Opinion Dynamics

PG&E ELECTRIC VEHICLE AUTOMATED DEMAND RESPONSE STUDY REPORT

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extensible
ENERGY

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GLOSSARY

We define terms commonly used in this study below. In efforts to support industry convergence around common definitions of terms, we leverage several definitions from the Smart Electric Power Alliance (SEPA) State of Managed Charging in 2021 Report.

Automated Demand Response (ADR): Automated demand response in its residential application provides demand reduction without a homeowner intervening manually. ADR solutions typically include controls for end-use technologies such as Electric Vehicles (EVs), lighting, thermostats, pool pumps, and water heaters.

Demand Response (DR): Demand response is a load management method that is used during periods of peak demand in order to relieve grid stress. For example, if a DR effort occurs during an EV charging session, the charger could be throttled to reduce energy consumption temporarily and returned to full charging capacity once grid stress is relieved.

Duck Curve: The California Independent System Operator (CAISO) created future scenarios of net load curves to illustrate changing grid conditions which convey the relationship between forecasted load and expected electricity production from variable generation resources. In certain times of the year, these curves produce a "belly" appearance in the mid-afternoon when solar generation peaks and then quickly ramps up to produce an "arch" similar to the neck of a duck when demand spikes in the evening—hence the industry moniker of "The Duck Curve."

Flex Alert: A Flex Alert is a call to consumers to voluntarily cut back on electricity and shift electricity use to off-peak hours (normally before 4:00 p.m. or after 9:00 p.m.). A Flex Alert is typically issued in the summer when extremely hot weather pushes up energy demand as it reaches available capacity.

Level 1 (L1) Charger: Level 1 chargers charge EVs at 120 volts of alternating current (AC) which equates to about five miles per hour of charge. Level 1 chargers can plug into standard AC 120-volt outlets.

Managed Charging (V1G, controlled charging, intelligent charging, adaptive charging, or smart charging): Managed charging includes a range of terms, but in general refers to central or customer control of EV charging to provide vehicle grid integration (VGI) offerings, including wholesale market services. This includes ramping up and ramping down of charging for individual EVs or multiple EVs whether the control is done at the charger, the EV, or elsewhere. In this report we use managed charging as a broad overarching term that encompasses the specific use case of using ADR technologies to call individual DR events. Managed charging can also include more dynamic and continuous approaches to managing EV charging such as Time of Use (TOU) rates and real-time pricing signals.

Non-Internet-Enabled Level 2 (L2) Charger: Level 2 chargers charge EVs at 240 volts or more of alternating current (AC) which equates to 13 to 25 miles per hour of charge. These chargers generally require a professionally installed 240-volt AC outlet on a dedicated circuit and do not have the ability to connect to the internet.

OpenADR: OpenADR is a standard two-way exchange protocol that allows utilities to communicate with equipment at customer facilities and send signals to automatically drop demand during DR program events.

Original Equipment Manufacturer (OEM): The original equipment manufacturer, or OEM, creates the parts that are used by other companies to build a final product. In the context of this report, that final product is an EV.

Public Safety Power Shutoff (PSPS): A PSPS occurs in response to severe weather that increases likelihood for wildfires. During PSPS, PG&E will remotely turn off power to customers in fire prone areas to help prevent hazardous conditions from harming communities. PG&E customers are notified of potential PSPS events in their area through automated calls, texts, or email alerts starting two days before the shutoff (if possible) and each day until power is restored.

Red Flag Warning: A Red Flag Warning is issued for weather events which may result in extreme fire behavior that will occur within 24 hours.

Resource Adequacy Window: The 4:00 p.m. to 9:00 p.m. "resource adequacy window" in California is the time period when shifting load has the greatest potential to support grid reliability and renewable energy integration because electricity generation from renewable resources declines during this window, while residential demand simultaneously peaks.

Smart Level 2 (L2) Charger: Smart Level 2 chargers are level 2 chargers that can connect to the Internet via a cable or wireless technology and communicate with the computer system that manages a charging network or other software systems, such as a utility demand response management system (DRMS).

State of Charge: The level of charge of an electric (in this case EV) battery relative to its capacity.

Telematics: In the context of this report, specifically, and EV charging in general, including managed charging, telematics refers to the communication of data between a data center (or "cloud") and an EV via cellular networks, including sending control commands and retrieving charging session data.

Tier 2 and Tier 3 Fire Threat Areas: Tier 2 fire-threat areas are locations where there is a higher risk (including likelihood and potential impacts on people and property) from utility-related wildfires. Tier 3 fire-threat areas are locations where there is an extreme risk (including likelihood and potential impacts on people and property) from utility-related wildfires.

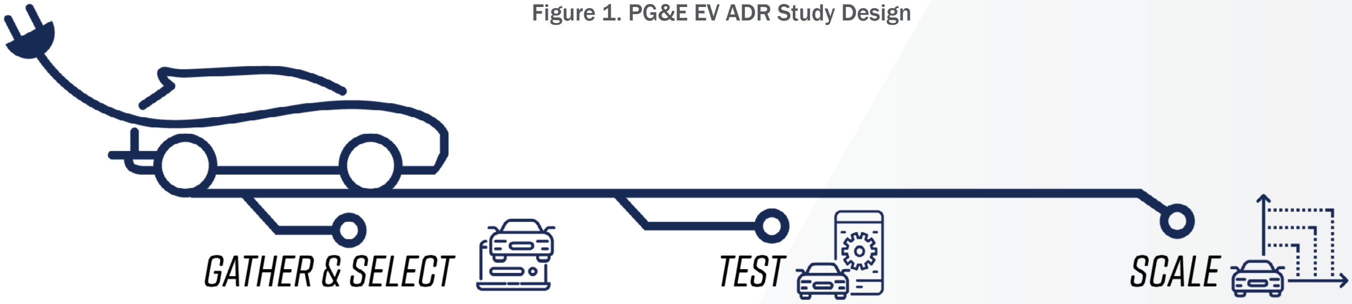
Vehicle-Grid Integration (VGI): VGI includes any action taken via a grid-connected EV and/or EV charger, whether directly through resource dispatching or indirectly through rate design, to alter the time, magnitude, or location at which grid-connected EVs charge or discharge, in a manner that optimizes plug-in EV charging and provides value to the customer and the grid. Examples of such actions include, but are not limited to, reducing charging expenses, increasing electric grid asset utilization, avoiding distribution or transmission infrastructure upgrades, integrating renewable energy, offering resiliency and backup power, and offering reliability and wholesale energy services. VGI spans a wide range of use cases, actors, assets, and technologies. The consensus in industry is that VGI includes both V1G (managed charging) and V2G (vehicle-to-grid) solutions.[1]

Vehicle-to-Everything (V2X): Vehicle-to-Everything (V2X): V2X refers to a suite of use cases where EV batteries have the ability to discharge to different entities. Vehicle-to-Grid (V2G) assumes energy is discharged from the battery of an EV beyond the customer's main electricity meter and onto the electric distribution grid. Other applications include Vehicle-to-Home (V2H) or Vehicle-to-Building (V2B) where no discharged energy from the EV battery is exported onto the electric distribution grid, and Vehicle-to-Load (V2L) where energy from an EV battery is discharged to a device (such as another vehicle, RV camper, or cooking stove) that is non-grid connected.

[1] The definition of (Electric) Vehicle-Grid Integration as defined by the California VGI working group is as follows: Any method of altering the time, charging level, or location at which grid-connected light-duty electric vehicles, medium-duty electric vehicles, heavy-duty electric vehicles, off-road electric vehicles, or off-road electric equipment charge or discharge, in a manner that optimizes plug-in electric vehicle or equipment interaction with the electrical grid and provides net benefits to ratepayers by doing any of the following: (A) Increasing electrical grid asset utilization and operational flexibility. (B) Avoiding otherwise necessary distribution infrastructure upgrades and supporting resiliency. (C) Integrating renewable energy resources. (D) Reducing the cost of electricity supply. (E) Offering reliability services consistent with the resource adequacy requirements established by Section 380 or the Independent System Operator tariff.

Opinion Dynamics and Extensible Energy (the Opinion Dynamics Team or Team) worked with PG&E to complete a study that assessed the potential to leverage Electric Vehicle (EV) Automated Demand Response (ADR) charging technologies through the Demand Response Emerging Technology Program (DRET) from 2020–2021. This study incorporated three phases of research and analysis: gather and select, test, and scale (Figure 1). The "gather and select" phase involved collecting information on the EV charging market and the capabilities of EV charging providers and third parties to implement strategies to remotely control residential EV charging that would support the design and execution of a technology field test. The "test" phase included the execution of the technology field test. This field test assessed the ability of EV charging providers and third parties leveraging vehicle telematics to remotely control residential charging through a series of nine DR events and an assessment of the load impacts of each event. For the "scale" effort the Team (1) analyzed interval data from 71,000 EV customers in PG&E's service territory to disaggregate EV charging load shapes from whole-house energy consumption, (2) developed charging clusters based on similar patterns of customer charging behavior, and (3) calculated the resource potential of these clusters for a given weekday and weekend. In addition to analyzing resource potential, the Team conducted a survey that revealed 3,000 PG&E EV owners' preferences for incentives to upgrade their existing charger or enroll in a DR program with their EV. This novel analysis provides PG&E with an understanding of the EV DR load reduction potential for all current EV owners in PG&E service territory—the largest EV market in the US—and the incentive amount and structure required to realize this resource potential.

Figure 1. PG&E EV ADR Study Design



GATHER & SELECT

- Identify viable EV ADR charging control technologies and their providers
- Vet EV ADR charging control technology providers and select three providers for participation in technology field test
- Gather information about similar EV ADR programs and field tests to inform the study design

Methods: Literature Review, Industry Expert Interviews, EV Control Technology Screening, Vendor interviews

TEST

- Recruit 212 study participants
- Test EV ADR controls technologies through a field test comprised of 10 DR events
- Assess load impacts for each DR event
- Understand customer experience with field test

Methods: Customer Recruitment Survey, EV Controls Field Test, Load Impact Analysis, Participant Close-out Interviews

SCALE

- Investigate customer incentive preferences for upgrading to a smart L2 charger and participating in an EV DR program
- Characterize the EV DR resource potential in PG&E service territory via EV load disaggregation and clustering analysis of charging behaviors
- Identify key considerations and best practices to inform potential future program designs

Methods: Incentive Preference Conjoint Survey, Load Disaggregation and Clustering Analysis

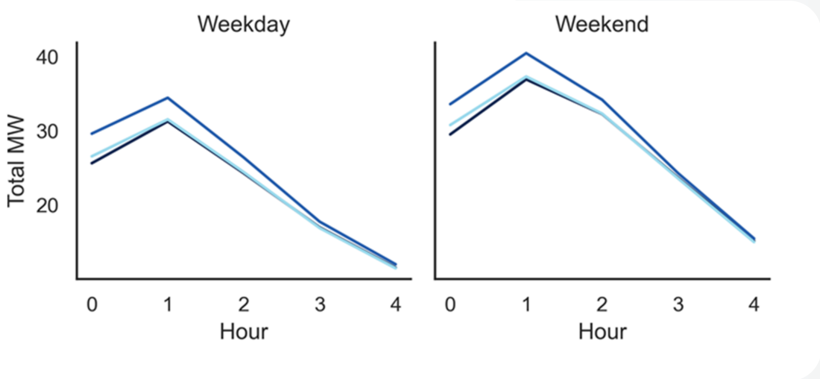
1.1 KEY STUDY CONCLUSIONS

We synthesized results across all research activities to recommend a future path forward for incentivizing EV ADR technologies.

Vehicle telematics and EV charger controls are both effective strategies for curtailing EV charging during DR events with minimal impact on participants. All vendors were able to successfully curtail most of the EVs under their control for each event, with stronger performance rates for events during overnight periods, when more customers tend to charge their EVs, in comparison to events called during the peak period of 4:00 p.m. to 9:00 p.m. Furthermore, multiple results indicate that the study was not intrusive for customers. For example, customer attrition and opt-out rates remained low throughout the entire study. Please see Section 3 for more details about the field test.

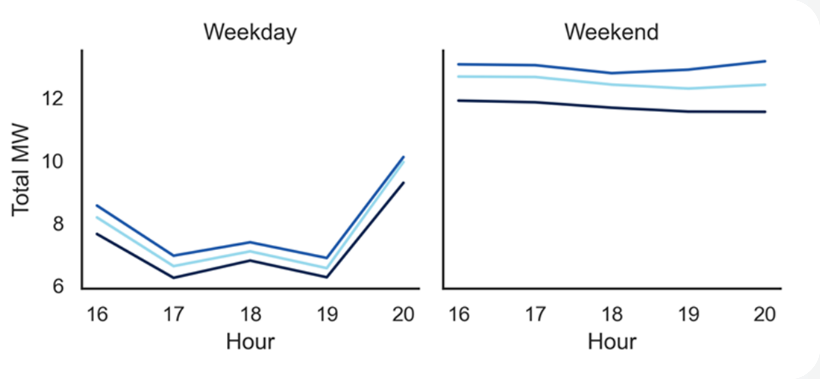
EV ADR charging controls technology holds promise for mitigating overnight peaks (Figure 2). The highest EV DR load resource potential is between 12:00 a.m. and 4:00 a.m. (with a maximum resource potential of between 31 MW and 40 MW when extrapolated to the current population of 366,000 PG&E EV owners). As EV penetration increases, the high levels of demand generated by overnight charging may pose risks to PG&E's distribution system. The field test demonstrated that curtailing EV charging from 12:00 a.m. to 4:00 a.m. resulted in a load shift of up to 601 kWh over the four-hour event period for the group of 212 study participants. As such, partnering with EV ADR charging controls vendors to stagger overnight charging could provide a low-cost alternative to investing in distribution system upgrades to support an increased penetration of overnight EV charging in coming years.

Figure 2. PG&E EV DR Resource Potential Estimates for the Overnight Period



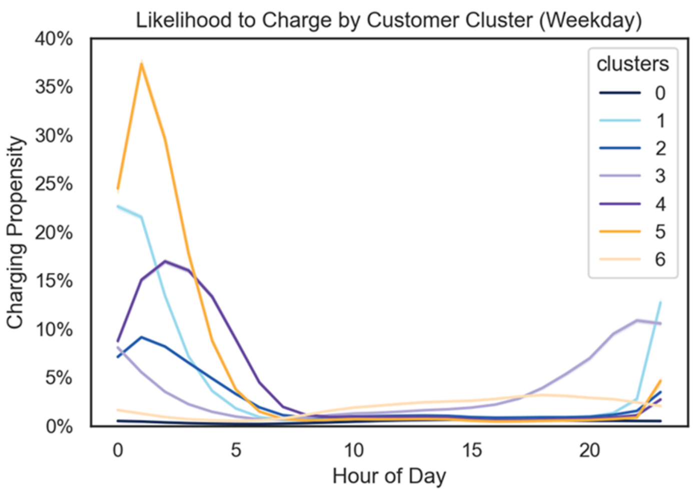
The maximum resource potential for EV ADR control technologies is 9 MW to 13 MW during the peak period from 4:00 p.m. to 9:00 p.m. for the current population of 366,000 EV owners in PG&E service territory (Figure 3). The peak period maximum resource potential is equivalent to approximately 25% of PG&E's current SmartAC program resource potential (50 MW) and 50% of the current SmartRate program resource potential (25 MW), at an incentive level of $50 per enrollment. This potential will continue to grow as PG&E has a goal of serving two million EVs by 2030.

Figure 3. PG&E EV DR Resource Potential Estimates for the 4:00 p.m. to 9:00 p.m. Peak Period



In alignment with the resource potential findings, almost half of PG&E EV owners regularly charge overnight or during the 4:00 p.m. to 9:00 p.m. peak period and would be good targets for EV DR programs. We leveraged the EV charging load shapes from 70,000 EV owners in PG&E service territory to identify clusters of similar customer charging behaviors and common charging trends. The clustering analysis results reveal that 28% of EV owners are "overnight chargers," who could be targeted to mitigate distribution system impacts in areas with high EV adoption (clusters 1, 2, 4 and 5 in Figure 4). An additional 20% of EV owners are "peak period chargers" and would be good targets for DR efforts designed to curtail consumption during the peak period 4:00 p.m. to 9:00 p.m. window (clusters 3 and 6 in Figure 4). Furthermore, 52% of EV owners are "variable and low-level chargers" and would be poor targets for EV DR programs (cluster 0 in Figure 4).

Figure 4. Clusters of Common Charging Patterns among PG&E EV Owners



Please see Section 4.2 for a more detailed description of the clustering analysis and resource potential method and results.

EV ADR incentives should focus on customers who already own Level 2 chargers. A $50 enrollment incentive can encourage 45% of PG&E EV owners who already own a smart L2 charger to participate in an EV DR program while a $300 incentive is required to encourage the same share of EV owners to upgrade from an L1 or non-networked L2 charger to a smart L2 charger. Results from the customer incentive survey of 3,183 PG&E EV owners indicate that 71% of these customers have a smart or non-Internet-enabled L2 charging station. Customers with L2 charging stations are good candidates for EV DR because they charge more frequently and have more predictable charging patterns than customers with an L1 charger. Furthermore, the EV owner survey responses suggest that providing incentives to encourage customers who already have an L2 charger to enroll in an EV DR program is more cost-efficient than incentivizing customers who have a L1 or non-Internet-enabled L2 charger to upgrade to a smart L2 charger. For customers with smart L2 chargers (approximately one-third of PG&E EV owners), PG&E could consider partnering with vendors that control EV charging through vehicle telematics or directly through the charger. Vehicle telematics solutions provide an avenue to reach the additional one-third of PG&E EV owners with non-Internet connected L2 chargers. Please see section 4.1 for more details about the EV owner incentive preference survey.

1.2 FUTURE CONSIDERATIONS

Our research efforts also revealed other holistic program design, market, and methodological findings that PG&E may want to consider if they decide to develop a residential managed charging offering. We provide a detailed explanation of these offerings in Section 7.

1.3 STUDY BACKGROUND

The PG&E Residential ADR Program has been offering smart thermostat rebates since 2017 and intends to expand its rebate catalogue to include other technologies. In 2019, the Opinion Dynamics Team conducted a Collaborative Stakeholder Process to help PG&E identify and vet emerging ADR technologies for potential inclusion in the DRET program. This research found that EV charging controls were an excellent fit for DRET, based on the rigorous criteria and stakeholder process employed in the study[2]. References for the two qualifying EV controls vendors and their respective control technologies, however, indicated that they were not ready for full-scale rollouts. The two qualifying vendors lacked experience (1) implementing utility managed charging programs beyond the pilot level and (2) field testing OpenADR communications from the utility down to the end device.

PG&E recognized that there was potential for EV charging to serve California ratepayers and help the utility achieve grid management needs. However, PG&E recommended conducting a technology demonstration study, prior to incorporating any EV control technologies into the full-scale DR program, to assess the potential to leverage EVs for DR with funding through the DRET program.

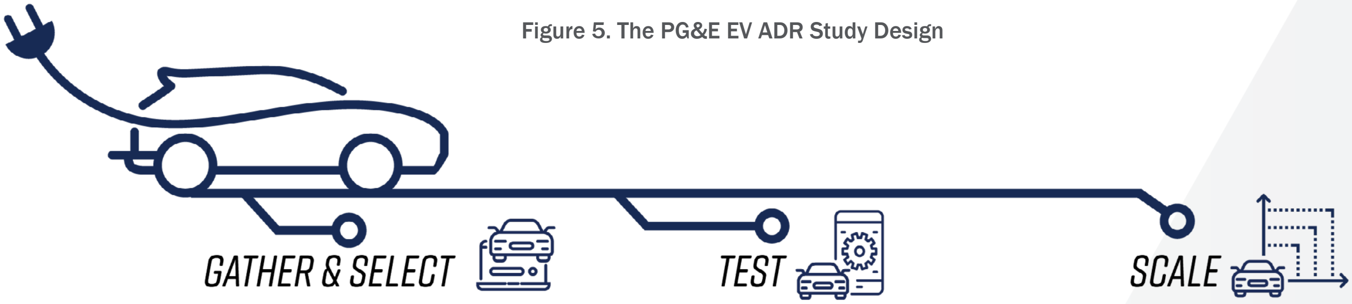
As a result of the ADR Collaborative Stakeholder Process, the Opinion Dynamics Team worked with PG&E to complete a study that assessed the potential to leverage EV ADR charging technologies through the DRET program from 2020–2021. This study incorporated three phases of research and analysis: gather and select, test, and scale (Figure 5). The “gather and select” phase involved collecting information on the EV charging market and the capabilities of charging providers and third parties with the ability to remotely control residential EV charging to support the design and execution of a technology field test.

The “test” phase included the execution of a technology field test to understand the capabilities of third parties that can remotely control residential charging via the EV charger directly or vehicle telematics (herein referred to as vendors) through a series of nine DR events. The Team also interviewed selected field test participants to understand how the study impacted them.

For the “scale” phase, the Team (1) analyzed interval data from over 70,000 EV customers in PG&E’s service territory, (2) developed charging clusters based on similar patterns of customer charging behavior, and (3) calculated the resource potential of these clusters for a given weekday and weekend. This novel analysis provides PG&E an understanding of the EV DR load reduction potential for all current EV owners in PG&E service territory, the largest EV market in the US. In addition to analyzing resource potential, the Team conducted a survey that tested customers’ preferences for different incentive options for (1) upgrading to a smart (Internet-enabled) L2 charger for customers that did not already own a smart L2 charger or (2) participating in an EV DR program for customers that already owned a smart L2 charger. Taken together, the resource potential sheds light on the value of including EV charging in a DR program and the survey findings provide PG&E with a better understanding of the incentive amount and structure needed to encourage EV owners to participate in a DR program in the future. The Team also synthesized key findings across all research efforts to identify key considerations and best practices to inform potential future program designs that leverage EV ADR technologies.

[2] Please see companion report, CALMAC Study ID PGE0469.02

Figure 5. The PG&E EV ADR Study Design



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Section 2 of this document outlines the components of the gather phase of the study. Section 3 provides an overview of the technology field test and the results of the impact analysis of the nine DR events called over the course of the study, from July to October 2021. Section 4 covers the scale phase of the study detailing the results of the EV load management resource potential assessment and insights from the customer incentive preference survey of current PG&E EV owners to inform a residential EV ADR incentive. Section 5 includes a synthesis of results across all research efforts to identify key market and customer insights that further contextualize the results from this study and can help inform potential future managed charging offerings. We summarize key study conclusions across all research efforts in Section 6 and provide key considerations for developing future managed charging offerings in Section 7.

The Team completed a review of 24 studies that focus on best practices and lessons learned from utility programs that optimize EV charging to provide value to the customer and the grid, herein referred to as "managed charging programs.[3]" In addition to the literature review, we interviewed three EV managed charging experts in the industry as well as eight utility program managers with direct experience leading EV managed charging programs with the vendors selected for this Study; Enel X, ChargePoint, or Geotab. The objective of these interviews was to (1) identify best practices and lessons learned from other managed charging programs; (2) gather utility and experts' perspectives on the path forward for managed charging including barriers, opportunities, and market leaders; and (3) learn about utilities' experiences working with each of the vendors selected for this study both in terms of program implementation and technology performance.

The section below provides key findings from the literature review as well as the expert interviews. The results of this research are organized by how they shaped the study. We first describe the findings related to the field test design, then insights on EV resource potential and managed charging incentive designs from other jurisdictions, and finally, we provide an overview of the future direction of managed charging programs.

2.1 KEY FINDINGS SHAPING THE FIELD TEST

Through the literature review, utility interviews, and expert interviews, we identified three key technology considerations for the design of the field test. These considerations included (1) whether to leverage vehicle telematics, charger telematics, or both; (2) whether to use the OpenADR protocol in the field test; and (3) addressing home Wi-Fi issues. These are described in more detail below.

2.1.1 VEHICLE TELEMATICS VS. THE CHARGER

Currently, EV charging control technologies can be categorized in three main technology types: (1) smart chargers (e.g., Enel X Juicebox and ChargePoint home chargers); (2) software platforms that can aggregate and control multiple types of chargers, and in some cases other home technologies (e.g., EnergyHub); and (3) vehicle telematics applications that enable third parties to control EV charging in the vehicle directly. Notably, Tesla now allows third parties to manage charging for Tesla customers through the Tesla Application Programming Interface (API), which increases the viability of the telematics approach. For this study, PG&E was specifically interested in designing an incentive that didn't involve a whole home platform, so we excluded any technologies that fell under the second category.

Overall, the consensus among the expert interviewees is that it is too soon to tell whether controlling the charger or the vehicle directly is the best approach for managing EV charging and utilities should be prepared to support both pathways. As such, the Team selected two vendors for the field test that control chargers directly (ChargePoint and Enel X) and one vendor that leverages vehicle telematics to control EV charging (Geotab Energy). We provide a summary of considerations for each approach in Table 1 and additional explanation and details on the benefits and drawbacks of each approach in Section 5.5.

Table 1. Summary of Considerations for Leveraging EV Telematics vs. EV Chargers to Manage Charging

Telematics Considerations	EV Charger Control Considerations
▪ Possibility for greater EV owner reach (can leverage customers with L1, L2, and smart L2 chargers) ▪ Reduced cost (customers don't need to own a smart L2 charger) ▪ Can provide more detailed data about vehicle (e.g., EV state of charge) ▪ Mobile resource ▪ OEM (automaker) may have ultimate control over how vehicle telematics are leveraged depending on contractual agreements	▪ Customers must own or purchase a smart L2 charger to participate in managed charging programs ▪ Stationary resource ▪ Technology performance can be impacted by Wi-Fi issues

[3] Please see the glossary for a more detailed definition of managed charging programs.

2.1.2 WI-FI ISSUES

Several utilities reported that a substantial subset of their managed charging program participants experienced Wi-Fi connectivity issues with their EV charger, likely because their home Wi-Fi signals did not reliably reach their driveways or garages. One utility lost connection to their participants' chargers after they changed their Wi-Fi password or purchased a new Wi-Fi system. As a result, these utilities were unable to reliably control EV charging for a subset of participants. For example, Avista's Electric Vehicle Supply Equipment (EVSE) Pilot Program identified that customer Wi-Fi networks were unreliable and lead to over a third of systems losing connection with the charging device.[4] Similarly, Potomac Electric Power Company (PEPCO) found that due to EV charger Wi-Fi connection and firmware issues, the embedded Itron meter only successfully logged and communicated the charge events 30% of the time.[5] To address these challenges, experts recommended utilities incorporate a performance incentive into their managed charging program designs, which could possibly help encourage participants to ensure their charger stays connected. Another interviewee suggested this issue could be addressed technologically by embedding a Wi-Fi amplification device into the charger.

To address potential Wi-Fi issues, the Opinion Dynamics Team identified vehicles that were either not transmitting data or showing an offline status before the field test and we worked with vendors to help these participants troubleshoot their connectivity issues before we began calling DR events.

2.1.3 OPENADR

OpenADR is a standard two-way exchange protocol that allows utilities to communicate with customer vehicles or EV chargers and specifically enables the utilities to send signals that automatically curtail EV charging during DR events. One utility that used OpenADR to manage EV charging in the past advised against using it again, noting it required a higher level of effort than originally expected, and they had better luck using a direct API integration to control vehicles. This representative noted that OpenADR is better suited for situations where a utility has plans to scale the software or platform but doesn't work as well for a pilot or one-off project because of the high level of investment required to configure the system to accept the signal.

While only OpenADR-capable vendors were evaluated under this study, it is important to note that neither the schedule nor budget permitted integration with an OpenADR Virtual Top Node (e.g., PG&E's DR Management System [DRMS]). Hence, events were scheduled and executed through a combination of emails and vendor APIs.

2.2 KEY INSIGHTS OF LOAD IMPACT POTENTIAL

The utilities and experts interviewed acknowledged the load impacts from residential EVs can be less predictable than other types of DR resources because customer charging schedules are subject to variation. Across the interviewed utilities that deploy EV rates, there was consensus that these rate signals effectively encourage off-peak charging for a high percentage of EV owners. One utility noted that even their customers who aren't on a TOU rate but received a rebate for a smart L2 charger tend to charge off-peak. In addition, the program manager of a different utility that does not have a TOU rate, noted their EV owners primarily charge off-peak, even without a price signal.

Results from other managed charging programs across the US, including Maui Electric's JUMPSmart Maui Program (2011–2016)[6] and PEPCO's Demand Management Pilot (2014, 2015),[7] found that a small fraction of the total number of EVs enrolled in each study were plugged in and charging during DR events. In the case of the Demand Management Pilot run by PEPCO, of the seven DR events called, only three of their 35 participants were plugged in during each event. For EVs that were plugged in, however, previous studies have found that event opt-out rates are low and EVs that were curtailed had an appreciable amount of load.

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[4] *2020* Avista Corporation. *Electric Vehicle Supply Equipment Pilot Final Report. October 18, 2019.*
[5] Electric Power Research Institute (EPRI). *Pepco Demand Management Pilot for Plug-In Vehicle Charging in Maryland: Final Report—Results, Insights, and Customer Metrics.* May 5, 2016.
[6] Irie, Hiroshi. *Japan-US Collaborative Smart Grid Demonstrations Project in Maui Island of Hawaii State: A Case Study.* 2017.
[7] EPRI. Pepco Demand Management Pilot for Plug-In Vehicle Charging in Maryland: Final Report—Results, Insights, and Customer Metrics. May 5, 2016.

A couple of interviewees specifically noted that the EV resource variability is especially challenging in the California wholesale market context as aggregators must first specify a minimum level of DR resource they can commit to providing when they bid into the California Independent System Operator (CAISO) market and are penalized if they don't meet this minimum requirement. Consequently, since EV load is variable and less reliable, aggregators will likely be conservative in their EV resource estimates and bids, which makes the EV resource less valuable in this context.

Together, insights from the literature review and expert interviews led us to conclude that load impacts from this field test would likely correlate with the PG&E EV rate schedules. The most common PG&E residential EV rate (EV2-A) incentivizes customers to charge between 12:00 a.m. and 3:00 p.m. and limit charging between 4:00 p.m. and 9:00 p.m., which is a consistent peak period across the state of California.[8] Furthermore, utility interviewees indicated high proportions of their customers are beginning to charge their EVs right at midnight. As EV penetration increases, there is a growing risk that utility distribution systems may not be able to handle the increased capacity requirements for communities with exceptionally large clusters of EV owners that begin to charge at midnight. For the purposes of this study, we will refer to demand peaks that occur in clusters such as this as "timer peaks" as the term was coined in a prior PG&E study with BMW.[9]

To address these factors, the field test framework for this study included scheduling DR events between 12:00 a.m. and 5:00 a.m. in addition to calling events during the peak period of 4:00 p.m. to 9:00 p.m. Calling the overnight events enabled us to (1) better evaluate the efficacy and load management potential of the technologies because a higher proportion of vehicles were plugged in and charging at the time of the event, and (2) test out the ability to leverage EV charging control technologies to address potential distribution system impacts resulting from burgeoning timer peaks.

2.3 KEY FINDINGS SHAPING INCENTIVE DESIGN RESEARCH

Overall, our literature review revealed that the incentive amounts and formats utilities offer through their managed charging programs vary widely across jurisdictions. We provide a detailed summary of elements of program designs in other jurisdictions and lessons learned from these programs in Appendix A.[10]

As managed charging programs are still in the early stages, there is not a clear consensus on the incentive level required to encourage customers to purchase an internet-enabled "smart" Level 2 (L2) charger, enroll in a managed charging program, or respond to DR events. Incentive designs from managed charging programs in other jurisdictions vary considerably and approaches include covering the full cost of a smart L2 charger, paying the $300 differential between an internet-enabled "smart" L2 charger and non-Internet-enabled L2 charger, and providing enrollment incentives for participating in EV DR events or dynamic managed charging programs with vehicle telematics. Notably, one utility program manager emphasized the importance of educating prospective smart L2 charger buyers about the total cost of installing a charger, including the additional costs of wiring their home and/or upgrading their electric panel.

Based on this information, we chose to assess two of the most common incentive designs that emerged from our review of other program designs. The first explores the incentive needed to encourage customers to upgrade from either a L1 charger or a non-Internet-enabled L2 charger to a smart L2 charger. In our survey, we informed respondents that a smart L2 charger normally costs $1,500 to install, including the charger, labor, and any requisite electrical upgrades. The second option focused on incentives needed to encourage participation in an EV DR program with customers who already have a smart L2 charger. It should be noted that the second option also applies to managed charging approaches that leverage vehicle telematics for customers with non-Internet-enabled L2 and/or Level 1 (L1) chargers since this approach works through the vehicle and is not reliant on the charger to connect to the Internet.

[8] Pacific Gas and Electric (PG&E). "Electric Vehicle (EV) Rate Plans." *Making Sense of the Rates.* Last Modified January 10, 2022.
[9] Alexander, Matt, Noel Crisostomo, Wendell Krell, Jeffrey Lu, and Raja Ramesh. Assembly Bill 2127 Electric Vehicle Charging Infrastructure Assessment: Analyzing Charging Needs to Support Zero-Emission Vehicles in 2030 – Commission Report. July 2021. California Energy Commission. Publication Number: CEC-600-2021-001-CMR.
[10] For a current summary of managed charging incentive designs and incentive levels from utility programs across the US we also recommend reading the Smart Electric Power Alliance (SEPA)'s October 2021 report on Managed Charging Incentive Design.

2.4 KEY FINDINGS RELATED TO FUTURE DIRECTION OF MANAGED CHARGING

According to the California Vehicle Grid Integration (VGI) working group, the prioritization of VGI interventions in California is passive managed charging strategies including TOU rates, then active managed charging, and, finally, vehicle-to-grid (V2G) communication.[11] Our research was limited to managed charging (V1G) use cases, and thus did not explore V2G applications.

Passive managed charging or indirect load control strategies are currently the most prevalent intervention employed by utilities to manage charging load. The most common passive managed charging strategy is a time-of-use (TOU) rate. EVs can be included in a whole-house TOU rate or an EV-specific rate. EV-specific TOU rates allow customers to isolate the charging load of their EVs but require a submeter, which could increase the upfront cost. PG&E offers both a whole-house TOU rate and an EV-specific rate.[12] Overall, results across multiple jurisdictions indicate that TOU rates are an effective strategy for encouraging EV drivers to shift their charging off-peak.

Other passive management strategies include behavioral load control incentive programs where participants are encouraged to reduce, and sometimes increase, charging at certain times by physically plugging and unplugging the EV at specific times of day. Very few managed charging programs deploy these types of strategies because they require effort on the part of the customer which has proven to be less effective than automated "set it and forget it" type approaches. In the viewpoint of grid operators, the preference is for firm load reducing resources which automated controls provide.

Active managed charging strategies provide vehicle charging through direct load ADR control technologies. These types of strategies allow energy providers to automatically curtail or reduce charging during a DR event or they can be used in a more continuous fashion to shift load to off-peak periods in response to price signals and/or grid needs.

Managing the sizable projection of growth in EVs and the impact on the grid in the coming decades will likely require a combination of both passive and active managed charging approaches. Passive managed charging approaches can incentivize EV owners to charge simultaneously but can potentially lead to new local timer peaks. The threat of timer peaks will intensify as the electrification of transportation reaches beyond light-duty passenger vehicles and into more heavy-duty fleets. EV TOU rates can help mitigate the risk of overlap between general peak load and EV load, but they do not help address timer peaks as described earlier; in fact, TOU rates can actually cause local peaks on distribution feeders with high penetrations of EV owners. Active managed charging methods, however, can allow an energy provider to stagger charging, which would help to flatten the peaks, whenever they occur.

Several utilities are now beginning to experiment with leveraging a combination of passive and active managed charging strategies as well as more granular and flexible price signals that target EV load reduction on an hourly basis, at the precise time when the resource is needed. These experiments and pilots are at an early stage of deployment. There is still an open question as to which types and combinations of interventions are optimal for generating load reductions. Further, interventions to encourage charging during times of high production from renewables (e.g., the mid-day "belly of the duck" part of the duck curve in California) are even less well developed today. We explore potential options to structure an integrated managed charging program approach based on the literature review, interviews, and customer research in Section 7 of this report.

[11] CPUC. *Final Report of the California Joint Agencies Vehicle-Grid Integration Working Group.* June 30, 2020.
[12] PG&E. *"Electric Vehicle (EV) Rate Plans." Making Sense of the Rates.* Last Modified January 10, 2022.

We tested the effectiveness of EV charging control technologies through the following steps:

1. Researched the current market of EV charging control providers (vendors) and selected three vendors for inclusion in the study
2. Recruited and enrolled EV owners in PG&E service territory in the field test
3. Executed the field test by calling nine DR events and one practice event from June to October 2021
4. Ingested and cleaned EV charging telemetry data from each vendor
5. Assessed the load impacts resulting from each DR event
6. Completed interviews with field test participants

We describe each of these steps and the associated results in detail in the following section.

3.1 VENDOR SELECTION

Through a rigorous vetting process, the Opinion Dynamics Team and PG&E selected three vendors for participation in the study. To inform the vendor selection, the Team leveraged brief intake surveys of the broader market of managed charging vendors, interviews with vendors that met key selection criteria, as well as the aforementioned literature review and utility program manager and expert in-depth interviews. We began by researching a broad range of EV charging companies to understand the universe of available technologies. We sourced potential vendors from the PG&E ADR Collaborative Process Assessment Study results, the PG&E EV Fleet approved vendor list,[13] the PG&E EV Fast Charge approved vendor list,[14] the list of EV charging control technologies that were certified as OpenADR-compliant from the OpenADR database at the time of the study,[15] and the Team's expert knowledge of active companies in the EV managed charging space. In addition, the Team drew upon market scan findings focused on past and current EV managed charging programs to gather insights into program performance and how other utilities have worked with these vendors.

After generating a list of potential vendors from this secondary research, the Team fielded a vendor intake survey to the vendors that met the baseline criteria for the Field Test. Baseline criteria required that the vendor must have (1) the ability to control L2 chargers or directly control the vehicle; (2) OpenADR certification of their headend system (virtual top or end node[16]); (3) the capability to manage charging for at least 300 residential EVs in PG&E territory as of November 1, 2020, and (4) the ability to engage with residential customers. The Team further refined the list of potential vendors based on the intake survey responses. The Team then conducted hour-long in-depth interviews with these "pre-qualified" vendors to gather additional insight into the vendors' capabilities.

