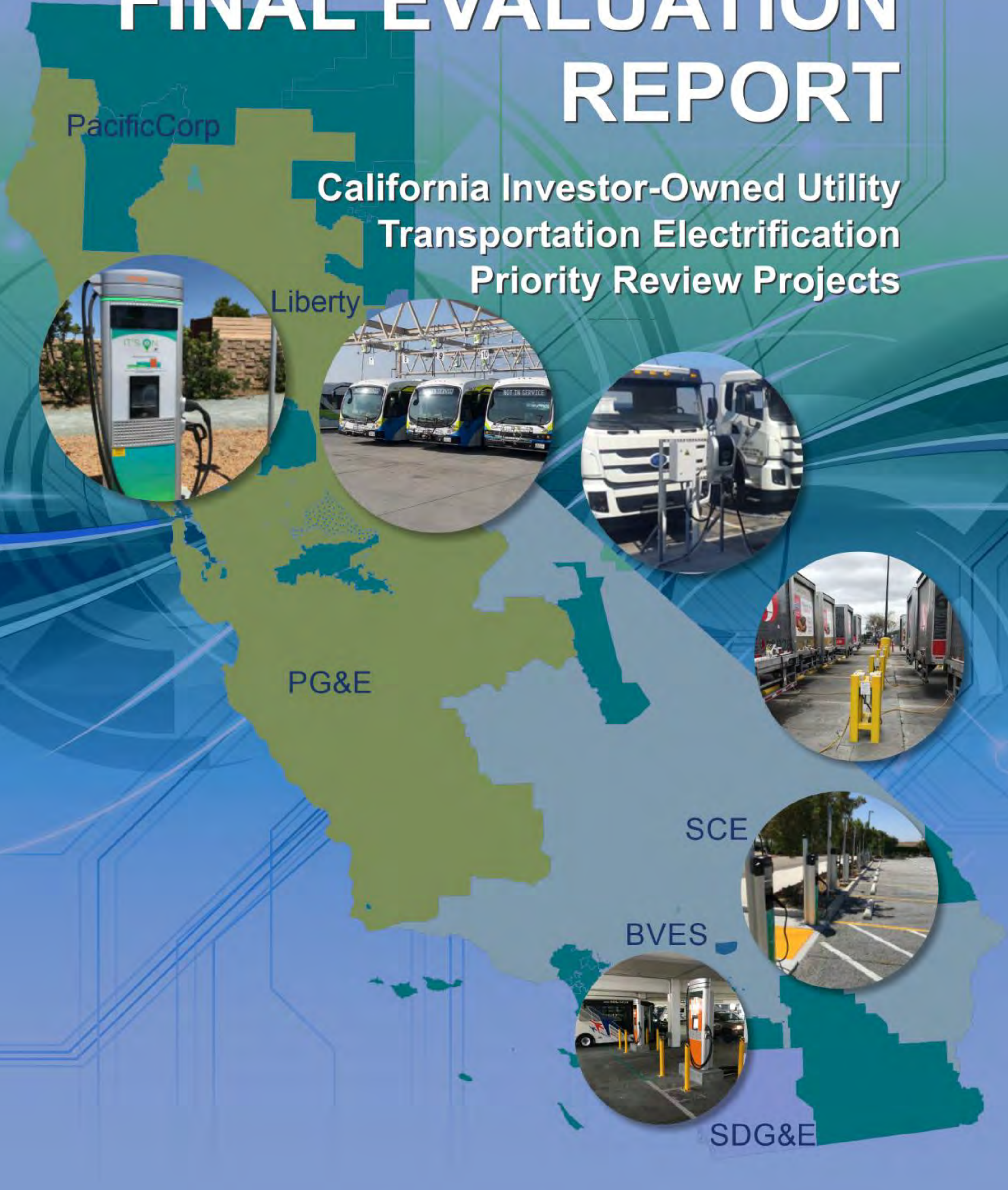
FINAL EVALUATION REPORT

California Investor-Owned Utility Transportation Electrification Priority Review Projects



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Priority Review Projects

April 2021

This report was prepared by Energetics Incorporated under a contract with Southern California Edison. Cadmus Group, National Renewable Energy Laboratory, Idaho National Laboratory and DAV Energy Solutions were contributing authors.

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1.1 Priority Review Projects High-Level Metrics

Meeting California's greenhouse gas (GHG) emissions reduction goals is a critical step toward the state's long-term climate commitments. Transportation electrification (TE) is a key measure for reducing GHG emissions. In support of the widespread TE goals of Senate Bill (SB) 350 Clean Energy and Pollution Reduction Act of 2015,[1] the California Public Utilities Commission (CPUC) issued two major decisions in 2018.

The first decision (18-01-024) in January authorized the three large investor-owned utilities—Southern California Edison (SCE), Pacific Gas and Electric (PG&E), and San Diego Gas and Electric (SDG&E)—to invest a combined budget of $41 million (M) for launching 15 TE pilot demonstrations. The second decision in September (18-09-034) authorized three small investor-owned utilities—PacifiCorp, Bear Valley Electric Service (BVES), and Liberty Utilities (Liberty)—to spend up to $7M on seven additional priority review projects (PRPs).

The PRPs were intended to be short-term investments (no longer than 12 months), with none exceeding $4M and each utility PRP portfolio limited to $20M. The two decisions required the utilities to select a third-party evaluator to assess the success of each PRP and determine whether and how each PRP could be scaled for future success. This report presents the findings of the third-party evaluation conducted from October 2018 through November 2020.

As the program outcome summary, this section presents high-level PRP metrics including budget and spending, charging ports installed, charging infrastructure costs, energy consumption, electricity costs, and GHG emissions reductions.

1.1.1 Budget and Spending

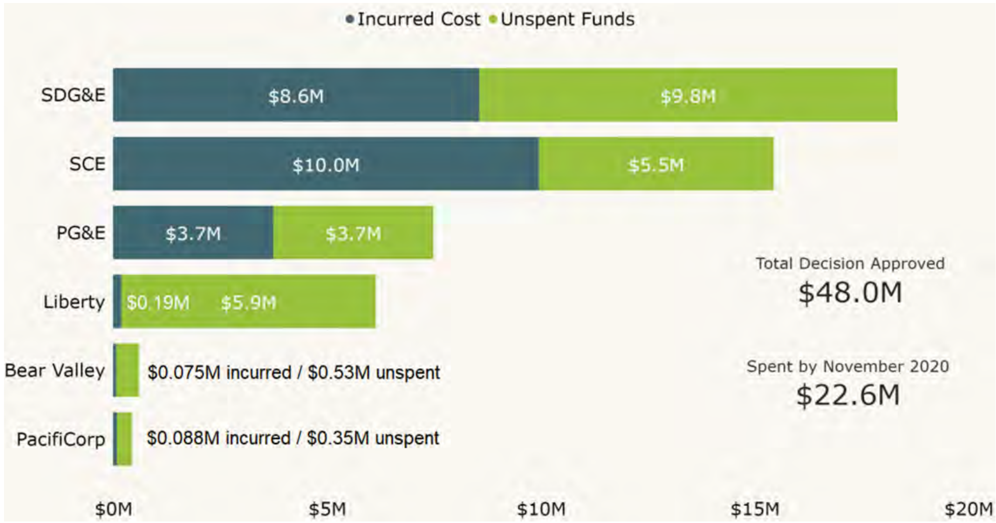
Out of the $48M approved by the CPUC decisions for the PRPs across all investor-owned utilities (utilities), only $22.6M (47%) was spent by the end of 2020. Figure 1 shows the incurred costs and unspent funds for each utility, which together equals the total CPUC decision approved budgets. It is impossible to interpret these high-level budget numbers as an indication of success because many factors contributed to the result. For example, utilities installed more charging ports than planned under some PRPs, while other PRPs did not reach the target number because fewer ports per site were needed or there was a lack of customer interest or ability to participate in the PRP. Many PRPs accurately budgeted for utility-side make-ready upgrades; however, customer-side upgrades varied significantly, as many PRP customers were not selected until after the PRPs were launched.

