service application is received from a customer. However, completing a utility service application requires a substantial amount of costly engineering work on the customer's side, as well, all of which can be wasted if the selected site turns out to need capacity upgrades during the subsequent utility review. To address this information asymmetry, some utilities have begun offering a capacity check option. This pre-application, fee-based service involves utility engineers conducting the same capacity analysis they would do after a service application, so the customer has a real indication of capacity at the site (or multiple sites) before they continue their design and engineering work.

Utilities developing a capacity check offering should consider how to standardize the offer, including customer eligibility, fees, internal personnel capacity, and timeline for delivering results.

Service Sizing Refinements

Historically, utility distribution planning presumed that a connecting customer would use all their requested capacity, and at the exact wrong time—when the parts of the grid that serve the site are already most constrained. And the distribution engineering studies were typically based on the nameplate capacity of the equipment at the site. This "worst-case" planning approach addresses the utility's fundamental obligation to maintain reliability, but it can result in estimation of capacity constraints which may not exist in real-world conditions.

Increasingly, utilities are using sophisticated tools and data analytics—and communicating more actively with their customers—to consider whether there are refinements to the methods for calculating service size that might enable service connections in grid-constrained locations without threatening reliability. In this approach, utilities leverage data from current customers to hone the load profiles and more granularly assess the load diversification of the connecting customer. Of course, utilities exploring this approach must carefully balance the opportunity to increase grid utilization with risks to system reliability.

As a practical matter, if service size calculation processes are documented in formalized service connection rules and approved by PUCs, utilities may need to consider whether changes to these rules are needed to support a different approach. Utilities should also harmonize their approach to individual service connections with their broader planning assumptions for the distribution system.

Solution Summary

The advantage of these decision support tools and approaches is that they can help utilities and their customers “get to yes” more frequently, taking better advantage of existing grid capacity. Given the wealth of data and information available to many utilities today, implementing these solutions is more attainable than ever. But collecting, integrating, analyzing, and operationalizing such data takes time and resources, and smaller utilities, in particular, may struggle to justify the costs of such investments. These approaches can also require significant cultural shifts within the utility, away from business-as-usual and into a more open, collaborative, communicative, customer-centric, and risk-tolerant way of operating.

Some stakeholders do not believe that these tools go far enough toward meeting customers’ needs in a timely way, and advocate for more standardization in the utility service connection process across service areas and jurisdictions, along with service level agreements around timelines and greater process transparency (e.g. defined roles and responsibilities, and online project management portals to coordinate tasks within the energization process). Some of these approaches have been deployed by a handful of utilities already, but their use is far from universal.

Figure 6 shows how these decision support systems fit into the overall service connection process, where they influence the determination of whether grid capacity is available or not.

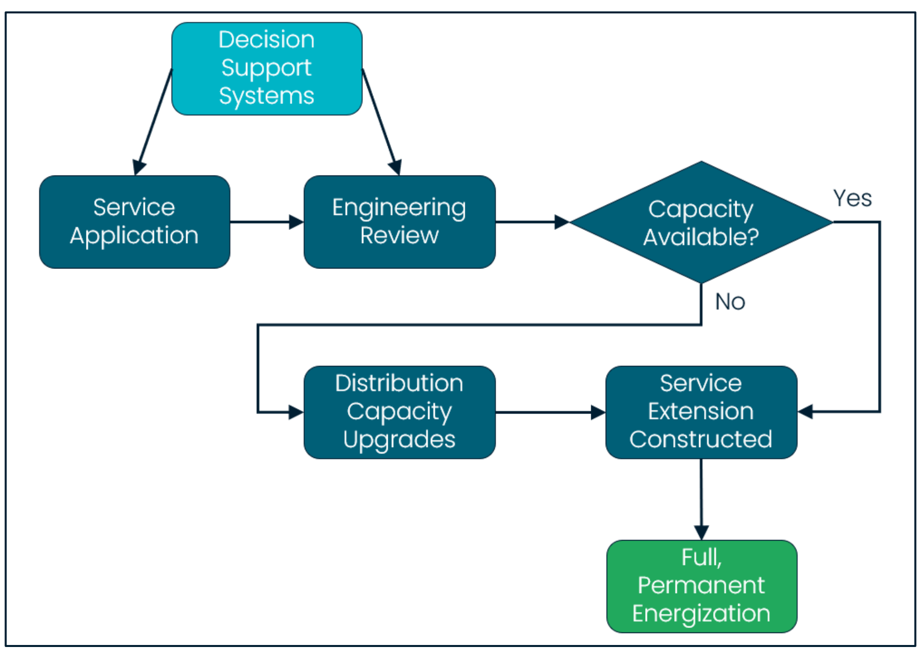

Figure 6: Utility Service Connection Process with Decision Support Systems

Solution Deep Dive: Bridge-to-Wires Solutions

Bridge-to-wires solutions—called “bridging solutions” or “bridging strategies” in some jurisdictions—are emerging measures that can support partial or temporary energization of a site while the utility builds longer-term grid infrastructure. Today, these solutions are only implemented in a handful of jurisdictions, but are of increasing interest to utilities, customers and regulators seeking to address lengthy energization timelines and bring load to the grid faster.

Because these solutions are largely in pilot phase or limited deployments today, data on implementation and lessons learned are scarce, but should materialize in the coming months and years.

Mobile Asset Deployment

Mobile assets, such as utility-owned battery energy storage systems (BESS) or mobile substations, can be deployed at or near customer sites to create near-term capacity while permanent grid infrastructure is constructed on a longer timeline. For example, BESS can discharge when load exceeds the limit on a capacity constrained circuit and charge when load on the circuit is low, essentially increasing the load that can be connected to that circuit. A mobile substation is a fully functional trailer-mounted substation that can make a localized connection directly to a sub-transmission line and resolve larger-scale grid constraints. Once the customer is fully energized, the utility is free to move the mobile assets to a different customer site, extracting maximum value out of the utility’s investment and avoiding the risk of stranded assets.

