



Southern California Edison Company 2025 GRC

A.23-05-010

TURN HEARING EXHIBIT

TURN-315

**Tesla Response to TURN Data Request TURN-Tesla-01
& Attachments**

Tesla

Application 23-05-010 – SCE 2025 General Rate Case

Data Request TURN-Tesla-01

To: Public Advocates Office

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Received Date: May 10, 2024

Response Date: May 17, 2024

Question 01: What is Tesla's interest in the Load Growth sections of SCE's GRC application?

Response: Tesla has an interest in ensuring that the Load Growth sections of SCE's GRC application accurately reflect the actual EV-related load growth over the GRC period. If the Load Growth assumptions in the GRC underestimate actual EV-related load growth, then funding for distribution system investments to support EV charging will fall short of the need, potentially leading to insufficient distribution system capacity to serve Tesla's planned Supercharger sites in SCE territory.

If there is insufficient distribution system capacity to serve Supercharger sites, energization of sites will be delayed for months or years while SCE completes the necessary upgrades, which could lead to insufficient direct-current (DC) fast-charging sites to serve EV drivers. This not only harms Tesla's mission, but also hinders the state's broader EV adoption goals as Tesla continues to open its Supercharger sites to drivers of other EVs.

Question 02: As a manufacturer of electric vehicles is Tesla concerned about high electricity prices?

Response: While high electricity prices could affect demand for electric vehicles in theory, respondent is not aware of any studies that show a direct correlation between retail electricity prices and EV sales. Moreover, at current electricity rates and gas prices in California, Tesla Model Y driver charging overnight off peak on SCE's TOU-D-Prime rate would save more than \$1,000/year on fuel costs compared with driving a similar gas car. The "off-peak" rate for residential in-home charging (where most EV charging occurs) would need to increase to \$0.60/kWh (more than double the current rate) for EV fueling costs to be on par with a gas car.¹ For this reason, at their current level, electricity prices do not pose a significant concern from an EV sales perspective.

Question 03: Do high electricity prices and/or increases in electricity prices impact Tesla's sales of electric vehicles and/or Tesla customer satisfaction?

¹ Assumptions: Gas car is a 4-cylinder Subaru Crosstrek averaging 31 mpg; average gas price is \$5.26/gallon; miles driver per year are 10,920. Calculation done using: <https://chargevc.org/ev-calculator/>

Response: There are a wide range of factors that impact EV sales, including interest rates, government incentives, consumer awareness, consumer confidence, gas prices and environmental concerns. To isolate the impact of electricity prices on Tesla’s car sales would require an econometric analysis designed to isolate the impact of electricity prices from all other variables. We are not aware of any such study, nor have we seen any other evidence that high electricity prices and/or increases in electricity prices impact Tesla’s sales of electric vehicles and/or Tesla customer satisfaction.

Question 04: Will SCE’s load growth request, as part of its GRC application, increase electricity prices?

Response: Whether or not SCE’s load growth request will increase electricity prices in the long run depends on whether increased revenue SCE generates from electricity sales due to load growth exceeds the ratepayer revenue requirement of those investments. If revenue generated by SCE’s investments to facilitate load growth is less than the revenue requirement to serve that load, rates will increase; likewise, if revenue exceeds the revenue requirements, rates will decrease.

Studies examining the impact on electric rates of utility investments in infrastructure needed to support EV deployment have shown that those investments result in downward pressure on rates for all electric ratepayers. For example, in August 2023, the Public Advocates Office PAO found that even though the cost to upgrade distribution grids to accommodate EV growth through 2035 would be about \$26 billion, “electrification applies an overall downward pressure on rates across all three of the large electric utilities,” with SCE rates reduced by about \$0.02 because of electrification. As PAO explains, “This is because, all other costs being equal, upward pressure on rates due to increased infrastructure costs due to electrification is more than offset by downward pressure on rates due to the increased consumption of electricity resulting from electrification.”²

Synapse Energy Economics similarly conducted a nationwide survey of the impact of EV adoption on electric rates and found that EV adoption results in lower electric rates for all ratepayers.³

Thus, while we cannot say for certain what effect SCE’s load growth request will have on rates, available evidence indicates that investments supporting EV charging are likely to put overall downward pressure on rates.

Question 05: Is Tesla concerned about the impact of the rate increases proposed in SCE’s GRC application and the impact on its customers? Please explain why or why not?

Response: Tesla is not aware of a proposal to increase rates in SCE’s GRC application. The GRC application proposes ratepayer-funded investments in SCE’s distribution grid, among other things. Tesla supports proposed investments in SCE’s distribution grid intended to support transportation

² CPUC Public Advocates Office Distribution Grid Electrification Model Study and Report, August 2023, p. ES-2

³ “Electric Vehicles are Driving Down Rates for all Customers,” by Synapse Energy Economics, Inc., January 2024 <https://www.synapse-energy.com/sites/default/files/Electric%20Vehicles%20Are%20Driving%20Rates%20Down%20for%20All%20Custo%20mer%20Update%20jan%202024.pdf>

electrification. Whether or not these investments ultimately result in increased rates or decreased rates depends on the amount of revenue the investments generate through electricity sales to EV drivers.

Based on the analysis described above from PAO and the Synapse study Tesla believes that the investments SCE proposes in its GRC will ultimately put downward pressure on electric rates as more customers adopt EVs and generate revenue for the utility from fuel purchases that once went to oil companies. In addition, empirical evidence suggests that increasing EV sales – which depend on sufficient public charging – will result in lower rates for all ratepayers. For example, in January 2023, San Diego Gas and Electric Co. (SDG&E) announced a reduction in transmission and delivery costs due in part to increased electricity sales. According to an article in the *San Diego Union Tribune*, “As more electric vehicles come onto the San Diego market and an increasing number of homes and businesses move to all-electric appliances, the fixed costs of running the system are spread over a wider base of customers. That, the utility said, puts downward pressure on delivery costs for the 3.7 million customers in its service territory.”⁴

Question 06: Page 3 of Exhibit TSL-01 states “Tesla also owns and operates an extensive network of Direct Current fast chargers (“DCFCs”) known as the Supercharger network.” Is Tesla continuing to operate its Supercharger program? If not, please explain why not.

Response: Yes, Tesla continues to operate its Supercharger program.

Question 07: Page 6 of Exhibit TSL-01 states that Tesla does “support the use of the TEGR as a supplemental to SCE’s base demand forecast,” and states that “SCE’s supplemental TEGR analysis aligns closely with the adoption trends for light-duty and heavy-duty EVs in the 2022 IEPR AATE 3 forecast.” What analysis have you performed to assess the strength of the TEGR for distribution system planning? Please explain and provide any supporting analysis or workpapers not included in Exhibit TSL-01.

Response: Tesla supports the use of the TEGR primarily on the basis that the TEGR EV adoption forecast aligns closely with the light-duty (LD) and heavy-duty (HD) EV adoption trends in the Energy Commission’s 2022 Integrated Energy Policy Report (IEPR) Additional Achievable Transportation Electrification (AATE 3) scenario, which assumes California will achieve the mandates for LD and HD EVs established by the Air Resources Board (ARB).⁵ This alignment is shown in Figure 1 and Figure 2 below.

⁴ “Fingers crossed: The outlook for SDG&E bills in the new year appears positive,” by Rob Nikolewski, *San Diego Union Tribune*, Dec. 5, 2023.

⁵ These mandates are Advanced Clean Cars II, Advanced Clean Trucks, and Advanced Clean Fleets

Figure 1 - Comparison of Light-Duty Vehicle Forecasts in California

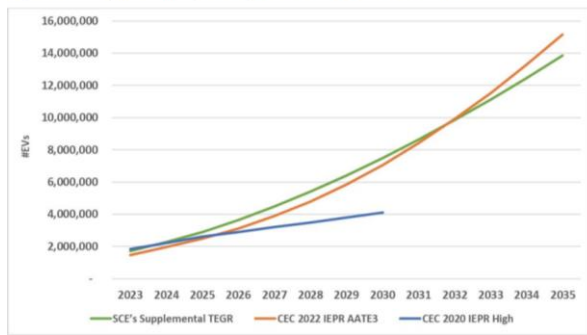
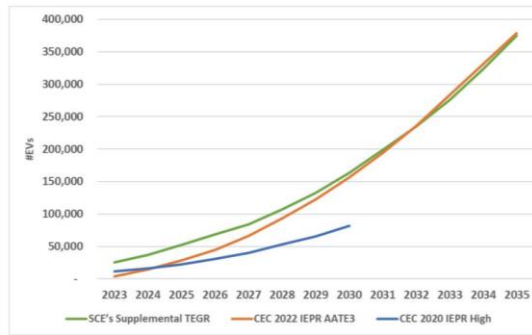


Figure 2 - Comparison of Medium & Heavy-Duty Vehicle Forecasts in California



Tesla feels strongly that if the state hopes to achieve the EV adoption mandates established in state policy and law, it must use planning assumptions that forecast those adoption goals being met. To use a planning assumption that forecasts lower adoption than state goals would result in insufficient infrastructure to serve the number of EV drivers and fleets required to meet state goals. This would in turn lead to fewer consumers and fleets purchasing EVs due to lack of charging. In short, the forecast used in infrastructure planning can become a self-fulfilling prophecy.

Beyond comparing the TEGR forecast to the IEPR AATE 3 forecast, Tesla also met with SCE staff to discuss the “bottom-up” methodology by which SCE has disaggregated the gross demand forecast and allocated the demand to individual circuits using regression analysis incorporating EV adoption indicators, such as customer adoption and socio-economic data, in addition to likely locations for DC fast-charging stations along travel corridors. SCE also described its methodology for disaggregating heavy-duty charging needs based on customer surveys, port and warehouse locations, and shipping corridors.

Tesla did not independently perform any analysis to confirm SCE’s TEGR forecast disaggregation methodology, and we did not conduct engineering assessments to independently verify SCE’s forecast of distribution system overloads.

Question 08: How does incremental light-duty and medium/heavy duty vehicles forecast in the TEGR compare to recorded incremental vehicle adoption in 2023?

Response: Based on a data request Tesla issued to SCE,⁶ the TEGR forecast overestimated incremental light-duty vehicle adoption in 2023. The adoption of light-duty EVs assumed by the TEGR forecast in 2023 was 601,992, compared with about 438,164 new plug-in EVs registered in CA in the same year.⁷ The TEGR forecast also overestimated heavy-duty EV adoption in 2023, but it underestimated medium-duty EV adoption. Table 3 below shows SCE’s TEGR forecast compared with recorded incremental vehicle adoption in 2023.

⁶ See Attachment A: TESLA-SCE-03 Question 2.a

⁷ <https://www.energy.ca.gov/data-reports/energy-almanac/zero-emission-vehicle-and-infrastructure-statistics-collection/new-zev>

	Light-duty EV	Medium-duty EV	Heavy-duty EV
SCE TEGR (2023)	601,992	201	8,319
2023 Recorded adoption	438,164	1,191	2,390

Table 1: Comparison of TEGR 2023 forecast and 2023 recorded adoption

Question 09: How does incremental light-duty and medium/heavy duty vehicles forecast in the TEGR compare to forecast incremental vehicle adoption in the 2022 or 2023 IEPR updates?

Response: The TEGR forecast for incremental light-duty and medium/heavy duty EVs slightly exceeds that of the AATE 3 scenario of the 2022 IEPR in the early years of the forecast, while AATE 3 scenario adoption exceeds the TEGR forecasted adoption in the later years of the forecast period, starting in about 2032 as shown in Figure 1 and Figure 2 above. However, at the 2035 end point, the two forecasts are similar, with the light-duty forecast for 2035 in the AATE 3 exceeding the TEGR forecast by about 7 percent, and the two forecasts for 2035 being nearly identical for medium and heavy-duty.

Question 10: Page 8 of Exhibit TSL-01 references a paper from Energy Systems Integration Group, “Charging Ahead: Grid Planning for Vehicle Electrification” published in January 2024.

- a. Please provide a PDF copy of this paper.
- b. “Charging Ahead: Grid Planning for Vehicle Electrification” states on page 6, that for grid planning related to EVs, “Regulators must review plans and ensure that ratepayer funds are spent prudently. This is a delicate balancing act.” Do you agree with that statement? If you do not agree, please explain why not.

Response:

- a. A copy of the report has been provided as an attachment.
- b. I agree with the statement identified on page 6

Question 11: Page 9 of Exhibit TSL-01 explains that delays in the energization of new Supercharger sites could lead to longer wait times for drivers waiting to charge. How does Tesla define a delay in energization?

Response: In the context of this statement, Tesla defines a delay in energization as a waiting period of 1 year or more in receiving energization of the site while the utility performs distribution system upgrades.

Question 12: What does Tesla do when it is told by a utility that there will be a delay in energization of over 1 year due to a lack of distribution capacity? Please include in the response an explanation of any distribution capacity work or mitigations Tesla does when faced with an energization delay due to distribution capacity issues, including if Tesla installs less than the originally planned number of superchargers.

Response: Tesla often needs to open new Supercharger sites because we see an increase in “waiters” at existing sites, which is why expansion is critical. When Tesla is told by a utility that there will be a delay in energization of over 1 year due to lack of distribution capacity, there are several potential actions

we can take. First, Tesla typically works with the utility to try and identify how much power is available at the existing site and will work to maximize use of that available power to bring as many chargers online as possible while full power to the site is made available through a distribution upgrade. Additionally Tesla will explore the use of a flexible interconnection agreement with SCE where Tesla fully powers the site while reducing max power during certain times of the year based on a schedule provided by SCE. If Tesla and SCE can agree to the flexible interconnection agreement, full power may be made available sooner with some reductions in max power to the site throughout the year while distribution upgrades proceed.

Question 13: What are the current average wait times for drivers charging at Tesla Superchargers in SCE's service territory?

Response: Based on the most recent data, about 5% of drivers experience a wait at Superchargers sites in SCE territory, with an average wait time of 6 – 7 minutes.

Question 14: In 2023, how often did drivers have to wait to charge at Tesla Superchargers in SCE's service territory?

Response: Drivers have to wait to charge at Tesla Superchargers in SCE about 5% of the time.

Question 15: What is the current average utilization rate for Tesla's Superchargers in SCE's service territory?

Response: In 2023 the average monthly load factor across all of our SCE Supercharger sites was 28%

Question 16: Page 14 of Exhibit TSL-01 references the Synapse study "Electric Vehicles Are Driving Electric Rates Down" published in 2023, which has been updated and republished in January 2024

- a. Please provide a PDF copy of the study.
- b. Do you believe it's likely that EVs studied during the research period required the same types of distribution upgrades that future EVs will?
- c. Does the study evaluate the costs to serve and charging revenues from medium and heavy-duty vehicles?
- d. Does this study include the costs of distribution upgrades in determining whether the benefits of EVs outweigh the costs of utility EV programs?
- e. The study states that "if the utility revenues from EVs exceed the utility system costs, then EV adoption can reduce electricity rates for all customers. Conversely, if the costs are greater than the revenues, non-EV owners could end up paying more for their electricity." Do you agree with that statement?

Response:

- a. A PDF copy has been attached to the responsive email

- b. I do believe it is likely that the EVs studied during the research period required the same types of distribution system upgrades that future EVs will, since future EVs load will put similar types of stress on the grid as EVs studied during the research period. These upgrades include transformer upgrades, line reconductoring, and other types of capacity additions. However, given the accelerating pace of EV adoption, I expect the degree of upgrade needs in the future to be greater.
- c. No, the study focuses on light-duty passenger vehicles and the impact of those vehicles on residential electric rates.
- d. The study does include distribution system costs in determining whether the benefits of EVs outweigh the costs of utility EV programs. However, it is not clear from the study how distribution system upgrades costs are allocated to EV load, since upgrades serve multiple customers and end uses.
- e. Yes

Question 17: Are you familiar with SCE's recently approved Automated Load Control Management Systems Pilot, which would allow new load to be interconnected more quickly in grid capacity constrained areas during certain times of the day prior to upgrading capacity if the customer agrees to use Automated Load Control Management Systems? (See attached SCE AL 5138-E-).

a. Would Tesla agree to participate in SCE's Automated Load Control Management Systems pilot? If no, please explain why not.

b. Does Tesla utilize Automated Load Control Management Systems at any of its Superchargers in California? If yes, please explain the technologies used and the load mitigation capabilities.

Response: Yes, I am familiar with the pilot.

- a. Tesla currently participates in SCE's Automated Load Control Management Systems (LCMS) with 2 Supercharger sites and 56 stalls energized under that pilot.
- b. Tesla is currently working directly with PG&E and SCE on flexible interconnection contract arrangements but does not have a widely applicable automatic load management system available for replicable deployment at this time.

Charging Ahead

GRID PLANNING FOR VEHICLE ELECTRIFICATION



A Report of the Energy Systems
Integration Group's Grid Planning for
Vehicle Electrification Task Force

January 2024





About ESIG

The Energy Systems Integration Group is a nonprofit organization that marshals the expertise of the electricity industry's technical community to support grid transformation and energy systems integration and operation, particularly with respect to clean energy. More information is available at <https://www.esig.energy>.

ESIG's Publications

This report and its accompanying fact sheet are available at <https://www.esig.energy/grid-planning-for-vehicle-electrification/>. All ESIG publications can be found at <https://www.esig.energy/reports-briefs>.

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Charging Ahead: Grid Planning for Vehicle Electrification

**A Report of the Energy Systems Integration Group's
Grid Planning for Vehicle Electrification Task Force**

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Abbreviations Used

ADMD	After diversity maximum demand
ALM	Automated load management
DER	Distributed energy resource
EV	Electric vehicle
NERC	North American Electric Reliability Corporation
PV	Photovoltaic
TOU	Time of use
V2H	Vehicle-to-home
V2G	Vehicle-to-grid
V2X	Vehicle-to-everything

Executive Summary

Transportation electrification is accelerating and will affect all facets of the power system, but the effects will be most pronounced for distribution systems where vehicle charging could quickly overwhelm grid edge equipment. Public charging sites and vehicle fleet depots can be planned, permitted, and constructed much more quickly than other loads such as commercial sites or industrial facilities. Utilities therefore have much less time to upgrade distribution system infrastructure for electric vehicle (EV) integration compared with new loads historically.

Faced with this rapid change, planning practices need to evolve to keep pace. Decisions today will strongly affect the preparedness of the grid for vehicle electrification. This has implications for customers' EV adoption, vehicle manufacturers' ability to sell new cars, and public policies

intended to reduce emissions and encourage EV growth. The distribution planner's job is not an easy one. Planners must grapple with the possibility of either over-building the system for load that may not materialize or under-building and potentially leaving the system with insufficient infrastructure to meet EV charging demand.

Depending on the approach chosen, the distribution system can be a bottleneck for vehicle electrification, hamstringing EV adoption, or it can support more sustainable transportation thanks to thoughtful planning. Despite incomplete information about the timing, magnitude, and location of EV charging behavior, there are opportunities to lay a grid planning foundation today that will support the evolution of the grid and enable widespread vehicle electrification.



Priority Actions to Take Today

Priorities for effectively integrating vehicle electrification into grid planning include improving forecasting, embracing smart charging, incorporating future-ready equipment, and promoting proactive upgrades.

Improve Forecasting

Forecasting vehicle impact can be improved by enhancing adoption and behavior models to consider multiple vehicle end uses, new vehicle technologies, and additional data sources. First, forecasting adoption at a granular level can be achieved through likelihood models informed by costs, policies, and customer preferences, as well as through new sources of data, such as fleet electrification surveys. These adoption models can include locational components and characterize the types of vehicles that will connect to the grid, including the technology that underpins the vehicle (the battery technology, size, and charger). Second, forecasting charging behavior and how the vehicle is used (e.g., school bus vs. city bus) will inform impacts of EVs both temporally and locationally.

These two key elements—the location and timing of charging—are intertwined, elastic, and changing as EV adoption increases and vehicle technologies progress. Even with the best models and data, forecasts will not capture everything. In time, we will learn how technological, regulatory, and social-human factors will impact EV charging. Embracing the uncertainty around EV adoption and charging patterns through scenario planning helps planners think in broad strokes rather than narrow solutions. Scenario planning can help identify the suitability of the power system—generation resources through distribution equipment—to support a range of futures, not just the adoption timeline and charging behavior that grid planners hope will manifest.

Targeted smart charging, operating limits, and strategically located storage can help with immediate load growth, and these remain useful as more solutions are implemented over time.

Embrace Smart Charging

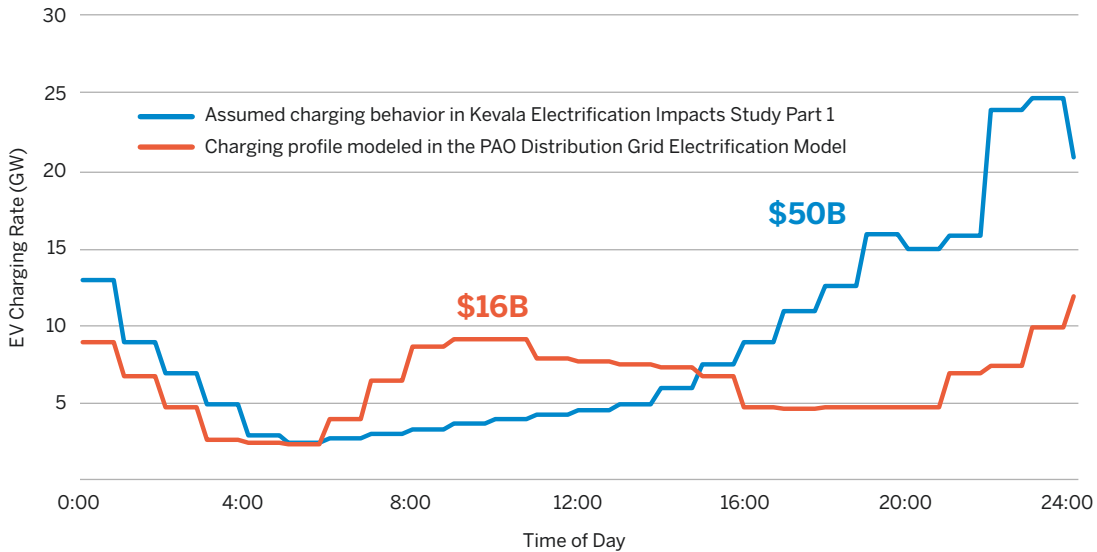
Smart charging programs hold great promise for utilizing grid infrastructure efficiently, aligning charging with infrastructure capabilities and the lowest-cost electricity. Smart charging options using rate designs, automation, or demand response programs can align charging with more affordable energy and reduce total infrastructure needs at every level of the grid from the premise to the bulk system. Targeted smart charging, operating limits, and strategically located storage can help with immediate load growth and remain useful as more solutions are implemented over time.

Studies recently completed in California highlight the impact of smart charging on estimates of distribution upgrades that will be needed as vehicles electrify (Figure ES-1, p. xi). One study found that unmanaged EV charging, coupled with some electrification of other loads, could lead to \$50 billion in distribution upgrades in California alone (Kevala, 2023). Another study, which used different assumptions on charging behavior, found that distribution upgrade costs could be \$16 billion (roughly \$800 per metered user) (PAO, 2023). While these studies assessed different levels of electrification, they underscore the wide range of potential costs being contemplated. With smart charging increasing the utilization factor of grid infrastructure, new EV loads may be able to justify grid upgrades by spreading the costs across a larger volume of electricity sales, thereby potentially decreasing rates for everyone, not just EV owners.

Smart charging strategies vary from simple tools (such as predefined time-of-use rates and demand charges) to sophisticated control measures (like dynamic operating envelopes) that can address varying grid needs. The overarching goal of each strategy is to align charging within grid infrastructure limits, help integrate clean energy, and reduce the costs of charging. As such, the costs of sophisticated smart charging solutions, including participation incentive costs, can be evaluated against the cost of traditional upgrades, such as the installation of larger equipment. Multiple smart charging strategies could be used to simultaneously address multiple grid constraints, as is shown in Figure ES-2 (p. xi).

FIGURE ES-1

Differences in EV Charging Assumptions and Costs of Distribution Upgrades in Two Recent Studies

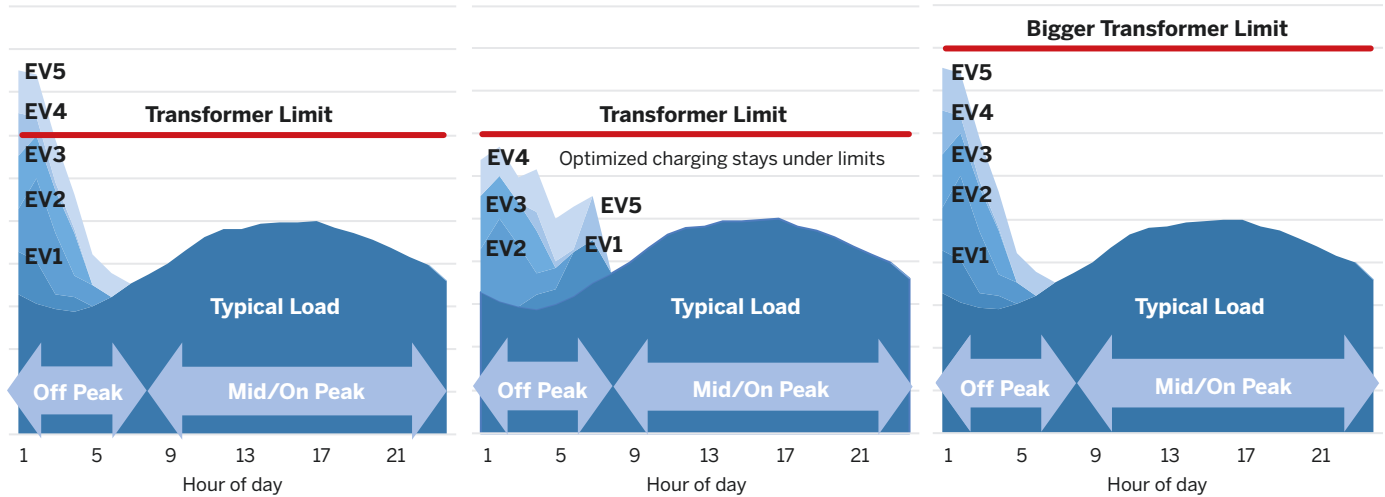


Differences in charging assumptions can have a large impact on the cost of distribution upgrades. Smart charging can adjust the charging profile.

Source: Energy Systems Integration Group. Data from Kevala (2023) and the California Public Utilities Commission’s Public Advocates Office (2023).

FIGURE ES-2

Optimized Charging Aligned with Time-of-Use Rates



Time-of-use (TOU) rates with load optimization can simultaneously address bulk system and distribution constraints. If we only focus on bulk system needs with rate designs, EV charging may all start at the beginning of the off-peak period and overwhelm the distribution equipment (left). We can instead stagger charging and get the bulk system benefits of TOU without overwhelming the distribution system (middle). However, simply upgrading the distribution transformer may be more cost-effective and requires less of customers (right). The industry is learning more about the best mix of solutions to enable charging.

Source: Energy Systems Integration Group.

Incorporate Future-Ready Equipment

The optimal grid plan will likely be some combination of smart charging paired with infrastructure upgrades. More subtle strategies can enable electrification over time, including using future-ready equipment designed to support future load growth from EVs and other sources. Distribution utilities can strategically plan for the future by upgrading equipment when it is slated to be replaced or first commissioned, thus making better use of the labor and maintenance costs associated with grid equipment with the goal of limiting the long-term cost associated with grid upgrades for higher levels of electrification.

Planning for EVs requires a holistic analysis of the assumptions that drive grid planning decisions. Many of those assumptions are embedded in equipment design standards, which are assessed infrequently, and leading utilities are re-evaluating these design standards because

The risks of over-building and under-building the distribution system have asymmetric impacts. The impact of over-building includes increased costs, while under-building leads to stunted interest in electric vehicles and falling short of public policy.

of vehicle electrification. Unfortunately, there is no consensus on optimal designs today as engineers balance uncertain equipment loading levels (driven in part by the diversity of charging behavior) and equipment rating methodologies that are also undergoing innovation thanks to new equipment-ageing methodologies.

Promote Proactive Upgrades

Future-ready grid upgrades that take place over decades may not be sufficient to meet all projected EV charging needs, and specific locations within a region may need upgrades before the existing equipment has reached the end of its expected lifespan. Widespread just-in-time upgrades of distribution equipment to support the level of electrification projected would likely be both costly and infeasible for utility construction crews. Distribution utilities can be proactive but should do so intelligently by working with multiple stakeholders and using improved, granular forecasts that may help to avoid overbuilding the system and creating stranded assets. The risks of over-building and under-building the distribution system have asymmetric impacts. The impact of over-building includes increased costs, while under-building leads to stunted interest in electric vehicles and falling short of public policy. By analyzing forecasts, working with a multi-stakeholder group, and considering these asymmetric impacts, distribution planners can prioritize areas for targeted upgrades.



TABLE ES-1

Multiple Processes Provide a Holistic Approach to Grid Planning for EVs

Existing Processes
While today’s grid planning processes vary across the country, they generally include:
<ul style="list-style-type: none"> • Annual system reviews • Regularly updated grid plans with a medium- to long-term planning horizon • Isolated evaluation of interconnection requests
Customer-Collaborative Processes
A customer-collaborative process between planners and customers allows for open communication about:
<ul style="list-style-type: none"> • Multiple options for interconnection • Multiple locational alternatives
Proactive, Multi-Stakeholder Processes
Given the volume and multiple use cases of EVs, proactive processes can be well suited to:
<ul style="list-style-type: none"> • Ensure access to EV charging for underserved communities and determine where local, traffic-related pollution may be mitigated through vehicle electrification • Facilitate regional networks • Provide clear roadmaps for electrification planning progression

Multiple planning processes can be used together to effectively plan the grid for vehicle electrification. This approach supplements existing processes with customer-collaborative processes and proactive, multi-stakeholder processes.

Source: Energy Systems Integration Group.

Proactive upgrades could include larger equipment, new equipment, or non-wires alternatives, such as batteries or behind-the-meter generation. These upgrades can be strategically implemented based on improved forecasting techniques and identified by a multi-stakeholder group, to help ensure a targeted and efficient response to changing needs. Regulatory and policy efforts may be needed to support proactive upgrades because these upgrades may not be “used and useful” when they are first implemented.

Diversifying Planning Processes

Different processes can be used to identify different types of grid solutions. While much of distribution system planning has traditionally been handled by utilities, the role of state legislators, regulators, and other state officials will continue to grow as multiple power

grid objectives compete for priority. Similarly, retail rate designers, vehicle manufacturers, and charge station operators will need to work with grid planners to design solutions that balance the cost of new infrastructure with customer charging flexibility. And the need to ensure equity in designing the grid that supports an electrified future is best accomplished through a broad range of stakeholder input.

Design of a grid that supports an electrified future can draw from multiple planning processes working together by supplementing existing processes with new approaches.

Given the scale and layers of considerations that go into grid planning for vehicle electrification, three types of planning processes can be helpful to facilitate EV grid integration. Table ES-1 describes the role for existing processes, customer-collaborative processes, and proactive multi-stakeholder processes in enabling vehicle electrification.

This report walks through four high-level steps in grid planning and suggests good, better, and best practices associated with the planning attributes that lead to effective grid planning for vehicle electrification. It also discusses the areas where improvements are needed, gaps in our collective knowledge, and the role of various stakeholders. The four steps are to: (1) improve forecasting, (2) embrace smart charging, (3) incorporate future-ready equipment, and (4) promote proactive upgrades and processes to support an electrified future. Because of the multi-billion-dollar scale of these grid planning decisions, coordinated and holistic planning is needed to design grid architecture that effectively balances uncertainty around EV adoption and when and where vehicles will charge, which can lead to an overly cautious investment approach, with ensuring the grid is adequately prepared for EVs. Grid planning for vehicle electrification is an opportunity to further integrate the energy systems that power our lives while establishing a platform for a wholly sustainable future.

Introduction

While electricity loads across the United States have been relatively flat or declining over the past 20 years, with sectoral changes in the economy and improved energy efficiency reducing load even as the economy grew (EIA, 2023), loads are now projected to grow dramatically. The rapid rise in electric vehicles (EVs), the electrification of buildings and industry, and a proliferation of data centers will increase loads significantly and require substantial changes to grid planning (Figure 1, p. 2). However, no consistent or thorough method exists for grid planners to integrate EVs into the power grid as both a load and potentially a resource.

No consistent or thorough method is available across the industry for grid planners to integrate EVs into the power grid.