For the three large utilities, the incurred costs represent the total amount of the budget spent on their PRPs, as the utility activities for almost

[1] State of California, Senate Bill No. 350, Chapter 547: "Clean Energy and Pollution Reduction Act of 2015," October 7, 2015, https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350.

all of those projects have been completed. **The three large utilities plan to return the unspent funds to the ratepayers.** The smaller utilities' PRPs are all still active, and those utilities anticipate incurring additional costs that may reach the approved PRP budget ceiling.

Figure 1. Utility PRP portfolio budget and spending

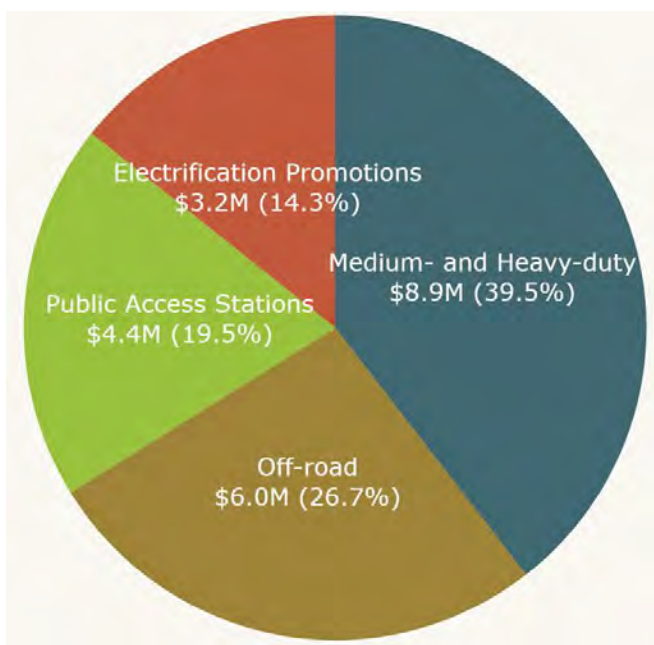


Source: SDG&E, SCE, PG&E, Liberty, BVES, and PacifiCorp

SDG&E had the largest approved PRP portfolio budget ($18.4M), and SCE had the greatest incurred PRP costs ($10.0M), as the latter spent 65% of the utility's approved PRP budget. Both PG&E and SDG&E spent approximately 50% of their approved PRP budgets. Each of the three smaller utilities has spent only a small fraction of its approved budget as of the end of 2020 but anticipates additional costs, as the PRPs are ongoing.

The PRPs comprise a diverse range of pilot projects targeting different markets (e.g., vehicle class and customer type). As such, the evaluation team categorized the 22 PRPs into four sectors: medium- and heavy-duty fleet electrification, off-road fleet electrification, public access stations, and electrification promotions. Fleet electrification projects include known vehicles and operators using the installed electric vehicle (EV) charging infrastructure. Public access station projects include EV charging infrastructure that serves a broad array of vehicles. Electrification promotion projects target EV adoption barriers for private owners, from challenges installing EV home charging solutions to poor dealership experiences when purchasing EVs. Costs incurred by each sector are shown in Figure 2. The fleet electrification sectors (medium- and heavy-duty and off-road) represent the highest spending at $14.9M, or two-thirds of the total.

Figure 2. Utility-incurred PRP costs by sector

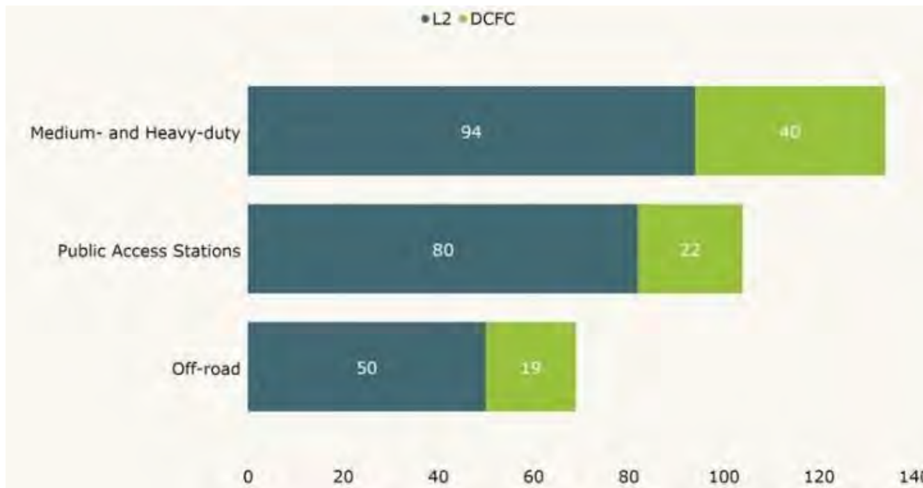


Source: SDG&E, SCE, PG&E, Liberty, BVES, and PacifiCorp

1.1.2 Charging Ports Installed

The utilities' $22.6M PRP investment spent to date resulted in deployment of 307 EV charging ports (see Figure 3). Nearly three-quarters of the installed charging ports across each sector are Level 2 (L2), which has an alternating current power output below 19 kilowatts (kW); higher-power direct current fast chargers (DCFCs) represent the balance of the installed ports. It is expected that additional charging ports will be installed by the small utilities, who had not commissioned any EV charging sites by the end of 2020.

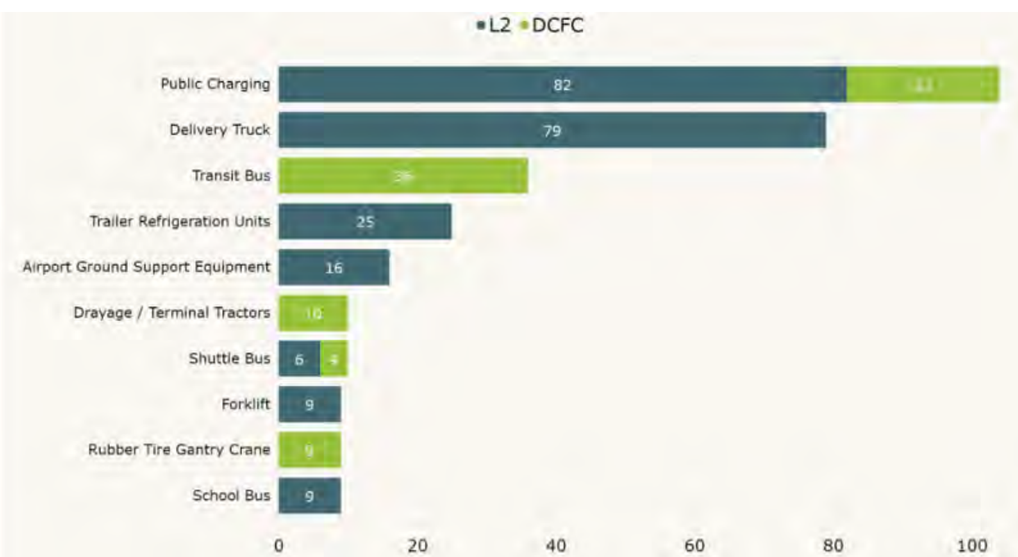
Figure 3. EV charging ports installed by sector



Source: SDG&E, SCE, and PG&E

Each sector includes specific vehicle applications supported by the PRP investments. Figure 4 shows the charging ports installed by specific vehicle application, along with their associated power levels (L2 or DCFC). The most charging ports were installed for light-duty EV public charging (104), with delivery trucks as the other major application (79). A significant number of charging ports were installed for transit buses (36) and trailer refrigeration units (TRUs, 25).