One of the advantages of mobile assets is that they are transportable and modular, making them flexibly useful in a variety of applications. And if they are no longer needed to support customer energization, they could be applied in secondary uses such as peak load management, reliability enhancements during planned and unplanned outages, or as back-up power for critical infrastructure.

Mobile assets are not appropriate for all sites—for example, load shape on the circuit must be able to accommodate the asset without introducing new constraints or violations; there must be physical space for the assets; and the provided capacity must be able to accommodate partial or full energization of the customer. Temporary batteries lack precedent with permitting authorities, meaning local permitting processes and timelines can be very challenging. Mobile assets can be capital-intensive and technically complex, and come with ongoing costs relating to deployment, operations and maintenance, and removal and redeployment. There is also the question of cost allocation for mobile assets, and whether costs should be borne by ratepayers or by the individual customers that are impacted. Because they are a capital-intensive investment, mobile assets face limits to their scalability within a utility's portfolio of solutions.

Case Study: National Grid's Mobile Battery Energy Storage Systems (NY)

In New York, National Grid received approval[15] from the Public Service Commission (PSC) to procure, own and operate mobile BESS at three New York Thruway travel plazas to alleviate constraints relating to vehicle electrification and charging. While the batteries are in use, National Grid will build sub-transmission service as a long-term solution to the constraint. At one location, National Grid estimates that mobile BESS, coupled with a small reconductoring project, will provide the travel plaza with an additional 4 MW of capacity during peak times (2 MW from the batteries and 2 MW from reconductoring).[16] The approved $21.6 MM project scope includes the cost of the batteries, site work, and costs relating to interconnection of the batteries. The batteries are sized to offer significant deployment flexibility to the utility—once the distribution capacity is upgraded, National Grid plans to redeploy the batteries to other constrained sites as needed. Other potential use cases for the batteries include peak shaving, emergency power, event support, and ancillary services such as voltage regulation.

The mobile BESS proposal was included in National Grid's Urgent Upgrade Projects filing within New York's Proactive Planning docket and was approved in June of 2025. The utility is projecting an in-service date of December 2026. National Grid is in close communication with New York Thruway and its travel plaza vendor, and the timeline meets their forecasts of when additional capacity will be needed.

Phased Service Connections

Phased service connections, sometimes referred to as staggered grid connections, offer customers a temporary capacity limit for their site while distribution system capacity is constructed to serve their full request.

With adequate planning and communication, it is possible that investments on the customer and utility sides of the meter can be built in matching phases such that the customer's full nameplate capacity can be provided at any given time. For example, a fleet

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[15] New York Public Service Commission. *Order Addressing Urgent Upgrade Filings*. July 12, 2025. NY 24-E-0364. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={F05F6597-0000-C17B-B068-916CB5B91D67}

[16] National Grid. *Urgent Upgrade Projects*. November 13, 2024. NY 24-E-0364. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={60862793-0000-C755-99D5-45B99DF5AC13}

or charging provider that plans to phase in vehicles or charging infrastructure over time may have a long-term plan for significant capacity but may not need all that capacity in the near term. Even if the utility can only provide a portion of the needed capacity temporarily, it's possible that the fleet can use charge management systems to manage their load below the capacity limit.

EPRI identifies that phased service connections that rely on existing site power are most appropriate when the load increase to support EV charging is incremental (less than the existing site power) versus transformative (more than the existing site power), because on-site work may be the only near-term upgrade needed to provision new EV chargers.[17]

Many stakeholders are urging utilities to employ phased service connection—which requires limited investments on the part of the utility, compared to other bridging solutions explored here—as soon as possible.

Case Study: Greenlane's Colton Site (CA)

In April of 2025, Greenlane—a joint venture of Daimler Truck North America, NextEra Energy, and BlackRock Alternatives—opened its flagship public medium- and heavy-duty EV charging site in Colton, California. The site was completed eight months after breaking ground and includes 12 pull-through charging stalls for large trucks, equipped with 400 kW dual-port chargers, along with 29 220 kW "bobtail" charging stalls for trucks without attached trailers.

Today, Greenlane uses a charge management system to keep demand below the current 4 MW capacity at the site. But the site is physically configured to accommodate many more chargers, and Greenlane plans to expand the site up to 12 MW in the near future. Greenlane worked closely with the City of Colton Electric Utility, the small municipal utility that serves the site, to match near-term need and availability to get the site constructed, as well as put plans in place for the longer-term capacity upgrades that will be needed to serve the site its full demand. Greenlane selected the site not just for its location at the intersection of I-215 and I-10, but also due to the municipal utility's willingness and ability to deliver the necessary near-term power within Greenlane's timeframe.

Figure 7: Greenlane's Colton Site

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[17] Electric Power Research Institute. *Interim Service Solutions and Timely Grid Connections for Large Transportation Electrification Projects*. July 2024. https://www.epri.com/research/products/000000003002030647

Flexible Service Connections

In some cases, the utility's engineering review indicates while the customer's requested capacity is not available during each of the 8,760 hours of the year, it *is* available for many or even most of those hours. In these cases, flexible service connections can be considered. Flexible service connections can be divided into two types: static (capacity availability changes according to set schedules), and dynamic (capacity availability is calculated and communicated on a more granular schedule).[18]

Broadly, flexible service connections (FSCs) give utilities the ability to more quickly energize a customer's new load on the distribution system, with variable limits placed on the import of electricity at certain times that enable the customer to access capacity for more hours than a phased service connection. These limits are typically documented between the utility and the customer in an FSC agreement (not necessarily a tariff). Customers who agree to FSCs can have their sites energized faster, which can be a significant benefit to their business. The customer can implement behind-the-meter solutions such as automated load management or DERs to remain within the limits and still meet their business and operational needs. While the customer equipment used to adhere to the capacity limits can be like what customers use to participate in traditional managed charging programs, an FSC differs in that the load limit can be contractually enforced.