The electrification of transportation affects all facets of the power system—from generation to transmission—but the effects will be most pronounced for distribution systems. Distribution system equipment is smaller and has lower power transfer capabilities, and will be impacted by even a few EVs charging at the same time in a local area. In addition, the first deployments of EV charging stations tend to be concentrated in specific locations—at depots for fleet vehicles, alongside highways and transportation corridors, and in communities with relatively high early adoption. As EVs become more common, they can quickly overwhelm local distribution systems.

Distribution networks will be able to support more EV charging at some grid locations than others. For example, some substations are more amenable to electrification, or

EV adoption will require new infrastructure upgrades across the country, but often at a highly local level—simultaneously challenging system planners to evaluate impacts across a broad region while targeting upgrades with precision.

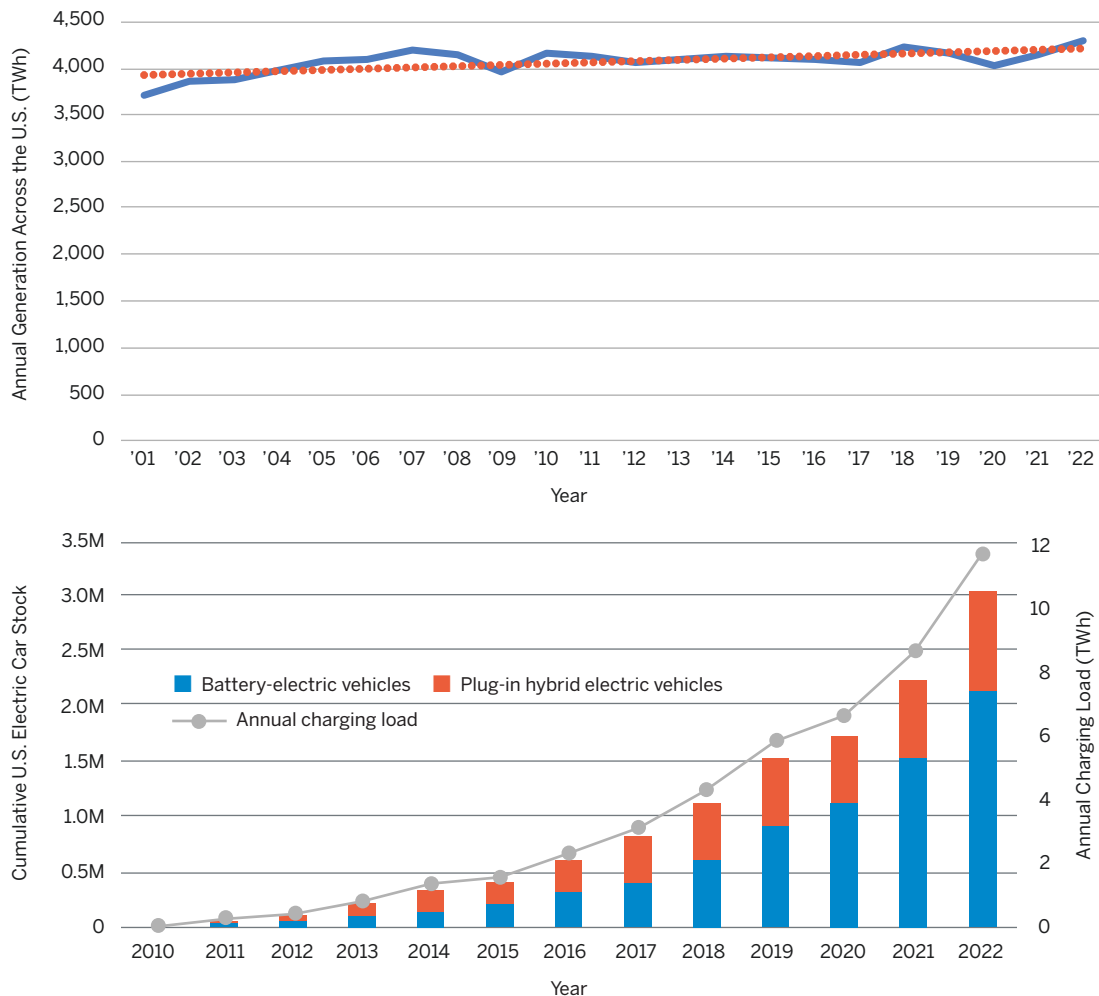
more capacity is available at one service transformer than another. In the past, a utility may have provided more headroom at a given distribution level than another, making it more suitable to integrate EVs at the sub-station level than the service transformer, or vice versa. EV adoption will require new infrastructure upgrades across the country, but often at a highly local level—simultaneously challenging system planners to evaluate impacts across a broad region while targeting upgrades with precision.

New technologies and solutions are available that can help manage EV charging and discharging. This report explores ways that planners can prepare the distribution system for EV growth now by both determining where to make upgrades and evaluating the efficacy of smart charging solutions.

Increased Adoption of EVs

Transportation electrification is accelerating due to consumer demand, commitments from vehicle manufacturers, and public policy targets and incentives. U.S. sales of electric cars increased by 55% from 2021 to 2022, led by all-electric vehicles, which saw increased sales of 70% in 2022 (IEA, 2023). Thirty-eight percent of U.S. adults say they are somewhat likely or very likely to seriously consider an EV for their next vehicle purchase. That

FIGURE 1
Fairly Flat Annual Generation Compared to Rapidly Rising EV Charging Demand



Total generation across the country has remained relatively steady in recent years (top). Meanwhile, the cumulative EV stock has grown rapidly in the last decade (bottom), and the charging load will soon influence the generation trends.

Source: Energy Systems Integration Group. Data from the U.S. Energy Information Administration and the International Energy Agency.

number rises to 45% for people under the age of 50 (Pew, 2023).

Vehicle manufacturer commitments, such as the adoption of electrification targets and announcements of corporate net-zero pathways to reduce carbon emissions by 2030, are leading to major car manufacturers investing billions

of dollars annually in research and development. Ford, General Motors, Toyota, and Volkswagen each invested at least \$6 billion annually from 2019 through 2022 in EVs and digital technologies (IEA, 2023).¹

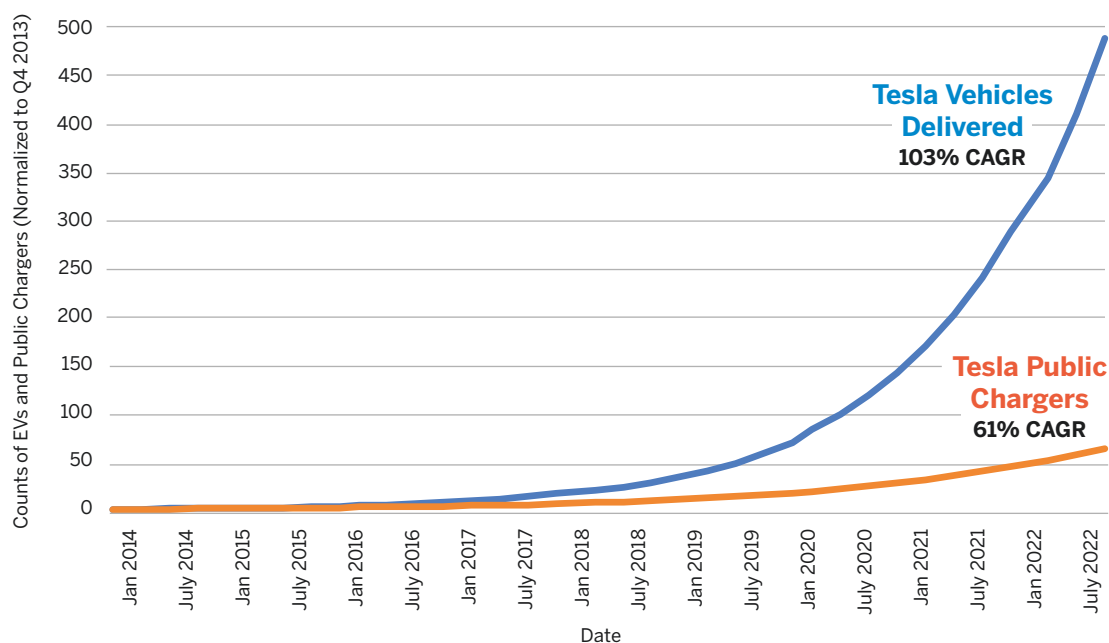
While EV adoption accelerates, public charging infrastructure has lagged (see Figure 2, p. 3).² However, this

¹ Recently, some car manufacturers have backed off of some of their near-term execution plans for electrification, but their long-term goals remain intact.

² This report adopts language proposed in Wood et al. (2023) that groups various types of charging together into at-home and public charging. In this context, public charging includes any charging that takes place away from a person's primary residence, including workplace charging, destination charging, and corridor charging en route, and may be provided free for the driver or require payment.

FIGURE 2

Comparison of Number of EV Vehicles on the Road and Number of Public Chargers



The increases in the number of Tesla vehicles on the road has far exceeded Tesla public charging network roll-out for a variety of reasons, including a lack of sufficient grid infrastructure. This illustrates the challenge in building out an EV charging network fast enough to keep up with demand from EV drivers. This trend is also seen in non-Tesla charger deployments and highlights the accelerating demands of grid planning to support vehicle electrification.

Note: CAGR = compound annual growth rate.

Source: Tesla comments to the California Energy Commission, 9/1/2023 (<https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=23-IEPR-03>).

is changing quickly with recent public policy focusing on both getting more EVs on the road and getting the chargers installed. The Inflation Reduction Act (IRA) provides tax credits of up to \$7,500 per vehicle, and the Infrastructure Investment and Jobs Act (IIJA) makes \$7.5 billion available for EV charging infrastructure. Many states and municipalities have additional incentives for both vehicle purchases and charging infrastructure. As of March 2023, an estimated \$23.7 billion had been committed by federal, state, and local governments, as well as from private firms, for publicly accessible EV light-duty charging infrastructure, which represents between 43% and 76% of the funding that will be needed for public chargers to support a mid-adoption EV scenario by 2030 (Wood et al., 2023).

Resulting Grid Planning Challenges for Charging Infrastructure

However, despite interest in and commitments to EVs from consumers, manufacturers, and policymakers, distribution system planning for vehicle electrification remains a challenge. Since public charging sites require relatively little supporting infrastructure beyond the electrical equipment and the charger itself, they can be planned, permitted, and constructed much more quickly than other types of sites with similar power requirements (such as housing, commercial sites, and industrial facilities). This means that utilities have much less time to upgrade distribution system infrastructure for public charging sites compared with new loads historically. Faced with

Utilities have much less time to upgrade distribution system infrastructure for public charging sites compared with the new loads that have historically required energization. Faced with this rapid change, grid planning practices need to evolve to keep pace with EV charger deployment.

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The rapid increase in EVs and associated grid upgrades is under discussion in individual jurisdictions and state regulatory proceedings, and specific issues have been explored at a national scale. For example, studies have been done on national charger requirements to support EVs (Wood et al., 2023), the role of smart charging in grid integration (SEPA, 2022), and generation requirements for new EVs (MISO, 2021). The Modern Distribution Grid (DSPx) reference documents discuss EVs and distribution engineering amongst myriad other considerations (PNNL, 2019). EPRI has recently launched a three-year initiative, EVs2Scale2030™, to support the rapid deployment of EVs while minimizing grid impacts

and enabling benefits to the nation's grid. The EPRI initiative recently published eRoadMAP™, an interactive energy map that presents the amount of energy needed to electrify transportation with granularity down to 0.28 square miles.³

However, there is a need for coordinated and holistic evaluation of how distribution planning practices and processes can adjust to support continued increases in EV adoption. Aligning grid planning and charger siting will be crucial in transitioning to an electric transportation future.

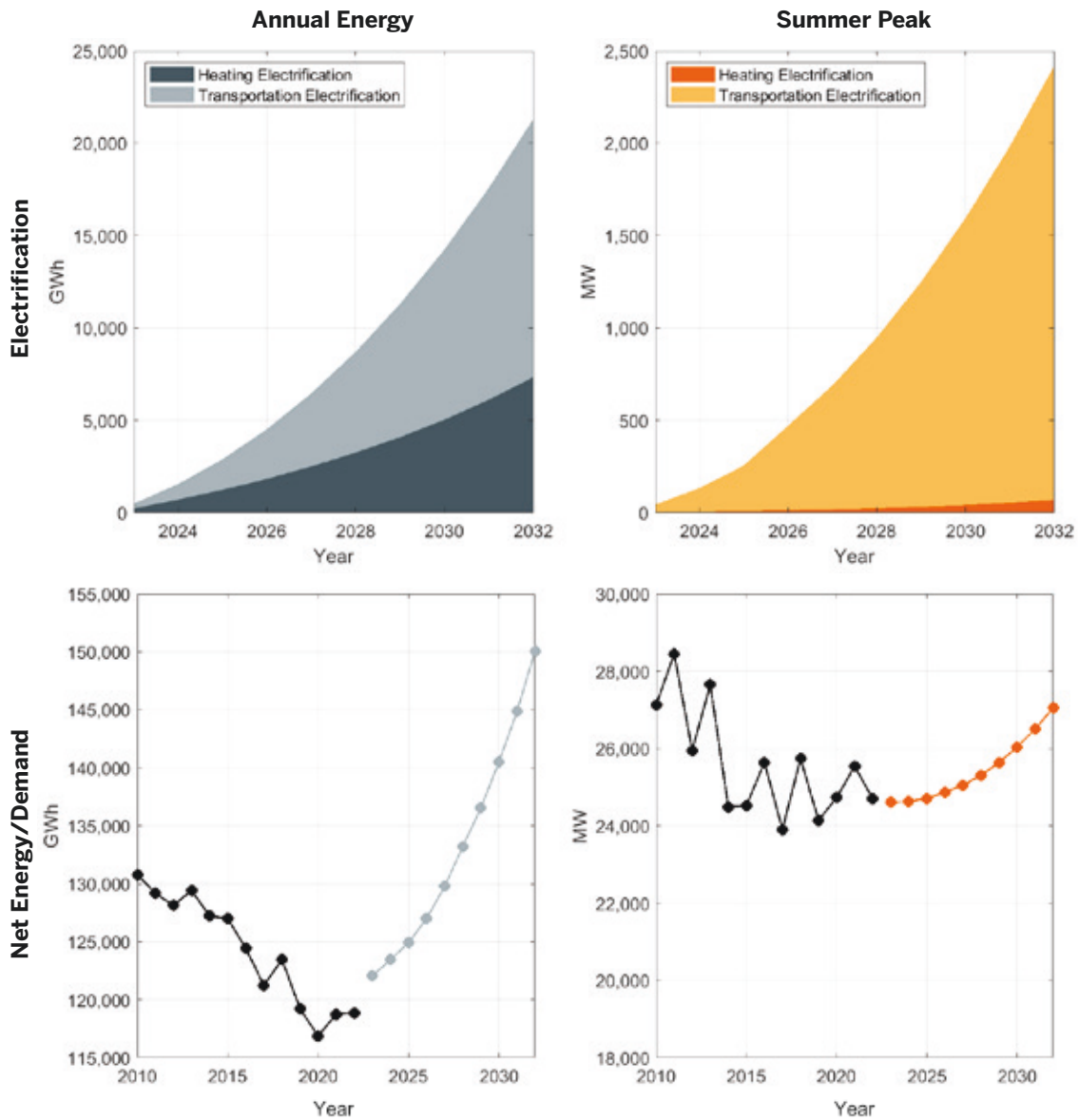
A Need for Smart Approaches to Grid Planning for EV Growth

EVs will change power system needs more than at any time since the uptake of air conditioning in the 1960s. Rapid and sustained increases in electricity demand from EV charging will put increasing stress on distribution systems. One EV could double the maximum demand from an individual household (Engel et al., 2018), and a concentration of EVs in a neighborhood could overwhelm local distribution system capacity. When high levels of EV charging occur across a region, it becomes a significant impact across all voltage levels. For example, the Independent System Operator of New England



3 See <https://eroadmap.epri.com/>.

FIGURE 3
ISO-NE System Load Forecast



The load forecast for the ISO-New England system shows growth across both energy and demand due to vehicle electrification (in light gray and light orange) and heating electrification (in dark gray and dark orange). On certain distribution circuits, growth will be more rapid than shown here.

Source: Independent System Operator of New England.

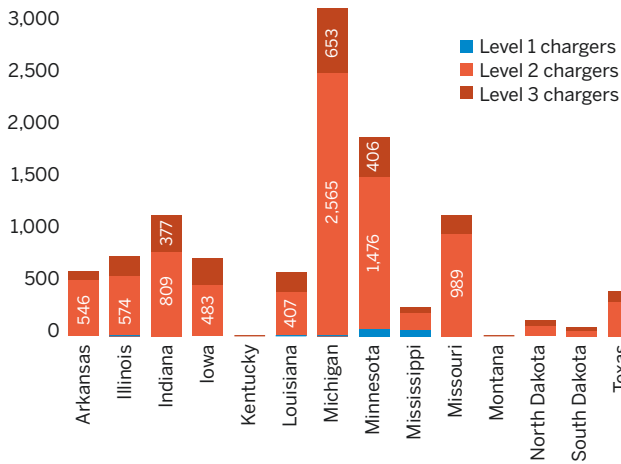
(ISO-NE) has forecast that transportation electrification will increase annual energy requirements for the region by 10% and contribute between 8% and 12% to system peaks by 2032 (Figure 3).

EV adoption rates will vary significantly from community to community, amplifying challenges in specific regions

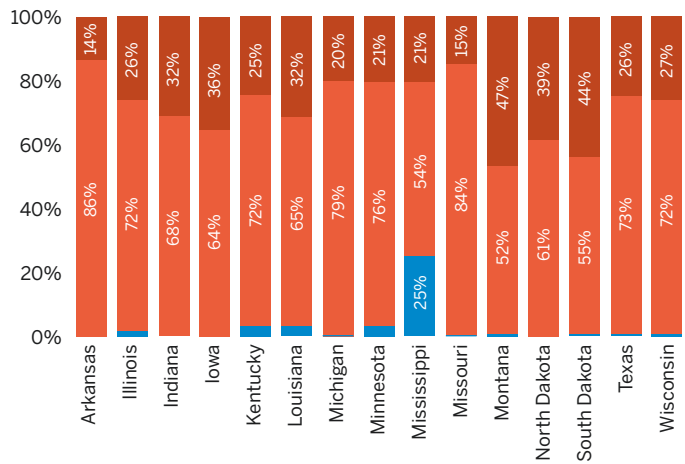
at a pace rarely seen in power system planning. For example, the Midcontinent Independent System Operator (MISO) is seeing chargers deployed at very different paces across the states that it serves. Variation in EV charging will be even more pronounced on the distribution level (Figure 4, p. 6). This variation in geographical location increases the need for accurate forecasting.

FIGURE 4
Variability in EV Charger Deployment in MISO States

Number of Chargers by State



Proportion of Charger Type by State



States in the MISO territory deploy chargers at very different paces and with different mixes of Level 1, Level 2, and Level 3 chargers. This variation in EV charging will be even more pronounced on the distribution level.

Source: Midcontinent Independent System Operator, based on U.S. Energy Information Administration data with participation rates applied.

Maintaining Reliability at a Reasonable Cost

Studies have found a wide range of potential costs for grid upgrades. While it would be costly to build the infrastructure necessary to accommodate unconstrained EV charging, new technologies and incentives can change consumer charging behavior and reduce the need for new distribution system infrastructure. One study’s high- and low-cost cases differed by a factor of 10, with the high case estimating cumulative investment across the country by 2050 at around \$200 billion (Cutter et al., 2021). Analysis of California, meanwhile, found that unmanaged EV charging and electrified space heating could cost Californians \$50 billion in distribution grid upgrades by 2035—roughly \$2,500 per utility customer (Kevala, 2023). The second phase of that study will estimate the reduced costs with managed charging. Similarly, MISO analysis found that generation requirements could increase substantially depending on base assumptions for demand profile and utilization rates of grid equipment (MISO, 2021).

As distribution system planning increasingly includes higher levels of EV adoption, both utility engineers and utility regulators are grappling with new and complex challenges. Grid planners must estimate how many EVs

Grid planners must estimate how many EVs to expect, predict where and when they will charge, account for technology innovation, and prioritize grid upgrades to supply them. Regulators must review plans and ensure that ratepayer funds are spent prudently. This is a delicate balancing act.

to expect, predict where and when they will charge, account for technology innovation, and prioritize grid upgrades to supply them. Regulators must review plans and ensure that ratepayer funds are spent prudently. This is a delicate balancing act. Inadequate distribution infrastructure will stall EV adoption, frustrating consumers and policymakers alike. Underestimating load growth could jeopardize reliability at both the local distribution and bulk system levels, while overestimating demand could lead to over-investment in infrastructure and stranded utility assets, raising electricity costs without commensurate benefit. And the lack of planning and support for bi-directional charging or further technology innovation could strand assets that could otherwise provide significant value. At the same time, EV charging can



increase the utilization factor of new and existing infrastructure, potentially decreasing electricity rates (PAO, 2023; Cutter et al., 2021).

Making Use of Smart Charging, Data Analytics, and Advanced Grid Technologies

There are ample opportunities to mitigate the undesirable outcomes. Consumer-side resources—most notably, smart charging—can be part of the solution. And the power industry can look to recent advances in analytics and data science, while embracing advanced grid technologies that would make the most of existing infrastructure, to integrate new EV demands. The industry can also apply lessons learned from other activities—for example, demand response programs to manage air conditioning loads.

Planning for transportation electrification requires coordination among a wide range of stakeholders—from utility planners and policymakers to vehicle manufacturers, charge station aggregators, commercial fleets, public transportation departments, and EV users. An integrated distribution planning approach would incorporate modern grid technologies and distributed energy resources (DERs) into distribution planning, with linkages to bulk power system planning and alignment with community and state goals, objectives,

and priorities. Such an approach can help to determine where and when EV adoption will likely happen and help to prioritize the grid upgrades necessary to effectively integrate EV charging with input from multiple perspectives.

Focus of this Report

The Energy Systems Integration Group (ESIG) convened the Grid Planning for Vehicle Electrification Task Force to discuss the challenges throughout the grid planning process from multiple perspectives, identify gaps in distribution system planning for vehicle electrification, discuss ways to address these gaps, and articulate promising practices and next steps. The task force included grid planners from across the globe, vehicle and charge station manufacturers, charging network operators and aggregators, regulators and state offices, researchers, and consultants active in the intersection of EVs and grid planning.

This report provides a holistic, national-level examination of transportation electrification challenges that directly impact integrated distribution planning, and outlines how coordinated planning that addresses the largest grid challenges can help instill confidence in long-term plans. The primary audiences are utilities, utility regulators and other state decision-makers, EV manufacturers, charge station operators, aggregators, and other technical experts. With such rapid changes, approaches to meeting distribution system needs in light of vehicle electrification need to remain nimble. The themes, concepts, and areas of emphasis conveyed in this report will continue to evolve as we learn more.

This report provides a holistic, national-level examination of transportation electrification challenges that directly impact integrated distribution planning, and outlines how coordinated planning that addresses the largest grid challenges can help instill confidence in long-term plans.

Grid Planning in the Context of Vehicle Electrification

EVs are the latest addition to the list of emerging distribution planning considerations, which have included rooftop solar photovoltaics (PV), aging infrastructure, enhancements in grid modernization technology, and improvements in analytic capabilities. Historically, distribution system planning was a “black box” exercise wholly contained within the utility and primarily oriented around ensuring that energy could be delivered from the transmission grid to meet load growth throughout local networks. As expectations of electricity systems have changed in recent years, many states require utilities to file some type of plan that describes how the utility intends to upgrade its distribution system. Plans vary significantly in how they consider EVs, depending on the jurisdiction and utility. There is a lack of consensus on how to address EVs alongside other distribution planning considerations.

Many states require holistic integrated distribution system plans that provide detailed analyses and roadmaps for the next 5 to 10 years for distribution system expenditures to meet projected load, enhance utility capabilities through improvements to data and tools, make the best use of DERs, improve reliability and resilience, and meet other public policy objectives.⁴ Other states, either as part of integrated distribution system planning filings or separately, require utilities to file electrification plans that articulate how they are aligned with state policy objectives related to vehicle and building electrification.

A distribution system built to maximize every objective simultaneously would be unaffordable; however, these objectives can be prioritized and optimized for an affordable outcome. Figure 5 (p. 9) shows how the integrated

Distribution system plans vary significantly in how they consider EVs, and there is a lack of consensus on how to address EVs alongside other planning considerations.

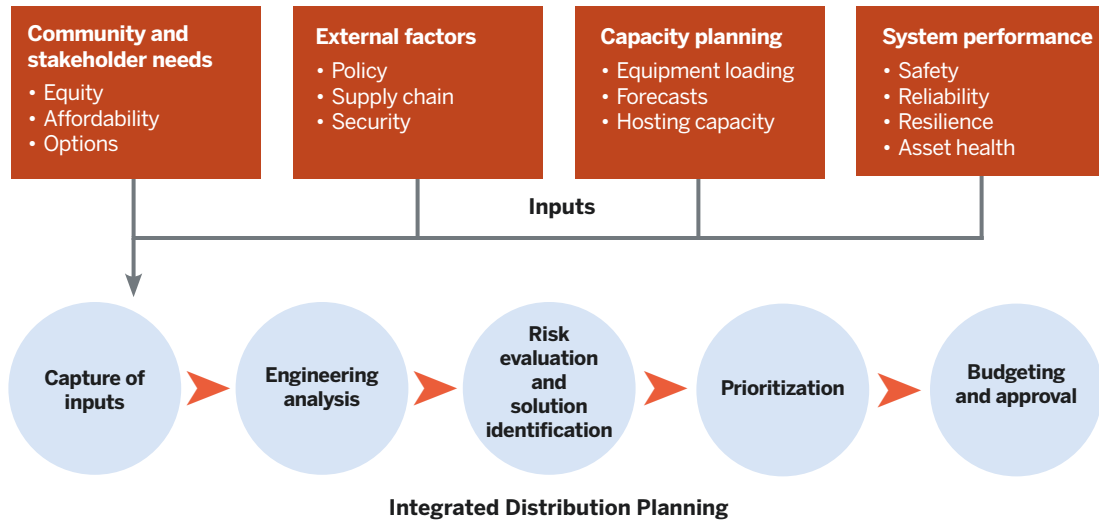
distribution system planning process includes inputs beyond load growth in determining the grid plan. Increasingly, ensuring equity and access for grid upgrade benefits is a key outcome for these processes.

Integrated distribution system planning processes are driven by a need to optimize across multiple objectives, including grid resilience, reliability, affordability, and safety, as well as to empower customer choice through



⁴ Twenty-six states, the District of Columbia, and Puerto Rico are somewhere in the process of enhancing their distribution planning processes (Cutler and Chew, 2020).

FIGURE 5
An Integrated Distribution Planning Framework



A simplified integrated distribution planning framework inspired by ComEd's 2023 Multi-Year Integrated Grid Plan. This report considers the entirety of integrated distribution system planning, but is primarily focused on capturing inputs and assessing risks and mitigation measures.

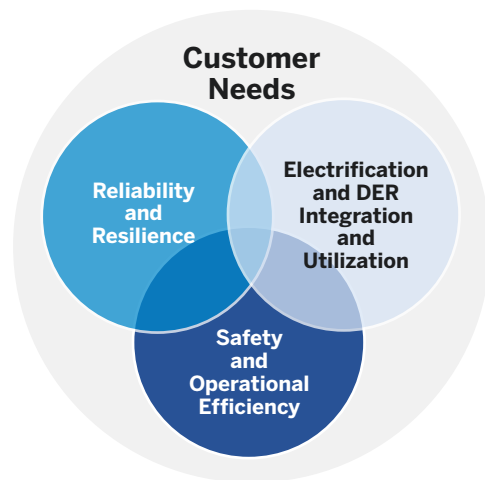
Source: Energy Systems Integration Group. Adapted from Commonwealth Edison (2023).

DER and EV integration and utilization (Figure 6). Still, simply switching to a process that considers these objectives is insufficient for solving grid planning for vehicle electrification; innovation and change is also needed in engineering and regulating. EV sales have outpaced the deployment of public charging infrastructure in recent years, which will lead to insufficient charging access if this trend continues.

Figure 7 (p. 10) summarizes the steps needed to plan the grid for vehicle electrification. This report discusses these steps in sequential order, but in practice, numerous feedback loops are needed, as smart charging strategies can alter plans.

EV sales have outpaced the deployment of public charging infrastructure in recent years, which will lead to insufficient charging access if this trend continues.

FIGURE 6
Electrification as One of Many Considerations in Integrated Distribution Planning

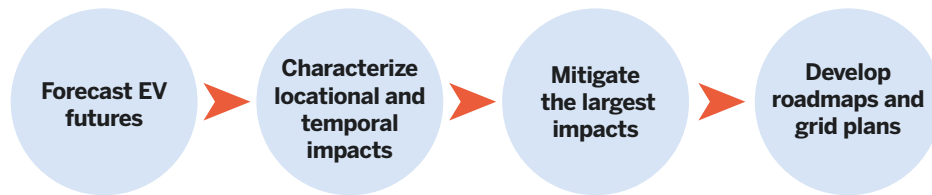


EVs are among multiple considerations of a consumer-centric grid planning process.

Source: Pacific Northwest National Laboratory (2019).

FIGURE 7

High-Level Steps in Grid Planning for Vehicle Electrification



These are simplified steps needed to plan the grid for vehicle electrification. There will be feedback loops and iterations between and within these steps, to be discussed throughout this report.

Source: Energy Systems Integration Group.

Impact of EVs on the Distribution Planning Process

This new source of load will affect all layers of the power grid. In addition to requiring changes to wiring in individual homes and businesses, EV adoption may require utilities to install equipment capable of carrying more electricity, which would mean larger primary and secondary wiring and larger (or more) service transformers, lines, or substation equipment.

Figure 8 (p. 11) shows a typical grid hierarchy with bulk system, distribution, and premise levels. Depending on the size, EV chargers can be installed at any of these levels. In some places, the equipment can handle the added EV load. In other areas, EVs can cause equipment to be overloaded. At the bulk system level, new capacity may be required to meet demand, particularly during peak charging periods. EVs can affect different grid topological levels differently and affect individual pieces of equipment within a level differently.⁵

Historical Approach to Planning

Traditionally, distribution planning has used a standards-based approach that provides engineers with a select set of equipment to design sufficient capability on the system to serve load. Equipment standards serve two primary functions: (1) to help streamline utility supply

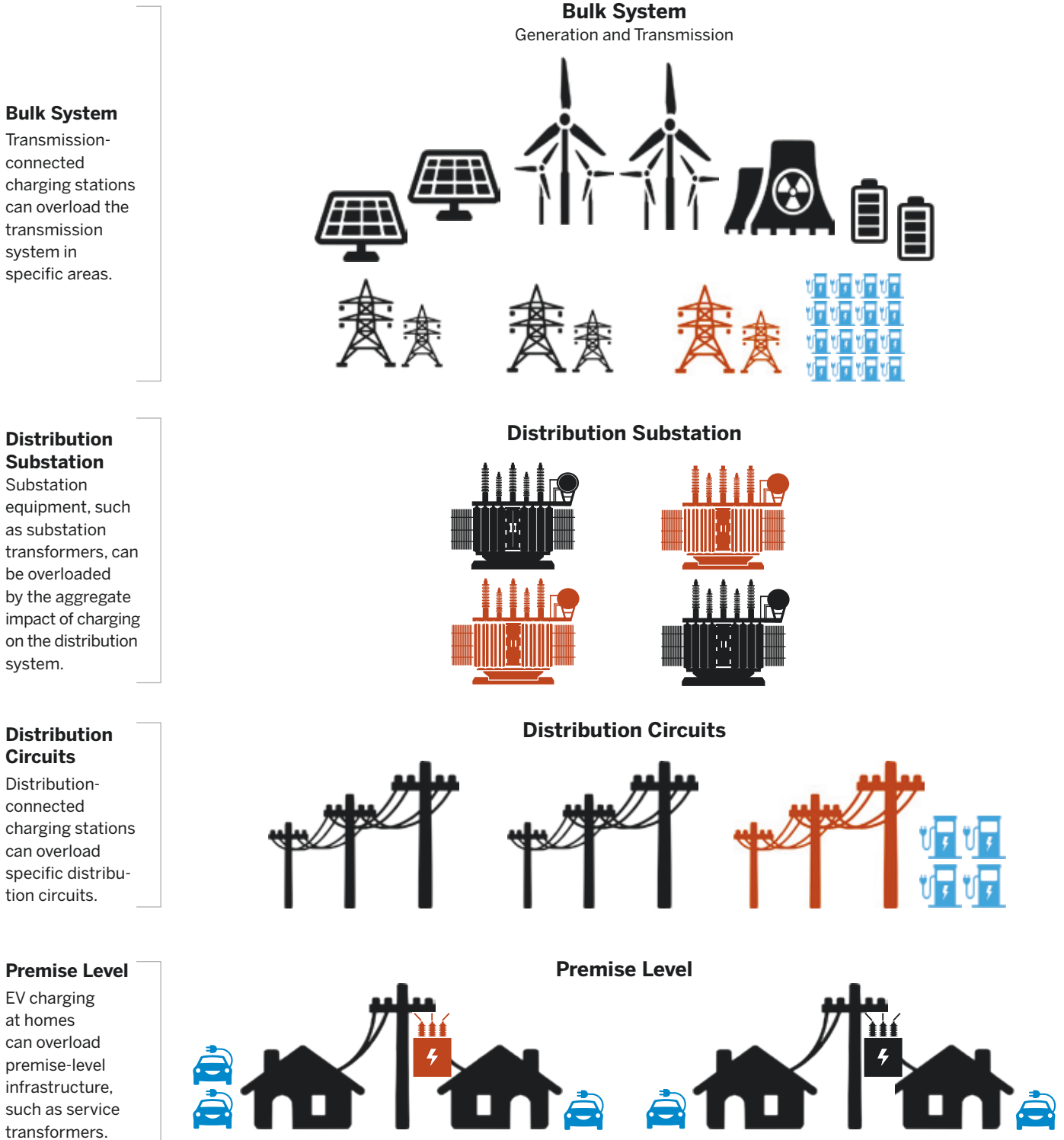
chains and inventory and simplify installation and construction processes, and (2) to provide sufficient headroom for distribution equipment serving ordinary premises.⁶ For example, an equipment standard could specify that a certain size of service transformer can serve 10 single-family homes with sufficient headroom to preserve the equipment capabilities over its useful life. As distribution system planners design the power system for a new 100-home neighborhood, they would use 10 of these service transformers. Utilities also commonly extend this approach to procuring land for substations and other equipment. By leaving room for additional equipment in a substation, future flexibility is preserved.

