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FINAL PROJECT REPORT

Improving Commercial Viability of Fast Charging by Providing Renewable Integration and Grid Services With Integrated Multiple DC Fast Chargers

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PREFACE

The California Energy Commission's (CEC) Energy Research and Development Division supports energy research and development programs to spur innovation in energy efficiency, renewable energy and advanced clean generation, energy-related environmental protection, energy transmission, and distribution and transportation.

In 2012, the Electric Program Investment Charge (EPIC) was established by the California Public Utilities Commission to fund public investments in research to create and advance new energy solutions, foster regional innovation, and bring ideas from the lab to the marketplace. The EPIC Program is funded by California utility customers under the auspices of the California Public Utilities Commission. The CEC and the state's three largest investor-owned utilities — Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company — were selected to administer the EPIC funds and advance novel technologies, tools, and strategies that provide benefits to their electric ratepayers.

The CEC is committed to ensuring public participation in its research and development programs that promote greater reliability, lower costs, and increased safety for the California electric ratepayer and include:

- Providing societal benefits.
- Reducing greenhouse gas emission in the electricity sector at the lowest possible cost.
- Supporting California's loading order to meet energy needs, first with energy efficiency and demand response, next with renewable energy (distributed generation and utility scale), and finally with clean, conventional electricity supply.
- Supporting low-emission vehicles and transportation.
- Providing economic development.
- Using ratepayer funds efficiently.

For more information about the Energy Research and Development Division, please visit the CEC's research website (www.energy.ca.gov/research/) or contact the Energy Research and Development Division at ERDD@energy.ca.gov.

ABSTRACT

This research project addresses the high cost of financing, building, and operating direct current fast charging stations that charge plug-in electric vehicles in California. The project goal was to demonstrate a direct current fast charging station with limited impact to the electric grid infrastructure. The project's test site consisted of four 50-kilowatt direct current fast chargers and a second-life battery energy storage system, located at a shopping center in Monterey Park, California. Data was collected on site and added to representative data from other fast charger installations. Operational data of the plug-in electric vehicle charging site, the second-life battery energy storage system, and the site controller were analyzed to identify potential savings. The project simulated and evaluated multiple applications, including participation in demand response programs, renewable integration from onsite solar photovoltaics, and demand charge mitigation.

Keywords: Electric vehicles, electric vehicle supply equipment, fast charging, energy storage, second-life battery, solar photovoltaics, charging demand, load management

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Background

Large-scale use of plug-in electric vehicles will be critical for California to meet its mandate for greenhouse gas and criteria pollutant emissions reduction. The state has enacted numerous policies and programs to increase adoption of these vehicles to accelerate climate change mitigation and improve air quality. In 2020, Governor Gavin Newsom issued Executive Order N-79-20, which mandates that all new light-duty passenger vehicles sold be zero emission by 2035, and that all medium- and heavy-duty vehicles sold be zero emission by 2045, where feasible. Meeting these targets will require widespread installation of public chargers, including more than 30,000 direct current fast chargers by 2030, according to the California Energy Commission's Infrastructure Assessment for Assembly Bill 2127. Direct current fast charging stations have high capital and operational costs, particularly early in their deployment when driver utilization can be low. There is a critical need to develop technologies that reduce the costs of installing and operating direct current fast charging stations and increase their availability to support the state's ambitious environmental goals.

Deploying multiple direct current fast chargers in a single location can place high stress on the electric distribution system, since the chargers require high and variable peak power use. To recover the cost of providing high-power service, utilities typically charge plug-in electric vehicle charging station operators a maximum demand charge (dollars per kilowatt or $/kW), in addition to an energy usage charge (dollars per kilowatt-hour or $/kWh) on their monthly bills. These demand charges can create significant costs for direct current fast charging station operators, and the costs may then be passed on to drivers. Recognizing this, California's investor-owned utilities (Pacific Gas & Electric Company, San Diego Gas & Electric Company, and Southern California Edison) have temporarily waived demand charges for direct current fast chargers for the next several years but will gradually begin phasing them back in over the last half of this decade. As demand charges are phased in, operators of public direct current fast charging stations will require technologies and operational strategies that manage costs and maximize potential new revenue streams that will ultimately improve their long-term economic viability.

Project Purpose and Approach

This project improved the commercial viability of operating direct current fast charging stations by using second-life battery energy storage systems, a local site controller, and a suite of cloud-based software tools to control charging. These technologies can manage plug-in electric vehicle charging loads, integrate onsite energy storage and other distributed energy resources, participate in demand response programs, and schedule charging for plug-in electric vehicle fleets. The software both optimizes these technology assets and minimizes costs, while still meeting drivers' charging needs.

The demonstration site was located at a commercial shopping center in Monterey Park, California, and consisted of four 50-kW direct current fast chargers and a 48-kW and 110-kilowatt-hour (kWh) second-life battery energy storage system.

Construction at the site was completed in March 2020 at the beginning of statewide shelter-in-place orders during the COVID-19 pandemic. Consequently, use of the direct current fast chargers at the site was low, although there was improvement toward the end of the project as travel approached normal levels. To produce more reliable analyses, the project team added data collected from the pilot site with charging data from a similar installation of direct current fast chargers operated by Greenlots (now called Shell Recharge, Shell's electric vehicle charging network). The dataset was evaluated to ensure that it was statistically representative of the early utilization documented at the Monterey Park installation.

Using this data, the project team ran simulations to evaluate the economic savings achievable from the onsite second-life battery energy storage system and plug-in electric vehicle charging management software, as well as estimated potential payback times. Simulated scenarios included demand charge mitigation, participation in demand response programs, and solar photovoltaic integration.

Key Results

Site utilization in the second half of 2020 and in the first half of 2021 was low due to the impacts of the COVID-19 pandemic on travel. During that time, there were approximately 1,068 charging sessions (approximately three sessions per day) and a total of 15,515 kWh dispensed during those charging sessions (approximately 43 kWh per day). As California's pandemic restrictions relaxed during June 2021, site use increased. In June 2021 there were approximately 129 charging sessions (approximately four sessions per day), totaling 1,928 kWh dispensed (approximately 64 kWh per day). From the battery data collected in 2020 (April to December), it was discovered that, out of the 5,945 kWh used for vehicle charging in that period, 464 kWh (7.8 percent) was from stationary storage.

Simulated Demand Charge Reduction

From January 2019 to August 2020, only three percent of total site energy was delivered at power levels greater than 80 kW. However, because utility demand charges are determined by monthly peak demand, it takes only a single 15-minute interval of high-power demand to incur large costs for the month. Charging energy and demand data was used, with anticipated eventual demand charge rates (beginning in 2029), to calculate an estimated annual site utility cost of approximately $42,000, of which more than 40 percent ($18,600) was for demand charge costs.

The project team modeled the extent to which the second-life battery energy storage system could limit peak demand to reduce potential demand charges at the site, and it also evaluated optimum demand thresholds above which the storage system would discharge to offset energy from the grid. By reducing peak demand by 60 kW, the second-life battery energy storage system could save approximately $4,300 annually in avoided site demand charges, a 23 percent reduction.

According to data from the U.S. Energy Information Administration in a report entitled *Battery Storage in the United States: An Update on Market Trends*, the capital cost for four-hour utility-scale storage is expected to range from $143/kWh to $248/kWh by 2030. While projections for behind-the-meter energy storage systems are not available, it can be assumed that battery costs are going to come down significantly. By comparison, the average capital cost of all storage projects (utility and behind-the-meter) was $589/kWh in 2019.

The California Public Utilities Commission's Self-Generation Incentive Program is available in California to provide incentives for commercial energy storage use by covering most of the cost of installing an energy storage system; unfortunately, the program is not available for second-life batteries. Assuming that new batteries were used and that the Self-Generation Incentive Program was available, the incentive amount would be $350/kWh. For the 48-kW and 110-kWh battery on the site, the Self-Generation Incentive Program subsidy total would be $38,500 and the total capital cost of the system would be reduced to $26,290, resulting in a payback period of 6.1 years.

Reducing the site peak demand threshold at which the battery energy storage system discharges can potentially result in larger economic savings and shorter payback periods. However, additional simulations and studies of customer response are required to evaluate if these lower thresholds are feasible, since lower thresholds could slow plug-in electric vehicle charging despite improving the site's economic performance.

Demand Response Capacity Simulations

Participation in a demand response program is akin to a demand charge reduction in terms of controlling installed assets to lower site load for the local utility. In demand response programs, the site controller responds to signals from grid operators to shed load at times of peak system demand.

Simulations were performed to calculate the site's energy reduction during capacity bidding program events in 2020. Parameters were set that limited the amount of electricity (equal or less than 10 kW) and energy that electric vehicle supply equipment drew from the grid. When the curtailment was compensated using the battery, approximately 20 percent to 40 percent of grid power was reduced (a net reduction as high as 58 kWh). The electric vehicle supply equipment energy curtailed was limited to less than 17.5 kWh so that customers would be unaffected.

Renewable Integration Simulations

The project simulated the potential for onsite solar photovoltaics to charge the second-life battery energy storage system, reducing total utility costs and marginal greenhouse gas emissions. Simulated solar performance from 2011 to 2016 for a characteristic photovoltaic solar array located at the Monterey Park location was approximately 3 to 6 kWh, produced per kW installed over the course of a year. Based on data from the California Distributed Generation Statistics database, the simulations showed that a photovoltaic array of approximately 100 kW to 150 kW would provide enough energy to the second-life battery energy storage system to support daytime peak shaving as well as meet most overnight demand. Using the photovoltaic array to charge the battery energy storage system saved approximately $4,780 to $6,000 per year in avoided utility energy costs; combined with California's Low Carbon Fuel Standard credits, this represented a 13-percent reduction. However, based on data from the energy company Infinite Energy (2024), the current installed cost for a 100-kW solar array is approximately $165,000, which would complete payback after more than two decades.

Simulated Fleet Scheduling

This project's fleet scheduling simulations showed that operators could easily shift their loads through cloud-based load controls to periods of low energy costs, reducing their fleet charging costs. This project also revealed potentially valuable use cases for midday fast charging at the fleet depot, when there is a need to ready vehicles quickly for the next shift. Adding onsite stationary energy storage could shave off-peak charges and reduce impact to the grid, though not all fleets are the same; some can shift easily, and some cannot.

Evaluating Second-life Battery Response and Degradation

During battery evaluation, engineers periodically measured capacity degradation by discharging the battery at different current levels and measuring the cell voltages. The capacity loss during a five-month period was 5 percent between the two battery stacks, which can be extrapolated to an approximate 27 percent reduction in two and a half years. This could translate to an estimated life expectancy of four to seven years.

Knowledge Transfer and Next Steps

Greenlots continues to share the results of this project within Shell Global, with utilities, at industry workshops, and through public reports published on the Greenlots website. Greenlots also engaged the technical advisory committee to solicit input and transfer knowledge from this project to utility participants Southern California Edison and the Sacramento Municipal Utility District, national laboratories (Argonne National Lab), government agencies (the Vehicle Technologies Office and the Advanced Grid Research and Development Division, United States Department of Energy), and nongovernmental agencies (World Resources Institute).

The site managed plug-in electric vehicle charging algorithms demonstrated in this project, which have been implemented at numerous Greenlots direct current charger installations, in California and nationally. Lessons learned and incremental improvements made through this project helped Greenlots improve the algorithm. The newer version of the algorithm uses priority lists that apply different parameters in different periods of operation; each list has greater flexibility in handling various electric vehicle supply equipment and battery limitation and site requirements. Going forward, Greenlots is pursuing partnerships and greater investment to scale deployment of intelligently managed charging solutions for plug-in electric vehicle drivers and fleets.

Greenlots plans to continue to provide raw data from the project site for an additional two years after project completion, including continued assessment of second-life battery energy storage system degradation.

CHAPTER 1: Introduction

Large-scale deployment of plug-in electric vehicles (PEVs) will be critical for California to meet its mandate for greenhouse gas and criteria pollutant emissions reduction. The state has enacted numerous policies and programs to increase adoption of PEVs to accelerate climate change mitigation and air quality improvements. In 2020, Governor Gavin Newsom issued Executive Order N-79-20, establishing that all new light-duty passenger vehicles sold be zero emission by 2035, and that all medium- and heavy-duty vehicles sold be zero emission by 2045, where feasible (Newsom, 2020). Meeting these targets will require the widespread deployment of public chargers, including potentially more than 30,000 direct current (DC) fast chargers, according to the California Energy Commission's (CEC) infrastructure assessment for Assembly Bill 2127 (CEC 2021a). However, DC fast charging stations have high capital and operational costs, particularly early in deployment when use by PEV drivers can be low (Nelder 2019). There is a critical need to develop technologies that help reduce the costs of installing and operating DC fast charging stations to increase their availability to drivers and support state energy policy goals.

Deploying multiple DC fast chargers in a single location can place high stress on the electric distribution system because the chargers have high and variable peak power usage. To recover the costs of providing high-power service, utilities typically charge PEV charging station operators a maximum demand charge (dollars per kilowatt or $/kW) in addition to an energy use charge (dollars per kilowatt-hour or $/kWh) on their monthly bills. These demand charges can create significant costs for DC fast charging station operators that would likely be passed on, ultimately, to PEV drivers. Recognizing this, California investor-owned utilities (Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company) have temporarily waived demand charges for DC fast chargers for the next several years, but they will gradually begin phasing them back in over the last half of the decade (CPUC 2018a). As demand charges are phased in, operators of public DC fast charging stations will require technologies and operational strategies to manage costs and maximize potential new revenue streams to improve their long-term economic viability.

DC fast charging stations in California can be expensive to own and operate due in part to potential demand charges that recover costs associated with grid impacts from high-power requirements. There was no established way to directly manage the issue or to create new revenue streams for charging station operators that could help offset these deployment and operation costs. This research project, begun in July 2017, focused on addressing the high current cost of financing, building, and operating DC fast charging stations, with the goal of accelerating their deployment and adoption.