Figure 4. PRP EV charging ports installed by vehicle application



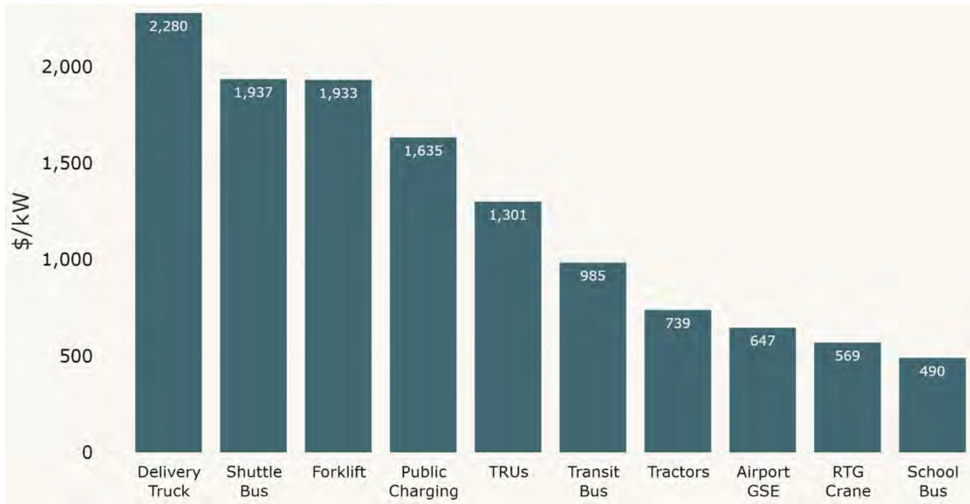
Source: SDG&E, SCE, and PG&E

1.1.3 Charging Infrastructure Cost

Figure 5 compares the cost of the charging infrastructure among the different vehicle applications based on the installed charging capacity. The delivery truck application had the highest cost per kilowatt ($2,300), because of custom installations for three of the four sites and at least 16 chargers (all L2) were installed at each site.

The next-highest cost applications were the shuttle bus pilots (mix of DCFC and L2), which had a relatively small number of charging ports installed per site, and the forklift pilot, which was a relatively low power level (10 kW). Public charging pilot costs were $1,600 per kW; a low number of DCFCs (2–4) were installed at each site and a significant number (20) of relatively low-power-level L2 chargers (6.6 kW) were installed at some sites. At the low end, the rubber-tired gantry (RTG) crane pilot was a high-power-level application with no charging unit (direct power feed), and the single school bus site installed nine low-cost, non-networked L2 chargers with an aftermarket charge management solution.

Figure 5. PRP EV charging infrastructure cost by application

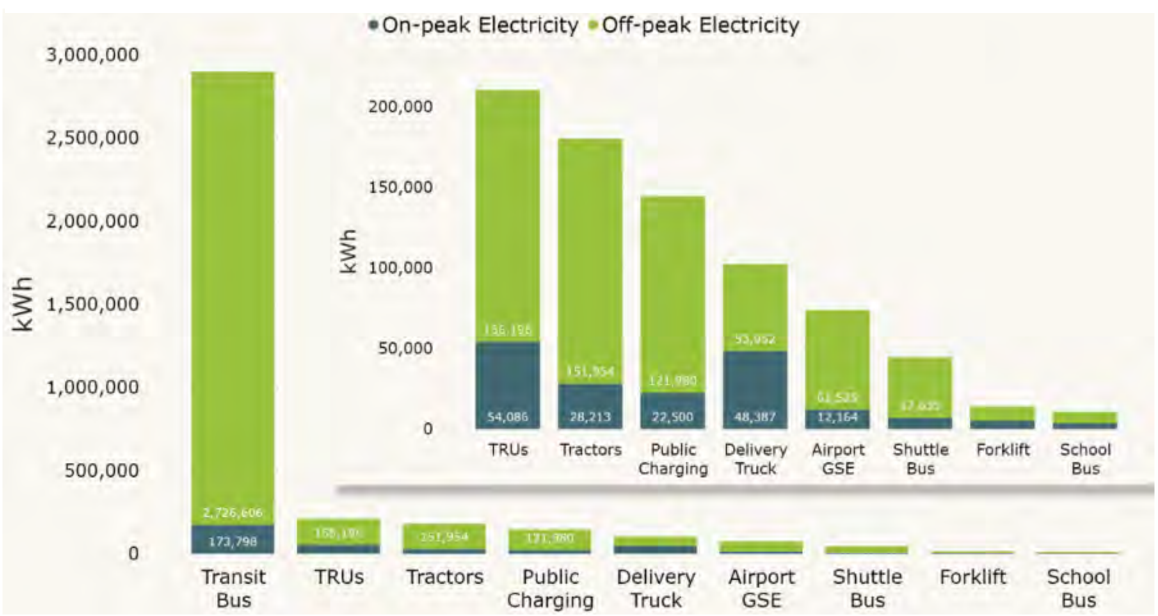


Source: SDG&E, SCE, and PG&E

1.1.4 Energy Consumption

The annual equivalent amount of electricity dispensed by the installed PRP EV charging infrastructure is shown in Figure 6 for each vehicle application. The grid impact is presented as on-peak versus off-peak energy consumption based on each pilot's specific utility rate. Note that this energy consumption is not normalized

Figure 6. PRP energy consumption by application



Source: SDG&E, SCE, and PG&E

across the PRPs and is impacted by the number and type of vehicles supported by the installed infrastructure.

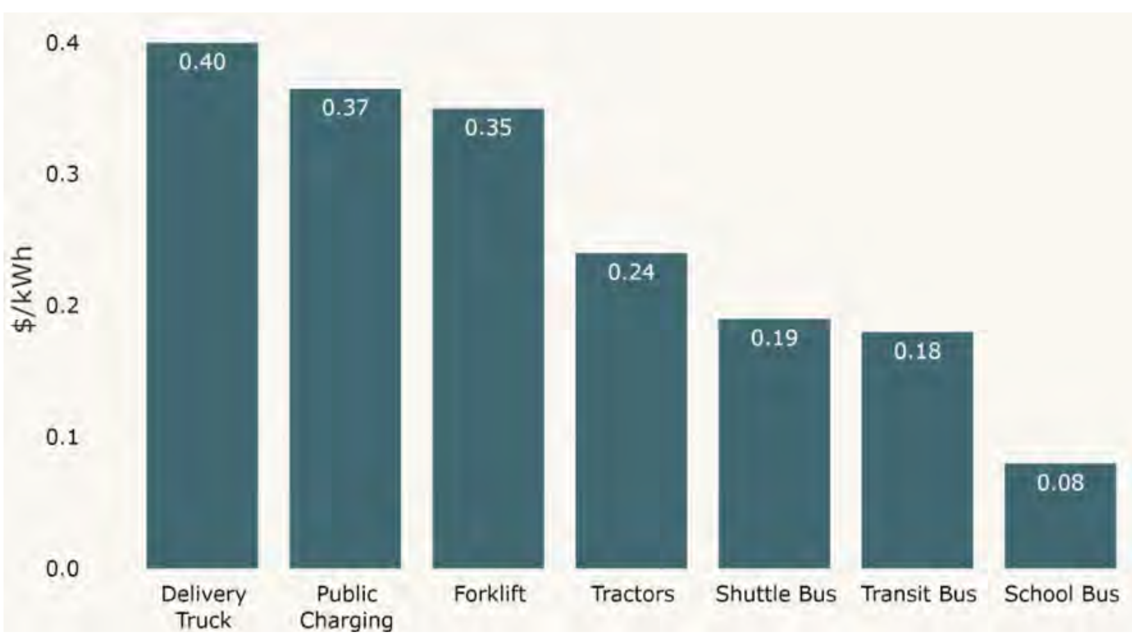
The transit bus pilots (39 EVs supported by 35 DCFCs) dwarfed all other pilots, with the highest electricity consumption of nearly 4 gigawatt-hours and only 6% consumed during on-peak time. While no actual RTG crane operation occurred during the evaluation period, this pilot has the second-highest potential electricity consumption among the PRPs (800 megawatt-hours [MWh] for 9 cranes). TRUs (25 electrified units), tractors (10 EVs), public charging, delivery truck (15 EVs), airport ground support equipment (GSE) (32 electric pieces of equipment), and shuttle bus (2 EVs) pilots follow in descending order ranging from 200 to 50 MWh. Forklift (9 electric units) and school bus (4 EVs) pilots had limited vehicles and use, which resulted in the lowest electricity consumption on an annual basis among the PRPs, as observed during the evaluation. The delivery truck pilot had the largest percentage of on-peak electricity consumption (47%), followed by TRUs (26%); all other pilots had on-peak electricity consumption below 16%.

1.1.5 Electricity Cost

From a participating fleet and EV driver perspective, the cost of electricity is a key factor because it has a significant impact on the total cost of EV ownership. Based on the electricity consumed as shown in Figure 6, Figure 7 presents the average electricity cost observed during the evaluation period for each PRP by vehicle application. There is a significant variation (a factor of 5) between the lowest and highest costs.