However, this approach was developed when load grew much more slowly, entirely new types of loads were not emerging, and distributed generation and storage were rare. But increasingly, these standards are being revisited as engineers evaluate new data and question the assumptions underpinning design criteria. Given the potentially large impact of EVs and the impact of various EV load shapes on distribution equipment, standards and approaches will need to be reevaluated for long-term suitability. For example, including more headroom on today's distribution equipment may help avoid the cost of mid-life upgrades driven by EVs. Ensuring more space in new substations would allow for future growth in electrification.

5 Throughout this report, "topological level" indicates when granular analysis beyond "distribution system" is helpful. For instance, premises, circuits, and substations are all part of the "distribution" system, but EVs may impact these components differently depending on the circumstance.

6 The amount of headroom afforded on the distribution system is highly variable across utilities, with some evaluating their loading under normal operations and others using N-1 contingency situations to drive sizing. Still, many utilities have historically allowed 10% to 30% headroom for future load growth.

FIGURE 8
High-Level Layers of the Power Grid



EVs affect all layers of the power system and can cause system overloads (represented by orange objects) at each level. EV charging is represented by the blue icons.

Source: Energy Systems Integration Group.

Grappling with Uncertainty Introduced by EVs

Distribution system planners need to consider a wide range of potential outcomes for EVs. Each of the plausible outcomes identified in Table 1 has ramifications for how the distribution system is planned and ultimately operated in the future. Moreover, these uncertainties stack on top of each other and are often correlated.

These questions highlight the need to better understand (1) types of EVs and associated consumer behavior, and (2) adoption trends and medium- and heavy-duty fleet decisions. Some regions are already experiencing grid bottlenecks for public and private charging. It is important to understand grid bottlenecks and approaches to

alleviate them, especially for medium- and heavy-duty fleets, which can introduce large new loads effectively overnight and outpace utilities' grid planning and construction capabilities.

Thinking Holistically: Forward-Looking Planning with Incomplete Information

At the core of the planning challenge is right-sizing the power grid for an uncertain future, while maintaining affordability and equity. Because of the rapid widespread adoption of EVs and since public EV charging plazas can be built much faster than traditional types of new electricity demand, distribution system planners may need to build out distribution system capacity in advance

TABLE 1
Questions about EV Futures and Plausible Outcomes

Question about EV Futures	Plausible Outcomes
At what pace will EV adoption take place?	<ul style="list-style-type: none"> • Current policy trends hold, and the majority of new light-duty vehicle sales are EVs by 2035. • Waning consumer interest stalls EV adoption following early adopter sales. • Battery technology improves and EV costs continue to decline, leading to rapid adoption. • Medium- and heavy-duty EVs become cost-competitive for some use cases and are rapidly deployed.
When will consumers want to charge EVs? Can we rely on early adopter or commuting trends to forecast the future?	<ul style="list-style-type: none"> • Existing charging profiles continue into the future—with most public charging in the daytime and at-home charging at night. • Charging coincides with commuting trends as people charge immediately upon arrival at most destinations. • Rapid charging times similar to refueling a gas vehicle become common. • Midday public charging becomes common.
How will EV technology change?	<ul style="list-style-type: none"> • EVs only get bigger, trending toward sport utility vehicles (SUVs) and trucks with bigger batteries. Consumers want a longer range. • Consumer interest in vehicle-to-home (V2H) discharging for resilience purposes leads to an increase in EVs with bi-directional charge/discharge capabilities. • Ride-sharing and work-from-home trends fundamentally change how society uses vehicles.
What will charging and discharging demands look like?	<ul style="list-style-type: none"> • EV charging demands (peak and energy) remain at their present level. • Charging demands decrease as work-from-home trends continue with level 1 (120 V) charging supporting transportation needs.
Where will consumers want to charge EVs?	<ul style="list-style-type: none"> • EV charging reflects traffic patterns. • Consumers prefer charging at home. • Destination charging is common. • Commercial truck fleets initially rely on depot charging.
To what extent will EV owners be willing to adjust their charging?	<ul style="list-style-type: none"> • EV owners prioritize economics over convenience. • EV owners attempt to maintain maximum battery capacity, regardless of economics. EV owners are not effectively incentivized by economic indicators. • EV owners allow third-party managed charging. • Commercial truck fleets are as flexible as their business model will allow.

Source: Energy Systems Integration Group.

Because of the rapid widespread adoption of EVs and since public EV charging plazas can be built much faster than traditional types of new electricity demand, distribution system planners may need to build out distribution system capacity in advance of new service connection requests.

of new service connection requests. Carrying out such a forward-looking build-out would include more uncertainties than the just-in-time planning that utilities have typically performed, thus bringing with it a greater risk of wrong-sizing the grid.

Avoiding Over- and Under-building

If significant new infrastructure is built to support EVs and the load fails to materialize, the industry risks stranding investments. In most state regulatory environments, assets that are not “used and useful” are denied rate recovery by public utility commissions, and utilities are generally reluctant to take on this risk. Depending on the nature of the asset and state regulatory decisions, the customer that spurred the need for new assets could have to pay for most of the new equipment, or the utility could be denied rate recovery and costs would be paid by utility shareholders. In some cases, the cost of unused equipment could be spread across all utility ratepayers (Wilson, 2023). Each of these has downsides, with the risks stemming from policy choices being borne by different groups.

If, in contrast, the industry underbuilds and provides insufficient infrastructure to meet EV charging demand, the result could be an unreliable power grid that can at times not handle demand, increasing reliability risks. A grid with insufficient capabilities could lead to constraints on charging that stunt public interest in EVs or prematurely degrade utility infrastructure. Just 17% of Americans are extremely or very confident that the U.S. will build sufficient infrastructure to support large numbers of EVs (Pew, 2023). High-profile restrictions on EV charging could further erode confidence in electrification.

Simply put, this new load source seems to be driving grid planning toward two paths: (1) increasing the utilization of existing distribution infrastructure, and (2) expanding the grid to meet new local peaks. Faced with similar problems in the 1960s and 1970s as air conditioning loads transformed consumer demand, grid planners used both paths in building large new infrastructure projects combined with some demand response (Eto, 1996). A similar plan today would supplement traditional infrastructure investments with modern grid technology, load flexibility, rigorous planning, and improved asset utilization. Because of the multi-billion-dollar scale of these planning decisions, coordinated and holistic grid planning is needed to design distribution system architecture that effectively balances the risks of over- or under-building the system to serve EV demand.

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Equity and Affordability

To maintain affordability as the system transitions, careful planning is needed to ensure that distribution system capacity is built in areas that will have high utilization, while also providing opportunities for charging to all consumers, whether they use it yet or not. Building infrastructure to support EV adoption could put either upward or downward pressure on electricity rates, depending on the revenue received from EV charging compared to the investments made to serve that load. For example, a public charging site with low utilization could bring less revenue than its cost to serve, increasing rates for other customers, whereas a site with high utilization could provide significant revenue to the utility relative to the cost of the equipment needed to serve that site, and the increased revenue could reduce rates for other customers in that rate class.

Accounting for energy equity is also important when evaluating grid plans. Improper planning and cost allocation could inequitably burden low-income ratepayers with the costs from affluent early adopters. Because of risks associated with uncertain grid equipment utilization when enabling EV charging plazas, the regulatory landscape may need to re-evaluate how costs are attributed and recovered. The traditional cost recovery mechanisms—through rates—may be insufficient as smart charging incentivizes different types of behavior and the anticipated amount of charging may not materialize.

Energy equity has many dimensions. Ensuring distributional equity will help protect vulnerable consumers from unmanageable energy prices, while transitional equity will ensure that the shift to vehicle electrification happens at a pace that communities can handle. Finally, procedural equity promotes an inclusive engagement of affected parties in the decision-making process.⁷

Decisions Needed at Multiple Levels

These grid planning activities are not solely the responsibility of utilities. The role of state legislators, regulators, and other state officials will continue to grow as multiple energy system objectives compete for priority. Similarly,

Retail rate designers, vehicle manufacturers, and charge station providers will need to work with distribution system planners to design solutions that balance the cost of new infrastructure with consumers' charging flexibility.

retail rate designers, vehicle manufacturers, and charge station providers will need to work with distribution system planners to design solutions that balance the cost of new infrastructure with consumers' charging flexibility. Analytical rigor and adaptability will be needed to incorporate new lessons learned and technological advances quickly into grid plans.

Decision-makers will need to think holistically as costs are shifted from one industry (petroleum) to another (electricity). The impact on rates of this shift will depend on the utilization of grid infrastructure, among other things. With high utilization, electrification could make electricity more affordable on a dollar-per-kilowatt-hour basis due to the increased consumption of electricity. With low utilization, the cost of new infrastructure to support electrification could exert upward pressure on rates. However, the California Public Advocates Office has found that all ratepayers, even those who cannot electrify, could financially benefit from electrification (PAO, 2023). Ultimately, the impact of electrification is still being determined, with many options available on how to enable electrification.

The costs for enabling vehicle electrification will need to be balanced against competing priorities and uncertainties in other industries as policymakers aim for an equitable energy transition. Priorities for the electric power system include enabling electrification, supply-side changes, reliability, and resilience, as well as safety and security. Uncertainties in other industries, such as fossil fuel and supply chain industries, could have large impacts on the future and our ability to execute the energy transition. Grid planning for vehicle electrification needs to be considered in this wider context.

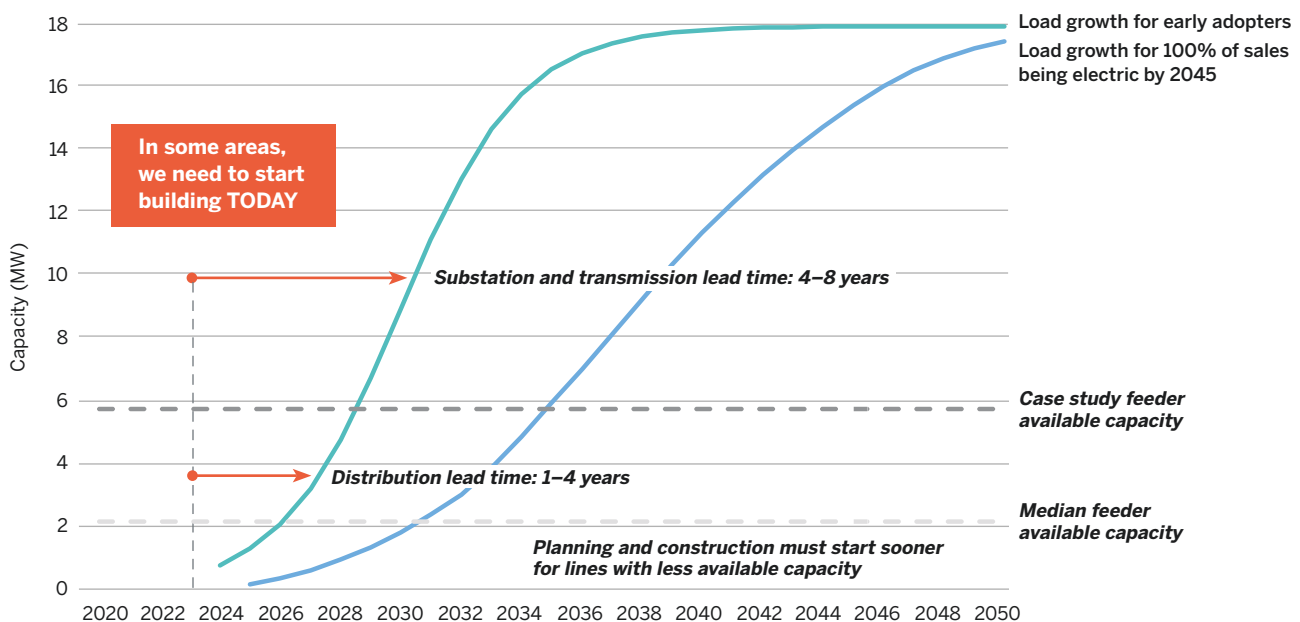
⁷ The various dimensions of energy equity and how to plan for each in the context of vehicle electrification are important but not the focus of this paper. For more complete discussions of equity, and particularly energy equity in the context of DERs, see Woolf et al. (forthcoming) and Morell-Dameto et al. (2023).

Forecasting EV Futures

The first step in planning for EVs is to forecast potential EV futures so that upgrades can be prioritized based on forecasts of the timing and locations of EV impacts. Historically, distribution projects did not require long-term forecasts, because they could be constructed at roughly the same pace as specific areas saw load growth. But going forward, longer-term forecasting of EV adoption and behavior will be critical for prioritizing regions and grid topological levels for various grid solutions since EV charging stations can be built much more quickly than new grid infrastructure.

As shown in Figure 9, the rapid increase in load growth from fleets together with the lead time needed to plan and build new infrastructure means that decisions on building new infrastructure should start today if electrification goals are to be met. Decisions about grid equipment, such as transformers, are expected to support grid needs for many years, as grid equipment has historically had a useful life of (and been depreciated over) 45 years or more (Eversource, 2023). However, grid planners have to make these decisions without perfect foresight on how local grid needs will evolve.

FIGURE 9
Time Frames for Grid Infrastructure to Meet Fleet Electrification Needs



The lead time needed for deploying grid equipment means that in some areas, to support electrification targets, decisions are needed today. Given that grid equipment is expected to be used for 45 to 50 years, the grid designed today will be expected to support our electricity needs in 2070.

Source: National Grid and Hitachi Energy (2023).

The rapid increase in load growth from fleets, paired with the lead time needed to plan and build new infrastructure, means that decisions on building new infrastructure should start today if electrification goals are to be met.

Unfortunately, general trends in EV adoption are insufficient to make distribution infrastructure decisions, as they do not inform a particular circuit's electrification trajectory or outline when consumers will want to charge throughout the day and week. While forecasting is not perfect for any type of load, modern forecasting practices can make grid planning decisions more informed by providing ranges of likely futures. The magnitude of likely EV adoption means that forecasting for EVs requires the best data, probabilistic methods, and scenarios to inform grid planning.

Forecasting EVs' impact on the distribution system boils down to two key questions:

- How fast will EVs be adopted?
- For each use case, when and where will customers charge?

Forecasters need to consider how quickly vehicles of different types will electrify, estimate how they will be used and charged, and assess how technological change may lead to different grid impacts. The nuances of translating regional forecasts of the timing of EV adoption to local distribution levels also need to be captured.

Anticipating EV Trends: Light-, Medium-, and Heavy-Duty EVs and Their Charging Technologies

First, it is important to understand how a particular vehicle will be used across the year. EV classification



needs to be more granular than high-level categories such as buses, trucking, and light-duty vehicles; for example, school buses and city buses have very different charging patterns. Similarly, medium- and heavy-duty truck categories can be broken down into nearly countless end uses including long-haul, drayage around ports, and delivery vans (NACFE, 2018). Light-duty categories can be broken into commuter and secondary vehicles with charging patterns that vary significantly depending how the vehicle is used.

Modeling these end uses quickly becomes an exercise in managing model granularity and scenarios. The industry has developed tools to manage these large datasets, but care should be taken to limit the quantity of variables, and an early effort to align assumptions can be helpful. Still, agent-based simulations can be used to model how operators of these different types of vehicles make individual charging decisions.⁸ Ultimately, it is individual decisions (represented by “agents” in a model) that stack together to create load profiles.⁹ Forecasting the medium- and heavy-duty fleet is an area where improvement is needed. Fleet operations are not common knowledge among power systems engineers and load forecasters,¹⁰ and these loads can be large on an individual vehicle level, with driving patterns that can vary significantly.¹¹

8 Idaho National Laboratory's Caldera tool is built to simulate multi-agent decisions algorithms to better understand the light-duty charging requirements across multiple charging levels (Level 1 and Level 2 charging, DC fast charging, etc.) and is available as an open source tool for more broad industry utilization (INL, 2023).

9 These individual agents can be used to simulate how charging profiles may be different by changing certain assumptions, such as how an autonomous ride-hailing fleet is dispatched for different optimization functions (Yi and Smart, 2021).

10 The North American Council for Freight Efficiency has a large library of white papers on commercial electric trucks and has conducted demonstrations in recent years to provide insights into the behaviors of fleets with electric trucks. See <https://www.nacfe.org> and <https://www.runonless.com>.

11 Lawrence Berkeley National Laboratory is developing a tool, HEVI-Pro, that is built to inform decision-makers on medium- and heavy-duty charging requirements based on a trip activity model from real-world datasets (Wang, 2021). HEVI-Pro is being used to underpin the medium- and heavy-duty load forecasts in California with consideration for 11 vehicle end uses for the medium- and heavy-duty segment alone.

As of today, the largest charger for a single truck is a 750 kW charger, but larger charging systems and connectors are in development, including plugs that provide individual vehicles with over 1 MW of charging. Recognizing these different use cases of charging, Box 1 outlines how Southern California Edison has developed forecasts to capture those impacts.

Changing battery technology is another major consideration for vehicle trends, which goes beyond the plug used to connect the EV. As EV batteries get larger and have faster charging capabilities, grid impacts will change. With larger batteries, EVs may not need to charge every day. With faster charging capabilities, we will see more diversity of charging behavior as fewer cars charge simultaneously. However, with both larger batteries *and* faster charging, the diversity benefits may erode—for example, cars will charge faster for longer—and the importance of larger infrastructure or more sophisticated load management solutions grows.

With larger batteries, EVs may not need to charge every day. With faster charging capabilities, fewer cars charge simultaneously. However, with both larger batteries and faster charging, the diversity benefits may erode, and the importance of larger infrastructure or more sophisticated load management grows.

Different vehicles also pull power at different rates across their state of charge, which forecasters and planners can try to capture in their models. By understanding the intricacies of a variety of EV technologies and their future, grid planners can begin to navigate the uncertainties of EV charging.

Forecasting Adoption Timelines

Added to the question of vehicle technology and use patterns is the question of when vehicles will electrify. For light-duty vehicles, stock turnover models that incorporate historical trends, along with policy and

BOX 1

Southern California Edison's Multi-Pronged Approach to Fleet Electrification

Southern California Edison demonstrates an example of the customer-collaborative model, in which the customer and utility collaborate to identify the best solution to the charging needs. In anticipation of significant EV growth in California, Southern California Edison first developed a transportation electrification load forecast informed by the state of California's policies to achieve its greenhouse gas goals. This approach focused on the increase in demand around major freight transportation corridors, medium/heavy-duty vehicle truck stops, and warehouse distribution centers, and identified long-lead-time grid expansion investments needed over the next five to seven years to ensure the grid is ready to serve this increase in demand.

For discrete EV charging requests, Southern California Edison works with some customers to select sites that best meet their needs. The utility's geographic information system (GIS) Power Site Search Tool maps 7,000 industrial buildings and land sites over 50,000 square miles to enable consideration of land, building, power, and broadband fiber availability for locating charging sites in its service territory. Customer-collaborative processes are covered in more detail in the "Coordinated and Holistic Planning" section below.

economic factors, can be informative. Meanwhile, electrification decisions for medium- and heavy-duty fleet vehicles can be difficult to model and can happen very quickly, potentially outpacing both existing grid capabilities and grid construction timelines. While historical and current data still establish the starting point for forecasts, estimates of future trends are needed and can be gleaned from a variety of sources. Effective adoption forecasting is based on three principles: (1) understanding the impact of policy, (2) effective use of available data and models, and (3) recognizing that individual fleet decisions can disrupt forecasts.

Incorporating Policy

“Backcasting” from stated policy objectives can be a helpful tool for forecasting. For instance, seven states have adopted advanced clean trucks rules that require vehicle manufacturers to sell zero-emission vehicles as an increasing percentage of their sales from 2024 through 2035 (McNamara, 2023).¹² This accelerated adoption of medium- and heavy-duty EV trucks is not in the historical record, but can be projected using estimates of policy effects. By “backcasting” from policy objectives rather than forecasting from scant historical observations, forecasters can better understand the trajectory needed to achieve the policy.

Effectively Using Available Data and Models

Trends can also be observed in department of motor vehicle registrations to establish a solid starting point from which to forecast the local vehicle stock, although assigning load to a given location based solely on vehicle registration data is problematic.¹³ More information is required to effectively characterize where and how a given vehicle will charge.

By “backcasting” from policy objectives rather than forecasting from scant historical observations, forecasters can better understand the trajectory needed to achieve a policy goal.

Electrification likelihood models can also be highly informative in prioritizing areas where the distribution system may be insufficient in the near term. These models can be created in a variety of ways, including through surveys, heuristics, analysis of public data,¹⁴ or agent-based tools.¹⁵ The models capture local trends and key indicators for electrification likelihood at levels granular enough to help prioritize distribution system upgrades.

For example, Eversource introduced an adoption propensity model that combined variables that drive electrification likelihood with circuit-level information to prioritize circuits where EV adoption may quickly outpace grid capabilities. Even more simply, customer demographics, such as the mix of residential and commercial customers on a circuit, can be included when downscaling estimates of regional load impacts to the distribution level.

However, while electrification likelihood models can be helpful, any model must be enhanced with real-world data and an understanding of the decision-making considerations. Many of today’s data collection efforts focus on combining indicators of potential EV impact. A wide range of data types can be informative, such as the number of buses by transportation authority (from state agencies), school bus ridership (from state agencies), employment level in the transportation and warehousing industry (from the census), traffic patterns (from state and federal agencies), population density (from the census), and car registrations. However, these datasets are not sufficient to characterize future grid impacts. For example, they do not provide expected charging locations and primary transportation use case.

The good news about data collection is that many regions are still in the early stages of vehicle electrification, and systematic data collection on behalf of grid planning at the time of vehicle purchase can still be implemented. Data on an EV driver’s likely charging location or primary use of the vehicle will help grid planners characterize both where and when the vehicle is likely to charge. There are multiple ways that EV adoption data may make their way to the utility, but distribution system planners could be involved in designing data collection efforts, including those by state agencies. Data collection efforts by state departments of motor vehicles or departments of transportation may be the most suitable avenue for utilities to collect what they need; there is no need

¹² The seven states are California, Maryland, Massachusetts, New Jersey, New York, Oregon, and Washington.

¹³ Department of motor vehicle registration data are often insufficient for medium- and heavy-duty vehicles, as these may be registered at a headquarters building but operate exclusively at a warehouse in another state from headquarters.

¹⁴ The Brattle Group performed an EV allocation study for the Electric Reliability Council of Texas (ERCOT) that projected the impact of vehicle electrification at each substation in ERCOT’s territory. The medium- and heavy-duty vehicles were allocated using a variety of metrics and methods that considered things like the employment level in the transportation and warehousing industry in a given zip code (Sergici et al., 2022).

¹⁵ Similar to forecasting the impact of the type of EV from bottom-up agent-based simulations, Exelon is using a tool developed by Argonne National Laboratory that simulates individual decisions about whether or not to switch from gasoline-powered vehicles to EVs (Sagodd, 2019).

The good news about data collection is that many regions are still in the early stages of vehicle electrification, and systematic data collection on behalf of grid planning at the time of vehicle purchase can still be implemented.

to request the same information of consumers across multiple large entities.

Recognizing Fleet Impact on Forecasts

The electrification of medium- and heavy-duty vehicles can happen at a pace faster than typical utility planning. These vehicles are usually replaced at end of life (typically 12 years) or as vehicles are up for trade-in (typically every five years). Thus, all new vehicles in a fleet can potentially be electrified in a span of just a few years. Electrifying fleets would bring a significant new

demand at a particular location very quickly, and utilities typically have little data on the fleets that operate in their territories and the fleets' electrification plans.

For commercial fleets, the best data available publicly and through private providers are still insufficient to meet grid planning needs. In response to this need, the distribution utility Oncor developed a suite of tools to characterize the likely fleet locations and their impacts on substations (Treichler, 2020). Oncor's Clean Fleet Partnership Program also provides prospective EV fleets with educational materials on how the process of electrification works and collects information from the fleets on their operations and electrification potential (Oncor, 2023).

Table 2 outlines good, better, and best practices associated with forecasting EVs, with some examples. Similar tables appear below with respect to different planning attributes.

TABLE 2
Potential Practices for Forecasting EVs

PLANNING ATTRIBUTE	
Forecasting includes consideration of: <ul style="list-style-type: none"> • EV trends, including granular end use characterization • Local EV adoption trends 	
Good practices	<ul style="list-style-type: none"> • Multiple EV end uses are modeled (light-duty vehicles, fleet vehicles, trucking, etc.), including different charging profiles for each. • Backcasting from today's policy goals is reflected in the forecast of EV stock turnover used to estimate rate of EV adoption. <p>Example: The Independent System Operator of New England's Transportation Electrification Forecast includes multiple end uses and policy impacts at both the federal and state levels.</p>
Better practices	<ul style="list-style-type: none"> • Forecasting considers trends in vehicle battery sizing and efficiency. • Customer demographics, such as the mix of residential and commercial customers, are included when downscaling estimates of regional load impacts to individual circuits. <p>Example: Portland General Electric uses the AdopDER model to conduct bottom-up forecasting of EV locational adoption trends.</p>
Best practices	<ul style="list-style-type: none"> • All model results are supplemented with data collected from local surveys and observations. • Planners partner with EV manufacturers to use telematics data for grid planning. <p>Example: Oncor's Clean Fleets Partnership Program surveys fleets in its service territory to find more information about their electrification plans.</p>

Practices identified by members of the Grid Planning for Vehicle Electrification Task Force.

Source: Energy Systems Integration Group.

Characterizing Locational and Temporal EV Impacts

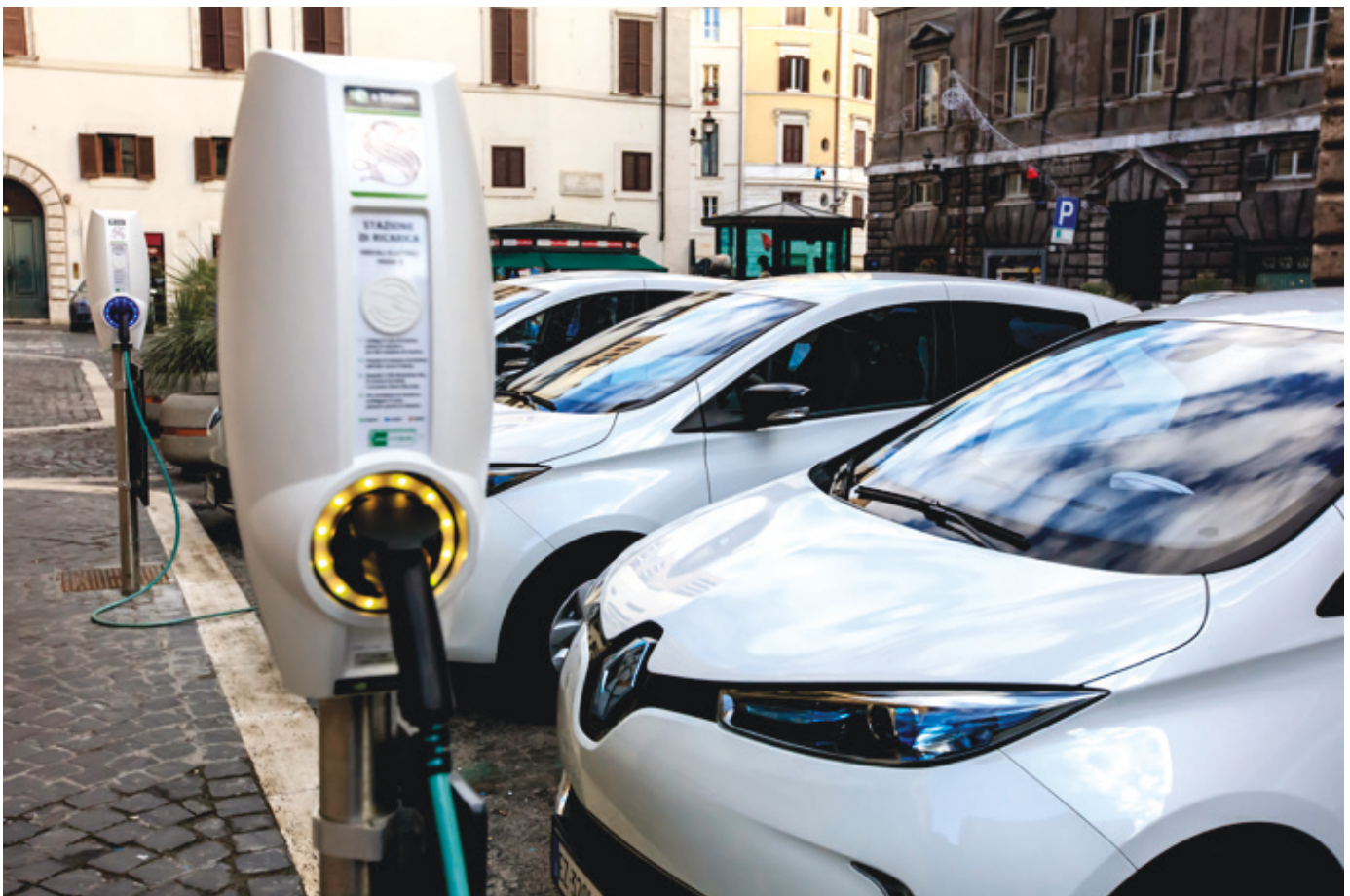
Once the base inputs of EV forecasting are gathered, the second step is to characterize EV load across time (by hour of day, season, etc.) and space, using scenarios to understand potential futures. This section translates the modeling inputs and assumptions into tangible grid impacts. Once the grid impacts have been estimated, plans can be developed to most cost-effectively integrate EVs, as discussed in the following section, “Mitigations: Avoiding the Largest Impacts.”

Best practices around EV forecasting to guide analysis include to:

- **Take into account the vehicle use case.** For example, a personal pickup truck and a company pickup truck may have very different charging patterns.

They likely have different access to charging infrastructure and different purposes for travel, which shape their charging behavior in time and space.

- **Consider calendar effects.** A “typical day” analysis will be insufficient, as charging will vary between weekdays, weekends, and holidays, and potentially seasonally (e.g., related to tourism, temperatures, school calendars).
- **Evaluate charging flexibility.** Many EV use cases leave room for flexibility in charging within a charging session, but some EV owners can also choose between charging sessions—a driver could choose to charge at their workplace or at home. Planning studies can consider some form of smart (managed) charging either



embedded in the load profile or, preferably, as a tool available to distribution system planners to evaluate the efficacy of smart charging to address grid needs.