A NOTE ON POWER CONTROL SYSTEMS

Depending on the terms of the FSC agreement, a customer may be required to use a power control system (PCS) at their site. PCS is a combination of hardware and software that monitors the loads at a site level, regulating or limiting power at connected devices to remain within a specified limit. This can involve a single device, or a complex array of devices working together. PCS differs from an energy management system (EMS) because it focuses on load control and safety versus optimizing energy usage and reducing customer energy costs. A PCS can now be certified to UL 3141, a recently finalized standard that supports safety and reliability within these systems. However, UL 3141 is certified at the system level rather than the component level (software, firmware, hardware), making certification bespoke, complex, and costly. While UL 3141 certification may offer some real advantages to utilities and their customers, requiring certification may make program participation cost-prohibitive for some customers, especially if the solution is only in place temporarily.

[18] For more, see Electric Power Research Institute's one-pager, *Flexible Interconnections – A Customer Reference for Two Utility Approaches*, at https://www.epri.com/research/products/000000003002033890

Static Flexible Service Connections

Static FSCs mean the capacity limits are "firm," or documented in the FSC agreement and do not change for the duration of the agreement, though the capacity limits can be variable (changing between established limits hourly, seasonally, or both).

Utilities face various considerations when designing static flexible service connection offerings. For example, the granularity of the load limits: today, utilities offer between two and six operating limits. Some stakeholders suggest that more operating limits could enable customers to meet their needs more flexibly, while others caution that large gaps between firm and maximum capacity, or certain hours of zero capacity, might create operational challenges for certain customers and should be avoided. What is clear is that it is important to balance the grid and customer value that a more granular approach can offer with the added operational complexity and associated risks that it might present, such as non-compliance or non-participation. Utilities should also consider the level of education and modeling that may be required for a customer to be sufficiently informed to sign, and adhere to, the FSC agreement.

For utilities and regulators interested in exploring flexible service connections, static FSCs, used as a bridge solution, are a natural starting point. Static FSCs can be used to speed energization timelines and may offer operating schedules that are straightforward for EV charging sites to implement. But it is also clear from the case studies below that implementation faces barriers to scale, and even within the same jurisdiction, utilities demonstrate significant differences of approach.

Case Study: PG&E's Load Limits (CA)

In California, PG&E offers a static flexible service connection in the form of a variable load limit to customers requesting capacity in constrained areas. Load limits are offered to customers when distribution substation or primary distribution upgrades are necessary, and they allow PG&E to accelerate customer energization while longer-term upgrades are developed. PG&E alerts the customer to their eligibility with a non-contractual notification letter as part of the service connection process. The letter outlines the amount of load that can be served under current system constraints, along with the anticipated timeline for completion of system upgrades. Load limits are voluntary, but customers who decline them need to wait for system upgrades to be complete before they can connect to the grid.

PG&E's load limits are temporary, and only valid for a specified period. The limit applies at the point of connection, and the customer has discretion as to how to accommodate the limit (i.e., no specific technology is required). In some cases, PG&E allows customers to request temporary increases, such as for special events or holiday peaks, so long as these *requests are made within a typical weather forecasting window so the utility can evaluate whether the temporary increase would risk grid stability.*

PG&E engineers manually design each limited load profile (LLP), tailoring them to the customer, their expected usage, and existing grid conditions and forecasts. The limits are set such that a customer's failure to comply might result in exceeding the normal ratings of the equipment, but not the short-duration emergency ratings. Some sites have protective equipment that will trip before emergency ratings are exceeded, de-energizing the customer. To avoid overcommitting constrained infrastructure, PG&E only offers a load limit to one customer per capacity-constrained asset.

PG&E uses a layered approach to enforce customer compliance, consisting of customer education; automated monitoring with manual review; customer-specific or system-level protection equipment; and manual de-energization as a last resort. PG&E has successfully implemented load limits without modifying any existing rules, regulations, or tariffs.

PG&E has reported that more than one hundred customers are currently load-limited within their service area.

Case Study: SCE's Load Control Management System Pilot (CA)

Also in California, Southern California Edison (SCE) offers a different approach to static flexible service connections in the form of its Load Control Management System (LCMS) Pilot. SCE offers the LCMS program to customers if the energization engineering review determines that off-peak capacity is available. Today, LCMS is used as a static FSC based on limits programmed onsite, but SCE expects that it will eventually evolve to a dynamic program once the utility's distributed energy resource management system (DERMS) is deployed.

Distinct from PG&E's load limit, SCE's LCMS pilot does require the customer to install a PCS. With the recent finalization of UL 3141, SCE will phase in a requirement that the PCS be certified to that standard.

SCE's LCMS schedule lays out "on-peak" restrictions and associated "on-peak restriction timeframes" for summer, spring and winter (giving the customer a total of 6 operating limits per year). The utility applies a 5% load buffer to the capacity-constrained asset, to protect the grid if the customer's PCS fails to operate as intended or if the actual load of other customers on the asset is higher than projected. Like PG&E, SCE only offers LCMS to one project per constrained asset, on a first-come, first-served basis.