The project evaluated the following methods of improving key operational and commercial aspects of DC fast charging stations:

- Simulated site demand charge reductions using the installed second-life battery energy storage system (BESS) to limit peak power drawn at the utility meter, on a 15-minute basis.
- Simulated demand response (DR) participation with the local utility to evaluate the potential for additional revenue generation from the site.
- Simulated solar photovoltaic (PV) generation integration by using onsite stationary energy storage to store renewable energy for cost arbitrage and additional credits.
- Simulated fleet scheduling for the site to generate additional revenue in the future.
- Evaluation of the degradation of the second-life BESS to determine the life expectancy and commercial viability of onsite stationary energy storage.

This project explored the potential value of second-life batteries, working together with innovative load management algorithms, to reduce the costs of financing, building, and operating DC fast charging stations.

PEV batteries are typically replaced after they lose 20 percent to 30 percent of their original capacity, which means that up to 80 percent capacity remains when the batteries are retired from PEV use, making them potentially useful for other applications. Retrofitting lithium-ion (Li-ion) batteries used in PEVs for second-life applications requires extensive testing and upgrades to ensure the batteries perform reliably in their new applications. The lithium-ion batteries used in today's PEVs are already being deployed within the electrical power grid for a variety of purposes, including, for example, smoothing fluctuations in solar renewable power generation. The lifetime of these second-life batteries varies, depending on the thermal environment and how they are charged and discharged. The nascent second-life battery market is in the process of developing a steady battery supply, building a customer base, and securing funding.

Some estimates suggest that stationary storage comprising used PEV batteries could exceed 200 gigawatt hours (GWh) by 2030 (Engel, et al. 2019). Second-life PEV batteries could potentially lower both the costs and greenhouse gas emissions of stationary storage systems, yet their performance and degradation rates remain uncertain, with limited available field data.

The general approach of this research project was to analyze data from a PEV charging site equipped with a second-life BESS, working with a custom algorithm to minimize peaks in the load profile and reduce site demand charges. The project included simulations of various scenarios to evaluate the effectiveness and limitations of an onsite second-life BESS in conjunction with a load management algorithm developed on a local controller that controlled both charging stations and the BESS.

The primary application addressed was demand charge reductions in cases where the site paid a large portion of its monthly utility bill for the infrastructure used for getting required power to the site. With a low utilization factor of less than 20 percent, the proportion of the demand charges was significantly higher, making commercial DC fast charging hubs a nonstarter.

This project reduced the monthly utility bill and improved project economics by reducing coincident peaks from multiple DC fast chargers when engaged simultaneously. Recently, special tariffs in California have been approved that offer low- or no-demand charge tariffs but higher energy charges, with demand charges beginning in 2024. This is a welcome step for PEV charging hub adoption, but the value of this project remains, given the expected increase of PEVs as both general and fleet vehicles. There is also an opportunity to do energy arbitrage, where some of the energy consumption can be shifted from peak hours to off-peak hours using the battery. This offers drivers the option of charging at normal rates without paying for peak electricity costs. Participation in utility DR programs was also evaluated, including how much capacity could be provided to the market and the value of that capacity. The value grows when multiple sites across a utility's service territory are aggregated to offer capacity into the market.

CHAPTER 2: Project Approach

Demonstration Site Overview

The research site was located at 4000 Market Place Drive in Monterey Park, California. The site has been in public operation (with data collection) since March 9, 2020. The station charges drivers a flat fee (comparable to other DC fast charging stations in the area) that is accessible through either the Greenlots' mobile app or a radio-frequency identification card.

Site Management System Overview

The following is an overview of the Greenlots site management system, with a local energy management algorithm running the site controller. While the system configuration and hardware mentioned are specific to the Monterey PEV charging site shown in Figure 1, the algorithm and system architecture are flexible enough to accommodate a wide range of hardware, configurations, and requirements.

Figure 1: The EV Charging Site at Monterey Park, California

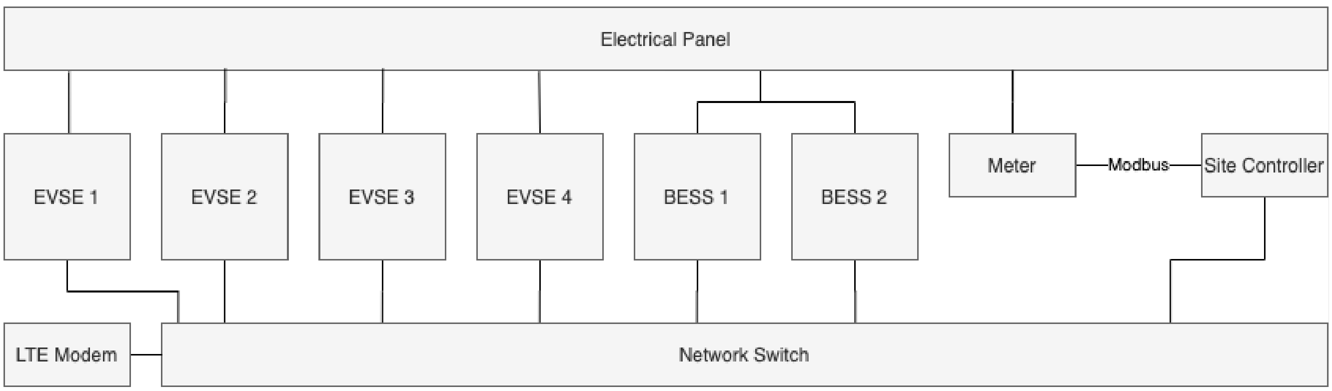
Source: Greenlots/Will Wang

In Greenlots' system architecture, the algorithm was implemented as one of many microservices running on the local site controller at the PEV charging site. The site controller was physically installed at the site using an industrial microcomputer. This approach allowed for robust offline functionality since algorithm decisions could be made at the site without requiring either cloud processing or an internet connection. This also provided online functionality, including configuration through a web portal, site monitoring, and remote distribution of software updates.

The site controller and the local algorithm communicated with the individual hardware components in real time. Key parameters for the specific site could be set and communicated from the cloud-based Greenlots SKY™ network using the SKYWave protocol that Greenlots specified for communication.

The algorithm was expected to run every 15 seconds, with communication to all four DC fast charging Tritium 50-kW units via the Open Charge Point Protocol (OCPP), Ideal Power battery inverters via Modbus (Transmission Control protocol) TCP, the Nuvation battery management system (with Spiers second-life batteries via Modbus TCP), and the Greenlots SKY™ network in the cloud (via SKYWave protocol). The physical hardware layout is shown in Figure 2, and the communication paths are shown in Figure 3.

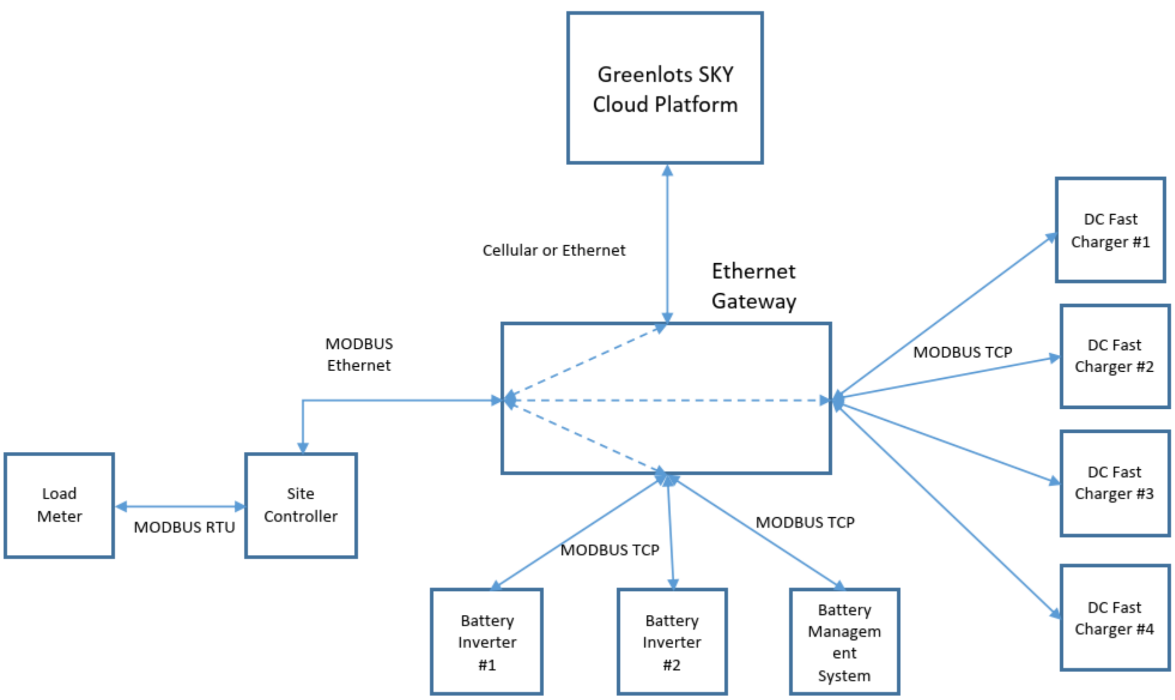
Figure 2: Site Electrical Indicative Setup



EVSE = electric vehicle supply equipment

Source: Greenlots

Figure 3: Site Communication and Layout



Source: Greenlots

For a diagram showing electric vehicle supply equipment (EVSE) status changes in different stages of operation, see Appendix A. For details on the Watt Tower energy storage system, see Appendix B.

Developing Controls for DC Fast Chargers and Batteries

Open communications standards are key enablers for the smart grid, where two-way power flows and real-time information and control are critical. Open standards are fundamental enablers of open interoperable platforms so encourage innovation. The Open Charge Point Protocol (OCPP) is an internationally recognized initiative with the purpose of creating an open application protocol that allows PEV charging stations and central management systems from different vendors to communicate with one another. With this protocol, it is possible to connect any central system with any charge station, regardless of the vendor; OCPP acts as the intermediary between the charging station and the back end (or network management software). A PEV charging network is needed that allows network owners to communicate with their charging stations, which, in turn, allows charging stations to communicate with the power grid.

An advanced PEV charging network allows operators to obtain real-time information on the performance of their PEV charging stations, manage charging status, enable dynamic pricing tools, process payments, instantly detect faults, and issue tickets for servicing. The network management software takes information from the charging station and communicates it to the back-office server at a utility, municipality, or other administrator. On the consumer side, this allows for services such as billing, access control, authentication, and payment. Site hosts can set pricing and usage policies, as well as leverage data to understand the behaviors and preferences of customers.

Managing Load With the OCPP 1.6 Protocol

Control communication between the Greenlots SKY™ network, the site controller, and the DC fast chargers is performed using OCPP 1.6. This protocol represents an open standard for PEV manufacturers when developing communication protocols with general charge point operators, enabling manufacturers to avoid developing customizations for each specific operator. Greenlots previously validated Tritium Veefil units, testing integration capabilities between the site controller, the cloud network, and Tritium software over OCPP 1.6.; this allowed the cloud or local site controller to manage at either a session level or the charger level, setting both a charging curve for a driver or fallback settings when there was no communication to the site.

The OCPP 1.6 protocol supports the functionality of load control from cloud-based network management software. Smart charging functionality in OCPP was selected for this project so the technology developed could be used across different manufacturers, models, and charger types.

The following messages were used for load control.

- **TxDefault Profile:** This was the default power setting of the charger; the charger continued to charge at this power setting unless overridden by TxProfile.

- **TxProfile:** This message was used for the power setting for a specific charging session at the charger and overrode any TxDefault profiles. The profile with constraints was imposed by the charger on the current transaction and was no longer valid when the transaction was terminated.
- **ChargePointMaxProfile:** This power setting configured both the maximum power and the current available power to the charger, taking precedence over other load-control messages.

Using the OCPP Proxy on the Local Controller

Control of chargers through the OCPP protocol could be managed either from a cloud network or through a local site controller at the site. The project used a local controller that was physically connected to the chargers through an Ethernet connection. All the DC fast chargers used in this project were designed to communicate to a cloud platform through OCPP. This allowed the chargers to send actual charging loads to the cloud while getting signals from the cloud that managed charging power. This cycle of operation took a few seconds and was dependent on the network connection between the charger and the cloud.

By installing a local copy of the Greenlots SKY™ data on the site controller, the project team enabled faster monitoring and control of data (under five seconds), and the system reacted more quickly to changing loads. Since a standard protocol was used for all communication to and from the chargers, the system was agnostic to the type of manufacturer and charger (for example, Level 2 versus a DC fast charger) if the site's system supported the OCPP 1.6 Smart Charging profile.

Site Controller Implementation

The site controller was the key component for all control architecture at the site level. The site controller communicated with the individual hardware components in real time and sent information to the Greenlots SKY™ platform through the SKYWave protocol defined for communications. Locally, the site controller communicated with four, 50-kW DC fast chargers, two Ideal Power inverters, two Nuvation battery management systems, and power meters to monitor loads. The control algorithms ran every 15 seconds, with communication to multiple devices in real-time to obtain accurate device-level data.

Development of Battery Control Interfaces

Introduction to Battery Control Interfaces

Greenlots developed algorithms for site-level load management, including the charger and battery controls, and this algorithm was deployed on a local controller. While the high-level decisions of load management were done by the local controller, the actual battery management was done by a battery management system (BMS) that monitored and controlled the battery system. This simplified development and enabled Greenlots to develop a hardware agnostic load-management solution.

For battery control, Greenlots interfaced with a Nuvation BMS module. The Nuvation High-Voltage BMS™ modules managed a battery stack, including a stack controller, a power interface, and a cell interface. The Nuvation BMS™ was compliant with Draft 3 of the MESA-Device/SunSpec energy storage model.