The vetting process began with over 50 potential vendors with EV controls. The Team ultimately selected three vendors who qualified under the criteria. Figure 6 provides a visual breakdown of the vetting and funneling process that led to the final three vendors.

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[13] PG&E. *PG&E EV Fleet Program Approved.* Accessed January 2022.
[14] PG&E. *EV Fast Charge Program.* Last Modified January 10, 2022.
[15] OpenADR Alliance. *OpenADR Certified Product Database*. Last Modified January 10, 2022.
[16] OpenADR Alliance. *"What is a VEN?" Frequently Asked Questions.* Last modified February 10, 2022.

Figure 6. Vendor Selection Process

PG&E and the Team selected Enel X, Geotab, and ChargePoint as the field test study vendors. Table 2 summarizes the key attributes of the final three vendors. ChargePoint and Enel X both had many charging stations deployed in PG&E's service territory, which indicated these vendors would be likely to meet the customer enrollment target of 75 customers per vendor for the field test. Additionally, both ChargePoint and Enel X had substantial experience with load management programs. Geotab Energy had the ability to control EV charging of Tesla vehicles through a vehicle telematics approach (via Tesla's API) and by proxy had access to more detailed vehicle data (e.g., State of Charge [SOC]) and provided a unique customer experience in comparison to the other two vendors. Like ChargePoint and Enel X, Geotab Energy had a significant amount of utility experience and access to many vehicles in PG&E's service territory. Again, this selection of vendors allowed us to test the effectiveness of both the vehicle and charger telematics approaches.

Table 2. Key Attributes of Selected Vendors

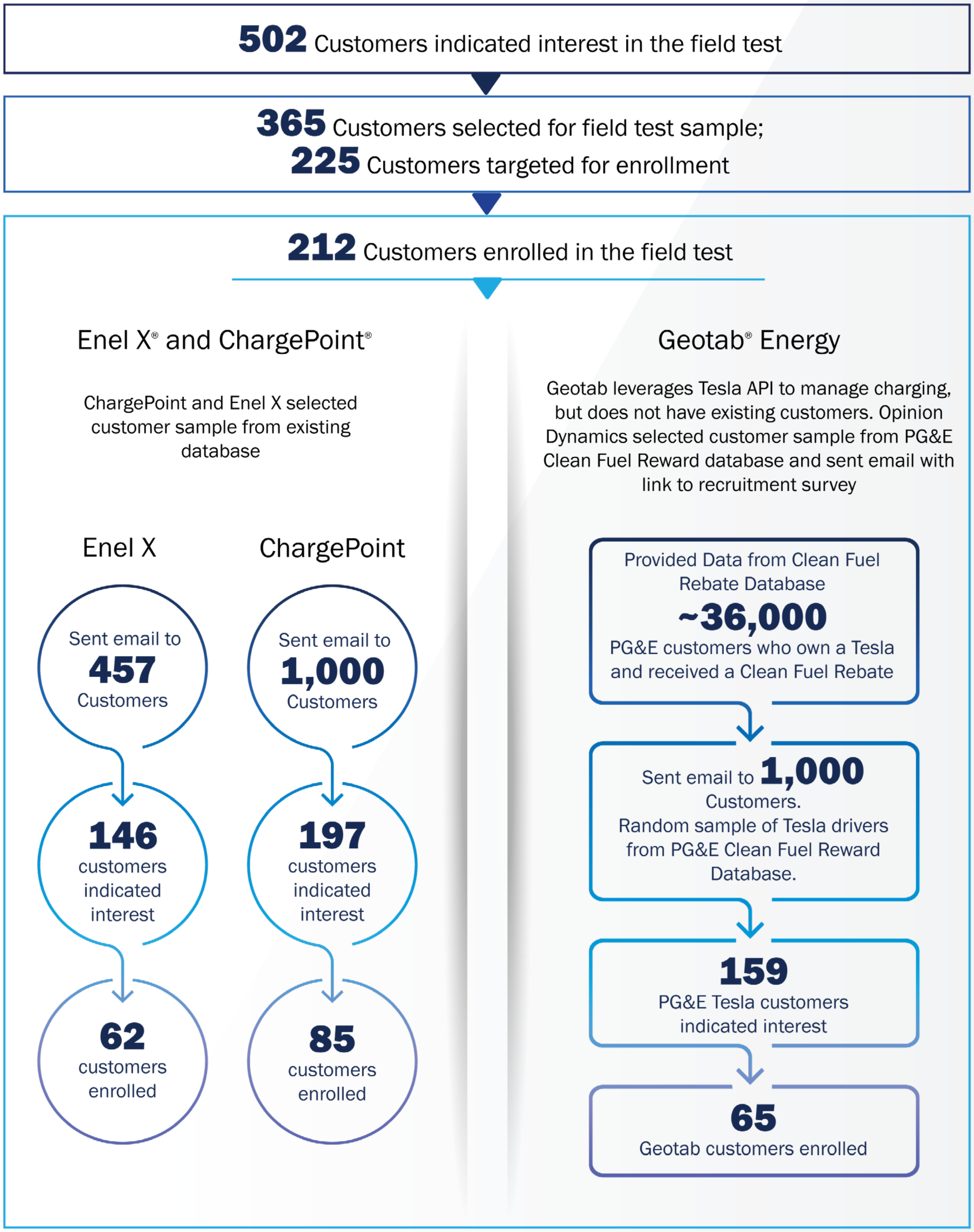
Criteria for Qualified Vendors	ChargePoint	Enel X	Geotab Energy
Devices Deployed: ▪ Minimum of 300 devices deployed in PG&E territory ▪ Ability to control EV charging for a minimum of 75 residential customers in PG&E territory for field test	✓	✓	✓/X (Approval from Tesla to leverage their API and partner with Tesla owners in PG&E service territory)
Data Access and Format: ▪ Able to share customer data subject to customer approval ▪ Can provide interval and charging session data	✓	✓	✓
Managed Charging Experience: ▪ Vendor has experience running ADR pilots in other jurisdictions	✓ SDG&E Direct Load Control, ConEd Smart Charge (11+ programs)	✓ >15 residential utility programs underway (e.g., SCE, Xcel Direct Load Control)	✓ >31 existing utility programs, (e.g., ConEd Smart Charge)
Demand Response Capability: ▪ Ability to call DR events ▪ Proven ability to communicate events to participants	✓	✓	✓

3.2 RECRUITMENT AND SELECTION OF FIELD TEST PARTICIPANTS

3.2.1 OVERVIEW OF PROCESS

Figure 7 outlines the field test participant recruitment process and the roles and responsibilities for the Opinion Dynamics Team, PG&E, Vendors (ChargePoint, Enel X, and Geotab), and participants recruited for the field test.

Figure 7. Field Test Participant Recruitment and Selection Process



3.2.2 FIELD TEST PARTICIPANT RECRUITMENT SURVEY

We fielded a web survey to 2,457 EV owners in PG&E service territory as a first step in recruiting customers to participate in the field test. ChargePoint and Enel X sent out the initial round of email invitations to their customers in PG&E service territory using their internal customer databases.

Unlike ChargePoint and Enel X, Geotab Energy did not have an internal database of customers, so the Team leveraged contact data from PG&E's Clean Fuel Reward (CFR) database to build a random sample of 1,000 PG&E customers who owned Tesla EVs from which customers could be recruited to participate in the field test with Geotab. Please see Appendix C for more details about the Geotab sample frame development. All respondents received a $10 incentive for taking the recruitment survey. To encourage interest in the field test, respondents were informed that they would receive a $100 incentive for their participation. The field test participant recruitment survey covered a number of characteristics that informed participant selection. These characteristics included type of EV (Battery Electric Vehicle [BEV]) vs Plug-in Hybrid Electric Vehicle [PHEV]), vehicle make and model, type of EV charger, charging habits, current rate plan, presence of solar panels, presence of home storage devices, participation in existing DR programs, housing type, and demographic and household characteristics. Please see Appendix G for a complete list of questions asked on the survey.

3.2.3 FINAL SELECTION OF FIELD TEST PARTICIPANTS

We used the 502 responses from the field test participant recruitment survey to develop a stratified sample of 225 target customers and 140 back-up customers to invite to participate in the field test. To make certain we would be able to observe load reductions, we stratified our sample to ensure we had representation from both customers on an EV rate and customers who indicated they regularly charge for at least one hour during the 4:00 p.m. to 9:00 p.m. peak period window. We also sought to ensure that the percentage of BEV owners and PHEV owners were representative of the distribution of these vehicle types in PG&E service territory. Furthermore, we worked to ensure we had relatively equal numbers of participants from each vendor. Through the sample selection process, we also monitored the frequencies of other key customer characteristics that could influence field test outcomes including self-reported rooftop solar ownership and weekly vehicle miles traveled to ensure our sampling approach did not result in abnormal distributions of these variables. For a more detailed explanation of our sample stratification strategy please see Appendix C.

To finalize the participant list, we contacted the 225 primary target customers and asked them to sign a digital participation agreement. We conducted multiple rounds of outreach and contacted additional customers from the group of 140 back-up customers on an as needed basis. A total of 212 customers with 214 chargers were ultimately confirmed as enrolled in the field test. The stratified sampling strategy proved to be effective as the characteristics of the field test participants aligned closely with the quotas we developed for each type of characteristic (Table 3).

Table 3. Field Test Participant Sample Quotas and Characteristics of Enrolled Participants (n=212)

	Target Quota	Field Test Participant Characteristics (self-report)[a]
Rate	50% on EV rates 50% on non-EV rates	50% on EV rates (n=105), 50% on non-EV rates (n=106)
Charging Patterns	50% peak chargers 50% non-peak chargers	54% peak chargers (n=113), 46% off-peak chargers (n=98)
Vehicle type	20% PHEV, 80% BEV	16% PHEV (n=33), 84% BEV (n=178),
Vendor	33% Geotab customers, 33% ChargePoint customers, 33% Enel X customers	31% Geotab customers (n=65), 40% ChargePoint customers (n=84), 30% Enel X customers (n=62)

[a] One customer enrolled in the field test but provided incomplete information. As such, we provide information on participant characteristics for 211 participants, however 212 participants enrolled in the field test.

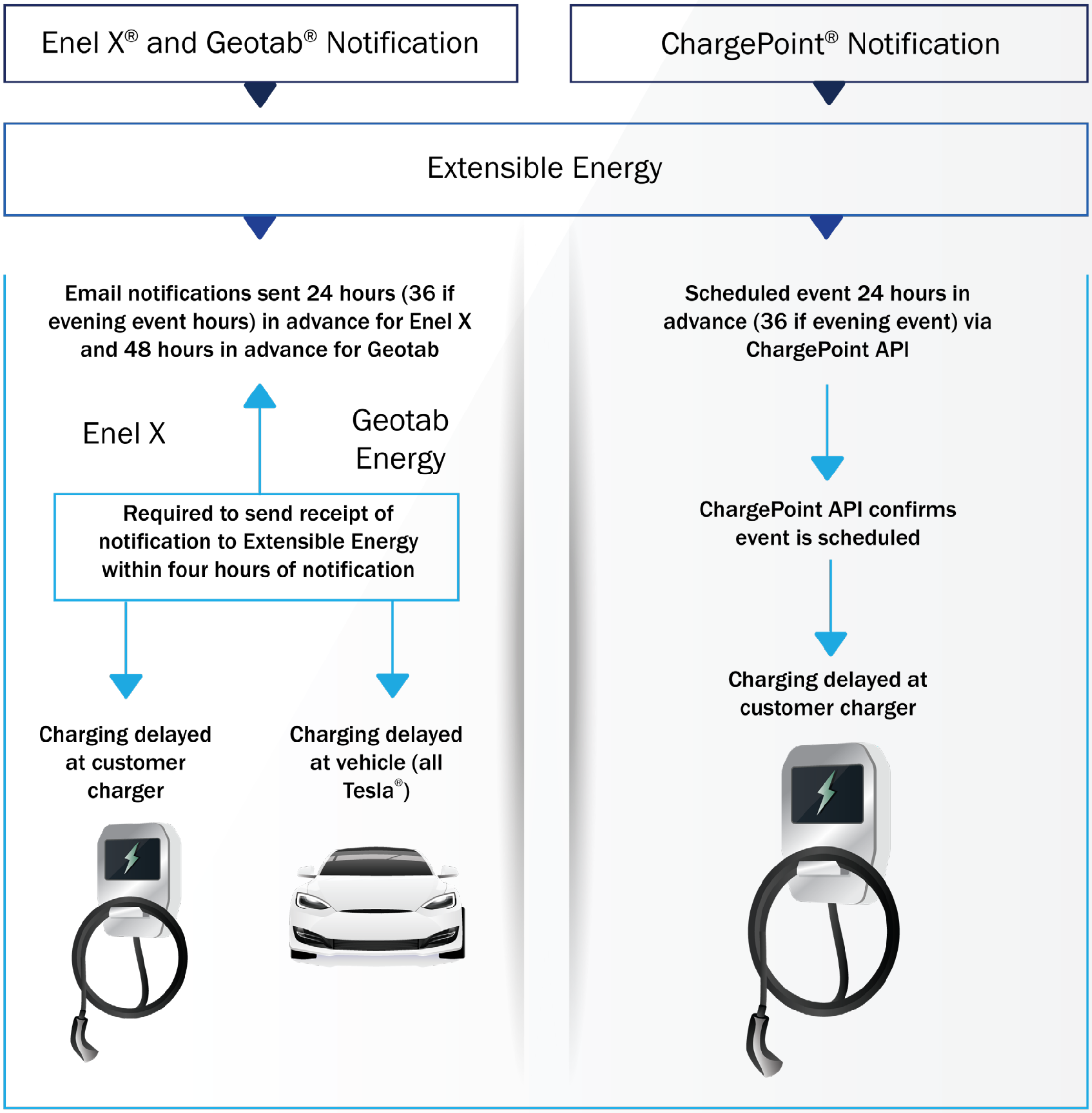
It is important to note that we designed the field test to assess the technology performance and not the characteristics of study participants. The study was not designed to be representative of the broader population of EV owners in PG&E service territory.

3.3 FIELD TEST EXECUTION

The Team developed a Field Test Plan for the implementation of ten planned DR events including one test event and nine evaluated events. The Test Plan specified protocols for data sharing, established points of contact with each vendor, and set up a process through which the Team and the Vendors could jointly schedule and/or cancel events.

While the project evaluated only OpenADR-capable vendors, it is important to note that neither the schedule nor budget for this project permitted integration with an OpenADR Virtual Top Node (e.g., PG&E's DR Management System [DRMS]). Hence, events were scheduled and executed through a combination of emails and vendor APIs. Extensible Energy was responsible for managing the notifications for each event. As shown in Figure 8, Extensible Energy notified Enel X and Geotab of upcoming events via email, and Extensible Energy scheduled events directly through ChargePoint's API. Enel X and ChargePoint received notification 24 hours in advance for weekdays and 36 hours in advance for weekends. Geotab built a Minimum Viable Product (MVP) specifically for the field test. This MVP was designed to meet the minimum capabilities of the field test while also helping Geotab to gather feedback and for refinement into a potential future product that could be more widely offered on the market. Given this context, Geotab received five days of notice for the first two events and then 48 hours of notice for all subsequent events. All vendors have stated that 24 hours of notice would be sufficient in a full-scale production program, and they would likely be able to execute events with fewer than 24 hours of notice if PG&E were to send the event signal in an automated fashion.

Figure 8. Field Test Event Dispatch Protocol



3.3.1 EVENT CHARACTERISTICS

There were two primary reasons for dispatching events: first, to evaluate the performance of each vendor's system in responding to events; and second, to estimate the load impact of each event. Hence, as described above, events were scheduled using a mix of dates (day of week) and times. Specifically, the "resource adequacy window" from 4:00 p.m. to 9:00 p.m. on weekdays is the time period when shifting load has the greatest potential to support grid reliability and renewable energy integration because electricity generation from renewable resources declines during this window, while residential demand simultaneously peaks. The 4:00 p.m. to 9:00 p.m. period was of greatest interest for system load shape purposes, while the period from midnight to 5:00 a.m. was of interest for local timer-peak reasons. As shown in Table 4, the Team scheduled a mix of four-hour events across these two periods on multiple different days of the week throughout the period from July 18 to October 6, 2021.

Because the field test was executed during fire season, protocols for canceling events were quite important. As shown in Table 4, four events were scheduled, canceled, and rescheduled due to Public Power Safety Shutoff (PSPS) events, Red Flag Warnings, and/or Flex Alerts. PSPS and Red Flag warnings indicate high fire risk and an abundance of caution was exercised by not dispatching DR events when these incidences impacted any participant, to ensure they would have the ability to charge their vehicles in case they needed to evacuate from a fire. Flex Alerts also encourage customers to voluntarily reduce their household energy use and EV charging between 4:00 p.m. and 9:00 p.m. on days of high electricity demand, which introduces a potential confounding variable that could impact load impact results on event days.

Once notified by the Team, the vendors were able to quickly cancel all events. Despite the incidence of PSPS and Red Flag warnings, one preliminary test event and nine evaluated events were successfully executed during the field test.
When the Team notified each vendor that an event had been scheduled, the vendor was required to acknowledge receipt of that notification by 8:00 a.m. on the morning of the event. All vendors performed well on this function after the initial preliminary test on July 18, 2021. All participants had the ability to opt out of any specific event. Only ChargePoint provided advanced notification of events to their participants via their API platform which automatically sends a notification to drivers once an event is scheduled.

Table 4. Field Test Event Schedule

	Event Date	Notes
1 (test)	Thursday, July 18, 8 p.m.–12 a.m.	Completed
2	Tuesday, August 3, 12 a.m.–4a.m.	Completed
3	Saturday, August 14, 1 a.m.–5 a.m.	Completed
4	Wednesday August 8, 5 p.m.–9 p.m.	Rescheduled due–PSPS Event and Red Flag warning
4	Wednesday, August 25, 5 p.m.–9 p.m.	Completed
5	Thursday September 2, 12 a.m.–4 a.m.	Rescheduled due–Red Flag Warning
5	Friday, September 3, 12 a.m.–4 a.m.	Completed
6	Friday, September 10, 4 p.m.–8 p.m.	Completed
7	Thursday, September 16, 12 a.m.–4 a.m.	Completed
8	Sunday, September 19, 12 a.m.–4 a.m.	Completed
9	Wednesday, September 22, 12 a.m.–4 a.m.	Rescheduled due–PSPS Event
9	Monday, September 27, 4 p.m.–8 p.m.	Completed
10	Wednesday, September 29, 12 a.m.–4 a.m.	Rescheduled due–Red Flag Warning
10	Wednesday, October 6, 12 a.m.–4 a.m.	Completed

3.4 DATA MANAGEMENT AND TRANSFER

Each of the three vendors provided EV charging behavior data to support our field test analytical efforts. Table 5 summarizes the key data fields collected from the vendors to support the load impact analysis and the resource potential assessment.[17] In addition, to the telemetry data, each vendor provided a report on opt-outs and a list of EVs for which they successfully curtailed charging after each event.

Table 5. Summary of Key Data Fields included in Vendor Telemetry Data

Type of Data	Description
Interval data	Timestamped readings from the car or charger in kWh and/or kW at 15-minute intervals[a]
Charging session data	The total energy transferred in an individual charging session in kWh
Vehicle information	The vehicle telemetry vendor was able to provide vehicle make, model, and year; the state of charge (SOC) of the battery before and after the DR event; latitude and longitude; and a flag for whether the vehicle was charging at home or away from the owner's residential address
Other key variables	Unique identifier for each charger or vehicle, in cases where there are multiple chargers/vehicles at a single location

[a] Geotab and ChargePoint provided interval data in units of energy. Enel X provided interval data in units of power, which we converted to units of energy.

3.4.1 DATA TRANSFER

We used different data transfer processes for each vendor. Enel X manually uploaded their data to a secure file transfer (Sharefile) site on a weekly basis. The data became available three days after the event. The Team accessed ChargePoint's data on an as needed basis by executing an API call for the data fields necessary for our analysis. Geotab hosted their data in a PowerBi® dashboard within a secure web portal, which the Team also accessed on an as-needed basis.

3.4.2 DATA CLEANING

We ingested the data for all three vendors and checked the data quality. The data from the three vendors was then cleaned and formatted so all three data streams could be aggregated for the load impact analysis. This included converting the Enel X data from units of power to units of energy and ensuring missing data was handled consistently across all three datasets. Additional cleaning steps were conducted to address individual known edge cases where customers switched chargers, dropped out of the field test, or did not receive an event signal etc. These edge cases are further described in the following section.

3.5 LOAD IMPACT ANALYSIS METHODS AND RESULTS

3.5.1 LOAD IMPACT ANALYSIS

The team leveraged interval charging data from each vendor and applied a Customer Baseline Load (CBL) approach to estimate load impacts (defined as total kWh shifted) during each four-hour event period on a per-participant basis. Ultimately, the CBL approach was selected after exploring multiple approaches for assessing load impacts because it offered advantages relative to the other approaches and is currently the standard measurement and verification approach for evaluating DR programs in California (as specified by the CAISO Load Impact Protocols).[18] The other approaches—a randomized control trial (RCT) approach and a "propensity to charge" approach—offered the potential for enhanced methodological rigor but also required a much higher level of effort to execute. It was found that the sample size for the RCT approach was not large enough to produce reliable estimates of event impacts due to the high variability of customers' charging patterns.[19] The "propensity to charge" approach estimates the load impacts of a treatment group of participants prior to the beginning of any event using a propensity model and historical charging data, then adjusts that estimate with any day-of variation between estimated and actual participation rates in the treatment and control groups. As the main purpose of the field test was to assess technology effectiveness, the costs of leveraging these more advanced approaches outweighed the benefits for this context.

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[17] In the months leading up to the field test, sample data was requested from the vendors, reviewed, and discussed with each vendor to ensure evaluability. ChargePoint, Enel X, and Geotab provided telemetry data for their customers starting in April, May, and June 2021, respectively.
[18] CPUC. *Decision 08-0-050.* April 24, 2008.
[19] This approach enabled us to use a control group, which allowed us to create a same-day adjustment ratio of how many customers were charging their vehicles vs. customers that were not charging to apply to the treatment group baseline.

To develop estimates of customer-specific load reduction utilizing the CBL method, the Team (1) established a baseline, or the amount of energy the field test participant's EV would have consumed absent a signal to curtail charging; and (2) calculated the difference between the baseline and actual energy consumption during the DR event. Following standard CBL methods, an X out of Y days approach was used (e.g., 4 of 5, 3 of 10, or 10 of 10)—to identify specific days similar to the event day, from which a baseline was constructed. Multiple baselines were tested to inform the selection of the CBL final approach using synthetic event days to study how well the baseline estimated actual load. Both a day-of-week CBL (using a baseline comprised of only the same day of the week as the synthetic event) and a weekday/weekend CBL (using all the baseline days on a weekday or weekend, whichever the event was called on) were tested as well as using evening and early morning hours to understand whether time of day impacted accuracy.

After sensitivity testing, a day-of-week CBL without an adjustment was found to be the most appropriate baseline for this effort. With this approach, if the event was held on Tuesday, Tuesdays were used in each baseline type (weekday and weekend) and measured the kWh impact of each event against those baselines. To better account for the variability in EV load, final results were calculated using as much baseline data as possible by re-evaluating events at the end of the event season utilizing all of the eligible days (non-holiday, non-event days, both pre- and post-event that fulfilled our requirements) for which data was available from April to October 2021.

It is important to note that the day-of-the-week CBL approach carries risk if there are limited days with similar charging patterns. While the CBL approach is the standard protocol for evaluating DR events in California, CBL performs poorly when there is significant day-to-day variation in customer charging behavior—as is the case with EV charging. The CBL also does not allow us to produce estimates of uncertainty around the impact measurement. Exploring new approaches such as a propensity to charge approach could likely help PG&E better account for the greater variability in load associated with EVs. PG&E may want to consider engaging in current discussions that are occurring with CAISO and California stakeholders about new strategies for establishing DR methodology in California.

To develop estimates of customer-specific load reduction utilizing the CBL method, the Team (1) established a baseline, or the amount of energy the field test participant's EV would have consumed absent a signal to curtail charging; and (2) calculated the difference between the baseline and actual energy consumption during the DR event. Following standard CBL methods, an X out of Y days approach was used (e.g., 4 of 5, 3 of 10, or 10 of 10)—to identify specific days similar to the event day, from which a baseline was constructed. Multiple baselines were tested to inform the selection of the CBL final approach using synthetic event days to study how well the baseline estimated actual load. Both a day-of-week CBL (using a baseline comprised of only the same day of the week as the synthetic event) and a weekday/weekend CBL (using all the baseline days on a weekday or weekend, whichever the event was called on) were tested as well as using evening and early morning hours to understand whether time of day impacted accuracy.

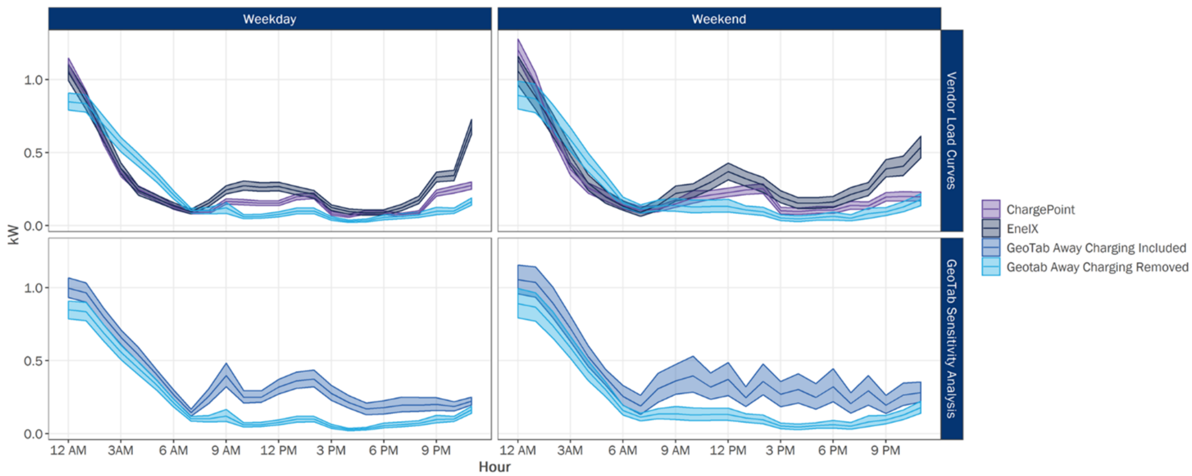
After sensitivity testing, a day-of-week CBL without an adjustment was found to be the most appropriate baseline for this effort. With this approach, if the event was held on Tuesday, Tuesdays were used in each baseline type (weekday and weekend) and measured the kWh impact of each event against those baselines. To better account for the variability in EV load, final results were calculated using as much baseline data as possible by re-evaluating events at the end of the event season utilizing all of the eligible days (non-holiday, non-event days, both pre- and post-event that fulfilled our requirements) for which data was available from April to October 2021.

3.5.2 FIELD TEST PARTICIPANTS' AVERAGE LOAD CURVES

As a first step in the load impact analysis, participants' average load curves were plotted by vendor using the data for the entire study period. The results in Figure 9 align with findings from the market scan and indicate that most study participants charge during the 12:00 a.m. to 6:00 a.m. overnight window and the proportion of participants that charge during the 4:00 p.m. to 9:00 p.m. peak period is small relative to the magnitude of off-peak charging, which corresponds with PG&E EV rate and TOU rate price signals. Geotab exclusively controlled Tesla EVs, which generally have larger batteries that take longer to charge; this may help explain why Geotab has higher overnight load from 3:00 a.m. to 6:00 a.m. Enel X TOU rate program customers are automatically scheduled to charge between 11:00 p.m. and 7:00 a.m., which can help explain why more Enel X customers start charging at 11:00 p.m. compared to other vendors.

Because Geotab leverages vehicle telematics, EV charging interval data for Geotab customers included instances of both home and away from home ("away") charging sessions. Figure 9 also shows a comparison of Geotab customers' home and away charging patterns. What became evident is that including the away charging sessions increases participants' mid-day and evening load and causes more spikes in the load shapes. This is likely because participants are using public direct current (DC) fast chargers away from their home to charge or are charging at work during the day and evening. Geotab was not able to exclude customers who were outside of PG&E service territory during the field test events. The Geotab team noted they can build geofencing capabilities that would allow them to geotarget events for specific customers for future programs. Home and away designations were used to exclude customers who were charging away from home from the load impact analysis because PG&E would not be able to claim the load impacts associated with vehicles charging away from their home in a future residential DR program as performance is typically measured via a home's meter data.

Figure 9. Field Test Participants' Average EV Charging Load Curves with 95% Confidence Intervals (April–October 2021)



3.5.3 OVERALL EVENT PERFORMANCE

Estimates of per-participant load reduction were aggregated from the load impact analysis to assess total field test performance overall and by vendor for each event. It is important to note the purpose of the field test was not to compare load impact results across vendors but rather to assess the effectiveness of each vendor's EV charging control technology. While the two outcomes are interrelated, there are limitations to directly comparing load reduction from each event across vendors: each vendor controlled a different number of vehicles, there were differences in the types of vehicles they controlled (e.g., Geotab controls only Tesla EVs), and each vendor likely had different numbers of customers who were plugged in and charging at the time of each event.

Overall, the DR event load impact analysis results demonstrate that all three of the EV charging control technologies were effective as all vendors successfully curtailed EV charging, with some variation in performance across events (Table 6). To provide an additional understanding of event performance compared to the expected load reduction potential, we also divided total event performance (kWh shifted) by the estimated baseline to calculate an event performance rate. Event performance generally improved as the field test progressed and vendors were able to adapt and learn from prior events. In alignment with load curves in Figure 9., which show most customers charge off-peak starting at midnight, the load impacts associated with the events called overnight between 12:00 a.m. and 5:00 a.m. (255 kWh to 601 kWh) were considerably larger than the load impacts for the events called during the resource adequacy window from 4:00 p.m. to 9:00 p.m. (9 kWh to 37 kWh). The performance rates for overnight events were also generally better than the peak period events, likely because customers were asleep when these events occurred so there was less opportunity to override them. Customer opt-outs were reported from each vendor.

Table 6. Field Test Load Impact Analysis Results

Event Number	Event Date and Time	Total Event Participation[a] (number of chargers, total n=214)	Energy Reduction by Vendor (kWh Shifted)			Total Energy Reduction (kWh Shifted)	Overall Event Performance Rate[b]
			Geotab n= 66 Vehicles	ChargePoint N=85 chargers	Enel X n=64 Chargers		
Event 2	Tuesday, August 3. 12 a.m.–4 a.m.	186	-14.79	198.39	71.57	**255.18**	52%
Event 3	Saturday, August 14, 1 a.m.–5 a.m.	212	106.80	176.61	153.43	**436.84**	85%
Event 4	Wednesday, August 25, 5 p.m.–9 p.m.	147	0.00	28.48	8.10	**36.58**	56%
Event 5	Friday, September 3, 12 a.m.–4 a.m.	213	180.85	211.45	132.33	**524.64**	76%
Event 6	Friday, September 10, 4 p.m.–8 p.m.	213	-36.71	21.13	24.28	**8.70**	13%
Event 7	Thursday, September 16, 12 a.m.–4 a.m.	213	142.81	238.89	137.75	**519.46**	79%
Event 8	Sunday, September 19, 12 a.m.–4 a.m.	213	208.87	213.74	178.70	**601.31**	91%
Event 9	Monday, September 27, 4 p.m.–8 p.m.	212	-9.16	19.45	19.22	**29.50**	48%
Event 10	Wednesday, October 6, 12 a.m.–4 a.m.	211	114.24	249.46	154.15	**517.85**	83%

Note: Event #1 was a practice event and therefore results are not included in this report.
[a] Total event participation is defined as the total number of participants that were known to be able to receive the event signal at the time of the event, whether they were plugged in, charging, or not. Total event participation is reported in the units of number of chargers (212 customers had 214 chargers at the start of the study). The total event participation varied across events as some participants dropped out of the study and human error prevented some participants from receiving event signals for certain events.
[b] The event performance rate is total event performance (kWh shifted) divided by the estimated baseline.

Overall, customer attrition and opt-outs remained low throughout the entire study. Only two out of 212 participants dropped out of the study after the first event,[20] and there were only seven instances of participant opt-outs across the ten events (including one test event).[21] These results indicate that the DR events were likely minimally intrusive for the study participants. This finding aligns with results from other programs; for example, one utility program manager in California reported a 2% to 4% opt-out rate for their EV DR program.

We cross-referenced instances of vendor-reported opt-outs with the participant-level load impact results to identify instances of participants that did not opt out but still charged during each event (event failures).

Overall, instances where participants charged during events despite not opting out (event failures) were minimal but they had variable impacts on resource adequacy window and overnight event performance (Table 7). Overall, a handful of customers charged during each event, but the event failure rate for the study was relatively low; the average failure rate across all events was only 4%.[22] These event failures had varying impacts across events. Few participants tended to charge their EVs during the 4:00 p.m. to 9:00 p.m. resource adequacy window, so failures for even just two or three cars during events called during this window had considerable impacts on event performance. Failures for events called between 12:00 a.m. and 5:00 a.m.—when participants regularly charge—were generally less impactful. This is reflected in the lower event performance rates for the events called during the resource adequacy window (performance rates of 0.13 to 0.56) in comparison to the overnight events (performance rates of 0.52 to 0.91) (Table 6).

[20] 212 participants/214 chargers enrolled in the study and two participants (and two chargers) dropped out after the first event, while one additional customer activated their charger after the first event.
[21] Geotab participants could opt out of an event by physically charging their vehicle, scheduling their vehicle to charge during the event, or opting out via the Tesla app. It is important to note that Geotab does not have a formal way of tracking customers that formally opt out of an event. We suspect that Geotab customers who began charging shortly after their EV charging was curtailed might have intentionally opted out; however, when we followed up with four of these participants through interviews, most of them did not realize the event was happening and that they had opted out. As such, we characterized all instances where Geotab participants charged during an event as event failures.
[22] A customer was considered to have charged during an event if their hourly event performance was greater than or equal to 0.7 kW for Enel X and ChargePoint and greater than or equal to 0.3 kW for Geotab for at least one hour during a four-hour event period. ChargePoint and Enel X only deployed smart L2 chargers for this study which generally charge at 2.8 KW. The vendors provided data to us in 15-minute increments, which we rolled up into hourly results. As such, if a customer charged at 2.8 kW for at least one 15-minute interval, their hourly event performance would be 2.8 kW (hourly rate)/4 (there are 4, 15-minute intervals per hour) = 0.7 kW. Geotab customers could have L1 chargers, which charge at 1.3 kW, so we applied the same logic for Geotab customers 1.3 kW/4 = 0.3 kW.

The reasons charging still occurred during events, despite participants not opting out, varied across each vendor. Geotab is currently not operationally able to curtail vehicles that start charging after the event begins. The Team does not expect this issue to persist in the long run as Geotab reported they are building out the capability to curtail charging that starts after the event begins as part of their product roadmap.

At the time of report publication, ChargePoint was further investigating the root cause of instances where drivers charged during DR events. ChargePoint commonly had instances of low-level charging during events which may indicate a firmware or other technical issue. In addition, ChargePoint customers can manually opt out of an event by unplugging their charger and then plugging it back in again. This "double-pumping" mechanism does not register as a formal opt-out and may have been a potential contributor to event failures as well.

For Enel X, one customer had intermittent Wi-Fi connectivity causing their charger to go offline regularly and this customer was responsible for six of Enel X's 18 event failures. In addition, Enel X automatically sets the charging schedule for customers on PG&E's TOU rate schedule to charge from 11:00 p.m. to 7:00 a.m. This option includes protections to ensure these customers' vehicles are fully charged by 7:00 a.m. Consequently, these settings could have overridden portions of the overnight field test events to ensure these customers' vehicles would be fully charged in the mornings. This likely helps explain why Enel X generally had a higher incidence of customers who charged, but did not opt out, for overnight events compared to events during the resource adequacy window.

One-off human error issues impacted the performance of individual events. For the second event (12:00 a.m. to 4:00 a.m. on Tuesday, August 3, 2021), Geotab sent the DR signal at 11:58 p.m. Because Geotab doesn't have the ability to curtail vehicles that began charging after an event begins, vehicles that began charging at 12:00 a.m. in alignment with EV rates were not curtailed. This impacted Geotab's performance for the second event. Geotab addressed this issue for all subsequent events by sending the DR signal two minutes after the event began.

Enel X runs a distinct program where they aggregate residential EV chargers and bid this resource into the CAISO wholesale market. Customers in the CAISO program receive DR signals in alignment with California grid needs. In two separate instances, Enel X inadvertently removed participants from the field test and placed them in the CAISO wholesale market program, including moving three customers before the field test started and 26 customers for Event 2. Twenty-six customers were dropped from the load impact analysis for Event 2 and adjustments were made to the baselines of any customers who were moved into the CAISO program (either before the field test started or for Event 2) to account for any DR signals they may have received during the time when they were participating in CAISO.

For Event 4, Geotab inserted start and end times in Coordinated Universal Time (UTC) instead of Pacific Daylight Time (PDT), which resulted in the curtailment starting at 5:00 a.m. PDT instead of the correct start time of 12:00 a.m. PDT. As such, all results from Geotab for Event 4 were dropped.

Two utility representatives interviewed during the market scan noted incidents where vendors executed a DR event at the wrong time. One issue was related to communication about the specification of the time zone of the event. The other incident was related to the time clock in the vendor's platform, and the utility representative noted this only happened during one of the 100 DR events they called.

For this field test, Geotab and Enel X programmed events manually. One vendor noted that in the future, automated approaches could help eliminate human errors from the event dispatch process. More broadly, it is important to note that the three vendors selected for this study were viewed as the most capable OpenADR-certified EV vendors in the market as of late 2020. The market is changing rapidly, and new errors—and fixes—are being discovered frequently. Field test programs like this one are an essential tool for utilities, vendors, and the entire EV charging ecosystem to accelerate improvements in this promising market.