- Owing to a large percentage of on-peak electricity consumption and a commercial and industrial tariff with demand charges, the delivery truck application had the highest average electricity costs ($0.40 per kilowatt-hour [kWh]).
- All public charging PRPs ($0.37/kWh) were on EV time-of-use (TOU) rates, but several EV drivers commented on the high cost of charging, especially during on-peak times.

Figure 7. Average PRP electricity cost by application



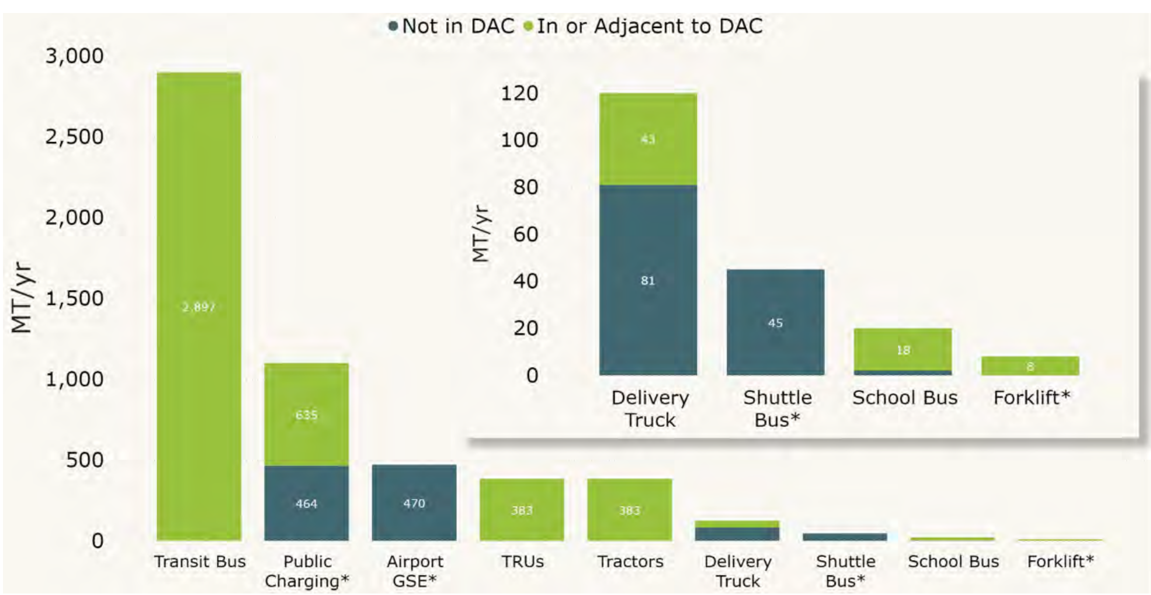
Source: SDG&E, SCE, and PG&E

- The forklift PRP ($0.35/kWh) started on a commercial and industrial (C&I) tariff with demand charges before switching to a tariff with much lower demand charges since no EV-TOU rates were available.
- Tractor pilots ($0.24/kWh) had one PRP using an EV-TOU rate and the other on a C&I tariff with high demand charges (no EV-TOU rates were available for that pilot).
- The shuttle bus PRP ($0.18/kWh) was unique, as it piloted a grid-integrated rate based on day-ahead hourly dynamic pricing. This resulted in the lowest electricity price in the SDG&E PRP portfolio.
- Three of the four transit bus fleets ($0.18/kWh) utilized EV-TOU rates and had minimal on-peak electricity use.
- Electricity costs were not released by two off-road PRPs because they shared a transmission line with a single billing meter, but the rates were estimated for airport GSE ($0.20/kWh) and TRU applications ($0.16/kWh).
- Average electricity costs for RTG cranes are anticipated to be around $0.18/kWh based on baseline operation and use of an EV-TOU rate, as no actual operation occurred during the evaluation period.
- The school bus PRP (PG&E) application had the lowest average electricity costs ($0.08/kWh) because integrated renewable energy provided some of the EV charging electricity. This PRP application also had the smallest charging load, with a maximum of only four EVs using L2 chargers.

1.1.6 GHG Emissions Reduction

The primary goal of SB 350 is GHG emissions reduction. Figure 8 presents the net annual GHG emissions reduction for each PRP vehicle application based on the best observed period of performance. The GHG emissions reduction that occurred in or adjacent to disadvantaged communities (DAC) is also shown. Since PRPs varied in their ramp-up of EV charging infrastructure utilization and several PRPs experienced challenges with EV availability,

Figure 8. Net GHG emissions reduction by PRP application



* Public charging calculation used higher L2 utilization than observed during the evaluation period due to COVID-19 pandemic impact; airport GSE, shuttle bus, and forklift applications used a conventional fuel baseline (gasoline, diesel, and propane, respectively) as electric GSE and forklifts were already used in fleet operations before the PRP and green shuttle fleet used renewable diesel fuel with very low carbon intensity.

customer demand, and COVID-19 pandemic impacts, a smaller “best observed” window of operation (a single month, for most PRPs) was used to calculate the GHG emissions benefits. It is important to note that although the primary goal of SB 350 is to maximize GHG emissions reduction, it was not necessarily each PRP’s primary objective.

The transit bus pilot showed the largest net GHG emissions reduction (2,900 metric tons [MT]/year). The RTG crane pilot is expected to result in potentially even larger net GHG emissions reduction; however, since no actual RTG crane operation occurred during the evaluation period, an estimate was calculated (3,100 MT/year) but not shown in Figure 8.

The public charging PRPs exhibited the next-highest GHG emissions reduction potential (1,100 MT/year), as those stations will likely serve a large population of EVs. However, COVID-19 pandemic restrictions significantly impacted personal EV use. As such, an estimate was calculated based on the highest single week of use for DCFCs and scaled-up L2 use.

The delivery truck, shuttle bus, school bus, and forklift pilots showed the lowest GHG emissions reductions, but it is important to note the number of EVs included under each PRP, as the GHG benefits result from vehicle use. For example, while nine L2 chargers were installed as part of the school bus PRP, the fleet had only four electric school buses which were used sporadically. In comparison, the transit pilots installed 35 DCFCs that supported 39 electric buses in regular service, with relatively minimal impacts from the COVID-19 pandemic.

1.2 PRP Vehicle Application Rankings

It is very difficult to rank individual PRP performance, as many assumptions are required to fairly assess and compare the PRP applications. Table 1 has been developed to illustrate PRP application achievements based on the PRP evaluation findings. The ranking is based on the evaluator’s expert opinion and intimate familiarity with the PRPs. Four icons indicate the highest rating per category, while a single icon indicates the lowest rating.

The ranking considers the following aspects within the six categories:

- **Technology Maturity** – charger and vehicle availability, customer feedback, EV range, and vehicle features
- **Operational Applicability** – consistent routes, vehicle/equipment suitability, and sufficient charging time
- **Grid Integration Ability** – flexibility in charging times to avoiding on-peak charging and charging management capability
- **Operational Cost Effectiveness** – cost per mile compared to baseline assuming California Air Resources Board (CARB) Hybrid and Zero-Emission Truck and Bus Voucher Incentive Project (HVIP) and utility make-ready investment
- **GHG Reduction per Investment** – metric tons of GHG per year, utility investment
- **Market Size and Potential** – statewide impact based on total vehicle population and portion deemed suitable for electrification

Green, yellow, and red shading represents the highest to lowest priority of utility investment for scale-up based on the PRP evaluation. This color coding is based on equal weighting of the six categories, although these factors are ordered from left to right based on importance. Scale-up potential starts with technology maturity, a primary requirement for deployment; less mature technologies have fewer commercial offerings and tend to present more operational issues.

Operational applicability is considered next, as even mature technologies will not result in significant use if they are not a good fit for a vehicle application. After the vehicle or equipment meets fleet mission reliably, grid integration is factored in, because charging time has a significant impact on operational costs, in addition to electricity generation emissions. Fleet flexibility to schedule charging during off-peak hours and technology to automate the process will result in significantly lower average electricity costs.