A typical single-stack system configuration included one stack controller, one power interface, and one or more cell interfaces, connected in series. This modular architecture supported battery pack voltages as high as 1,250 volts (V). Cell interface modules could manage up to 16 cells each. One stack controller could manage up to 48 cell interface modules. The grid battery controller (GBC) managed multi-stack battery configurations by aggregating the stack controllers and managing all cells and stacks as a single unified battery.

Communication From Site Controller Through SKYWave

In addition to OCPP communication, Greenlots developed the proprietary communication protocol SKYWave between the site controller and the cloud-based Greenlots SKY™ platform. Through this interface, the site controller sent real-time data about the chargers, battery, and meter readings. Data transfer could be configured to define the data fields sent, as well as its frequency.

Strategies for Managing Site Charging Loads

Developing Load Management Algorithms and Approaches

The purpose of the PEV site energy and charging management algorithm (often referred to as simply the "algorithm" in this report) was to provide PEV charging sites with automatic control software that dynamically allocated energy resources (for example, grid power import, battery discharging, and solar PV) to various loads (for example, grid power export, battery recharging, and electric vehicle supply equipment), given different factors and limitations, including time-of-use tariff, rate charges, physical meter and breaker limits, business considerations, and customer experiences.

From an overall control architecture perspective, this load management algorithm was implemented on the site controller as a local microservice, obtaining parameter set points and a list of priorities from the Greenlots SKY™ cloud network. The algorithm then determined, at the site level, how best to operate the BESS and chargers, with the goal of reducing the energy required from the grid during high occupancies (based on local Southern California Edison Company (SCE) tariffs and demand-charge requirements.

With the algorithm implemented locally, unnecessary communications and delays between the stations and the cloud server were eliminated, improving operational efficiency while reducing bandwidth requirements. The site controller passed through all OCPP messages from the Tritium DC fast chargers to the Greenlots SKY™ EV charging network software, intended to communicate session information, authentication, error codes, and logs. The site controller did not read or edit messages to prevent the interruption or corruption of messages to the Greenlots SKY™ network, but it did reference these messages in cases of communication losses.

Algorithm Design Principles

The algorithm was designed to accommodate any number of DC fast chargers and any size of onsite energy storage. This was accomplished through flexible input parameters for the Greenlots site operator, customizable scheduling, and a prioritized discharge rate of stored energy based on hardware specifications, onsite usage data, and business considerations. The algorithm was designed to be powerful and fast enough for the site controller to communicate and control up to 100 charge points.

After several iterations of algorithm development, Greenlots adopted a priority-list approach for algorithm parameter setups. The priority list had two main attributes: the window and the rule list. The window was a calendar entry, and every window had a window priority. The rule list contained an arbitrary number of rows of assets, their limits, and optional special properties. For example, a row in plain language may be "the 15-minute average of the site meter cannot be over 160 kW." The top row had the top row priority, and subsequent rows had gradually lower row priorities. The algorithm traversed down the row priority list to satisfy as many rows as possible. Furthermore, there could have been multiple priority lists, each with its specific window priority. The algorithm, at any specific time, looked at all priority lists with this exact time in its window, then used the priority list with the highest window priority.

By using the priority lists in this way, the site controller could control the amount of stored energy dispensed and match it with the onsite PEV charger load. A typical use case dispensed the stored energy during peak demand after the site reached a certain preset threshold, limiting the amount of electricity imported from the grid. The BESS then recharged when site demand was low.

Two important factors were prioritized when developing the algorithm: configurability and flexibility. The evolution of the algorithm and its final choice of priority list reflected the project team's strategy to most effectively optimize these goals.

- **Configurability:** In Version 1 of the algorithm, the only configurable value was the target demand set point. The site controller would attempt to stay below the target demand set point, first by using the battery and then by curtailing EVSE, as needed. The current version of the algorithm had many more configuration parameters due to the use of priority lists. This allowed a site to handle higher priority entries, which take precedence during both peak and mid-peak hours, or during DR events. The lists comprised business considerations and constraints for the site level meter, EVSE, and batteries. The site controller satisfied the constraints in priority order and satisfied as many constraints as possible.
- **Flexibility:** In Version 1 of the algorithm, when too much power was drawn from the site, the site controller would first attempt to use the BESS to supply enough power to keep the site below target demand. If that was inadequate, the site controller would curtail EVSE to meet the target demand set point. The challenge with this approach was that it led to very poor performance for drivers. If PEV demand was high, the BESS depleted and the EVSE was curtailed with no support from the battery. This severely slowed down a public site, leading to dissatisfied drivers.

The current algorithm used priority lists so the site could automatically adjust to higher-than-expected charging volumes, so that priorities could also be assigned according to business logic and other considerations. For example, the project team wanted to satisfy drivers by giving them a higher priority of minimum power, rather than keeping the site's total power drawn from the grid. But, for other lower-priority constraints, the maximum power drawn from the grid took precedent. The introduction of the window attribute enabled more flexibility for different priority lists during different times of the day, days of the week, and seasons, and for other inputs.

In addition, several improvements were made as the Greenlots team developed iterations of the algorithm, including:

- Measuring and reporting uncurtailed power, which helps customers better understand potential savings and predict their usage.
- Optimizing 15-minute windows for EVSE charging, so that charging speeds remain constant in a 15-minute window, minimizing customer confusion and frustration.
- Correcting an imperfect BMS from reporting incorrect state of charge (SOC) numbers.
- Calculating reasonable worst cases for minimum power consumption (export) and maximum power consumption (import) for different time frames and meeting as many of the priorities as possible.

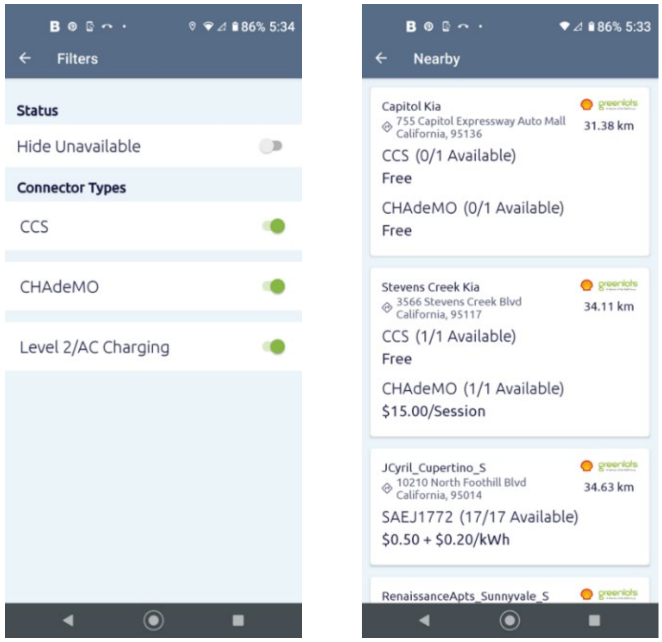
Engaging With Drivers

The Greenlots Mobile App

The Greenlots mobile application for PEV chargers engaged drivers looking for EV charging sites and was available for Apple and Android smart devices. The mobile app made it convenient and easy for drivers to:

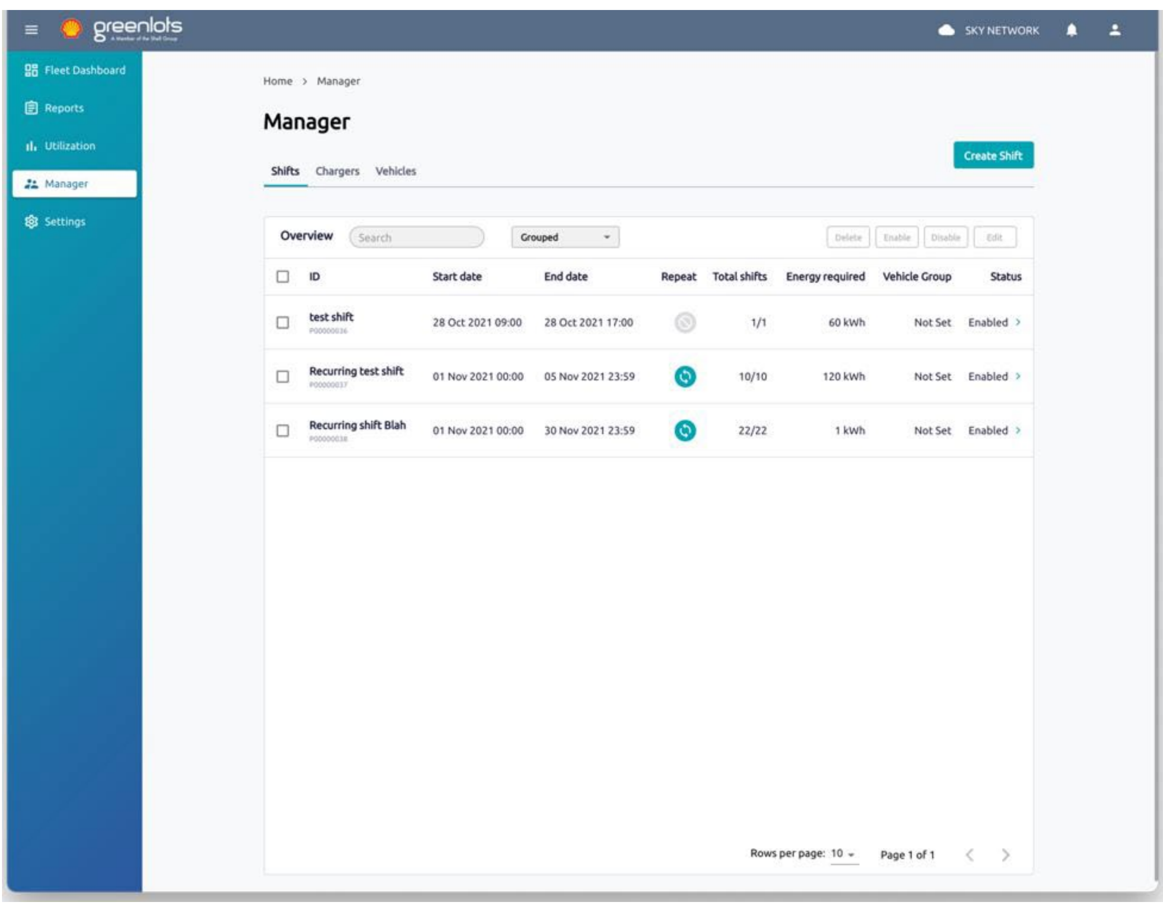
- View all public charging spots with easy, quick access. PEV drivers could find available public charging stations near them, making it easier for them to charge their vehicles conveniently and reliably.
- Locate the nearest charger. The mobile app used location services, making it easy for PEV drivers to find the closest charging station. Drivers could filter results based on charger type and create a list of their favorite charging spots. See Figure 4 and Figure 5.
- Pay with their phone using a QR (quick-response) code or station ID (identification). Mobile app users could quickly scan a QR code with their smart phones to pay for charging sessions.

Figure 4: Greenlots Mobile Application



Source: Greenlots

Figure 5: Greenlots Fleet Scheduling Tool — Manager



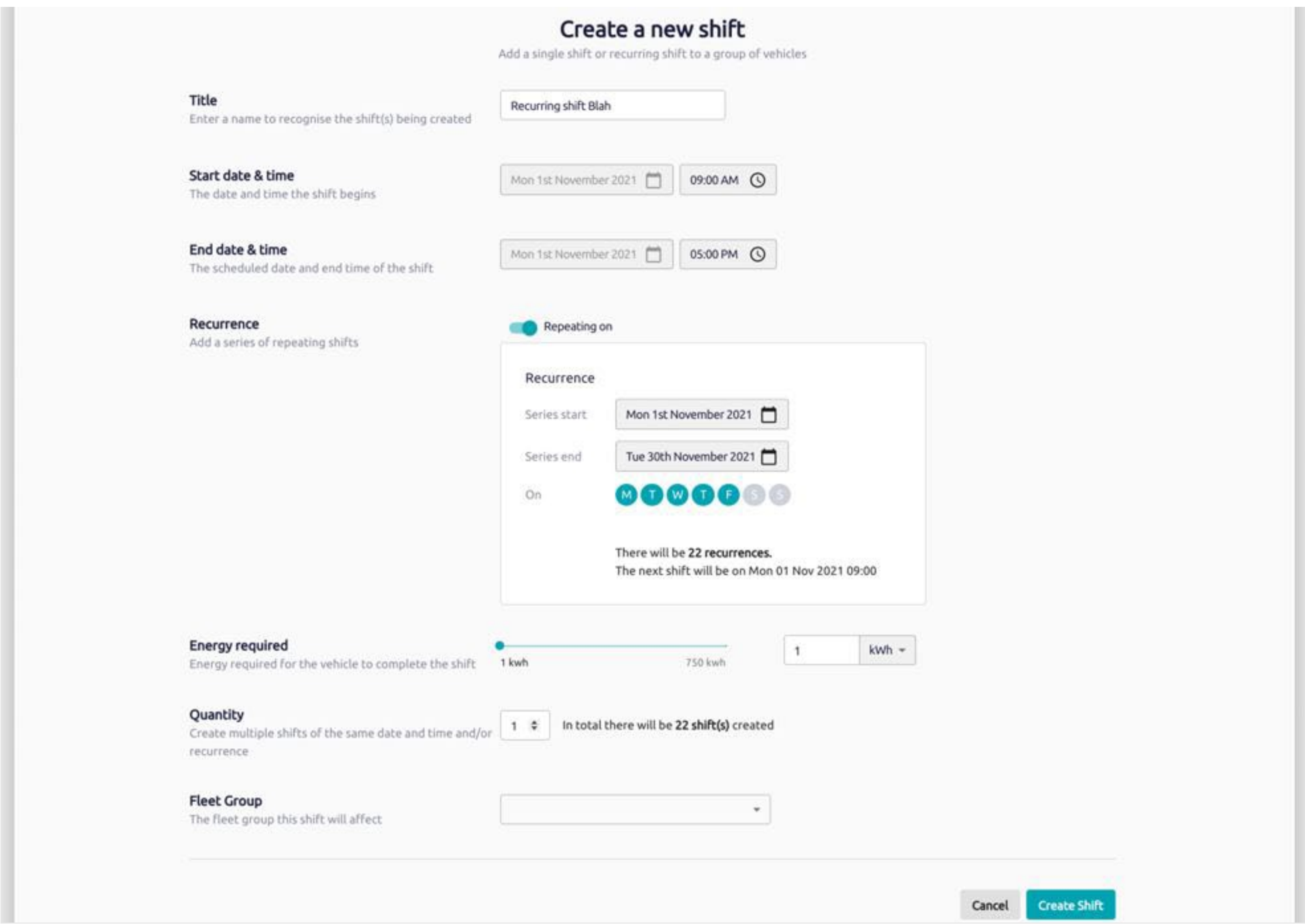
Source: Greenlots

Engaging With Fleet Customers

Companies and cities around the world are electrifying their fleets to reduce operating costs and meet environmental goals. Fleets will be key drivers of increased adoption of PEVs in California. With predictable usage patterns and a focus on cost efficiency, fleet customers are very interested in reducing the total cost of ownership (TCO) of their fleets, while ensuring that their operational needs are met.