KEY CONSIDERATION

In the future, PG&E should leverage automated methods for dispatching DR events to minimize instances of human error in future DR programs.

Please see Appendix D for individual results for each of the nine DR events.

Table 7. Participant Opt-Outs and Failures for Each Event

Event Number	Event Date and Time	Total Event Participation[a] (number of chargers, total n=214)	Opt-Outs	Opt-Out Rate	Participants that Charged without Opting Out (Failures)	Failure Rate Percentage
Event 2	Tuesday, August 3. 12 a.m.–4 a.m.	186	0	0.00%	15	8%
Event 3	Saturday, August 14, 1 a.m.–5 a.m.	212	0	0.00%	6	3%
Event 4	Wednesday, August 25, 5 p.m.–9 p.m.	147	1	0.68%	4	3%
Event 5	Friday, September 3, 12 a.m.–4 a.m.	213	1	0.47%	14	7%
Event 6	Friday, September 10, 4 p.m.–8 p.m.	213	2	0.94%	9	4%
Event 7	Thursday, September 16, 12 a.m.–4 a.m.	213	0	0.00%	11	5%
Event 8	Sunday, September 19, 12 a.m.–4 a.m.	213	0	0.00%	5	2%
Event 9	Monday, September 27, 4 p.m.–8 p.m.	212	2	0.94%	6	3%
Event 10	Wednesday, October 6, 12 a.m.–4 a.m.	211	1	0.47%	8	4%
Total		**1820**	**7**	**0.38%**	**78**	**4%**

Note: Event #1 was a practice event and therefore results are not included in this report.
[a] Total event participation is defined as the total number of participants that were known to be able to receive the event signal at the time of the event, whether they were plugged in, charging, or not. Total event participation is reported in the units of number of chargers (212 customers had 214 chargers at the start of the study). The total event participation varied across events as some participants dropped out of the study and human error prevented some participants from receiving event signals for certain events.

PARTICIPANT FIELD TEST EXPERIENCE

We conducted brief close-out interviews with 12 participants at the end of the field test. These interviews were designed to learn about participants' experience with the field test, and covered topics including how the field test impacted their charging behaviors, their experience with DR events, why they opted out of certain events (if opt-outs occurred), how COVID-19 impacted their driving and charging behavior, and what motivating strategies could be used to mitigate opt-outs for future program events. We also leveraged findings from the event impact assessment to inform tailored questions for specific customers regarding their performance. Results from these interviews provide context around event performance and insight into how to optimize future program designs. To ensure the participants we interviewed would be able to speak to our questions of interest and represent a variety of experiences, we selected participants for interviews based on a number of factors, including the vendor they participated with, their charging propensity, whether they opted out or dropped out of the study, and whether they lived in a high fire risk area.[23] We provide insights from the close-out interviews in this section and throughout the rest of report.

Over half of the field test participants were not aware PG&E and vendor partners called DR events that curtailed their EV charging. Only five out of the 12 interviewed participants were aware that PG&E had called DR events. All five "aware" participants reported receiving some form of alert or notification of the event. Of these "aware" participants, only one became aware that the events were occurring because of the alert notification, another participant was aware of the events but mistakenly believed that PG&E turned their charging on during an event, instead of curtailing it. The other seven "unaware" interviewed participants reported that they did not remember receiving any alert notifications about the events. One was aware that events would be called but was not aware that the study had started. The other six were not aware that events were happening or going to be called. Although, one "unaware" participant caveated that they were away for most of the summer.

[23] The sample was stratified to equally target participants from all three vendors and split the sample between those that had a propensity to charge overnight (12:00 a.m. to 4:00 a.m.) or during peak hours (4:00 p.m. to 9:00 p.m.). Within the stratification above, we prioritized participants that opted out of events, lived in a Tier 2 or Tier 3 fire threat area, dropped out of the study, or had extremely high or low propensity to charge.

The DR events had very little, if any, impact on participants. Participants reported the events had no impacts on their driving patterns. "Aware" respondents who recalled an event occurring, reported experiencing no impacts on their ability to use their EV to get to school, work, or other destinations. Only three participants stated the events had any impact on their charging habits.

One "unaware" participant was on a TOU rate. This customer noticed their car was not fully charging this summer, likely as a result of the DR event, and assumed it was user error. In response, they shut off their programmed charging schedule and set their car to charge any time they plugged in their vehicle. This participant believes that this led to a large increase in their electricity bill for a month before they caught the issue because they started charging more frequently on peak.

> *I would say that I did make an added effort to make sure that the car was charged before the event, although I knew that it likely wouldn't have had an impact. But just checking my schedule and make sure I didn't have any long-distance driving that I would have to do. I did take a couple extra precautions.*

Enel X customers on EV or TOU rates were the only participants that had the benefit of the vendor automatically adjusting their charging schedules prior to or after events to ensure their vehicles would return to normal charging levels. All other participants did not have a mechanism to ensure the vehicle was fully charged when they needed it. For example, if they had their vehicle set to charge for six hours but the event was scheduled for four hours within that time frame, the vehicle would only charge for two hours out of the original scheduled six-hour charge window. As a result, one participant woke up to find their car wasn't fully charged and decided to force their vehicle to charge in the morning after an event:

KEY CONSIDERATION

In the future, PG&E may want to consider working with vendors that can dynamically adjust participants' charging schedules to charge before and after DR events to minimize impacts on the customer experience.

> *Instead of waiting, I just forced the charging. But it's a little easier for me because I'm on the tiered plan. I'm not on the EV plan.*

Very few participants opted out of events. There were only seven instances of participants opting out of one or more events; we were able to interview two of these participants. The reasons participants opted out of events varied. One participant mistakenly believed the purpose of the events was to turn their charging on, not off, and they opted out of a 4:00 p.m. to 9:00 p.m. DR event because they were on an EV rate and did not want to charge during the peak period. The other participant we spoke to could not remember why they opted out, but they intentionally charged through the event. Most participants that opted out did not appear to have any issues with the ease of opting out. One participant reported they did not realize opting out was even an option and thought that it should be communicated more clearly.

All interviewed customers reported they would participate in a program like this study if it were offered in the future. This provides further evidence that the DR events had minimal impacts on field test participants. Participants also reported their participation experience had little impact on their satisfaction with PG&E. Only two participants reported their participation slightly improved their satisfaction; others reported their satisfaction remained the same.

4. SCALE: EV LOAD MANAGEMENT RESOURCE POTENTIAL ASSESSMENT, AND RESIDENTIAL EV ADR INCENTIVE AND DR PROGRAM DESIGN INSIGHTS

Overall, results of the field test demonstrated that the technology is effective and there is potential to leverage EV control technologies for PG&E DR programs and to establish an ADR incentive. To further understand the opportunity, the Team conducted a survey to assess customer preferences for EV ADR incentive designs and an analysis of the resource potential associated with EV ADR technology. These research efforts allowed for a more detailed exploration of the impact of incentives on load management with a larger and more varied audience than was feasible in the field study.

4.1 CUSTOMER INCENTIVE PREFERENCE SURVEY METHODS AND RESULTS

The following section presents the customer incentive preference component of the study.

4.1.1 RESEARCH BACKGROUND

The team used a survey methodology called choice-based conjoint[24] to explore EV owner willingness to participate in EV DR programs given various program designs and ADR incentive offers. The survey results allowed us to identify the program elements that resonate most with customers and what incentive structure is optimal to induce a sufficient proportion of EV owners to participate in an EV DR program that would result in meaningful load impacts.

Based on working sessions with PG&E staff and our market scan research, we identified two primary incentive scenarios to explore in the conjoint study: (1) providing incentives for smart L2 charger upgrades and (2) EV DR program participation incentives and/or enrollment incentives through an EV DR program.

- We directed the smart L2 charger upgrade scenario questions to PG&E EV owners that currently charge at home using either a L1 charger (approximately one-third of PG&E EV owners) or a non-Internet-enabled L2 charger (approximately one-third of PG&E EV owners). These smart L2 charger incentives would help subsidize the cost of upgrading the customer's home charging station to a smart L2 charger, which would provide a non-telematics mechanism to receive and respond to dispatchable DR events via the internet.
- The EV DR program participation scenario questions were directed to EV owners who already have smart L2 charging infrastructure at home. This incentive offering would provide EV owners with direct financial compensation in exchange for allowing PG&E to disrupt their EV charging during DR events.

In concert, investigation of these two incentive scenarios provide insight into the relative effectiveness of either incentive to garner customer interest while simultaneously maximizing reduction potential and minimizing program costs.

In addition to general incentive strategy (i.e., smart L2 charger upgrade vs. EV DR program participation incentives), we explored other DR program components that utilities must consider when designing and implementing a program. For example, what incentive amount is necessary to cultivate sufficient smart L2 charger upgrade adoption? And what incentive format (e.g., digital gift card vs. paper check) is most appealing to customers? Collectively, the conjoint data can be used to understand which hypothetical program designs are predicted to be most successful with customers and what programmatic approaches strike the best balance between customer interest, cost-effectiveness, and load impacts.

The survey of EV owners with the conjoint scenarios also included questions to understand EV owners' charging habits, demographics, and awareness and attitudes towards allowing PG&E to adjust their charging. We report on the results from these additional questions in Section 5.

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[24] Choice-based conjoint studies are used for revealing respondents' preferences for the combinations of features that make up products or services, for this approach respondents express preferences by choosing their favorite products and services from sets of options with different features, rather than by rating or ranking them.

4.1.2 METHODOLOGY

The survey sample frame consisted of households who applied for the EV rebate on PG&E's website. Several steps were taken to develop our sample frame from the CFR database, which are documented in Table 22 in Appendix F. We conducted a simple random sample of 20,000 households from the sampling frame, while ensuring enough diversity in rate status (EV rate vs. non-EV rate) and type of vehicle (PHEV vs. BEV) to make meaningful comparisons between customer groups for the conjoint analysis. The survey was fielded online from September 30 to October 19, 2021 in two waves. For the first wave, 11,000 EV owners were invited to complete the survey and provided a $10 incentive. To ensure there was enough representation from smart L2 charger owners, invitations were sent to an additional 9,000 EV owners in a second wave.[25] Given the high survey response rates in the first wave, an incentive was not provided for the second wave. A total of 2,698 EV owners completed either conjoint exercise for a 15.9% response rate.[26]

After answering standard survey questions in the customer incentive preference survey, respondents were presented with one of the two conjoint exercises. A total of 828 EV owners completed the "EV DR program participation" exercise for owners of smart L2 chargers. The remaining 1,870 survey respondents with L1 or non-Internet-enabled L2 chargers received the smart L2 charger upgrade scenario.

CONJOINT EXERCISE I: SMART L2 CHARGER UPGRADE

Table 8 shows the concepts tested in the smart L2 upgrade conjoint exercise. In conjoint terminology, the high-level program design components that were tested are called "attributes" and various options for a given attribute are called "levels." In addition to these attributes and levels, EV owner likelihood of choosing not to participate in a hypothetical smart L2 upgrade program was tested, given the offers presented to them in the conjoint exercise. Note that each attribute is independent from the other attributes, and respondents were presented a randomized selection of the levels on each conjoint screen.

Table 8. Concepts Tested in Smart L2 Charger Upgrade Conjoint

Attribute	Level 1	Level 2	Level 3	Level 4	
Incentive amount	$50	$100	$200	$300	**None of these incentive offers would motivate me to install a Smart Level 2 charger**
Incentive format	Emailed gift card	Paper check	Bill credit		
Incentive delivery timing	50% at time of sale/50% after install	After install	At time of sale		
Mandatory enrollment in PG&E's EV demand response program	Yes	No			

As seen in Table 8, various incentive amounts were tested, ranging from $50 to $300. These incentive amounts were chosen to represent various low, medium, and high incentive amount scenarios that PG&E might reasonably offer (given that the market price to install a smart L2 charger could easily exceed $1,000 depending on charger type and household installation needs).

Consumer behavior is more complex than just price; however, consumers may be willing to pay more for something if they find the increased price is justified by other unique attributes associated with the product or service. In the program design context, this means that other non-monetary program components may exert some additional level of influence on customers' willingness to participate. For that reason, incentive format and incentive delivery timing were also included in the conjoint. The levels in these attributes were selected in collaboration with PG&E staff to represent a mix of realistic program design options and predicted customer ideals. In addition to revealing relative preference for the options tested in these program attributes, they serve a methodological purpose: by providing respondents with some non-monetary program attributes to weigh when choosing between various incentive offers, respondents won't necessarily just choose the highest incentive offer on their screen, which creates a methodological environment where price sensitivity can be measured.

[25] In this case, stratification based on charger type was unable to be achieved in the sample because we did not know the distribution of L1, L2, and smart L2 chargers in the population before fielding the survey.
[26] Standard survey question results from Section 5 were included. Note that some respondents did not complete the conjoint portion of the survey, which is reflected by larger sample sizes presented in Section 5 (n=3,143).

The smart L2 upgrade conjoint also tested whether or not receipt of the incentive was conditional upon mandatory enrollment in PG&E's EV DR program.[27] This was a critical component of the exercise, as PG&E ultimately wants customer permission to control these devices as dispatchable Distributed Energy Resources (DERs). Instead of making this an inherent condition of hypothetical incentive program participation, it was tested as a program attribute to assess its relative impact on EV owner interest in charging upgrade incentives. This enabled an assessment of the assumption that some EV owners would be unwilling to take the incentive if mandatory DR was required.

CONJOINT EXERCISE 2: EV DR PROGRAM PARTICIPATION

Table 9 shows the concepts tested in the EV DR Program Participation conjoint exercise. In addition to these attributes and levels, we tested EV owner likelihood of choosing not to participate in a hypothetical EV DR program, given the offers presented to them in the conjoint exercise.

Table 9. Concepts Tested in EV DR Program Participation Conjoint

Attribute	Level 1	Level 2	Level 3	Level 4
First-time enrollment incentive	None	$50	$100	$150
Per-event incentive	None	$5	$10	$20
Annual participation incentive	None	$25	$50	$100
Event time window	4 a.m. to 3 p.m.	3 p.m. to 10 p.m.	10 p.m. to 4 a.m.	N/A
Number of events per year	5	10	20	50
Charging speed reduction	75% of normal charging speed	50% of normal charging speed	25% of normal charging speed	0% (charging is completely paused)

None of these: I would not be willing to participate in any of these demand response programs

As seen in Table 9, various incentive types were tested: a first-time enrollment incentive, a per-event incentive, and an annual participation incentive. These represent various incentive type formats observed in the market scan as well as approaches that are consistent with other PG&E DR incentives in the residential sector. For each incentive type, levels that represented various low, medium, and high incentive amount scenarios that PG&E might reasonably offer were included. These tested incentive levels were right sized for their frequency: the more frequent the incentive type would be paid, the lower the dollar value range for the incentive type. We also included "none" levels for each incentive type, which facilitated subsequent modeling of predicted participation in EV DR program offerings with one incentive type. Ultimately, the analysis of these attributes revealed the most potent incentive type for garnering EV owner EV DR program interest as well as the relative impact on predicted participation as incentive levels are increased.

The EV DR program conjoint exercise also tested three different event time windows: 4:00 a.m. to 3:00 p.m., 3:00 p.m. to 10:00 p.m., and 10:00 p.m. to 4:00 a.m. These time periods were selected to understand variations in customer preference across a range of time periods with varying relevance to PG&E grid needs. The resource adequacy window occurs in the 3:00 p.m. to 10:00 p.m. period, the overnight timer peak period exists within the 10:00 p.m. to 4:00 a.m. window, and the 4:00 a.m. to 3:00 p.m. window exists entirely within the off-peak period.

To gauge how event frequency impacts EV owner willingness to participate—as well as to facilitate respondent consideration of annual event payments in a given scenario—a number of events per year were included in the EV DR program conjoint exercise. Event frequency ranged from as few as five to as many as fifty events per year.

Although the field tests relied on total cessation of charging during an EV DR event, the market scan revealed that some vendors' technologies have the capability to modulate the level of EV charging speed reduction (0% to 100% of normal charging speed) during DR events. This capability is analogous to air conditioner (AC) load control devices that have the ability to cycle the AC or temperature ramping versus shutting off completely during DR events. Finding this gentler approach was critical to the proliferation of DR programs throughout the country. For EV customers, this capability could enable customers to participate in DR events while still meeting some of their charging needs. Given this technological advancement, the EV DR program conjoint included a charging speed reduction attribute, with levels ranging from 75% of normal charging speed to 0% (where charging is completely paused). Even if charging speed throttling is not an immediate option for PG&E, inclusion of this attribute allowed us to model how EV owner interest in DR programs varies by relative impact to charging speed.

[27] Prior to completing the conjoint exercise, EV owners were educated on the details of managed charging EV demand response programs.

Conjoint Survey Experience

Respondents cycled through several screens (or, discrete choice scenarios) that presented different incentive/program configurations to choose from on each screen (program configurations were algorithmically drawn from the attributes and levels presented in Table 8 and Table 9, respectively). On each screen, respondents could choose from one of the unique alternative program configurations, or they could select "none" (i.e., choose not to participate in any of the program offerings presented on their screen). See Appendix F for example screens of each conjoint exercise and additional information on the conjoint methodology.

Conjoint Analysis

The Opinion Dynamics Team analyzed conjoint data separately for each exercise. Hierarchical Bayesian (HB) methods were utilized to analyze the responses to the conjoint exercises. HB methods enabled an estimation of the relative importance or utility of each program component for each respondent. In addition, market simulations were conducted to assess the relative share of preference for different program configurations. Ultimately, these results revealed the maximum proportion of customers who are predicted to participate in a given program design and how this varies by key customer attributes.

4.1.3 Key Findings

Providing incentives for existing L2 charger owners to participate in an EV DR program is more cost-efficient than incentivizing EV owners to replace their existing non-Internet-enabled charger with a smart L2 charger. The research reveals that a one-time $50 enrollment incentive can encourage nearly half of EV owners in PG&E's service territory who already own a smart L2 charger to participate in an EV DR program. Conversely, a $300 incentive is needed to garner similar levels of DR participation when using a hardware upgrade incentive strategy. Given that vehicle telematics allows for L2 chargers without Internet capabilities to participate in EV DR events, and that 71% of surveyed EV owners already own an L2 charger, the evidence points to simply incenting DR program enrollment (and not hardware upgrades) as the most cost-efficient yet impactful approach.[28]

We provide a detailed discussion of customer preferences for different incentive levels and program attributes for each conjoint scenario in the sections that follow.

4.1.4 Detailed Results

Conjoint Scenario 1: Smart L2 Charger Upgrade

To upgrade to a smart L2 charger, EV owners prefer higher incentives and not being required to participate in a DR program. In addition to revealing levels of EV owner interest in hypothetical charging hardware upgrade programs (among those with either a L1 charger or a non-Internet-enabled L2 charger), the smart L2 charger upgrade conjoint reveals EV owner preference for various hardware upgrade program elements (e.g., paper check vs. emailed gift card for incentives). Figure 10 shows all the smart L2 upgrade program design elements tested in this conjoint, as well as the relative preference for each element. The relative preference for program elements is the proportion of program designs chosen in the conjoint survey screens that included a given program element. For example, when selecting a smart L2 upgrade program offering, respondents chose a program configuration with an incentive amount of $300 in 62% of discrete choice scenarios presented to them. Readers should not interpret these results as evidence that a certain proportion of EV owners prefer lower incentive amounts over higher ones; for example, "3% of EV owners prefer a $50 incentive and 62% prefer a $300 incentive" is an inaccurate interpretation of these results. Rather, the conjoint results reveal that the $300 incentive level is dramatically more appealing to EV owners than $50, at a roughly 20:1 ratio (62:3) of relative preference. As seen in Figure 10, EV owners demonstrated a clear preference for higher incentive amounts and programs without mandatory DR enrollment.[29] However, customer preference was fairly split for incentive delivery timing and format. These results are not surprising, given that we would naturally expect EV owners to prefer higher incentive amounts and the opportunity to receive a rebate without the potential perceived downsides of participating in a DR program.

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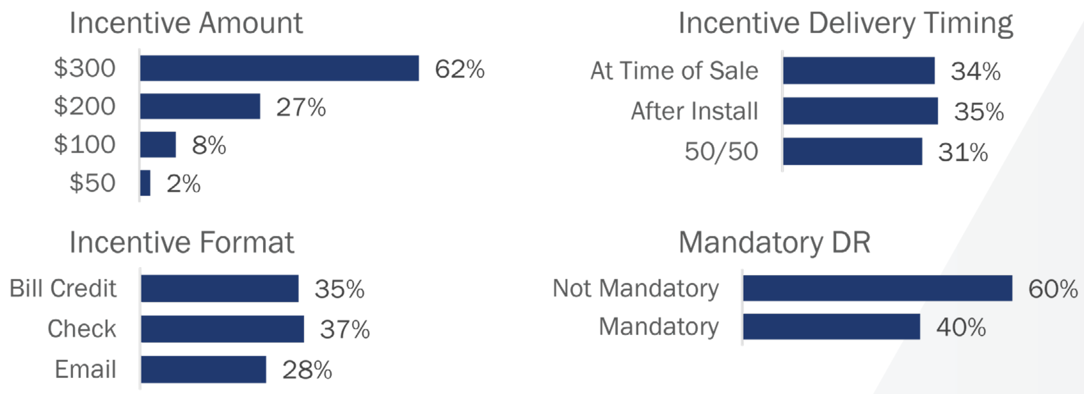
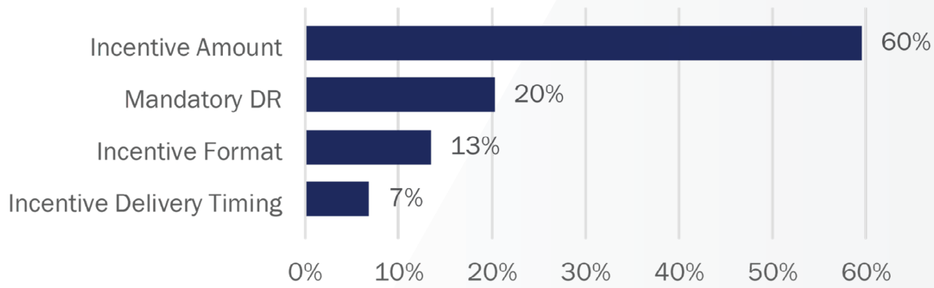
[28] PG&E may wish to provide incentives for EV charging infrastructure to meet other goals and objectives such as reducing range anxiety and encouraging EV adoption in contexts where EV charging infrastructure is less common (e.g., multifamily buildings). The results from the conjoint scenario are not meant to be applied to contexts outside of DR applications for EVs.
[29] Notably, the randomized nature of conjoint screens means that there were inevitably times that a given screen of program elements did not include any $300 incentive options, revealing that—when only presented with sub-$300 offers—many EV owners were still willing to participate in a hardware upgrade program with an incentive of less than $300.

Figure 10. Relative Preference for Tested Smart Level 2 Charger Upgrade Program Elements (n=1,870)



Incentive amount is the most important consideration when considering smart L2 hardware upgrade program offers. Relative importance of each program component was also tested. The relative importance of program elements measures the influence each higher-level program element tested in the conjoint had on respondent decision-making behavior in the conjoint exercise relative to the other program elements (e.g., incentive amount vs. incentive format). These relative importance values sum to 100%, revealing the proportional influence of each program element has on respondent decision-making. Reinforcing the findings seen in the figure above, conjoint results demonstrate that EV owner choices in discrete choice scenarios were most influenced by incentive amount (Figure 11). In other words, incentives drive 60% of EV owner decision-making behavior when choosing between various smart L2 charger upgrade program offers. When deciding between various program offers, EV owners were comparatively less influenced by DR participation requirements, incentive format, and incentive delivery timing.

Figure 11. Relative Importance of Tested Smart L2 Upgrade Program Components (n=1,870)



A $300 incentive is needed to entice about half of current in-market EV owners to upgrade to a smart L2 charger. Using the most preferred incentive format and delivery elements (Figure 10), we conducted market simulations that use the conjoint data to predict the relative share of preference for each incentive amount—both with and without mandatory enrollment in a DR program (Table 10). These results predict the proportion of EV owners that would participate in a given program offering.[30] Given the elements tested, the simulations reveal that up to 53% of EV owners who do not currently own a smart L2 charger could be incented to upgrade to a smart L2 charger if PG&E provided a $300 paper check incentive that was delivered after installation and did not require participation in an EV DR program. Given that PG&E is unlikely to incentivize a smart L2 charger through DR funding sources without mandating DR program participation, we also simulated EV owner interest if receipt of the incentive was conditional upon participating in EV DR events. If DR participation was required, EV owner willingness to participate drops to 45%. On the low end, only 14% of EV owners who do not currently own a smart L2 charger would be willing to upgrade for a $50 incentive if DR participation was required.

[30] Note that share of preference simulations are blind to real-world factors such as successful marketing campaigns (which could expand participation beyond what the simulations suggest) or level of enrollment burden (which could inhibit participation from achieving what the simulations predict).

Table 10. Predicted Participation Rates for Select Smart L2 Upgrade Program Configurations

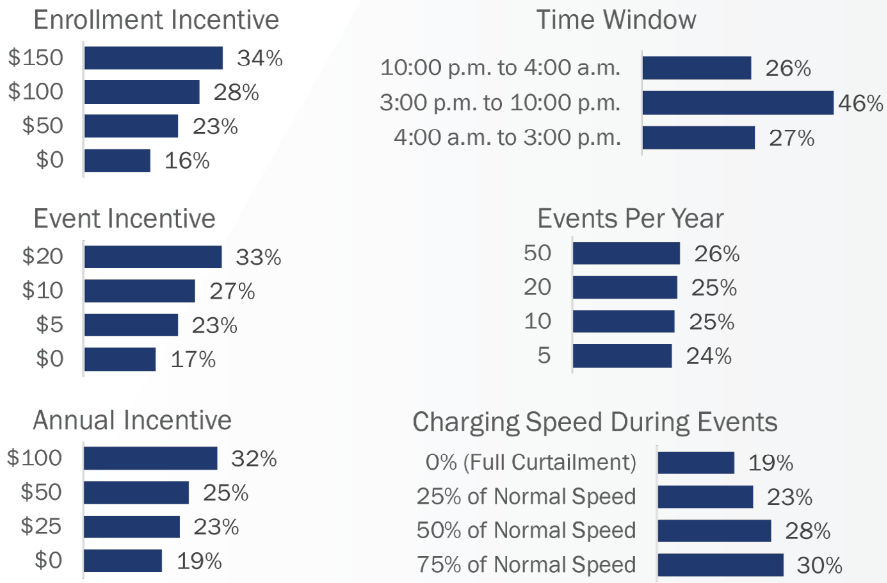
Participation Condition	Smart L2 Upgrade Incentive Amount			
	$50	$100	$200	$300
With Mandatory DR	14%	26%	34%	45%
Without Mandatory DR	20%	31%	41%	53%

Note: Simulated share of preference when program provides a paper check incentive that is delivered after smart L2 hardware installation.

CONJOINT SCENARIO 2: EV DR PROGRAM PARTICIPATION

When considering EV DR programs, current smart L2 charger owners prefer higher incentives and peak period (afternoon/early evening) event times. In addition to revealing EV owner interest in participating in EV DR programs (among those with a smart L2 charger), the EV DR conjoint uncovers these smart L2 charger owners' preferences for various potential EV DR program elements (e.g., whether events are called in the evening or overnight). Figure 12 shows all EV DR program elements tested in the conjoint, as well as the relative preference for each element (which is the proportion of EV DR programs chosen in the conjoint survey screens that included the given program element). For example, when selecting an EV DR offering, respondents chose a program configuration with a $150 enrollment incentive in 34% of discrete choice scenarios presented to them. Again, readers should not interpret these results as evidence that a certain proportion of EV owners prefer lower incentive amounts over higher ones; for example, "16% of EV owners prefer no enrollment incentive and 34% prefer a $150 enrollment incentive" is an inaccurate interpretation of these results. Rather, the conjoint results reveal that the $150 enrollment incentive level is dramatically more appealing to EV owners than none, at a roughly 2:1 ratio (34:16) of relative preference. As seen in Figure 12, EV owners demonstrated a clear preference for higher incentive amounts and lesser charging impacts. Additionally, EV owners dramatically prefer an event time window of 3:00 p.m. to 10:00 p.m. We know from the literature review, field test, and resource potential analysis that EV owners are already substantially less likely to be charging during the peak period of 3:00 p.m. to 10:00 p.m. As such, EV owners likely have a preference for events called during this period because they would be less disruptive to their normal charging schedules; yet, with enrollment and annual incentive offers, they could still receive compensation for enrolling in the program. EV owners were not nearly as concerned with the number of events per year, as shares of preference were fairly split for the tested elements in this program component.[31]

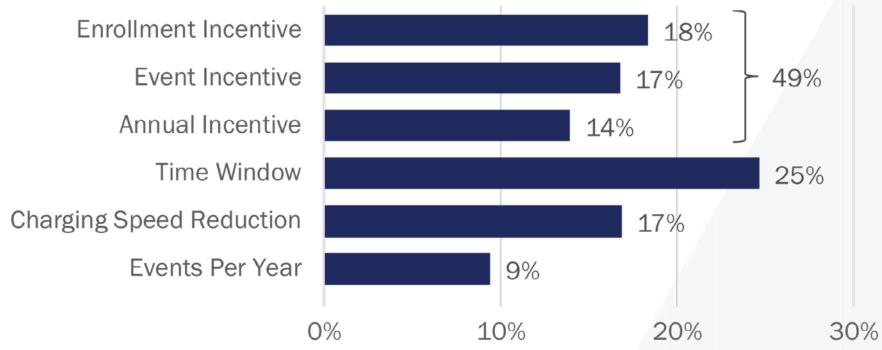
Figure 12. Relative Preference for Tested EV DR Program Elements (n=828)



[31] Notably, the conjoint screens allowed for multiple incentive types within a given offer, which explains why considerable proportions of program configurations were chosen with a $0 incentive value for a given incentive type. Although a given program configuration may have had no enrollment incentive, it likely had a per-event incentive and/or an annual incentive. Subsequent simulation analysis allowed us to predict participation when only one incentive type was offered.

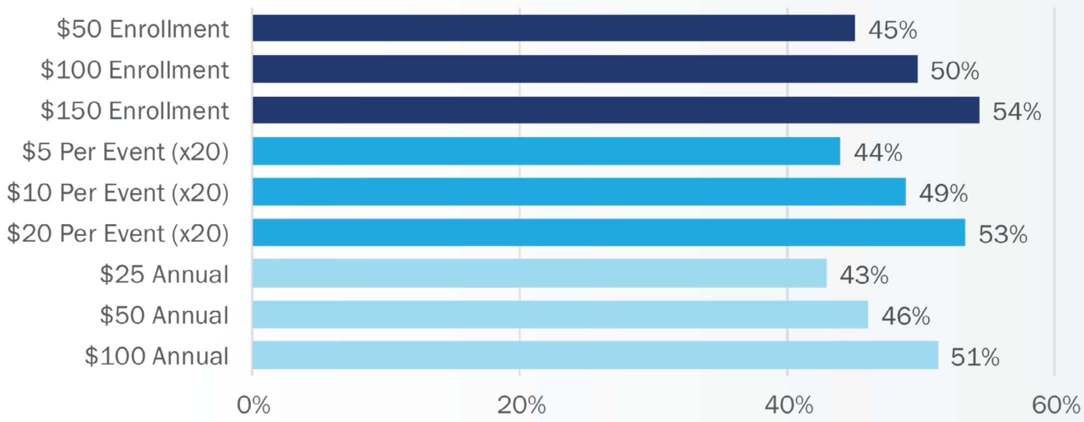
Incentive details and event timing are the most important considerations when considering EV DR program offers. We also tested relative importance of each program component for the DR program participation scenario. Conjoint results demonstrate that EV owner choices in discrete choice scenarios were most influenced by various incentive types (Figure 13). In other words, the three various incentive types tested (one-time enrollment, per-event, and annual incentives) collectively drive 49% of EV owner decision-making behavior when choosing between various EV DR program offers. The time window in which events would be called was also a strong driver of the hypothetical DR programs in which respondents were willing to participate.

Figure 13. Relative Importance of Tested EV DR Program Components (n=828)



A $50 enrollment incentive is all that is needed to entice about half of in-market smart L2 charger owners to participate in an EV DR program. Several market simulations were conducted that use the conjoint data to predict the relative share of preference for various EV DR program configurations. These results predict the proportion of EV owners that would participate in a given EV DR program offering.[32] Figure 14 presents several mutually exclusive single-incentive-type scenarios, where participants would only receive one incentive type for participating (e.g., a one-time enrollment incentive only). For all scenarios shown in Figure 14, it is assumed that charging would be completely curtailed during an event, 20 events would be called per year, and the events would be called during the peak period of 3:00 p.m. to 10:00 p.m. as these are some of the most likely scenarios for a future PG&E EV DR offering based on discussions with the PG&E project team. As seen in Figure 14, all three incentive types perform similarly, with slightly less than half of EV owners willing to participate with the smallest incentive amount (regardless of incentive type) and a little over half willing to participate with each of the highest incentive offers. These results reveal that dramatic increases in incentive offers only deliver net marginal gains in program interest. For example, doubling any of the incentive amounts does not double EV owner interest. Thus, it can be concluded that large incentives are not necessary to encourage participation for an EV DR program among customers who already have smart L2 chargers.

Figure 14. EV Owner Interested in Select EV DR Program Configurations



Note: Simulated share of preference when event time window is 3:00 p.m.–10:00 p.m. with total cessation of charging during 20 events annually.

[32] Note that share of preference simulations are blind to real world factors such as successful marketing campaigns (which could expand participation beyond what the simulations suggest) or level of enrollment burden (which could inhibit participation from achieving what the simulations predict).

The great majority of EV owners are willing to participate in an EV DR program if the incentive offers are high enough. Given the elements tested, the simulations reveal that up to 82% of EV owners (with smart L2 chargers) would participate in an EV DR program under the optimal combination of tested program design elements. This participation level assumes:

- EV owners would receive the maximum incentive amount possible (i.e., $150 enrollment incentive, $20 per event incentive, and a $100 annual incentive).
- Events would be called from 3:00 p.m. to 10:00 p.m.
- There would be 10 to 20 events per year.
- Charging speed would only be reduced by 25%.

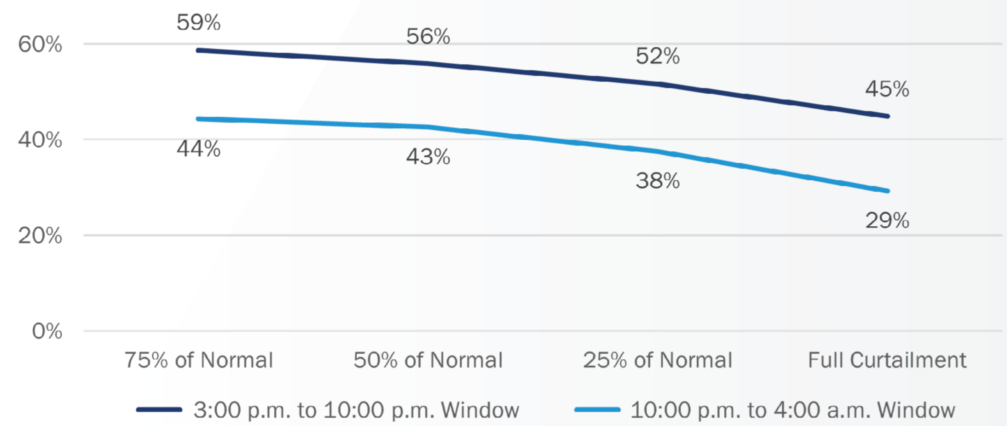
Over three-quarters of respondents would still be interested, assuming the following parameters:

- Multiple incentives offered (including lower incentive amounts)
- Events called from 3 p.m. to 10 p.m.
- Charging is never completely paused.

Significant drops in predicted participation rates are not observed until scenarios are simulated with only one incentive type (e.g., participants would only receive a one-time enrollment incentive; no event or annual incentives would be offered).

Smart L2 charger owners are also interested in participating in EV DR program designs that provide opportunities for more dynamic grid management applications beyond just peak period DR. Through the market scan, we learned utilities in other jurisdictions are deploying solutions that dynamically optimize the magnitude and timing of EV charging speed reduction based on grid needs and customer preferences. Moreover, the field test demonstrated that EV charging control technologies can help manage overnight timer peaks that result from most EV owners charging at midnight. Using a $50 enrollment incentive, we modeled the EV owner interest curve for a variety of charging speed reductions for both a 3:00 p.m. to 10:00 p.m. event time window and a 10:00 p.m. to 4:00 a.m. event time window (Figure 15). Although the curves are similar because more participants are willing to participate as charging speed reduction is minimized, about 15% fewer customers are willing to participate at any level of charging speed reduction when the event window is 10:00 p.m. to 4:00 a.m. compared to 3:00 p.m. to 10:00 p.m. This finding reveals that although 3:00 p.m. to 10:00 p.m. is the preferred time window for most, significant proportions of EV owners are still willing to participate if events are called overnight (when many owners typically charge their EVs at home). Furthermore, we can surmise that EV owners may prefer not to have their charging completely curtailed because they gain some peace of mind by knowing they would still retain some level of charging in case of emergency or an unexpected trip.

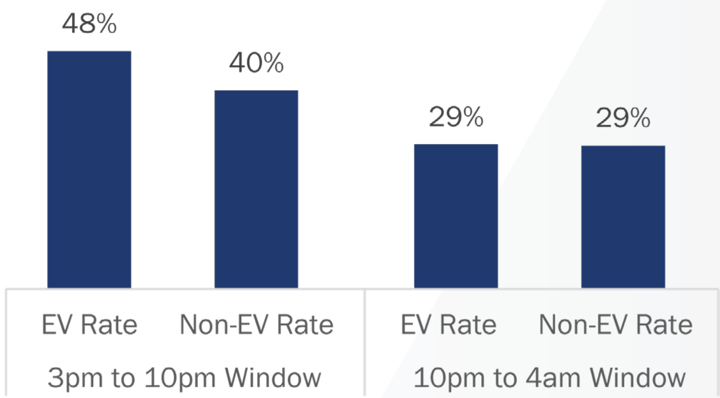
Figure 15. Predicted Participation Rates by Charging Speed and Event Times with $50 Enrollment Incentives



Note: Simulated share of preference when only a $50 enrollment incentive is offered (i.e., no annual or per-event incentives) with 20 events annually.