SCE plans to offer LCMS to up to 15 customers through the end of the pilot period (January 2026). SCE reports that six participants have enrolled in LCMS (five EV customers and one *non-EV customer), with an additional 3 participants awaiting their initial energization. Of the participants, four remain active in the program, and the other two have exited the program because their long-term grid upgrades have been completed. Given these successes, SCE plans to seek an extension of the LCMS pilot with the Commission.*

Dynamic Flexible Service Connections

A more advanced approach, dynamic FSCs, are emerging as an area of interest for utilities, customers, and regulators. In addition to the firm capacity laid out in an FSC agreement, dynamic FSCs use real-time grid information to communicate incremental, “non-firm” capacity availability on a more frequent and granular basis. As practiced today, this arrangement requires equipment and technology on both sides of the meter that can establish, communicate, and adhere to these limits:

- Supervisory Control and Data Acquisition (SCADA) equipment on the constrained distribution asset, to gather and analyze real-time data;
- Advanced Distribution Management System (ADMS), to provide operational connectivity and forecast available capacity;
- Distributed Energy Resource Management System (DERMS), to dispatch limit schedules to the customer’s site; and
- Power control systems (PCS) at the customer’s site, to accept the limit schedules and apply them to the customer-sited equipment.

The advantages of dynamic FSCs are that they enable the customer to operate their site at or near full capacity for more hours of the year than static FSC. However, to capture that value, this approach requires significantly more investment from the customer and the utility. Today, this approach is piloted at a single utility in the United States, though several other utilities are exploring their own pilots.

Case Study: PG&E’s Flex Connect Pilot (CA)

Flex Connect is a pilot offered by PG&E that provides dynamic operating limits to load and/or generation customers based on day-ahead forecasted grid conditions. It is implemented as a temporary, bridging solution, and relies on use of PG&E’s enterprise DERMS. In contrast to the load limits in PG&E’s static FSC approach, where the limits are based on a multi-year forecast, dynamic limits in Flex Connect are instead based on day-ahead forecasts and real-time loading conditions and communicated via the DERMS. This approach helps unlock significant additional load-serving capability for customers. PG&E is also exploring the use of Flex Connect to send real-time emergency control signals.

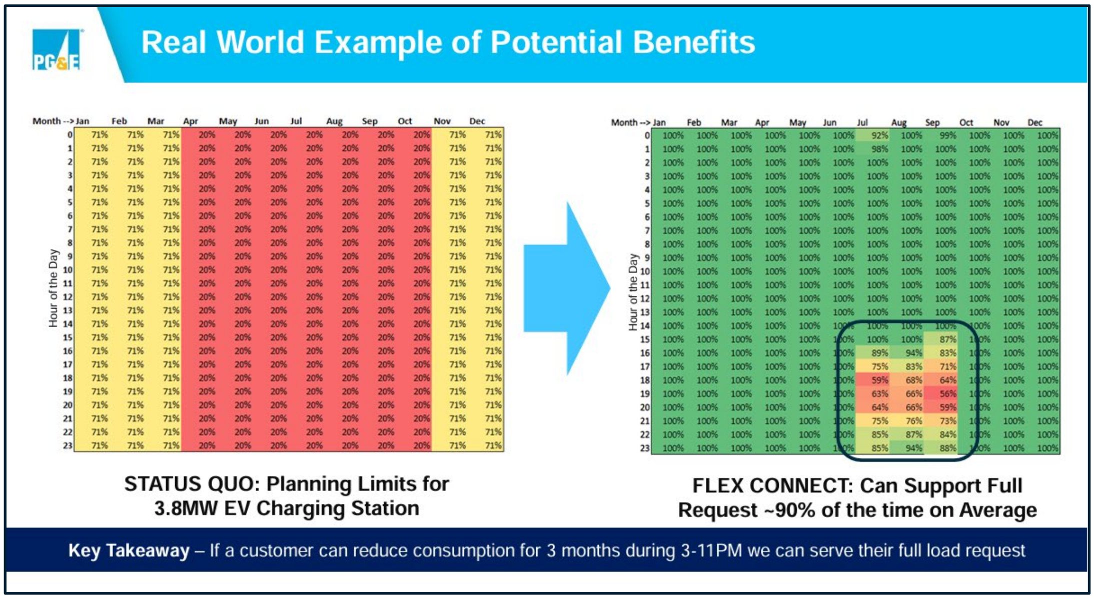

Figure 8: PG&E's Flex Connect capacity availability vs. status quo planning limits.

PG&E offers Flex Connect to customers who are load-limited, meaning that Flex Connect customers operate within a firm capacity limit and then have the opportunity for additional capacity up to the non-firm limit (the rated capacity of the site) per an amendment to their load limit agreement. Flex Connect is a good fit when a customer is projected to have limited hours or days of the year when they operate at peak, with significant off-peak capacity available at the site. PG&E is evaluating improvements in the new business process to more proactively identify customer sites that may be good candidates for Flex Connect.

Flex Connect equipment at the customer site is customer-owned and must use the IEEE 2030.5 smart grid communication standard to adhere to limits, respond to failsafe events, and provide telemetry to PG&E through the DERMS platform. Customer costs for such equipment are estimated at $20,000-$90,000. To make Flex Connect participation attractive, customers must be able to adjust their load, and the value to the customer of the added capacity must outweigh the associated costs to implement the customer-side requirements. For this reason, PG&E acknowledges that Flex Connect is a better fit for larger customers who can recoup technology investment costs more quickly through higher utilization.

PG&E reports having 23 projects signed on to Flex Connect, most of them EV sites, with an additional 12 projects under review each month. Figure 9 shows the interplay of the equipment, technology, standards, and communication protocols that PG&E uses to implement Flex Connect.