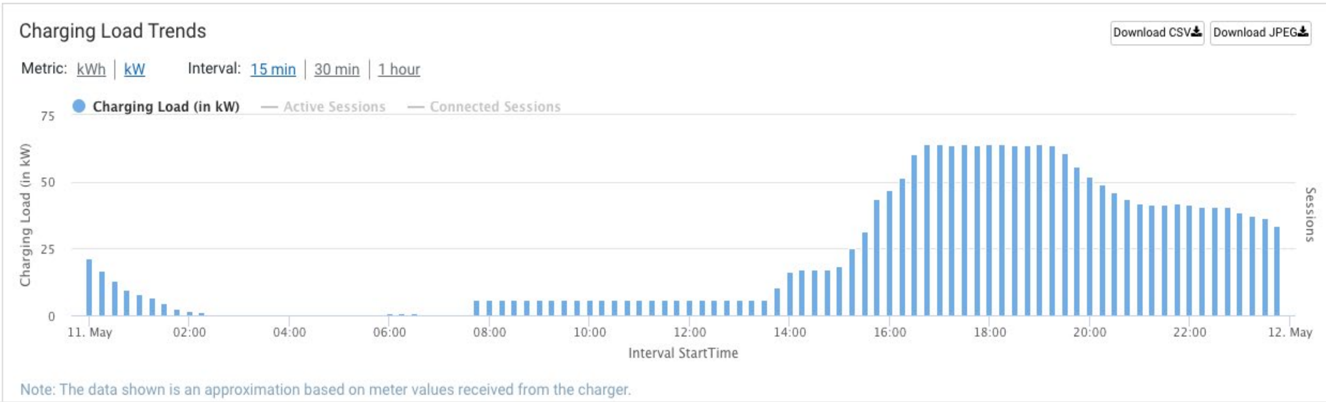
Fleets that operate during the day can charge when their vehicles are parked overnight. Other fleets have more demanding operations and may not be able to accommodate long charging periods. In these cases, it is ideal for fleet operators to shift their charging load to off-peak hours while making sure there is enough time to charge their vehicles. The load can be shifted through cloud-based load controls to periods of low energy cost, when utilities are offering simple time-of-use (TOU) rates with low or no demand charges. Figure 6 and Figure 7 show the fleet scheduling tool developed for this project.

Figure 6: Greenlots Fleet Scheduling Tool: Create a New Shift



Source: Greenlots

Figure 7: Regular Schedule Where Drivers Charge During Peak Hours

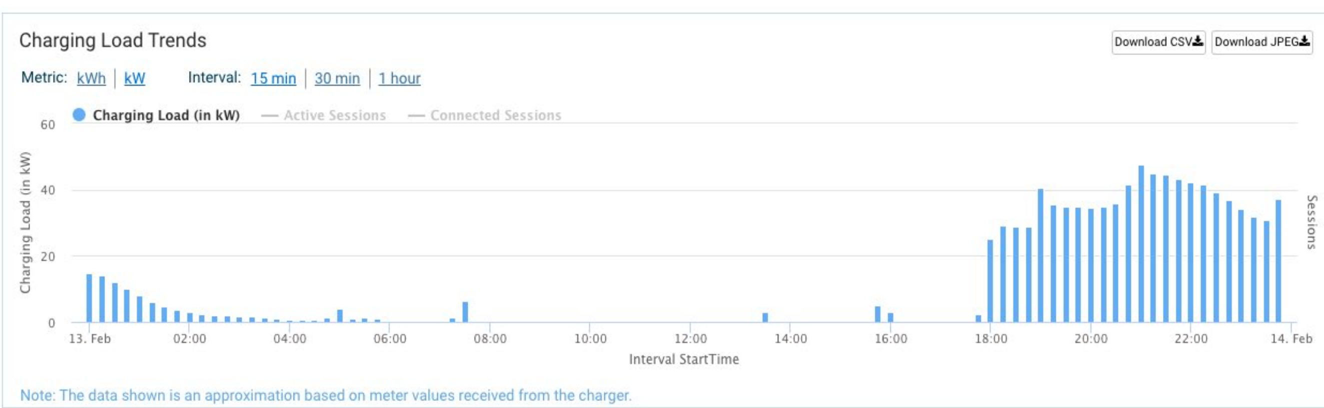


Source: SKY Insights

Use cases were found for midday opportunistic charging on a DC fast charger back at the depot in cases where there was a need to prepare the vehicle quickly for the next shift. Fleet arrivals could be staggered over time (for example, during middle-mile delivery, when goods are transported from a warehouse to a retail facility). A managed charging solution could consider available vehicle range, shift schedules, demand, and energy charges. Adding onsite stationary energy storage could shave off-peak charges and reduce impacts on the grid. The PEV industry is engaged with these fleets and is developing solutions for this customer need (Figure 8).

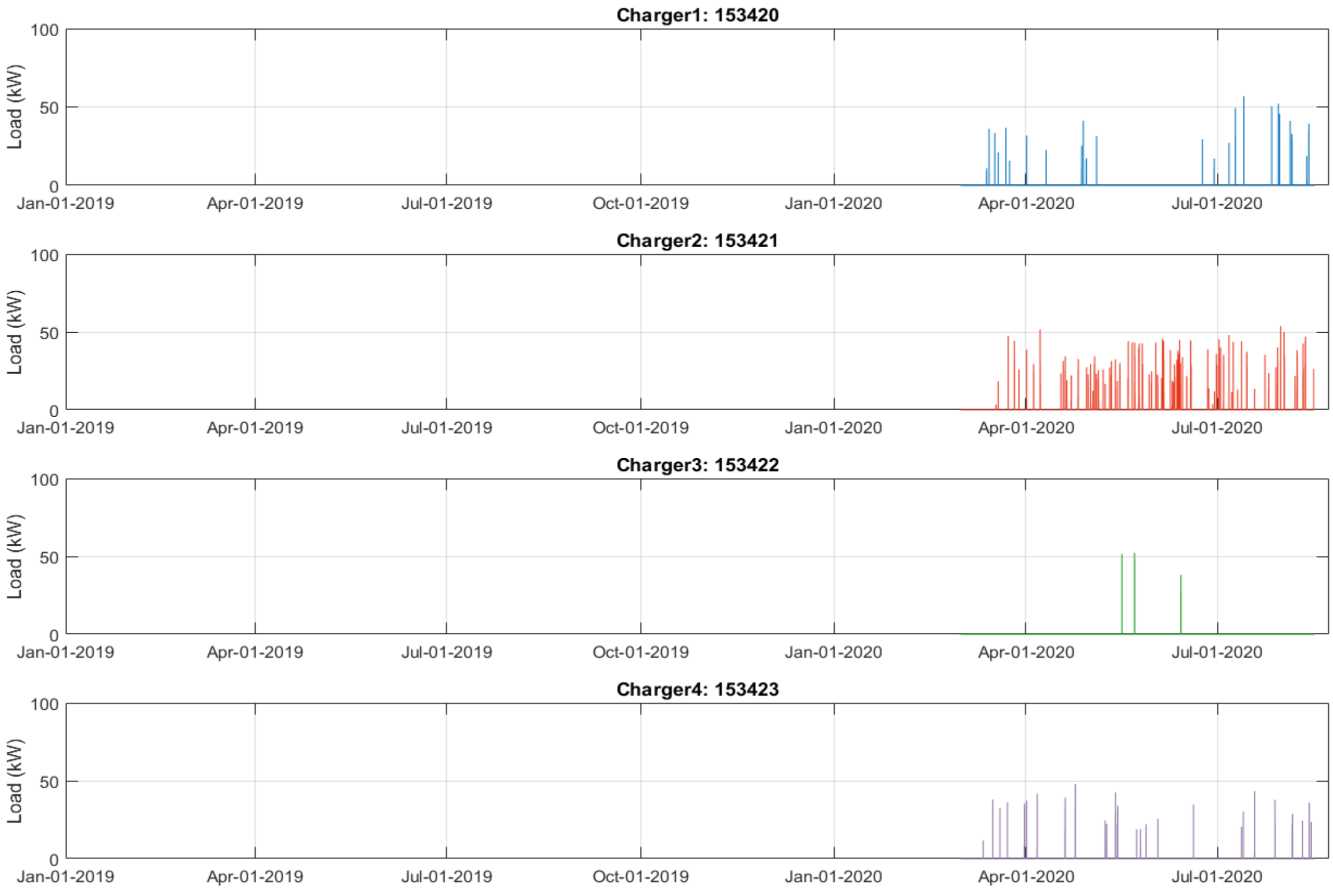
Another use case is opportunistic charging on the road, based either on need or cost of energy. Not all fleet operations have set routes (for example, the Transportation Network Company), and the driver might want to charge on the road to extend his or her vehicle's operating range. Fleet operators and their drivers can be provided incentives to shift their fleets' operating patterns to take advantage of periods of low-cost charging. These hours can be planned a day ahead, with clear information to drivers on when and how to take advantage of this pricing. Using a mobile app to engage with these drivers on the road, and encouraging them to use these low-cost hours for charging, can benefit drivers and the utility (Figure 9).

Figure 8: Modified Schedule Where Drivers Delay Charging Until 6 p.m. to Reduce Peak Usage



Source: SKY Insights

Figure 9: Site EVSE Utilization, Monterey Park, California



Source: Shell

CHAPTER 3: Project Results

The project's simulated demand-charge reduction estimated annual site utility costs of approximately $42,000, of which more than 40 percent (or $18,600) was for demand charge costs. With forecasted costs of approximately $260/kWh to $630/kWh for installation of a BESS in 2029, it would take between 6 years and 15 years to recover the cost of the BESS through demand-charge reductions alone. Using a solar PV array to charge the BESS saved approximately $4,700 to $6,000 per year in utility energy costs combined with low carbon fuel standards (LCFS) savings, which represented an approximate 13-percent reduction. However, the current installed cost for a 100-kW solar array is approximately $165,000, which would achieve payback after more than two decades. Unfortunately, the test site experienced faults with both battery stacks in May 2021, causing both to be disconnected, and that limited analysis of the second-life batteries.

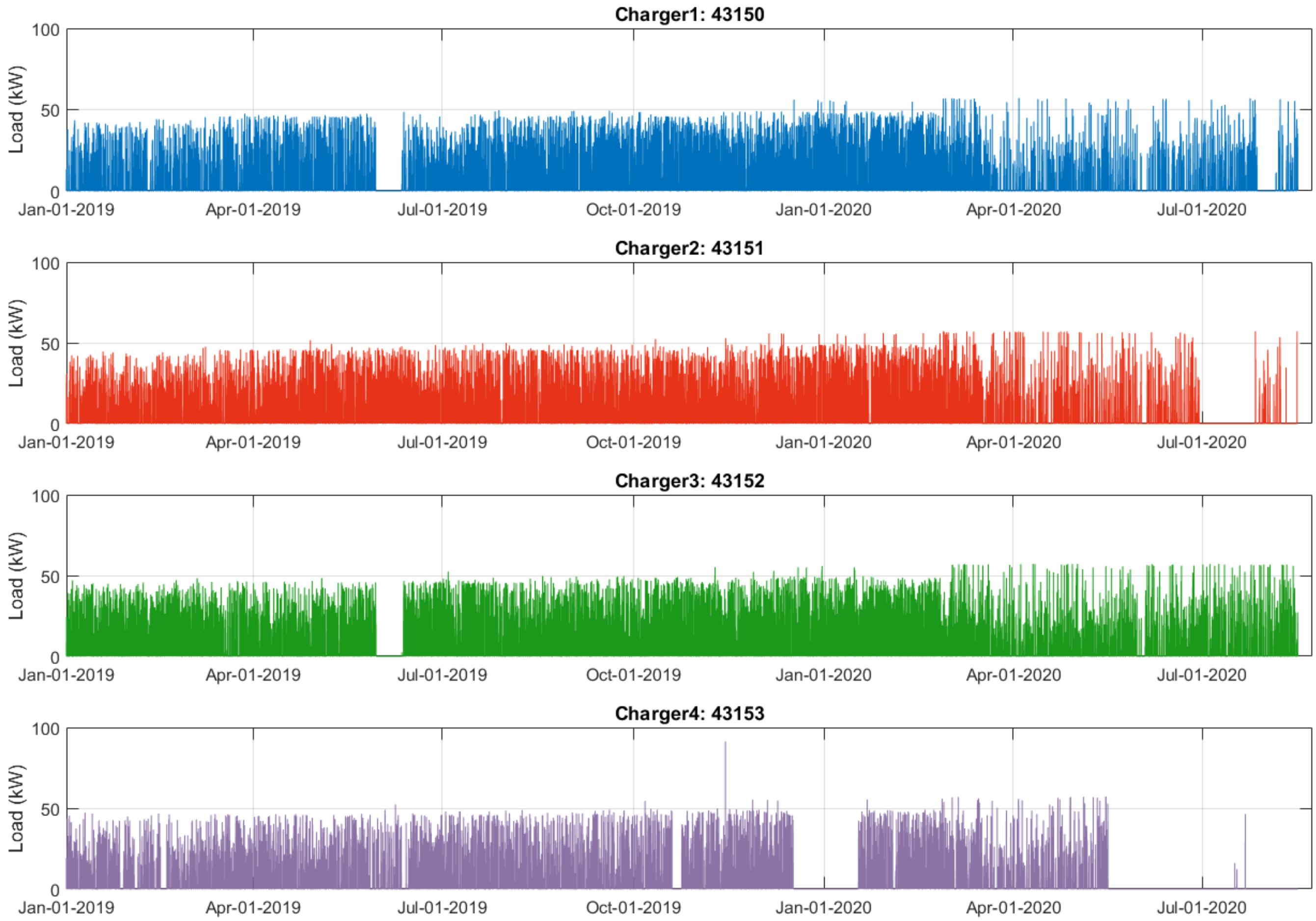
Operational Data and Use of Data From Other Sites

This research project conducted several one-year simulations of the algorithm in several scenarios, using cases for the Monterey Park site.