Households on an EV rate are more willing to participate in an EV DR program with afternoon/early evening events; we can surmise this is because they are less likely to be charging during these times in the first place. Additional analysis reveals that EV owner willingness to participate is somewhat differentiated by rate type, with EV rate households demonstrating greater interest in EV DR participation than non-EV rate households when events are only called from 3:00 p.m. to 10:00 p.m. (Figure 16). Nearly half (48%) of EV rate households are interested in participating in an EV DR program that completely stops charging (for up to four hours) for a $50 enrollment incentive if the events are only called from 3:00 p.m. to 10:00 p.m. In comparison, only two-fifths of non-EV rate households expressed interest in participating in the same program. This difference is presumably because EV rate households are not generally charging during this event time window in the first place due to nighttime charging discounts, which motivate them to charge overnight. Meanwhile, non-EV rate households are comparatively more likely to be charging during the 3:00 p.m. to 10:00 p.m. time window as they lack the same economic motivation to concentrate their charging overnight; thus, this timeframe is less acceptable to them. Some EV owners are similarly willing to participate for a $50 enrollment incentive with a 10:00 p.m. to 4:00 a.m. event time window regardless of their home's rate type; however, significantly fewer participants of either group (29%) indicated interest in that program design.

Figure 16. Predicted Participation Rates by Rate Type and Event Times with $50 Enrollment Incentive and Complete Cessation of Charging



Note: Simulated share of preference when only a $50 enrollment incentive is offered (i.e., no annual or per-event incentives) and charging is completely stopped during 20 events annually.

KEY CONSIDERATION

This study did not include an assessment of customer interest in initiation of charging through EV DR, as PG&E's current residential ADR program does not include this attribute. Future work should include a technical and customer assessment of the potential for residential EV DR as a method of shifting usage into the "belly of the duck."

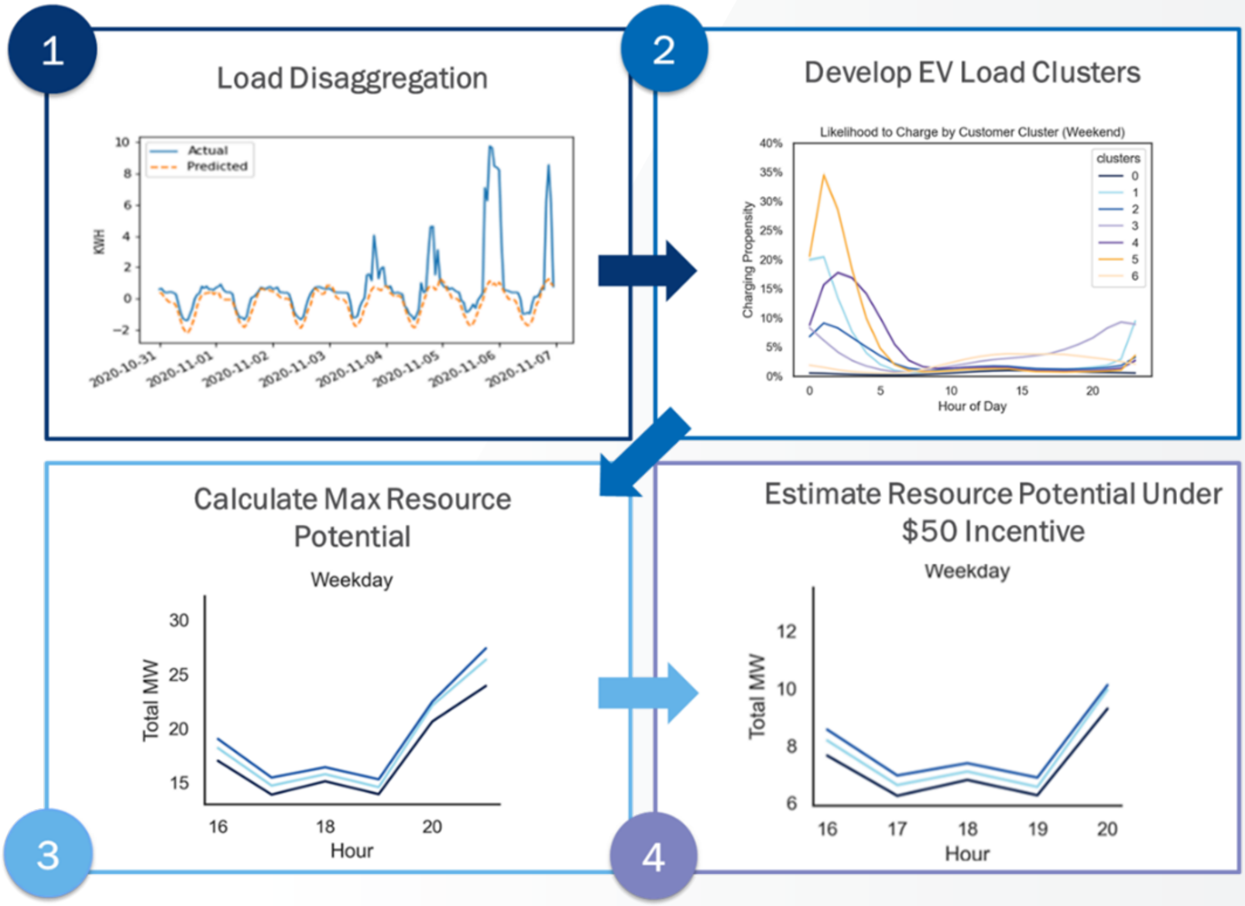
4.2 RESOURCE POTENTIAL ASSESSMENT METHODS AND RESULTS

The customer incentive conjoint study revealed that providing incentive to customers who already own L2 chargers is a cost-effective approach to encouraging EV DR program participation. Another critical aspect of developing a cost-effective incentive structure for EV control technologies is understanding the magnitude and characteristics of the load management potential associated with residential EVs. To fully understand the value that EVs can provide as a DR resource, we completed an assessment of the EV DR load reduction potential of the 366,000 EV owners in PG&E service territory.

We developed an estimate of EV DR resource potential in PG&E service territory using a four-step process (Figure 17):

1. **Load Disaggregation:** Disaggregated EV charging patterns from whole-house AMI data for 71,000 PG&E EV owners to isolate their EV charging demand from the remaining appliances or demand sources present in the whole-house AMI data.
2. **Clustering Analysis:** Leveraged a K-means clustering approach to identify seven common charging patterns present across the 71,000 modeled EV owners in PG&E territory and identified opportunities for PG&E to target each cluster/charging pattern type for participation in a future EV DR offering based on their EV charging behavior.
3. **Resource Potential:** Applied the DR event performance rate from the field test to the clustering analysis outputs to estimate EV DR resource potential under multiple potential adoption scenarios.
4. **Resource Potential Incorporating Realistic Program Enrollment Projections:** Adjusted the estimates of resource potential to reflect program enrollment likelihood results from the conjoint survey, with a specific focus on the $50 enrollment incentive.

Figure 17. Summary of Resource Potential Assessment Methods



4.2.1 EV LOAD DISAGGREGATION METHODS AND RESULTS

The first step in identifying the larger PG&E EV resource potential is determining the charging behavior of the larger customer population. The analysis was completed using whole-house AMI data as this data source offered the greatest coverage of EV owners in PG&E service territory. This load disaggregation process consisted of (1) Requesting and cleaning the whole-house AMI data for PG&E EV owners dating back two years prior to EV purchase date; and (2) Using the consumption information to isolate customers' EV charging signals and identify specific times where the customer is predicted to be charging their EV, as well as the associated demand.

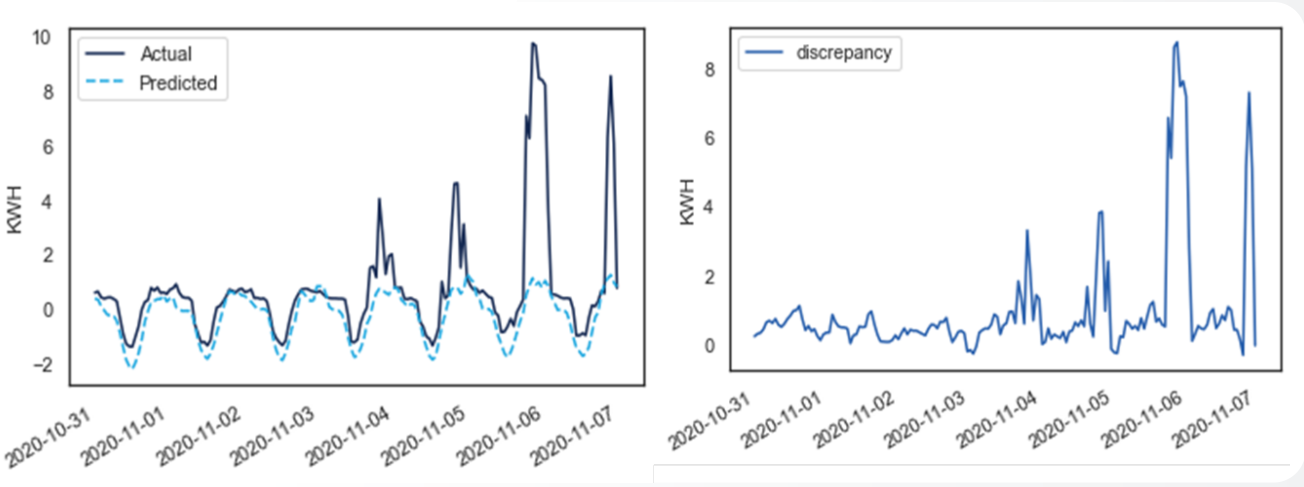
AMI DATA PROCESSING AND CLEANING

PG&E provided data for all known PG&E EV owners that had either received an EV rebate according to the CFR database or signed up for an EV rate according to the PG&E EV rate database. To ensure we had enough pre-EV adoption data to support the development of a pre-post consumption model, we requested AMI data for the period from two years prior to the date of each EV owners' EV registration to May 2021. The data was for approximately 125,000 PG&E customers. The data was then processed and cleaned using the steps outlined in Appendix H to ensure each customer had sufficient data to run a pre-post model to estimate baseline usage. A total of 71,311 customers met the data sufficiency criteria for inclusion in the final analysis.

AMI BASELINE MODELING

The processed and cleaned pre-vehicle adoption AMI data was leveraged to create an estimate of whole-house baseline load before customers purchased their EV, and then identified the discrepancy between this estimate of whole-house load from non-EV sources and the actual AMI reading to parse-out EV charging load. The two years of pre-EV-adoption data was then used to create a pre-post temperature-time-of-week (TTOW) regression model to describe AMI load.[33] In this application, this model was used to estimate baseline household consumption from all non-EV sources throughout the post-EV-adoption period by combining the temperature, day/time-of-week, and pre-post indicator terms to net-out the effect of temperature on aggregate household energy consumption.[34] This model was then used to forecast pre-EV-adoption usage levels throughout the post-adoption period, creating the estimate of baseline demand absent an EV. Likely EV charging periods were identified by comparing the actual AMI data to the predicted baseline load from non-EV sources, and then highlighted periods of large discrepancies between them as potential instances of EV charging for further refinement. A sample of this disaggregation process and the accompanying discrepancy calculation is shown in Figure 18.

Figure 18. Load Disaggregation Baseline Modeling and Discrepancy Calculation



[33] The TTOW model was developed by Lawrence Berkeley National Lab (LBNL) and is commonly used to estimate whole building energy consumption.
[34] The full model specification can be found in Appendix H.

DISCREPANCY SIGNAL PROCESSING

The discrepancy estimates were further analyzed to isolate EV charging signals from other end uses (e.g., washing machine, dishwasher, air conditioner) or noise from the baseline modeling by leveraging a z-score-based robust peak detection algorithm. This approach is commonly used to identify anomalous signals in time-series data for removal or adjustment. Using this approach, anomalous signals were identified as likely charging sessions in comparison to the surrounding discrepancy information. This signal processing involved first examining each customer's AMI history and calculated discrepancies and using this iterative algorithm to flag any anomalously high discrepancy values as potential instances of EV charging. The minimum power draw for L2 charging stations is 2.8 kW.[35] Using this information, we further refined the likely instances of EV charging identified in step one by filtering out any identified peaks below 2.8 kW, as those peaks were likely generated by noise, other appliances, or L1 chargers.

Given the similar demand profiles of L1 chargers to other household appliances (as L1 chargers frequently operate at just 1.3 kW), we were less confident in our ability to disaggregate L1 charging load. Disaggregating load from L1 chargers is a known challenge across the industry. In addition, the higher variability in charging patterns and lower magnitude of power draw associated with L1 charging makes customers with L1 chargers less suitable candidates for DR programs. As such, we decided to restrict the signal finding to L2 charging.[36]

L2 chargers tend to draw power at a variety of common rates including 2.8 kW, 3.8kW, and 5.7 kW. Using our existing knowledge of these common rates, we identified the most common (mode) charging peak height for each customer and mapped it to the closest known charging power levels in an attempt to determine the standard power draw for the customers' vehicle and charging infrastructure (see Appendix H for more details). This allowed us to better estimate overall demand because we knew what the expected power draw was for a given customer for a future event, without needing all of the specific information regarding the car and charger type(s). We finally adjusted the peak heights to the nearest common demand-level associated with EV charging, producing the final instances and levels of EV charging sessions. For example, a customer with a mode charging demand of 3.5 kW would be mapped to the known common charging level of 3.8 kW, as this is the closest possible wattage and accounts for noise during the disaggregation process. The specific parameters of the approach as well as a table of common charging demand levels are shown in Appendix H.

VALIDATION

The Team leveraged EV charging interval data from the field test as a test set to validate disaggregation performance. As the unit of analysis for both the field test and the peak detection analysis was PG&E EV owners, EV charging interval data for the participants in the field test was mapped to the peak detection outputs for approximately 100+ participants who appeared in both datasets. This enabled us to compare the predicted charging sessions from the peak detection analysis to actual charging sessions from the telemetry data for common participants between the two datasets. Given the relatively small number of overlapping participants between the model training and field test datasets, the Team was able to perform predominantly visual inspection of all test-set customers. Both the frequency and magnitude of the predicted sessions were evaluated against known values by comparing the estimated charging sessions and capacities from the load disaggregation analysis to the known power draws based on the EV charging interval data from the field test. It was determined that the approach was successful in isolating EV charging based on this visual inspection. An example of this disaggregation in comparison to known charging behavior is shown for a sample field test customer in Figure 19. In the example figure, the red dots indicate predicted charging sessions based on the discrepancies between the predicted and actual whole-house AMI data (shown in light blue). In this example, the approach captures nearly all of the charging session and charging magnitudes (shown in dark blue).

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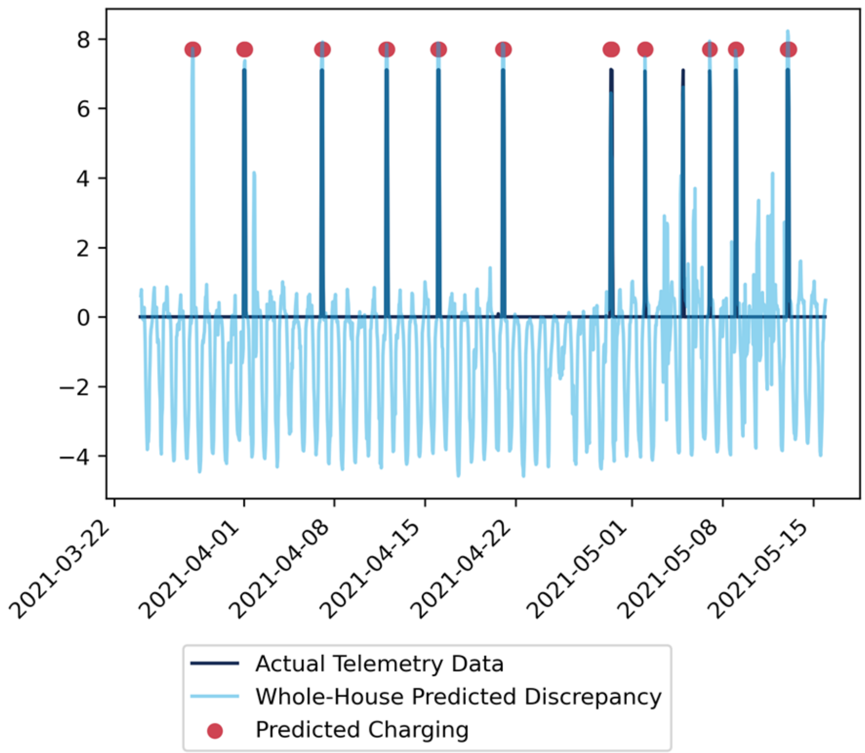
[35] L2 charging stations can also have power draws greater than 2.8 kW. Any additional demand beyond 2.8 kW will generally depend on the make and model of the EV. In general, vehicles with larger batteries tend to have higher power draws.

[36] There were instances where we were unable to completely remove likely L1 chargers (based on the responses present in the conjoint survey) from the analysis. This likely occurred when an L1 charger was also running with another appliance, such as a dishwasher or washer/dryer, which raised the aggregate demand signal above the 2.8 kW threshold. These customers exhibited a more variable charging pattern (due to the relative infrequency of the concurrent demand) and are explored further in the clustering analysis in Section 4.2.2.

Figure 19. Example of Signal Charging Validation



4.2.2 CLUSTERING ANALYSIS METHODS AND RESULTS

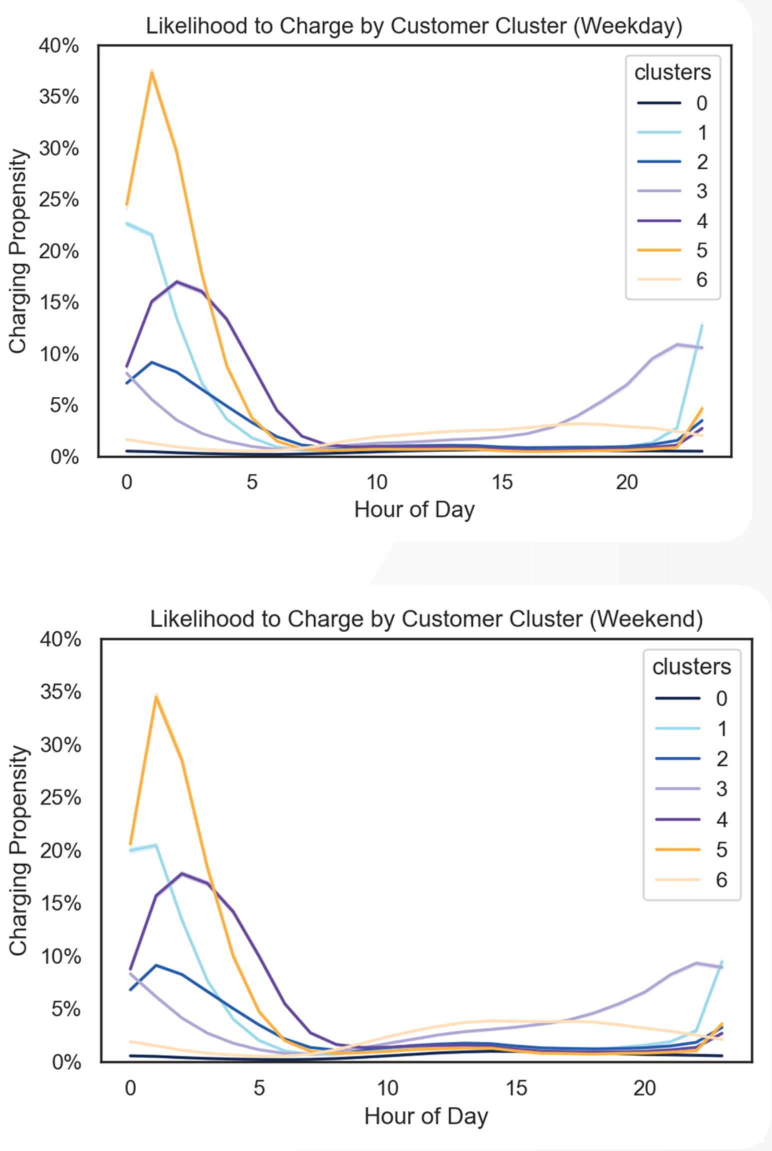
EV charging signals from the load disaggregation analysis were used to identify clusters of similar customer charging behaviors and common charging trends. The first step calculated average charging behavior for each hour of the of the day for both weekdays and weekends utilizing the charging peaks calculated in the previous step. We then determined each customer's likelihood of charging during a given hour-long window by dividing the number of charging sessions during which the customer charged by the total number of day-type/hour time periods throughout the customers' AMI history for each day-type/hour time period. These proportions were used as inputs to an unsupervised machine learning model to determine clusters of similar charging patterns.

Several unsupervised clustering approaches including DBSCAN, OPTICS, and other algorithms were assessed and tested, and finally selected k-means unsupervised clustering with seven distinct clusters was designated as the final approach. The k-means approach was selected because it was best able to distinguish between more than two separate clusters, or one cluster and an "other" cluster. K-means involves dividing up the customer population into several different clusters, and then grouping customers based on their distance to cluster means.

Using the k-means approach, different parameter values were further tested within the approach to find clusters of customers exhibiting similar charging propensities at similar times of the weekday/weekend. After multiple rounds of evaluation to find a balance between the variability within each cluster (an output of the k-means clustering process) and the interpretability of each cluster's behavior patterns (i.e., we sought to identify distinct customer charging patterns without just further differentiating very similar customers), relying on a technique known as the "elbow method" to narrow down the range of potential cluster options. The elbow method is described in additional detail in Appendix H. The elbow method and visual analysis of charging behaviors suggested that we should select seven final clusters for this study.

The final distribution of clusters, shown in Figure 20, revealed that four customer clusters (1, 2, 4, 5) have largely overnight charging behavior (with varying likelihoods in a given hour), two customer clusters are more frequent peak period chargers (3, 6), and a seventh customer cluster has a consistently low charging propensity across all 24 hours of the day (0). The variability within the overnight charging clusters primarily derives from differences in maximum charging propensities (between 10% and 40%); however, there is also variability in the timing of the propensity peak, or the time at which the relevant customers are most likely to charge by an hour or two. Within the peak period chargers, one cohort (6) has a relatively consistent likelihood to charge throughout most of the afternoon and early evening, while the other cohort (3) appears to begin their charging later in the afternoon, with a much higher propensity to charge in the early evening. The final cluster shows an overall low propensity to charge (<5%) regardless of the time of day.

Figure 20. PG&E EV Customer Clusters



Additional information about each EV owner present in our analysis from the CFR and PG&E EV rate databases and customer data from the conjoint survey for respondents that were also present in the clustering analysis was leveraged to further describe the common characteristics of each cluster and understand the underlying drivers behind each cluster's charging patterns. Common customer characteristics were grouped into clusters and these groupings are summarized in Figure 21. Please see Appendix H for more detailed figures that depict cluster characteristics.

Figure 21. Common Customer Charging Profiles

Overnight Chargers

(Clusters 1,2,4 and 5)
28% of Customers

More likely to:
- Be on an EV rate
- Program their charger to charge at specific times
- Own a BEV
- Own a smart level 2 charger

Variable and Low-Level Chargers

(Cluster 0)
52% of Customers

- Less likely to:
  - Be on an EV rate
  - Program their charger to charge at specific times
  - Own a BEV
- Highest incidence of Level 1 chargers
- Lowest average demand when charging

Peak Period Chargers

(Clusters 3 and 6)
20% of Customers

- Less likely to:
  - Be on EV rate
  - Program their charger to charge at specific times
- Group 3 has the highest likelihood of owning a BEV
- Group 6 has a lower likelihood of owning a BEV and a higher likelihood of owning a Level 1 charger

28% of EV owners are "overnight chargers," who could be targeted to mitigate distribution system impacts in areas with high EV adoption. Overall, clusters 1, 2, 4, and 5 all exhibited similar charging patterns that involved a higher propensity, or likelihood, to charge overnight (specifically between 12:00 a.m. and 5:00 a.m.), as well as a low propensity to charge their EV during the day or early evening. These customers are more likely to be on an EV rate and program their charger to charge at specific times of day, which likely explains why these customers are charging overnight. Cluster 1 is unique in comparison to the other three clusters in that there is a higher propensity of charging during the 11:00 p.m. hour (approximately 10% likelihood). This could be due in part to a higher incidence of the historical time-of-use (TOU) rate across the customer AMI data; where the cost of electricity was cheaper beginning at 11:00 p.m. as opposed to 12:00 a.m. with the most recent TOU and EV rates. Collectively, customers in these clusters will be important to target if overnight timer peaks become a concern for the distribution system.

52% of EV owners are "variable and low-level chargers" and would be poor targets for EV DR programs. Cluster 0 demonstrates a low propensity to consistently charge at any given hour of the day. This group had the highest percentage of customers who charge using an L1 charger, and they were more likely to own PHEVs. Furthermore, the low overall propensity to charge of cluster 1 is likely due to a combination of lower overall charging demands (as shown by the higher proportion of customers charging at 2.8 kW, the lowest demand value we could use for modeling and clustering). These three characteristics (low propensity to charge consistently, high incidence of L1 charger use, and low propensity to charge overall) mean that not only was it difficult to disaggregate the EV charging load due to the lower overall demand PHEVs and L1 charging infrastructure place on the grid in comparison to other household appliances, but also that these customers are unlikely to provide consistent resource potential for future DR events.

20% of EV owners are "peak period chargers" and would be good targets for DR efforts designed to curtail consumption during the resource adequacy window. Clusters 3 and 6 have the highest likelihoods to charge during the key resource adequacy window of 4:00 p.m. to 9:00 p.m. Cluster 3 shows a moderate likelihood to charge across most hours of the day, with specific focus on the late afternoon and evening time periods. Cluster 6 shows a moderate propensity to charge during daylight hours between 9:00 a.m. and 12:00 p.m., with an increased propensity on weekends. Logically, these customers are less likely to be on an EV rate and program their charger to charge at specific times. We can surmise that these customers charge during peak periods because they are not as driven by rate price signals. Overall, customers in this group constitute 5% (cluster 3) and 15% (cluster 6) of the overall modeled accounts. The high proportion of BEVs and low frequency of L1 charging infrastructure present for cluster 3 customers could, in combination, make cluster 3 customers especially good targets for peak load reduction. Given the charging profiles and customer characteristics, we would prioritize targeting customers in cluster 3 for the greatest immediate impacts for a future EV DR offering, then proceeding to target customers in cluster 6 for future peak load reduction.

4.2.3 RESOURCE POTENTIAL METHODS AND RESULTS

The final step in calculating resource potential is combining the results of the clustering analysis with the event performance values obtained during the field test. To do this, the charging propensity values were first multiplied by the customer-specific predicted infrastructure power draw, as estimated during the disaggregation process, to generate an expected demand per customer for each day type/hour combination. This expected demand was further adjusted using the DR event "performance rate" estimated from the field test. A performance rate accounts for imperfect event performance and provides a more realistic estimate of expected demand shed if these customers were to participate in actual DR events. The performance rates were calculated by comparing the potential load shed during an event to the actual load curtailment.[37] The performance rate was used to adjust the expected resource potential to account for departures from expected charging behavior, event opt-outs, and other conditions that would prevent a 100% demand reduction during a DR event. This performance rate adjustment was made at the cluster and weekday/weekend level to produce a final per-customer estimate of demand across a weekday/weekend 24-hour day were an event to be called (Figure 22).

We recognize that the field test study was not designed to be representative of the broader population of EV owners in PG&E service territory and there is error associated with applying the performance rate from the field test to the customer-level resource potential estimates. However, the field test results reflected the best estimates of EV DR performance available to us at the time of this study. Each of the vendors also noted that the DR event performance from the field test aligned with their expectations based on how their technology has performed with other programs.

The per-customer maximum EV DR resource potential estimates ranged from 0.05 kW to 0.08 kW (averaged across all hours of the resource adequacy window) (Figure 23, Table 11) and from 0.21 kW to 0.26 kW per customer (averaged across all hours of the overnight window) (Figure 24, Table 12). These values greatly vary by cluster. Cluster 5, for example, has an expected per-customer demand of 2.0 kW–2.5 kW during the overnight window; whereas, the overall average is 10%–15% of this demand. Similarly, during the resource adequacy window, clusters 6 and 3 show a much higher average per-customer demand than the remaining clusters, indicating that the specific mix of customer profiles will greatly influence the variability of the expected demand from future EV DR offerings.

Figure 22. Per Customer Resource Potential Estimates

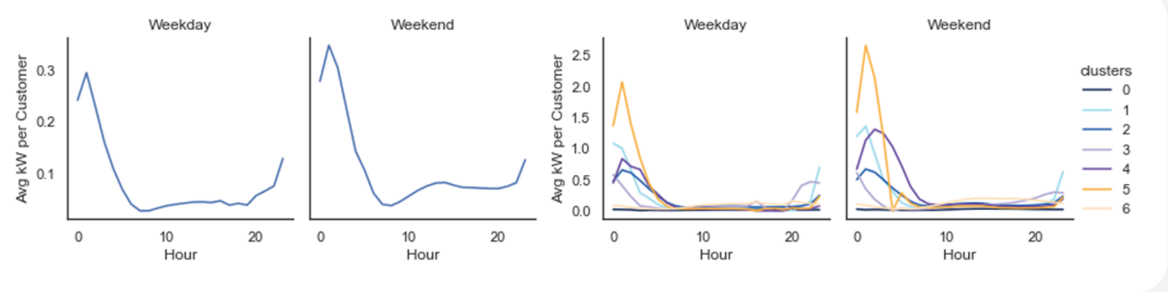
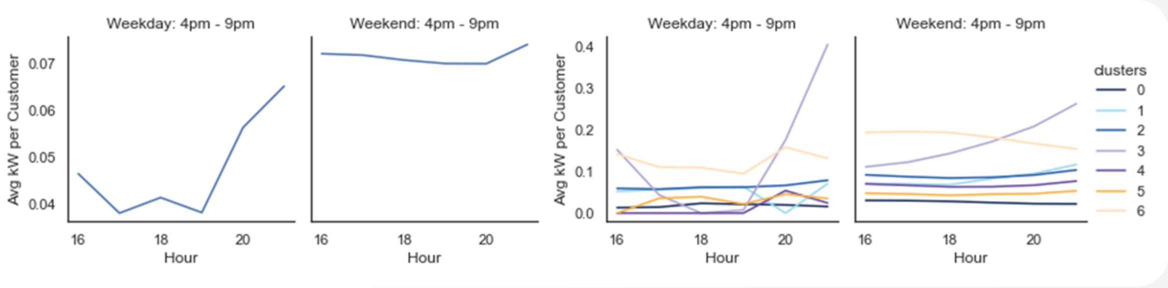


Figure 23. Per-Customer Resource Potential Estimates (Resource Adequacy Window)



[37] The specific event-level performance rates are described further in Section 3.5.

Figure 24. Per-Customer Resource Potential Estimates (Overnight Window)

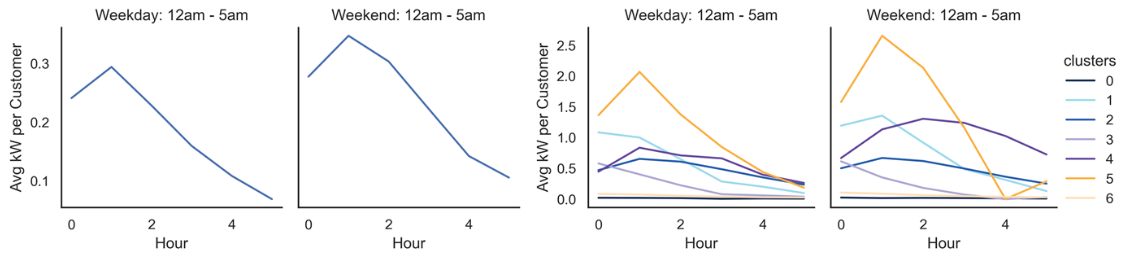


Table 11. Resource Adequacy Window Per-Customer Demand

Day Type	4 p.m. (kW)	5 p.m. (kW)	6 p.m. (kW)	7 p.m. (kW)	8 p.m. (kW)	Average (kW)
Weekday	0.0495	0.0401	0.0430	0.0397	0.0603	0.0465
Weekend	0.0768	0.0767	0.0752	0.0745	0.0752	0.0757

Table 12. Overnight Window Per-Customer Demand

Day Type	12 a.m. (kW)	1 a.m. (kW)	2 a.m. (kW)	3 a.m. (kW)	4 a.m. (kW)	Average (kW)
Weekday	0.2497	0.2965	0.2297	0.1588	0.1078	0.2085
Weekend	0.2894	0.3509	0.3038	0.2217	0.1410	0.2614

We aggregated and extrapolated per-customer demand estimates to the current PG&E EV customer population of approximately 366,000 customers to determine the full 2021 resource potential of an EV DR program.

We used three different extrapolation techniques to scale up estimates of EV DR resource potential from the 71,000 customers in our study to the current population of 366,000 EV owners in PG&E service territory.

1. **Simple Scaling:** We scaled the existing 71,000 customers from the modeling dataset to the larger 366,000 customer total, by multiplying the existing per-customer average by 366,000 to get the total resource potential under full participation.
2. **BEV and PHEV Distribution Adjustment:** The relative proportion of BEVs to PHEVs in the CFR databases is 80% BEVs to 20% PHEVs and the proportion in our database of 71,000 EV owners used for the analysis was 60% to 40%. The underrepresentation of BEVs in our analysis could potentially result in an underestimate of the EV DR resource potential, as BEVs have larger batteries, with longer charge times and therefore we can surmise that BEV owners would be more likely to have L2 chargers with higher power draws compared with PHEV owners which are assumed to have a higher likelihood of owning L1 chargers. This under-representation was corrected for in the second extrapolation technique by computing average customer demand for BEV and PHEV customers independently across all 71,000 modeled customers, then adjusting this balance from a distribution of approximately 60% to 40% in the sample to 80% to 20% (BEV to PHEV, respectively) to better represent the likely composition of all PG&E EV customers and their respective vehicle types.
3. **Conjoint Survey Cluster Distribution Adjustment:** The relative proportion of customers in each cluster varied between the modeling dataset and the customers we could map from the conjoint study. Given that the conjoint survey data was comprised of a random sample of EV owners in PG&E service territory, we believe the distribution of customers in each cluster from the conjoint study is more representative of the overall PG&E customer population. For the third extrapolation method, the customer distribution across clusters was adjusted in the analysis to reflect the distribution in the conjoint survey data and also applied the BEV/PHEV distribution adjustment described in the BEV and PHEV Distribution Adjustment above.

The BEV/PHEV distribution and conjoint survey cluster distribution adjustments each resulted in progressively higher estimates of overall demand, which suggests the existing sample used for modeling could be an underestimate of true resource capacities.

The extrapolations to all 366,000 EV owners in PG&E service territory show a peak of 21–22 MW on weekdays and 26–29 MW on weekends during the resource adequacy window of 4:00 p.m. to 9:00 p.m., as well as an overnight peak demand of approximately 108–119 MW on weekdays and 127–140 MW on weekends (Figure 25, Figure 26, and Table 13). These results assume that all 366,000 customers would enroll in an incentive program for EV ADR control technologies; however, the conjoint study indicated that some customers are unlikely to participate regardless of incentive levels, so these results are likely to represent the upper estimate of potential demand.

Figure 25. Resource Potential Extrapolations with Perfect Participation (Resource Adequacy Window) (n= 366k)

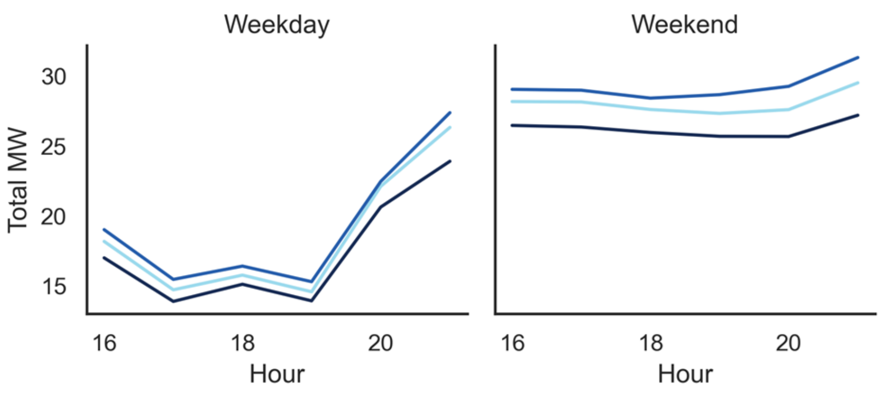


Figure 26. Resource Potential Extrapolations with Perfect Participation (Overnight) (n=366k)

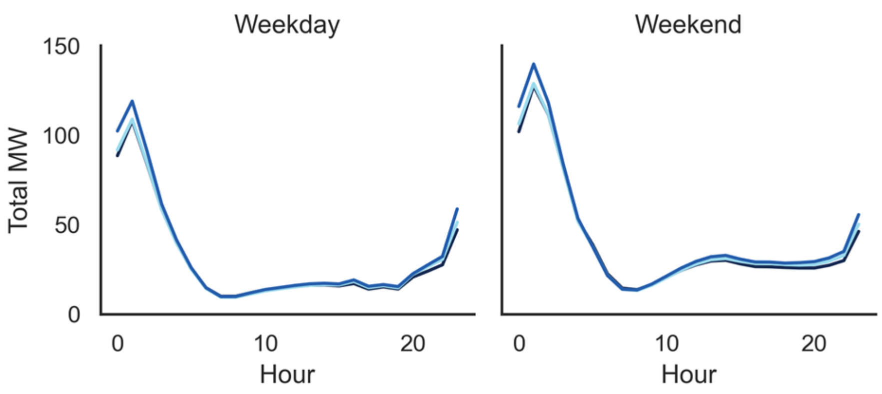


Table 13. Maximum Resource Potential Estimates (with per-Customer values) by Extrapolation Method Only

Time Period	Day Type	Simple Scaling	BEV vs. PHEV Scaling	Cluster and BEV vs. PHEV Scaling
Overnight (12 a.m.–5 a.m.)	Weekday	108 MW (0.29 kW)	109 MW (0.30 kW)	119 MW (0.32 kW)
Overnight (12 a.m.–5 a.m.)	Weekend	127 MW (0.35 kW)	129 MW (0.35 kW)	140 MW (0.38 kW)
Resource Adequacy (4 p.m.– 9 p.m.)	Weekday	21 MW (0.06 kW)	22 MW (0.06 kW)	22 MW (0.06 kW)
Resource Adequacy (4 p.m.– 9 p.m.)	Weekend	26 MW (0.07 kW)	28 MW (0.08 kW)	29 MW (0.08 kW)

Finally, we adjusted the final resource potential estimates to reflect the conjoint survey result that approximately 45% of EV owners who own L2 chargers would be willing to participate in an EV DR program at an incentive level of $50 for a program with events called during the resource adequacy window and 29% of EV owners who would be willing to participate with events called overnight (as shown in Figure 27, Figure 28, and Table 14). These results represent a more realistic expectation of program demand potential given likely enrollment and participation rates and subsequently, drastically lower values.