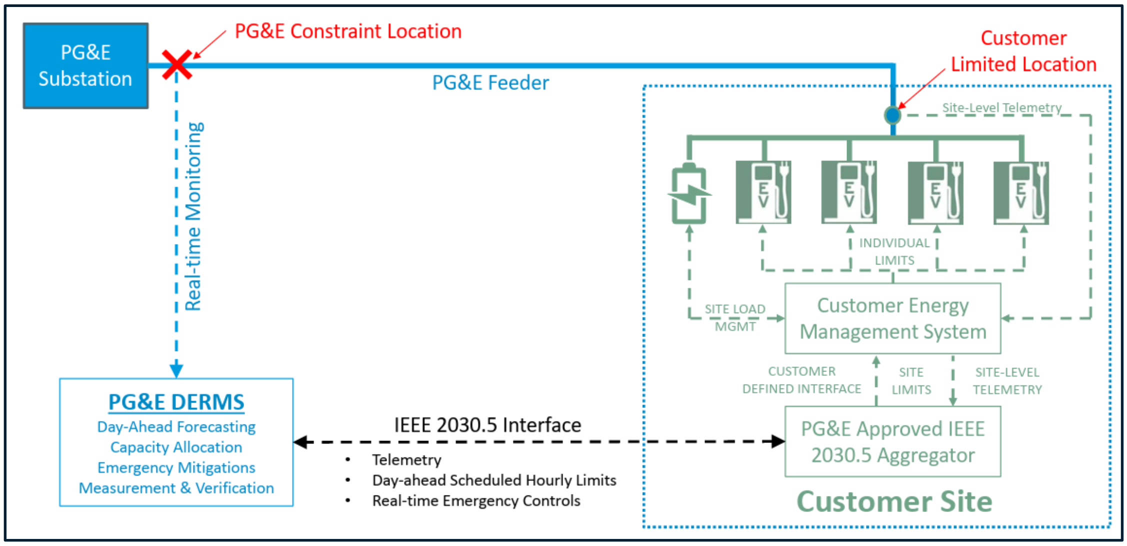

Figure 9: PG&E Flex Connect Illustrative Site Configuration

Solution Summary

Bridge-to-wires solutions can energize specific customers faster and result in higher throughput on existing grid assets, resolving some of the energization timeline delays that customers experience and increasing near-term energy sales in a way that puts downward pressure on rates. For these reasons alone, they are worth exploring anywhere that energization timelines and rate affordability are a customer concern.

Figure 10 shows how bridge-to-wires solutions fit into the overall service connection process.

Note that bridge-to-wires solutions flip the sequence of construction steps for grid-constrained sites: the service extension is constructed, and the customer is connected to the grid, prior to the distribution capacity upgrades.

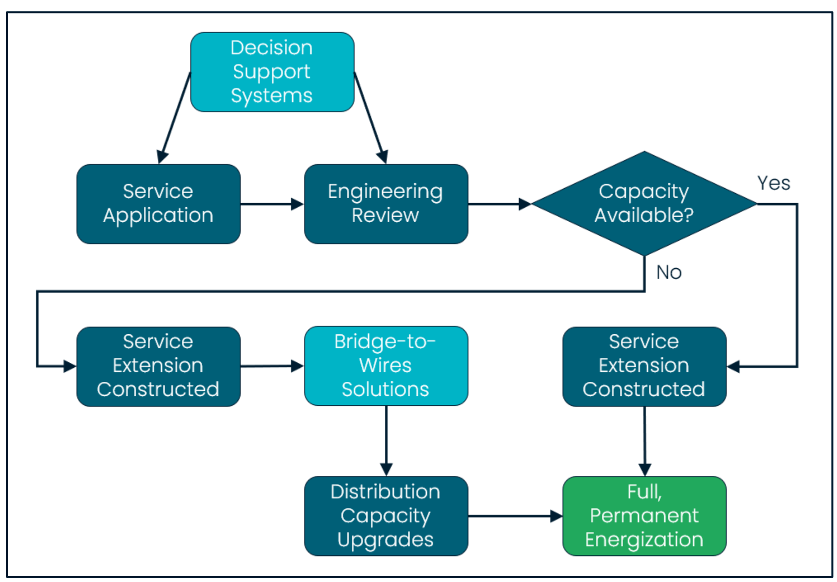

Figure 10: Utility Service Connection Process with Bridge-to-Wires Solutions

However, as practiced today, bridge-to-wires solutions face limitations:

- Bridge-to-wires solutions are temporary measures, meaning they do not avoid the costs of upgrading the grid, nor do they have an impact on the length of the energization queue and the timelines that other customers in the queue will experience.
- Because they are deployed to address distribution system capacity constraints, bridge-to-wires solutions do not avoid timelines associated with service extensions, which may remain impacted by supply chain constraints, permitting timelines, and other reasons for delay.
- The scalability and applicability of bridge-to-wires solutions are limited: static load limits may become outdated quickly, and utilities do not yet find it practical to offer flexible service connections to more than one customer on the constrained asset (though this is capability that utilities are exploring).
- Early FSC implementation challenges for utilities include a lack of national standards for PCS (now addressed with the development of UL 3141); a lack of standard operating procedures for operating the grid in tandem with these new technologies; and a lack of established regulatory procedures to accept this type of technology in the planning and operation of the distribution system. These challenges are not insurmountable, but their resolution will take some time and may look different for each utility.
- Dynamic flexible service connections may require the utility to have a DERMS platform, which few utilities currently have, and certain customers' operational needs may limit their ability to take full advantage of the additional capacity that dynamic FSCs offer. For these customers, a static FSC may be preferable.
- All flexible service connections require some level of investment on the customer's side to manage their load within established operating limits. These hardware and software investments can be costly, so must be balanced against the benefits.