At a typical Greenlots site, the power usage data for assets (including batteries, EVSE, and meters) are stored locally every second and sent to the cloud Greenlots SKY™ network every minute. The simulation resolution is one minute. However, the EVSE data for the Monterey Park site, which began operation in March 2020, was unreliable due to the COVID-19 pandemic. From the data collected from March to September 2020, the site was completely unoccupied 97.4 percent of the time, with negligible coincident use of multiple charging stations, as shown in Figure 10.

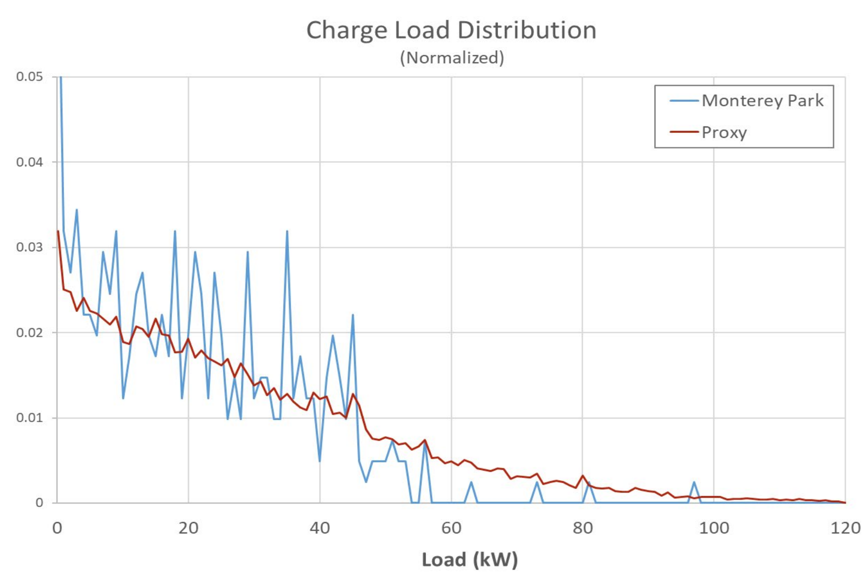
To find a replacement source of data, a Greenlots PEV charging station in Portland, Oregon, was considered, with the same number of PEV chargers (four), and nearly 60 percent of the usage from coincident charging, as shown in Figure 11. The analysis, as illustrated in Figure 12, showed that the normalized charge load distributions for the two sites looked remarkably similar and the Portland site could be used as a suitable proxy. The proxy EVSE data has the same one-minute resolution.

Figure 10: Portland, Oregon, Site EVSE Utilization



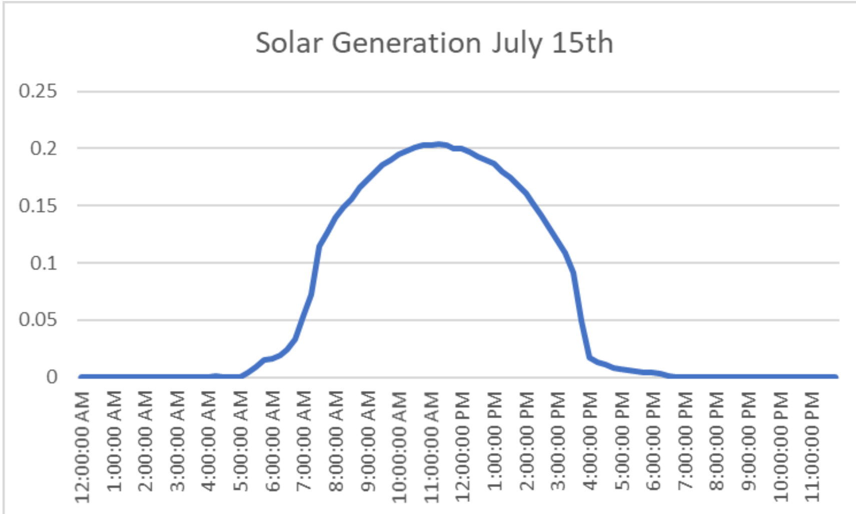
Source: Shell

Figure 11: Charge Load Comparison Between Portland and Monterey Park Sites



Source: Shell

Figure 12: Solar Generation Profile for a Typical Day, Zip Code 91006

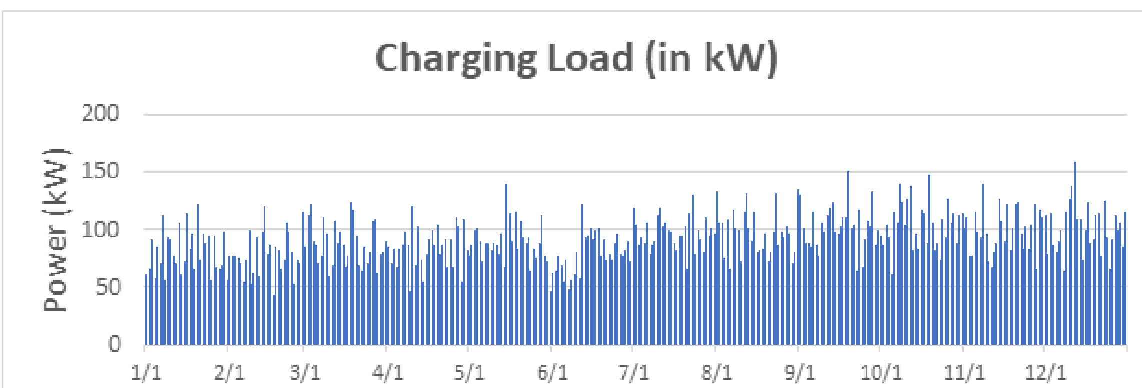


Source: California Distributed Generation Statistics

The Monterey Park site did not have a solar installation at the time of data collection. For the simulation, a 10-kW system was chosen based on real-world feasibility (empty and with available roof space) at the Monterey Park site. The research team used data from the California Solar Initiative database, available from the California Distributed Generation Statistics website (CSI 2018).

The data was collected from various zip codes across California. Data from 2011 was used from a selection of solar installations within the 91006 zip code (the cities of Arcadia and Monrovia), which is about nine miles from the Monterey Park site. The unit of data was in kWh per 15-minute intervals and was scaled to have a year-round maximum of 10 kW. This proxy solar data had a 15-minute resolution (Figure 13).

Figure 13: 15-minute Charging Loads for Entire Year, With No Battery Output



Source: SKY Insights

Evaluation of Second-life Battery System for Load Management

The BESS is likely the only energy storage component on a PEV charging site to balance the load and, in the case of solar installation, the generation. The BESS should be used to store energy when the energy price is low, demand is low, or generation outpaces demand. Batteries should be used when the energy price is high or when demand outpaces other available energy resources. The algorithm leverages the capacity of the BESS to its full benefit, as demonstrated by the demand response and solar PV integration simulations.

Other nontechnical factors may be considered when a BESS is used. For example, the Monterey Park site BESS dispensed only when there were at least two vehicles charging simultaneously (due to restrictions from the utility).

The most important factors used to evaluate the usefulness and effectiveness of the BESS are capacity and the charge and discharge rates. Research estimated that the second-life batteries had lifetime effective capacities of between four years and seven years, with the discharging rate measured under 30A and 60A test conditions. The algorithm used these numbers as part of energy storage parameters and performed simulations accordingly. It is noteworthy that the diminishing capacity was not factored in the simulation (assuming the capacity was constant throughout the year).

It is also worth noting that challenges arose with second-life batteries in the field. Testing done in May 2021 encountered numerous issues with both batteries. The south battery stack constantly showed as disconnected despite repeated manual interventions, including attempts to reconnect the stack from the BESS web user interface. This blocked any control of the battery system for use in the field, or manual control for testing and data collection. At the same time, an issue was found with the north battery stack, where it unexpectedly entered a charging state, even when commanded to discharge during test scenarios. Both battery stacks were disconnected, and the project team worked with engineers from Spiers and Nuvation to restore functionality.

Savings With Second-life Batteries

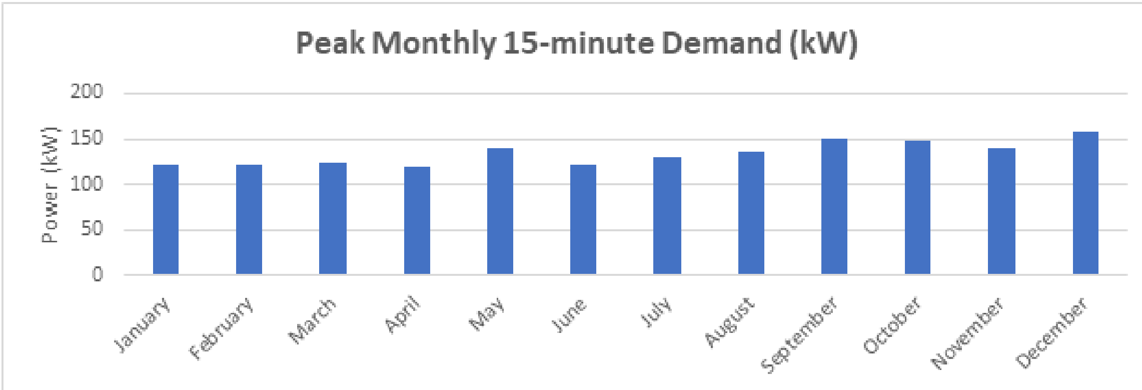
A detailed cost analysis of using second-life batteries versus new batteries is needed to provide valuable data and insights. A general description of how PEV charging sites can save with batteries is described in this report.

Demand Charge Mitigation

To understand market opportunities for load management, it is important to look at the impact of load management at the site level. In this project, a DC fast charging hub was developed with four 50-kW DC fast chargers and a 48-kW/110-kWh second-life BESS. The system had a peak load of 200 kW when all chargers were operating at maximum power simultaneously, with no battery output. Figure 14 is a view of the 15-minute charging load (in kW) for the entire year with no battery output.

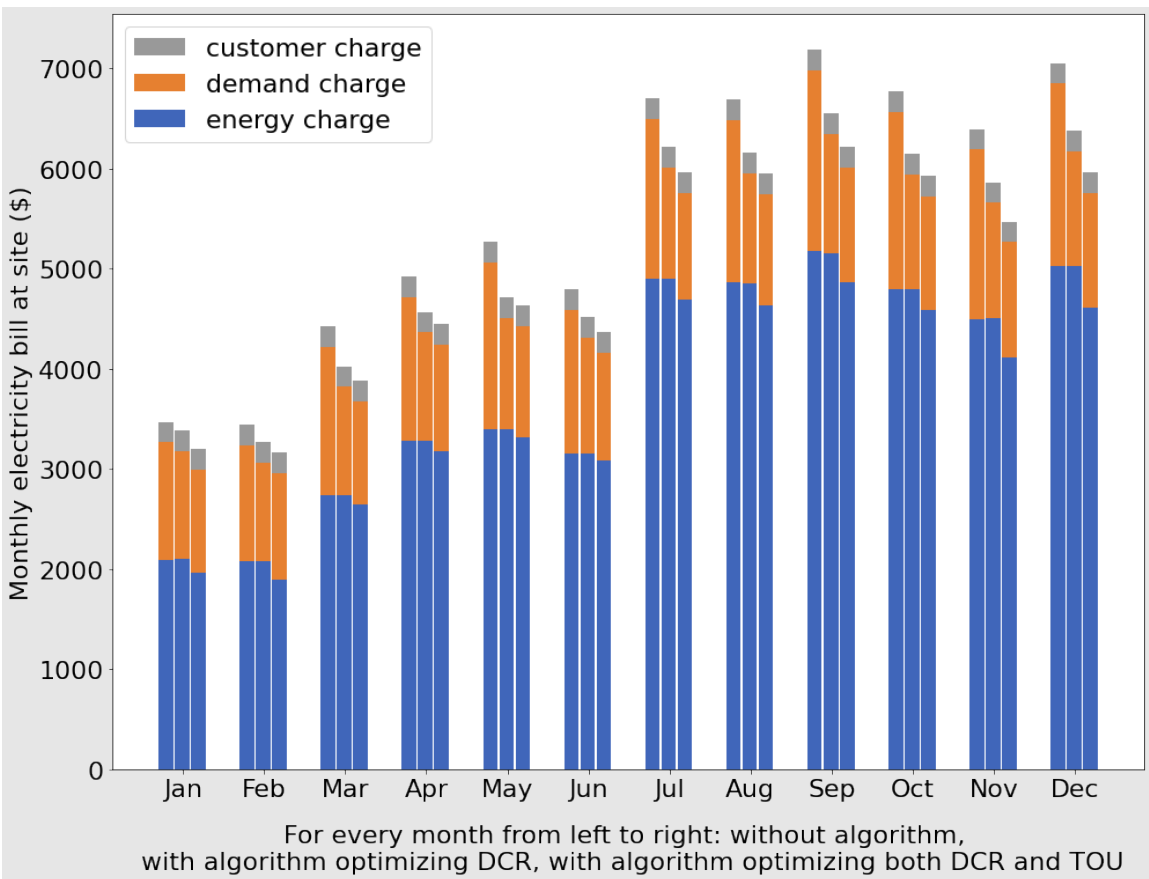
Demand charges were calculated at the peak 15-minute load across the month. Figure 15 shows the spread of the 15-minute load at the site by month, assuming utility billing began on the first of every month.