- **Prepare for technological evolution.** Technological advances—such as faster charging capabilities and larger vehicle batteries—may affect forecasted EV impacts in terms of both their charging (energy (kWh) and peak demand (kW)) and their discharging (vehicle-to-home (V2H) or vehicle-to-grid (V2G) operation).
- **Use blended forecasts.** For developing scenarios, blended forecasts provide the most well-rounded insights for distribution planning because they consider both the top-down and granular bottom-up inputs. Blended forecasts allow policy shifts to be considered, while also incorporating local trends in the analysis. Admittedly, bottom-up analyses are data intensive, but they provide the most granular insights for distribution planning purposes.¹⁶

Timing: Developing Charging Profiles

Assembling the inputs and assumptions about types of EVs and their adoption allows us to stack data together to develop location-specific charging profiles. These charging profiles can start with understanding day-to-

day charging behavior, showing likely variability throughout the day and across weekdays and weekends, and then move on to understanding charging around holidays and extreme weather.

Helpful sources of typical EV daily load shapes include EV Watts (managed by Energetics), EPRI's Load Shape Library, the National Renewable Energy Laboratory's EVI-X suite of modeling tools, Stanford University's SPEECH model, and other sources of publicly available data (such as independent system operators' load forecasts).¹⁷ Vehicle manufacturers, charge station operators, and national aggregators will also have data on charging across jurisdictions. Utilities can make use of any directly metered EV loads within their jurisdictions to understand how their local circumstances may differ from national datasets. These data sources are growing in sample size; as more charging sessions inform the underlying datasets, forecasters can be more confident that they are capturing typical behavior. However, all of these datasets are biased in that they only reflect early adopters and are not necessarily representative of how vehicles will charge as more and different types of consumers go electric. The timing of charging will continue to be evaluated as different users electrify and as smart charging programs are implemented.

Setting the Baseline: Typical-Day Behavior

EV charging experience to date shows that charging profiles will vary based on location but generally follow a diurnal pattern, with more charging in the daytime for public chargers and in the evening and overnight for at-home charging. Figure 10 (p. 22) shows how public charging usage changes from weekdays to weekends. Early research also indicates that traffic patterns can be indicative for EV charging needs en route, but that light-duty vehicles still spend roughly 70% of the time parked at home (Pearre, 2013).

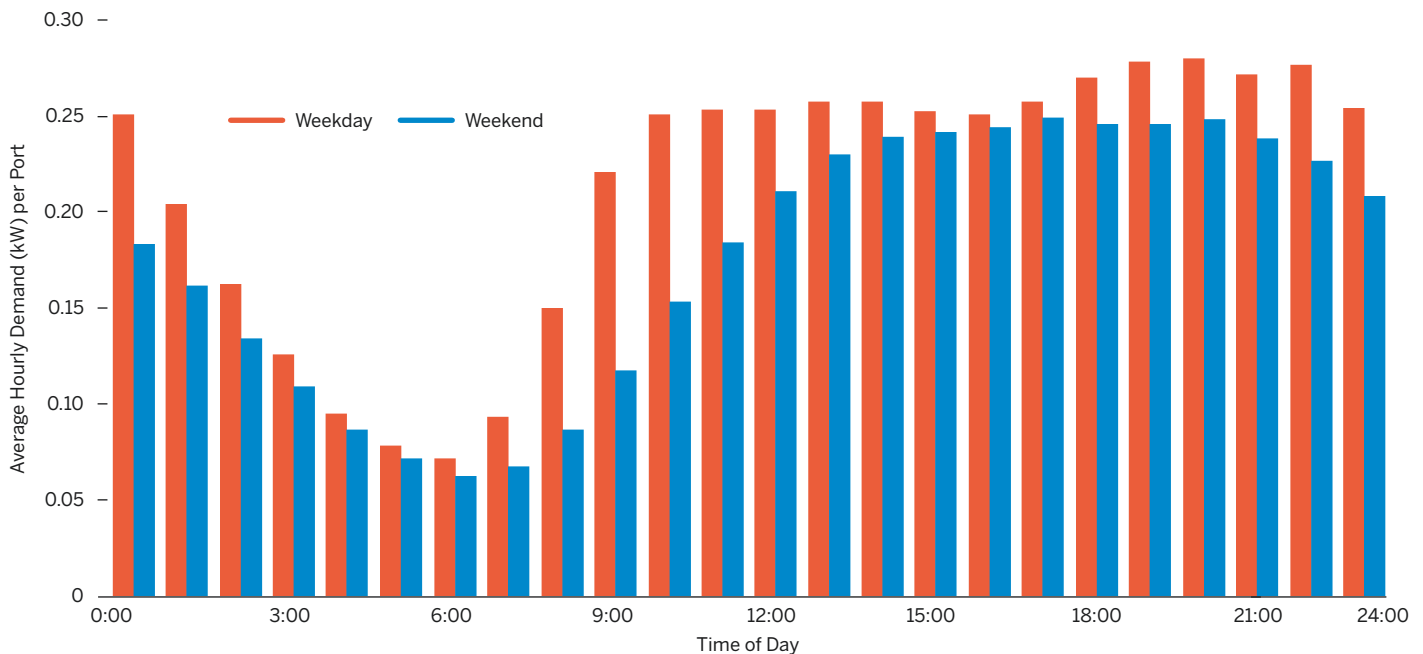
However, it remains to be seen how flexibility afforded by larger batteries will manifest in charging profiles and charge session duration (Avista, 2019). Recent advances in EV range that are made possible by larger batteries could allow for flexibility both within and between



¹⁶ As covered elsewhere, bottom-up analyses often gather data from sources that are not traditionally used in utility planning, such as telematics information, department of motor vehicle records, or fleet data providers.

¹⁷ See <https://www.energetics.com/ewatts-station-dashboard>, <https://loadshape.epri.com/>, and <https://www.nrel.gov/transportation/evi-x.html>.

FIGURE 10
Typical Aggregate Charging Profile for Public Charging



The typical charging profile for public charging differs on weekend and weekdays with the highest usage coinciding with traditional system peaks in evenings on weekdays, and the minimum charging occurring at 6:00 am.

Source: Energy Systems Integration Group. Data from Energetics, “EV Watts Charging Station Dashboard Q3-23,” 2023, <https://www.energetics.com/evwatts> (accessed July 1, 2023).

charging sessions. Flexibility within a session could take the form of delayed start charging, where the vehicle waits to charge for some time after it is plugged in. Flexibility between sessions could take the form of a driver choosing to charge in public during the day instead of at home overnight.

Related to between-session flexibility, we do not yet know the preferred mix of public vs. at-home charging for the majority of EV drivers.¹⁸ Will light-duty EV drivers charge primarily in public or at home? How will this vary based on residence type, income level, and adoption likelihood? We also do not know whether drivers will want to charge immediately upon arrival or whether delayed charging will be acceptable with appropriate incentives. These dynamics will become clear as EVs are more heavily adopted, through open conversation about early experiences, and through

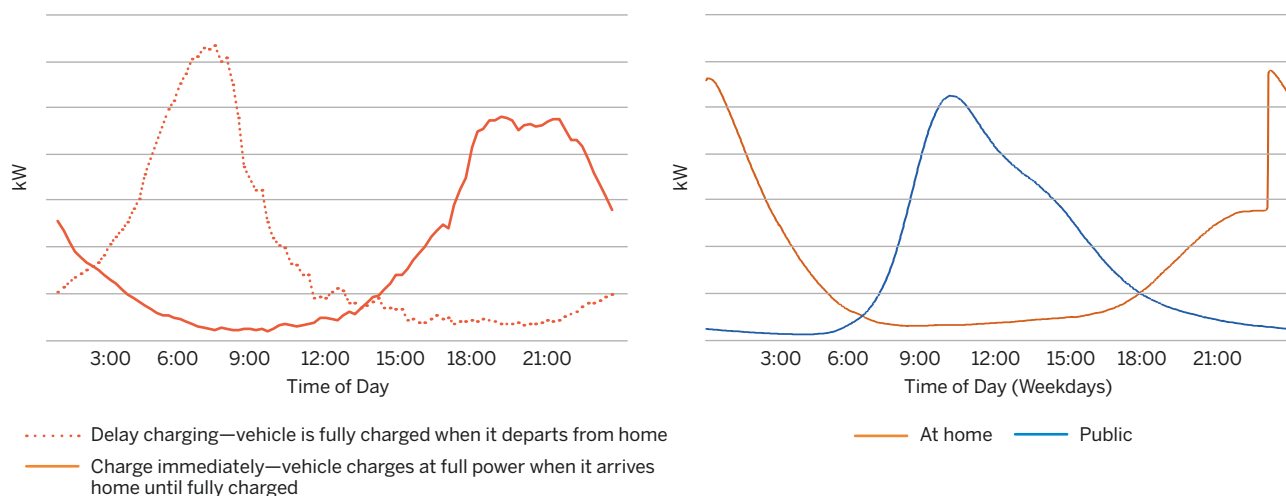
analytical studies. Customer charging behavior can also be influenced through policy, pricing, and programs. For example, free public charging may incentivize drivers to forgo home charging. These behaviors and decisions will also change over time as the type of EV adopter changes and public charging networks become more robust.

Specific assumptions made in analytical studies can significantly alter the charging profile for grid planners. Figure 11 (p. 23) shows the impact to the aggregate load shape of different assumptions around immediate vs. delayed at-home charging (left) and public vs. private charging profiles (right). The graph on the left isolates at-home charging behavior, while the one on the right shows how charging behavior can vary by location, illustrating how an EV charging profile needs to consider the impact of public vs. at-home charging along with the timing of vehicle charging.

¹⁸ This report adopts a public vs. at-home charging paradigm that has been used in other recent publications (see, for example, Wood et al. (2023)), in which workplace charging is grouped into public charging. This framework allows for consideration of EV drivers who may not have a distinct workplace.

FIGURE 11

Charging Profiles Can Vary Based on Location and Charge Time Strategy



Large differences can be observed in charging profiles based on charging assumptions that can have a large impact on the aggregate profile observed from EV charging. The left-hand graph shows that the shape of at-home charging can vary significantly based on the charging strategy. Similarly, the right-hand graph shows how at-home and public charging profiles can vary significantly. These graphs are conceptual and meant only to show general charging shapes.

Source: Energy Systems Integration Group. Data from the U.S. Department of Energy's Electric Vehicle Infrastructure Projection Tool (EVI-Pro) Lite (left) and Powell, Cezar, and Rajagopal (2022) (right).

Planning for Peaks

For the power system, marginal investments in capacity—for generation, transmission, and distribution—are not made based on average conditions, but rather the highest loading. Abnormal circumstances determine when the grid is most stressed and drive the largest investments. Planning for EVs is no different, and studies must consider how consumer charging expectations may change around holidays and weather events.

Another key input affecting EV forecasting is the impact of temperature, as batteries are less efficient when they are cold; their capacity declines and they take longer to charge (Motoaki, Yi, and Salisbury, 2018).¹⁹ Additionally, the vehicle occupant uses battery-provided heat to keep the cabin comfortable, so miles travelled per kWh decrease as ambient temperature falls. This will contribute to increased weather-dependence of the power system, which is also driven by availability of wind and solar resources, heating and cooling demand, and increased

Abnormal circumstances drive the largest investments, and studies must consider how consumer charging expectations may change around holidays and weather events.

electrification. There is a growing trend in resource adequacy analysis to consider the impact of multiple weather years on the load profile, and distribution planning could use such an approach as well.

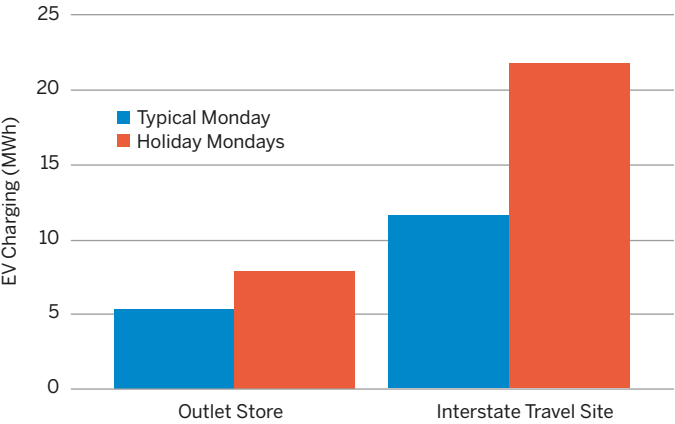
Extreme weather will also need to be considered. Because EVs still represent a relatively small portion of the primary driving mix today, there is limited public data on how charging needs change around extreme weather events that may require evacuation, such as hurricanes, wildfires, and floods. With the multiple days' notice that is typical for hurricanes, there may be an opportunity to stagger charging as people prepare to

¹⁹ Motoaki, Yi, and Salisbury (2018) found that "the average deterioration of a 30-min [direct current fast charger] charge from warm temperature (25°C) to cold temperature (0°C) can be as large as a 36% decrease in the end [state of charge]."

evacuate. However, without sufficient notice or sufficient grid infrastructure, the grid could be unable to support charging requirements in this type of emergency. Lessons for how to prioritize EV charging within grid capabilities prior to extreme weather events can come from experiences pre-cooling homes and ensuring fully charged EVs in response to California’s Public Safety Power Shutoff events. There is an opportunity for the industry to learn from early experiences, but only if information is exchanged openly with ramifications readily discussed.

Lastly, charging profiles around holidays need to be considered. Just as highway rest areas are busier during holidays, public charging adjacent to transportation corridors sees a rise in traffic and charging demand around holidays. At-home charging may also see increases prior to holidays as EV owners prepare for longer trips. These spikes in demand may warrant grid infrastructure upgrades, but they could also be offset by reductions in demand from commercial sectors during these holidays. At the system level the net effect may be limited, but the distribution system could be stressed in specific locations. The industry has little experience with the holiday effect on charging. What we do know is that charging profiles will vary across the year aligned with trends that may not appear in typical load forecasting efforts.

FIGURE 12
Utilization of Public Charging Infrastructure Can Vary by Site and on Holidays



Public charging stations can have distinct utilization rates that are also affected differently by holidays.

Source: Energy Systems Integration Group.

Figure 12 shows how two sites experienced notable increases in charging demand associated with holidays in 2022. Increases of this magnitude can strongly affect infrastructure sizing considerations, consumer experience, and grid operations.

There is still much to learn about when the early majority of EV drivers will want to charge their vehicles. Early adopters’ choices are informative, but mass adoption will adjust the early trends in subtle but important ways.

Charging Location: Where the Grid Needs Arise

When prioritizing distribution system locations for added grid planning attention, location-specific needs can be assessed via scenarios that illustrate different possible

Scenario analysis must bridge the gap between two overlapping definitions of location: the geographical origin, corridor, and destination locations for EV traffic, and the grid’s topological (or electrical) locations.

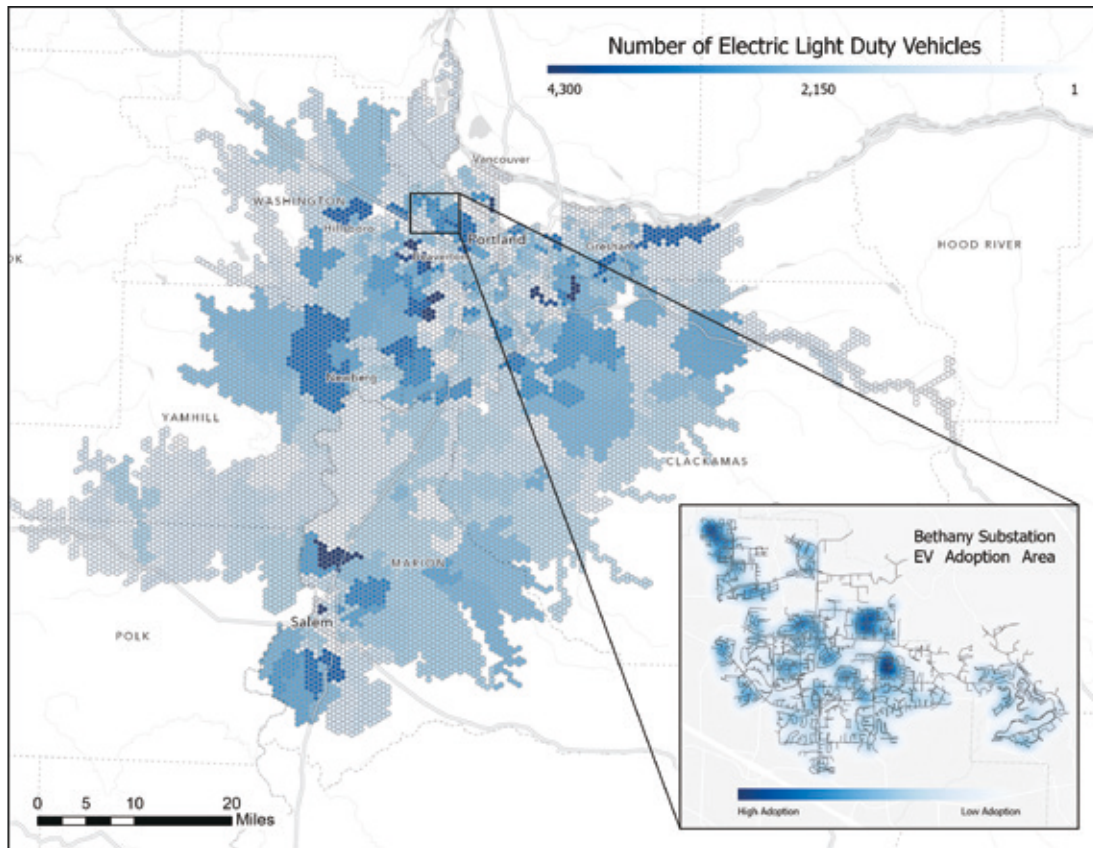
future pathways. This analysis must bridge the gap between two overlapping definitions of location: the geographical origin, corridor, and destination locations for EV traffic, and the grid’s topological (or electrical) locations. Distribution planners usually have good information about the locations of grid assets, so the discussion here focuses on pairing that information with charging demand location, which arises from transportation and parking behavior.

Location-Sensitive Adoption and Access

Geographic locational analysis considers how EV adoption may be localized to certain sections of a planning region, creating EV hotspots. For instance, local municipalities may have decarbonization plans or tax incentives that drive the electrification of light-duty vehicles or medium- and heavy-duty fleets. Locations around ports or colleges and universities may also be hot spots in the near term. The implications of EV hotspot scenarios can help with prioritizing initiatives in distribution system plans.

FIGURE 13

Light-Duty EV Adoption Forecasts by Location in Portland, Oregon



Various neighborhoods around Portland, Oregon, are forecasted to see different rates of adoption. Portland General Electric has developed forecasts that show the effects of EVs at different points served by each of its substations.

Source: Portland General Electric.

Topological location hot spots can be a function of the existing infrastructure loading and times when EVs charge—namely, whether they charge at home, typically at night, or in public, typically during the day (Powell, Cezar, and Rajagopal, 2022). Local housing situations also influence EVs’ impacts. In multi-family housing and areas with higher percentages of renters, EV drivers may rely more heavily on public charging than those who live in single-family homes.

Figure 13 shows how various neighborhoods around Portland, Oregon, are forecasted to experience different adoption. It zooms into a specific substation and shows the differing effects on the various electrical locations served by a given substation.

By varying the grid charging location assumptions, grid planners can better understand how the distribution system can support the charging needs. Early understanding of grid and EV capabilities can be helpful in designing effective solutions to future challenges.

Vehicle Mobility

EVs’ ability to move around represents a new type of load for grid planners. There is still much to learn about the incentives required to convince folks to charge in different locations, but the first step in understanding EV movement is to understand today’s transportation behaviors. The troves of data available via global positioning system (GPS) tracking of vehicles can shine light on how and when people drive their vehicles. GPS

By varying the grid charging location assumptions, grid planners can better understand how the distribution system can support the charging needs.



tracking data are generally available for a price from vehicle telematics for light-duty vehicles and other tracking systems for medium- and heavy-duty fleets.

For example, Eversource Energy uses anonymized GPS vehicle tracking data to understand vehicle electrification impacts on the power system. In Eversource's evaluation of the transportation trends in Cambridge, Massachusetts, winter traffic was found to be roughly 10% higher than summer traffic due to local universities' schedules (Walker, 2023). There were also upticks in vehicle miles traveled around holidays and at weather-driven vacation destinations (such as Cape Cod in the summer). Translating these traffic patterns into forecasts of power requirements still requires some assumptions on state of charge across vehicle trips and consumer behavior; however, understanding trip origin and destination can inform likely charging locations and charge start times.

Scenarios to Manage Inherent Uncertainty in Forecasts

Given the uncertainty in EV adoption and the timing and location of charging, distribution system planners can use scenarios to understand how the grid may be affected by a variety of key variables. Distribution planners are just beginning to use scenario analysis to understand potential futures, and scenarios run explicitly for EVs have not yet been implemented broadly across the industry; thus they represent an aspirational best practice.

Embracing the uncertainty around EV adoption and charging patterns through scenario planning helps planners think in broad strokes, rather than narrow solutions. Scenario planning helps identify the suitability of the power system (generation resources through distribution equipment) to support a range of charging behavior. Solutions can then be designed to improve the power system as appropriate or encourage alternative charging behavior. Table 3 (p. 32) lists good, better, and best planning practices.

Early identification of the key scenarios to use for grid planning purposes is important. First, wide bookends can be evaluated to understand the implications of very different futures. For instance, an unmanaged charging scenario would show the many huge investments in the generation fleet that would be required to serve such a load. Although wholly unmanaged charging is usually untenable, unmanaged charging scenarios can nonetheless be informative for considering the magnitude of potential grid needs as we learn more about how to best manage charging. Another bookend to consider is that a community's vehicle transportation needs may diminish with urbanization and remote work trends. These bookends can address the medium-term horizon, leaving longer-horizon, speculative technology advancements to be addressed in future iterations of grid planning.

Embracing the uncertainty around EV adoption and charging patterns through scenario planning helps planners think in broad strokes, rather than narrow solutions.

In addition to bookend analysis, forecasts for distribution planning include top-down policy implications blended with data on local trends. Scenarios built from the blended forecast can provide broad ranges of outcomes as they vary underlying assumptions to capture multiple potential futures.

Since significant action is likely required to meet the vehicle electrification needs on even a 10-year horizon, three scenarios targeting the short- to medium-term are recommended, each of which highlights different plausible ways that the grid might be stressed. These would include the following:

- Some sort of stress on the charge-time expectations from consumers, such as their prioritizing rapid **15-minute charging** to get to some extended level of charge. Some auto manufacturers have recognized the need for rapid charging capabilities to relieve range anxiety; the long trend toward faster and faster charging continues.
- A **medium- and heavy-duty vehicle growth** scenario. This will help to understand how and whether the typical stock turnover in this segment may shift expectations rapidly if electric trucks become cost-effective for medium-duty fleets.
- A scenario that emphasizes **at-home charging**, which would stress the premise-level distribution equipment.

Scenario analysis becomes increasingly challenging as different planning sensitivities are considered simultaneously. Utilities and regulators will want to coordinate with stakeholders early—local community members, consumer and environmental advocates, and others—to understand how vehicle electrification scenarios should be considered alongside other planning variables, such as the growth of distributed solar, building electrification, dealing with aging assets, and other challenges for reliability and resilience.

TABLE 3
Planning Practices Associated with Characterizing EV Impacts

PLANNING ATTRIBUTE	
EV impact characterization varies across time of year and by location.	
Good practices	<ul style="list-style-type: none"> • Use case: Differences in charging access between geographical regions are considered, and charging profile matches charger type. For example, distribution circuits serving predominantly multi-family housing would have a higher percentage of public charging, which is likely to occur more during the day than at night. • Calendar effects: Analysis goes beyond “typical day” characterization to capture differences in weekday, weekend, and holiday charging patterns. • Scenario analysis: Multiple scenarios are considered to understand the implications of key modeling assumptions. For example, distribution planners characterize how varying charging profiles on representative circuits can change the grid solution needed. <p>Example: The New York State Energy Research and Development Authority (NYSERDA) used a scenario-based analysis to understand distribution upgrade costs associated with various clean transportation futures.</p>
Better practices	<ul style="list-style-type: none"> • Use case: Different load profiles are developed for different vehicle use cases (e.g., personal pickup truck vs. company pickup truck). • Calendar effects: Changes are captured in charging profiles across the year due to weather and seasonal travel trends in the study region. • Scenario analysis: A variety of stress-test scenarios are built, each highlighting a different way in which the distribution system might be stressed. <p>Example: The California Energy Commission is using a tool developed by Lawrence Berkeley National Laboratory, HEVI-PRO, to capture 19 use cases for medium- and heavy-duty trucking.</p>
Best practices	<ul style="list-style-type: none"> • Blended forecasts: Top-down trend data are supplemented with bottom-up behavioral data to understand temporal and spatial transportation patterns in the study region. These bottom-up data could include GPS data or observed charging session data, if available. • Use case: Statistical variability of observed charging behavior is captured within each defined use case. The effect of vehicle-to-everything (V2X) is also captured to the extent that charging needs are affected by the EV battery used for non-mobility use cases. • Scenario analysis: Separate scenarios are carried all the way through distribution planning to identify impact on specific distribution equipment decisions. <p>Example: Eversource, Portland General Electric, and Pacific Gas and Electric use Stanford’s SPEECH model to capture statistical variability of charging behaviors.</p>

Practices identified by members of the Grid Planning for Vehicle Electrification Task Force.

Source: Energy Systems Integration Group.

Mitigations: Avoiding the Largest Impacts



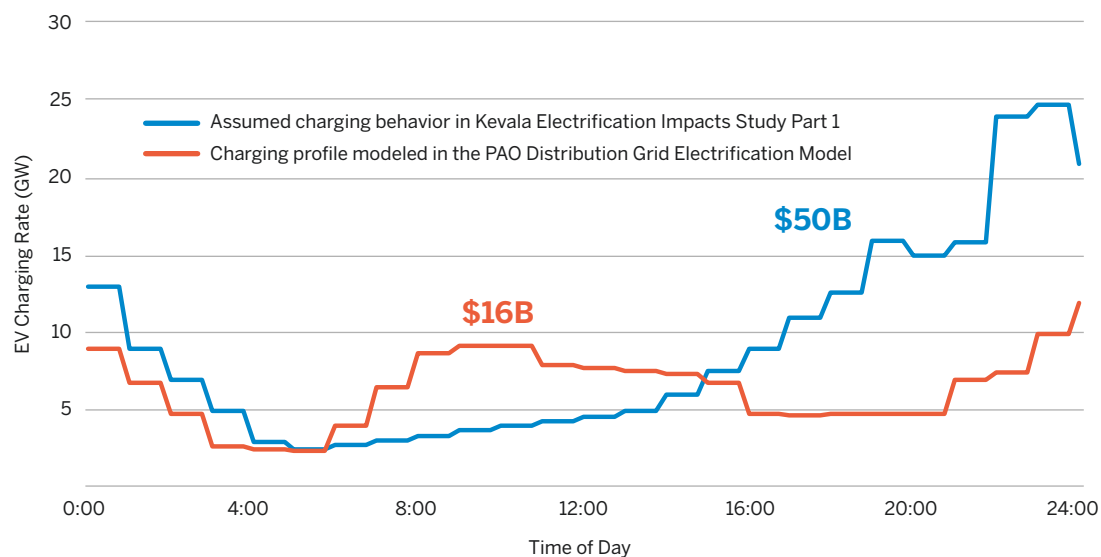
The third step in grid planning for vehicle electrification is to consider mitigations that can diminish, defer, or eliminate the need for grid upgrades. New technologies, programs, rate design, and other mitigations can be included in grid plans to help address EV integration challenges, increase EV hosting capacity, and potentially reduce costs, while providing EV opportunities for all consumers. These mitigations may be suitable for near-term implementation while EV adoption is in its early stages, to gain experience and bridge the gap between today and the future grid design, yet to be identified. They may then be part of that future to help keep down costs in the long term. Early assessments of the effectiveness of various mitigation strategies will be of tremendous value as EV growth progresses.

New technologies, programs, rate design, and other mitigations can be included in grid plans to help address EV integration challenges, increase EV hosting capacity, and potentially reduce costs, while providing EV opportunities for all consumers.

Historically, utilities assumed load profiles for grid planning to be static inputs that did not vary in modeling efforts according to grid conditions or the availability of supply-side resources. When the impact of time-of-use

FIGURE 14

Differences in EV Charging Assumptions and Costs of Distribution Upgrades in Two Recent Studies



Differences in charging assumptions can have a large impact on the cost of distribution upgrades. Smart charging can adjust the charging profile.

Source: Energy Systems Integration Group. Data from Kevala (2023) and the California Public Utilities Commission's Public Advocates Office (2023).

(TOU) rates or other demand management programs is included in the load forecast, these are also typically considered to be static inputs. However, EV demand can fluctuate based on local (or bulk) system needs, prompting an evolution in demand management planning practices. Programs and tariffs can address grid needs, with planners incentivizing EV-related behavior change as an alternative to building new infrastructure.

Recent work in California highlights the importance of managed charging to adjust the EV load shape, which in turn can reduce the need for distribution upgrades. Two recent studies—the Electrification Impacts Study Phase 1 (Kevala, 2023) and the Distribution Grid Electrification Model (PAO, 2023)—analyzed distribution upgrade costs in California due to vehicle electrification. A comparison of the two studies, and accounting for differences in capital costs between them, shows that different charging profile assumptions can reduce forecasted distribution upgrade costs. The Phase 1 Kevala study estimated \$50 billion in distribution upgrades costs,

while the Public Advocates Office study estimated those costs at \$16 billion.²⁰ The charging profiles, captured in Figure 14, highlight the importance of robust data and analytics in planning studies, while also highlighting the importance of TOU rates and other incentives to adjust charging behavior based on system needs at both the bulk and distribution levels.

Smart Charging—Getting to the Right EV Load Shape

Smart charging ranges from predetermined price signals (such as demand charges and TOU rates) that inform EVs when it is cheaper to charge based on typical grid characteristics during different time periods, to dynamically managed charging that addresses grid needs as they arise. Each can be an important tool in planning the grid and managing variability on a daily basis by helping to avoid the degradation of grid equipment and operational challenges before they arise.

20 Additional cost savings could be accrued from bulk system capacity deferral and curtailment reductions.

Demand management, including smart charging, will not be able to mitigate the need for all EV-related infrastructure investments. However, many planning studies show that smart charging can alleviate grid stress induced from unmanaged charging profiles (Greenblatt, Zhang, and Saxena, 2021). Indeed, forecasting for EV adoption usually begins with understanding the raw charging demand and then layering in smart charging impacts (Kevala, 2023). Smart charging has been shown to have a significant effect on power system reliability and infrastructure costs (PAO, 2023).

Smart charging will be needed on a regular basis to address potentially conflicting grid needs. Given the scale of EVs to be integrated, demand management approaches that embrace each type of mitigation in Table 4 may be most effective. Embedding smart charging capabilities in distribution planning can lead to greater utilization of existing infrastructure, helping to meet the charging requirements of multi-family housing and constrained corridors without requiring upgrades. For that same reason, smart charging is a tool to integrate more EVs quickly. However, consideration of smart charging in planning should be grounded in studies of actual consumer behavior and technology adoption.

Table 4 broadly categorizes common mitigation measures, indicating the relative suitability for a given grid level and the relative ease and cost to implement. The degree of shading in the table cells indicates the suitability of the measure to address challenges for the grid level and the complexity associated with implementing the measure. Lighter shading indicates greater suitability and less complexity.

Each of these measures aims to encourage charging at times that are optimal from the grid perspective. While some stakeholders assert that managed charging of EVs is needed, others believe that price signals provided by time-varying rates can sufficiently incentivize EV charging behavior. Each approach has advantages and

Smart charging will be needed to address potentially conflicting grid needs. While some stakeholders assert a need for managed charging of EVs, others believe that pricing signals provided by time-varying rates can sufficiently incentivize EV charging behavior.