Figure 27. Resource Potential Extrapolations with Observed Participation (Resource Adequacy Window) (n= 366k)

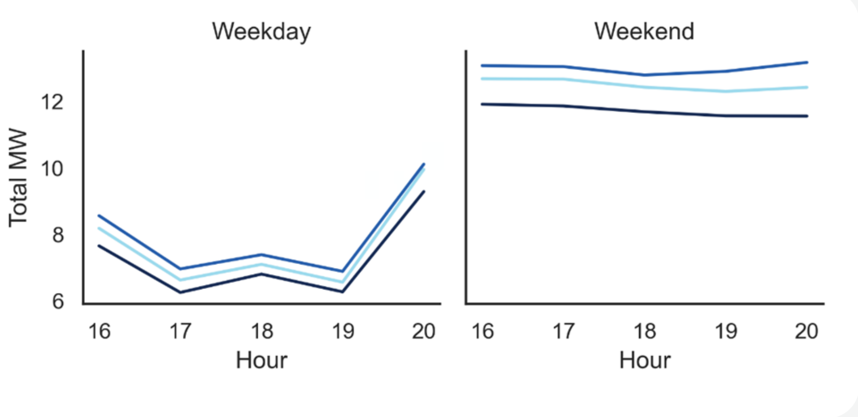


Figure 28. Resource Potential Extrapolations with Observed Participation (Overnight) (n=366k)

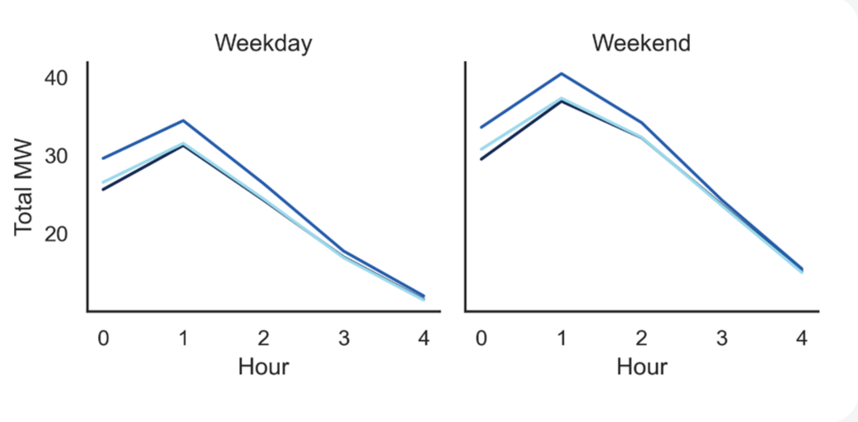
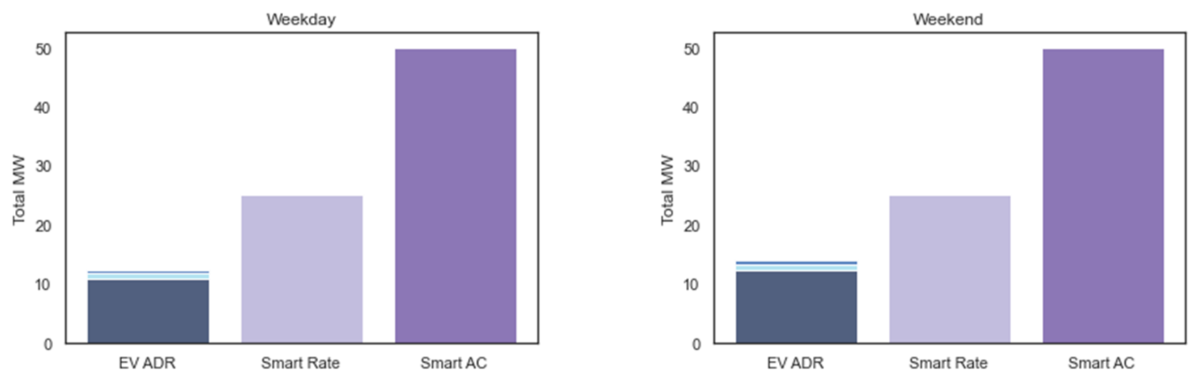


Table 14. Maximum Resource Potential Estimates (with Per-Customer values) by Extrapolation Method with Observed Participation (n=366k)

Time Period	Day Type	Simple Scaling	BEV vs. PHEV Scaling	Cluster and BEV vs. PHEV Scaling
Overnight (12 a.m.–5 a.m.)	Weekday	31 MW (0.29 kW)	32 MW (0.30 kW)	34 MW (0.32 kW)
Overnight (12 a.m.–5 a.m.)	Weekend	37 MW (0.35 kW)	37 MW (0.35 kW)	40 MW (0.38 kW)
Resource Adequacy (4 p.m.– 9 p.m.)	Weekday	9 MW (0.06 kW)	10 MW (0.06 kW)	10 MW (0.06 kW)
Resource Adequacy (4 p.m.– 9 p.m.)	Weekend	12 MW (0.07 kW)	13 MW (0.08 kW)	13 MW (0.08 kW)

Figure 29. Comparison of EV DR Potential to Existing PG&E Programs (Resource Adequacy Window)



The maximum resource potential for EV ADR control technologies is 9 MW to 13 MW during the 4:00 p.m. to 9:00 p.m. resource adequacy window and 31 MW to 40 MW during the 12:00 a.m. to 5:00 a.m. overnight window (Table 14) based on a customer population of 366,000 current EV owners in PG&E service territory. This analysis was based off driving patterns and EV adoption in the summer of 2021 and several assumptions went into these estimates. For example, future EV adoption is projected to increase and driving patterns may change when the COVID-19 pandemic recedes, both of which would likely increase the DR resource potential. Moreover, these estimates leverage performance rates from the field test study which was not designed to be representative of the broader population of EV owners in PG&E service territory. Nevertheless, these resource potential estimates can help inform future decision-making for EV DR program offerings. The peak period resource potential is equivalent to approximately 50% of PG&E's current SmartRate resource potential (25 MW) and 25% of the current SmartAC resource potential (50 MW), at an incentive level of $50 per enrollment (Figure 1). As most EV owners charge during off-peak periods, EV DR resource potential for the overnight period from (12:00 a.m. to 5:00 a.m.) is on par with or higher than the SmartAC and SmartRate programs.

The resource potential for EV control technologies will likely grow rapidly in the next decade. It is important to note that the resource potential for the SmartAC and SmartRate programs may grow marginally over time as demand for AC increases. In contrast, PG&E has a goal of supporting more than two million EVs by 2030, which is a five-fold increase from the 366,000 EVs currently on the road in PG&E service territory.[38] Uncertainties about how this adoption will occur make it impossible to accurately extrapolate our current resource potential estimate to two million customers. We believe that our estimate likely represents a lower bound of expected resource potential as we can expect the share of PHEVs in the population to decrease and the share of BEVs to increase in the future. Moreover, the new EV models that will be in the next few years are projected to have larger power electronics onboard the vehicles, more advanced battery management systems, and larger batteries with longer sustained power draws, which will likely motivate customers to purchase higher power charging infrastructure. Together, these factors will likely cause EVs to have higher instantaneous power draws in the future, which would increase the EV DR resource potential.

KEY CONSIDERATION

As a next phase of this study, PG&E may want to consider leveraging the clustering analysis and resource potential assessment to better understand the distribution system impacts of EV charging. As EV penetration increases, high densities of overnight chargers clustered in the same area could pose potential risks to the distribution system. Conducting an additional analysis that examines the resource potential results by customer address to better understand how the resource potential is distributed across PG&E service territory could help PG&E inform distribution system planning.

[38] PG&E. "Clean Transportation." *Plan of Reorganization Commitments: Customers and Communities.* Last modified October 30, 2020.

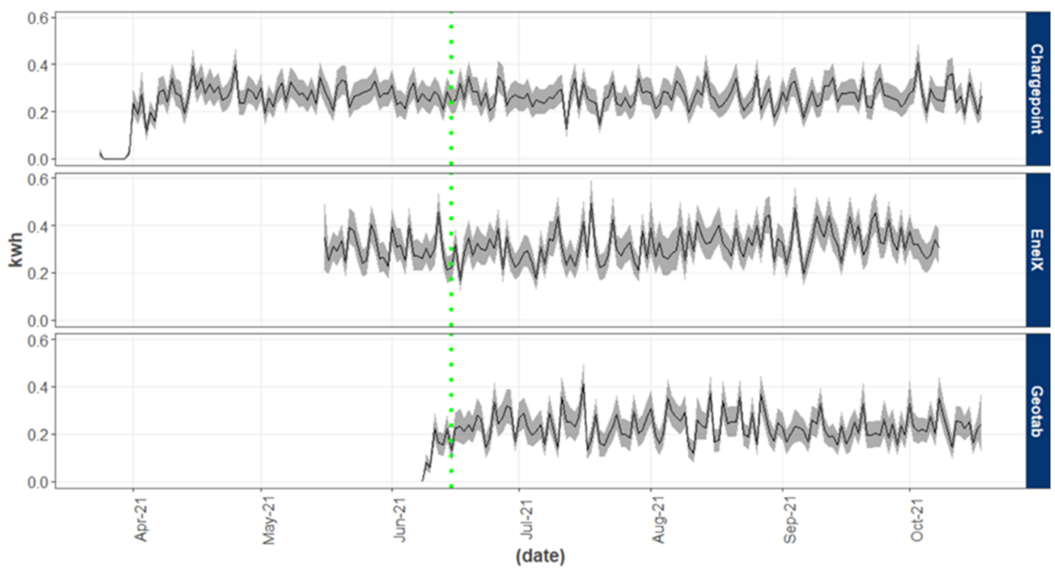
The Opinion Dynamics Team synthesized results across all research efforts to identify key market and customer insights that further contextualize the results from this study and will help PG&E to develop a future EV DR program. We summarize these insights in the following section.

5.1 COVID-19 IMPACTS

The Team competed this study from 2020 to 2021 when the COVID-19 pandemic had widespread impacts on California residents' lifestyles. The Team explored the impacts of COVID-19 on the driving and charging patterns of field test participants and EV owners to understand how pandemic-induced changes may have affected study results.

Americans overall, and residents of the Bay Area in particular, have considerably reduced the amount of mileage they drive as a result of the COVID-19 pandemic. Data from INRIX, a global mobility platform, indicates that vehicle miles traveled for the Bay Area dropped steeply to 40% of normal levels at the start of the COVID-19 pandemic, then rebounded to 70% of normal levels in July 2020 and generally held constant from July 2020 to March 2021.[39] Figure 30 shows that EV charging patterns for field test participants remained constant throughout the study period, indicating that COVID-19 induced impacts on driving patterns have likely continued to remain stable. Utility program managers also noted that COVID-19 has caused EV owners in their program to drive less, which diminishes the resource potential associated with managing EV charging.

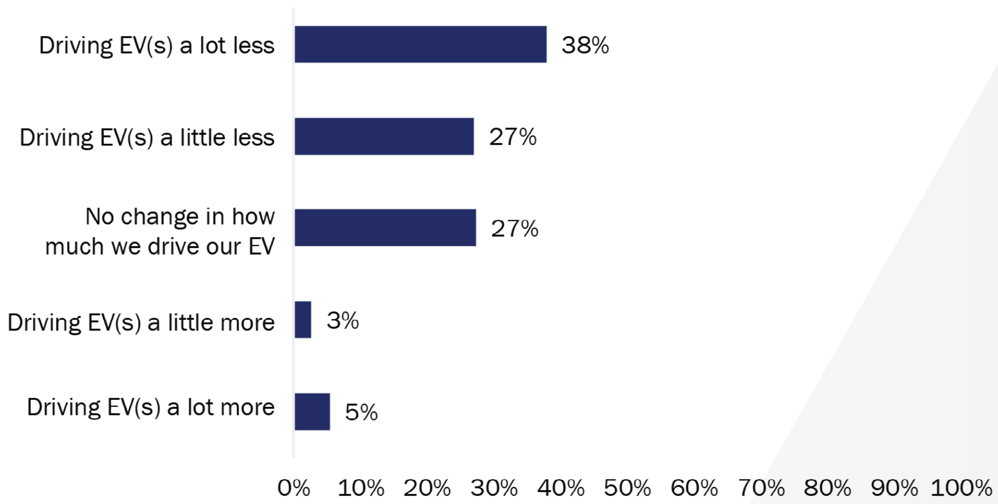
Figure 30. Field Test Participant Charging Patterns (April 2021 to October 2021)



Results from the customer preference survey of PG&E EV owners generally indicates that the pandemic caused customers with EVs to drive fewer miles and charge less, and market data indicates Bay Area EV owners are unlikely to return to their pre-pandemic driving levels. Most surveyed EV owners who purchased their EV before the pandemic (65%) reported the pandemic caused them to drive their EV less (Figure 31). This group of pandemic-impacted EV owners most frequently reported that they have been commuting to work less often during the pandemic (Figure 32). A recent survey indicated that most Bay Area employers only expect to require their employees to commute to the office two to three days per week even after the pandemic ends.[40] This could indicate that some level of reduced driving patterns may persist over time.

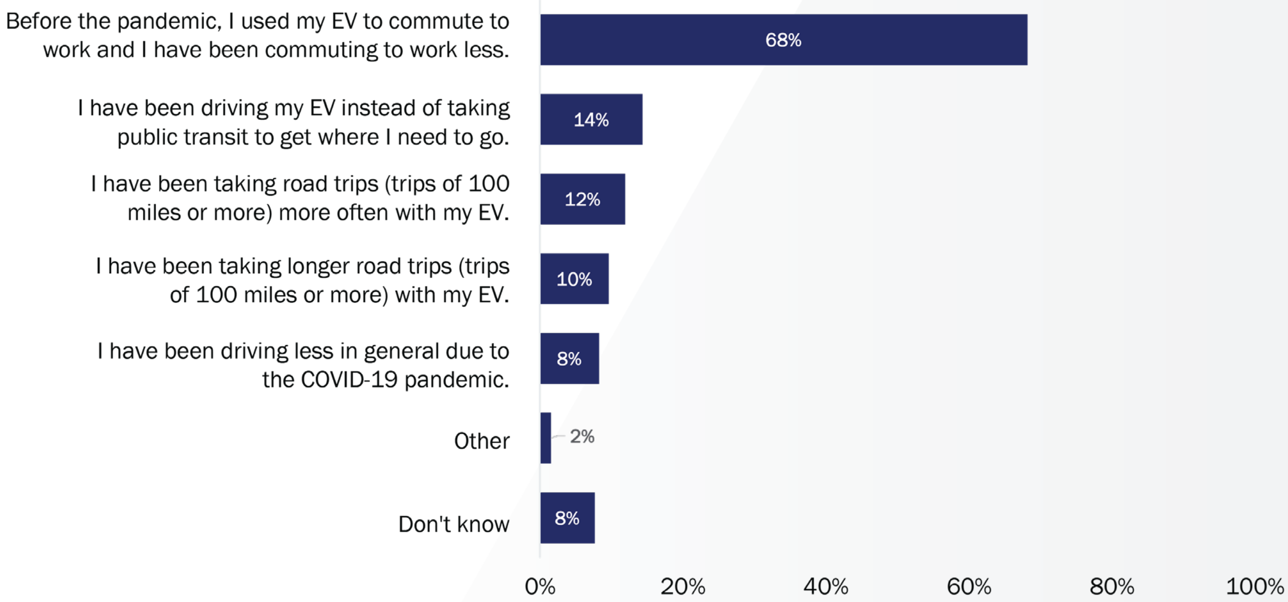
[39] Savidge, Nico. "Chart: Five Ways COVID Changed Bay Area Traffic." *The Mercury News.* March 8, 2021.
[40] Cowan, Greer. *Bay Area Council Employer Network: Return to Transit Tracking Poll.* August 4, 2021.

Figure 31. COVID-19 Pandemic Impacts on Vehicle Miles Traveled Per Week (n=2,524)



Notes: Respondents who purchased their EV after May 2020 were asked, "To what extent has the pandemic affected the number of miles your household drives your EV(s) in a typical week?"

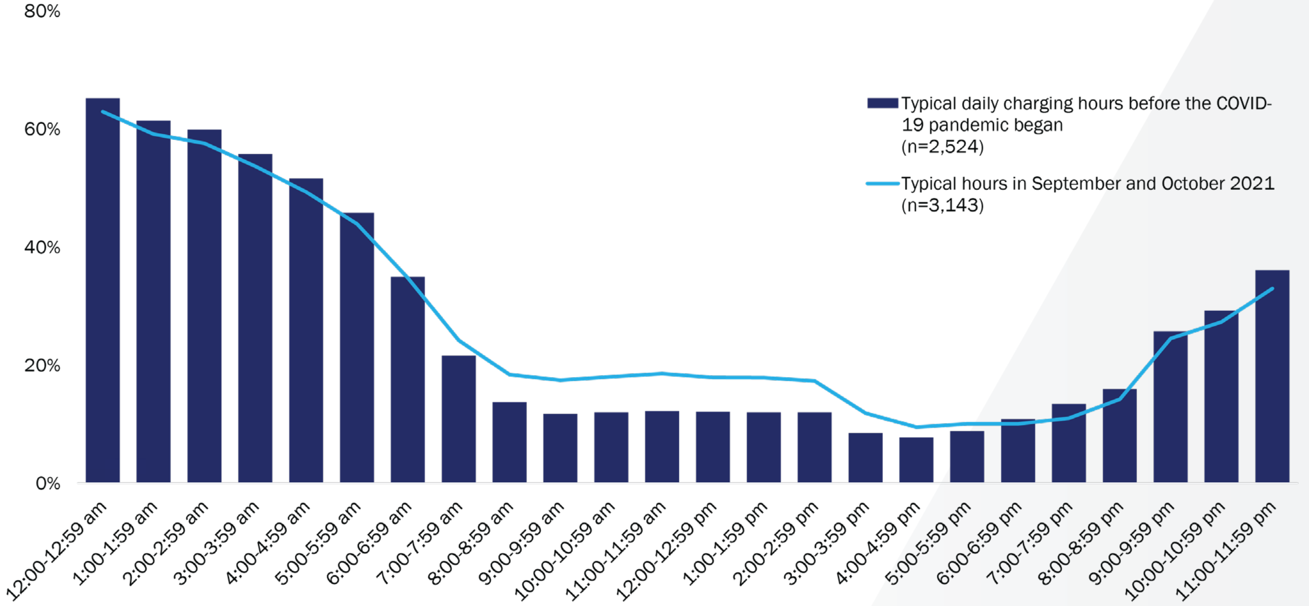
Figure 32. COVID-19 Impacts on EV Owners' Driving Habits (n=1,839)



Though the pandemic has impacted how much PG&E EV owners drive, it has had a limited impact on their daily charging schedules. Comparisons of EV owners' self-reported pre-pandemic and current daily charging schedules reveal that charging patterns for these two time periods remain consistent for the hours from 4:00 p.m. to 8:00 a.m. However, more EV owners are currently charging during the middle of the day from 9:00 a.m. to 4:00 p.m. in comparison to before the pandemic (Figure 33). We assume that at least some survey respondents were likely thinking about the hours their vehicle was plugged in or scheduled to charge rather than the hours their vehicle was actually charging when they answered the survey question, which can help explain why respondents' self-reported daily charging schedules held constant even though they reported driving less. A recent SEPA report analyzed COVID-19 impacts on EV driving patterns across several vendors and found that EV owners' charging patterns were more distributed throughout the day and the average duration that EVs remained plugged in increased while residents worked from home during the pandemic.[41] This aligns with the finding that more PG&E EV owners reported charging during the middle of the day during the pandemic. Notably, these extended plug-in times have enabled some utilities, including Silicon Valley Clean Energy, to have greater flexibility to align customers' charging schedules with grid needs.

[41] Smart Electric Power Alliance (SEPA). The State of Managed Charging in 2021. November 2021.

Figure 33. PG&E EV Owners' Self-Reported Pre-Pandemic and Current Hourly Charging Patterns



Field test participants also reported that COVID-19 caused them to drive less, in some cases permanently. Overall, most interviewed field test participants reported the pandemic caused them to drive less because they were commuting less. Two respondents reported that although they were commuting less, they were also driving longer distances, for example driving to a vacation rather than flying. Some participants anticipate that driving activity will return to pre-pandemic levels at some point, while others believe that their current charging patterns are unlikely to change.

When considered holistically, these results indicate that EV resource potential in terms of average load reduction potential per customer is unlikely to return to pre-pandemic levels soon. The Team completed this study after driving patterns stabilized in April 2021. Because driving patterns have stabilized for the time being, we did not adjust study results to address COVID-19 impacts. We recognize, however, that the COVID-19 pandemic is ongoing and continues to impact Californians' lifestyles and travel patterns, which could impact the generalizability of study results to future time periods.

The pandemic has caused more EV owners to permanently work from home and these owners may be more amenable to charging their car during the middle of the day. Given, challenges with the midnight peak load, this provides further evidence that PG&E may want to explore opportunities encourage EV owners to charge during the middle of the day.

5.2 PSPS, FIRE RISK, AND RESILIENCY

A PSPS occurs in response to severe weather that increases likelihood for wildfires. During a PSPS, PG&E will remotely turn off power to customers in fire prone areas to help prevent hazardous conditions from harming communities. PG&E customers are notified of potential PSPS events in their area through automated calls, texts, or email alerts starting two days before the shutoff (if possible) and each day until power is restored. As noted in Section 3.3, DR events were not called if there was a risk of a PSPS or Red Flag warning as a precaution to ensure field test participants would have fully charged vehicles if they needed to evacuate.

The autumn climate change-induced fire risk in California is projected to grow over time.[42] Consequently, PG&E may want to consider developing solutions that enable them to call DR events when there is a risk of PSPS while still protecting EV owners' safety. These solutions could include encouraging EV owners to pre-charge before a PSPS, deploying V2G technologies, and calling DR events in a way that doesn't fully curtail charging.

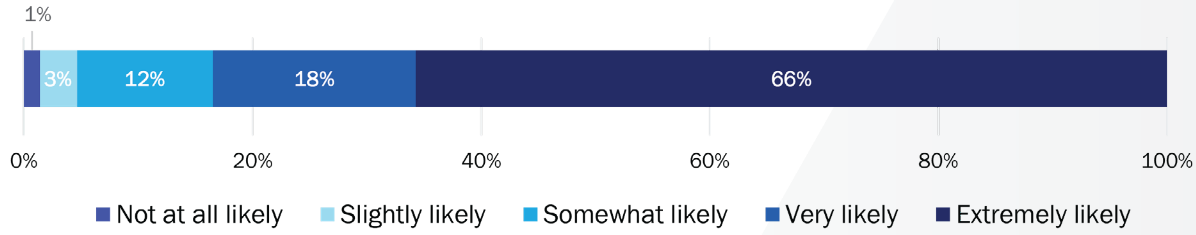
[42] Michael Goss et al. "Climate Change is Increasing the Likelihood of Extreme Autumn Wildfire Conditions across California." Environ. Res. Lett. 15 094016. 2020.

Field test participants have low levels of concern about power outages impacting their EV charging abilities. Only three out of twelve participants reported they were concerned about power outages at their residence impacting their ability to charge, another two reported minor concerns while seven reported no concerns. However, three participants also reported having batteries at their home.

Overall, multiple results indicate that asking EV owners to pre-charge before events may be a potential solution to help them deal with the impacts of PSPS.

Most PG&E EV owners are willing to charge their vehicles before a PSPS event. If provided with advanced notification, 84% of EV owners would be very or somewhat likely to charge their vehicles before a PSPS event (Figure 34).

Figure 34. EV Owners' Likelihood of Charging their Vehicle before a PSPS Event (n=3,080)



PSPS events and concerns about fire risk had little impact on high fire risk zone residents' willingness to participate in managed charging programs. The field test participant interviewees who live in high or extreme (Tier 2 or Tier 3) fire threat areas (n=2) reported being comfortable allowing PG&E to adjust their EV charging during fire season. They also both reported that their EV is their primary evacuation vehicle. One participant stated "Even if I do a busy day of driving, it's still about half-full. And so, if there were an emergency, I've still got plenty of juice to be able to go 20 miles if I need to," while the other emphasized the fact that they had a PHEV and were thus less reliant on their electric motor than if they had a BEV. Both participants also stated they would be willing to charge their vehicle before a PSPS if they received advanced notification, which further supports results from the EV owners survey. One participant referenced a feature on their Tesla Powerwall called a "Storm Warning."[43] When there is a storm warning the Powerwall does not discharge, rather it overrides customers' preset schedules to keep the battery full because it knows that power may be shut off.

In the short run, PG&E should consider developing marketing, education, and outreach strategies to notify EV owners to charge their vehicles ahead of PSPS. In the long run, PG&E may want to consider partnering with vendors to incorporate a PSPS warning system, similar to the Tesla Storm warning into future managed charging programs that would override EV owners' charging schedules to automatically charge their EVs in the hours prior to a PSPS event. This would likely be more feasible to deploy for more mature managed charging programs, when the cost of developing this feature could be spread across many customers.

In the future, vehicle to grid, building, or home (V2X) technologies could allow EV owners to power their homes using their EVs during a PSPS outage. Although V2X technologies are still emerging and not yet available on the market to residential customers, one expert interviewee emphasized that V2X should be an important priority for the industry because of the resilience benefits this technology can provide to customers.

[43] Tesla. "Storm Watch." Power Wall: Mobile App. Last modified January 12, 2022.

Generally, field test participants are interested in the potential opportunity to power their residences using their EV batteries but do not know much about the technology. Eight participants reported they were very interested in the technology. One participant caveated their interest, however, expressing their concern about the infrastructure upgrades the technology may require. Another participant reported that they had never thought about this technology, but had questions about its feasibility:

> *I noticed that with the new Ford truck and I found that very interesting given the situation here in Napa with the fires and the power outages. So, if that was a feasible option that did not require a ton of infrastructure upgrades with the house in terms of powering, the refrigerator and certain key things that that would be a very nice option to have.*

Of the four participants interviewed that were not interested, two cited their battery/Powerwall as the reason they would not need that technology while the other two reported that they never really thought about it.

PG&E plans to develop a residential pilot program targeted at encouraging the adoption of EVs that could provide energy back to customers' homes. These interview findings indicate that PG&E EV owners are likely to be receptive to this type of offering. In addition, PG&E should consider providing residential customers with information and technical assistance to help them understand the types of infrastructure upgrades they may be required to complete to support vehicle to V2X technologies at their home.

5.3 EV OWNERS' EV DR PROGRAM AWARENESS, MOTIVATIONS, PERCEPTIONS OF BENEFITS, AND CONCERNS

EV owners' motivators, as well as their perceptions of the risks and benefits associated with allowing PG&E to adjust their charging, can be important predictors of their willingness to participate in an EV DR program. Overall, findings indicate there is a strong need for marketing, education, and outreach (ME&O) to help EV owners understand the individual and society benefits of allowing PG&E to manage their charging and to ease customer concerns about how a potential future EV DR program would impact them. Overall, these results indicate EV owners have low awareness of EV DR programs and their associated benefits, and they have concerns about allowing PG&E to control their charging. Targeted ME&O efforts can PG&E help address these issues and we provide specific ME&O recommendations throughout this section.

5.3.1 AWARENESS AND KNOWLEDGE OF MANAGED CHARGING PROGRAMS

Most EV owners have never heard of EV DR programs. When provided with a definition of an EV DR program, only 24% of respondents said they had heard of this type of program before taking the survey.[44] Predictably, EV owners that primarily use a smart L2 charger were more likely to have heard of this type of program (30% aware, n=1,093) compared to customers who use a non-Internet-enabled L2 charger (22% aware, n=1,135) or an L1 charger (20% aware, n=914).

In general, field test participants correctly identified PG&E's overarching motivations for conducting the field test. We explored field test participants' knowledge of the purpose behind managed charging by asking them why they thought PG&E conducted the field test. A few participants (three) hypothesized that that PG&E conducted the study to better understand EV owner charging patterns. Three other participants believed the purpose of the study was to understand how to manage distribution of power and prepare for increased EV adoption. Others speculated that it could be to help save customers money (one), find out if new programs supporting EVs worked as expected (one), or understand the needs of EV owners and provide better offerings (three).

[44] Survey respondents received the following question: "Did you know that there are voluntary "demand response" (or, "managed charging") programs in some parts of the country for owners of internet-connected "smart" L2 chargers? Households that agree to participate in these programs receive financial compensation for allowing their utility to remotely adjust their home EV charging station. During DR events, the home EV charger automatically reduces or ceases its charging speed for up to four hours. After the event is over, the EV automatically resumes charging at its normal rate. If needed, participants can adjust their charger back to its normal settings to charge more quickly."

5.3.2 EV OWNERS' MANAGED CHARGING BENEFITS AND MOTIVATIONS

Most EV owners (66%) were not able to identify any benefits associated with allowing PG&E to adjust their EV charging (unaided). EV owners were asked an open-ended question about the benefits they associate with allowing PG&E to adjust their EV charging and most respondents said they either didn't know (38%) or believed there were no benefits (28%). The finding that most EV owners had not heard of managed charging programs prior to taking the survey may help to explain why respondents were unable to identify managed charging program benefits without prompting.

EV owners most frequently associated financial benefits and grid reliability as the benefits associated with allowing PG&E to adjust their charging. Of the 34% EV owners that were able to identify benefits of managed charging unaided, financial benefits and enhanced grid reliability were the most common responses (Figure 35). The financial benefits respondents commonly identified included electricity bill savings and program rebates. Interestingly, some respondents share the misperception that managed charging can be used to prevent PSPS (7%). We further explored which factors would motivate participants to enroll in managed charging program by asking them a close-ended question about their willingness to allow PG&E to adjust their EV charging to achieve different benefits. EV owners' responses provided further indication that respondents most frequently associate financial and grid reliability benefits with allowing PG&E to adjust their charging (Figure 36). Respondents were mostly willing to allow PG&E to adjust their charging to ensure they charged when electricity costs were lowest (82% at least moderately willing), help their community improve grid reliability (73% at least moderately willing), improve the reliability of the electric grid (71% at least moderately willing), and ensure that the cleanest sources were used to charge their EV (66% at least moderately willing).

Figure 35. EV Owners' Perception of Benefits Associated with Allowing PG&E to Adjust their Charging (Unprompted) (n=1,066)

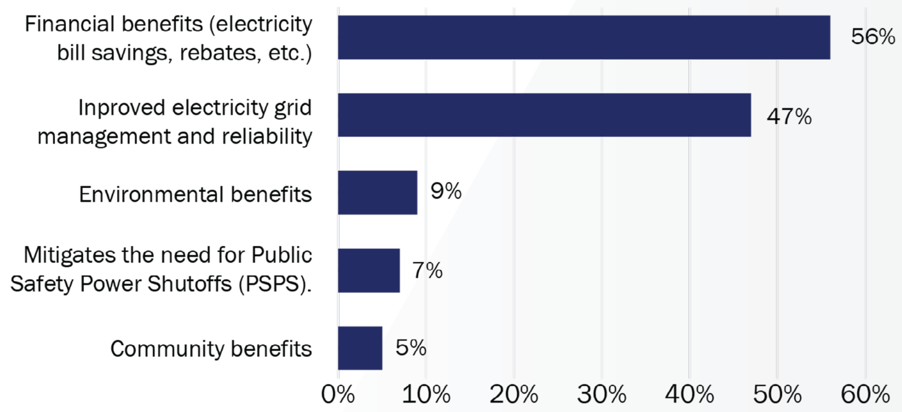
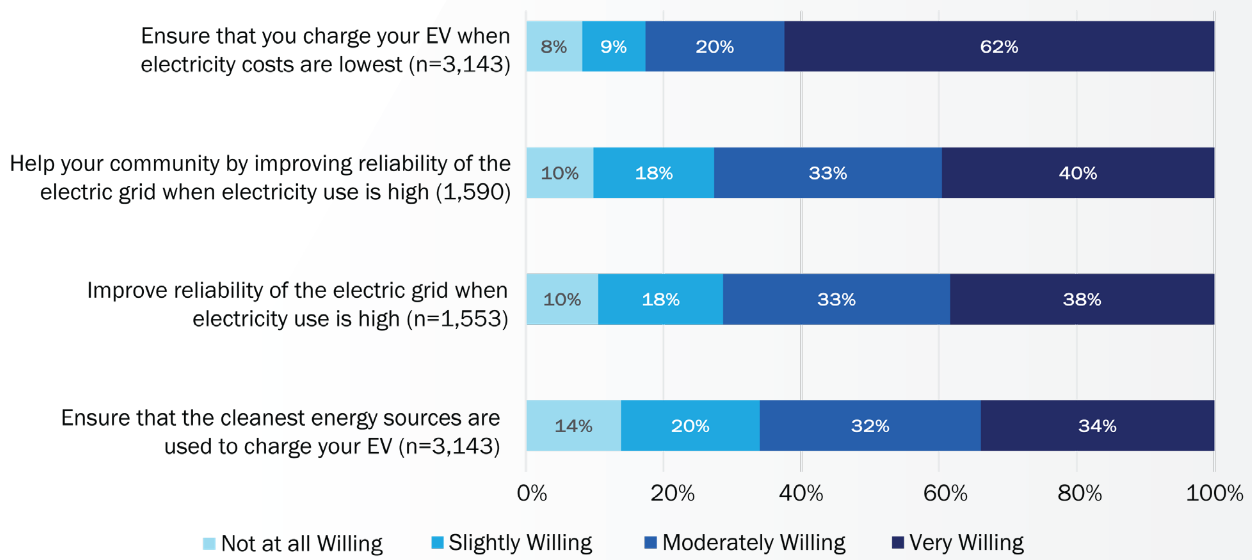
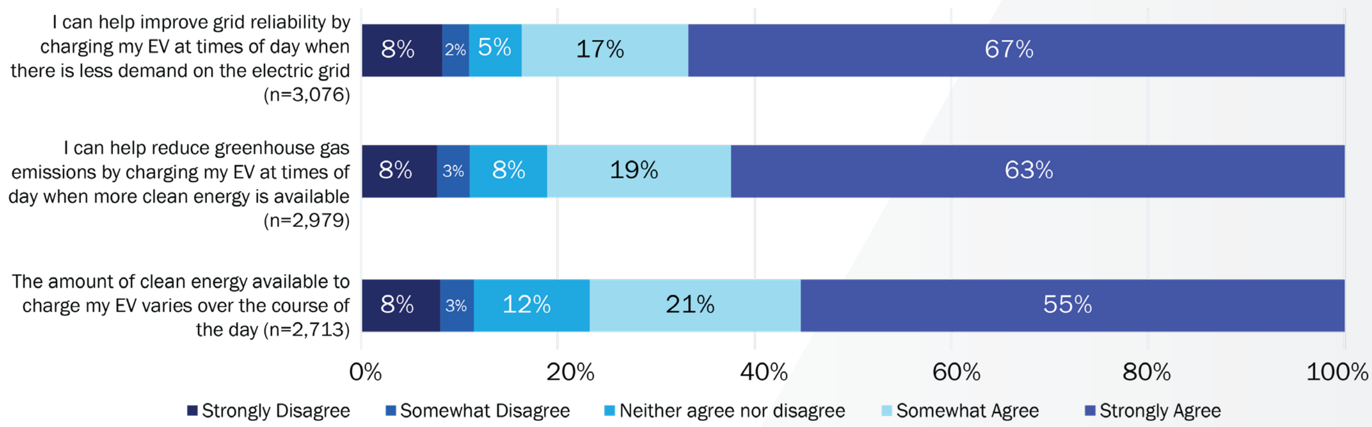


Figure 36. EV Owners Willingness to Allow PG&E to Control their Charging to Achieve Benefits (Prompted)



There are opportunities to educate EV owners about the environmental benefits of allowing PG&E to manage their charging (Figure 37). Existing literature indicates many early EV adopters are motivated to purchase their EVs for environmental reasons.[45] Despite this, only 9% of these respondents associated environmental benefits with allowing PG&E to adjust their EV charging unaided through an open-ended question format. We further investigated EV owners' knowledge of how managed charging can benefit the electricity grid in a close-ended format. This question format further reveals that EV owners do believe there are environmental benefits associated with allowing PG&E to manage their charging. Eighty-two percent of respondents at least somewhat agree that they can help reduce greenhouse gas emissions by charging their car when more clean energy is available; yet, fewer respondents (76%) realize the amount of clean energy available to charge their EV varies over the course of the day. The results indicate that environmental benefits may not be the top benefit that comes to mind when EV owners think about managed charging, but most are able to make the connection when prompted.