Figure 14: Spread of 15-minute Load at the Site, by Month



Source: SKY Insights

Figure 15: Cost Savings With the Algorithm



Source: Project findings

As charging usage at the site goes up, the coincident 15-minute peaks will be higher, since the probability of more vehicles charging simultaneously is higher. With the ability to discharge the battery and curtail charging to reduce peaks within 15-minute intervals, it is possible to reduce peak demand by 100 percent of the battery inverter power rating through a combination of battery discharge and charge curtailment. By restricting charging power to 40 kW, the system should be able to reach up to 125 percent of the battery inverter power rating with 15-minute demand reductions. At this site, with a 48-kW battery, the demand reduction per DC fast charger is 12 kW to 15 kW. In other words, it is 25 percent to 30 percent of the rated capacity of the DC fast charger.

With SCE's average demand charge for commercial and industrial customers between $10/kW/month to $20/kW/month (averaging both summer and winter demand charges), the average demand charges would be between $16,000 and $32,000 per year, depending on the tariff. (Note: Current PEV tariffs have no demand charges until 2024 and will start a demand charge ramp-up to 2029). The annual demand savings at the site are estimated at between $5,760 and $14,400 per year, depending on the tariff. This translates to between $1,440 and $3,600 of annual savings per 50-kW DC fast charger.

To evaluate if demand charge reduction (DCR) and TOU arbitrage could be stacked to gain even more savings, simulations were performed, and the algorithm parameters were optimized to perform TOU arbitrage without sacrificing the monetary gain from DCR. The following figure shows the site savings if SCE levied demand charges at an estimated rate now (SCE 2021; CPUC 2018b).[1] Based on this estimated rate, an annual savings of $7,947, or about 12 percent, was calculated on the total energy bill.

While it might be tempting to increase the size of the battery to maximize demand savings, there needs to be a balance between the battery capacity and the maximum charging load. As onsite charging utilization goes up, the amount of possible demand reduction goes down, since the battery does not have enough capacity to shave all peak demand. Being aggressive with the demand curtailment targets means drivers are going to be impacted with excessive charge curtailment, leading to poor charging experiences.

The California Public Utility Commission's (CPUC) Self-Generation Incentive Program (SGIP) is available in California to provide incentives for commercial storage use by covering most of the cost of installing an energy storage system. Unfortunately, since this program was created to support new and emerging DER, these SGIP rebates are not applicable for second-life batteries.

For this analysis, it was assumed that new batteries and the SGIP were available. For the base use case of DCR and demand response in SCE territory, the site was at step three of the incentive, with a subsidy of $350/kWh offered for commercial battery storage systems greater than 10 kW. Fifty percent of the subsidy was available upfront, while the rest was spread over 5 years and was based on performance. For the 48-kW and 110-kWh battery at the site, a new battery would be eligible for an SGIP subsidy of $38,500. Using the average capital cost of storage from 2019 (about $589 per kWh), the total capital cost would be reduced to

[1] Energy and customer charges are based on the SCE TOU-EV-8 rate table, effective March 1, 2022. The demand charge is based on the CPUC's existing rate structures. Note that, on page 9 of the document, the energy rate is decreasing from 2024 to 2029. The project team did not use those decreasing numbers but rather constant rates from the current TOU-EV-8 schedule.

$26,290, bringing the payback period to 6.1 years (Self-Generation Incentive Program, 2020; Fosterling, 2020).

Reducing the site peak-demand threshold at which the BESS discharges can potentially create larger economic savings. For example, the simulated annual savings from demand charge mitigation with BESS threshold values to 80 kW and 40 kW were approximately $7,160 and $12,900, respectively, bringing payback with the SGIP down to 3.7 years and 2 years. However, additional simulations and studies of customer response are required to evaluate if these lower thresholds are feasible, since lower thresholds could slow PEV driver charging despite improving the economic performance of the site.

Participation in Utility DR Programs

There are many demand response (DR) programs offered by SCE and third-party aggregators. In this research project, only SCE's DR programs were considered.

SCE provides the following OpenADR-compliant programs.

- **Capacity Bidding Program (CBP):** Customers make monthly nominations (also known as "bids") to reduce energy load and are compensated with payments based on actual energy reduction when a CBP event is called.
- **Critical Peak Pricing (CPP):** Customers are offered discounts on summer electricity rates in exchange for higher prices during 12 CPP event days per year (usually occurring on the hottest summer days).
- **Real-Time Pricing (RTP):** Customer price rates are set according to season, temperature, and time of day.
- **Base Interruptible Program (BIP):** Customers choose how much energy they need to stay up and running, and SCE provides credit depending on the level of energy reduction.

Just about every DR program reduces power usage on hot summer days when energy consumption reaches or exceeds generation capacity. Not all programs are available to PEV charging operators, but for this report it was assumed they were universally available because the main interest was to see how the algorithm worked under these example situations and events. Usually, DR programs are for regional aggregators because they can pool wider categories of commercial customers to better control demands. As a future task, it would be interesting to investigate if a large PEV charging operator in a local area would see enough different charging patterns across its managed sites to serve as a de-facto aggregator.

The use of OpenADR benefits the system and the algorithm since it provides real-time event and pricing information, and the algorithm can respond to these events and pricing by introducing new priority lists. Supporting OpenADR is on the Greenlots technical and business roadmap. The simulation assumed real-time OpenADR data.

With a site that does not have any battery or other energy storage capacity, the only possible way to reduce energy use is to curtail power to EVSE. The algorithm needs to strike a balance between driver satisfaction (slow charging may mean losing business), the extra energy cost at a high-price DR event, and revenue from PEV drivers.

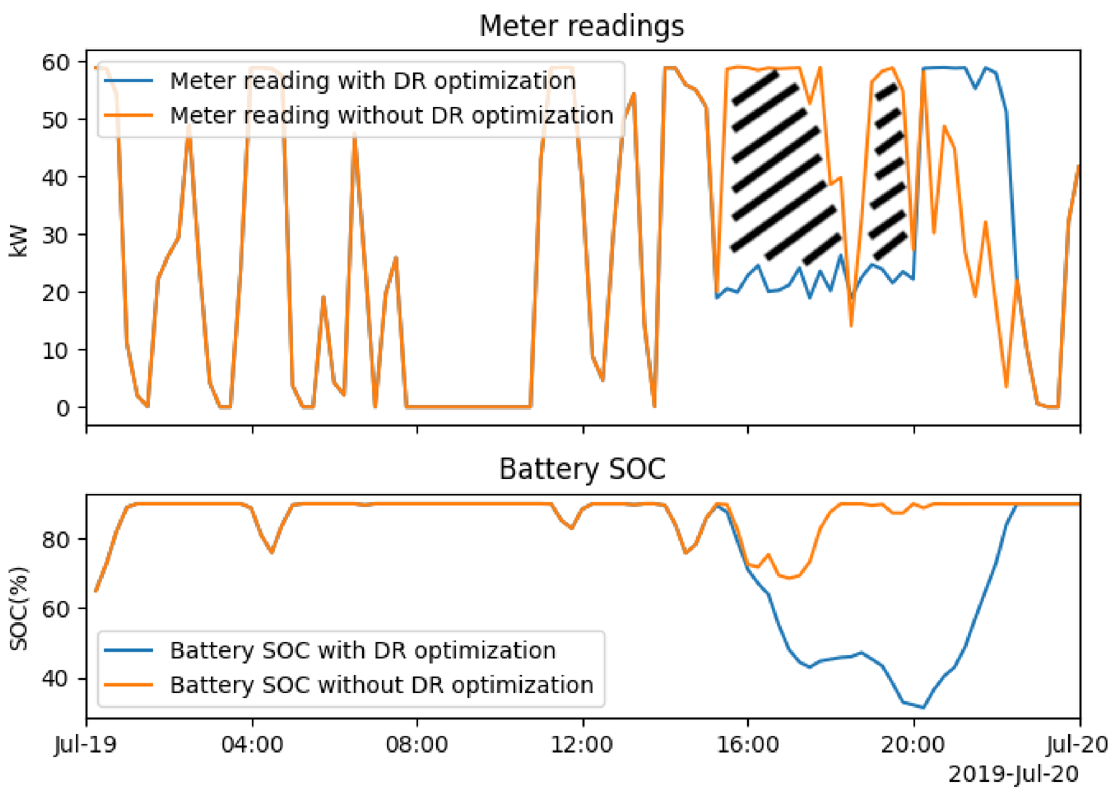
The algorithm works best with an onsite BESS. Ideally, the battery would charge at nonpeak periods and provide power when DR events occur. Realistically, the battery has limited capacity, and the algorithm would need to control the schedule to either charge or discharge.

The Capacity Bidding Program is an extreme example. This program has two options. The day-ahead option announces an event the day before, so any reasonable BESS should have ample time to schedule the recharge. The day-of option, however, can announce any event as imminent as soon as one hour before it happens. To deal with day-of events, the algorithm cannot discharge the battery to the point where one-hour charging would not bring it back to adequate levels. On the other hand, the algorithm needs to discharge the battery to charge vehicles when demand is high to avoid demand charges.

A Case Study That Illustrates the Algorithm in Action With DR Events

Figure 16 shows how the algorithm responded to a hypothetical DR event that encouraged the reduction of power use from 15:00 hours (3:00 p.m.) to 20:00 hours (8:00 p.m.) on a hot summer day. A general requirement was that the site should draw no more than 60 kW due to demand charges, and that the battery be maxed at 60 percent SOC. When the demand during the day exceeded 60 kW (for example, around 6:00 a.m.), the battery started to discharge to provide the extra power to the EVSE. If the algorithm was not configured to handle the DR event, as shown with red lines in the chart, it did not give any special treatment between 15:00 hours and 20:00 hours (3:00 p.m. and 8:00 p.m.), where peak demands were at 60 kW around 16:00 hours and 19:00 hours (4 p.m. and 7:00 p.m.).

Figure 16: Configuring Algorithm to Handle DR Events



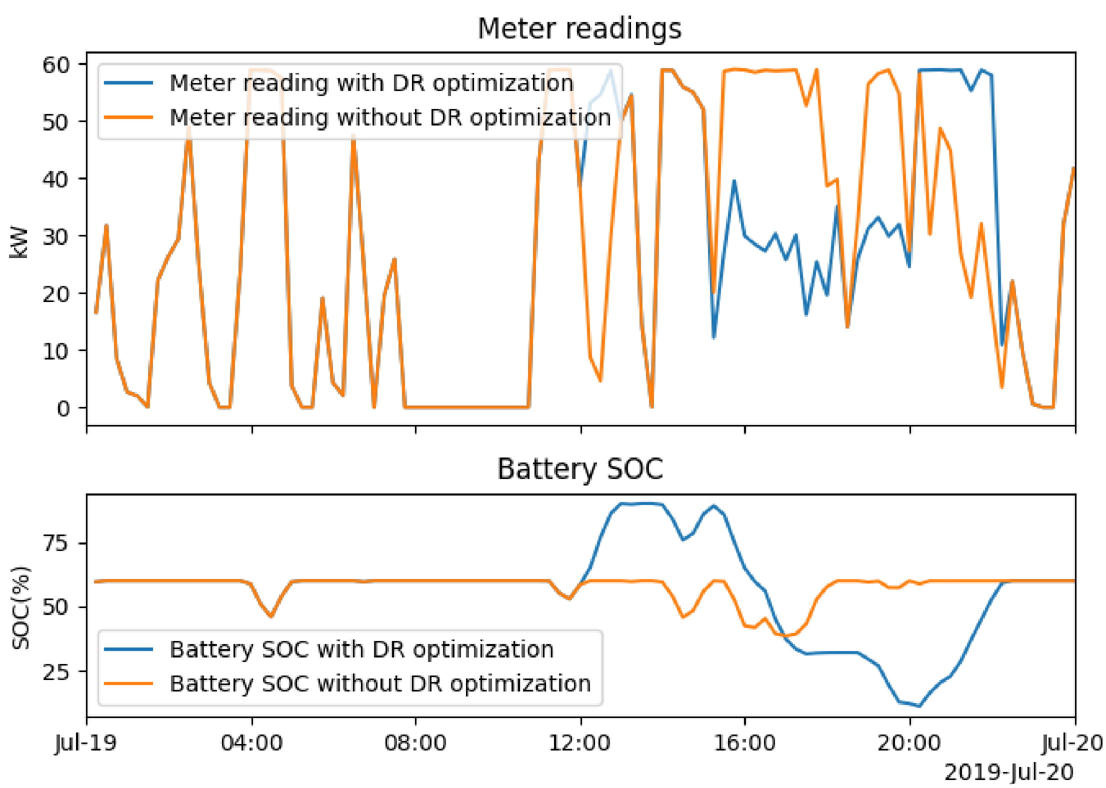
Source: Project findings (Demand Response Algorithm Implementation and Simulation report)

When the algorithm was configured to handle the DR event, it was set up to give, at most, 20 kW during the event window. In the lower Battery SOC graph shown, the battery with DR optimization discharged more than the battery without DR optimization. The shaded area in the upper Meter Readings graph represents net power savings. Near the end of the event, the battery SOC approached the preset 10 percent minimum, meaning that if the event had lasted a little longer, or if charging demand during that window had gone higher, there was a risk that the battery could no longer help. Immediately after the event, the site drew more power trying to replenish the battery. Furthermore, the figure does not show the high-priority set to reduce power usage during that event. In turn, EVSE charging was heavily curtailed to below 20 kW, which likely dissatisfied charging drivers.