TABLE 4
Suitability of Different Types of Smart Charging to Address Grid Challenges

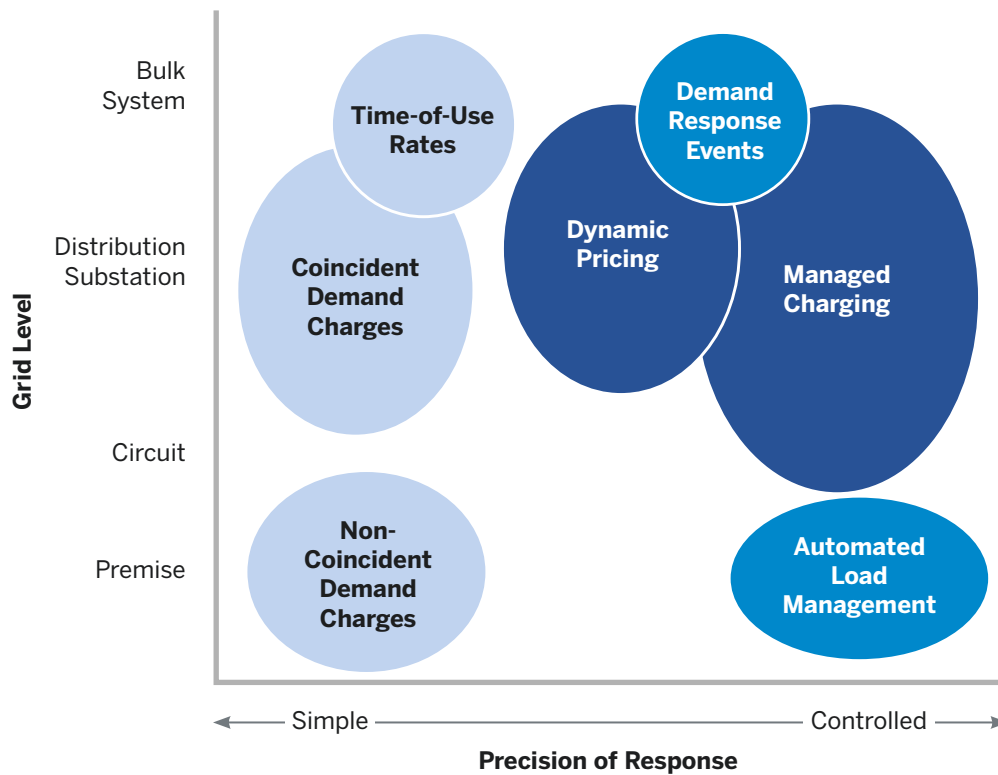
Mitigation Measure	Classification		Suitability to Address Challenges at Multiple Levels				Ease of Implementation	Cost
	Signal	Timing	Site	Distribution	Transmission	Generation		
Demand charge	Pricing	Preset	Light	Light	Dark	Dark	Light	Light
Time-of-use rate	Pricing	Preset	Light	Light	Dark	Dark	Light	Light
Dynamic price signal	Pricing	Dynamic	Light	Light	Light	Light	Dark	Dark
Consumer response to event-based demand response	Control	Dynamic	Dark	Dark	Light	Light	Dark	Light
Dynamic managed charging	Control	Dynamic	Light	Light	Light	Light	Dark	Dark
Automated load management	Control	Preset	Light	Light	Dark	Dark	Dark	Dark

More to less suitable Less to more complex

Various types of smart charging can be accomplished through pricing or control programs, with preset or dynamic definitions, and can address grid challenges at different levels. The ease of implementation and relatively lower cost tend to go hand in hand, and this type of mitigation measure should be evaluated against all alternatives including infrastructure improvements. The degree of shading indicates suitability of the measure to address challenges for the grid level and the complexity associated with implementing the measure. Lighter shading indicates more suitability and less complexity.

Source: Energy Systems Integration Group.

FIGURE 15
Smart Charging Measures' Precision of Response and Alignment with Grid Needs



Demand-side management measures range from blunt tools to readily adaptable measures to address varying grid needs. The measures can address challenges at all grid levels, but the chart indicates the best alignment. The shading reflects ease of implementation, with lighter shading denoting measures that are easier to implement.

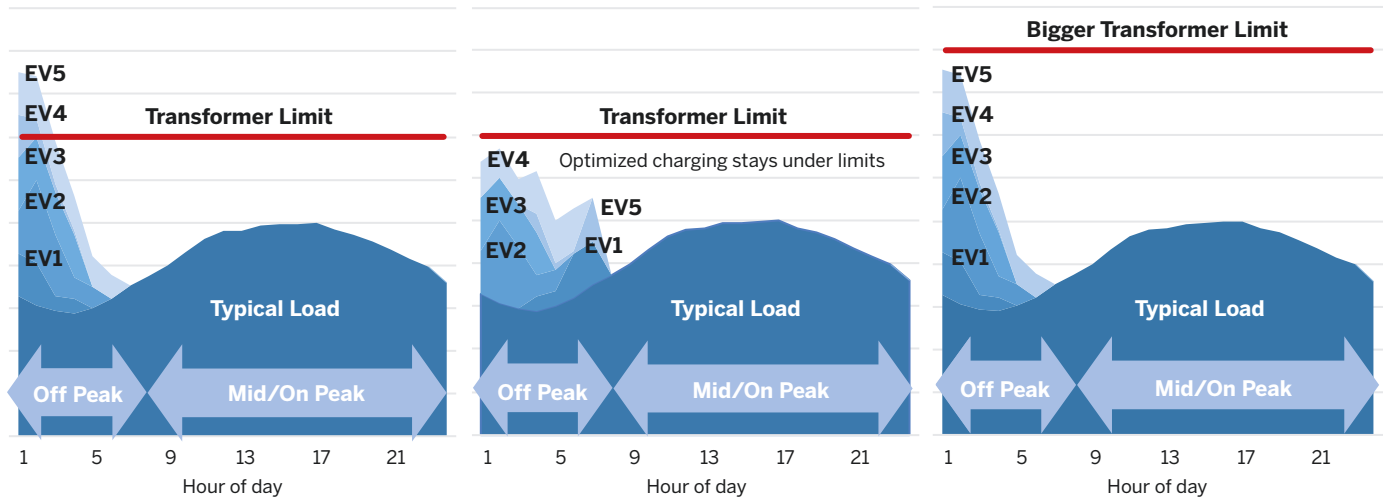
Source: Energy Systems Integration Group.

disadvantages, and because consumers are not monolithic, it is important that they have choices that suit their needs. Prices and programs can be used in concert, with prices providing general shaping of demand and programs providing a precise tool to manage real-time events.

Figure 15 shows how demand-side management measures vary from simple tools to more precise, adaptable measures to address different grid needs. Some demand-side management measures—specifically, TOU rate structures and demand response events—have typically been oriented toward addressing bulk system challenges. The shading in the figure reflects ease of implementation, with lighter shading denoting easier implementation.

As noted above, TOU rates represent a somewhat blunt instrument, most often aligned with bulk power system needs, that can potentially lead to spikes in demand in the hour when the off-peak rate takes effect. In EV-dense neighborhoods, this can lead to the sudden overloading of distribution system infrastructure. Recent work by Portland General Electric and Weavegrid outlines how TOU with load optimization can simultaneously unlock value in the bulk system without creating unintended impacts on the distribution system (Mills et al., 2023). This stacking of smart charging is shown in the middle image of Figure 16 (p. 32). The costs of such management solutions should be evaluated against the cost of traditional upgrades, such as the installation of larger equipment.

FIGURE 16
Optimized Charging Aligned with TOU Rates



Time-of-use (TOU) rates with load optimization can simultaneously address bulk system and distribution constraints. If we only focus on bulk system needs with rate designs, EV charging may all start at the beginning of the off-peak period and overwhelm the distribution equipment (left). We can instead stagger charging and get the bulk system benefits of TOU without overwhelming the distribution system (middle). However, simply upgrading the distribution transformer may be more cost-effective and requires less of customers (right). The industry is learning more about the best mix of solutions to enable charging.

Source: Energy Systems Integration Group.

There is still much to learn. Designing smart charging programs and rates requires an understanding of the customer and the grid needs. In particular, the industry needs to better understand customers’ willingness to adopt smart charging and adjust charging profiles dynamically (temporally and locationally), both in everyday circumstances and during extreme weather events. There are opportunities to learn more about customers’ responsiveness to rates and the price elasticity of charging demand. Demand-side management strategies almost universally include a customer override or opt-out provision, and grid planners will want to understand smart charging override statistics before relying on it. Finally, data are available on enrollment success, but there is a need to extend the data to track consumers from recruiting through smart charging participation to understand effective enrollment practices that accomplish smart charging.

Pricing

Some utilities have established EV-specific rates. EV rate design focuses on three principal paths: demand charges, TOU tariffs, and dynamic pricing.²¹

Demand Charges

Demand charges have been applied to large commercial and industrial customers for many years. These charges are based on the customer’s peak demand in a billing cycle, with some programs using the customer’s highest monthly demand to set the demand charge for each bill in a year. Demand charges can comprise minor additions

There are opportunities to better align demand charges with distribution system costs, including setting coincident peak demand charges specific to a given distribution circuit or zone.

21 See the series of white papers written by members of ESIG’s Aligning Retail Pricing and Grid Needs Task Force, including the framing paper by Ela, Lew, and Linvill (2023), at <https://www.esig.energy/aligning-retail-pricing-with-grid-needs>.

or a majority of the bill. They are intended to reflect the costs of infrastructure needed to support high demand.

However, there are opportunities to better align demand charges with distribution system costs, including setting *coincident peak* demand charges specific to a given distribution circuit or zone. These types of demand charges are common in regional transmission organization and independent system operator markets to reflect a load-serving entity's (e.g., a utility's) contribution to peak demand. Demand charges coincident with local peak conditions would need to be applied retroactively—charge station operators would be charged after the fact based on how their demand interacted with their neighbors' to create a coincident peak impact on equipment.

There are also opportunities to better align demand charges with affected infrastructure. For instance, San Diego Gas & Electric's Vehicle Grid Integration rate is a dynamic, hourly charge that includes a distribution capacity adder for the top 200 hours of distribution circuit load, with those hours varying by circuit. Equity should be taken into account in the design of such rates, because, among the considerations, coincident peaks may differ by circuit and could unfairly penalize some consumers based solely on how and when their neighbors use electricity.

Time-of-Use Tariffs

TOU tariffs can incentivize EV charging during targeted hours. Prices and times are predetermined with set schedules throughout a day or week, which is preferable for some charge station operators that can optimize charging in line with TOU price signals. In addition, as shown in Figure 16 (p. 32), a diversification of TOU rates can avoid unintended consequences. However, TOU rates cannot be adjusted in real time to allow flexible loads to respond to real-time grid stress. Absent sufficient planning, autonomous response to TOU rates may trigger thousands of vehicles to simultaneously charge, creating a new peak issue for the utility companies.

TOU rates are most often used to align loads with bulk system generation capabilities, but they can also be used to shift loads for other purposes, such as limiting the



Traditional assumptions for what can be accomplished through TOU rates should be re-evaluated in the context of EVs. For example, San Diego Gas & Electric observed that 77% to 87% of charging happened off-peak across various versions of TOU rates.

impact of EV charging on distribution system equipment. About 9% of U.S. retail electricity customers are on some form of time-varying rate (EIA, 2022a). TOU rate designs with large price differences between peak and off-peak pricing have been shown to be more effective in encouraging customer behavior change (Satchwell, 2022). For example, the Hawaii Public Utilities Commission recently approved tariffs that charge customers three times as much during the evening peak period (5 pm to 9 pm) as the daytime period (9 am to 5 pm).²² AusNet in Australia has proposed a tariff that *pays* customers to charge their cars from 10 am to 3 pm (AusNet, 2023).

Because EVs have the potential to be flexible loads, the impact of TOU rates on their load profile can be significant. San Diego Gas & Electric observed that 77% to

²² Hawaii Public Utilities Commission Order 40118, 2019-0323, July 11, 2023. <https://hpsc.my.site.com/cdms/s/search?term=Order%2040118&excludeObjects>.

87% of charging happened off-peak across various versions of TOU rates (Cutter et al., 2021). That stands in contrast to TOU pilots from 2008 through 2012 targeting the whole home, which resulted in a 2% to 21% reduction in daily peak load (Badtke-Berkow et al., 2015). An Octopus Energy program in the UK showed that program participants who had an EV reduced peak consumption by 47% compared to 28% for non-EV drivers (Octopus Energy, 2018). Traditional assumptions for what can be accomplished through TOU rates should be re-evaluated in the context of EVs.

Dynamic Pricing

Dynamic pricing programs incentivize EV load-shifting behavior based on fluctuating pricing that reflects the needs of either the bulk or distribution system on a closer-to-real-time and granular level. These prices can be determined in a day-ahead time frame or reflect real-time needs.

Utilities are working with aggregators and vehicle manufacturers on technology that optimizes charging at times when it is most beneficial for the grid based on price signals.

Dynamic pricing depends on individual customers' response. Automation technology enables customer charging decisions based on pricing changes. Utilities are working with aggregators and vehicle manufacturers on technology that optimizes charging at times when it is most beneficial for the grid based on price signals. Xcel Energy's Charge Perks program is one such program that works with aggregators and vehicle manufacturers to automate charging schedules aligned with grid prices and customer charging requirements. The utility is recruiting customers with a \$100 upfront incentive and sharing savings at the end of each year (Xcel Energy, 2023).

Dynamic pricing increasingly considers distribution infrastructure. The California Public Utilities Commission developed a policy roadmap and retail rate strategy known as CalFUSE (California Flexible Unified Signal for Energy) that prioritizes dynamic prices and demand flexibility. The rate design concept includes distribution capacity among the calculation inputs.²³

Vehicle-to-everything (V2X) applications can also be enabled through dynamic rates with export compensation. For example, the New York Value of Distributed Energy (VDER) tariff has a location-specific component in addition to other components of the value stack referred to as the Locational System Relief Value (LSRV), which compensates resources located within zones that are constrained.

Control

Three primary types of potential control over EV charging are event-based demand response, dynamic managed charging, and automated load management (AML). The control paradigm considered here allows customers to opt out of utility or aggregator management if needed.

Event-Based Demand Response

Event-based demand response provides signals to customers to curtail EV charging when it would help manage grid stress. Events could be called based on the day's forecasts or as system conditions change in real time. Events can include calling on EVs to begin charging or increase charging level for a period of time.

Event-based demand response allows consumers to respond to grid events that may occur just a few times per year. These programs typically allow the consumer to opt out of events. Some programs penalize customers for non-conformance with the demand response event or allow only a certain number of times per year the customer can opt out, while others provide incentive mechanisms alone. Portland General Electric, Holy

23 Decision 23-04-040, Rulemaking 22-07-005, California Public Utilities Commission, April 27, 2023, <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M507/K837/507837776.PDF>.

24 Portland General Electric's Smart Grid Test Bed tariff explicitly tested price-based demand response as a non-wires alternative to distribution substations. Peak time rebates in the test bed area reduced peak demand by about 4% in summer and 3% in winter. In a recently announced study, the utility took this concept further by introducing location-based price signals to achieve load-shifting or load-reduction goals for a specific distribution circuit or geographical area. See <https://portlandgeneral.com/smart-grid-test-bed-ev-charging-study>.

Cross Energy, and Baltimore Gas and Electric are among those utilities that offer a peak time rebate that rewards consumers who reduce their consumption during peak events.²⁴

Event-based demand response targeting EV charging holds promise because, unlike other types of load, energy inefficiencies from delaying EV charging are minimal. For example, programs that adjust buildings' air conditioning thermostat settings can suffer from energy losses when precooling leads to increased losses through the building envelope or after events as the building is re-conditioned following the event. Depending on the home's efficiency, this can be less efficient than keeping the building conditioned continuously.²⁵ But with respect to EVs, the charging loads simply shift in time and remain of the same magnitude.

EV participation in demand response programs can sometimes be constrained by consumers' state-of-charge requirements. Similar to event opt-outs for thermostat programs at times when consumers do not want to adjust temperature settings, some EV customers will need to have their vehicle fully charged for a specific reason—a road trip, for example—regardless of the grid conditions.

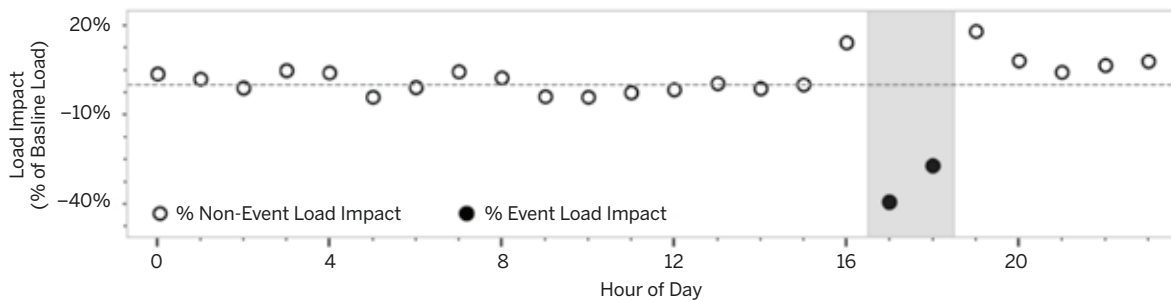
With any of these options, care must be taken to avoiding “snapback” or rebound effects. Rebound effects

can influence the power system in multiple ways (Morash, 2018). Figure 17 shows these effects in action, with the demand response event highly effective at limiting demand during the event, but increasing demand immediately before and immediately after the event. Care should be taken such that these before- and after-event spikes do not cause more stress than the original event avoided. Some utilities have adopted a simple approach of limiting charging in the first hour post-event to 50% charging capability. While this strategy subdues the rebound, other solutions have been proposed to stagger the start and end times of control signals to improve the overall event performance, particularly for EVs (Pennington, 2023).

Dynamic Managed Charging

Dynamic managed charging involves the utility or a third party adjusting the vehicle's charging in real time to align with consumer requirements and grid constraints. The architecture of dynamic managed charging can be a hierarchical mechanism with a managing entity coordinating charging. This can be implemented through centralized control with all signals originating from a central entity, or a decentralized architecture in which control signals could originate from multiple managers. The decentralized approach could involve signals originating from the regional transmission organization

FIGURE 17
Snapback Effect in Demand Response Events



EVs can be highly effective at limiting charging during events, but care should be given to avoid snapback effects before and after the event. This chart shows a classic whole-home demand response event with good performance during the event (shaded area), but with rises in usage immediately before and after the event.

Source: Glass et al. (2022).

²⁵ These energy losses are highly dependent on the length of the event and efficiency of the home, and have historically been of secondary importance to the capacity constraints on the grid.

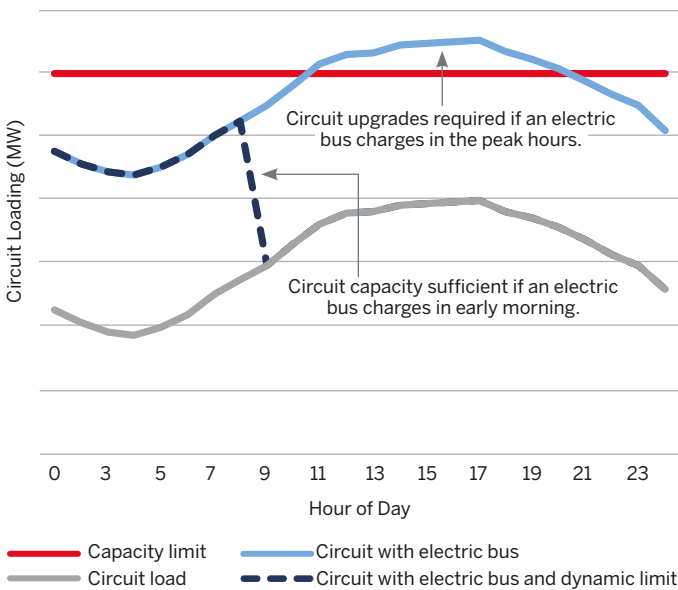
or independent system operator to be implemented by distribution utilities, or it could involve distribution utilities issuing commands to field equipment that uses local information and communication with nearby devices to coordinate actions. Similarly, a utility could issue a command to multiple aggregators for execution. The benefit of this hierarchical approach, which is aligned with IEEE 2030.11, is that the control mechanisms can adapt and change based on different factors, including how grid needs arise at the distribution or bulk system level and the priority of those grid needs.²⁶

Dynamic operating envelopes and dynamic interconnection limits can shape load based on grid conditions. Dynamic operating envelopes can be used in an operational setting to communicate allowable ranges of charging by time of day. Meanwhile, dynamic interconnection limits can be used to limit EV charging to certain times of day as a condition of connection with



the grid. Both are valuable tools for distribution planners considering how the system can support EV charging.

FIGURE 18
Dynamic Operating Limits Specify when Electric Buses Charge



To avoid exceeding the capability of the circuit, the electric bus is provided with a dynamic operating limit that restricts charging to early morning hours.

Source: Energy Systems Integration Group.

Figure 18 shows how circuit loading varies throughout the day and how the addition of a 2 MW electric bus would exceed the circuit’s capacity limit at certain times of day. To avoid exceeding the capability of the circuit, the electric bus confines charging to overnight hours. Vector, a distribution system operator in New Zealand, is using this approach, and other utilities have indicated interest (Head and Heinen, 2022).

It is possible that entities focused on different levels of the grid could request that the same vehicle perform different charging or discharging actions to meet different objectives, and these various layers of demand-side management will need to be coordinated. Some jurisdictions are pursuing tariff options that simply pay customers based on when the vehicle is plugged in and leave the complex optimization and accounting between the utility and a third-party manager.

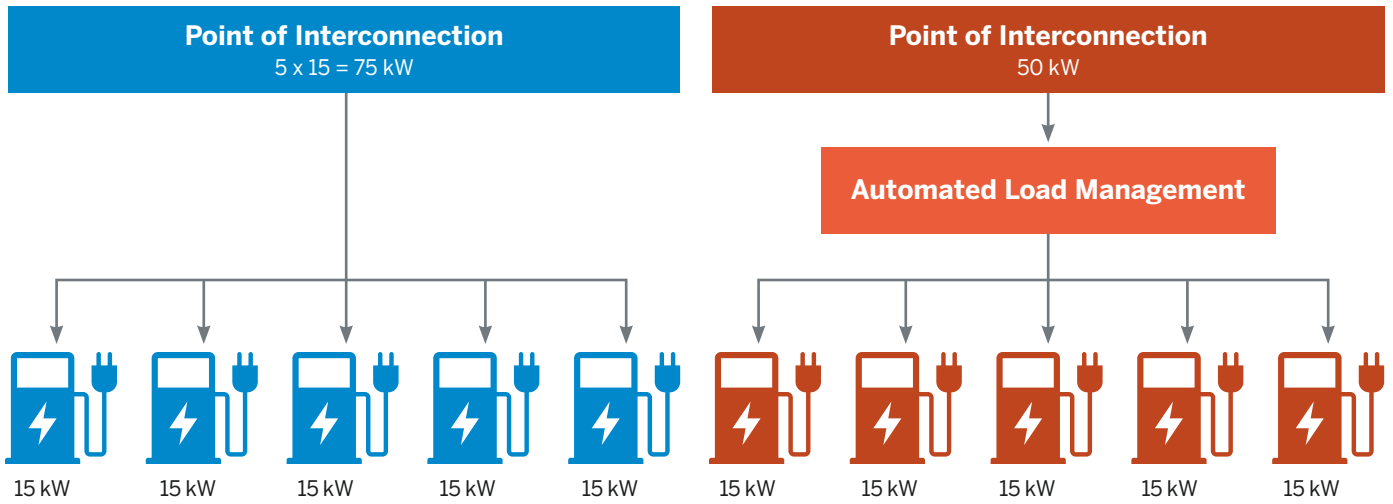
Automated Load Management

ALM schedules EV demand to keep it within a specified range over time. As grid planners develop the grid to support greater volumes of EVs, there may be a tendency to build distribution equipment to serve the sum of the nameplates of all chargers. However, ALM is executed at

26 IEEE 2030.11 is the IEEE Guide for Distributed Energy Resources Management Systems (DERMS) Functional Specification. It outlines the aggregation function and describes the grid services that aggregated DERs can provide.

FIGURE 19

Example of Using ALM to Integrate the Same Charger Rating at Points of Interconnection with Lower Limits



Automated load management (ALM) schedules and prioritizes EV demand to remain within a specified range over time. On the right side in this example, five chargers are integrated with ALM to remain below a 50 kW interconnection limit. This allows for more efficient use of distribution infrastructure.

Source: Energy Systems Integration Group.

When developing the charging network in its territory in northern California, Pacific Gas and Electric used ALM to reduce requested distribution capacity by more than 50%, with cost savings of \$30,000 to \$200,000 per project.

the premise level and can allow the nameplate of downstream chargers to exceed the maximum power available at the point of interconnection (see Figure 19). ALM then manages the downstream chargers within that point of interconnection limit, helping to minimize the EVs' impact on the distribution system.

ALM is beginning to be implemented in some U.S. jurisdictions. For example, Pacific Gas and Electric

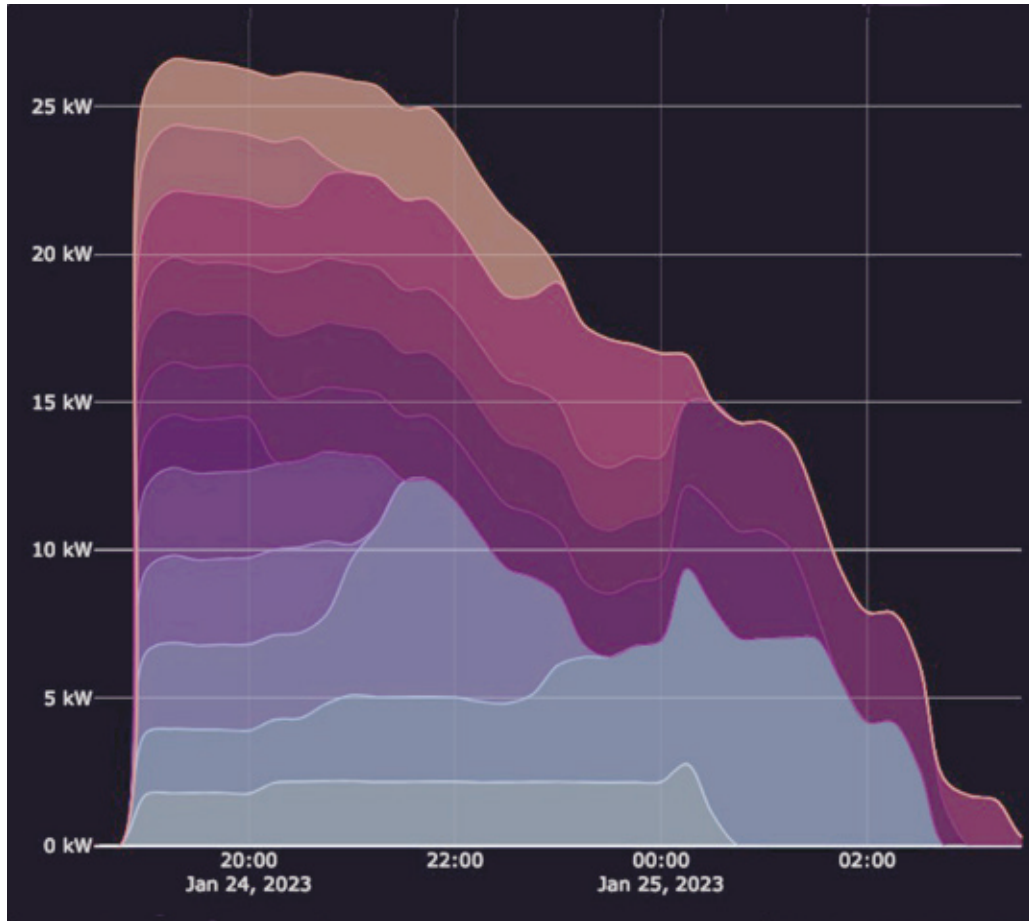
included ALM in its plan for developing the charging network in its territory in northern California. The utility used ALM “in order to reduce costs and physical design constraints at customer sites.... When using ALM, PG&E deployed charging infrastructure ‘at sites in a manner that reduced the originally requested capacity by more than 50 percent to stay within the electrical capacity of the existing or lower cost infrastructure.’ This resulted in cost savings ranging from \$30,000 to \$200,000 per project.”²⁷ The California Public Utilities Commission found that “utilization of ALM will help lower program costs and promote efficient use of electric grid infrastructure.”²⁸

ALM is more common in the European Union and UK for both fleet and residential loads. The mail delivery service in Ireland, Irish Post, is an example of ALM in action. Irish Post is using ALM technology to manage its EV loads at more than 100 sites across the country.

27 Opening Brief of Pacific Gas and Electric Company, California Public Utilities Commission Application No. 21-10-010 (August 24, 2022). <https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=496592994>.

28 Decision Authorizing Pacific Gas and Electric Company's Electric Vehicle Charge 2 Program, 22-12-054, California Public Utilities Commission, December 19, 2022. <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M500/K043/500043974.PDF>.

FIGURE 20
Example of EV Load Scheduling Using Automated Load Management



The mail delivery service in Ireland uses automated load management to allow the total nameplate rating of their chargers to exceed site infrastructure limits. In this example, the site's nameplate rating is 88 kW, but automated load management coordinates EV charging to keep the simultaneous demand below the site's service limit of 28.9 kW. As the fleet operator prioritizes some chargers to receive more power, others decrease their usage to limit aggregate load. This type of automated load management system allows more flexibility than standard power sharing, which splits connection capacity evenly across all chargers.

Source: The Mobility House.

At one site, the total nameplate rating of the chargers is 88 kW, while the site service limit is 28.9 kW (Figure 20).

ALM shifts some of the risk of service from the utility to the charge station operator. The utility must provide reliable power only at the level agreed to at the point of interconnection. The charge station operator takes on the risk of managing charging demands that may exceed the service limit, including managing customer expectations. It is the responsibility of the charge station operator to

accurately model customer EV usage and help customers understand if avoiding an upgrade would compromise the customer's mobility experience.

In implementing ALM, some utilities may use separate distribution protection hardware to enforce infrastructure limits and ensure the efficacy of ALM. Utility hardware solutions would stack on top of vendor-provided software control mechanisms. Rigorous testing of third party-managed ALM software capabilities can avoid potentially redundant equipment, such as utility-managed protection



devices placed upstream of the ALM solution. Underwriters Laboratory (UL) is investigating standards and certifications so that individual utilities would not need to perform their own testing of ALM reliability. UL 916 and UL 60730-1 are both potential standards that can be applied to ALM, but there is little consensus among the engineering community on the applicability of these standards to ALM, making it hard for vendors to justify pursuing certification. Such certifications would guarantee implementation of software safeguards, including a safe failure mode if communication with the command module is lost.²⁹ Regardless of hardware/software implementation, consistently defined rules are needed upfront for using ALM in distribution planning and operations.

Smart Charging Challenges

Smart charging is a central tool in limiting the impact of EVs on distribution infrastructure and can help to minimize the grid upgrades needed to support a transition away from gasoline-powered cars. However, even using the smartest of charging strategies, it may be necessary to upsize distribution equipment, particularly if customers do not participate in demand response programs or will not provide flexibility based on price differentials. While smart charging is an imperfect solution with things still to learn, and distribution system investments would carry a price tag, these should be evaluated against the broad benefits of EVs, including sustainability.

²⁹ OSCP (Open Smart Charging Protocol), the standard that enables smart charging between the EV and charger, embraces such a “fail-safe” approach.

Customer Participation

The principal challenge with smart charging is convincing customers to participate, incentivized by the value stream that the utility or aggregator can monetize. But while this value stream may include reduced costs of electricity generation or reduced need for new generation capacity, transmission capacity, or distribution upgrades, these values may be difficult for the utility, and especially for an aggregator, to monetize. Even though large infrastructure investments may be deferred by managing demand across many EVs, the savings passed on from a utility or aggregator to an individual EV owner may not be large enough to incentivize the EV owner's participation. Research from Pacific Gas and Electric's service territory suggests that a \$50 enrollment incentive would entice about half of the owners of smart level 2 chargers (240 V chargers) to participate in an EV demand response program, but work remains to translate this finding to practical grid impacts (Opinion Dynamics, 2022).

In some cases, it may simply not be possible to recruit enough customers into a load management program to avoid distribution system upgrades at localized points. For example, the California investor-owned utilities have regularly held solicitations inviting third-party DER aggregators to submit bids for load management projects to avoid planned distribution system upgrades, and those solicitations have largely not attracted significant interest from the developer community.³⁰

Preserving Benefits of Load Diversity

Load diversity, a core principle of distribution planning used to size infrastructure, allows planners to use smaller equipment than would be required if every load's maximum demand were simply added together.³¹ However, large numbers of EV owners participating in demand response programs could remove the diversity of their charging behavior and overload distribution equipment. For example, smart charging that is driven by bulk power

Given the multiple standards required to enable effective communication of smart charging signals, early definitions are essential.

system needs could undermine load diversity on the distribution system by concentrating charging during specific time periods that address bulk system needs but exacerbate stress on the distribution system. A combination of ALM and other mitigation measures that avoid uniform load responses may help to preserve diversity benefits while aligning with other grid needs.