Figure 37. PG&E EV Owners' Awareness of Managed Charging Grid Benefits



To further understand perceived benefits associated with allowing PG&E to manage EV charging, we asked field test participants why they decided to enroll in the study.

Field test participants were motivated to enroll to be a good neighbor, receive the incentive, and learn more about the technology. Participants noted they wanted to be good neighbor by helping provide PG&E with data that could be used to make better decisions about EVs (five), they want to receive the $100 incentive/gift card (four), and they had curiosity and interest in the technology (two) and community sustainability goals (one). Four participants identified that the ease of enrolling and participating in the program also contributed to their motivation to enroll.

5.3.3 CONCERNS ABOUT ALLOWING PG&E TO MANAGE EV CHARGING

Most EV owners (61%) were not able to identify any concerns associated with allowing PG&E to adjust their EV charging. On the conjoint survey, we provided EV owners a description of an EV DR program and asked them to identify their biggest concerns with enrolling in this type of program with an open-ended response.

More than half of the respondents did not identify any concerns. Again, the likely explanation for this is that EV owners don't know enough about EV DR to have well-formed opinions about it.

The 39% of EV owners who have concerns about allowing PG&E to adjust their charging are most concerned about giving up control of their EV charging and specifically that their car will not be charged by the time they need to use it. The 1,235 respondents who were able to come up with a concern, were primary worried that their EV would not be fully charged when they needed it, which included concerns around being inconvenienced by this type of program and not feeling fully in control of their own charging. Some EV owners also shared the misperceptions that this type of program may increase the cost for them to charge their car or that the program incentives would not offset the increased costs to charge. Similarly, when we asked all

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[45] Hardman, Scott and Gil Tal. "Exploring the Decision to Adopt a High-End Battery Electric Vehicle: Role of Financial and Nonfinancial Motivations." *Journal of the Transportation Research Board* 2572, no 1 (2016). SAGE Journals.

respondents about their level of concern about aspects of a potential future PG&E managed charging program, most respondents were at least moderately concerned about their car not be charged when needed (66%), allowing someone else to have control over the charger (56%), and disruptions to their usual charging schedule (51%).

Field test study participants also provided similar responses as only 3 of the 12 interviewed participants reported having any concerns about enrolling in the study. Similarly, these participants' concerns were centered on not being able to charge their car when needed. We specifically asked participants if they had concerns about allowing PG&E to control their EV charging overnight and during the day. In general, most participants did not have concerns about allowing PG&E to adjust their charging at either time. Some (two) had no concerns about having their charging curtailed as long as they received advanced notification about the event. Other participants (two) specified that they did not care if their utility curtailed their EV charging overnight if their vehicle would be fully charged when they needed it in the morning. One participant discussed the impact of the billing rate and the price of electricity. As noted in Section 3.5, two participants ended up overriding events because they wanted their car to be charged by a certain time.

Figure 38. PG&E EV Owners' Concerns about Allowing PG&E to Adjust their Charging (n=1,235)

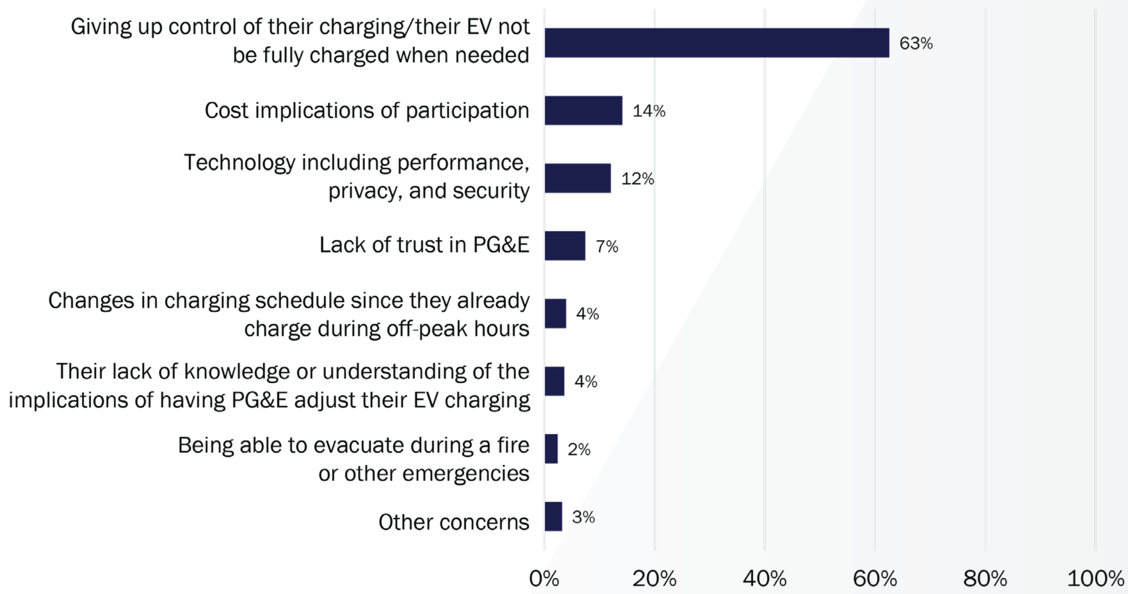
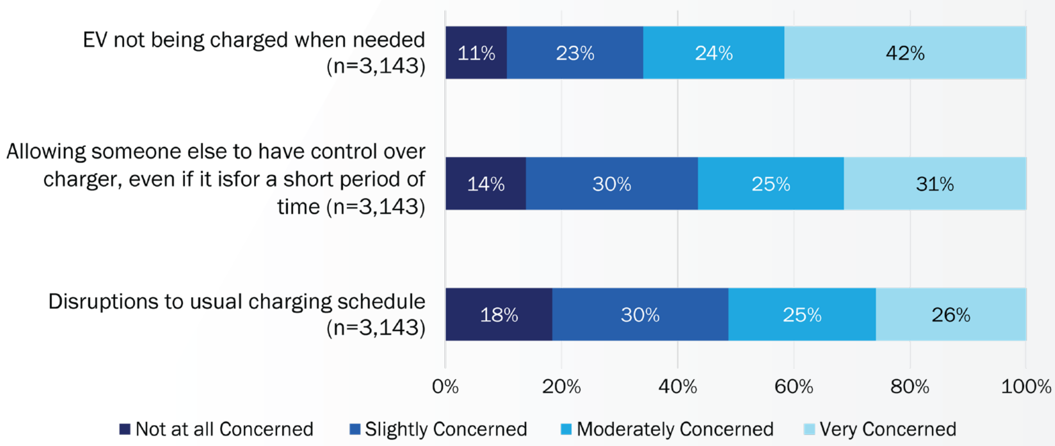


Figure 39. PG&E EV Owners' Concerns about a Potential Future Managed Program (n=3,143)



Note: The question was as follows, if PG&E were to offer a home EV DR program… How concerned would you be about the following… As a reminder… Households that agree to participate in these EV DR programs receive financial compensation for allowing their utility to remotely adjust their home EV charging station. During DR events, the home EV charger automatically reduces or ceases its charging speed for up to four hours. After the event is over, the EV automatically resumes charging at its normal rate. If needed, participants can adjust their charger back to its normal settings to charge more quickly.

KEY CONSIDERATION

These results indicate EV owners could benefit from ME&O efforts designed to educate them about the suite of benefits associated with allowing PG&E to adjust their charging and address their concerns. In particular, helping EV owners realize that (1) The amount of clean energy available to charge their car varies over the course of the day, (2) They can reduce their greenhouse gas emissions by charging when clean electricity is most plentiful, and (3) Allowing PG&E to manage their charging also provides another pathway to help maximize the use of clean energy. These facts could be a beneficial area of focus for future ME&O efforts focused on managed charging. Helping EV owners understand that if they participate in a managed charging program their EV can still be ready when they need it, could also be effective recruitment messaging. As EV owners are navigating a steep technology learning curve, a recent SEPA report recommends providing customer education in the marketing and recruitment phases of a program, technical education after customers enroll, and extending awareness education efforts to non-EV owners. Addressing common managed charging concerns through an FAQ sheet could also help customers see PG&E as a trusted resource for their EV charging needs.

COMMUNICATION PREFERENCES

Field test participants received information about the rationale for the study and notification that PG&E would be curtailing their charging for up to four hours across ten days from June to October 2021. ChargePoint provided advanced notice to the customers ahead of the event; the other vendors did not provide any notice.

The majority of field test participants want to receive an alert before an event. Only one participant reported that they would not like to receive any event notifications. While almost all (ten) reported wanting notification before an event, with some participants reporting that they would want an alert during (six) or after (2) as well. Most participants identified text messages and email as their preferred methods of event notification, while some also mentioned a desire to receive notification through the charger app, text messages, emails, and phone calls.

KEY CONSIDERATION

PG&E may want to provide customers with email, text, or app-based notifications ahead of DR events so that customers are able to recognize when events impact their normal charging patterns or levels. Furthermore, providing messaging in the event notification to assure customers who the events will be minimally impactful can also help to prevent opt outs.

Participants suggested they would like to see increased communication and earlier relationship development if they were to participate in a similar study. One field test participant suggested an additional form of communication that would be useful is something represented on the charger or in the charge port. By providing the information at the charger, customers can decide whether or not to plug in knowing if there is an event or will be an event, without having to check other forms of communication.

5.4 MANAGED CHARGING PROGRAM DESIGN BEST PRACTICES

Utility program managers in in other jurisdictions shared key lessons learned from their experience leading programs. These interviewees report that the biggest pain points for their programs generally occurred during the program set up and contracting process. Thereafter, the programs required minimal effort once they were up and running.

Findings from other jurisdictions suggest the best time to enroll customers in a managed charging program is at the time of sale. Previous studies support this, finding that it was easier to get customers to enroll at the time of purchase rather than after the fact. One utility program representative noted about 75% of customers who purchased a new smart charger, opted-in to DR during the checkout process at the web store. Another utility program manager also noted it is harder to find and engage customers after they have purchased their charger. This program manager ran a program with a multi-step process where customers had to enroll first with the vendor then the utility. Thinking retrospectively, this program manager would have like to develop partnerships with marketplaces like Amazon to offer customers a bundled experience where they could seamlessly enroll in a managed charging program with both the vendor and the utility at one time upon purchasing their charger. Ideally, this marketplace would also sell an add-on service for an electrician to set up the charger at the customer's home and ensure it is connected properly and ready to receive DR signals.

Two customers who participated in the field test would have liked to receive more information about PG&E EV rates and program offerings at the point of sale of the vehicle. When customers purchased their EV they had to learn and make decisions about charging on their own. They noted the point of sale would have been a good time to establish a connection with PG&E and understand more about the vehicle, charging options, and program/study options. One participant noted they wished:

> *If PG&E had some sort of a presence in the way of a pamphlet, or a calling card, or something. Right from the time you drive off the lot, you should know that PG&E wants to get in touch with you and you should want to get in touch with PG&E, so that you don't fumble the first month of owning the car.*

KEY CONSIDERATION

PG&E may want to explore opportunities to enable EV owners to enroll in an EV DR program when they purchase a L2 charger from the PG&E marketplace. Developing partnerships with EV charging vendors and other external marketplaces like Amazon to add EV ADR program enrollment options when customer purchase their charger can also help PG&E reach a larger share of prospective program participants.

5.5 THE PATH FORWARD FOR MANAGED CHARGING

The study team identified several factors both PG&E, and the industry as a whole, will need to consider for optimizing the use of EVs as a grid resource in the next five years. These considerations are especially relevant for activating residential EVs in a more dynamic manner such that they can provide a flexible load resource that is responsive to evolving grid needs.

Determining program eligibility requirements and who gets to control the EV. FERC 2222 and other policy decisions create incentives for companies that provide EV charging control technologies to compete to control customers' EVs,[46] either through the charger directly, telematics, software platforms, or other technologies such as smart panels.[47] As EV penetration and managed charging program enrollment increases, the likelihood of scenarios where a customer enrolls with two different vendors (e.g., one vendor controls the telematics and another controls the charger) or two different managed charging programs also increases. This scenario occurred in this study when one vendor removed customers from this study after the first event and placed them into CAISO. These types of occurrences can result in a poor customer experience, incentive double dipping and sub-optimal managed charging outcomes. Furthermore, several CCAs in PG&E service territory, including Sonoma Clean Power (SCP), Marin Clean Energy, and Peninsula Clean Energy, are currently working with vendors to design and implement EV managed charging programs optimized to balance load in their own jurisdictions. This further creates opportunity for overlap in EV charging controls and conflict over optimization of EV charging resources. PG&E and the entire EV industry will need to address these open questions as EV adoption and managed charging program enrollment scales.

KEY CONSIDERATION

PG&E may want to consider developing a framework or protocol that governs the management of EV resources in PG&E service territory. As this issue spans multiple vendors, energy providers, and government organizations, PG&E may want to consider convening a working group or engaging the existing California VGI working group to support the development of broader policies that address this issue.

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[46] Federal Energy Regulatory Commission (FERC). *FERC Order No. 2222: A New Day for Distributed Energy Resources.* September 17, 2020.
[47] Span. "Charge Your Car Cleaner, Faster, and Smarter. And Even During an Outage." *Span Drive—Span™: A Smarter Electric Panel.* Last modified January 13, 2022.

Holistic program DER designs could maximize the benefits of customer-sided resources. SCP's Grid Savvy program aggregates multiple OpenADR-enabled end uses within a customers' home (e.g., water heater, thermostat, and EV). Most of SCP's EV drivers off-peak and have found that aggregating multiple DR resources along with EVs has helped them to bolster their peak load reductions during DR events and manage the variability associated with each individual resource. Some expert interviewees believe these types of whole-house DR program designs are the way of the future; ideally, the utility could order slight reductions in the end use load in a customer's home and minimize the impact to the customer. Another utility program manager called EV chargers a gateway to electrification, as purchasing an EV often leads to customers to becoming more interested in upgrading to a smart panel and electrifying their home.

CASE STUDY: SONOMA CLEAN POWER GRID SAVVY PROGRAM

SCP Aggregates customers' smart thermostats, HPWHs and EVs

Key Insights:

- There was a high correlation between those who opted into one offering that are also interested in others. With this structure, they could participate with multiple technologies
- SCP was able to market across the technologies through one bundled offering
- The seasonal and daily load shapes of each resource were complementary (chargers are year-round and off peak, thermostats are seasonal, HPWHs provide daily load shift opportunities)
- When aggregated, the three resources helped SCP maximize peak load reductions

Ideally, whole-house program designs like this would allow the utility to adjust the energy consumption of each individual end use slightly and during hours when each might be of greatest value, to the point where the customer may not even recognize the adjustment. This type of approach would also increase the resource potential of each participating customer and help utilities manage the daily and seasonal variations in the load shapes of each individual end use.

PG&E may want to explore future opportunities to combine Smart AC and EV ADR offerings programs along with other emerging residential ADR technologies to enhance the value of each customers' ADR resource while simultaneously minimizing impacts to the customer.

Managing EV charging through vehicle telematics vs. directly through the charger warrants unique considerations. Results from the technology field test revealed solutions that curtail EV charging through the vehicle telematics and through the charger directly are both effective. Results from the market scan revealed several implications of each approach:

- **Reach and cost:** Telematics providers can leverage the existing chargers of all customers who own EVs manufactured by their partner OEMs, whereas charging providers can only control their own smart L2 chargers. For customers who do not already have smart L2 chargers, telematics provides a lower cost solution as customers are not required to upgrade their charger.
- **Data Quality:** Some telematics providers can provide additional data points about the vehicle, including the State of Charge (SOC) of the battery. The SOC variable can provide resource planners with more granular information about the amount of load reduction they can expect to see from each vehicle during a DR event.
- **Fixed vs. Mobile Resources:** EV chargers are a fixed resource, whereas approaches that leverage vehicle telematics are mobile. Vehicle telematics approaches pose complications for utility and grid planning because mobile resources are harder to predict and forecast. GPS-based geo-fencing or other technology solutions could allow PG&E to monitor and manage the locational impact of vehicle telematics-based DR resources.
- **OEM Partnerships:** OEMs ultimately have control over how they design their vehicles and give third parties access to vehicle telematics. Most OEMs are still in an early stage of developing contractual relationships that enable third parties to leverage vehicle telematics for managed charging applications. As such, these third parties may need to adapt to changes in contracting processes and protocols as OEMs gain more contracting experience.
- **Internet:** Smart L2 EV chargers require internet connectivity, whereas some vehicle telematics providers can tap into 5G for communications, which allows them to bypass potential internet outages.

A SEPA report on the State of Managed Charging in 2021 suggests that utilities should partner with vendors that manage EV charging using vehicle telematics and through controlling smart L2 chargers directly because the two approaches are complementary, and together they maximize the number of EVs that utilities have access to.[48]

Utilities in other jurisdictions are beginning to deploy innovative program designs that combine elements of DR and more dynamic price signals and enable them to adjust EV charging in response to real time capacity needs while accounting for customer needs. Our review of existing managed charging programs revealed utilities across the country are beginning to test out more dynamic approaches to managing EV charging designed to manage overnight time peaks, peak period impacts, and other grids needs simultaneously.

[48] SEPA. The State of Managed Charging in 2021. November 2021.

For their Charging Perks Pilot, described below, Xcel is working with OEMs and third parties to optimize participants' charging schedules based on customer preferences and grid needs using a vehicle telematics approach. This type of approach could potentially mitigate customers' concerns about their car being charged when they need it and address both evening peak period and overnight timer peak constraints. Alectra is working with Geotab to test out two managed charging approaches that address dynamic grid needs. The first approach incentivizes customers to charge more often at times when there is excess supply of electricity, and the second program leverages a dynamic rate that asks residential customers to pay different prices for EV charging based on grid needs. Other utilities, such as Baltimore Gas and Electric are exploring which types of signals (gamification, price signaling, direct load control) are most effective for EV DR. At the time publication of this report, these programs were still in the early stages and results were not yet available.

CASE STUDY: XCEL CHARGING PERKS PILOT

- Leveraging vehicle telematics to manage charging for EV models from BMW, Chevrolet, Ford, Honda, or Tesla by partnering with the OEMs directly and a third-party provider (WeaveGrid)
- Xcel is working with their partners to send a signal that will optimize charging schedules based on multiple parameters such as customers' charging preferences, commute times, type of vehicle, state of charge, and 48 hour ahead forecasts of grid needs
- Addressing timer peaks by staggering customers' nighttime schedules, so one groups of customers starts charging at 9pm and another starts at midnight
- Incentives: $100 enrollment gift card and $100 at the end of the program

In the future PG&E may want to investigate opportunities to combine elements of DR and more dynamic price signals to adjust EV charging in response to real time capacity needs while accounting for customer preferences.

6. KEY STUDY CONCLUSIONS

We synthesized results across all research activities to answer the key research questions and recommend a future path forward for incentivizing EV DR technologies.

Overall, the field test results demonstrate that both vehicle telematics and controlling the charger directly effectively curtailed EV charging and the events had minimal impact on participants. All the vendors were able to successfully curtail at least some of the EVs under their control for each event, with stronger performance rates for overnight events in comparison to events called during the resource adequacy window. Furthermore, multiple results indicate the study was not intrusive for customers as customer attrition and opt-out rates remained low throughout the entire study.

EV ADR charging control technology holds promise for mitigating overnight peaks. The highest EV DR load resource potential is between 12:00 a.m. and 4:00 a.m., as the maximum overnight resource potential is between 31 MW and 40 MW when extrapolated to the current 366,000 PG&E EV owners. As EV penetration increases, the high demand levels generated by overnight charging may pose risks to PG&E's distribution system. The field test demonstrated that curtailing EV charging from 12:00 a.m. to 4:00 a.m. resulted in a load shift of up to 601 kWh over the four-hour event period for the group of 212 study participants. As such, partnering with EV ADR charging control vendors to stagger overnight charging could provide a low-cost alternative to investing in distribution system upgrades to support an increased penetration of overnight EV charging in coming years. Furthermore, our clustering analysis results revealed that 28% of EV owners are "overnight chargers," who could be targeted to mitigate distribution system impacts in areas with high EV adoption.

Despite the fact that resource adequacy hours offer less DR value than overnight hours, there is DR value available. The maximum resource potential for EV ADR control technologies is 9 MW to 13 MW during the 4:00 p.m. to 9:00 p.m. resource adequacy window. The peak period resource potential is equivalent to approximately 25% of PG&E's current SmartAC 50 MW resource potential and 50% of the current SmartRate resource potential, at an incentive level of $50 per enrollment. Furthermore, our clustering analysis shows that 20% of EV owners are "peak period chargers" and would be good targets for DR efforts designed to curtail consumption during the resource adequacy window. This potential will continue to grow as PG&E is projected to have two million EVs by 2030.

PG&E should consider investigating opportunities to encourage customers to charge during the middle of the day. PG&E's load management objectives currently reflect system-wide and local capacity area load shed; however, moving forward, load shift, the locational or distributional value of load shed, and load increase during the belly of the duck may all produce new value streams. In particular, results from the clustering analysis show that PG&E may benefit from encouraging EV owners to charge in the middle of the day, when more clean energy is available. Furthermore, conjoint survey results and data from other jurisdictions suggests that EV owners may be more amenable to charging during the middle of the day as they are more likely to be working from home in comparison to before the pandemic. As such, PG&E may want to explore opportunities to encourage customers to charge during the middle of the day through rates or partnering with managed charging providers.

PG&E should consider providing incentives for customers who already own L2 chargers by partnering with vendors that control chargers directly and/or leveraging vehicle telematics to manage L2 charging. Results from the customer incentive conjoint survey of 3,183 PG&E EV owners indicates that the 71% have a smart or non-Internet-enabled L2 charging station. Customers with a L2 charging station charge more frequently and have more predictable charging patterns than L1 chargers. Furthermore, the conjoint survey suggests providing incentives to encourage customers who already have an L2 charger to enroll in a managed charging program is more cost-effective than incentivizing customers who have a L1 or non-Internet enabled L2 charger to upgrade to a smart L2 charger ($50 for EV DR program enrollment vs. $300 for a smart L2 charger upgrade incentive). For customers who already have a smart L2 charger, PG&E could consider partnering with vendors that control EV charging through the charger directly or partner with third-parties or OEMs that provide vehicle telematics solutions. Vehicle telematics providers also provide an opportunity to reach customers who have non-Internet-enabled L2 chargers.

7. FUTURE MANAGED CHARGING PROGRAM DESIGN CONSIDERATIONS

Our research efforts also revealed other holistic program design, market, and methodological findings PG&E may want to consider if they decide to develop a residential managed charging offering. We summarize these findings in the following section.

7.1 PROGRAM DESIGN CONSIDERATIONS

7.1.1 EVENT EXECUTION

Provide future program partners with detailed guidance and geographic data that enables them to make informed decisions about whether to call DR events for customers who are affected by PSPS. The greatest need for EV DR resources occurs on hot days in the summer, which also tends to correlate with a higher risk of PSPS and Red Flag warnings. To address potential safety concerns, it also is important to ensure customers in high fire risk areas can charge their EVs enough to allow them to evacuate during a wildfire. As such, there are unique concerns associated with relying on EVs as a DR resource during Public Safety Power Shutoffs and Red Flag warnings. Although 2021 was a relatively cool and mild summer, the Team still had to make challenging judgment calls and re-schedule several DR events in the late summer as the fire season threat escalated. In the future, PG&E may want to consider developing a set of clear rules that can help partners make decisions about how or if to call DR events during PSPS and Red Flag warnings. Providing partners with geocoded data that clearly delineates which customers are in Tier 2 and Tier 3 fire zones could also help vendors exclude customers who are impacted by PSPSes from events on days with elevated fire risk.

Leverage automated approaches to execute DR events in the future. Although Enel X, Geotab, and ChargePoint are all capable of receiving automated DR signals, the Team used a manual approach for calling DR events with Enel X and Geotab because setting up an automated approach required too much effort for the scale of this project. We were able to call events via an API for ChargePoint. The manual approach required us to provide the vendors with at least 24 hours of advanced notification, which created issues when we needed to reschedule events due to PSPSes, Flex Alerts, and Red Flag warnings, whereas the API allowed us to easily reschedule events. In addition, the manual approach did not provide us with any record of whether the customer received the DR event signal. Furthermore, the vendors noted that manual approaches to event calling are more prone to human error. Based on these findings, we recommend that PG&E consider using an automated method for calling EV DR events in future programs through DERMS, DRMS, or other automated systems.

7.1.2 CUSTOMER EXPERIENCE

There are opportunities for PG&E to develop strategies to help managed charging program participants deal with the impacts of PSPSes. In the short run, PG&E should consider developing ME&O strategies to notify EV owners to charge their vehicles ahead of a PSPS. In the long run, PG&E may want to consider partnering with vendors to incorporate a PSPS warning system, similar to the Tesla Storm Warning, into future managed charging programs that would override EV owners' charging schedules to automatically charge their EVs in the hours prior to a PSPS event, in a staggered manner that does not overwhelm the distribution system. This would likely be more feasible to deploy for more mature managed charging programs, when the cost of developing this feature could be spread across many customers. In the future, V2X technologies could also allow EV owners to power their homes using their EVs during a PSPS outage.

Consider partnering with charging vendors, and other providers to allow EV owners to enroll in a managed charging offering at the Point of Sale. Literature review results and findings from program managers in other jurisdictions suggest customers are most likely to enroll in a managed charging program when they purchase their charger. Field test study participants also reported they would have liked to receive more information about available EV rates and program options. PG&E may want to explore opportunities to enable EV owners to enroll in a managed charging program when they purchase a L2 charger from the PG&E marketplace. Developing partnerships with EV charging vendors and other external marketplaces like Amazon to add EV DR program enrollment options at the point of sale can also help PG&E reach a larger share of prospective program participants.

EV owners could benefit from targeted marketing, education, and outreach (ME&O) designed to raise awareness and about managed charging and its associated benefits, and address concerns and misperceptions. EV owners tend to be more energy literate than the general population; however, just 24% of EV owners had heard of managed charging programs prior to taking the conjoint survey. Likewise, only a small share of EV owners were able to name benefits and concerns associated with allowing PG&E to adjust their charging unprompted. When prompted, most EV owners expressed concerns about allowing PG&E to adjust their charging; primarily, apprehension that their car would not be fully charged when needed. Prior to launching a future EV DR offering, PG&E may want to consider expanding current ME&O efforts targeted towards EV owners to include content designed to educate EV owners about the financial, grid reliability, community, and environmental benefits associated with managed charging. Leveraging these efforts to address customer concerns—letting them know that managed charging doesn't have to cost them more and their car will still be charged when then need it—would also be beneficial. As new EV owners navigate a steep technology learning curve, managed charging program design best practices suggest PG&E should provide customer education in the marketing and recruitment phases of a program and technical education after customers enroll. Addressing common managed charging concerns through an FAQ sheet could also help customers see PG&E as a trusted resource for their EV charging needs.

Provide customers with notifications ahead of DR events, while assuring them they will be minimally impacted. For this study, most customers did not receive pre-event notifications which may have contributed to low opt-out rates. While over half of interviewed study participants did not realize any DR events had even been called, a few participants noticed instances when their EV didn't fully charge, which they attributed to technical issues or human error instead of the field test. PG&E may want to provide customers with email, text, or app-based notifications ahead of DR events so customers are able to recognize when events impact their normal charging patterns or levels. Furthermore, providing messaging in the event notification to assure customers that the event will be minimally impactful can also help to minimize opt outs.

7.1.3 FORWARD-LOOKING CONSIDERATIONS

In the future, consider exploring the opportunity to offer a holistic residential ADR offering that bundles EV charging with other residential ADR control technologies (water heater, smart panel, thermostat, etc.). Other utilities have found that developing customer offerings that incentivize and aggregate multiple DR resources along with EVs has helped to bolster peak load reductions during DR events and manage the resource variability associated with each individual technology. As ADR technology improves, this type of holistic program design could allow PG&E to adjust the energy consumption of each individual end use just slightly, to the point where the customer may not even recognize the adjustment. As such, PG&E may want to explore future opportunities to combine SmartAC and EV DR programs along with other emerging residential ADR control technologies to enhance the value of each customers' DR resource while simultaneously minimizing impacts to the customer.

Investigate opportunities to combine elements of DR and more dynamic price signals to adjust EV charging in response to real time capacity needs while accounting for customer preferences. Each of the vendors in this study have demonstrated the capabilities to both call DR events and manage EV charging on a more dynamic level in response to price signals. In addition, our review of existing DR programs reveals utilities are moving to more dynamic managed charging program designs, enabling them to adjust EV charging in response to real time capacity needs. This type of approach could allow PG&E to leverage the same pool of customers for both applications, thus expanding the eligible customer population and eliminating potential issues (e.g., requiring customers to enroll in two different programs or customer confusion around differing eligibility requirements for each program). Similarly, some managed charging vendors are building out solutions that incorporate customer charging patterns and other data streams to minimize the impact of DR events on each customer. As most PG&E EV owners expressed concern that their car wouldn't be ready when needed if they allowed PG&E to adjust their charging, PG&E may also want to investigate opportunities to incorporate customer preference data into future EV DR program designs.

7.2 MARKET CONSIDERATIONS

Consider developing a protocol and convening a working group to support the development of broader policies that address potential jurisdictional, technological, and vendor overlap in EV DR charging control programs. Ultimately, individual EVs can only respond to one charging signal at a time; however, overlaps in managed charging program jurisdictions, technology types, vendors, and optimization algorithms can result in competition over control of EV charging. This is likely to result in a range of sub-optimal managed charging outcomes including incentive double dipping, competing signals, and conflict over optimization of EV charging resources. We observed some examples of this competition in the field test and the current California market landscape; however, this issue will become more exigent as EV and managed charging adoption increases. PG&E may want to consider developing a framework or protocol that governs the management of EV resources in PG&E service territory. As this issue spans multiple vendors, energy providers, and government organizations, PG&E may want to consider convening a working group or engaging the existing California VGI working group to support the development of broader policies that address this issue.

Conduct annual managed charging market scans to keep up to date with rapid changes in the market. The study team recognizes that the managed charging landscape changed rapidly during the study period from September 2020 to January 2021. During this time, several new managed charging providers emerged in the market and existing providers rapidly built out new capabilities. Managed charging is a new business opportunity with a significant value proposition. Consequently, the landscape is likely to continue to shift over the next five years. Therefore, we recommend PG&E conduct another market scan comprised of vetting eligibility of EV DR providers and reviewing the results of new managed charging programs in other jurisdictions before launching an EV DR program. PG&E should also consider continuing to conduct these scans on an annual basis thereafter.

7.3 METHODOLOGICAL CONSIDERATIONS

As a next phase of this study, consider leveraging the clustering analysis and resource potential assessment to better understand the distribution system impacts of EV charging. The resource potential results demonstrate that EV rates are motivating customers to charge overnight, which is resulting in an overnight peak of 108 MW to 140 MW. As EV penetration increases, high densities of overnight chargers clustered in the same geographical area could pose potential risks to the distribution system. As a next step in this study, we recommend conducting an additional analysis that examines the resource potential results by customer address to better understand how the resource potential is distributed across PG&E service territory. These results can help inform distribution system planning and managed charging program designs.

The load disaggregation methodology developed for this study proved to be an effective way to disaggregate the magnitude and frequency of L2 EV charging from other home end uses. This methodology enabled us to accurately detect L2 EV charging in cases where AMI data was available for customers before and after they acquired an EV. In the absence of data before and after a customer acquires an EV, using the signal-finding algorithm by itself could help indicate presence of an EV by identifying unusual peaks in consumption, although accurately assessing the magnitude of the EV charging will be more difficult without pre-post modeling to forecast whole-house consumption without an EV. Other researchers may want to consider leveraging the EV load disaggregation methodology we used in this study to disaggregate EV load from whole-house load in future studies.

Consider engaging in current discussions with CAISO and other California stakeholders about investigating alternative strategies to using a CBL approach for assessing EV load impacts. The study Team leveraged a CBL approach to estimate load impacts from the field test, which has been the standard approach for estimating DR impacts in California. However, the daily and monthly variation in EV charging patterns poses limitations to using this approach to evaluate EV DR load impacts in comparison to other customer-side DR resources, such as heating or cooling loads. One potential evaluation approach that holds promise is a propensity to charge approach. Leveraging additional data points available through vehicle telematics—such as when a customer plugs their EV in, when EV charging is scheduled, the state of charge of the battery, and how long the customer has been charging before the event—could help establish an even-more accurate counterfactual. PG&E may want to consider engaging in current discussions that are occurring with CAISO and California stakeholders about new strategies for establishing DR methodology in California.

APPENDIX

APPENDIX A. OVERVIEW OF MANAGED CHARGING PROGRAMS ACROSS THE US

Table 15 provides a summary of managed charging programs we reviewed during the market scan process.

Table 15. Summary of Managed Charging Programs Included in the Market Scan

Utility Program	Sector	Years	Program Type	Program Description	Mechanisms: ADR, TOU, DR	Vendors	Demand Impacts Evaluation Key Findings
Baltimore Gas and Electric[49]	Residential	Ongoing	Data collection	BG&E pays a $300 incentive to purchase a smart L2 charger, which is the difference in price between a non-Internet-enabled charger and a smart charger. In exchange for the incentive, customers agree to share their EV charging data with the utility.	Data sharing	Weavegrid, Enel X, Siemens, ChargePoint	N/A
Con Edison Smart Charge New York[50]	Residential Fleet Operators (Expanded to medium and heavy-duty vehicles in 2018)	2017 2018	Behavioral Load Control	The Smart Charge New York program incentivized drivers to charge their vehicles off-peak. Participants needed to physically unplug their vehicle or schedule their charger to charge at off-peak times. The process was not automated. There was an upfront incentive of $150 to install and register a Fleet Carma C2 device that tracked charging behavior and a performance incentive of $5/month for keeping the C2 device in the vehicle and charging at least once within the Con Edison territory. Bonus incentives were also offered: ▪ $20/month in June through September for not charging during 2:00 p.m. and 6:00 p.m., Monday through Friday. ▪ 10¢/kWh for any charging between 12:00 a.m. and 8:00 a.m., every day year-round. ▪ $25 for each satisfaction survey completed. ▪ $25 for each referral who completes enrollment in the program.	TOU-like rate (passive DR)	FleetCarma (Residential) Charge Point (Fleet Operator)	The calculated reduction per vehicle was 0.1 kW for the NYISO peak period and 0.05 kW for the Con Edison weekday peak period. Participants had a 0.3 kW to 0.5 kW reduction per vehicle between 7:00 p.m. and 12:00 a.m., relative to the baseline for both peak periods.
Green Mountain Power e-Charger Program (Vermont)[51]	Residential	2019	Direct Load Control via charger	The e-Charger Program offered a free smart L2 charger for up to 300 customers and unlimited off-peak charging for up to two EVs for a flat monthly rate per vehicle. Customers were notified 8–24 hours before a peak demand event; charging was curtailed during an event via OpenADR, Customers could opt out but would be billed at higher rates.	ADR	Charge Point FLO	N/A

[49] Baltimore Gas and Electric. "Residential Charger Rebate." *Smart Energy*. Last Modified January 13, 2022.
[50] Con Edison. *SmartCharge Electric Vehicle Program Impact Evaluation Final Report.* February 8, 2019.
[51] Green Mountain Power. *eCharger Rate Design Workshop.* April 16, 2020.

Utility Program	Sector	Years	Program Type	Program Description	Mechanisms: ADR, TOU, DR	Vendors	Demand Impacts Evaluation Key Findings
Hawaiian Electric Company Electrification (HECO) of Transportation: Strategic Roadmap (Initiative 4)[52]	Workplace charging Multi-unit dwellings e-buses	HECO released their Roadmap in 2018	Direct Load Control via charger	HECO plans to offer rates incentivizing drivers and fleet managers to charge when most valuable to the grid at their workplace and offered incentives for their participation. HECO will rely upon aggregators to combine fleets of vehicles to provide these services, and to offer compensation to drivers and fleet managers.	TOU for EVs or DR through aggregators	Does not specify	N/A
HECO: Maui Electric: JUMPSmart Maui (Phase 2)[53]	Residential and Small Business	2011 2012 2013 2014 2015 2016	Direct Load Control via charger: V2G	In Phase 1 of the JUMPSmart Maui program, the project recruited more than 200 EV owners or lessees of the Nissan Leaf and 30 homeowner volunteers. JUMPSmartMaui installed 13 Fast Charging stations across Maui. Participants were offered access to the Fast Charging stations as well as the installation of L2 chargers and smart energy monitoring devices at their homes. In Phase 2, a total of 80 volunteers were provided with EV-Power Conditioning System (EV-PCS) units at their homes. As part of the demonstration, the EV-PCS, a technology developed by Hitachi, charged the EV and discharged the power to the home, business, or to Maui Electric in response to the needs of the electric grid.	ADR (Managed by utility)	Hitachi EVOhana Nissan	At maximum, the EVs provided about 3 kW of peak load reduction through discharged electricity. Hitachi saw from the pilot that 14%–31% of EV batteries at homes may be available for discharge at peak times, while 2.1%–3.9% may be available for charging during peak solar generation (10:00 a.m.–4:00 p.m.)
Hawaiian Electric Company: Maui Electric: OATI Electric Vehicle DR Aggregation[54]	Residential		Direct Load control via charger	Maui Electric provided 40 customers who own Nissan Leafs with devices to allow communication with the EV for data collection on usage.	ADR (Managed by utility)	Nissan OATI	Maui Electric used a performance scoring methodology adopted in the PJM interconnection to evaluate the pilot. The typical score for the aggregated resource on that methodology was 91%—well above the 75% performance score threshold for PJM participation. Each EV was shown to be able to follow charge and discharge instructions provided. Participants were satisfied overall with the project, but their vehicles were only available to respond less than half the time.

[52, 54] Hawaiian Electric, Maui Electric, and Hawai'i Electric Light. *Electrification of Transportation: Strategic Roadmap.* March 2018.
[53] Irie, Hiroshi. *Japan-US Collaborative Smart Grid Demonstrations Project in Maui Island of Hawaii State: A Case Study.* 2017.