Operational cost-effectiveness is a key factor for fleets considering adoption of EVs and charging equipment. Operational cost factors include electricity rates, off-peak charging ability, vehicle and charging infrastructure efficiency, and vehicle and equipment maintenance. When compared to baseline vehicle costs, EVs should have an operational cost benefit to help offset higher incremental vehicle and charging infrastructure costs. While most California fleets can apply to receive funding from the California Air Resources Board (CARB) Hybrid and Zero-Emission Truck and Bus Voucher Incentive Project (HVIP) to offset incremental vehicle costs and/or participate in utilities' TE standard review projects to cover make-ready charging infrastructure, EV charger equipment and installation costs remain. If fleet owners/operators do not realize operational cost savings or see a pathway to cost parity with conventional baseline operations, they would not be inclined to electrify their fleets unless required by zero-emission regulations.

Technology maturity, operational applicability, grid integration ability, and operational cost-effectiveness are the prerequisites that must be partially met before considering the final two scale-up factors–GHG emissions reduction per investment and market size/potential–which determine the potential utility investment effectiveness and impact. These factors provide an indicator for which vehicle applications should be prioritized if technology readiness is shown across the first four factors.

GHG emissions reduction is the driving factor behind utility TE programs approved under SB 350. Successful applications require a high vehicle or equipment utilization, along with a significant emissions benefit when compared to the baseline technology. Even if there is a significant GHG emissions reduction potential for a relatively low investment, a large number of vehicles or equipment in a given application statewide must be suitable for electrification to ensure the overall impact will be significant to make progress toward the state GHG goals.

Based on observed PRP performance, transit bus, airport GSE and public charging applications have the highest overall ranking and utilities should prioritize these for scale-up in their TE programs. This is attributable to mature products, history of successful use, and potential economic, and environmental benefits. TRU, delivery truck, school bus, shuttle bus and forklift applications ranked moderately; they have good potential, but experienced limited usage or technology challenges that impacted the economic and environmental benefits of electrification.

Drayage/terminal tractors and RTG cranes have the lowest overall ranking due to limited PRP operation resulting from implementation challenges associated with the deployment of these emerging technologies. Even with the COVID-19 pandemic impacting typical operations, the PRPs have validated the GHG reduction potential for nearly all selected applications.

Table 1. PRP application scale-up summary

Application	Technology Maturity	Operational Applicability	Grid Integration Ability	Operational Cost Effectiveness	GHG Reduction per Investment	Market Size and Potential
Transit Bus	3	3	2	3	4	3
	Driven by regulation, several manufacturers, regular routes with high utilization, overnight charging, and significant market size					
Airport Ground Support Equipment	4	4	3	3	3	1
	Mature products, history of successful use, overnight charging with daytime renewable energy charging opportunity					
Public Charging for Light-duty EVs	4	4	2	1	2	4
	Mature vehicle/charger technologies with incentives, grid management via fees, large future benefit potential by serving more EVs					
Trailer Refrigeration Units	3	2	1	3	3	3
	Upcoming regulation, existing eTRU technology, limited charge scheduling opportunities, significant benefits and market size					
Delivery Truck	2	3	3	2	2	3
	Emerging technology with limited vehicle availability, good fit for shorter routes, overnight charging, significant market size					
School Bus	2	2	4	2	1	3
	Emerging technology, charge management challenge, renewables charging opportunity, low use/benefits, significant market size					
Shuttle Bus	2	4	3	2	1	2
	Emerging technology, good fit for short routes, overnight L2 (low use) and DCFC with daytime charging (high use), limited benefits					
Forklifts	3	4	3	2	1	1
	Mature products, history of successful use, overnight charging, relatively low energy use/benefits/market size					
Drayage/Terminal Tractors	2	2	2	2	2	2
	Emerging technology, limited product offerings, high power DCFC without charge management ability, potential benefits					
Rubber Tire Gantry Crane	1	1	1	3	4	1
	New technology application, implementation challenges, grid-tied with no buffering, significant benefits, small market size					

1 – significant vehicle or charging technology deployment challenges, 4 – minimal deployment challenges

1 – not a good fit for electrification, 4 – very good fit for electrification

1 – no flexibility in avoiding on-peak charging, 4 – significant opportunity for off-peak charging

1 – minimal operational energy savings, 4 – operational energy savings cover significant portion of charging infrastructure costs

1 – less than 200 MT of CO_{2e} emissions reduction annually per \$1M of charging infrastructure investment, 4 – more than 1,000 MT of CO_{2e} emission reduction annually per \$1M of charging infrastructure investment

1 – less than 1,000 vehicles/equipment in California suitable for electrification, 4 – more than a million vehicles suitable for electrification

1.3 Overarching PRP Findings and Recommendations

While PRP-specific findings, recommendations, and lessons learned are in each individual PRP report section, **common findings and recommendations across the SB 350 PRP program** are summarized here.

1.3.1 Program Level

- **The make-ready planning, design, and construction activities were executed well in general.** As this is the utilities' core competency, this was expected. Construction durations were within expected timelines except for a few port projects that experienced significant delays. Utility-side make-ready budgets were fairly accurate; however, the accuracy of customer-side make-ready cost estimates varied significantly.
- **Many PRP schedules were extended by 12 months or more.** The primary cause was pre-construction delays due to contracting agreements, determining charging requirements based on vehicle capabilities and anticipated use, and permitting with jurisdictions unfamiliar with TE infrastructure projects. Utilities have applied lessons learned from these pilots to standard review projects.
- **Incentives and rebates programs fell short of spending their approved incentives budget due to customer eligibility and application requirements**. The Clean Fuel Reward as a time-of-sale incentive supported by utilities provides a much simpler and more effective mechanism for increasing light-duty EV adoption.
- **The small utilities experienced challenges with their PRPs due to their unique service territory characteristics.** Their residents tend to have lower incomes, along with low awareness of and interest in EVs. Increased outreach and education efforts are needed which is challenging for the smaller utilities with fewer staff resources and the complications COVID-19 placed on engagement activities. Future projects must account for these challenges to help increase customer participation in EV infrastructure deployment programs. Shortened EV range in colder climates and limited all-wheel drive EV models for winter and mountainous driving conditions are also barriers to EV adoption in these areas.
- **Customers and utilities learned important lessons about implementing emerging EV technologies for specific vehicle applications.** In addition to providing EV charging infrastructure for fleet electrification, utilities also educated their customers on EV technologies. In several instances, vehicle manufacturers, electric vehicle supply equipment (EVSE) manufacturers, and electric vehicle service providers (EVSPs) also gathered important information about performance of their products and services.
  - **Recommendation: To increase the success of ongoing and future TE programs, utilities' clean transportation programs should provide technical advisory services to fleets on EV technologies and charging solutions.** These staff (utility employees or consultants) should be experts on EV technologies and have a good understanding of fleet operations.
- **Periodic review of fleet operational performance identified opportunities that increased project benefits.** Third-party evaluator's review of PRP operational data (utility meter, charging session, and billing

data) identified sites with low utilization and high electricity costs which could be, and in several cases were, addressed by changing charging behavior to increase project benefits.

- **Recommendation: Within a year of a new fleet customer's joining a TE program, the utility should review the fleet's operational performance (utility meter, charging session, and billing data) with the customer at least once.** This interaction can be conducted by the utility account managers and/or customer representatives, supported by a technical advisor and other fleet staff when needed. This interaction will also provide an opportunity for utilities to receive additional fleet feedback and lessons learned.

- **Statewide vehicle purchase incentives (CARB HVIP), charging infrastructure funding (utility make-ready programs), and fueling credits (CARB low-carbon fuel standard [LCFS]) are needed for most vehicle applications to ensure a successful transition to zero-emission vehicles (ZEVs) over the next decade.** Operational savings from lower maintenance costs combined with any energy cost savings may not be sufficient to cover the additional capital costs of EVs and chargers without these incentives.