That said, bridge-to-wires solutions offer significant potential, and the utilities exploring them should soon have additional data and lessons learned to help address some of these limitations. As capabilities are scaled, improved, and standardized, it will become easier to envision offering these solutions to customers as a standard part of the utility service connection processes.

Solution Deep Dive: Long-Term Load Flexibility

Unsurprisingly, many utilities and regulators are looking toward a future when load flexibility is deployed as a long-term solution to capacity constraints, in addition to the other solutions previously discussed. In this case, grid upgrades may be avoided altogether—and this may offer significant benefits to the customer offering flexibility, as well as to utility ratepayers. While the technical implementation of long-term load flexibility is similar to flexible service connections (both static and dynamic), the solution is not limited to the service connection process and the programmatic and regulatory paradigm is different, notably regarding cost allocation and customer incentive structures. While not in practice in the United States today, this approach is being implemented in the United Kingdom and Australia,[19] and is under initial investigation in various regulatory proceedings in the U.S.[20]

Long-term load flexibility could be offered as an option to a variety of customers. Consider three illustrative customers:

- Customer A is applying for service on a constrained circuit, and wants to speed energization and avoid capacity upgrade costs;
- Customer B is applying for service on an *un*constrained circuit, and the utility wants their help to preserve capacity for future connecting customers; and
- Customer C is an existing customer on a constrained or unconstrained circuit, and the utility wants their help to create or preserve capacity for future connecting customers.

In all cases, questions of cost allocation, cost recovery, and customer compensation come into play. The solution must deliver economic value to both the customer and the grid, net of any costs and any impacts to customer operations:

- Customer A: If the cost of participating in long-term load flexibility is lower than their allocated cost of capacity upgrades—and if the flexible solution offers similar service from an operational perspective—they may be interested in enrolling. If not, they may need compensation to participate.
- Customers B and C: These customers are not faced with capacity upgrade costs, so they will need to be compensated for taking on operational complexity and implementation costs to participate.

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[19] CHARGED Initiative. *Inaugural Convening Report*. 2024. https://gridlab.org/wp-content/uploads/2024/12/CHARGED-Inaugural-Convening-Report-2024.pdf
[20] See Appendix B for more.

The mechanisms for engaging—and, crucially, compensating—these customers remain a subject of discussion, and will necessitate an exploration of valuation methodologies. And many customers may decline such programs at all, given the operational limitations they create, in which case the utility should fulfill its obligation to serve.

Meanwhile, the solution will be best supported if the utility's investment is treated with cost parity, as compared to the capital investments of grid capacity upgrades.

Utilities will also have other hurdles when transitioning flexible solutions from the current use case—bridge-to-wires—to a more permanent approach. It will be important to address current limits to scale, such as the time-bound nature of load limits and the inability to offer flexibility to multiple customers on a constrained asset. Utilities will need to create mechanisms for integrating flexibility assumptions and forecasts into distribution system planning and other utility planning functions. If load flexibility is not carefully planned and deployed in a synchronized way, the risks of getting it wrong will likely be higher. But the interest in—and potential value of—deploying flexibility in this way is significant and should not be ignored.

Figure 11 demonstrates how long-term load flexibility will fit into a future state of the utility service connection process.

For some customers, temporary measures such as bridge-to-wires will continue to be the right solution to speed their energization timelines near-term but meet their full load capacity needs long-term. For others, a long-term flexible approach might meet their operational needs, especially if they are compensated for that flexibility. And load flexibility on the existing system also begins to influence the question of whether capacity is available for new, connecting customers.

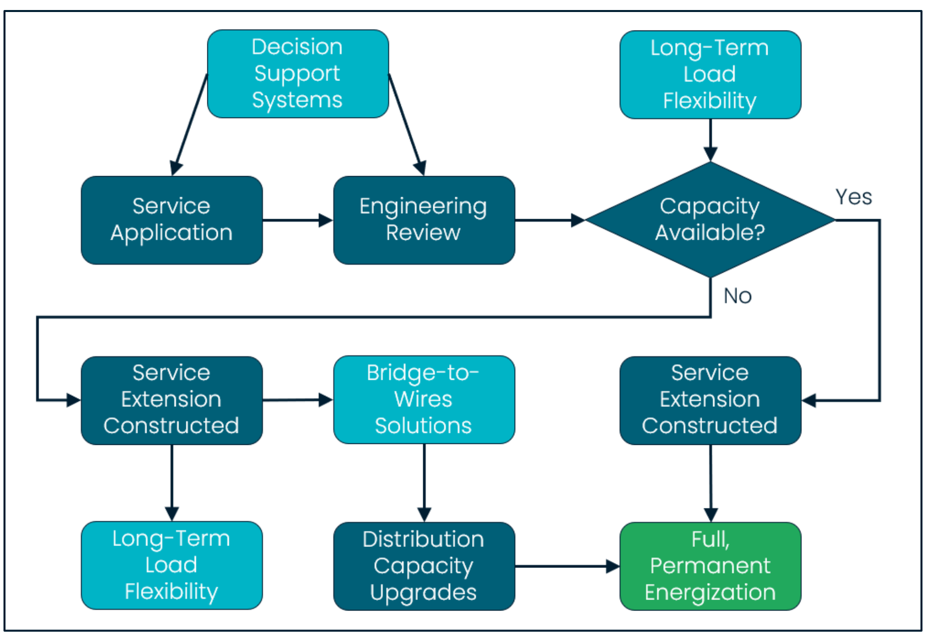

Figure 11: Utility Service Connection Process with Long-Term Load Flexibility

Recommendations

Utilities and state PUCs can engage in several ways to explore and implement new and flexible approaches to electric service connections and capacity constraints.