Communication and Control: Standards and Implementation

Smart charging requires appropriate development of communication and control architecture so that EVs can help address—and not exacerbate—grid issues. The architecture to enable smart charging requires data exchanges across multiple software systems designed by different vendors with different risk tolerances. Some utilities have developed interoperability guides to help shape the communication and control market in their service territory (Vector Electricity, 2023). These guides are helpful for charge station operators and aggregators to understand how the utility plans to manage activity across vendors. Early definition of open standards helps to avoid technology obsolescence from the deployment of proprietary data architectures. Given the multiple standards required to enable effective communication of smart charging signals, early definitions are essential (ElaadNL, 2017). Moreover, defining standards and certifications can help to de-risk the implementation of software safeguards, such as a safe failure mode if communication with the command module is lost.

Specifying a standard may not be enough to effectively ensure interoperability for EVs, however,³² and an interoperability profile, specifying how a standard will

30 For example, the Independent Evaluator Report for Southern California Edison's Distribution Investment Deferral Framework (DIDF) Partnership Pilot (prepared by Merrimack Energy Group) found non-competitive developer interest in the identified distribution deferral opportunities. See <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M509/K081/509081080.PDF>.

31 The interplay of load diversity and EVs is discussed at length in the "Future-Ready Infrastructure" section of this report.

32 For example, standards often allow for custom fields or special error codes. Unfortunately, vendor implementation of the early versions of the Open Charge Alliance's standards, Open Charge Point Protocol (OCPP) and Open Smart Charging Protocol (OSCP), used custom fields liberally. As a result, error codes meant different things depending on the vendor. Efforts are underway to remedy these interoperability issues at the data level (LF Energy, 2022).

be implemented, may be needed (SEPA, 2022; EEA, 2023). A similar effort was undertaken with the common smart inverter protocol (CSIP) that provided additional clarity for implementation of smart inverter functionality in PV installations (SunSpec Alliance, n.d.).

Pricing Sensitivity and Reliability

Pilots have demonstrated the potential of pricing to influence smart charging, but work remains to be done. As discussed above, some pilots and small programs have demonstrated the potential of dynamic pricing and control of EVs. However, recent research was unable to identify even one currently offered or proposed EV-specific rate that incorporated locational differentiation in the design (Cappers et al., 2023). Some pilots have paired EVs with distributed batteries to tailor the aggregate (EV+battery) charging profile to predefined TOU periods, but those EV+battery solutions may be cost-prohibitive for the customer.

Similarly, the degree to which we can rely upon pricing in all situations is still under investigation. Outlier events and peak conditions drive significant investment in grid infrastructure, and understanding how EVs will impact these outlier events will be critical in distribution system planning. There are few publicly available datasets on charging behavior around holidays and weather events—high travel periods. The Public Safety Power Shutoff events in California could offer some indication for how customers would charge around potential disaster events, such as winter storms or hurricanes, but information is scarce on EV behavior before and during these events. And overall, early lessons learned on the efficacy of targeted pricing will be informative in developing a strategy that effectively balances reliability, consumer choice, and cost effectiveness.

Modeling

Lastly, improvements are needed for modeling smart charging. Even after data on smart charging are widely available, distribution system planning tools and processes will need to be updated to consider smart charging as an option. Lawrence Berkeley National Laboratory has identified key barriers to integrating price-based demand

The blending of behind-the-meter asset classes offers the opportunity to create grid-friendly load through intelligent optimization strategies. In particular, the effects of distributed solar and EVs are helpful to analyze.

response in grid planning for bulk power systems and distribution systems (Carvallo and Schwartz, 2023). Price-based demand response resources are often ignored or treated as an input in grid modeling, rather than as part of the optimization function. Considering the scale and flexibility of EV charging, planning tools and processes will need to evolve to include a variety of smart charging options.

Considering EVs Together with Other Behind-the-Meter Solutions

EVs should not be planned in isolation, as they are part of a broader set of distributed resources that includes distributed solar, storage, energy efficiency, and grid-responsive loads. If each DER addition is studied independently, we may miss potential opportunities for grid solutions that consider generation, storage, and loads holistically. The blending of behind-the-meter asset classes offers the opportunity to create grid-friendly load through intelligent optimization strategies.

Analyzing Distributed Solar and EVs Together

The effects of distributed solar and EVs in particular are helpful to analyze together. With appropriate planning and well-designed retail rates, solar and EVs can be synergistic in helping to decarbonize the U.S. energy economy with little impact to the grid in many locations. At high levels, distributed PV produces surplus generation during midday hours that may not be usable locally given distribution system constraints. EV charging—potentially supplemented by distributed storage—can soak up excess generation. EVs also can address bulk system challenges by charging from utility-scale PV that may otherwise be curtailed, provided that the grid can facilitate the delivery.

33 The 1200 GWh figure assumes current battery sizes, a split of battery-electric vehicles and plug-in hybrid vehicles, and that each vehicle is half charged.

The integration of DERs into EV charging stations offers a prospective solution to alleviate stress on the distribution system. In addition to considering solar and short-duration battery solutions, charge station operators and utilities should consider their resilience plans. As EV adoption grows, there is a growing need for resilient charging infrastructure capable of withstanding severe weather and offering backup power potentially for weeks to facilitate emergency transportation needs. A project in Korea uses hydrogen as a back-up fuel to generate electricity to charge EVs at gas stations, which provides just this resilience benefit.

Accounting for Vehicle-to-Everything (V2X) Bi-directional Charging

Creating a future-ready system means evaluating each EV charging station for potential bi-directional charging capabilities. Many U.S. and global EV manufacturers have announced plans to make their EVs bi-directional, with most, including the leading EV automaker, Tesla, looking at the 2025 model year. Numerous charger manufacturers have publicly announced plans to design, build, and sell bi-directional chargers, adding to the

limited number of DC bi-directional chargers on the market today. This is not to say that vehicle export considerations should supersede the urgency of single-directional charger interconnection, but that vehicle exports should be considered as the grid is planned given the industry trends referenced (Greenblatt, Zhang, and Saxena, 2021).

Bi-directional charging is important because of the potential scale of storage accessible in EVs. The mid-adoption scenario of 33 million EVs in a recent report by the National Renewable Energy Laboratory could represent approximately 1,200 GWh of energy storage available across the U.S. in the EV fleet (Wood et al., 2023).³³ For reference, the amount of utility-scale batteries currently planned through 2025 is approximately 120 GWh (EIA, 2022b). The vehicle fleet could dwarf all utility-scale stationary batteries by an order of magnitude.

Bi-directional vehicles will be able to support energy needs for individual homes through vehicle-to-home (V2H) energy transfer for up to a few days in the event



TABLE 5

Planning Practices Associated with Mitigating Grid Impacts of EVs

PLANNING ATTRIBUTE	
Smart (managed) charging is used to mitigate the largest impacts of EVs aligned with grid needs.	
Good practices	<ul style="list-style-type: none"> • Smart charging is present as a load modifier for the load forecast. • Time-of-use rates are used throughout the planning process to adjust EV charging profiles. • Demand charges are aligned with coincident peaks that drive investment in bulk system and distribution infrastructure. <p>Example: San Diego Gas and Electric has a rate with a demand charge that varies based on the customer’s coincident demand with the top 200 hours of its distribution circuit’s load.</p>
Better practices	<ul style="list-style-type: none"> • Automated load management is used to integrate EVs in planning and schedule charging at the premise-level in operations. • Distributed solar, storage, and EVs are analyzed together to capture benefits of on-site consumption and storage of solar generation. • Bi-directional EVs are considered in the interconnection process to allow for future innovation and benefits for the utility system and consumers. <p>Example: Austria’s postal service uses automated load management to manage the charging across its fleet, limiting impact on the distribution system and aligning with grid capabilities.</p>
Best practices	<ul style="list-style-type: none"> • Interoperability guides are available to charge station developers and manufacturers to help shape the implementation of standards in utility service territories. • Dynamic pricing reflecting bulk and distribution system needs is available for interested consumers, including through aggregator-managed models that simplify the customer experience. • There are plans to leverage the expected growth of bi-directional charging in the coming years. <p>Example: The distribution utility in the Netherlands, EaadNL, publishes an interoperability guide to facilitate open communication within the charging ecosystem.</p>

Practices identified by members of the Grid Planning for Vehicle Electrification Task Force.

Source: Energy Systems Integration Group.

of a grid outage. In the short term, public charging networks can consider the incremental cost of bi-directional charger installations, even if the bi-directional capability is not used immediately. Grid planning practices will need to consider how to model bi-directional capabilities of chargers and associated EVs to consider dynamic and grid-responsive capabilities, including assessing the likelihood that EVs are not plugged in to provide response at a given time.

Many consumers will find value in vehicle-to-home applications that help ensure that their home has power through short outages as well as major events. In addition, this could in theory reduce resource adequacy and resilience requirements for the bulk system. And vehicle-to-home capability can help shape aggregate load profiles as vehicle export is integrated into power system operations in the long term. Good, better, and best planning practices associated with mitigating EVs’ grid impacts are given in Table 5.

Developing Roadmaps and Grid Plans

After establishing the likely amount, timing, and location of charging needs, distribution planners use that information to develop roadmaps and grid plans to guide distribution system upgrades to support the expected integration of EVs. These grid plans prioritize initiatives based on a variety of objectives, including meeting EV needs, addressing imperfect existing infrastructure, and designing a grid that is equitable, affordable, and reliable. Here we discuss grid planning actions that can be taken today to prepare the grid for vehicle electrification impacts in the long, medium, and near term. These actions manifest change in the grid in different ways, building toward supporting forecasted EV loads.

- Plans focused on **future-ready infrastructure** aim to ensure that the long-term infrastructure can support EV loads. These plans are more passive in nature and help to spread across years any costs of infrastructure upgrades required to meet long-term policy goals.
- **Targeted system upgrades** can be undertaken where forecasting scenarios or historical data show grid needs at localized points. These upgrades may take three to five years from conceptualization to commissioning.
- **Energization and interconnection plans** deal with discrete near-term requests to integrate new EV chargers.³⁴

Some of these planning practices are not currently part of annual cycles of distribution planning. For example, the suitability of standard equipment used on the distribution system is assessed infrequently. Similarly,

Grid planning actions can be taken today to prepare the grid for vehicle electrification impacts in the long, medium, and near term.

energization and interconnection requests typically arrive out of sync with regular distribution planning cycles.

Currently, near-term developer requests inform the distribution planning processes that are completed regularly, and those regular processes inform long-term studies. However, there is a need for long-term study findings to be integrated with medium- and short-term plans to avoid widespread constraints. Too often, long-term study results are left in isolation.

This section, rather than prescribe specific solutions or recommendations, describes the types of analysis that are needed. Each distribution system, policy landscape, and EV forecast represents a unique situation that will need to be addressed by local distribution planners.

Future-Ready Infrastructure

Planning for EVs requires a holistic analysis of the assumptions that drive grid planning decisions—assumptions that are embedded in design standards and load forecasts. Typically, equipment design standards are re-evaluated every decade or two; however, these standards are being reassessed by leading utilities facing

³⁴ “Energization” generally refers to situations where the EV is in load-only or islanded power configurations, whereas “interconnection” refers to situations in which the V2X can export to either the site or the grid. We find that “interconnection” is helpful to frame V2X and solar in similar terms for new audiences, while also allowing for future V2X strategies; however, both terms are used as appropriate throughout this report. For more on this, see VGIC (2022).

growing EV loads. Design standards typically use the diversity of demand to plan infrastructure with smaller equipment than would be required if maximum demand for every end use was simply added together.

Although future-ready equipment will not be sufficient to meet all projected EV charging needs, it is an important part of preparing for EV loads. In practice, future-ready design standards will manifest change on the distribution system both when replacing existing equipment (upgrading the size of the equipment when it is due for replacement) and when planning new distribution circuits (by building in additional margin from the beginning).

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Reconsidering Equipment Design Standards

Standards for grid equipment affect distribution planning in multiple ways, in particular, through voltage classes and equipment sizes. Generally speaking, costs increase with higher voltage and larger equipment, so distribution planners try to right-size the equipment to meet today's needs and expected future demand.

- **Voltage classes:** Utilities typically design power systems at discrete voltage steps to help maximize supply chain efficiency and simplify both construction efforts and some electrical engineering. The voltage classes most common in grid planning in the U.S. are 4 kV, 12 kV, 35 kV, 69 kV, 115 kV, 230 kV, 345 kV, and 500 kV. Utilities will increasingly be considering converting from one voltage class to a higher class at the same location to facilitate electrification.
- **Equipment sizing:** Distribution equipment is usually sized in a standard fashion: a given voltage class uses a certain size wire appropriate for thermal loading. Service transformers are sized at discrete blocks, such as 50 kVA or 100 kVA, to service a given need. These



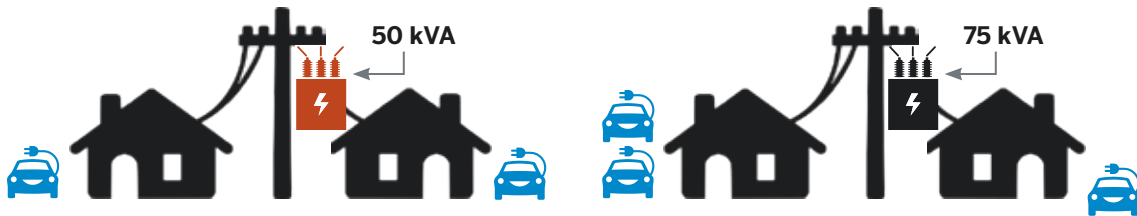
small transformers typically serve 3 to 15 residential customers or a few small commercial customers. They are typically sized assuming a certain amount of load diversity, which allows homes to exceed their expected load at any given time on the assumption that not all homes will hit their peak demand at the same time. With the introduction of EVs, these design decisions are being reassessed, and larger wires and larger-capacity service are being considered.

Reconsidering standard voltage classes requires a strategic shift that goes beyond typical distribution planning activities. Because of EVs' potential effect, they warrant just such a strategic shift in grid planning: distribution system wiring may need to get larger and voltage levels may need to increase. Planners are tasked with determining where to make those upgrades in the absence of definitive data on the where, when, and magnitude of EV charging. Historically, another substation or distribution circuit would be built if customers required more power capabilities. But as utilities look toward the long-term needs of customers and their EVs, they may consider upgrading system equipment rather than continuing to build more of an undersized network, particularly in areas where land acquisition for a new substation is challenging. Moreover, the industry faces a timeline challenge, as building grid infrastructure could be much slower than building the necessary EV charging infrastructure.

Since the shift up in voltage class (from 4 kV to 12 kV, for example) is an expensive investment, many utilities have staged this investment and architectural shift by upgrading equipment as it is due for replacement or by

FIGURE 21

Example Utility Approaches to Sizing Service Transformers



Exegol Utility District

When equipment is a candidate for replacement, the utility replaces legacy designs with similar design standards that may become overloaded with incremental EVs.

Tatooine Cooperative

When equipment is a candidate for replacement, either at end of life or when the utility is doing things like pole replacement, the utility replaces legacy designs with future-ready solutions.

Utility strategies for equipment sizing are being reconsidered as electrification adds load to the system. To be future-ready, some utilities are upsizing equipment when it reaches the end of its useful life or by providing all new construction with the upgraded voltage class. On the right, the service transformer has been upgraded and can accommodate increased EV adoption, while on the left, the legacy equipment (in orange) is at risk of overloading.

Source: Energy Systems Integration Group.

providing all new construction with the upgraded voltage class. Over time, the entire service territory will be upgraded to accommodate higher loading levels. A similar strategy has been used for most pieces of grid equipment, including service transformers. These upgrades allow for more electrification of vehicles and buildings at a pace that attempts to balance customer demand and costs.

The impact of design standards is shown in Figure 21, which compares two hypothetical utility strategies.

This upsizing approach holds promise because the cost of the grid equipment itself is only one part of the cost to replace aging infrastructure. Labor required for planning and installation makes up a large share of the cost of a service transformer upgrade; therefore, the marginal cost of a higher-capacity transformer is often small compared to the costs of replacing or supplementing the transformer in a few years. A national reference quantifying the soft costs of utility equipment and the cost-effectiveness of upsizing could help utilities and regulators think through this strategy within their territory.

Revisiting Load Diversity Assumptions

Determining loading levels and designing appropriate grid architectures centers on the interaction of the diversity of loads with equipment rating methodologies.

The diversity concept is central to grid planning. If all consumers hit their individual peak load at the same time, the grid would be overwhelmed. An example of this planning practice can already be observed on distribution circuits where the aggregated rating of service transformers far exceeds the capability of the distribution circuit to meet that demand. Similarly, the aggregate nameplate rating of the deployed charging infrastructure will soon outpace local distribution transformers, circuits, and even transmission and generation capabilities in some regions. This should not be too problematic on its own, as the aggregate rating of distribution equipment already outpaces generation capabilities, but distribution planning headroom may need to change or evolve to support integrating EVs. Planning appropriate headroom begins with understanding load diversity.

By their nature, load diversity calculations are inexact approximations of the grid impact of an aggregation of customers. Similarly, the ratings that protect grid equipment can be inexact thresholds in operations. IEEE C57.91—the guide for loading transformers and voltage regulators—follows a “loss-of-life” concept where excessive loading (among other factors such as ambient temperature) contributes to a reduction in equipment lifespan. In practice, this means that transformers and

other grid equipment can be operated above their rated capacity, but the equipment will degrade more quickly, potentially failing before it is fully depreciated from an accounting perspective. Taken together, diversity of load and loss-of-life calculations create multiple variables that drive infrastructure sizing considerations. When preparing future-ready plans for EVs, the interaction of these variables needs to be carefully considered.

Managing Changing Diversity Factors as EV Adoption Proceeds

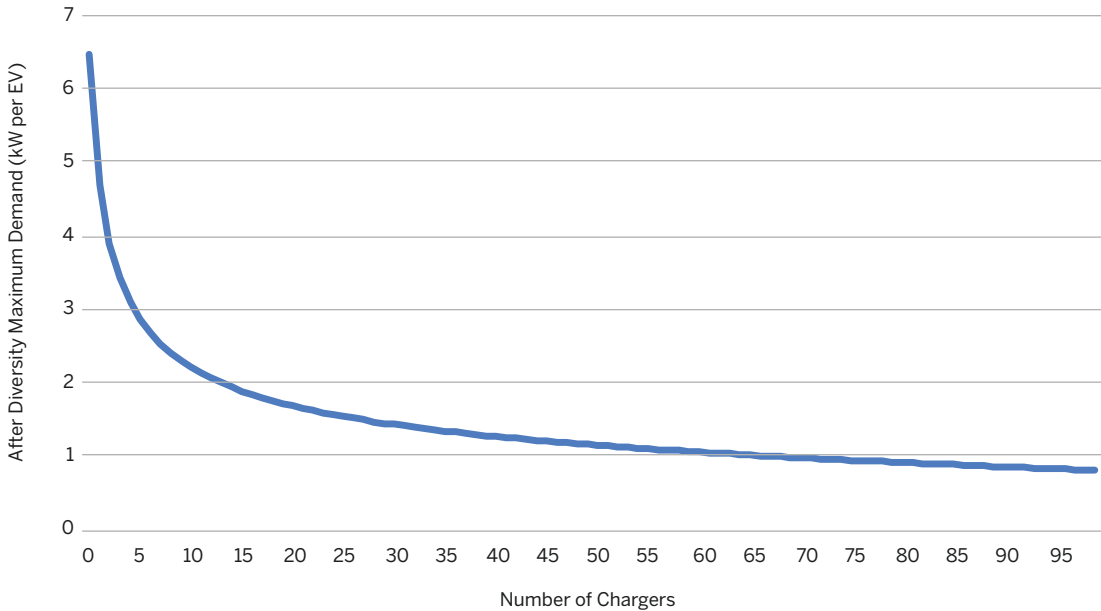
The diversity of load can be measured through diversity factors and calculations of “after diversity maximum demand” (ADMD). To meet the anticipated demand on the distribution system, ADMD is used to calculate the coincident peak that the distribution system is likely to experience based on the customers connected to the particular system. Infrastructure planners have historically discounted the demand contributed by individual customers, assuming a diversity benefit, and are able to get by with smaller equipment than would be required

if every home’s maximum demand were simply added together. Whereas a given house could add up to 20 kVA of new demand, it’s unlikely to do so at the exact time that all other houses maximize their demand.

The current diversity assumptions used by utilities are based on historical data in the coincidence of typical loads. However, there are relatively little data on EVs’ diversity factors. EVs will change ADMD calculations for typical customers, and some utilities are rethinking their ADMD curves to better evaluate how diversity of load is measured (NIE Networks, 2023). As evidenced by Figure 22, EVs appear to have large diversity in residential charging across a large number of EVs, as consumers vary their charging both by time of day and day of week. However, the maximum demand remains fairly high when there are few chargers.

Because of the change in ADMD as the charger count increases, diversity only goes so far in distribution planning. In the United States, most service transformers

FIGURE 22
After Diversity Maximum Demand (kW per EV)



The diversity of times when people choose to charge their cars means that the contribution to the coincident peak demand from charging declines as more chargers are considered. The diversity of all loads allows the distribution system to support individual demands with equipment that could not serve everyone’s peak demand simultaneously.

Source: Energy Systems Integration Group. Data courtesy of Vector.

serve relatively few households, often fewer than 10 (Taylor and Christian, 2023). With such few customers, there is little diversity available in charging behavior and a relatively greater likelihood that small numbers of residential EV chargers on the same street could cause a problem. Diversity assumptions and implications for distribution planning should be carefully evaluated.

Considering Potential Conflicts Between Bulk System and Distribution System Needs

As utility rates and other signals influence behavior, and as EV charging is shifted toward times with high levels of clean electricity, the degree of natural diversity in EV loads will likely diminish. With large peak vs. off-peak ratios for TOU rates, many drivers will charge when it is cheaper. But while this may be helpful for the bulk power system and align with low-emissions generation, the distribution infrastructure may not be able to accommodate this coincident charging demand.³⁵

Because of this potential conflict between the needs of the bulk system and distribution system, diversity

Because of the potential conflict between the needs of the bulk system and distribution system, diversity assumptions should be coordinated across stakeholders as the power system is optimized for different objectives.

assumptions should be coordinated across stakeholders as the power system is optimized for different objectives. Solutions—such as some rate designs—that are appropriate for bulk system planning may be particularly problematic for the distribution system. For example, a higher “cloudy day” rate could make it more expensive to charge EVs when solar generation is low. Currently, part of the diversity seen in EV charging comes from customers only charging their cars every three to four days, but such a rate could reduce some of this weekly diversity if the price signal from the bulk system were large enough. Moreover, this type of rate could place strain on the distribution system as drivers charge their cars on non-cloudy days exclusively.



³⁵ As discussed in the section “Smart Charging,” there are opportunities for managed charging programs to effectively stagger charging to avoid violations of localized infrastructure capacity.

TABLE 6

Planning Practices Associated with Future-Ready Design Standards

PLANNING ATTRIBUTE	
The suitability of upgrading standard distribution system equipment is assessed to facilitate vehicle electrification.	
Good practices	<ul style="list-style-type: none"> The suitability of distribution system voltage classes is assessed to determine whether they support long-term load growth and equipment standards are upgraded as necessary. <p>Example: A variety of utilities have upgraded 4 kV systems to 12.47 kV or even 34 kV to facilitate EV growth, including Los Angeles Department of Water and Power (LADWP) and Commonwealth Edison (ComEd).</p>
Better practices	<ul style="list-style-type: none"> Advanced metering infrastructure (AMI) data are integrated into demand diversity calculations to inform distribution equipment standards. A program is established to regularly assess the suitability of distribution equipment standards amid a dynamic planning reality. Suitability considerations include a broad range of stakeholder inputs. New smart charging programs include provisions that allow for staggered charging, preserving some diversity of loads. <p>Example: A distribution utility in New Zealand, Vector, used AMI data in its EV smart charging trial to better understand charging behavior and diversity.</p>
Best practices	<ul style="list-style-type: none"> Diversified EV loading shapes are developed using telematics or submetering and are regularly refreshed as the vehicle mix changes or smart charging influences patterns. Diversified EV loading shapes inform equipment standards. <p>Example: EPRI is developing maps for the U.S. that leverage vehicle telematics to better understand vehicle travel patterns.</p>

Practices identified by members of the Grid Planning for Vehicle Electrification Task Force.

Source: Energy Systems Integration Group.

Coordination is needed among rate design, charger availability, and grid architecture. A Stanford study found that more public charging is necessary to facilitate utility-scale solar powering EVs, because public charging tends to take place during daytime hours (Powell, Cezar, and Rajagopal, 2022). Such a strategy would also be coupled with distribution grid plans to prioritize such charging.

ADMD calculations will likely need to shift over time as vehicle patterns shift and smart charging becomes more of a complex optimization problem. In the short term, it seems likely that grid planners will plan for full capacity of the EV chargers even though the charging will seldom get anywhere close to that peak load. Diversity will remain an active area of research as data on charger site diversity continue to inform design criteria as more vehicles electrify.

These future-ready approaches serve to upgrade the power system over time, although the totality of upgrades required to reach the grid of the future cannot

happen through a single initiative over the course of just a few years. Promising practices for future-ready systems are given in Table 6.

Targeted System Upgrades

Future-ready infrastructure upgrades that take place over decades will not be sufficient to meet all projected EV charging needs, and specific locations within a region may need upgrades before the existing equipment has reached the end of its expected lifespan. By analyzing forecasts and electrification likelihood indices, distribution planners can prioritize areas for additional, targeted upgrades. These could include larger equipment, new equipment, or non-wires alternatives such as batteries or behind-the-meter generation. Grid solutions discussed in this section are independent of the EV itself; how EVs may be part of the solution is discussed in “Mitigations: Avoiding the Largest Impacts,” above.

Targeted system upgrades can be difficult to identify when the prioritized areas may not see load growth immediately or even in the typical distribution planning

horizon. However, longer planning horizons can identify the areas where grid needs will likely arise, and such horizons will help to achieve the goals of long-term electrification policy. Rather than wait for the grid needs to arise, proactive planning can consider solutions today to spread out the impact of construction more evenly on rates. If grid planners implement grid solutions only once they are needed, they risk infeasible construction timelines and drastic rate impacts hitting customers suddenly. Targeted system upgrades will, however, require distribution system planners to identify the exact locations where the grid will be stressed long before the dynamics of EV adoption and behavior are known.³⁶

An important component of grid planning is adaptability. Short-term solutions may look different from the long-term answers as we learn more about consumer behavior, adoption rates, and the types of EVs that drive the greatest grid impacts.

Because of the uncertainty in how exactly EVs will impact the grid, an important component of grid planning—for both transmission and distribution systems—is adaptability. Short-term solutions may look different than the long-term answers as we learn more about consumer behavior, adoption rates, and the types of EVs that drive the greatest grid impacts. For example, storage can be used as a short-term solution to address targeted issues in the near term while infrastructure is being built. Some utilities are temporarily siting storage to address short-term capacity needs and then moving it to a new location as needs shift. For example, Southern California Edison is planning to use movable storage as a short-term solution to facilitate a timely customer interconnection while a permanent solution (DER or wire solution) is being constructed. Attempting to serve customers that are asking for large service upgrades with short lead times, the utility plans to procure 37 1 MW/4 MWh batteries over the next five years and anticipates a large need for these to facilitate the electrification of medium- and heavy-duty vehicles. Because of storage's flexibility

and multiple value streams, storage that is placed for transmission and distribution capacity deferral today may find value as a bulk system resource after grid upgrades are made to the underlying infrastructure.

Storage can also be integrated into the design of a charging station. Charging stations can use storage to minimize the maximum demand on grid equipment or perform energy arbitrage with a goal of providing energy to vehicles at a lower price. Charging vehicle batteries from charge stations' batteries introduces energy losses but may help to avoid curtailment of utility-scale solar or wind and align cheap energy with consumer demand. Storage charging from grid or on-site resources in a microgrid configuration could be particularly beneficial for the electrification of medium- and heavy-duty fleets when the business function may not allow for smart charging aligned with grid capabilities—when the vehicles are in use during periods of high renewable generation.

Targeted upgrades are an opportunity for grid planners to provide leadership in early EV integration decisions. Rather than react to where consumers want to charge, grid planners can work with others to identify areas where consumers are likely to charge and that are aligned with existing grid capabilities. For example, collaborating with transportation agencies can help to identify opportunity zones to support future high-demand areas. Similarly, proactive interviews and/or surveys of commercial fleet customers can improve the accuracy of forecasts and better align grid upgrades with future fleet expansion plans, timing, demand, and location.

Targeted upgrades are an opportunity for grid planners to provide leadership in early EV integration decisions. Rather than react to where consumers want to charge, grid planners can work with others to identify areas where consumers are likely to charge and that are aligned with existing grid capabilities.

³⁶ This paper does not advocate for widespread proactive grid investments; rather, it emphasizes how a proactive grid planning process would identify targeted system upgrades that address customer needs both in specific locations and at the appropriate grid topology level. The decision to make those upgrades will depend on each utility's or system's needs.

TABLE 7

Planning Practices Associated with Targeting System Upgrades

PLANNING ATTRIBUTE	
Targeted system upgrades consider electrification impacts on the grid.	
Good practices	<ul style="list-style-type: none"> A longer planning horizon (seven or more years) is used in distribution planning to understand how forecasted electrification will impact grid needs. <p>Example: Hawaiian Electric's Grid Modernization Strategy considers ways to achieve the 2045 renewable portfolio standard.</p>
Better practices	<ul style="list-style-type: none"> Short-term solutions (like storage or smart charging) are used to quickly integrate EVs while permanent solutions that address the long-term need are identified. Proactive interviews and/or surveys of commercial fleet customers are conducted to understand fleet expansion plans, timing, demand, and location to improve accuracy of electrification likelihood indices. <p>Example: Avangrid is using a flexible interconnect capacity system to avoid costly upgrades caused by new DERs during some hours of the year.</p>
Best practices	<ul style="list-style-type: none"> Regular medium- to long-term locational forecasting is conducted, in collaboration with transportation agencies, to identify opportunity zones to support future high demand areas. <p>Example: GRE provided developers with a two-page summary of a vacant lot along a highway where 5 MW of distribution capacity was available.</p>

Practices identified by members of the Grid Planning for Vehicle Electrification Task Force.

Source: Energy Systems Integration Group.

The targeted system upgrade approach may be to initially enable public charging plazas in areas where the grid can handle it. Such decisions can help reduce some of the uncertainty that currently plagues grid planning decision-making, while these early deployments remain useful as levels of EV grow.

The targeted system upgrade approach may be to initially enable public charging plazas in areas where the grid can handle it. Such decisions can help reduce some of the uncertainty that currently plagues grid planning decision-making, while these early deployments remain useful as levels of EV grow. Targeted system upgrades can look like traditional solutions or non-wires alternatives, such as batteries. Similarly, these may be prospective or reactive, as the grid prepares for or catches up to charging needs. There are a variety of planning practices associated with identifying where to upgrade the grid, but Table 7 captures some of the characteristics of planning specifically for vehicle electrification.

Transparent Energization and Interconnection Processes

Roadmaps and distribution system plans will also need to include plans for responding to requests for public EV charging stations as they arise. Assessing EV charging requests will happen multiple times per year or potentially much more often. Given policy expectations for levels of EV adoption, energization and interconnection requests for EVs may exceed the volumes seen to date for solar PV installations and may further strain grid planning and line design departments unless new tools and increasingly streamlined processes can be deployed. Without proactively addressing this anticipated volume,

Distribution planning for EVs is an opportunity for the power industry to apply lessons learned from behind-the-meter solar deployment, such as developing retail rate designs that address EV impacts, new software tools to streamline processes, and public indicators of grid locational capabilities.

timelines for approval are likely to be longer than consumers expect to wait.

A cohesive plan is needed to deal with EV requests. Here, the power industry has an opportunity to apply lessons learned from behind-the-meter solar deployment to assist in distribution planning for EVs, such as developing retail rate designs that address EV impacts, new software tools to streamline processes, and public indicators of grid locational capabilities.