There are ways to configure the algorithm to improve its performance. The algorithm can be configured to pre-charge hours before the event, and the SOC level can be raised from 60 percent to an optimal point where, with the expected demand and length of the DR event, there is enough battery capacity (or the maximum it can charge and discharge) to reduce the power usage during the event to an acceptable level of charging performance.

Figure 17 shows a more optimized case, where the battery was allowed to charge up to 90 percent SOC three hours before the event. While it wasn't possible to keep the meter reading below 20 kW (most of the time during the event it was around 30 kW), the algorithm guaranteed each EVSE 30 kW of charging.

Figure 17: Optimizing the Algorithm to Handle DR Events



Source: Project findings (Demand Response Algorithm Implementation and Simulation report)

With the hypothetical event, the two algorithm configurations reduced energy usage by 136 kWh and 111 kWh, respectively. Though the optimized algorithm saved 25 kWh less, the 25 kWh was traded for a guaranteed 30-kW EVSE output each (rather than 20 kW in the non-optimized case) for a period of five hours. Certainly, the savings are not that significant, since the battery needs to be pre-charged or recharged outside the event window, which still costs money. If these pre-charging or recharging times are at on-peak rates, the savings will be further reduced, so the peak rate calculation needs to be factored into the optimization process.

Additional Revenue Opportunities From DR

The Demand Response Auction Mechanism (DRAM) offered site hosts in SCE's service territory the opportunity to participate in DR programs. These programs were either day-ahead or hour-ahead and required actual reductions in site load from a moving baseline load.

The technology developed in this project responds to DR events by changing how the battery is discharged, and by curtailing loads in the hours leading up to the event window. With a typical DR event window of four hours, the two-hour battery can be extended to operate for four hours at 50 percent of maximum power (24 kW).

Based on capacity-bidding pricing programs in SCE's service territory, a four-hour event that saved between 111 kWh and 136 kWh averaged about 27.75 kW to 34 kW of demand reductions during the event window (SCE, 2021). At an average of $6.43/kW/month, the site host would have an additional DR revenue of $2,140, up to $2,620 per year. Payments for DR participation peak in the summer, with July to September contributing 87 percent of annual DR revenue. This shows how a site host can participate in the DR program while still minimizing driver impacts.

Renewable Integration Simulations

This project simulated the potential for onsite solar PV to charge the second-life BESS, reducing total utility costs and marginal greenhouse gas emissions. Simulated solar performance from 2011 to 2016 for a characteristic solar PV array located at the Monterey Park location was approximately 3 kWh to 6 kWh produced per kW (alternating current) installed over a year. The simulations showed that a solar PV array of approximately 100 kW would provide enough energy to the second-life BESS to support daytime peak shaving, as well as to meet most overnight demand.

Analysis showed that adding solar PV at the site would allow the use of 18,176 kWh of solar energy for PEV charging. Any electricity used in California for EV charging is eligible for Low Carbon Fuel Standard (LCFS) credits. By default, the site used grid electricity (fuel pathway code: ELC000L00072021 – CI: 75.93g/MJ). For an estimated 18,176 kWh of energy delivered to vehicles from the grid, 15 credits could be claimed. If solar PV generated at the site was used (fuel pathway code: ELC037L00072019 – CI: 0g/MJ), 20 credits could be claimed, since solar PV has zero carbon emissions. This is an additional 5 credits due to using solar PV at the site.

The California Air Resources Board (CARB) website (CARB, 2021) shows the current average price of a credit as $180.86 per metric ton (MT), with a range of $156/MT to 200.5/MT (Table 1). From the simulation, using the solar PV array to charge the BESS would save 18,176 kWh per year, translating to approximately $4,000 to $5,000 per year in avoided utility energy costs; with solar PV at the site, an additional LCFS revenue of $780 to $1,002 per year could be claimed. The total savings of approximately $4,700 to $6,000 per year represents a 13 percent reduction.

Table 1: LCFS Weekly Snapshot October 2021

LCFS Weekly Snapshot	18th October 2021 – 24th October 2021	
Transfer Type	All Non Zero	Type 1
Average Price ($/MT)	$180.86	$173.01
Price Range ($/MT)	$156.00 - $200.50	$167.00 - $177.00
Total Volume (MT)	279,079	51,034
Total Value ($)	$50,472,856	$8,829,206

Source: CARB

However, since the current installed cost for a 100-kW solar array is approximately $165,000, payback would be achieved after more than two decades.[2]

Subsidies for solar integrated storage are available in the form of SGIP funding and investment tax credit (ITC) for applicable projects (Self-Generation Incentive Program, 2020; Fosterling, 2020). For cases where there is additional solar PV at the site and over 80 percent of all battery charging occurs from the solar PV, the SGIP incentive amount is reduced to $250/kWh, but the storage is eligible for invest ITCs of up to 30 percent, based on the tax structure of the company. In this case, the SGIP subsidy was $27,500, with an additional incentive of $30,000 from ITCs, bringing the total subsidy available to $57,500 on the battery. Using the average capital cost from 2019 ($589/kWh), the total capital cost of the battery was reduced to $7,290, bringing the payback period to 1.7 years.

The 2020 SGIP program offers an additional $150/kWh incentive adder for commercial customers that do not service low-income or disadvantaged communities. To qualify for the incentive adder, BESS projects must demonstrate that the storage system can provide resiliency (or back-up) power and operate in the event of grid outages. Added to the step incentive level the customer is eligible for, this incentive provides an additional $16,500 incentive. To be eligible, additional equipment and certifications are necessary to support this mode of operation.

Second-life Battery Evaluation

On the Monterey Park site, two second-life 56-kWh Spiers New Technologies (SNT) Watt towers were installed as the battery energy storage systems (see Appendix A for details). SNT

[2] This is according to data from Infinite Energy. However, it's worth noting that this savings is limited by the non-export agreement with SCE and does not factor in future demand charge savings. If a site can export extra PV power back to the grid and/or materialize demand charge savings, the payback will be achieved sooner.

was contacted to perform a series of measurements on the batteries before beginning the installation (in the factory) and subsequently at quarter-year onsite intervals to characterize the second-life batteries' performance and life expectancy. The modeling and test plans were heavily influenced by the *Life Prediction Model for Grid-Connected Li-ion Battery Energy Storage System,* by the National Renewable Energy Laboratory (NREL 2017). SNT executed a tightly controlled test plan, including measurements for states of balance and voltage drop at various SOC points and discharge rates. In addition to evaluation for performance consistency, the useful battery life was estimated according to the NREL model.

The state-of-balance tests summarized in Table 2 proved that the cell voltages of both battery energy storage systems were within a 15-millivolt range at all checkpoints, showing adequate balance of the systems and no noticeable performance degradation.

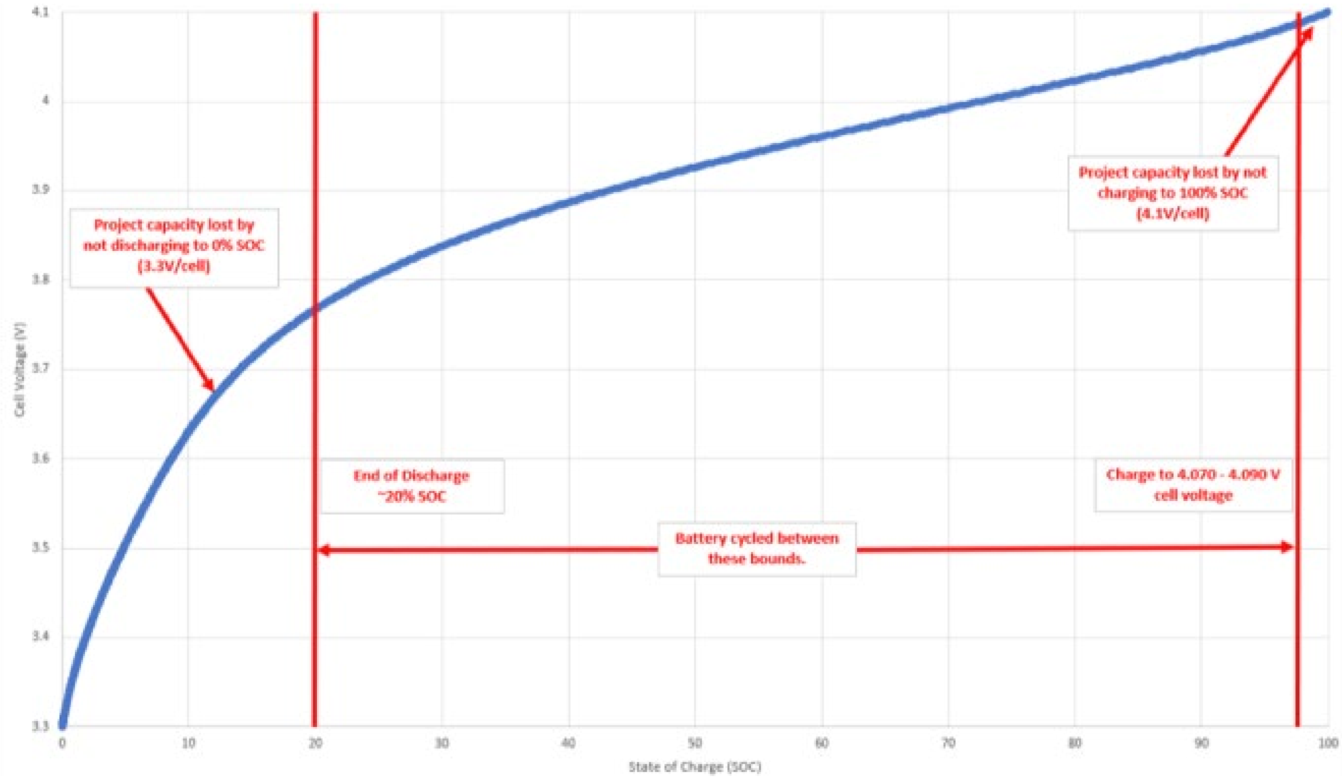
Table 2: State-of-Balance Test Results

	Cell Voltage (V)				Cell Temperature			
Date	**Max**	**Min**	**Avg**	**Delta**	**Max**	**Min**	**Avg**	**Delta**
Watt Tower: BESS 1								
03/06/2019	4.098 V	4.093 V	4.095 V	0.005 V	N/A	N/A	N/A	N/A
06/17/2020	4.095 V	4.091 V	4.092 V	0.004 V	24 °C	22 °C	22 °C	2 °C
11/17/2020	4.091 V	4.086 V	4.087 V	0.005 V	26 °C	22 °C	24 °C	4 °C
12/02/2022	4.08 V	4.065 V	4.071 V	0.015 V	18 °C	16 °C	16 °C	2 °C
Watt Tower: BESS 2								
01/29/2019	4.086 V	4.079 V	4.082 V	0.007 V	N/A	N/A	N/A	N/A
06/17/2020	4.083 V	4.079 V	4.081 V	0.004 V	24 °C	22 °C	22 °C	2 °C
11/17/2020	4.087 V	4.082 V	4.084 V	0.005 V	28 °C	25 °C	26 °C	3 °C
06/04/2021	4.064 V	4.060 V	4.061 V	0.004 V	27 °C	24 °C	25 °C	3 °C

Source: Spiers New Technologies

Voltage drop tests were used to estimate internal resistance, which, in turn, was used to model equivalent capacity. It is worth noting, however, that the battery is not cycled across the full operational voltage range, so the capacity estimation must account for capacity lost due to not fully charging and not fully discharging the cells, as shown in Figure 18.

Figure 18: Cell Voltage Versus SOC and Projected Capacity Loss



Source: Spiers New Technologies

The initial capacity was tested at SNT's factory and used different parameters. Among the most notable differences were the initial charge voltage and the end of discharge voltage. SNT performed calculations to transform the measured capacity to be equivalent to SNT's factory testing data, with a margin of error of two percent to five percent. Subsequently, the equivalent capacity was estimated at two quarter-year test points, as shown in Table 3.

- BESS1 had a usable capacity degradation of 5.33 percent (7.8 ampere hours, or Ah) and 5.86 percent (8.5 Ah) over a five-month period when tested at C/4 (30 amperes, or A) and C/2 (60A) run, respectively.
- BESS2 had a usable capacity degradation of 8.96 percent (13.3 Ah) and 1.88 percent (2.8 Ah) over a five-month period when tested at C/4 (30A) and C/2 (60A) run, respectively.

The 30A discharge appeared to have higher degradation due to the following:

- BESS2 was not fully charged on the second test. This caused the BMS to have a zero depth of discharge with lower initial cell voltage before the test initialized.
- The second test ended with higher end-of-discharge cell voltage, which resulted in much lower measured capacity. In theory, this results only in lower measured capacity and does not equate to lower equivalent capacity.