Recommendations for Utilities

- **Identify specific challenges**
  Utilities should track and analyze data from the service connection process, identifying process or timeline challenges (for utilities that offer EV infrastructure programs, evaluation reports can be a rich source of such data). Utilities should also engage their customers to understand how well the service connection process meets their needs, and to better understand customers' views on the solutions explored here. And utilities need to assess load growth in the context of the current distribution system and pursue a range of solutions to both upgrade and maximize efficient use of the grid.
- **Develop tailored solutions**
  Solutions should be tailored to the challenges identified. All utilities should consider how to advance their processes, tools and offerings to meet this new moment. While some common tools and best practices have been identified here, each utility should be allowed to address its unique needs in its distribution topology and customer base. Utilities should balance cost, complexity, benefits, and risk as they consider which of these solutions to pursue.
- **Evolve technologies, analysis and operational readiness**
  Each of the utility solutions outlined here requires that utilities work collaboratively and innovatively to plan, develop and implement new approaches to serving load. Internally, utilities may need to break down silos between distribution system engineers, new business teams, legal counsel, and transportation electrification teams to invest in new technologies, shape new processes, establish new analytical frameworks and operating procedures, develop customer offerings, and draw up customer-facing forms and agreements. This may require identifying, and addressing, internal cultural roadblocks to progress. Externally, utilities can work with regulators, and other utilities in their state, to develop common processes and approaches.
- **Consider necessary tariff and rule changes**
  The regulatory approach to these solutions is not one-size-fits-all, and a flexible approach will be key to successful implementation. Adjustments to the engineering review process may require changes to service connection rules governing how

connected load is calculated. A formal flexible service connection offering may require a tariff or other regulatory approach (e.g., SCE's LCMS pilot has a tariff; PG&E's Flex Connect pilot is authorized as part of its DERMS approval; PG&E's load limit letters are executed through customer service agreements rather than a tariff).

- **Design for success**
  When designing a flexible service connection offering, utilities should consider elements such as target customer personas; customer eligibility, engagement and outreach; communications protocols; implementation processes and technical requirements; customer agreements and compliance enforcement; customer service and technical support functions; and compatibility of these offerings with existing EV infrastructure programs as well as time-of-use rates, managed charging programs, or vehicle-to-grid (V2G) capabilities. Programs should be technology-neutral, allowing for maximum flexibility.
- **Share data and learnings**
  Utilities should plan to share data, analysis and lessons learned from implementing their solutions, including assessing how helpful the solution was in resolving the identified challenge—and help add to the body of knowledge around these emerging approaches.

Recommendations for Public Utility Commissions

- **Proactively address the topic**
  If the time and cost of building the distribution grid to accommodate EV charging and other large load is of concern—as it is in most states—consider whether new and flexible approaches to capacity constraints should be addressed in a workshop or proceeding. We focus here on EV load, but these solutions can be applied to any type of new load—meaning regulatory discussions should not be limited to EV stakeholders or EV-specific dockets.
- **Accelerate the process and be flexible**
  For customers, speed is of the essence. Some bridge-to-wires solutions, such as PG&E's load limits, may not require complex regulatory mechanisms or customer compensation, so their implementation should not be delayed by excessively long regulatory processes. At the same time, the operational and technical processes that underpin these programs can be complex, so we recommend starting soon with multi-year programs and allowing time for utilities to evolve and iterate their offerings along the way as they integrate learnings from customers and stakeholders.
- **Support targeted utility research and development**

The utilities at the cutting edge of service connection innovation have built their technical and operational capabilities over time, often through R&D funding or regulatory sandboxes. While many lessons learned can cross utility service territory boundaries, each utility must individually build the internal capabilities to implement these offers. We recommend that Commissions allow utilities to bring forward and test new and innovative ideas in targeted areas, with appropriate oversight and complemented with other sources of funding.

- **Consider cost-effectiveness**
  The solutions outlined here can save time and costs, but implementation carries its own costs for the utility and for connecting customers, and customer compensation and grid value remain open questions. A robust analysis of costs and benefits can help ensure that utilities are offering the right solutions to the right customers in a way that reduces grid costs for all. But it is important to keep in mind that the service connection process is different from EV program design and delivery, and the utilities and PUCs should keep a focus on straightforward solutions in the near term for the benefit of both its customers and the system.
- **Address cost allocation and recovery**
  As discussed above, existing cost allocation approaches have a significant impact on customer incentives and motivation. Consider whether customers need incentives, and how to create value for both the customer and for all ratepayers through their participation. Meanwhile, utilities that non-capital approaches to capacity constraints will forego the capital opportunities that are associated with upgrades. Commissions may consider creating aligned incentives for utilities to facilitate efficient utilization of existing distribution grid assets.
- **Obtain data and learnings**
  This is an emerging area of utility practice, and comprehensive data and learnings thus far are scarce. Stakeholders expect this to change over time, but Commissions can accelerate the process by requiring utilities to report on their offerings and share learnings.

Conclusion

Transportation electrification and other sources of load growth are challenging utilities to connect customers faster than ever. At the same time, technological advancements have given utilities and their customers more data, analytical tools, and control technology to help shape decisions and integrate this new load onto the grid in a timely, optimized way. Utilities have a range of options available to help maximize use of the existing grid through this transition, and they should start with smaller improvements as they look to moving up the maturity curve toward more advanced solutions. PUCs can help accelerate and support this process, while providing the public forum for sharing successes, identifying lessons learned, and assessing progress. Through collaboration and shared learnings, stakeholders in the EV ecosystem can work toward a future where service connections and grid capacity are enhanced along with more efficient utilization of the distribution grid across all jurisdictions.