Utility Program	Sector	Years	Program Type	Program Description	Mechanisms: ADR, TOU, DR	Vendors	Demand Impacts Evaluation Key Findings
PEPCO (Maryland): Demand Management Pilot Program for Plug-In Vehicle Charging Maryland[55]	Residential	2014 2015	Direct Load Control via charger	Pepco offered two types of rates: (1) R-PIV Rate: A Whole House TOU rate and (2) PIV Rate: a PEV-only rate. For customers on the PIV rate who didn't already have a separate PEV meter, Pepco installed a second AMI meter. 35 of the customers installed smart EVSEs and had the ability to respond to Pepco's DR events Pepco reduced chargers from a L2 to a L1 rate of charge for an hour during a DR event and provided opt-out capabilities for customers.	EV TOU and ADR	Itron	Results show EV owners charge mostly during off-peak times and that DR events can be an effective way to curb peak load events. Results suggest this is potentially powerful approach to reduce load on the grid during times of peak demand, as the program reduced peak demand by at least 50% while providing some level of charging. PEPCO recruited 101 participants and conducted seven DR events. Only three people charged during these event: One opted out and two reduced their charging.
PG&E: EV Charge Network Program: Load management plan[56]	Workplace Multi-unit Dwelling	2020	Direct/Behavioral Load control via charger	Participants will be asked to shift the amount of EV charging at their site during DR events to support the grid. The incentive payment was awarded to the participant as a credit on their PG&E bill on a quarterly basis. The site's event performance was determined by comparing the usage during an event hour to the site's average usage on recent, non-event days. The performance for each event type was averaged for the entire month. If the average monthly performance for a site was at least 20% of the site's total EV charging capacity, then the participant would be eligible for an incentive payment of $10 per kilowatt ($5/kW in each direction) multiplied by the monthly average performance, computed independently for load increase and load decrease. Participants could work with their EVSP vendor to determine a strategy to participate in the events, or they can implement their own tactics	DR	PG&E customers may select from one of two dozen vendors. The full list can be found on the EV Charge Program Approved Vendors page of the PG&E website	N/A

[55] EPRI. Pepco Demand Management Pilot for Plug-In Vehicle Charging in Maryland: Final Report—Results, Insights, and Customer Metrics. May 5, 2016.
[56] PG&E. EV Charge Network: Load Management Plan. 2018.

Utility Program	Sector	Years	Program Type	Program Description	Mechanisms: ADR, TOU, DR	Vendors	Demand Impacts Evaluation Key Findings
PG&E: BMW ChargeForward California[57]	Residential	2015-2020	Direct Load Control via Automaker Telematics	For each DR event, BMW provided PG&E with 100kW of grid resources by delaying charging for approximately 100 BMW i3 vehicles in the San Francisco Bay Area and drawing from a BMW Group second life stationary battery system (built from reused EV batteries) for a duration of one hour. As part of this pilot, customers receive an upfront incentive of $1,000 and an ongoing incentive for each day they did not opt-out (whether an event was called or not), up to $540 that was distributed after the pilot has ended. The majority of participants (84%) identified the up-front incentive was more important compared to the ongoing incentive (62%).	ADR	Olivine BMW	The BMW ChargeForward Project dispatched 209 DR events, totaling 19,500 kWh. On average 20% of the total contribution was attributed to the vehicle pool and 80% from the second life stationary battery system. The amount from the vehicle share was dependent on the time of day an event was called. Challenges: Problems occurred in various areas in the technical chain of command in the system, which was spread among different servers at different providers (Olivine, BMW Munich, BMW of N.A., and BMW Technology Office in Mountain View, CA).
SCE: DR Workplace Charging Pilot California[58]	Workplace	2015 2016	Behavioral Load Control	SCE deployed EV charging stations at nine SCE facility parking lots. Users paid a base, per hour TOU fee and a space management fee was implemented that assessed additional charges on vehicles that remained connected to the charging station more than 30 minutes after charging was complete. SCE successfully dispatched 19 DR events to evaluate DR potential from PEV charging, assess consumer response to premium pricing during DR events, and inform a methodology for accurately measuring PEV charging load curtailment. This pilot utilized the following elements: ▪ Time-of-Use pricing (i.e., off-peak and on-peak periods) for L2 charging and simulated L1; ▪ DR through dispatch and curtailment during nineteen 60-minute events at various times during the work week; ▪ Non-charging occupancy fee to test space management control; ▪ Real-time SMS messaging to communicate charging session status to drivers; ▪ Premium pricing during DR events to simulate Critical Peak Pricing scenarios.	TOU, DR	Greenlots Control Module, Inc. EVSE LLC AutoGrid Systems	Approximately 80% of drivers opted to charge during off-peak morning hours (5:00 a.m.–12:00 p.m.) hours regardless of the base fee charged. Survey feedback from stakeholders suggested that users considered access to PEV charging in the workplace and other personal benefits to be sufficient incentive to purchase or lease a PEV and/or participate in the workplace charging pilot.

[57] PG&E. BMW i ChargeForward: PG&E's Electric Vehicle Smart Charging Pilot Final Report. June 2017.
[58] Southern California Edison (SCE). Southern California Edison Plug-In Electric Vehicle (PEV) Workplace Charging Pilot. July 2016.

Utility Program	Sector	Years	Program Type	Program Description	Mechanisms: ADR, TOU, DR	Vendors	Demand Impacts Evaluation Key Findings
SCE: Honda Smart-Charge™ California[59]	Residential	2018	Direct Load Control via Automaker Telematics	The program used pricing signals to calculate when the most renewable energy was available at the lowest cost then sent participants an electronic notice telling them it was time to connect their vehicles via an app. The program applied only to Honda Fit EV drivers who were SCE customers and used a JuiceNet charger. Drivers were able to use the app to program in their desired charging time. The system was then able to take that information into account to compute the best time to charge based on the daily schedule participants specified in the app. Drivers received $50 from Honda to join the program, then $50 every two months as a reward if they followed the charging schedule suggested by the proprietary algorithm used by the JuiceNet system.	ADR	eMotorWerks (enel X) Honda	N/A
SDG&E: Power Your Drive[60]	Workplace Multi-unit Dwelling	2017 2018 2019 2020	Direct Load control	Power Your Drive installed over 3,000 charging stations at multi-unit dwellings and workplace locations. Dynamic pricing: Sent EV drivers information on the next days' charging rates that vary on an hour-by-hour basis. This allowed dirvers to schedule their charging demand and behaviorally shift charging to avoid higher priced periods.	ADR	ChargePoint Greenlots Siemens	Not reported
Sonoma Clean Power[61]	Residential	Ongoing	Direct load Control	Sonoma Clean Power bundles incentives for smart thermostats, EV chargers, and heat pump hot water heaters and leverages all three technologies for DR events. Participants receive a free smart L2 charger; they pay 50% of the charger cost upfront, sales tax and a $15 shipping fee. After the charger is installed and activated, Sonoma Clean Power reimburses the amount that customers paid when they placed their order. Customers can receive $5 incentive for keeping their charger connected.	ADR	Any smart L2 charger is available for incentives	N/A

[59] Hanley, Steve. "EMotorWerks, Honda, and Southern California Edison Offer Nation's First Smart Charging Program." CleanTechica. August 2, 2018.
[60] San Diego Gas and Electric (SDG&E). Electric Vehicle-Grid Integrated Pilot Program (Power Your Drive) Semi-Annual Report of San Diego Gas and Electric Company (U902-E). September 2018.
[61] Sonoma Clean Power. "GridSavvy." Sonoma Clean Power. Last modified January 13, 2022

Utility Program	Sector	Years	Program Type	Program Description	Mechanisms: ADR, TOU, DR	Vendors	Demand Impacts Evaluation Key Findings
Xcel Energy (Minnesota): EV Service Pilot Minnesota[62]	Residential	2018 2019 2020 (Expand in 2021)	Direct Load Control via charger	Xcel provides EVSE, installation, and operation and maintenance for a single monthly fee customers can pay for the charger up front or monthly. Load monitoring and data management are included in the service package and participants are automatically enrolled in the EV electric pricing plan, which uses the charger for billing purposes. Xcel programs the charger to charge the car between 9:00 p.m. and 9:00 a.m. The customer has the flexibility to charge during the day if needed at a higher, on-peak rate.	TOU rate	eMotorWerks ChargePoint	N/A
Xcel Energy (Colorado): Charging Perks[63]	Residential	2020 (Data Collection)	Direct Load Control via Automaker Telematics	Used onboard communications systems on EVs to help owners decide when and how to charge their cars while saving on energy bills and using more zero-carbon electricity. All customers received a sign-up incentive of $100. Customers who charged using a L1 charging station or a standard 120-volt wall outlet received a further $50 credit at the end of the first full year of the pilot (2020). Customers who charge using a L2 charging station received a larger incentive of $100 after the first full year of the pilot. L2 customers received higher incentives because the higher charging rate provides greater ability for Xcel to shift the customer's charging load.	ADR	BMW Ford General Motors Honda	N/A

[62] Xcel Energy. "Subscription Service Pilot: Xcel EV Shopping Advisor." Xcel Energy. Last modified January 12, 2022.
[63] Xcel Energy. "Charging Perks: Xcel EV Shopping Advisor." Xcel Energy. Last modified January 12, 2022

APPENDIX B. CUSTOMER RECRUITMENT SURVEY METHODS

CUSTOMER RECRUITMENT SURVEY SAMPLING APPROACH

GEOTAB SAMPLE DEVELOPMENT FOR CUSTOMER RECRUITMENT SURVEY

Table 16 documents the data cleaning steps we use to develop our sample of Geotab customers for the customer recruitment survey from the CFR Database. Notably, we checked for missing data fields. Geotab only works with Tesla EVs, so we selected Tesla EV owners and eliminated duplicate customers.

Table 16. Data Cleaning Steps for Geotab Sample Development

N	Accounts	Percent Retained Observations	Percent Retained Unique SA_UUID and ACCT_UUID combined Values	Reason of Drop
154,870	133,642	100%	100%	Initial Observations in Dataset
154,870	133,642	100%	100%	Missing Name
154,870	133,642	100%	100%	Missing Email
154,868	133,641	100%	100%	Missing Acct_UUID
154,868	133,641	100%	100%	Missing SA_UUID
154,868	133,641	100%	100%	Missing APPLICATION_NUMBER
154,868	133,641	100%	100%	Missing APPLICANT_LAST_NAME_EI__C
154,867	133,641	100%	100%	Missing VEHICLE_OWNER_FIRST_NAME_EI__C
154,865	133,639	100%	100%	Missing VEHICLE_OWNER_LAST_NAME_EI__C
154,864	133,638	100%	100%	Missing F_SERVICE_ADDRESS_EI__C
154,864	133,638	100%	100%	Missing F_STATE_EI__C
154,864	133,638	100%	100%	Missing F_ZIP_CODE_EI__C
154,864	133,638	100%	100%	Missing F_PAYABLE_TO_EI__C
153,859	133,060	99%	100%	Missing FUEL_TYPE_EI__C
153,859	133,060	99%	100%	Missing MODEL_EI__C
153,859	133,060	99%	100%	Missing YEAR_EI__C
153,859	133,060	99%	100%	VEHICLE_ID_NUMBER_EI__C
99,937	88,744	65%	66%	NEM Flag is Y
38,214	36,449	25%	27%	Not a Tesla Customer
36,090	36,090	23%	27%	Duplicated acct_UUID

DETAILED SAMPLING STRATEGY FOR SELECTION OF CUSTOMERS TO ENROLL IN THE FIELD TEST

We used the 502 responses to the customer recruitment survey to develop a stratified sample of EV owners to invite to the field test. We dropped several groups of customers for the reasons documented in Table 17.

Table 17. Documentation of Steps for Selecting the Sample Frame for the Field Test Study

Drop	Rationale	Number of Customers Dropped
Ineligible Customers		
DR customers: Customers who indicated they participated in a DR program in the survey	Customers already in a DR program were excluded due to concerns about possible double dipping.	97
Geotab customers with solar	We were unsure what the quality of the telemetry data coming directly from the vehicle would be like when we start field test recruitment efforts. If the data were of poor quality, then we would need to disaggregate EV load from whole-house load using AMI data for Geotab customers, and the presence of solar would have made this disaggregation analysis more difficult.	6
Geotab customers without a Tesla	Only customers with Tesla EVs were eligible to participate in the field test.	1
Customers Who Are Hard to Sample		
Customers with missing rate designations	Rate was a key variable used to construct the sample.	19
Customers with both a BEV and PHEV	These customers may have been challenging to model for the clustering analysis.	14
Total		**365**

The recruitment survey yielded 365 usable responses. These customers constitute the "population" from which we drew the sample that participated in DR events. The Opinion Dynamics Team identified four stratification variables we considered important to define the sample:

1. Three vendors: ChargePoint, Enel X, and Geotab
2. Two vehicle types: PHEV and BEV
3. Two billing rates: EV rates and non-EV rates
4. Customers who charge in at least one hour of the peak period, versus those that don't

The main reason for stratification, in this case, is to assure a sufficient number of participants in each stratum to support meaningful analyses. The plan and the budget allowed for a total of 225 participants out of the 365. Theoretically, it would be optimal to distribute the 225 evenly across all 24 design cells implied by this stratification scheme. As we can see in Table 18, however, the population is far from evenly distributed.

Table 18. Stratified Population Counts

	No Peak Charging				Peak Charging				
Vendor	Non EV Rate		EV Rate		Non EV Rate		EV Rate		Total
	PHEV	BEV	PHEV	BEV	PHEV	BEV	PHEV	BEV	
ChargePoint	9	33	6	38	11	27	12	20	156
Enel X	6	13	3	26	4	19	2	9	82
Geotab	0	25	0	47	0	33	0	22	127
Total	15	71	9	111	15	79	14	51	365

The Team developed a few guidelines for the allocation, i.e. we attempted:

1. An even distribution of vendors (75 each)
2. 50% peak chargers and 50% non-peak chargers
3. 50% on EV rates and 50% of non-EV rates
4. 20% PHEV and 80% BEV

Since the counts in some cells were very low, and some zero, it was impossible to meet all guidelines, especially given the reality that not all customers would agree to participate. Our approach was to meet the guidelines while assuming response rates would not be over 60% in any given cell. A 60% response rate would normally be considered impossible; however, this population had already agreed to participate, so we expected a much higher response rate than usual. The resulting sample plan is shown in Table 19.

Table 19. Stratified Target Sample Counts

	No Peak Charging				Peak Charging				
Vendor	Non EV Rate		EV Rate		Non EV Rate		EV Rate		Total
	PHEV	BEV	PHEV	BEV	PHEV	BEV	PHEV	BEV	
ChargePoint	5	17	4	20	6	15	8	11	86
Enel X	4	9	2	18	3	15	1	7	59
Geotab	0	17	0	25	0	22	0	16	80
Total	9	43	6	63	9	52	9	34	225

Summing across relevant cells allows us to see the target counts by each stratum, comparing them to the ideal numbers implied by the guidelines (Table 20).

Table 20. Target Sample Counts by Each Stratum

Stratum	Ideal	Planned Target	Implied Response Rate
Peak Charging	113	104	65%
No Peak Charging	112	121	59%
EV Rates	113	112	61%
Non EV Rates	112	113	63%
BEV	113	192	62%
PHEV	112	33	62%
ChargePoint	75	86	55%
Enel X	75	59	72%
Geotab	75	80	63%

To develop our final sample, we used the target sample counts as the quotas for our sample frame and then used random sampling to select participants for the field test study that met the quota specifications.

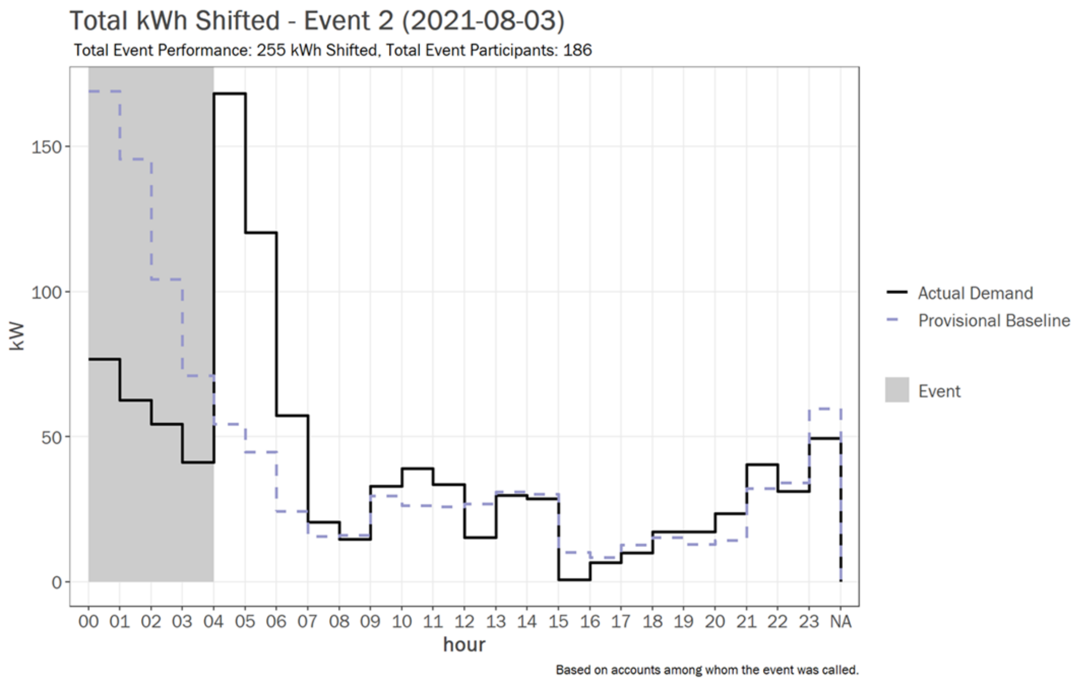
APPENDIX C. EVENT OPT OUTS AND FAILURES BY VENDOR

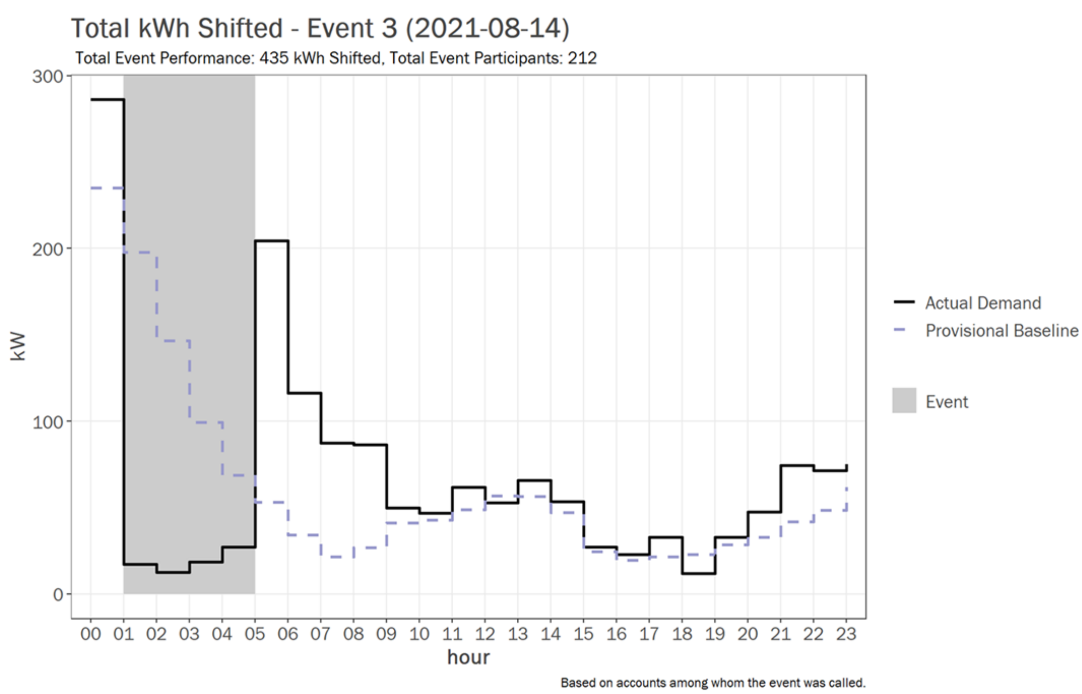
Table 21. Participant Opt Outs and Failures by Vendor for Each Event

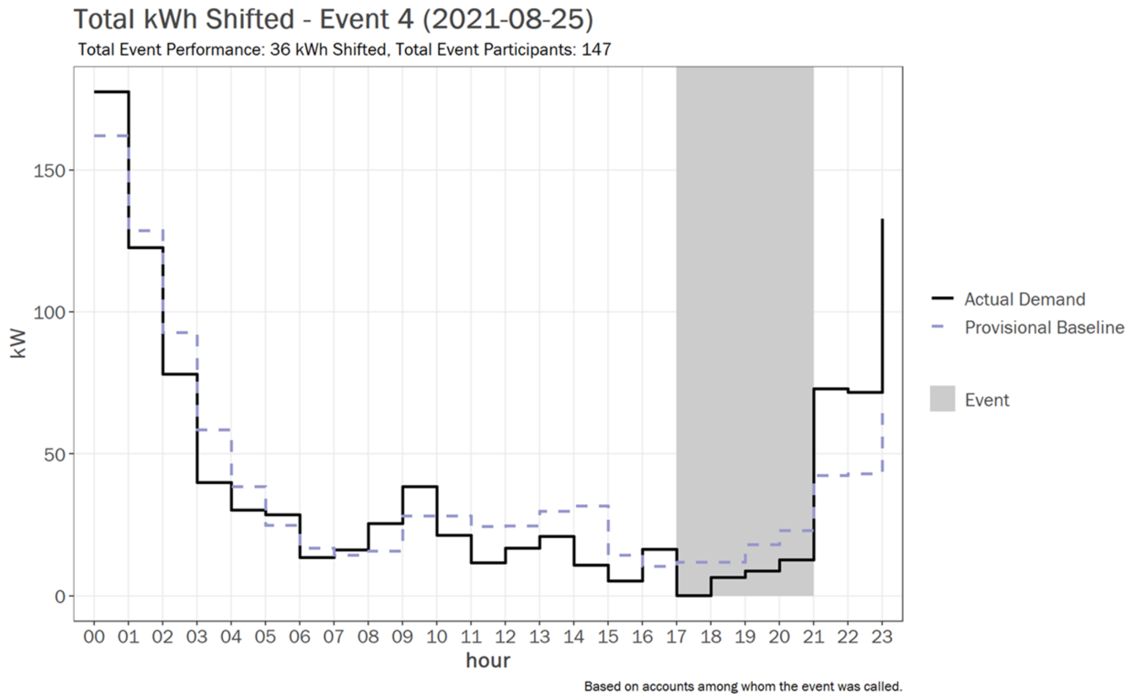
Event Number	Event Date and Time	Total Event Participants	Opt Outs				Charged During Event without Opting Out (Failures)			
			Enel X	Geotab	Charge Point	Total	Enel X	Geotab	Charge Point	Total
Event 2	Tuesday, August 3. 12 a.m.–4 a.m.	186	0	0	0	0	3	10	2	15
Event 3	Saturday, August 14, 1 a.m.–5 a.m.	212	0	0	0	0	0	4	2	6
Event 4	Wednesday, August 25, 5 p.m.–9 p.m.	147	0	N/A	1	1	2	N/A	2	4
Event 5	Friday, September 3, 12 a.m.–4 a.m.	213	1	0	0	1	5	5	4	14
Event 6	Friday, September 10, 4 p.m.–8 p.m.	213	2	0	0	2	0	6	3	9
Event 7	Thursday, September 16, 12 a.m.–4 a.m.	213	0	0	0	0	4	3	4	11
Event 8	Sunday, September 19, 12 a.m.–4 a.m.	213	0	0	0	0	1	1	3	5
Event 9	Monday, September 27, 4 p.m.–8 p.m.	212	1	0	1	2	1	2	3	6
Event 10	Wednesday, October 6, 12 a.m.–4 a.m.	211	1	0	0	1	2	6	0	8
Total		**1820**	**5**	**0**	**2**	**7**	**18**	**37**	**23**	**78**

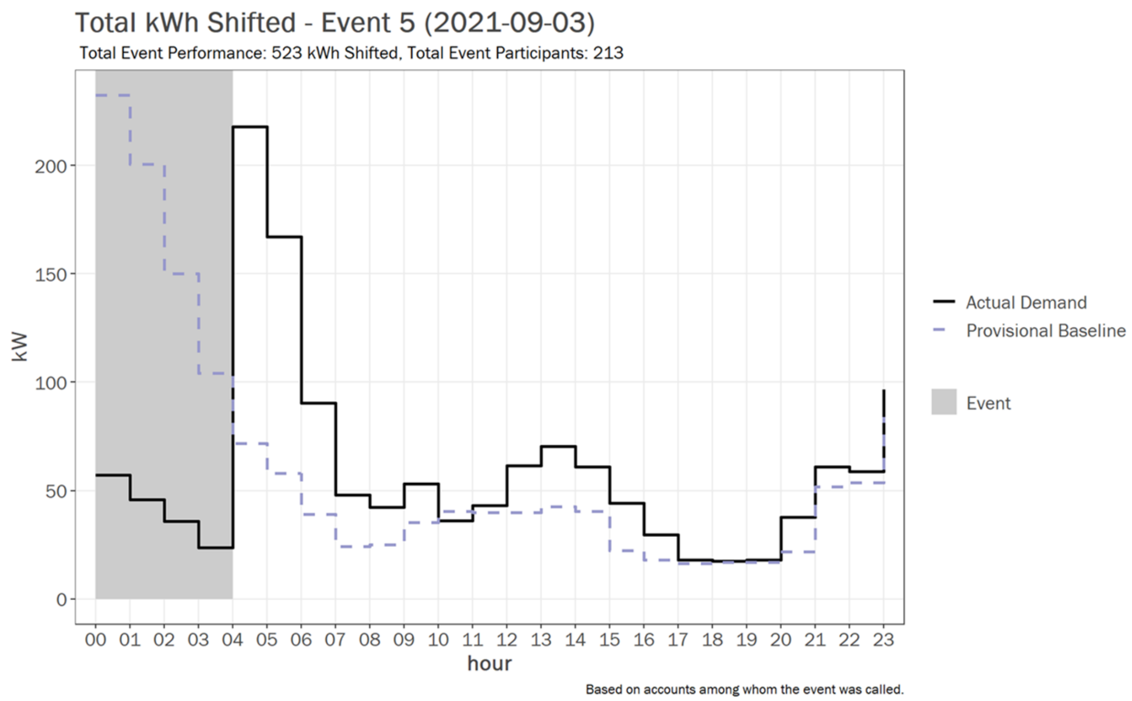
APPENDIX D. INDIVIDUAL DR EVENT RESULTS

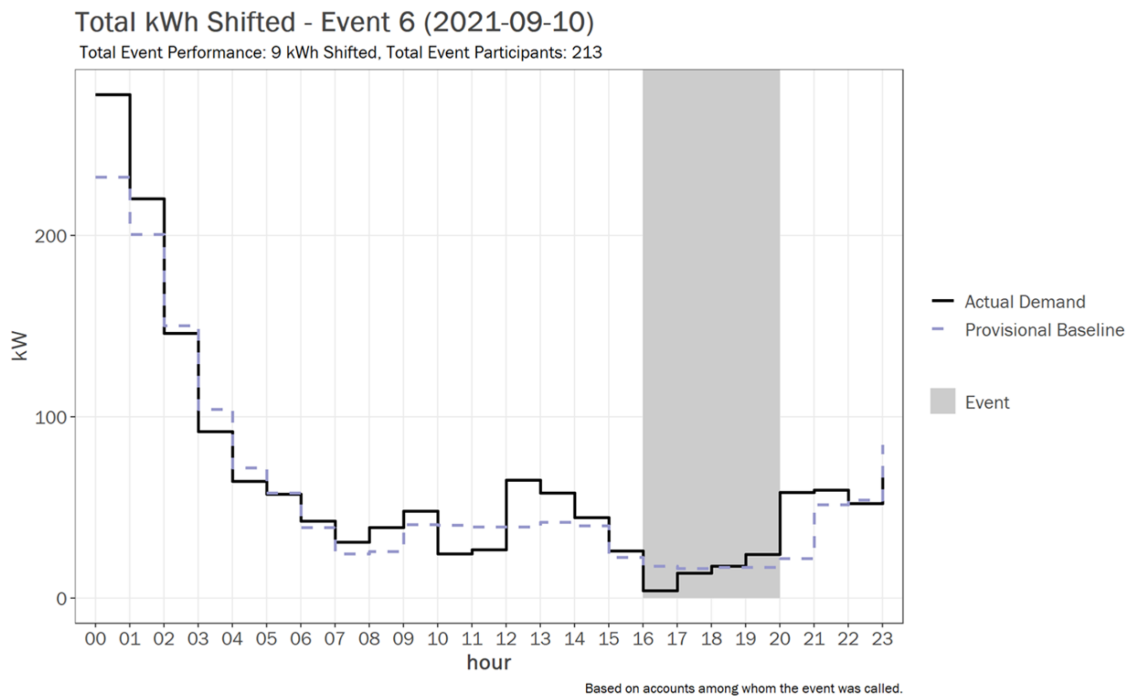
In this section, we present individual DR event results that summarize aggregated results across all vendors. We summarize the key drivers of event performance in Section 3.5.



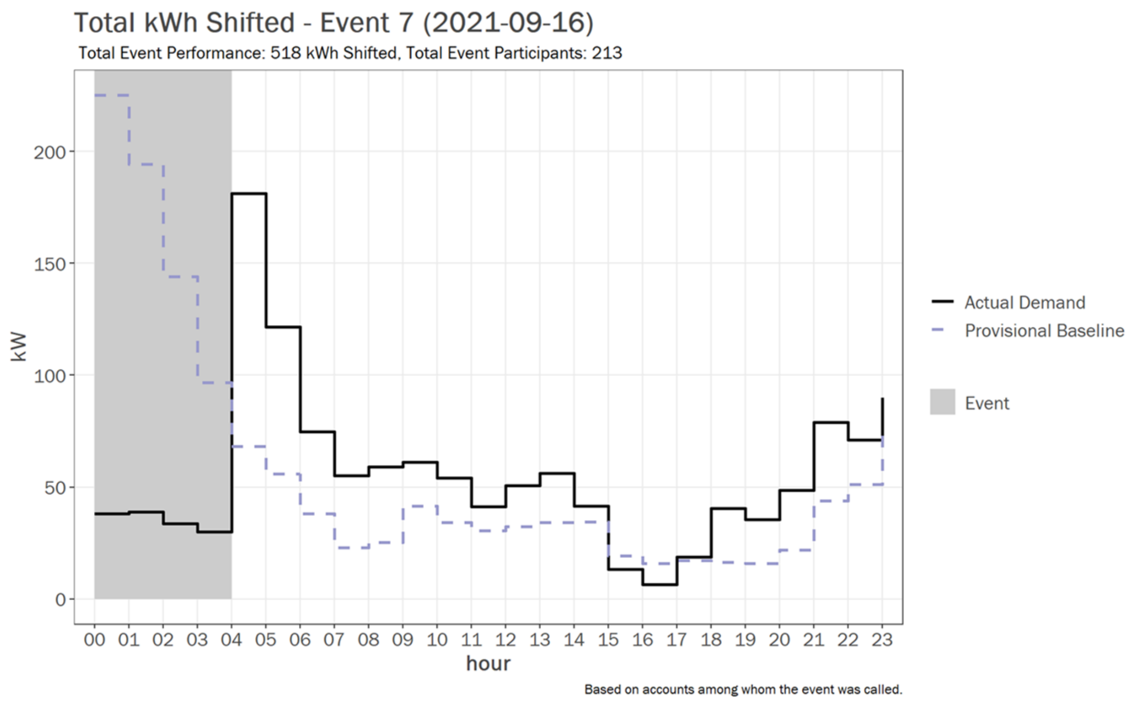



Total kWh Shifted - Event 4 (2021-08-25)
Total Event Performance: 36 kWh Shifted, Total Event Participants: 147
kW
0
50
100
150
00 01 02 03 04 05 06 07 08 09 10 11 12 13 14 15 16 17 18 19 20 21 22 23
hour
Actual Demand
Provisional Baseline
Event
Based on accounts among whom the event was called.

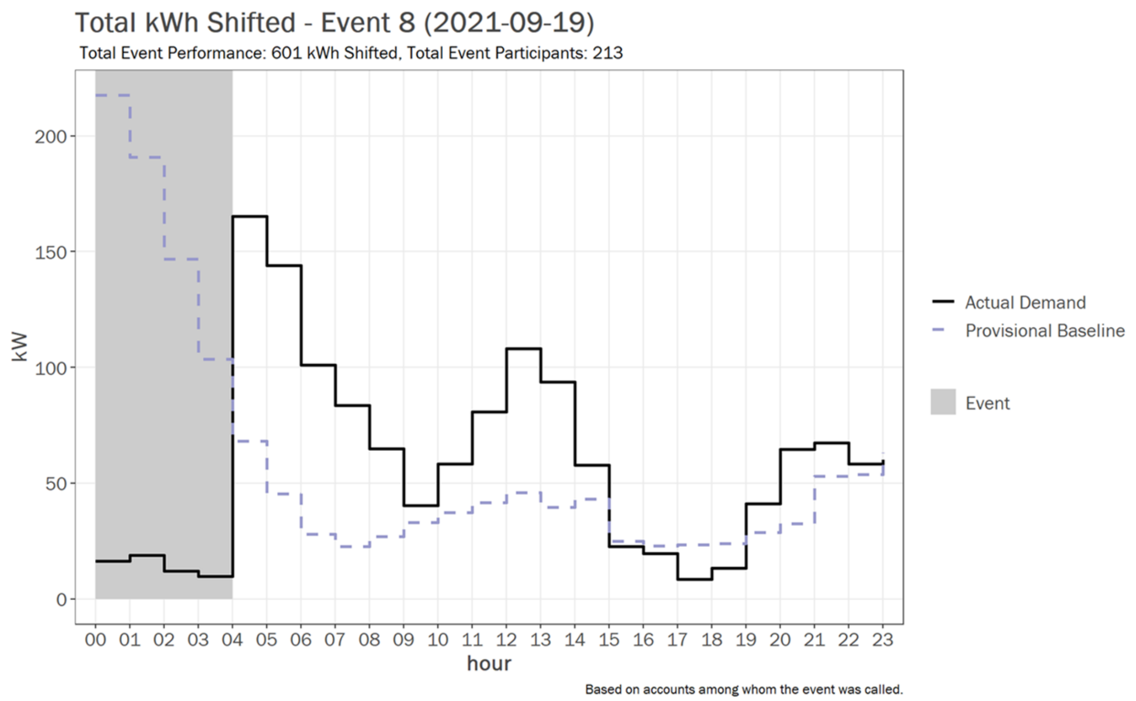

Total kWh Shifted - Event 5 (2021-09-03)
Total Event Performance: 523 kWh Shifted, Total Event Participants: 213
kW
0
50
100
150
200
00 01 02 03 04 05 06 07 08 09 10 11 12 13 14 15 16 17 18 19 20 21 22 23
hour
Actual Demand
Provisional Baseline
Event
Based on accounts among whom the event was called.



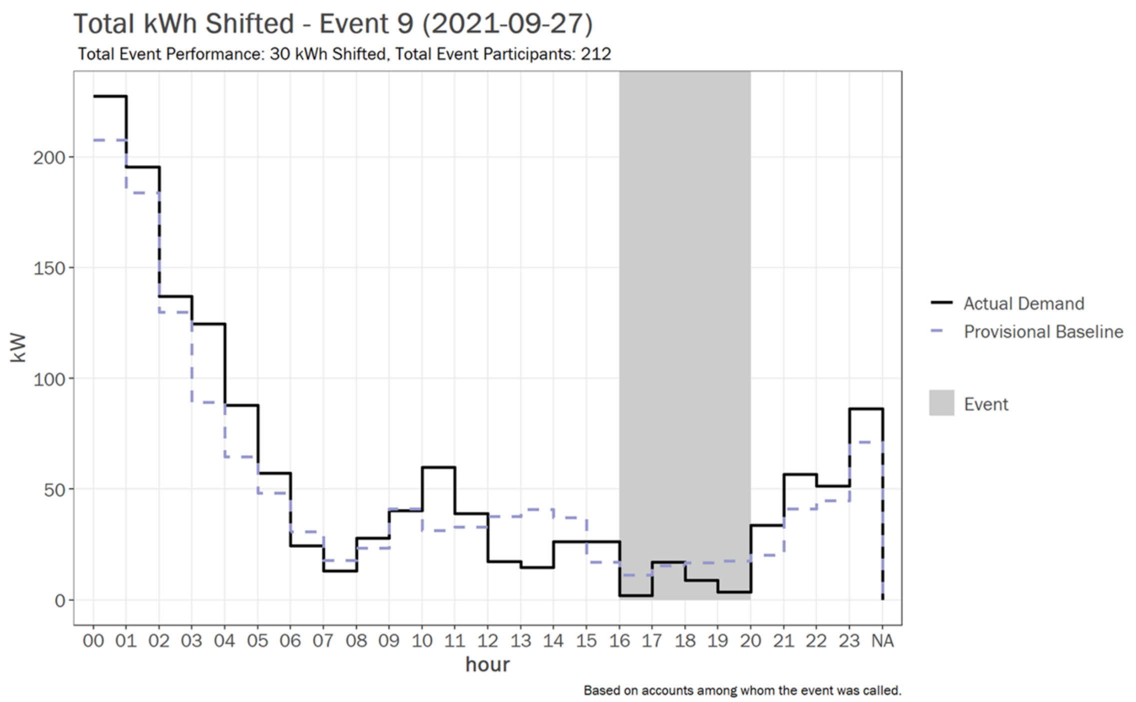
Total kWh Shifted - Event 6 (2021-09-10)
Total Event Performance: 9 kWh Shifted, Total Event Participants: 213
kW
200
100
0
00 01 02 03 04 05 06 07 08 09 10 11 12 13 14 15 16 17 18 19 20 21 22 23
hour
Actual Demand
Provisional Baseline
Event
Based on accounts among whom the event was called.