While public charging plazas and fleet depots will sometimes be constructed on the bulk system, and other public plazas will present large amounts of new load to small distribution systems, the effects of single-car charging stations at homes will be more subtle. These single-car charging stations will have a large aggregate impact on the power system even if their individual impact is minimal. Utilities have different degrees of visibility into at-home charging: most charging done with a 120 V charger (3 to 4 miles of charge per hour) can be done without utility approval, while in most cases, a 240 V charger (20+ miles of charge per hour) will need an electrical permit to install a new EV charging circuit. These applications for service will likely be voluminous, and a cohesive evaluation plan will be needed to assess the impact of EV chargers at the premise level and public chargers on the distribution system, in addition to transmission-connected highway charging plazas that support trucking electrification.



Distribution system planners can make processes for integrating EVs smoother and establish a trajectory for successful long-term integration of EVs by providing:

- Early indication of **likely capacity availability**
- Clear articulation of the **steps and data needed to connect new load**, including when the vehicle owners should engage their utility
- Defined expectations of the **grid-response characteristics of EVs**, along with any **control schemes used to manage load**

Indicating Capacity Through Queues and Maps

Queues and capacity-availability maps are needed at both the transmission and distribution level to give developers a better sense of where grid infrastructure is most capable of supporting public charging.

The concept of a public queueing process for new loads is relatively novel. Historically, projects that added new load to the system were concealed, as community developers protected their long-term plans from competitors. However, that is starting to change. For example, the Hawaiian Electric Company has requested regulatory approval for a customer reservation pilot program that would allow developers to reserve distribution capacity to serve their projects for up to five years (HECO, 2022). Reservation charges can be repaid through bill credits. This program gives developers certainty that the grid infrastructure will support their projects and provides the utility with more insights earlier in the development processes as it considers multi-year grid plans and multiple potential futures.

EV capacity maps can borrow from the concept of public hosting capacity maps that indicate the likely ability of the distribution system to accommodate new generation at different points on the grid. These EV capacity maps have been implemented in some regions, such as by

EV capacity maps can borrow from the concept of public hosting capacity maps that indicate the likely ability of the distribution system to accommodate new generation at different points on the grid.

California investor-owned utilities in their integration capacity analysis maps. However, additional information about capacity would also be useful for developers, such as whether or how others are queued in a given location. Such queues could be maintained as projects are energized or abandoned.

Hosting capacity analysis at the distribution level has become more sophisticated in recent years as simplified heuristics have been replaced with topology-specific simulations and the evaluation of multiple technology scenarios. Similarly, capacity maps can embrace topology-specific details and provide a range of feasibility across scenarios, even if they are just indicative of the results of more rigorous analysis. Appropriate data sharing will ultimately result in a more effective grid that integrates EVs at scale.

Articulating Process Steps and Data Requirements

Each utility has its own method for evaluating requests for public EV charging. Those processes are informed by the utility's capabilities and systems and should remain tailored to its circumstances. However, the basic data required to perform energization and interconnection studies can be standardized across utilities to assist data exchanges among stakeholders—between applicant and utility and between utilities. The industry could formulate a standard application for large charging station requests that builds upon similar efforts, such as Orange Button, the effort to standardize distributed PV data to enable data exchanges.³⁷ An effort like this for EVs would include information about the supply equipment, ranging from proposed nameplate ratings on the chargers to information about the electrical and information architectures that would support the site.

In addition, the timelines and process steps can be made readily available to homeowners, businesses, and developers, in terms understandable to people unfamiliar with electrical engineering grid considerations. For example, Oncor's Clean Fleets Partnership Program includes educational materials for fleets on the energization process. Developers need to be aware of the difference

between screening maps and detailed interconnection analysis, particularly as surprising grid upgrade costs can disrupt project economics after significant effort has been performed by the developer.

Establishing Grid Response Characteristics for EV Chargers

The power industry is currently working out inverter specifications for wind and solar resources at the bulk and distribution levels to ensure stable operations during grid disruptions, with significant attention from the North American Electric Reliability Corporation (NERC), standards organizations, and manufacturers. Many utilities have updated or are in the process of updating their requirements for new generator interconnections to align with the new NERC Reliability Guidelines³⁸ and/or specifications from IEEE Standard 1547-2018 and IEEE Standard 2800-2022, which establish the criteria and requirements for interconnection of inverter-based resources and DERs interconnecting with transmission and sub-transmission systems, respectively. However, similar attention has not yet been afforded to new loads, particularly EVs.

Because EVs' charging demand is large in aggregate, it behooves the power sector to work with the transportation sector to develop requirements and standards for the EV chargers—particularly with respect to their behavior on the grid, including responses to changes in grid voltage and frequency. In addition, V2G applications will see inverters either embedded in the vehicle itself or within the charger that will need to behave in a predictable and beneficial manner.

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37 See <https://myorangebutton.com/>.

38 See https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_IBR_Interconnection_Requirements_Improvements.pdf.

Defining a Grid-Friendly Operational Profile for Chargers

Aggregated charging loads, with EVs reacting in unison to conditions on the grid, pose both challenges and opportunities for utilities attempting to maintain reliability and serve load. Recent work examining the behavior of different types of chargers during a fault showed that some chargers have grid-friendly behavior in supporting fault-induced delayed voltage recovery (FIDVR) events while others do not (Tuffner et al., 2021). If chargers were required to provide sub-second responses—either increasing or decreasing their consumption—the aggregated benefits could be significant and the impact on charging times minimal.

Although EVs as a load can potentially have large impacts on sub-second grid operations, today's EV chargers do not share a standard grid-friendly sub-second operational profile (Tuffner et al., 2021). Grid operators and system stability would benefit from EV chargers that react to grid conditions, such as voltage fluctuations, in a standard and predictable manner.³⁹ Even beyond standardizing the grid response characteristics of EVs for system stability, there can be benefits to using a power electronics controls functionality to allow additional EV charging at the grid edge by mitigating the extent of service transformer overloading (Aswani and Mycko, 2022). Grid voltage measured by the EV charger could be used as a signal to throttle charging in real time (a volt-watt response function), but work remains to demonstrate the effectiveness of this concept around risks associated with more dynamic distribution system operations, such as potential overuse of on-load tap changers.

The need to define these types of grid response characteristics is immediately apparent when considering vehicle export applications in which the vehicle sends power back to the home, grid, or other end uses using V2G technology. This is another area where distribution planning for EVs can learn from integrating higher levels of PV and the “smart inverter” requirements that have been phased in for PV interconnections.



Grid-friendly EV loads are at the intersection of several standards across the vehicle and power industries, but no standards clearly define the expected grid response characteristics of EVs as a load. IEEE 1547 was intended for generators and does not directly apply to loads. Similarly, IEEE 1547.9-2022 covers energy storage and thus includes EVs only when they export energy from their batteries to the grid. IEEE 1668 provides a recommended practice for “voltage sag and short interruption ride-through performance and compliance testing” of equipment, but does not outline the performance requirements of loads on distribution systems. The Society of Automotive Engineers’ SAE J2894 provides a recommended practice for EV chargers to consider the impact of the power quality of the electrical service on the charger, but not the impact of the charger on the grid.⁴⁰ Distribution planners will need to communicate with automotive engineers about the grid interactive expectations and build these expectations into contractual agreements and chargers.

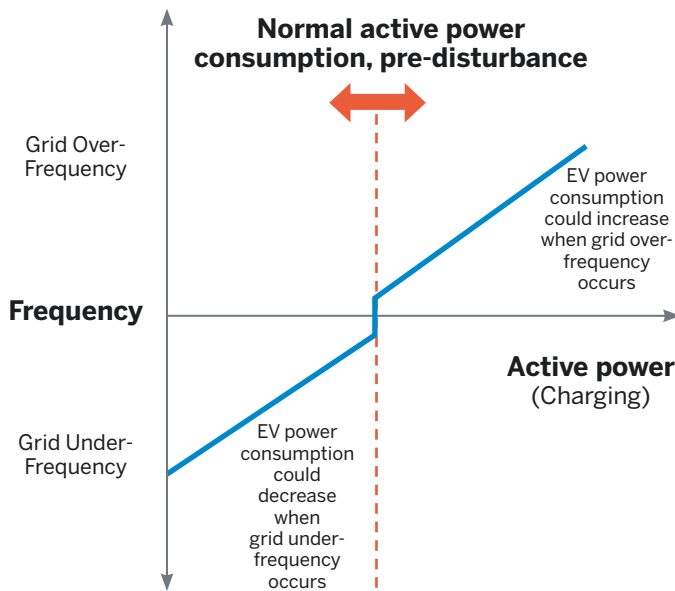
Characterizing Frequency Response and Voltage Support

A natural starting point for specifying grid-friendly response characteristics for grid stability time frames—sub-seconds to seconds—is to look to traditional characteristics of some loads and generators that are known to

39 Zhu et al. (2021) compared a standardized volt-VAR curve (the default IEEE 1547-2018 curve) with a customized curve applied to the individual circuit's topology and found that the standard is “good enough” for large station voltage controls, but more fragile locations may require more care.

40 See <https://standards.ieee.org/ieee/1547/5915/>, <https://standards.ieee.org/ieee/1547.9/10875/>, <https://standards.ieee.org/ieee/1668/6798/>, and https://www.sae.org/standards/content/j2894/1_201901/.

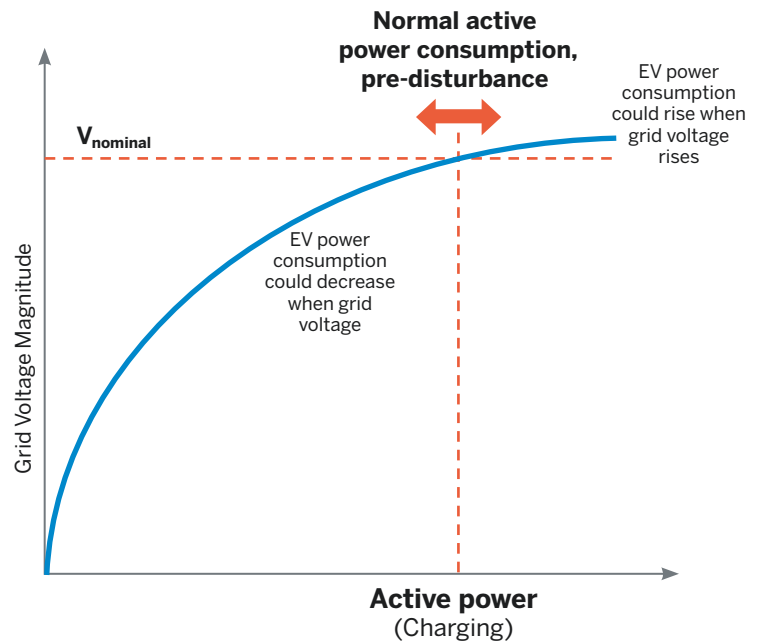
FIGURE 23
Potential Frequency-Response Characteristic of an EV



The droop curve (solid blue line) shows how an EV could respond to changes in system frequency according to grid needs. The vehicle's normal active power consumption with normal grid frequency is shown at the intersection of the X axis and the vertical dotted line. When the grid frequency is within a normal range, the vehicle charges and discharges normally. If the grid frequency rises above that range, the EV's active power consumption rises. Similarly, if the grid frequency drops, the EV's active power consumption drops.

Source: Energy Systems Integration Group.

FIGURE 24
Potential Voltage Response Characteristic of EVs



A constant-impedance characteristic would make EVs grid-friendly by responding to changes in distribution voltage. The vehicle's normal active power consumption with normal grid voltage is shown at the intersection of the nominal voltage on the Y axis and the vertical dotted line. If the grid voltage rises, the EV's active power consumption rises along the blue line to the right. Similarly, if the grid voltage drops, the EV's active power consumption drops along the blue line to the left. Similar behavior could be implemented for EVs in discharging mode.

Source: Energy Systems Integration Group.

provide a stabilizing effect for all power systems. Two stabilizing characteristics describe the response of grid-connected EVs to changes in grid frequency and grid voltage—frequency droop response and constant-impedance characteristics—and are applicable for charging operation and discharging (V2G) operation.

The frequency response characteristic is described with a droop characteristic, as shown in Figure 23, that has been used since the beginning of interconnected resources for passive coordination. The droop curve shows that increases in grid frequency, indicative of excess generation on the grid, cause an increase in power consumption (or a decrease in power generation for V2G operations). Conversely, for under-frequency events where the grid is temporarily “starved” for power, the EV would temporarily reduce consumption (or increase power

delivery to the grid). This operation is identical to that described in IEEE 2800 for stationary battery resources. Such frequency events on the grid typically last for tens of seconds and occur relatively infrequently, such that there is very little impact to the EVs’ state of charge. However, the maximum and minimum power limits of the equipment must be respected, even for brief excursions, which may limit the amount of response delivered by any single EV.

The voltage response characteristic, known as a constant-impedance characteristic, is shown in Figure 24, where the EV appears to the grid as a constant resistance, much the way a conventional toaster oven would appear to the grid. This characteristic gives the EV stabilizing properties during voltage excursions. When grid voltage is low, indicating that the grid is stressed and has a reduced



These frequency and voltage responses would have essentially no negative impact on the use and functionality of EVs, while allowing EVs collectively to offer a significant benefit to the stability of the grid at very little cost.

ability to transfer active power, the EV would reduce its active power charging from the grid, thereby mitigating grid stress.⁴¹ Dynamically, the constant-impedance characteristic exhibits a damping effect that helps to quell oscillations in the grid.

Both of these response functions would operate quickly in the EV inverter controls—with very low latency between detected deviations in the grid and the response of the EV. If implemented properly, these responses would have essentially no negative impact on the use and functionality of EVs, while allowing EVs collectively to offer a significant benefit to the stability of the grid at very little cost. Discrete requests for EVs to connect to the grid can come at all times of the year with different types of information flowing across stakeholders depending on the nature of the request. In addition to the distribution engineering required to evaluate these requests, planning practices related to the energization and interconnection of EVs are captured in Table 8.

TABLE 8
Planning Practices Associated with Energization and Interconnection Processes

PLANNING ATTRIBUTE	
The EV integration process provides information to developers and owners on the locations of available capacity, clearly articulates the needed steps and data, and defines the grid response characteristics expected of EVs.	
Good practices	<ul style="list-style-type: none"> The utility provides an overview of the steps and timelines for EV energization and interconnection review. Data requirements for the utility’s EV impact analysis are defined upfront. <p>Example: Pacific Gas and Electric has a guidebook for fleet electrification that provides a 15-step process and expected timeline for the utility’s process.</p>
Better practices	<ul style="list-style-type: none"> The interconnection/energization queue is available, maintained, and transparent to EV site developers. Load integration maps are publicly available to indicate the distribution system’s available capacity at different locations. <p>Example: Potomac Electric Power Company (PEPCO) provides an EV load capacity map to guide large-scale electrification toward areas where there is capacity on the system.</p>
Best practices	<ul style="list-style-type: none"> The grid-response characteristics of EVs as a load are defined, and consideration for their voltage responsive characteristics is included in the engineering analysis. <p>Example: No examples are available in practice, but the Pacific Northwest National Laboratory has simulated of EV load response to transmission faults.</p>

Practices identified by members of the Grid Planning for Vehicle Electrification Task Force.

Source: Energy Systems Integration Group.

⁴¹ This characteristic is focused on active power exchange with the grid because it is assumed that the EV is designed to operate at unity power factor with little to no exchange of reactive power.

Coordinated and Holistic Planning

For grid planning for EVs to be successful, utility grid planners and state regulators must coordinate across a wide range of stakeholders, including communities, consumers, vehicle manufacturers, charge station operators, aggregators, and others. Grid planners and regulators will need to navigate the macro trends of policies and consumer interests to implement distribution system plans that appropriately consider the opportunities and challenges that higher numbers of EVs will bring.

Coordinating the Approach

Utility planning processes are increasingly adopting an integrated grid planning approach that solicits input on grid plans from key stakeholders and the public at large. EVs will increase the need for these integrated approaches because of their impact at all layers of the power grid. Consumers' behavior will heavily affect how EVs impact the grid, and grid planning will need to consider consumer input and feedback. In addition, utilities will need to coordinate EV assumptions, inputs, and scenarios across planning processes and departments. This includes assessments of equipment standards that influence premise-level plans as well as annual distribution, transmission, and generation planning.

While a distribution upgrade may alleviate an overload in one part of the system, the new distribution capacity could move grid constraints elsewhere. A holistic grid plan ensures that the customers receive the benefits of upgrades wherever they are implemented. For example, upgrading every customer's electrical panel and every service transformer could still leave electric power deliverability insufficient without appropriate upstream capacity.

Utility planning processes are increasingly adopting an integrated grid planning approach that solicits input on grid plans from key stakeholders and the public at large. EVs will increase the need for these integrated approaches because of their impact at all layers of the power grid.

Smart EV charging, a key enabler of efficient utilization of grid infrastructure, requires coordination among distribution and transmission operators to align charging behavior with grid needs and capabilities. Certain charging behavior suited for the bulk system may not be feasible because of distribution system constraints.⁴²

Federal Energy Regulatory Commission (FERC) Order 2222 requires improved coordination to allow for distributed resource aggregations to participate in wholesale markets (FERC, 2020). Regulations will need to evolve along with planning practices to support policy and customer needs. Regulators can consider how to support proactive planning processes, determining how and when to approve projects that aim to address forecasted load growth that has large uncertainties. Beyond distribution projects explicitly aimed at EVs, such as building a new substation for a highway charging plaza, regulators will need to understand the costs and impacts of higher-capacity equipment for distribution components—for instance, increasing standard distribution voltages from 12 kV to 35 kV. While defining the suitability of distribution equipment for a heavily electrified future, regulators will need to understand how and when smart charging

⁴² See the discussion on smart charging above. Of particular interest is Table 4.

can provide a non-wires alternative for certain types of distribution system investments.

Importantly, utility equipment standards may need to be modified to specify larger (and more expensive) equipment to support EV charging needs. Equipment standards have a large and often understated impact on the grid’s ability to support electrification because of the volume of standards-based equipment deployed annually as part of regular utility maintenance. Standards should be continually evaluated as the impact of EVs and the electrification of buildings changes underlying assumptions about customer load that has not seen significant increases in decades.

An iterative and adaptable grid planning approach is called for. Grid plans are preferred that are cyclic, are innovative, and embrace new technologies, as grid planners keep pace with EV growth and learn from early deployments.

Aligning the Grid Planning Process with the EV Use Case

Both reactive and proactive grid planning present challenges. But it’s important to navigate these options because of the large climate change policy goals of vehicle electrification. There is a chicken-and-egg problem in which consumers are hesitant to buy EVs without sufficient charging infrastructure in place even as charging providers are hesitant to install charging stations without sufficient EV demand. One approach to balancing proactive and reactive actions is for grid planners and regulators to consider potential future scenarios for the power system by aligning planning processes with the EV use case, including vehicle type, supporting battery technology, and the function of the vehicle. For example, the same passenger van with a 200 kWh battery could be used as a flower delivery service or by a weekend hiking club, with very different charging (and potentially discharging) profiles for the same vehicle type. By focusing on which electrification use cases to enable, the appropriate planning process can be used, ultimately resulting in the appropriate grid design.

Collaborative and Proactive Planning Paradigms

Existing grid planning processes, which are regularly updated and include a medium- to long-term planning horizon (e.g., five years), can integrate EVs under some circumstances (Table 9). However, while existing processes vary significantly across the country in how they consider transportation electrification among other objectives, such as replacing aging assets,⁴³ they generally

Collaborative and proactive planning approaches could identify the need to build transmission and distribution infrastructure in advance of EV load arising in specific locations.

TABLE 9
Multiple Processes Provide a Holistic Approach to Grid Planning for EVs

Existing Processes
<p>While today’s grid planning processes vary across the country, they generally include:</p> <ul style="list-style-type: none"> • Annual system reviews • Regularly updated grid plans with a medium- to long-term planning horizon • Isolated evaluation of interconnection requests
Customer-Collaborative Processes
<p>A customer-collaborative process between planners and customers allows for open communication about:</p> <ul style="list-style-type: none"> • Multiple options for interconnection • Multiple locational alternatives
Proactive, Multi-Stakeholder Processes
<p>Given the volume and multiple use cases of EVs, proactive processes can be well suited to:</p> <ul style="list-style-type: none"> • Ensure access to EV charging for underserved communities and determine where local, traffic-related pollution may be mitigated through vehicle electrification • Facilitate regional networks • Provide clear roadmaps for electrification planning progression

Multiple planning processes can be used together to effectively plan the grid for vehicle electrification. This approach supplements existing processes with customer-collaborative processes and proactive, multi-stakeholder processes.

Source: Energy Systems Integration Group.

⁴³ Some utilities are adopting multi-objective planning that attempts to co-optimize across reliability, electrification, affordability, and other goals. On the other end of the spectrum, some utilities’ maintenance processes include like-for-like replacements that effectively refresh undersized equipment that is ill-suited to meet future electrification needs.

will not sufficiently integrate EVs as these vehicles become more numerous and travel between utility service territories. Collaborative and proactive planning approaches could identify the need to build transmission and distribution infrastructure in advance of EV load arising in specific locations. Benefits of these planning approaches include avoiding long wait times for enabling grid upgrades, identifying opportunities for cost savings by making larger upgrades at fewer circuits along travel corridors, and allowing for better community input and consolidation of services around locations where EVs charge. Table 9 outlines how these types of planning processes differ from existing processes.

Existing processes will need to continue to evolve to embrace new planning techniques, including new analytics capabilities and smart charging as tools to effectively design the grid. Even the most advanced utilities in North America can continue to build in new capabilities in grid planning practices. The customer-collaborative and proactive processes move beyond existing processes as follows:

- **Customer-collaborative processes** can help identify the best solutions to fulfill EV charging needs and V2G program participation. There are opportunities to integrate new EV loads without new grid infrastructure, but those can best be identified through conversations and trade-offs between grid planners and EV customers. Fleet owners can expedite planning processes by reaching out to the utility early about potential plans to electrify. Utilities can collaborate by providing options rather than a yes/no response to an EV charging request, such as “yes, with these restrictions.” To facilitate the collaboration, utilities can provide dynamic interconnection limits or make use of operating envelope restrictions that vary by time of day.
- **Proactive multi-stakeholder processes** are particularly helpful for regional and long-term planning for EV charging. Some types of EVs (such as long-haul trucks) require coordination across jurisdictions. These processes also help to align grid plans with the needs of communities and articulate a clear multi-year plan. Some jurisdictions already require integrated distribution plans and include electrification considerations in those plans. Multi-stakeholder planning

is similar to these proceedings but also includes inter-regional and longer time horizon considerations and is inclusive of different perspectives in the formulation of grid needs and solutions. The ESIG Grid Planning for Vehicle Electrification Task Force identified a wide variety of stakeholders who should be involved, including vehicle manufacturers, charge station operators, distribution utilities, transmission owners, regional grid operators, community-based organizations (leadership as well as constituents), state and local governments, fleet managers, rural communities, urban planners, community developers (single- and multi-family housing, commercial), environmental justice organizations, and large commercial centers or businesses (e.g., malls/town centers).

Large shifts in planning practice will initially be driven by groups of larger EVs—medium- and heavy-duty fleets—and the coordination of regional and national transportation needs, which includes highways and other charging corridors.

Large shifts in planning practice will initially be driven by groups of larger EVs—medium- and heavy-duty fleets—and the coordination of regional and national transportation needs, which includes highways and charging corridors. Another key outcome of proactive planning processes at each of the utility, regional, and national levels is ensuring access to EV charging for underserved communities and determining where local, traffic-related pollution may be mitigated through electrification of medium- and heavy-duty fleets in the area.

Suitability of Different Processes to Address Different EV Charging Needs

Figure 25 (p. 60) articulates the suitability of each type of process—existing, customer-collaborative, or proactive multi-stakeholder—to support a given need for EV charging. The amount of shading in each cell indicates the suitability of that process to support the stated EV charging need.

FIGURE 25

Suitability of Grid Planning Processes to Address EV Charging Needs

Managed Charging of Light-Duty Vehicles			Charging Along Highways and Corridors		
Existing processes	Customer-collaborative processes	Proactive processes	Existing processes	Customer-collaborative processes	Proactive processes
<ul style="list-style-type: none"> • Daily-routine charging • Demand for L1 charging • Elastic demand 	<ul style="list-style-type: none"> • Perceived charging deserts • Service provider requests 	<ul style="list-style-type: none"> • High vehicle deployment • Heavily loaded distribution • Inflexible demand 	<ul style="list-style-type: none"> • Minimal highway usage 	<ul style="list-style-type: none"> • Along private highways 	<ul style="list-style-type: none"> • Grid limitations along highways • Regional EV growth • Interregional trucking
Charging of Vehicle Fleets			Charging in Underserved Communities		
Existing processes	Customer-collaborative processes	Proactive processes	Existing processes	Customer-collaborative processes	Proactive processes
<ul style="list-style-type: none"> • Small fleets • Sufficient highway charging 	<ul style="list-style-type: none"> • Inflexibility in timing and location • Large fleets 	<ul style="list-style-type: none"> • Multiple fleets competing for capacity • Limited land availability 	<ul style="list-style-type: none"> • Equity considerations included • Incentives for EV purchase and smart charging 	<ul style="list-style-type: none"> • New multi-family housing 	<ul style="list-style-type: none"> • Insufficient opportunity for charging • MHD vehicles near communities

Each grid planning process can be used to address certain types of EV scenarios, but some processes are more suitable than others depending on the objective. All types are needed to enable widespread vehicle electrification.

Source: Energy Systems Integration Group.

The figure connects each EV charging need to the most suitable grid planning process.

- **Light-duty vehicles** can largely be integrated with existing planning processes as long as demand flexibility can be captured through managed charging and existing distribution infrastructure is not heavily loaded. If infrastructure is already heavily loaded, a long-term proactive plan for distribution upgrades will be needed to enable vehicle electrification.
- **Medium- and heavy-duty fleets** represent a unique combination of opportunity and challenge. Existing planning processes may be sufficient to integrate fleets under some circumstances, but a collaborative back-and-forth is likely needed to arrive at the most affordable and appropriate grid solution for fleet charging needs. The North American Council for Freight Efficiency has recommended early engagement between fleets and utilities to increase understanding of fleets’ charging needs (NACFE, n.d.; 2022).

- **Highways** often cross grid planning boundaries and thus require multi-stakeholder input. Planning for the Interstate-5 corridor by the West Coast Clean Transit Corridor Initiative illustrates a best practice for coordinating the charging corridor plan across utilities (WCCTCI, 2020).⁴⁴
- Ensuring EV and charging access to **underserved communities** requires proactive planning, given that affluent early adopters may use up available capacity. The electrification of medium- and heavy-duty vehicles in proximity to underserved communities can also be proactively planned to reduce street-level air pollution where there is heavy truck traffic.

Coordinating Equitable Plans

The fundamental challenges with proactive planning and creating a future-ready power system involve cost allocation and risk management:

44 The West Coast Clean Transit Corridor Initiative is a consortium of utilities working together to assess the feasibility of electrification of long-distance truck travel and goods movement along the Interstate-5 transportation corridor. See <https://westcoastcleantransit.com/>.

- Who pays for grid upgrades?
- What happens if the load doesn't show up?

Cost recovery for grid upgrades has historically been governed by a complex set of rules that differentiates grid upgrade costs borne by different types of projects. Generally, single-family residences are exempt from any costs associated with service lines and distribution system investments resulting from increased load. However, commercial customers can be responsible for these types of costs, which can sometimes total multiple millions of dollars.⁴⁵

California recently adjusted the rules to “socialize across all ratepayers the costs of service line extensions and electrical distribution infrastructure for EV charging.”⁴⁶ This decision is aligned with recent California legislation (AB 841) intended to accelerate the deployment of distribution infrastructure to support charging stations. These changes were made in part because it was found that “there is a significant need for more EV charging infrastructure in the near term to meet California’s [transportation electrification] and emissions goals.”⁴⁷ Other jurisdictions may also find it necessary to reconsider their rules governing cost allocation in support of electrification policy goals.

Proactively upgraded grid infrastructure targeting EV charging can be encouraged through regulatory mechanisms as well, although determining the prudence of proactive upgrades can be challenging for regulators. Stakeholders can work together to identify metrics appropriate for evaluating these utility upgrades. A combination of metrics that assess reliability, asset utilization, and levels of vehicle electrification could appropriately incentivize utilities to design distribution systems that support vehicle electrification while balancing other priorities.

Regulatory mechanisms, accounting measures, and policies can align grid planning with the needs of all consumers, providing opportunity and access to electrified transportation. This means that renters can charge their cars because there is sufficient public charging and the latest consumer to buy an EV is not stuck with the entire bill to upgrade the transformer they share with neighbors. These issues are complex and have no regulatory precedent in many areas, but broad stakeholder involvement can ensure that various interests are reflected in equitably planning the grid.



45 Some jurisdictions require customers to pay upfront distribution costs for new loads, while other jurisdictions have customers pay for grid upgrades over time through rates. With uncertainty around EV infrastructure utilization and future rate designs, thorough consideration of who pays for these distribution costs will promote equity.

46 California Public Utilities Commission Decision D.22-11-040, November 2022.

47 Ibid.

Next Steps

Despite interest in and commitments to EVs from customers, manufacturers, and policymakers, grid planning for vehicle electrification remains a challenge, particularly on distribution systems where vehicle charging could quickly overwhelm grid edge equipment. Public charging sites and vehicle fleet depots can be planned, permitted, and constructed much more quickly than other loads such as commercial sites or industrial facilities. Utilities therefore have much less time to upgrade distribution system infrastructure for electric vehicle integration compared with new loads historically.

Depending on the approach, the distribution system can be a bottleneck for vehicle electrification, hamstringing EV adoption, or it can support more sustainable

transportation thanks to thoughtful planning. Despite incomplete information about the timing, magnitude, and location of this new EV demand, there are opportunities to lay a grid planning foundation today that will support the evolution of the grid and enable widespread vehicle electrification.

Improve Forecasting

Industry forecasting of vehicle impact can be improved by enhancing adoption and behavior models to consider multiple vehicle end uses, new vehicle technologies, and additional data sources. First, forecasting adoption at a granular level can be achieved through likelihood models informed by costs, policies, and customer preferences, as





well as through new sources of data, such as fleet electrification surveys. These adoption models can include locational components and characterize the types of vehicles that will connect to the grid, including the technology that underpins the vehicle (the battery technology, size, and charger). Second, forecasting charging behavior and how the vehicle is used (e.g., school bus vs. city bus) will inform impacts of EVs both temporally and locationally.

Forecasting models that consider these impacts have been developed by leading researchers and industry and will continue to be improved as the underlying data becomes more robust. The two key elements of forecasting—the location and timing of charging—are intertwined, elastic, and changing as EV adoption increases and vehicle technologies progress. Even with the best models and data, forecasts will not capture everything. In time, we will learn how technological, regulatory, and social-human factors will impact EV charging. Embracing the uncertainty around EV adoption and charging patterns through scenario planning helps planners think in broad strokes rather than narrow solutions.

Embrace Smart Charging

Smart charging programs hold great promise for using grid infrastructure efficiently, aligning charging with infrastructure capabilities, and utilizing lowest-cost electricity. Smart charging options using rate designs, automation, or demand response programs can align

charging with more affordable energy and reduce total infrastructure needs at every level of the grid from the premise to the bulk system. Targeted smart charging, operating limits, and strategically located storage can help with immediate load growth and remain useful as more solutions are implemented over time.

Smart charging is a central tool in limiting the impact of EVs on distribution infrastructure and can help to minimize the grid upgrades needed to support a transition away from gasoline-powered cars. However, even using the smartest of charging strategies, it may be necessary to upsize distribution equipment, particularly if customers do not participate in demand response programs or will not provide flexibility based on price differentials. There is much still to learn on the practicalities of implementing smart charging, including customer participation, its impact on load diversity, effective and reliable operations, and incorporating it into modeling tools.

Recognizing that smart charging is an imperfect solution with things still to learn, the potential flexibility of EV charging merits fundamental consideration in planning. This goes beyond cursory evaluation and leads to utilities embracing smart charging as a tool to meet the challenges presented by vehicle electrification. In addition to smart charging, grid upgrades will be needed in some areas and the industry will need to continue to use the appropriate solutions to meet the multiple distribution planning objectives.

Incorporate Future-Ready Equipment

The optimal grid plan will likely be some combination of smart charging paired with infrastructure upgrades. More subtle strategies can enable electrification over time, including using future-ready equipment designed to support future load growth from EVs and other sources.

Planning for EVs requires a holistic analysis of the assumptions that drive grid planning decisions. Many of those assumptions are embedded in equipment design standards, which are assessed infrequently, and leading utilities are re-evaluating these design standards because of vehicle electrification. Unfortunately, there is no consensus on optimal designs today as engineers balance

uncertain equipment loading levels, driven in part by the diversity of charging behavior, and equipment rating methodologies that are also undergoing innovation thanks to new equipment-ageing methodologies.