Appendix A: Glossary

Bridge-to-Wires Solutions: temporary approaches to fully or partially energizing new loads that are used while distribution capacity upgrades are completed. Known in some jurisdictions as Bridging Solutions or Bridging Strategies.

Flexible Service Connection: a utility offering that energizes new load with variable capacity limits.

- **Static Flexible Service Connection:** provides Firm Capacity on a variable schedule that is documented in a flexible service connection agreement.
- **Dynamic Flexible Service Connection:** provides incremental Non-Firm Capacity on a dynamic schedule that is communicated on short notice (e.g., a day ahead).

Firm Capacity: the capacity that the utility will provide to the customer, as documented in a flexible service connection agreement.

Hosting Capacity: the amount of power that can be integrated into a distribution system before distribution capacity upgrades will be required to maintain safety and reliability.

Non-Firm Capacity: the incremental capacity that the utility may be able to provide to the customer, if grid conditions allow.

Phased Service Connection: a Bridge-to-Wires Solution wherein the utility provides flat Firm Capacity temporarily and increases this amount over time. Known in some jurisdictions as Staggered Service Connection.

Power Control System: a combination of hardware and software that monitors the loads at a site level, regulating or limiting power at connected devices to remain within a specified limit.

Appendix B: Relevant Legislation and Regulation

State	Legislation or Regulatory Proceeding	Details
California	SB 410 (2023): Powering Up Californians Act	SB 410 required the California Public Utilities Commission (CPUC) to establish average and maximum target energization time periods for investor-owned utilities, and required utilities to take actions to achieve the PUC's targets and report on their progress.
	Docket No. R. 24-01-018: Order Instituting Rulemaking to Establish Energization Timelines	Pursuant to SB 410, the CPUC opened R. 24-01-018 to develop and implement utility energization timeline targets, and track utilities' progress against those targets. The proceeding is also examining static flexible service connections that are implemented as bridging solutions when distribution capacity is temporarily insufficient to serve the full load of an energization request.
	Docket No. R. 21-06-017: Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future	Prior to the passage of SB 410, the CPUC opened R. 21-06-017 to prepare the grid for a high-DER future, including high penetration of transportation electrification. In mid-2024, the proceeding generated a report from the Smart Inverter Operationalization Working Group that described use cases and technology relating to DERMS that can help optimize use of the grid, including long-term load flexibility. The proceeding has gone on to address medium- and longer-term mechanisms for the implementation of dynamic load flexibility, and operational aspects to facilitate more efficient use of these mechanisms within the distribution system.
Colorado	SB 24-218 (2024): Modernize Energy Distribution Systems	SB 24-218 directs Xcel Energy (the largest investor-owned utility in the state) to propose to the Colorado Public Utilities

		Commission the use of an optional flexible interconnection or energization tariff, or phased interconnection or energization agreement, as an alternative to system upgrades that would otherwise be required for interconnection or energization. Xcel filed a tariff for flexible interconnection pertaining to generation in May 2025 in Proceeding No. 25A-0194E, though stakeholders disagree as to whether this filing fully complies with the statutory requirements of SB 24-218.
Illinois	Docket No. 23-0055: ComEd's Petition for Approval of a Multi-Year Rate Plan Docket No. 23-0082: Ameren's Petition for Approval of a Multi-Year Rate Plan	In December 2024, the Illinois Commerce Commission (ICC) issued Orders approving multi-year Integrated Grid Plans from Commonwealth Edison (ComEd) and Ameren. The plans are designed to support the clean energy goals laid out under Illinois' Climate and Equitable Jobs Act. The Orders specified that ComEd and Ameren should work with stakeholders to develop work plans to implement flexible interconnection approaches, applicable to both generation and load.
Massachusetts	Docket No. 24-11: National Grid Electric Sector Modernization Plan	In its June 2025 Order approving National Grid's Electric Sector Modernization Plan, the Massachusetts Department of Public Utilities approved funding for a flexible connection pilot for commercial and fleet charging customers as a bridging or long-term solution to distribution system upgrades.
Minnesota	Docket No. E-002/CI-24-318: In the Matter of a Commission Inquiry into a Framework for Proactive Distribution Grid Upgrades and Cost Allocation for Xcel Energy	In its September 2025 Order approving a Proactive Distribution Grid Upgrade Framework for Xcel Energy, the Minnesota Public Utilities Commission identified flexible interconnection (for load and generation sites) as a topic for Phase 2 of framework development, to be addressed by a stakeholder workgroup.

New York	Docket No. 22-E-0236: Proceeding to Establish Alternatives to Traditional Demand-Based Rate Structures for Commercial EV Charging	In August 2024, the New York PSC issued an Order approving the Joint Utilities' proposed Load Management Technology Incentive Program, which provides incentives for energy storage projects and other advanced load management software and equipment at EV sites such as PCS. The incentives are based on technical specifications, and participating customers are not required to participate in load reduction events. However, in the Order the PSC stated its anticipation that the program will reduce impacts on system peaks, and enable downward rate pressure by encouraging EV charging sites to maximize use of the existing grid.
	Docket No. 18-E-0138: Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure	In its September 2025 Order adopting a EV Queue Management Proposal for the Joint Utilities' Make-Ready Program, the PSC identified phased service connection, flexible service connections, and relating technologies as topics for further exploration. The Order states the PSC's intent to develop a statewide solution to electric load connection issues, and directs Department of Public Service staff to lead a stakeholder process and propose a solution to address these issues.
	Docket No. 24-E-0364: In the Matter of Proactive Planning for Upgraded Electric Grid Infrastructure	In its June 2025 Order on National Grid's Urgent Upgrades Projects, the PSC approved National Grid to procure, own and operate mobile battery energy storage systems at three New York Thruway travel plazas to alleviate constraints relating to vehicle electrification and charging.