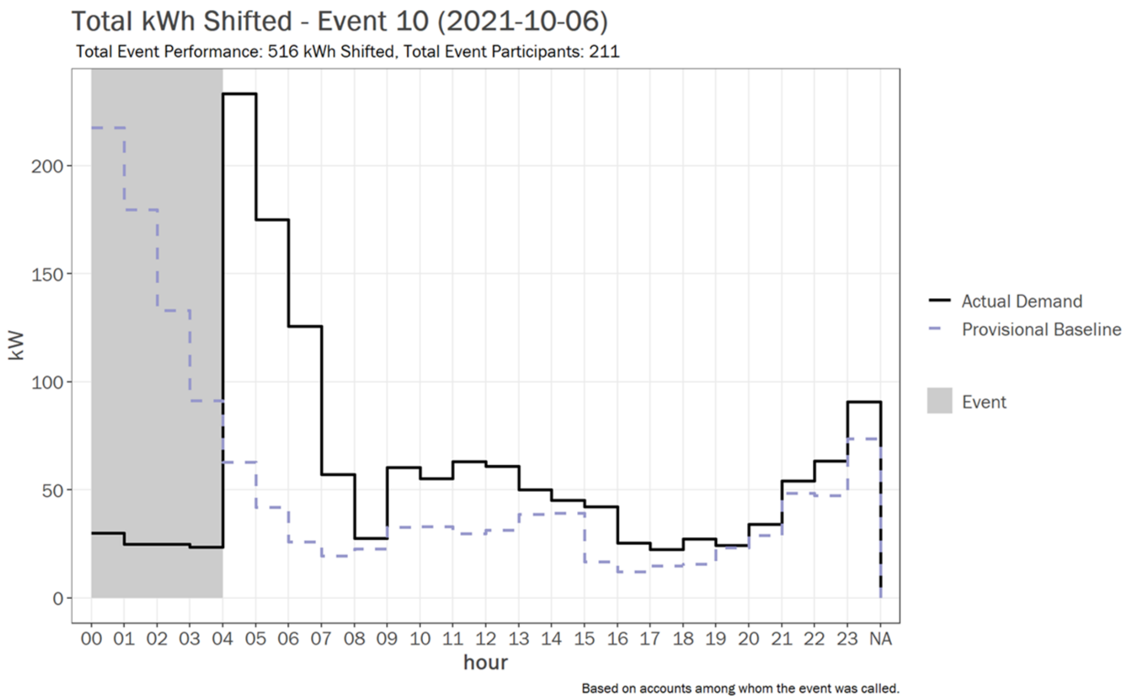
Total kWh Shifted - Event 7 (2021-09-16)
Total Event Performance: 518 kWh Shifted, Total Event Participants: 213
kW
200
150
100
50
0
00 01 02 03 04 05 06 07 08 09 10 11 12 13 14 15 16 17 18 19 20 21 22 23
hour
Actual Demand
Provisional Baseline
Event
Based on accounts among whom the event was called.



Total kWh Shifted - Event 8 (2021-09-19)
Total Event Performance: 601 kWh Shifted, Total Event Participants: 213
kW
200
150
100
50
0
00 01 02 03 04 05 06 07 08 09 10 11 12 13 14 15 16 17 18 19 20 21 22 23
hour
Actual Demand
Provisional Baseline
Event
Based on accounts among whom the event was called.



Total kWh Shifted - Event 9 (2021-09-27)
Total Event Performance: 30 kWh Shifted, Total Event Participants: 212
kW
200
150
100
50
0
00 01 02 03 04 05 06 07 08 09 10 11 12 13 14 15 16 17 18 19 20 21 22 23 NA
hour
Actual Demand
Provisional Baseline
Event
Based on accounts among whom the event was called.


Total kWh Shifted - Event 10 (2021-10-06)
Total Event Performance: 516 kWh Shifted, Total Event Participants: 211
kW
0
50
100
150
200
00 01 02 03 04 05 06 07 08 09 10 11 12 13 14 15 16 17 18 19 20 21 22 23 NA
hour
Actual Demand
Provisional Baseline
Event
Based on accounts among whom the event was called.

APPENDIX E. CUSTOMER INCENTIVE CONJOINT SURVEY METHODS

SAMPLE DEVELOPMENT APPROACH

We leveraged both the CFR and EV rate datasets to develop a sample of EV owners in PG&E service territory for the customer incentive conjoint survey. We used the CFR database of EV owners in PG&E service territory who applied for a rebate as the population from which we developed our sample frame. We merged in variables from the EV rate database for customers present in the CFR database to enable us to have more information about the characteristics of each customer, including rate schedule. We then cleaned this dataset using the steps documented in Table 22 to produce a sample frame of unique EV owners in PG&E service territory with contract information who were eligible to take the survey. We invited a random sample of 20,000 EV owners to take the survey using the final cleaned dataset.

Table 22. PG&E EV ADR Conjoint Survey Sample Cleaning Steps

Cleaning Sample Cleaning Step	Number of Records	Number of Accounts
Merge CFR and EV rate dataset	184,416	148,936
Drop duplicates: Acc_uuid, Email, fuel_type, and rate	165,602	148,936
Drop records which are not (EV or Non-EV rate) and PGE Employees	163,626	147,276
Drop Accounts participated in the Field Test	163,473	147,132
Drop records with Fuel Type Null or Gas/Electric Hybrid or Gasoline	130,005	115,944
Drop records where email ids are blank	130,005	115,944

CONJOINT SURVEY DESIGN AND ANALYSIS METHODOLOGY

Part 2 of the customer survey included two different conjoint exercises: one for owners of smart L2 chargers and another for customers who did not have this technology (i.e., they either only had a L1 charger or their L2 charger did not connect to Wi-Fi). Smart L2 charger owners received a conjoint exercise that assessed their willingness to participate in a home charging DR program, while the remaining respondents received a conjoint exercise that assessed their willingness to upgrade to a Smart L2 charger given various hypothetical incentive offerings. Respondents cycled through several screens that presented them with incentive/program configurations from which to choose on each screen. Respondents could choose from one of the unique alternative incentive offer configurations, or they could choose "none" (i.e., choose not to participate in any of the program offerings presented on their screen).

Table 23 and Table 24 show the concepts tested in the conjoint exercises. Figure 40 and Figure 41 show actual example conjoint screens to provide insight into the survey respondent experience.

Table 23. Concepts Tested in EV DR Program Participation Conjoint

Attribute	Level 1	Level 2	Level 3	Level 4
First-time enrollment incentive	None	$50	$100	$150
Per-event incentive	None	$5	$10	$20
Annual participation incentive	None	$25	$50	$100
Event time window	4 a.m. to 3 p.m.	3 p.m. to 10 p.m.	10 p.m. to 4 a.m.	N/A
Number of events per year	5	10	20	50
Charging speed reduction	75% of normal charging speed	50% of normal charging speed	25% of normal charging speed	0% (charging is completely paused)

None of these: I would not be willing to participate in any of these demand response programs

Table 24. Concepts Tested in Smart L2 Charger Upgrade Conjoint

Attribute	Level 1	Level 2	Level 3	Level 4
Incentive amount	$50	$100	$200	$300
Incentive format	Emailed gift card	Paper check	Bill credit	
Incentive delivery timing	50% at time of sale/50% after install	After install	At time of sale	
Mandatory enrollment in PG&E's EV demand response program	Yes	No		

None of these incentive offers would motivate me to install a Smart Level 2 charger

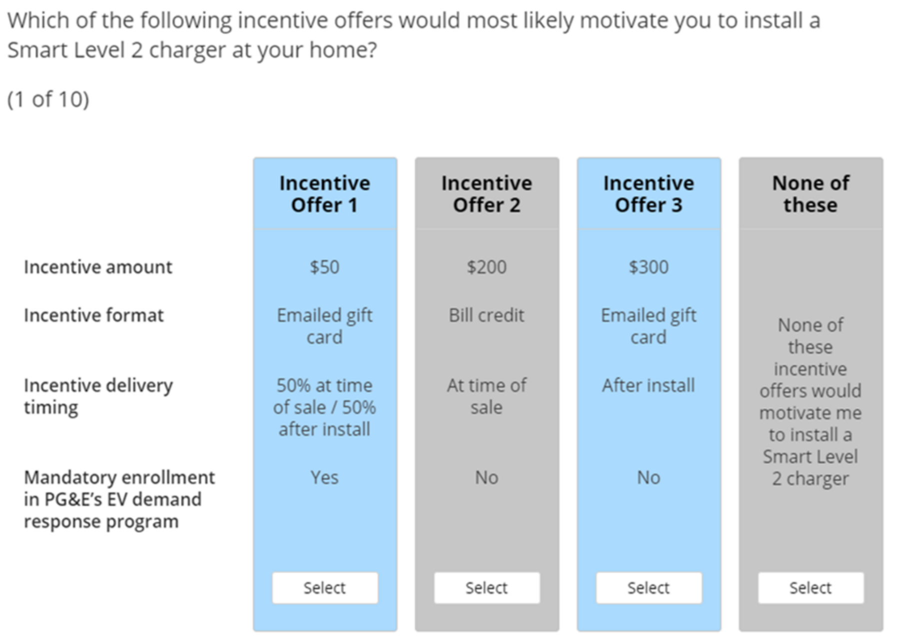
Figure 40. Example EV DR Program Conjoint Screen

Which of the following demand response programs would you be most likely to participate in?

(1 of 10)

	Program 1	Program 2	Program 3	None of these
One-time incentive for signing up	None	$150	$50	None of these: I would not be willing to participate in any of these demand response programs
Incentive for each event you participate in	$20	$10	$10	
Annual participation incentive	$25	None	$50	
Time period when charging could be slowed or stopped	Between 4am and 3pm	Between 3pm and 10pm	Between 10pm and 4am	
Number of events per year	50	20	5	
Charging speed reduction	75% of normal charging speed	0% (charging is completely paused)	25% of normal charging speed	
	Select	Select	Select	Select

Figure 41. Example Smart L2 Upgrade Conjoint Screen



Note: Respondents received custom footer text based on whether they currently owned a L1 or non-Internet-enabled L2 charger. The example shown in this figure shows the footer text for non-Internet-enabled L2 charger owners.

Each conjoint exercise included 10 screens: eight random discrete choice screens and two “holdout task” screens. The holdout task is a pre-specified set of options that every single respondent sees. By comparing simulated results (which use conjoint data collected on the random screens) to the observed results from the holdout tasks, we can evaluate the extent to which simulations are accurately forecasting respondent preferences. The smart L2 upgrade simulations were able successfully predict responses within 0.004% to 2.4% accuracy (depending on the item), suggesting these forecasts are extremely accurate predictors of EV owners’ preferences. EV DR simulations were able successfully predict responses within 1.9% to 11.2% accuracy (depending on the item), suggesting these forecasts are reasonably accurate predictors of EV owners’ preferences.

The Opinion Dynamics Team analyzed conjoint data separately for each exercise. The Team analyzed the responses to the conjoint exercises using Hierarchical Bayesian (HB) methods. Using HB methods enabled the Team to estimate the relative importance or utility of each of program component for each respondent. In addition, the Team used part-worth utility data to conduct so-called market simulations for different groups of consumers (e.g., vehicle type, rate type) to assess the relative share of preference for different program configurations. Market simulations used the “Share of Preference” calculation method. Ultimately, these results revealed the maximum proportion of consumers who are predicted to participate in a given program design and how this varies by key customer attributes.

APPENDIX F. SURVEY INSTRUMENTS AND INTERVIEW GUIDES

CUSTOMER RECRUITMENT SURVEY

VENDOR INTERVIEW GUIDE

EXPERT AND UTILITY INTERVIEW GUIDE

INCENTIVE CONJOINT SURVEY INSTRUMENT

APPENDIX G. RESOURCE POTENTIAL DETAILED METHODOLOGY

LOAD DISAGGREGATION

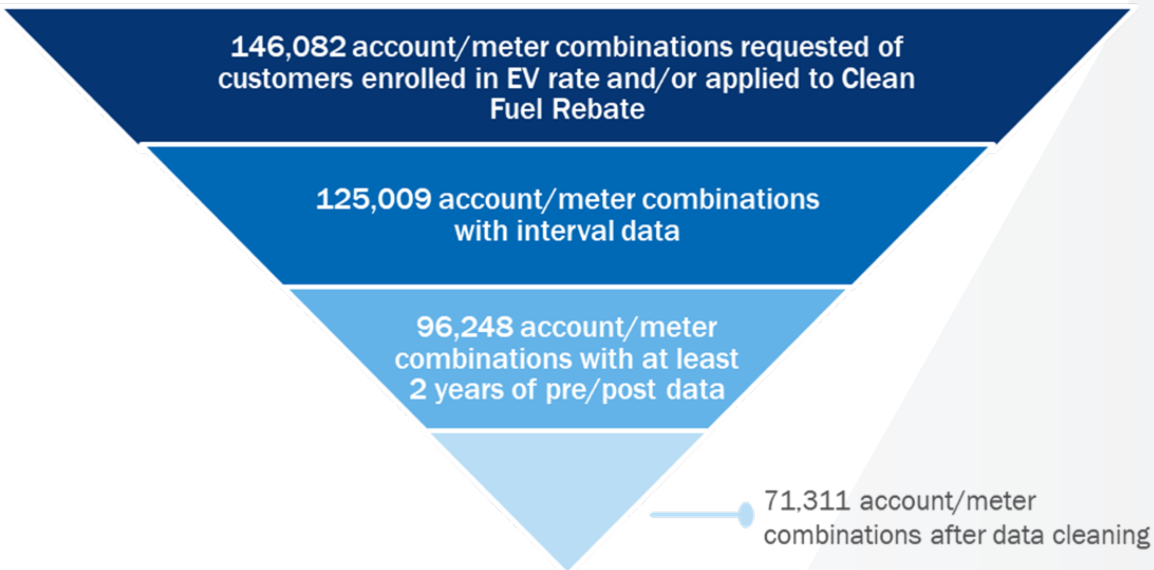
DATA CLEANING

Beginning with the entire ADR and CFR databases, the data cleaning process reduced the number of customers (account/meter combinations) down to those well suited for modeling. This required removing customers who had a lack of AMI data—either missing entire years of pre-period data (limiting the ability to create a useful pre-post TTOW model given the limited pre-period data) or containing insufficient post-period data—as well as customers who adopted solar after adopting an EV (as the baseline load would be erroneous due to the lack of pre-period solar on which the model could train), and customers for whom no charging signals were detected. Beginning with 146,000 customers, the final modeling dataset of 71,000 customers was developed by conducting the following data cleaning steps:

- **No AMI data:** Removed accounts for which no AMI data was available
- **Missing pre-period data:** Removed accounts for which no pre-period data was available
- **Duplicates:** Removed perfect duplicate records based on account/meter IDs, timestamps, and usage values
- **kWh values:** Removed records with missing kWh values, as they cannot be incorporated into the model
- **Timestamps:** Removed records with missing record timestamps
- **Insufficient pre-period data:** Removed any customer with fewer than 270 pre-period days of AMI data (9 months × 30 days), as it would be insufficient in developing models
- **Outlier readings:** Removed records with extreme outlier kWh values (+/-100000 kWh per hour)
- **Solar:** Removed post-period solar adopters, or customers who did not have any negative kWh values (which would indicate the presence of solar) prior to EV adoption, but then had negative kWh values in the post-period, indicating solar only in the post-period
- **Impute temperatures:** Imputed any missing temperature data by linear interpolation between the starting and ending points
- **No charging sessions:** Removed accounts for which no charging periods were identified/detected at a 2.8kW level, as those customers were likely L1 chargers users whose load could not be confidently disaggregated from whole-house baseline load

The progression of accounts available for clustering is shown in Figure 42.

Figure 42. Account/Meters Available for Modeling



BASELINE MODEL SPECIFICATION

We used a TTOW model originally developed by LBNL to estimate whole-house baseline load. We selected this model because it allowed us to isolate electric load from temperature and seasonal effects introduced by different months of the year. The model was trained at a per-customer level, and the extrapolation would be performed by "plugging in" a POST value of zero throughout the post-period to forecast baseline load in the absence of an EV. This model and associated forecasted load were used in the discrepancy calculation that served as the foundation of the disaggregation approach. We specify this model and the discrepancy calculation in Equation 1.

Equation 1. Baseline Load Model

$$KWH = POST + \sum(heat_i + POST: heat_i) + \sum(cool_i + POST: cool_i) + \sum(time\_of\_week_i + POST: time\_of\_week_i) + \sum(month_i + POST: month_i) + holiday + POST: holiday$$

Post – indicator variable for post-period

$heat_i$ – specific heat variable calculation for the given record (options were heat55, heat45, heat25, and heat20, specified in Table 25)

$cool_i$ – specific cool variable calculation for the given record (options were cool55, cool65, cool75, and cool90, specified in Table 25)

$time\_of\_week_i$ – indicator variable for day/hour of the day combination (e.g., Monday_00, Friday_16, etc.)

$month_i$ – indicator variable for month of the year

$holiday_i$ – indicator variable for holiday date

$heat_i$ and $cool_i$ were calculated by the following:

Table 25. Baseline Load Model Heat/Cool Term Equations

Variable	Calculation
Heat55	min(max(0, 55 – temp), 10)
Heat45	min(max(0, 45 – temp), 10)
Heat35	min(max(0, 35 – temp), 10)
Heat20	max(0, 20 – temp)
Cool55	min(max(0, temp – 55), 10)
Cool65	min(max(0, temp – 65), 10)
Cool75	min(max(0, temp – 75), 10)
Cool90	max(0, temp – 90)

POTENTIAL CUSTOMER CHARGING LEVELS

As part of the peak detection approach, we mapped the processed discrepancies between baseline load and actual AMI data to common infrastructure-informed charging levels in an attempt to infer the specific charging capacity of a given household. The mode (most common) of these discrepancies was adjusted to the "nearest" EV charging level as an approximation for the exact demand one could expect when charging. The specific levels to which these magnitudes were mapped is shown in Table 26. For example, a customer whose most-common charging magnitude was 7.5 kW (as determined by the discrepancy and signal processing calculations) would be mapped to the known value of 7.7 kW, to account for noise from the baseline load model as well as known infrastructure constraints on power draw. Note that 1.3 kW is another common charging level; however, the minimum demand for an L2 charger is 2.8 kW, and due to the uncertainty introduced in during the disaggregation process, only L2 charging was included in the study. All L1 chargers producing a demand of 1.3 kW were removed.

Table 26. Common EV Charging Levels

Common EV Charging Levels (kW)	
2.8	7.7
3.8	9.6
5.7	11.5

SIGNAL PROCESSING OVERVIEW

After calculating the discrepancies between predicted baseline load and actual load, these "peak" discrepancies needed processing in order to arrive at the final charging sessions used as inputs to the customer clustering process. This signal processing involved three key components:

1. Use a moving signal-finding algorithm to identify discrepancies significantly different in comparison to recent records for each customer
2. Clip signals below the 2.8 kW threshold and identify the most common discrepancy magnitude
3. Map the mode signal magnitude to the common charging levels to produce the charging session times and magnitudes

POTENTIAL CUSTOMER CHARGING LEVELS

The core of this process is the rolling signal finding algorithm.[64] The main idea is to move chronologically through the customer AMI-discrepancy history, subset values to only the most recent lag values, and classify points more than threshold standard deviations above these points as significant discrepancies. To accommodate longer-term changes in behavior, the input data is then adjusted by an influence parameter, which allows for the higher weighting of more recent signals in comparison to the remainder of the incorporated data. Table 27 shows the parameters used in the final implementation of the signal processing algorithm.

Table 27. Signal Processing Algorithm Parameters

Parameter	Value
Lag	140
Threshold	3.5
Influence	0.3

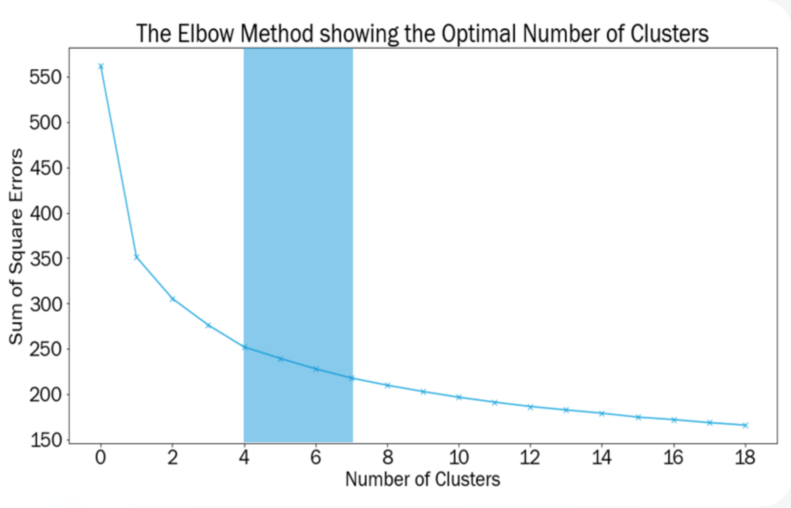
CUSTOMER CLUSTERING

K-MEANS CLUSTER IDENTIFICATION

As part of the k-means algorithm implementation, the sole parameter the Opinion Dynamics Team needed to specify was the number of clusters the algorithm would use in partitioning the participating customers. The industry standard approach is "the elbow method." We computed multiple iterations of the k-means clustering on a given dataset and, once the final clusters were identified, we calculated the total error or deviation present in the final clusters. This was repeated for multiple values of K, or multiple numbers of clusters, and the results plotted to form a curve showing the relationship between number of clusters and this total deviation. The Team identified an "elbow," or a range of values in which the curve appears to bend. This decrease in slope represents the specific number of clusters with which each additional cluster returns marginally diminishing information. This process helped us avoid introducing too many clusters so that we wouldn't overfit the data and produce hyper-specific clusters, while also maintaining as many uniquely distinct clusters as possible. Figure 43 shows the optimal number of clusters for this effort was between four and seven.

We supplemented the Elbow Method with a visual analysis of the resulting clusters across multiple different potential K values. Ultimately, this combination of statistical analysis and visual inspection produced the final seven clusters used throughout this analysis.

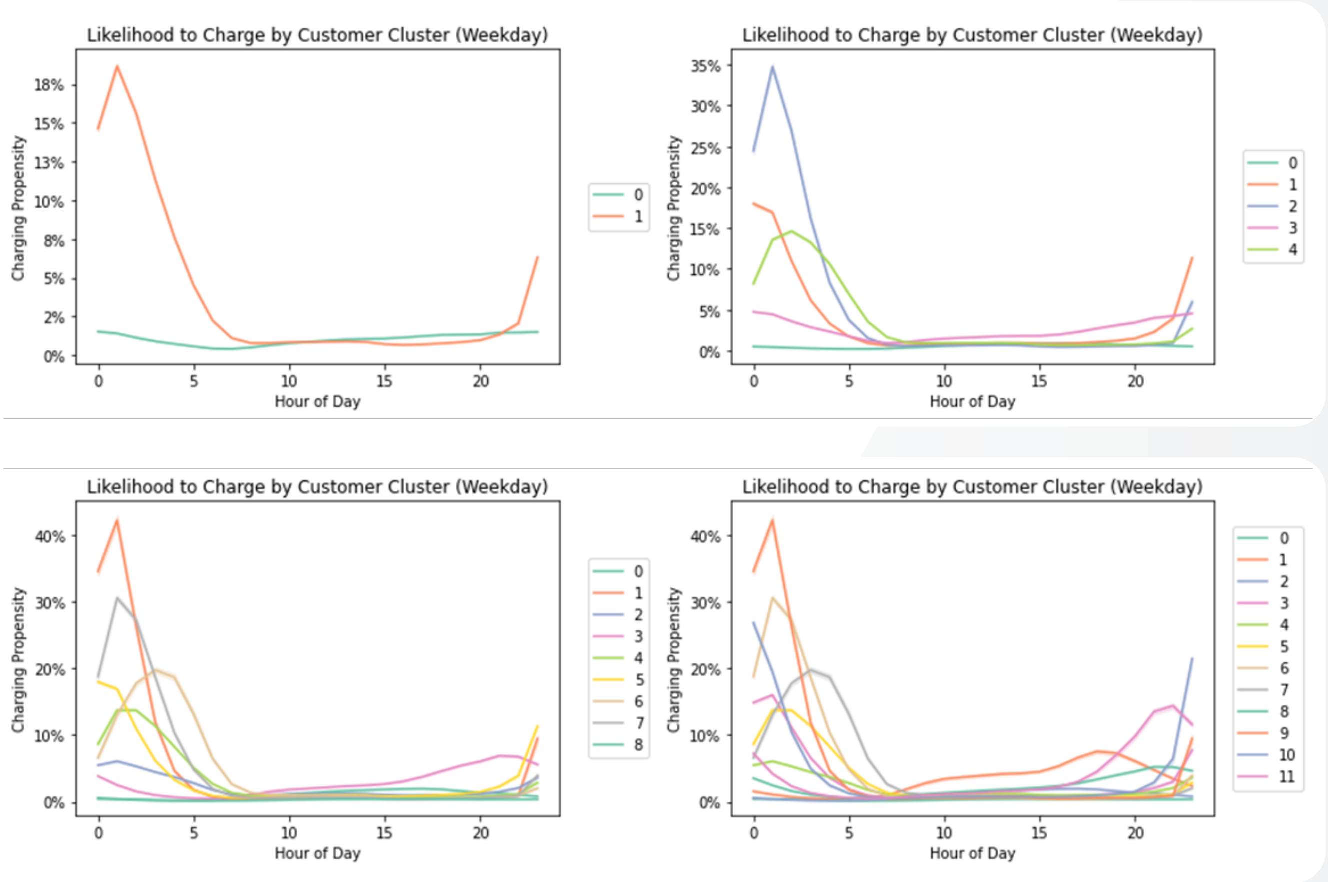
Figure 43. Clustering "Elbow Method" Diagnostic Plot



[64] Brakel, J.P.G. van. "Robust peak detection algorithm using z-scores". Stack Overflow. 2014, rev. November 8, 2020.

Figure 44 shows an example of clustering analysis outputs with different numbers of clusters, which we used for visual inspection to select the final seven clusters.

Figure 44. Number of Clusters Exploration



CLUSTER CHARACTERISTICS

CLUSTER COMPOSITION

Table 28 shows the final distribution of EV owners in our analysis across the seven clusters.

Table 28. Cluster Distribution

Description	Cluster Number						
	0	1	2	3	4	5	6
Customer #	37,242	3,753	9,807	3,600	4,418	1,995	10,496
Customer %	52.2%	5.3%	13.8%	5.0%	6.2%	2.8%	14.7%

Figure 45 through Figure 48 show how customer characteristics are distributed across each cluster.

Figure 45. Distribution of Customers on the EV Rate by Cluster

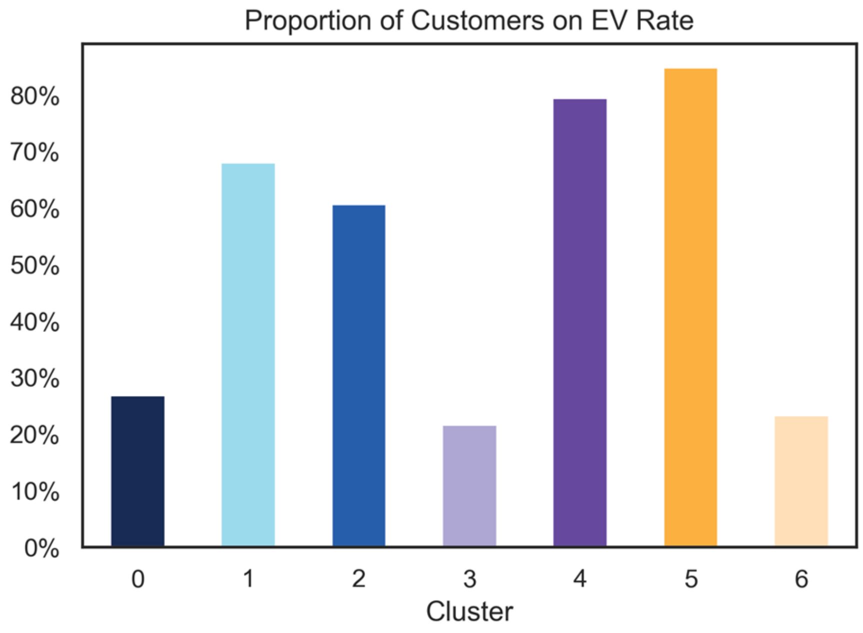


Figure 46. Distribution of Minimum Detectable Charging Level (2.8 kW) by Cluster

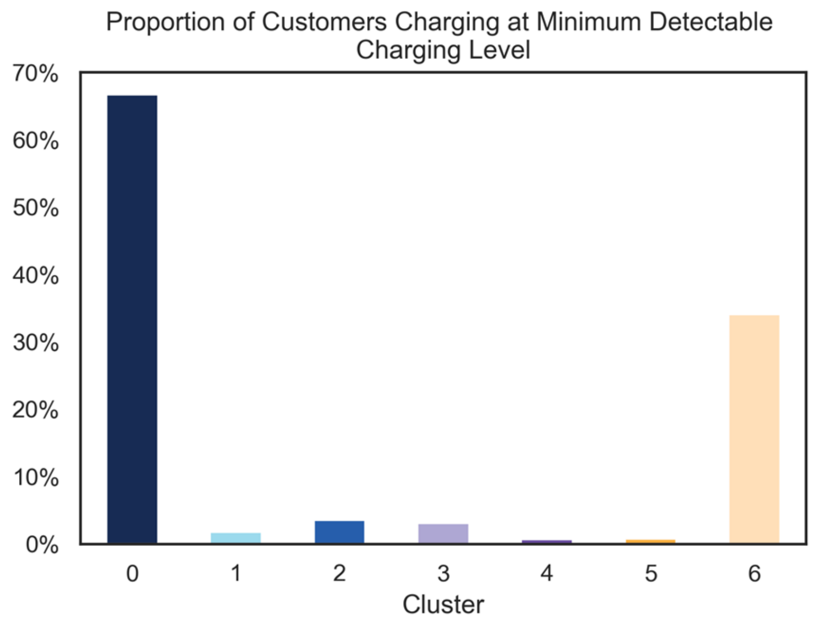


Figure 47. Distribution of BEVs by Cluster

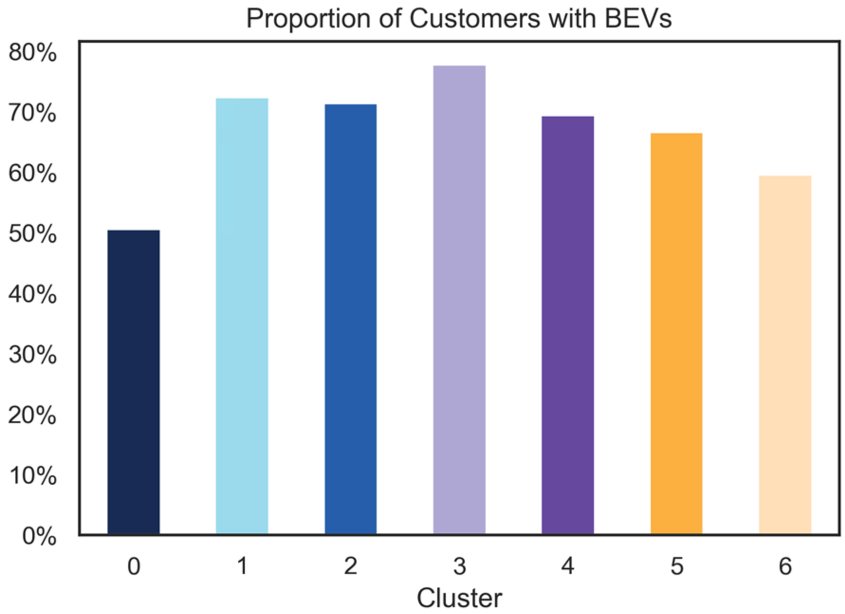
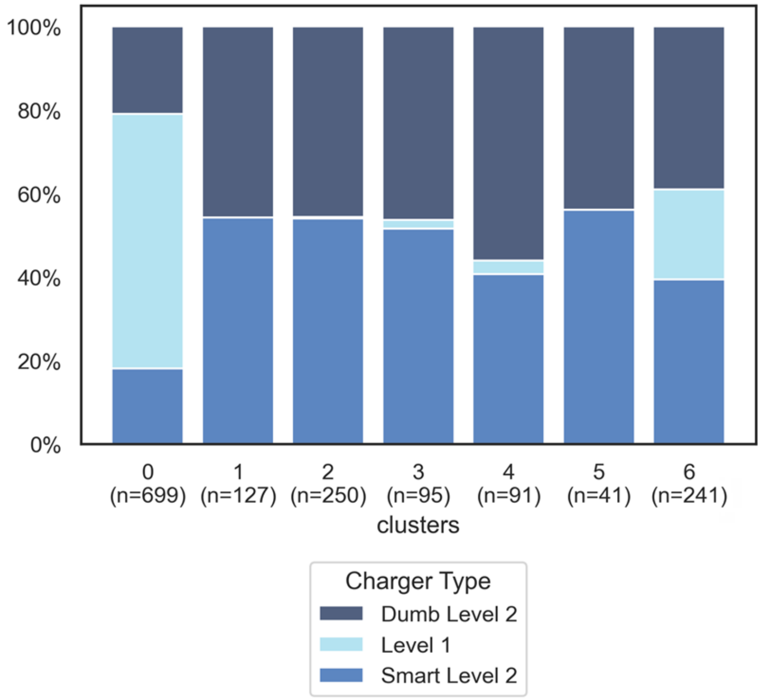


Figure 48. Distribution of Charger Type by Cluster (Conjoint Survey)



CLUSTER CHARACTERISTICS

EXTRAPOLATION-RELATED PER-CUSTOMER DEMANDS

Figure 49 and Figure 50 highlight the per-customer expected demand across weekdays/weekends at the battery and battery/cluster level. These expected demand values were used in the extrapolation techniques outlined in Section 4.2.3, as the per-customer demand values from the modeled set were extrapolated to the entire 366,000 PG&E EV owner population. Furthermore, Table 29 summarizes the investigation of battery type distribution across both the entire modeling dataset, as well as within each observed cluster. This distribution of BEVs and PHEVs, and the misalignment with the ratios observed in the CFR dataset, prompted the rebalancing by battery type in extrapolation approaches two and three.

Figure 49. Per-Customer Expected Demand by Battery Type and Day Type

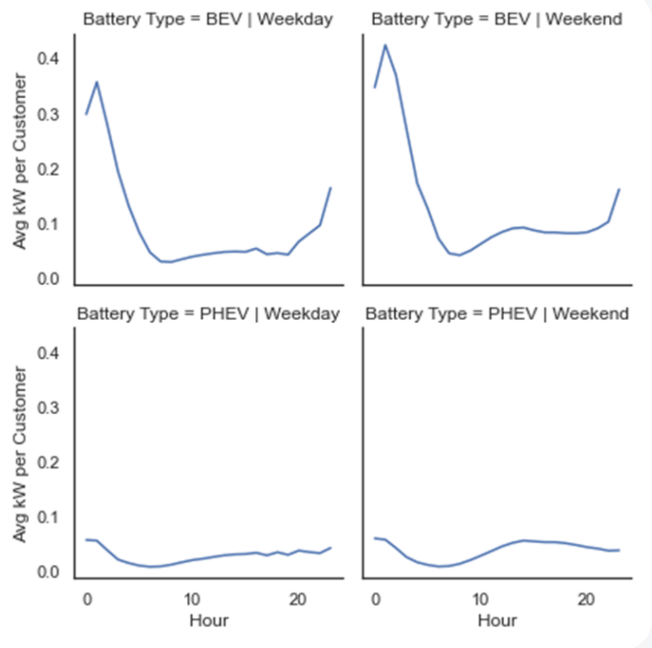


Figure 50. Per-Customer Expected Demand by Battery Type, Day Type, and Cluster

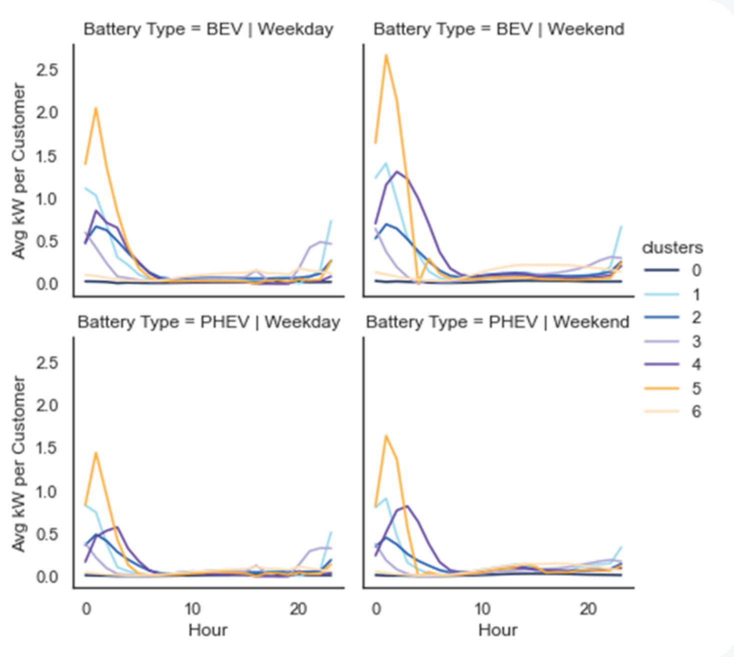


Table 29. Battery Type Composition by Cluster (Modeling Dataset)

Clusters	BEV	PHEV	Missing	Total Accts	% Total Accts
0	18,919	12,063	6,260	37,242	52%
1	2,722	282	749	3,753	5%
2	7,057	620	2,130	9,807	14%
3	2,819	377	404	3,600	5%
4	3,076	96	1,246	4,418	6%
5	1,329	55	611	1,995	3%
6	6,272	2,820	1,404	10,496	15%
Total	**42,194 (59%)**	**16,313 (23%)**	**12,804 (18%)**	**71,311**	**100%**

Opinion **Dynamics**

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