This future-ready approach holds promise because the cost of the grid equipment itself is only one part of the cost to replace aging infrastructure. Labor required for planning and installation makes up a large share of the cost of a service transformer upgrade; therefore, the marginal cost of a higher-capacity transformer is often small compared to the costs of replacing or supplementing the transformer in a few years. A national reference quantifying the soft costs of utility equipment and the cost-effectiveness of upsizing could help utilities and regulators think through this strategy within their territory.

Promote Proactive Upgrades Based on Multi-Stakeholder Input

Future-ready grid upgrades that take place over decades may not be sufficient to meet all projected EV charging needs, and specific locations within a region may need upgrades before the existing equipment has reached the end of its expected lifespan. Widespread just-in-time upgrades of distribution equipment to support the level of electrification projected would likely be both costly and infeasible for utility construction crews. Distribution utilities can be proactive, and by using improved, granular forecasts while working with a multi-stakeholder group, can prioritize areas for targeted upgrades that balance the asymmetric impacts of over- and under-building the distribution system.

Proactive upgrades could include larger equipment, new equipment, or non-wires alternatives, such as batteries or behind-the-meter generation. These upgrades will balance the short-term with the long-term as we learn more about charging needs. Regulatory and policy efforts may be needed to support proactive upgrades because these upgrades may not be “used and useful” when they are first implemented.

While much of distribution system planning has traditionally been handled by utilities, the role of state legislators, regulators, and other state officials will continue to grow as multiple power grid objectives

compete for priority. Similarly, retail rate designers, vehicle manufacturers, and charge station operators will need to work with grid planners to design solutions that balance the cost of new infrastructure with customer charging flexibility. And the need to ensure equity in designing the grid that supports an electrified future is best accomplished through a broad range of stakeholder input.

As air conditioning loads transformed customer demand in the 1960s/1970s, grid planners innovated by pairing large grid build-outs with demand response. Thanks to their lead, we do not need major technological innovation to meet EV demand. We know how to meet large demand growth; we have done it before. We do, however, need to quickly understand the magnitude of change that will be required and take action. Because of the multi-billion-dollar scale of these grid planning decisions, coordinated and holistic planning is needed to design grid architecture that effectively balances uncertainty around EV adoption (and when and where vehicles will charge), which can lead to an overly cautious investment approach, with ensuring the grid is adequately prepared for EVs. Grid planning for vehicle electrification is an opportunity to further integrate the energy systems that power our lives while establishing a platform for a wholly sustainable future.



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Charging Ahead: Grid Planning for Vehicle Electrification

**A Report of the Energy Systems Integration Group's
Grid Planning for Vehicle Electrification Task Force**

The report is available at <https://www.esig.energy/reports-briefs>.

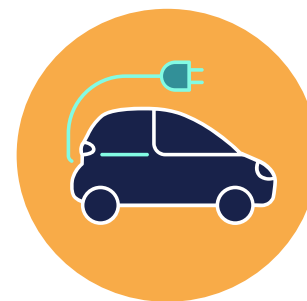
To learn more about ESIG's work on this topic, please send an email to info@esig.energy.

The Energy Systems Integration Group is a nonprofit organization that marshals the expertise of the electricity industry's technical community to support grid transformation and energy systems integration and operation. More information is available at <https://www.esig.energy>.



Electric Vehicles Are Driving Rates Down for All Customers

January 2024 | Sarah Shenstone-Harris, Paul Rhodes, Jason Frost, Ellen Carlson, Eric Borden, Courtney Lane, Melissa Whited



National Update

Electric vehicles (EVs) offer a key opportunity to reduce harmful emissions and save consumers key money at the same time. EVs are responsible for far fewer greenhouse gases and local air pollutants than conventional vehicles and become cleaner as more renewable electricity is added to the grid. In addition, EVs are generally much cheaper to operate than conventional vehicles.

The number of EVs on the road are rapidly growing and increasing in share among light-duty vehicles. By the end of 2022, more than 3.2 million EVs had been sold in the US alone. Federal, state, municipal and industry action to incentivize and increase the adoption of EVs promise to accelerate this transition. The new electricity load and flexible demand represented by these vehicles has major implications for our future energy system and could increase total electricity use by 25 percent. By charging during hours of the day when there is least demand on the grid, however, the electric vehicle transition could reduce electric rates for everyone.

Evaluating the impact of electric vehicles on the road today can help us understand their effect on the grid and how they might shape the power system in the future. Accordingly, this analysis examines costs and revenues associated with EVs between 2011 and 2021 across the United States. **We observe that over the last 11 years, EV drivers across the United States have contributed approximately \$3.12 billion more than their associated costs, driving rates down for all customers. When we also include utility expenditures for EV programs, EV owners have contributed approximately \$2.44 billion more in revenues than in costs.**

How Are EVs Affecting Electricity Rates?

Recent growth in EV adoption has raised the question of how EVs affect the electricity rates paid by all households, including those that do not own EVs. This is an important equity question that should be analyzed when determining the role that electric utilities should play in supporting the transition to EVs.

Answering this question requires comparing electric utility revenues from EV charging with utility costs associated with serving EV load. If the utility revenues from EVs exceed the utility system costs, then EV adoption can reduce electricity rates for all customers. Conversely, if the costs are greater than the revenues, non-EV owners could end up paying more for their electricity. This effect holds true even for utilities without revenue decoupling. Additional revenue will be accounted for in subsequent rate cases, and even during the time between rate cases, the revenue from EVs may be used to offset higher costs in other areas, delaying the need for a rate increase for utilities without decoupling.

Multiple prospective studies have forecasted that utility revenues will exceed costs with future electrification. However, to address this question using real-world data, Synapse evaluated the utility system revenues and costs associated with EVs purchased within the last decade across the United States. Specifically, this analysis tracks revenues and costs associated with over 2 million battery electric and plug-in hybrid EVs sold between 2011 and 2021.

We analyzed the electricity rates that EV owners pay compared to the marginal cost of providing that electricity (generation, transmission, and distribution costs) plus the expenditures associated with utility EV programs. We gathered cost and rate data from across the country to inform this analysis, including from RTOs, the Federal Energy Regulatory Commission, filed tariffs, and published marginal cost values. While managed charging and time-of-use (“TOU”) tariffs are becoming the norm across the country, we assume for the purposes of this analysis that most EVs are charging according to a non-managed shape, based on load curves developed by the U.S. Department of Energy. We also use a database of EV program expenditures, assuming that these investments will be paid off over 10 years. For California, where over 40 percent of the country’s EVs are located, we used hourly marginal costs based on the California Public Utilities Commission (“CPUC”)’s Avoided Cost Calculator and load curves from the CPUC’s Load Research Reports.

Tracking EV Adoption Across the 50 States

In 2011, which was the first year of our analysis, just 16,000 EVs were on the road nationwide. By 2021, the number of EVs has surpassed 2 million – over a 100-fold increase from 2011. Figure 1 shows cumulative EV sales by region in the United States.

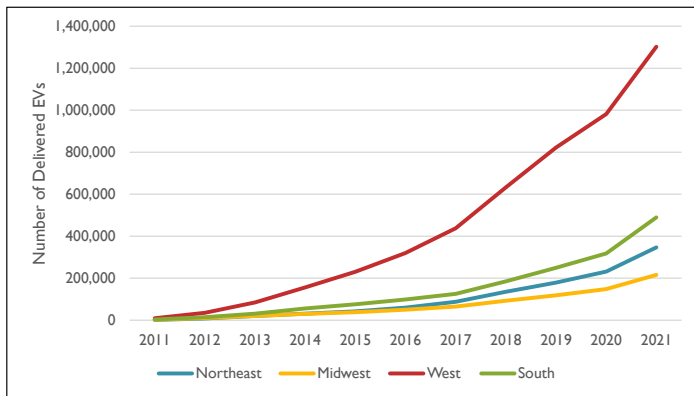


Figure 1. Cumulative EV sales in the United States, 2011-2021, by region

The Western region, anchored by California which counted over 1 million EVs in 2021, far outpaces the other regions of the US. Nevertheless, EV adoption rates are accelerating nationwide, with BloombergNEF predicting that EV sales will represent more than half of all car sales by 2030.

EV Charging Patterns and Time-of-Use Charging

EVs pull their energy from the electricity grid, but the time of day that the charging occurs defines the cost and carbon content of its power and the impacts on the grid overall. If vehicles charge when demand is already high and electricity is

the most expensive, EV could exacerbate grid impacts and costs. If they can take advantage of low overnight demand or plentiful solar power in the afternoon, however, they can improve the economic and environmental performance of the power system overall.

For this analysis, we assume the majority of EVs are charged at home and mostly in the early evening at the end of the workday. This hourly use pattern was developed by the U.S. Department of Energy (“DOE”) and corresponds with real-world data, representing charging patterns of EVs not taking service on time-of-use rates (which represents the vast majority of EVs on the road).

Time-of-use tariffs affect the costs that consumers pay depending on when they use electricity and can incentivize consumers to use electricity when it is least expensive for everyone (i.e. when there is less overall demand on the grid). We can already see the impact this has on EV charging based on data reported by California’s largest investor-owned utilities. Figure 2, below, shows the average daily charging curve for EVs on time-of-use (TOU) tariffs in California alongside DOE’s national average charging curves for EV owners not on TOU rates. The grey bars represent the number of states whose electric grid peaks in each corresponding hour, when electricity is most expensive.

As Figure 2 shows, the price signals provided by the time-of-use tariff, combined with EV technology that allows for managed charging, shifts typical EV charging from times of peak use to overnight periods, when demand is typically low. These shifts reduce costs to EV owners and operators for charging their vehicles, while also more efficiently using electricity infrastructure and reducing costs for everyone.

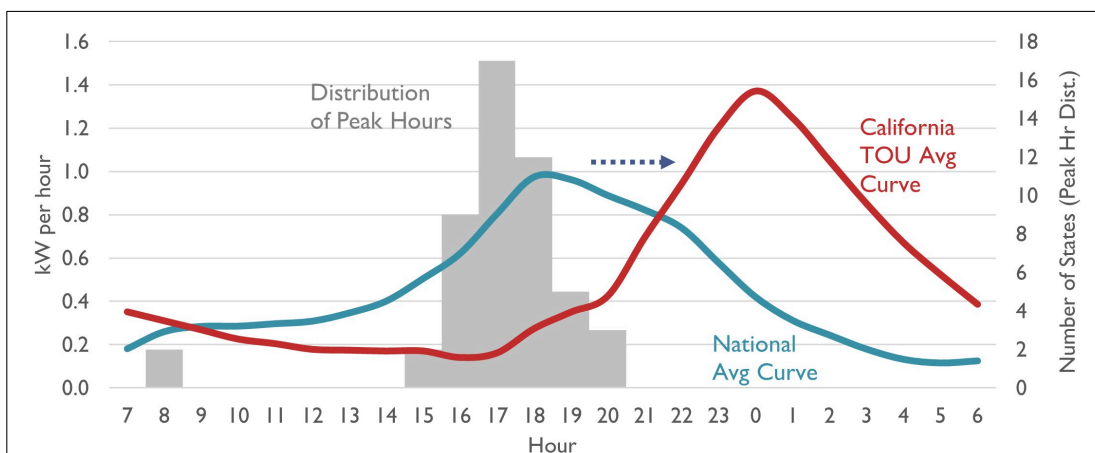


Figure 2. Typical EV charging curve versus the California TOU average EV charging curve, with the distribution of all states’ average system peak hour.

EV-specific or general TOU rates are less well subscribed outside of California. However, TOU rates, especially rates designed specifically for EVs, are beneficial for both utilities and customers. Since they can shift the majority of charging away from peak periods, they can help reduce the costs of upgrading the grid while also increasing utility revenues, thereby helping to put downward pressure on rates for all. These types of rates will become especially important as the number of EVs on the roads across the country will increase in the coming years.

How does EV charging impact overall electricity rates?

By comparing the revenues generated by EV charging to the utility’s marginal cost to serve these EVs, we can construct a picture of whether EVs are creating more revenues than costs (driving costs for everyone down) or creating more costs than revenues (driving costs for everyone up).

The results of our analysis indicate that, across all regions in the United States, **EVs have increased utility revenues more than they have increased utility costs, leading to downward pressure on electric rates for EV-owners and non-EV owners alike.**

Between 2011 and 2021, we estimate that EV drivers across the country have contributed \$3.12 billion *more* in revenues than associated costs, cumulatively over the study period (in 2021 dollars). Figure 3 shows the extent to which revenues from EVs outweigh the generation, transmission, and distribution costs for the period 2011-2021.

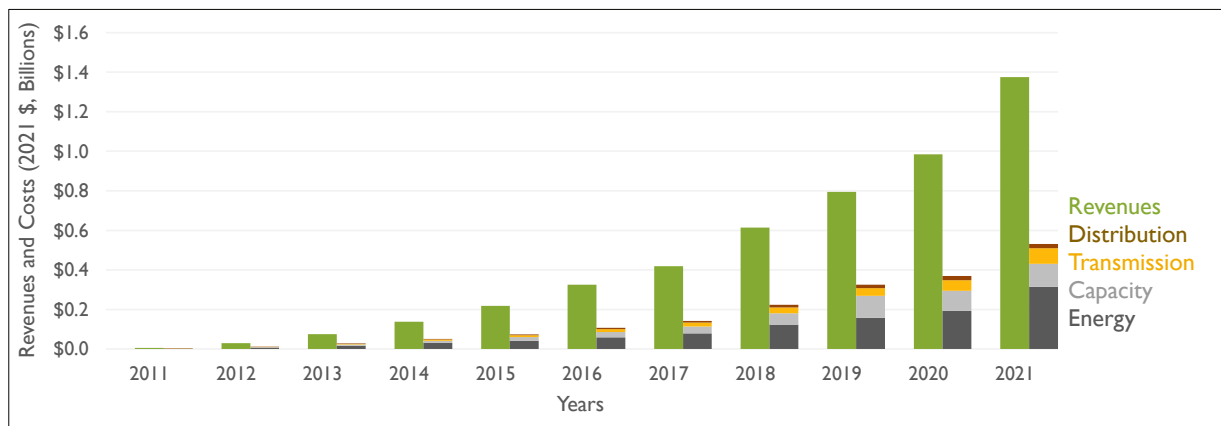


Figure 3. Total costs versus total revenues of EV charging across the United States per year from 2011-2021.

When also considering utility expenditures on EV programs, revenues from EVs outweigh costs by \$2.44 billion, cumulatively over the study period (in 2021 dollars) (Figure 4).

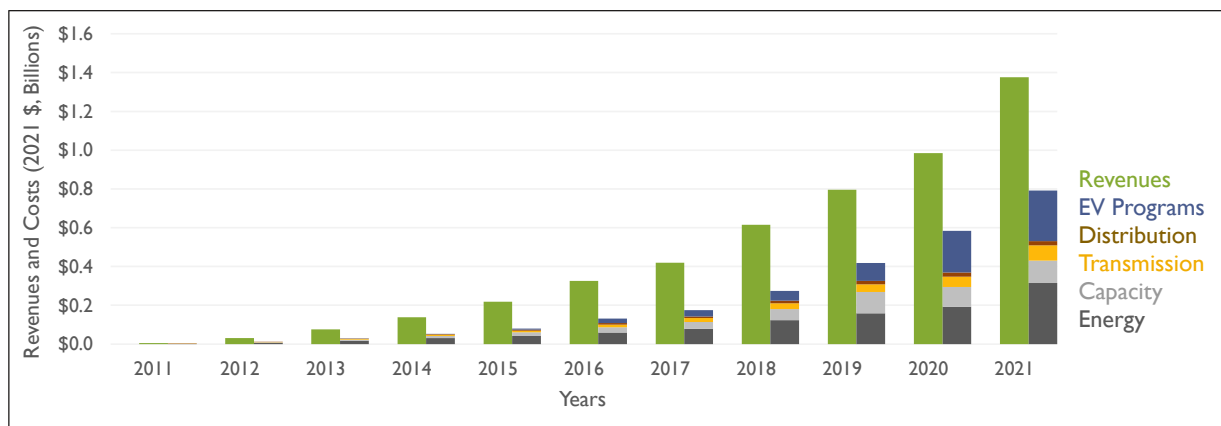


Figure 4. Total costs, plus EV program expenditures, versus total revenues of EV charging across the United States per year from 2011-2021.

Figure 5 shows revenues versus costs by US region. The Western region—anchored by California, which has the most EVs by far of any state—drives over two thirds of revenues and costs. Revenues outpace costs in every region.

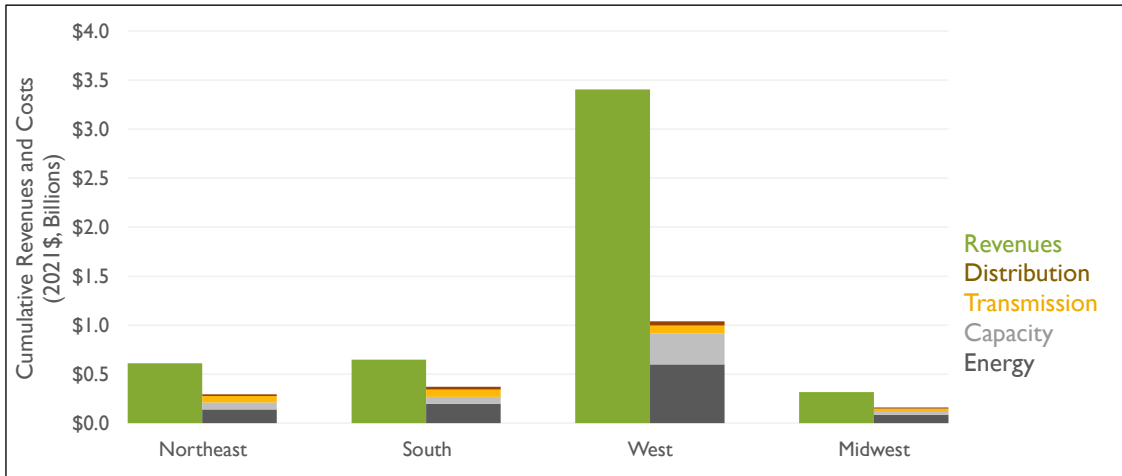


Figure 5. Cumulative total costs versus total revenues of EV charging across the United States from 2011-2021.

Once again, when also accounting for EV program spending, revenues exceed costs in every region (Figure 6).

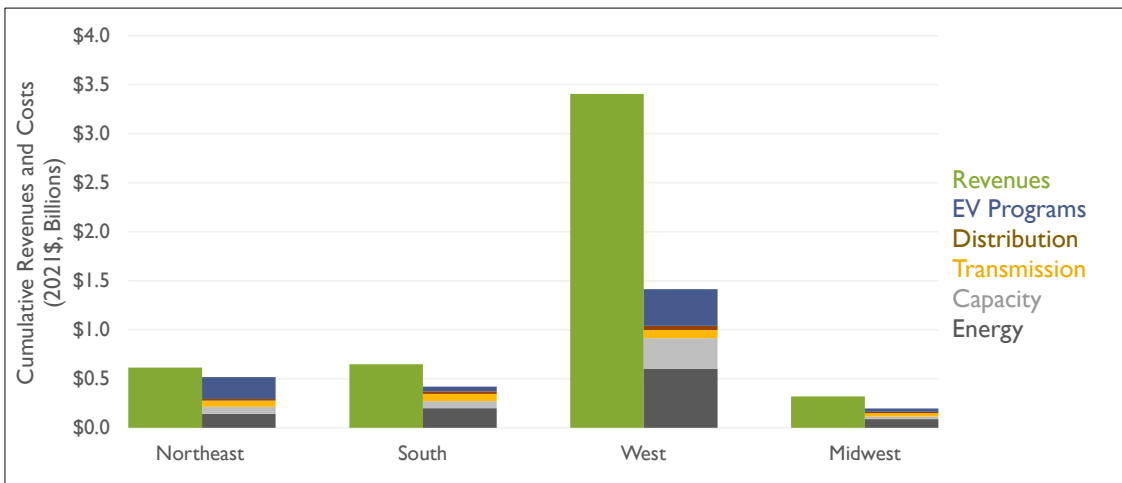


Figure 6. Cumulative total costs, plus EV program expenditures, versus total revenues of EV charging across the United States from 2011-2021.

As can be seen in Figure 7, the number of EVs is strongly correlated with the cumulative net rate impact (revenues minus costs).

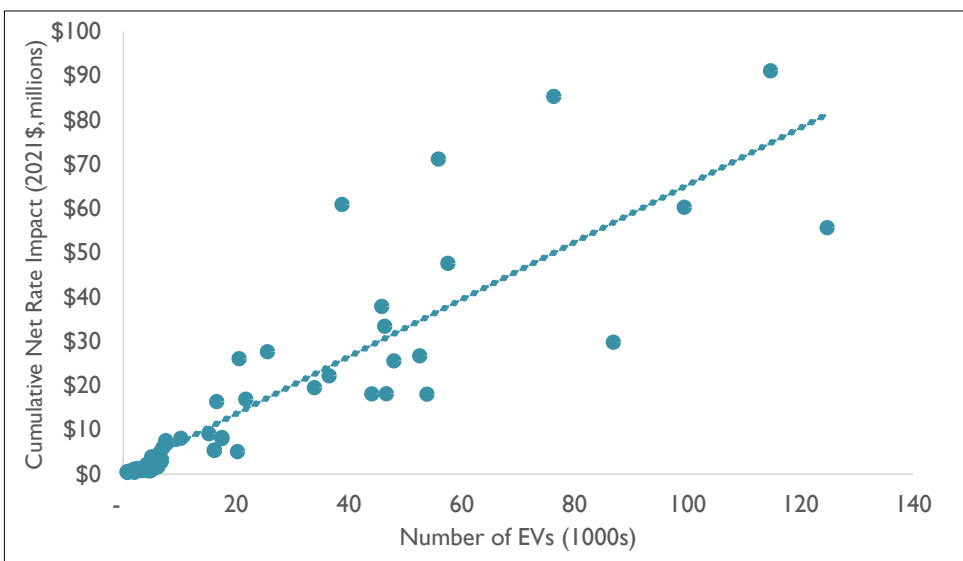


Figure 7. Correlation between the number of EVs and the cumulative net rate impact, with each dot representing a state.²³

In other words, as the number of EVs increases, the total net rate impact also increases. This is the case in every state across the country (Figure 8).

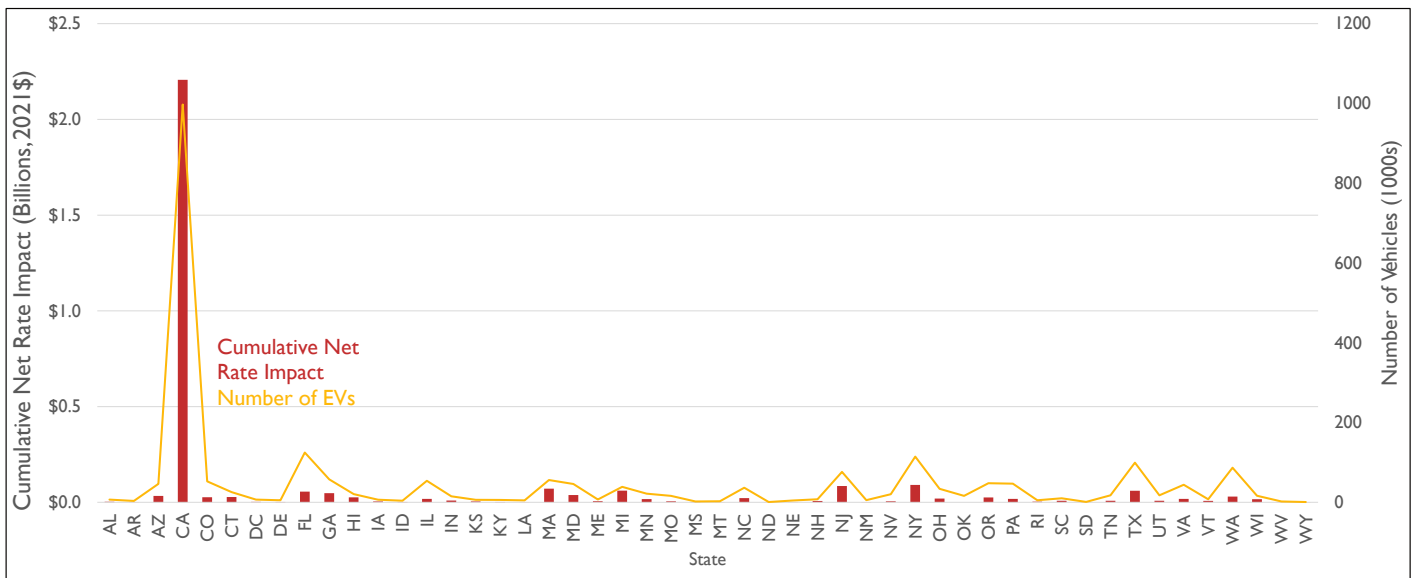


Figure 8. Cumulative Net Rate Impact (2011-2021) and the number of EVs by state.

A key reason why revenues from EVs outweigh the costs is that EV customers — particularly those on TOU rates — tend to charge during off-peak hours. By charging during off-peak hours, EVs impose minimal additional costs on the grid and help to utilize resources more efficiently. In fact, a report published in 2019 by Lawrence Berkeley National Laboratory, PG&E, and the Natural Resources Defense Council shows that shifting EV charging to off-peak times could allow the grid to accommodate all homes having EVs without upgrading most parts of the distribution system.²⁴

Revenues from EVs Can Help Fund EV Charging Infrastructure

As electric vehicle adoption accelerates across the country, utilities are implementing programs to expand charging infrastructure and help accelerate electrification. These investments both support EVs that exist today and help reduce barriers to future EV adoption.

Utility investments in EV programs varies considerably by state, with some investing \$1,000 per EV while others have not committed to any EV program spending. Our analysis shows however, that on a regional and national basis, revenues created by EV charging support both the costs to serve energy and public EV investments to date.

EVs Can Continue to Put Downward Pressure on Rates

EVs can provide substantial emissions reductions while also helping to reduce electricity rates for all customers by using the system more efficiently. Utilities can play an important role in ensuring that EVs benefit both EV drivers and non-EV drivers alike by encouraging EV customers to enroll in TOU rates and charge during off-peak periods. In addition, utility investments that facilitate the deployment of charging infrastructure can accelerate the EV market, growing the potential benefits from widespread EV adoption.

If implemented carefully, utility-funded investments can deliver benefits to all utility customers in excess of their costs. Our analysis indicates that EV adoption in the US has already resulted in more electricity revenues than costs, and future growth in the EV market will lead to further increases in utility revenues. Implementing TOU rates and targeted investments in charging infrastructure can accelerate EV adoption, reducing utility bill costs and harmful emissions for EV and non-EV owners alike.

Endnotes

¹ Rocky Mountain Institute (2022). More EVs, Fewer Emissions. Available at: <https://rmi.org/insight/more-evs-fewer-emissions>.

² Taylor, T., Rosenberg, J. (2022). Total Cost of Ownership Analysis. Atlas Public Policy. Available at: <https://atlaspolicy.com/wp-content/uploads/2022/01/Total-Cost-of-Ownership-Analysis.pdf>

³ Alliance for Automotive Innovation (2023). Advanced Technology Vehicle Sales Dashboard. Data compiled using information provided by S&P Global Mobility and Hedges & Co. Last updated 3/3/2023. Available at <https://www.autosinnovate.org/resources/electric-vehicle-sales-dashboard>.

⁴ See California's requirement that all vehicles sold by 2035 will be plug-in electric vehicles and General Motors' announcement that they will only sell zero-emissions vehicles by 2035.

⁵ National Renewable Energy Laboratory (2022). Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the United States. Available at: <https://www.nrel.gov/docs/fy18osti/71500.pdf>.

⁶ For example, see: Public Advocates Office, Distribution Grid Electrification Model – Study and Report, 2023, available at <https://www.publicadvocates.cpuc.ca.gov/-/media/cal-advocates-website/files/reports/230824-public-advocates-distribution-grid-electrification-model-study-and-report.pdf>, and California Public Utilities Commission, Utility Cost and Affordability of the Grid of the Future: An Evaluation of Electric Costs, Rates, and Equity Issues Pursuant to P.U. Code Section 913.1, 2021. Available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/office-of-governmental-affairs-division/reports/2021/senate-bill-695-report-2021-and-en-banc-whitepaper_final_04302021.pdf

⁷ We analyzed revenues and costs from EVs in 49 states, excluding Alaska, as there was not sufficient data to conduct the analysis for that state.

⁸ Atlas EV Hub. State EV Registration Data. Available at: <https://www.atlasevhub.com/materials/state-ev-registration-data/>.

⁹ California's Avoided Cost Calculator (developed by E3) were used for distribution costs. We reduced these by 10 percent to mitigate double counting of distribution-related EV program costs.

¹⁰ The load curve used for years 2011 through to 2020 are from United States Department of Energy, 2017, National Plug-In Electric Vehicle Infrastructure Analysis, Available at: <https://www.nrel.gov/docs/fy17osti/69031.pdf>. We developed a new average load curve for 2021, using data from DOE's EVI-Pro Lite tool. We took an average of the load curves from each state's largest city, weighted by number of registered EVs per state. Department of Energy, Alternative Fuels Data Center. Data retrieved July 2023. Electric Vehicle Infrastructure Projection Tool (EVI-Pro) Lite. Available at: <https://afdc.energy.gov/evi-pro-lite>.

¹¹ We assumed EVs were on non-TOU rates in California and TOU rates in Arizona (the majority of residential customers take service under TOU rates in Arizona). Data from 2021 Joint IOU Load Research and Charging Infrastructure Cost Report, filed on March 31, 2022. Public Utilities Commission of the State of California, Rulemaking 18-12-006. Available at: <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/transportation-electrification/10th-joint-iou-ev-load-report-mar-2022.pdf>.

¹² Atlas EV Hub. Electric Utility Filings. Available at: <https://www.atlasevhub.com/materials/electric-utility-filings/>

¹³ 2022 Avoided Cost Calculator for Distributed Energy Resources (DER). Available at https://www.ethree.com/public_proceedings/energy-efficiency-calculator/.

¹⁴ 2021 Joint IOU Load Research and Charging Infrastructure Cost Report, filed on March 31, 2022. Public Utilities Commission of the State of California, Rulemaking 18-12-006. Available at: <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/transportation-electrification/10th-joint-iou-ev-load-report-mar-2022.pdf>.

¹⁵ Atlas EV Hub. State EV Registration Data. Available at: <https://www.atlasevhub.com/materials/state-ev-registration-data/>

¹⁶ Regions based on US Census Regions. States in each region are as follows: Northeast: ME, NH, VT, MA, RI, CT, NY, PA, NJ; Midwest: OH, MI, IN, WI, IL, MN, IA, MO, ND, SD, NE, KS; South: MD, DE, DC, WV, VA, NC, SC, GA, FL, KY, TN, MS, AL, AR, LA, OK, TX; West: WA, OR, CA, NV, ID, MT, WY, CO, UT, AZ, NM. Pacific states (AK, HI) represent less than 1% of EVs in the U.S., and are included in the West category for readability and simplicity.

¹⁷ Boudway, Ira. "More Than Half of US Car Sales Will Be Electric by 2030." September 20, 2022. Bloomberg. Available at: <https://www.bloomberg.com/news/articles/2022-09-20/more-than-half-of-us-car-sales-will-be-electric-by-2030>.

¹⁸ National average load curves from the U.S. DOE, 2017, National Plug-In Electric Vehicle Infrastructure Analysis, Available at: <https://www.nrel.gov/docs/fy17osti/69031.pdf>, and the U.S. DOE's Alternative Fuels Data Center's Electric Vehicle Infrastructure Projection Tool (EVI-Pro) Lite tool, available at: <https://afdc.energy.gov/evi-pro-lite>.

¹⁹ For instance, 17 states have a peak at 5pm and two states have a peak at 8am. California's average peak is 6pm. Peak load data from U.S. Energy Information Administration, form 930.

²⁰ This assumes that program costs are depreciated over 10 years.

²¹ This assumes that program costs are depreciated over 10 years.

²² The correlation coefficient is 0.99 for all 49 states included in this analysis. When California is removed, the coefficient is 0.86.

²³ California is not included in figure.

²⁴ Coignard et al., "Will Electric Vehicles Drive Distribution Grid Upgrades?: The Case of California". June 5, 2019. Institute for Electrical and Electronics Engineers. Available at <https://ieeexplore.ieee.org/document/8732007>.