1.3.2 Technology

- **EV range expectations should not be based on an EV's advertised battery capacity and energy consumption alone.** Accounting for energy losses and fleet-specific duty cycles provides a more realistic driving range. For example, an electric bus with 400 kWh nominal battery capacity and a 2 kWh per mile average energy consumption rating might imply a potential 200-mile range on a single charge. However, when considering usable battery capacity (typically 20% lower than nominal) and minimum end of day state-of-charge (SOC) for fleet operational comfort (no lower than 20%, as in some cases EV power gets derated at low SOC) the effective range drops to 130 miles. The range may fall below 100 miles on extreme temperature days (ambient temperatures below 40 and above 80 degrees Fahrenheit) due to a 30% or more increase in energy consumption due to heating or air conditioning requirements.

- **EVSE field certification presents challenges that can result in significant delays due to various jurisdiction requirements.** This can be avoided by ensuring EVSE are Nationally Recognized Testing Laboratory (NRTL) certified.

- **The maximum rated EVSE power level does not necessarily represent the power delivered to the EV.** Power delivery depends on the most limiting piece of equipment (charging cable, vehicle receptacle, battery voltage, or battery management system) and the charging rate typically decreases for DCFC when the battery reaches 80% SOC.

- **There can be interoperability issues between EV battery management systems (BMS) and managed charging solutions.** School buses were unable to delay charging or adjust the power level during the charging event due to a BMS built-in protection.

- **Chargers with software management capability can significantly reduce on-peak electricity use**. Automated systems don't rely on staff to manage plug in times for avoiding on-peak charging.

  - **Recommendation: Charge management solutions should be**

strongly encouraged for all fleet applications, where cost-effective.

- **Deploying battery energy storage in EV charging applications may be more complex and time consuming than expected.** Local contractors may not be familiar with installation requirements, the cost of the components, and the required amount of labor. This issue may be resolved if product manufacturers develop a turnkey solution for these applications.
- **Variable electricity rates provide opportunities for significant cost savings if customers manage their charging patterns.** PRPs included a variety of rates from Commercial and Industrial (C&I) with minimal to very high demand charges which resulted in higher operational costs for some PRP participants, to EV-TOU rates and day ahead dynamic pricing which provided more savings. SCE pilots used a commercial EV-TOU rate, while PG&E did not have a similar rate available until mid-2020 and SDG&E only received interim approval for an EV-TOU rate in 2020 with a final rate anticipated in early-2022.
    - **Recommendation: Fleets should use commercial EV-TOU rates to lower operational costs.** A possible exception would be, if a fleet is using an existing meter and can manage the EV charging load to avoid baseline facility load peaks.

1.3.3 Data Collection

- **Less than 12 months of data were collected for most PRPs due to delays in EV charging infrastructure implementation and EV deliveries.** For some PRPs this impacted the ability to evaluate operational costs due to a small and early sample of data which might not be representative of optimized operation.
- Although the method of collection varied by utility, **accurate utility meter data for PRPs were readily available for evaluation.**
    - **Recommendation: For evaluation of large-scale utility TE programs, the third-party evaluator should have direct access to participating customer utility meter data (e.g., Green Button Connect). This allows access to data as needed, directly from the source, and would not require utility staff involvement.**
- **Direct access to EVSP online portals for charging session data streamlined collection and enabled more detailed evaluation.** Charging session data was available for several PRPs directly from EVSP online portals which made the data available in real time, directly from the source, and did not require utility staff or others involvement. Direct access to the EVSP online portal for public charging pilots provided additional charging session data such as generic driver identification, driver ZIP code (to support DAC attribution), and EV battery SOC. A few PRPs experienced significant delays (more than nine months) in making charging session data available to the evaluator due to EVSP delays in delivering the data to the utility or challenges with aftermarket dataloggers where networked solutions were not available.
    - **Recommendation: As part of the participation agreement, customers should be required to grant the utility and third-party evaluator access to their charging session data directly from their EVSP online portal.**

   - **Recommendation: Utilities should require all EVSPs as part of their approved product list for TE programs to enable the utility and third-party evaluator to view and download program participants' charging session data directly from their online portals based on signed customer participation agreements.**

- **Utility billing data were valuable to confirm tariff rates and report on electricity costs.** Access to customer billing data was arranged through the utilities after obtaining either individual customer agreements (SCE and PG&E) or a blanket customer data privacy agreement with the utility (SDG&E). Billing analysis showed that several sites were being billed on unfavorable rate schedules. Also, it was determined that an incorrect billing rate was assigned to a few sites which resulted in significantly higher electricity charges. (Note: the billing rate was corrected for these customer accounts.)

   - **Recommendation: Utility account managers should review the rate on new TE accounts to ensure appropriate billing.**

   - **Recommendation: As part of the participation agreement, a customer should be required to share electricity billing data with the third-party evaluator to support evaluation of costs.** (In SCE's current pilots and programs, they updated their customer program participation agreements to require customers to share billing data.)

- **Fleet operational data for electric and baseline vehicles provided the necessary information to evaluate PRP benefits.** Original equipment manufacturer (OEM) or aftermarket telematics data are more reliable than driver logs. The evaluator had direct access to these data for some PRPs. The evaluator collected these data in real time, directly from the source, and did not require any fleet involvement after making initial arrangements with the telematics provider. However, operational data was not available for many fleets and the analysis had to rely on electric and baseline vehicle performance information obtained through interviews.

   - **Recommendation: For pilots with early market technologies, as is the case for many PRPs, project-funded telematics devices should be included to ensure operational data is readily available.**

- **Data collection for transmission level customers is logistically challenging and can be expensive**. EV infrastructure installations can be in locations that are not easily accessible by the utility for collecting data (e.g., airport GSE) or for applications like eTRU, the charging solutions do not offer networking capabilities.

   - **Recommendation: To ensure direct access to charging usage data, automated utility metering solutions should be installed where possible.** One or two stand-alone check meters (non-billing utility meter) per site can transmit data automatically to the utility in the same way as the billing meter (SDG&E approach). Alternatively, lower-cost hockey puck meters (PG&E proposed) could be installed in the electrical cabinet of the make-ready-charging infrastructure to monitor individual chargers.

1.3.4 COVID-19 Pandemic Impact

- **Several pilots that were in construction or did not start construction by March 2020**

were directly impacted by the pandemic. Those PRPs experienced significant delays in completing construction and commissioning the stations to start operations.

- **Many PRPs never experienced normal EV operations and charging patterns due to pandemic impacts**. Some pilots had relatively small impact on operations (e.g., transit fleets), while others halted operations and did not resume prior to the evaluation concluding (e.g., forklifts and school buses).
- The stay-at-home orders significantly impacted private driver behavior at public charging pilot locations. DCFCs were intended to support regional travel and multi-unit resident charging in DACs; L2 chargers were intended to support daily commuters.
    - **Recommendation: Further collection and analysis of public charging station data over the next several years will provide additional insights to inform future public charging programs.**
- **Education and outreach efforts were severely hampered due to stay-at-home orders and restrictions on public gatherings.** Community events and in-person engagement with the potential customers were cancelled for several PRPs. Most PRPs turned to online marketing and virtual engagement tools to continue some level of outreach.

2. Program Overview and Project Evaluation

Meeting the state's electrification and greenhouse gas (GHG) reduction goals is a critical step toward the state's long-term climate commitments set forth in the California 2005 Executive Order S-3-05,[2] 2006 Assembly Bill 32,[3] and 2016 California Senate Bill (SB) 32.[4] In support of the widespread transportation electrification goals of SB 350,[5] the California Public Utilities Commission (CPUC) issued a Decision 18-01-024[6] in January 2018, authorizing the three large investor-owned utilities—Southern California Edison (SCE), Pacific Gas and Electric (PG&E), and San Diego Gas and Electric Company (SDG&E)—to launch 15 pilot demonstrations of transportation electrification investments with combined budgets of $42 million. In September 2018, CPUC Decision 18-09-034[7] authorized three small investor-owned utilities—PacifiCorp, Bear Valley Electric Service (BVES), and Liberty Utilities (Liberty)—to spend up to $7.2 million on seven additional priority review projects (PRPs). The two decisions required the utilities to select a third-party evaluator to assess the success of each PRP and determine whether and how each PRP could be scaled for the future. In response to this mandate, the utilities issued a request for proposals for consultants to fulfill this role. The utilities selected an evaluation team led by Energetics and supported by the Cadmus Group, Idaho National Laboratory, National Renewable Energy Laboratory, and DAV Energy Solutions.