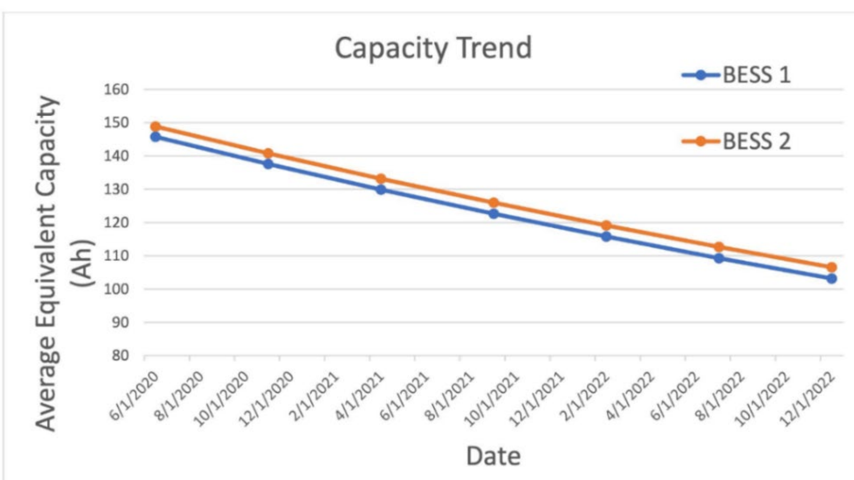
Table 3: Equivalent Capacity Estimation

Date	Initial Temperature (°C)			Initial Cell Voltage (V)			End of Discharge Cell Voltage (V)			Greenlots Measured Capacity (Ah)	Equivalent Capacity (Ah)		
	Max	Min	Avg	Max	Min	Avg	Max	Min	Avg		Max	Min	Avg
Watt Tower: BESS 1													
30A Discharge													
06/17/2020	26	24	24	4.082	4.080	4.081	3.755	3.719	3.743	122.4	154.3	146.4	150.0
11/17/2020	25	20	22	4.074	4.070	4.071	3.725	3.630	3.686	122.1	153.0	138.6	145.7
60A Discharge													
06/17/2020	24	22	23	4.092	4.088	4.089	3.731	3.703	3.720	125.1	150.3	145.1	147.9
11/17/2020	26	23	24	4.092	4.087	4.089	3.714	3.652	3.693	122.8	149.2	136.6	143.3
Watt Tower: BESS 2													
30A Discharge													
06/17/2020	26	24	24	4.084	4.080	4.081	3.752	3.729	3.742	123.9	153.4	148.4	151.0
11/17/2020	22	19	20	4.071	4.068	4.069	3.798	3.792	3.795	97.9	142.1	135.1	139.8
60A Discharge													
06/17/2020	24	23	22	4.078	4.076	4.074	3.754	3.744	3.748	123.9	152.9	149.3	151.4
11/17/2020	28	25	26	4.067	4.057	4.064	3.677	3.632	3.654	125.6	156.1	146.5	150.3

Source: Spiers New Technologies

Based on test data from 30A and 60A discharges, BESS1 and BESS2 had an average degradation of 5.60 percent and 5.42 percent, respectively, over a five-month period. Reasonable extrapolation would put it at about a 27-percent reduction in two and a half years (Figure 19); the estimated life expectancy of the second-life batteries is estimated at between four and seven years.

Figure 19: Capacity Prediction



Source: Spiers New Technologies

CHAPTER 4: Conclusion

To increase installation of DC fast-charging infrastructure and charging stations over the next decade, charging site developers, builders, and operators need to possess the technology and tools to balance site costs and PEV driver charging experiences.

Compared with traditional gas stations, which dispense tank-stored fuel as quickly as possible without any significant cost penalty, PEV charging stations face two seemingly contradictory factors of grid power costs and EVSE demands. Even with the help of battery storage, the majority of PEV "fuel" comes from the grid, which has power limits and generally becomes more expensive if it is needed faster.

Managing PEV charging, therefore, becomes a balancing act between cutting energy costs and maximizing EVSE dispensing rates, which are closely related to driver satisfaction. Working toward this goal, this project developed an algorithm that worked together with site controllers at PEV charging stations with second-life batteries. With data from this site, combined with other numerous data simulations, the project demonstrated the viability of this algorithm and site controller-based technology solution.

The current rule-based algorithm provides both flexibility and clarity for setting and enforcing the most important site-operating criteria. Among them are peak shaping and truncation for demand-charge reductions, battery and solar PV utilization, grid importing and exporting limits, and EVSE flow controls. The rules are also time-based, meaning that they can be set according to any date and time. Another feature is that the rules can take effect in a matter of minutes, making it extremely useful for emergency charging-pattern changes such as same-day DR events.

The project also demonstrated the following benefits:

- The technology has the potential to scale, since the control algorithms are agnostic to the hardware and can work with more than 100 chargers at the site.
- Standard load control signals are used for charger controls and are supported by OCPP 1.6J. Support for open standards across the industry is important and allows technology to be supported by multiple hardware and software vendors.
- For battery controls, integration with the battery is a one-time process for each manufacturer.

Pandemic-related Project Challenges

This project was not without significant challenges. A public health emergency was declared in the United States on February 3, 2020, and the World Health Organization declared COVID-19 a pandemic on March 11, 2020, including a travel ban on non-U.S. citizens, and a California statewide stay-at-home order shortly followed. The Monterey Park site was energized and made public on March 9, 2020, approximately a month after the public health emergency was announced in the U.S.

During the data collection and analysis period, the site experienced extremely low use due to the side-effects of the pandemic and related events. Drivers were limiting their commutes and their daily activities in general.

Issues With Second-life Batteries

It is also worth noting the challenges faced using second-life batteries in the field. Testing completed in May 2021 encountered numerous issues with both batteries. The south battery stack constantly showed as disconnected despite repeated manual interventions, including attempts to reconnect the stack from the BESS web user interface. This blocked any control of the battery system for use in the field or any manual control for testing and data collection.

At the same time, an issue was found with the north battery stack, where it would unexpectedly enter a charging state, even when commanded to discharge during test scenarios. The project team worked with engineers from Spiers and Nuvation to restore this functionality.

The threat of the pandemic and subsequent social distancing and other health and safety measures made it much more difficult to properly troubleshoot and restore connectivity to these battery stacks, as well as to perform general maintenance of the site, which required that employees be onsite and collaborate with other engineers.

Looking Ahead

From the technology standpoint, the project did meet the goals it set out to demonstrate. A local controller was developed that could communicate with both the chargers and the battery, control them, and reduce both peak power and 15-minute utility interval demands. The algorithm saved on power costs by determining how to curtail EVSE usage and leverage auxiliary power sources and sinks, such as battery and solar PV.

Recommendations

Managing PEV charging involves slowing down charge rates for individual drivers when usage at the site is high or when there is a DR event. The amount of slowdown determines site host revenue, but it still needs to be done without significantly affecting drivers' charging experiences. The next step would be to measure driver satisfaction. One possible solution is machine learning. With recent advances in machine learning, researchers and engineers can dig more deeply into the data to find insightful information. By combining site-charging patterns with business data such as customer retention rates and account usage, customer satisfaction could be measured indirectly. With site-charging data and other possible external data, better algorithm prediction parameters could automatically be applied to the site. This is certainly an area that will attract the attention and research efforts of both the PEV charging industry and utilities in coming years.

Demand charges are not a concern for site hosts, since most investor-owned utilities in California offer a PEV-specific tariff that waives demand charges. The solution is going to get more interesting for site hosts when the demand charges kick back in beginning in 2024, and this system will offer significant savings when compared with unmanaged charging.

In conclusion, market opportunities for this technology do exist and would allow PEV charging sites to provide grid services. More research is needed to develop and test solutions that improve economic profiles for building PEV charging stations, including work focused on integrating renewables, utilizing second-life batteries, and developing algorithms that adapt to DR events. Market participation models are needed to further evaluate economic benefits for site hosts.

GLOSSARY

Term	Definition
A	ampere or amps
Ah	ampere-hour
BESS	battery energy storage system
BIP	base interruptible program
BMS	battery management system
CARB	California Air Resources Board
CBP	capacity bidding program
CCS	combined charging system
CEC	California Energy Commission
CHAdeMO	A rapid-charging DC standard
CPP	critical peak pricing
CPUC	California Public Utilities Commission
DC	direct current
DCFC	direct current fast chargers
DCR	demand charge reduction
DER	distributed energy resources
DR	demand response
DRAM	demand response auction mechanism
EPIC	Electric Program Investment Charge
EV	electric vehicle
EVSE	electric vehicle supply equipment
GBC	grid battery controller
GWh	gigawatt hour
ITC	investment tax credit
kW	kilowatt
kWh	kilowatt-hour
LCFS	Low Carbon Fuel Standard
Li-ion	lithium
MT	metric ton
OCPP	Open Charge Point Protocol
PEV	plug-in electric vehicle
PV	photovoltaics
QR	quick response

Term	Definition
RTP	real-time pricing
SCE	Southern California Edison
SGIP	Self-Generation Incentive Program
SNT	Spiers New Technologies
SOC	state of charge
TCO	total cost of ownership
TOU	time of use
V	volt

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Project Deliverables

- Communications Specifications Report
- Algorithm Map Report
- Site Controller Requirements Documentation
- Site Controller Software Summary
- Component Functional Testing Validation Report
- Installation Specifications
- Vendor Selection Report
- Purchase Orders for Hardware
- On-site Photographs of Procured Equipment and Delivery Receipts
- Site Plans
- Electrical Plans
- System Specifications
- Vendor Purchase Order
- System-Level Electrical Installation and Commissioning Report
- Demand Charge Reduction Algorithm Implementation and Simulation Report
- Demand Response Algorithm Implementation and Simulation Report
- Renewable Generation Algorithm Implementation and Simulation Report
- Greenlots SKY Network Fleet Architecture Specifications
- Web Portal Tools
- Application and Portal Test Report
- Final Test Report
- Optimized Solution Performance Report
- Initial Battery Characterization Report
- Quarterly Battery Characterization Report - 1
- Quarterly Battery Characterization Report - 2
- Quarterly Battery Characterization Report - 3
- Final Battery Performance Report
- Electric Vehicle Pilot Survey Response
- Final Meeting Benefits Questionnaire
- Final Project Fact Sheet
- Final Presentation Materials
- High Quality Digital Photographs
- Final Technology/Knowledge Transfer Plan
- Final Technology/Knowledge Transfer Report

Project deliverables, including interim project reports, are available upon request by submitting an email to pubs@energy.ca.gov.

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APPENDIX A: EVSE Status Changes in Different Stages of Operation

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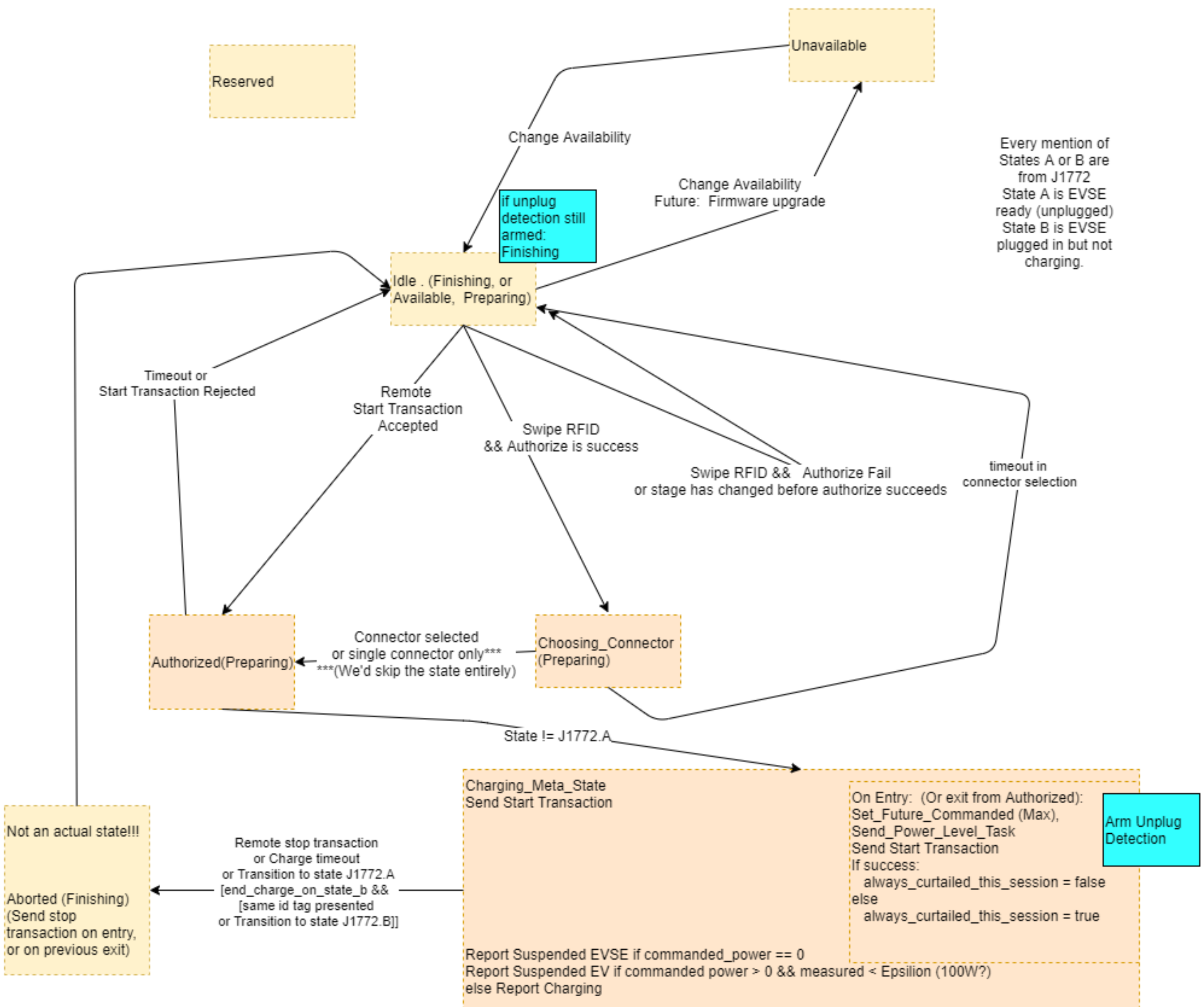
APPENDIX A:
EVSE Status Changes in Different Stages of Operation

See Figure A-1 which diagrams the EVSE status changes in different stages of operation.

Figure A-1: EVSE Status Changes in Different Stages of Operation



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APPENDIX B: Watt Tower — Energy Storage Systems

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APPENDIX B:
Watt Tower — Energy Storage Systems

See Figure B-1 for information about the Watt Tower — Energy Storage Systems.

Figure B-1: Watt Tower Specifications

Source: http://www.spiersnewtechnologies.com/energy-storage (Cox Automotive has since acquired Spiers New Technologies as of 2024).