As approved, the PRPs were anticipated to take 12 months for design, construction, and commissioning, followed by 12 months of data collection. Based on this anticipated timeline, the evaluation report for all PRPs was required by December 31, 2019.

However, these innovative transportation electrification investments were of a complex nature, and as a result, most PRP timelines were extended. In January 2019 utilities issued PRP interim reports, documenting challenges to securing site host commitments for participation. Several PRPs were delayed due to the timing of the acquisition of electrified vehicles (EV) or equipment that was not funded by the

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[2] State of California, Office of Governor Arnold Schwarzenegger, Executive Order S-3-06, June 1, 2005, http://static1.squarespace.com/static/549885d4e4b0ba0bff5dc695/t/54d7f1e0e4b0f0798cee3010/1423438304744/California+Executive+Order+S-3-05+(June+2005).pdf.

[3] State of California, Assembly Bill No. 32, Chapter 488: "Air pollution: greenhouse gases: California Global Warming Solutions Act of 2006," September 27, 2006, http://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=200520060AB32.

[4] State of California, Senate Bill No. 32, Chapter 249: "California Global Warming Solutions Act of 2006: emissions limit," September 8, 2016, https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201520160SB32.

[5] State of California, Senate Bill No. 350, Chapter 547: "Clean Energy and Pollution Reduction Act of 2015," October 7, 2015, https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350.

[6] Public Utilities Commission of the State of California, Decision 18-01-024: "Decision on the Transportation Electrification Priority Review Projects," January 11, 2018, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M204/K670/204670548.PDF.

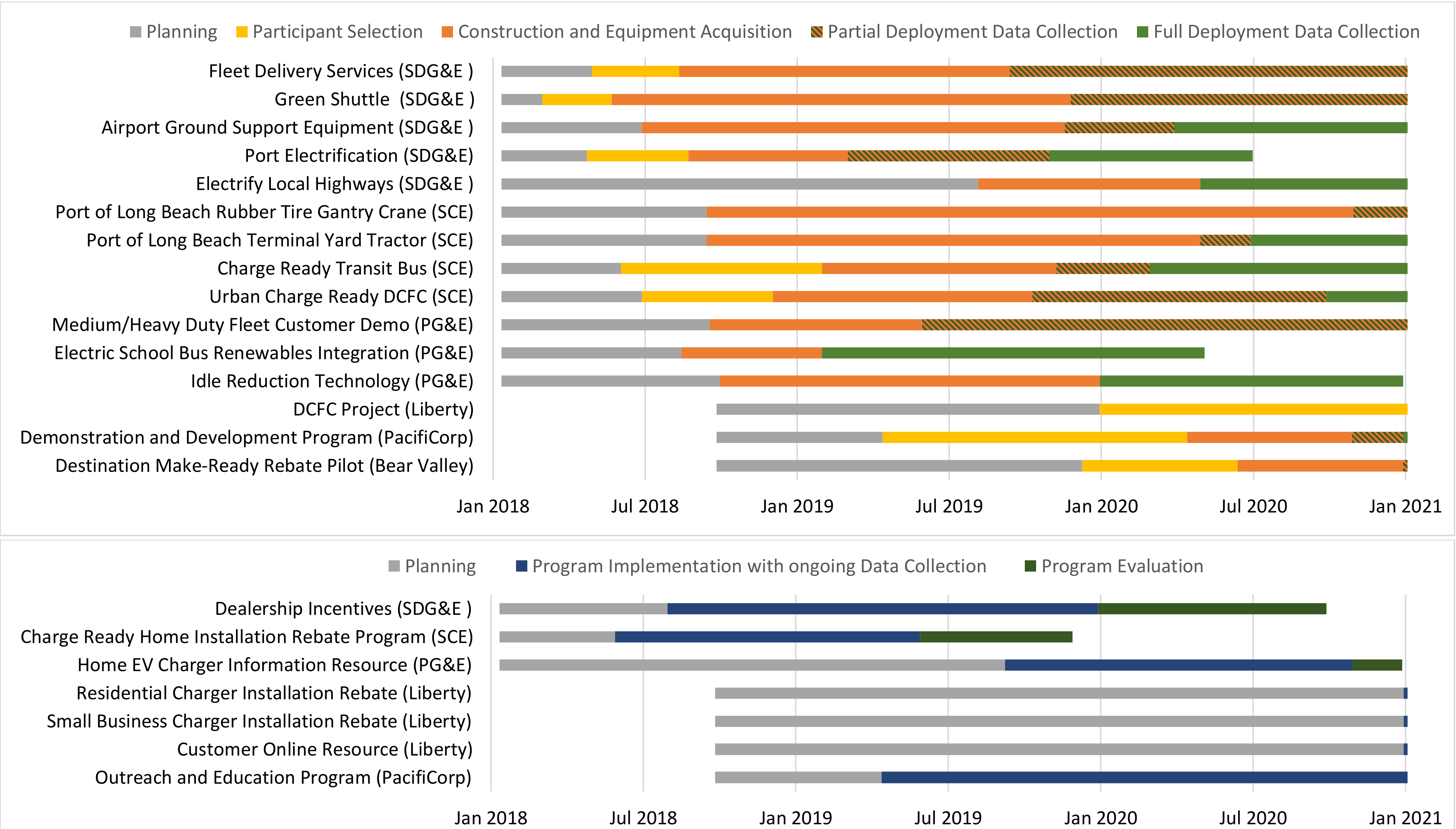
[7] Public Utilities Commission of the State of California, Decision 18-09-034: "Decision on the Priority Review and Standard Review Transportation Electrification Projects," September 27, 2018, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M231/K030/231030113.PDF.

utilities and therefore out of their direct control. Only two PRPs, containing rebates and outreach, were completed by the end of 2019, while a number of PRPs involving construction were just commissioning the EV charging infrastructure at that time. In June 2019, based on a joint utility request, the CPUC approved extending the final evaluation report to January 2021 while adding an interim evaluation report which was submitted in January 2020 and summarized accomplishments and findings to that date. Most of the large utility PRPs have generated operational data on the use of the installed charging infrastructure for this final evaluation report.

PacifiCorp, BVES, and Liberty received approval to launch their PRPs nine months after the three large utilities and issued a joint interim report in September 2019. All three of these utilities experienced challenges based on their unique territory locations and customers. Two of them had application periods open for a year or more but received very limited interest from commercial customers. One utility experienced staffing challenge and was unable to fully launch their programs for customer applications in 2020. All three utilities plan to continue their programs with two of them expecting completion by the end of 2022 (all have PRPs involving infrastructure installation, none of which took place in 2020).

Figure 9 shows the overall timeline for the PRPs encompassing planning (starting with the Decision), implementation (starting when construction or program began), and data collection (commencing with commissioning of charging equipment and vehicles, first rebate/incentive provided, or resources available).

Figure 9. Utility PRP timelines



Source: SDG&E, SCE, PG&E, Liberty, PacifiCorp, BVES

2.1 Evaluation Scope

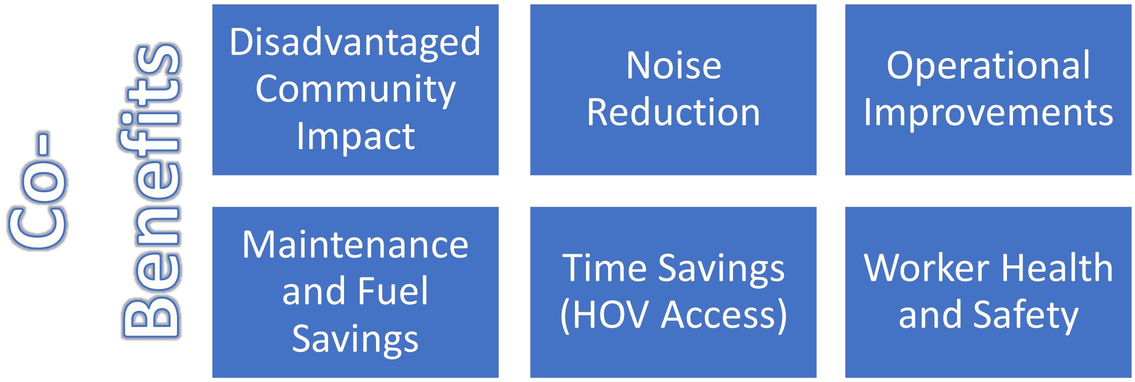
The PRPs are intended to test new approaches to overcoming barriers to transportation electrification, as well as to gather data on the approaches' implementation and outcomes. As such, it is anticipated that certain projects will be more successful in reducing barriers and accelerating transportation electrification than others. Therefore, it is important to identify those that can be scaled up immediately and those that would need modifications or technology improvements before they are ready to be scaled up. The evaluation seeks to uncover robust, conclusive, and actionable lessons learned that can be applied to the utilities' transportation electrification standard review projects (SRPs), as well as other future electrification efforts.

The three main steps of the evaluation approach are presented in Figure 10. First, the relevant research questions for each PRP are identified based on the transportation electrification goals and market intervention approach. Next, data sources are identified, data are collected, and appropriate analyses are conducted. Finally, the collected project information and analysis results are integrated to answer the research questions and draw conclusions to evaluate each PRP's success and potential for scaling up.

Figure 10. High-level three-phase evaluation approach

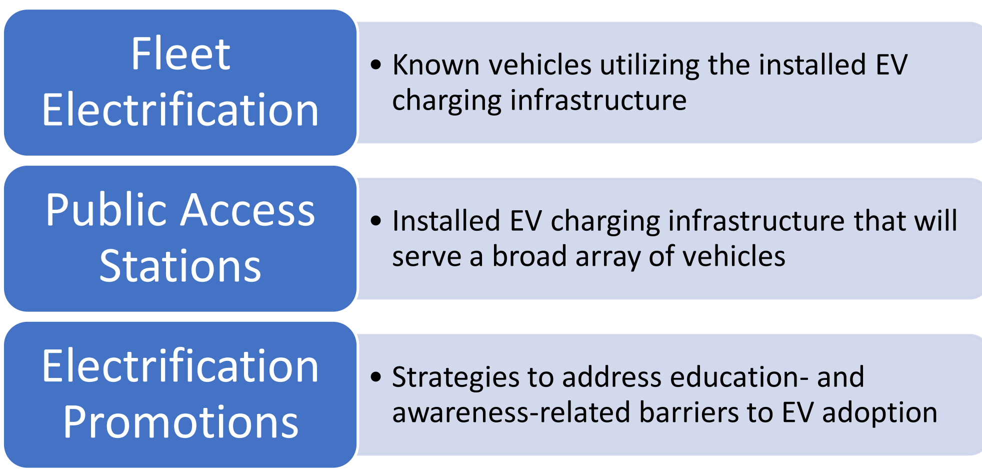
The PRP evaluation will quantify, as possible, direct project benefits, such as reductions in fossil fuel usage, criteria pollutants, and GHGs, along with economic impacts based on available data. The evaluation will also strive to measure ***co-benefits and identify the beneficiaries of those co-benefits*** to portray a comprehensive picture of the project's successes and use those insights to inform future efforts.

Figure 11. Potential PRP co-benefits



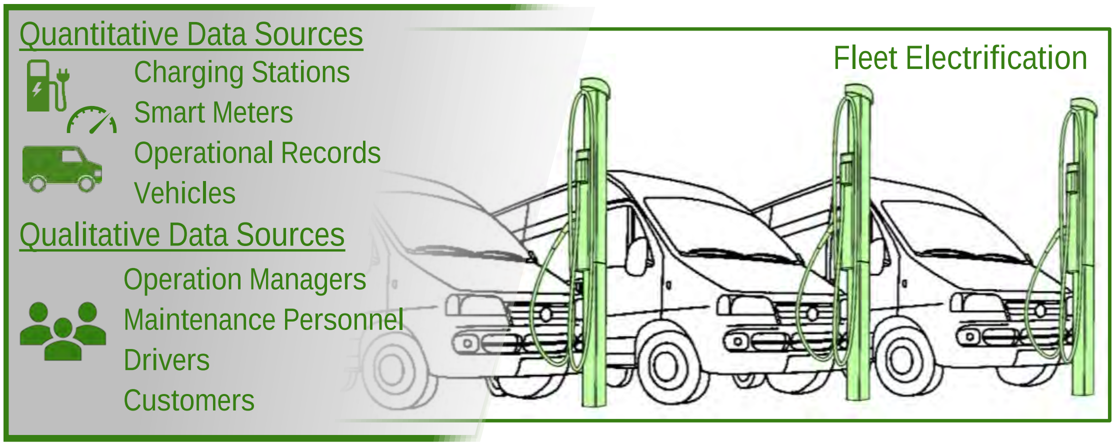
The PRPs comprise a diverse range of projects targeting different markets (e.g., vehicle class and customer type). As such, the evaluation team categorized the 22 approved PRPs into three groups or practice areas, shown below, for commonality in the analysis and comparisons.

Figure 12. PRP groupings



Fleet electrification projects include known vehicles and operators using the installed EV charging infrastructure. Available operational data includes the charging session data collected by the utilities and vehicle or equipment telematics to the extent available to the evaluator by the fleet customers. These data can be used to validate the fuel savings with either the vehicle mileage or vehicle operating hours and the electricity dispensed by the charging stations. In addition, the vehicle operating practices are typically known prior to project implementation and will serve as a baseline. It should be relatively straightforward to determine the potential for the participating fleet to scale up their adoption of electrified vehicles or equipment based on the available information from fleet electrification PRPs. A brief summary of Off-Road Fleet Electrification PRPs is presented in Table 2, and a summary of Medium- and Heavy-Duty Fleet Electrification PRPs is presented in Table 3.

Figure 13. Fleet electrification projects



Priority Review Project (Off-Road EV Charging Infrastructure)	Priority Review Project (Medium- and Heavy-Duty EV Charging Infrastructure)
Airport Ground Support Equipment (SDG&E)	Green Shuttle (SDG&E)
Port Electrification (SDG&E)	Fleet Delivery Services (SDG&E)
Port of Long Beach Rubber Tire Gantry Crane (SCE)	Charge Ready Transit Bus (SCE)
Port of Long Beach Terminal Yard Tractor (SCE)	Medium/Heavy Duty Fleet Customer Demo (PG&E)
Idle Reduction Technology (PG&E)	Electric School Bus Renewables Integration (PG&E)

Table 2. Fleet electrification off-road EV charging infrastructure PRP summary

PRP	Description	Proposed Deployment	Costs to Date & Approved Budget	Status
Airport Ground Support Equipment (SDG&E)	Phase I–retrofit existing chargers, assess charging behavior, and develop a load management plan (grid conditions, onsite solar generation). Phase II–up to 45 additional charger installations if warranted based on 6 months of Phase I data analysis.	Phase I–16 charging ports (8 dual head chargers) retrofitted with American Airlines. Phase II–additional charging ports if supported by the host site.	$835,859 out of $2,839,738	Phase I–16 charging ports retrofitted, nine months of data (December 2019–August 2020). Phase II declined.
Port Electrification (SDG&E)	Support electric MD/HD vehicles and forklifts to promote the development of EVs in this market segment. Analyze how grid integration for the MD/HD and forklift EV market segment can be implemented and optimized.	30-40 charging stations, data loggers and load research meters for electric trucks and forklifts with San Diego Port Tenant customers.	$645,787 out of $2,405,575	Three DCFCs installed for Pasha for three Class 8 electric trucks, seven months of data (between September 2019 and May 2020) Nine L2 (10 kW) chargers for nine Metro Cruise electric forklifts, 18 months of data (March 2019–August 2020)
Port of Long Beach Rubber Tire Gantry Crane (SCE)	Make-ready infrastructure for 9 rubber tried gantry cranes (grid-tied)	Installation of electrical supply for nine Rubber Tire Gantry Cranes converted to electric	$2,322,934 out of $3,038,000	Utility upgrades completed, first eRTG converted and begun operation in December 2020 (no utilization data collected)
Port of Long Beach Terminal Yard Tractor (SCE)	Make-ready infrastructure to support 20 charging stations for electric yard tractors	Electric infrastructure for 20 charging stations (200 kW) for Class 8 BYD electric yard tractors; ITS deploying seven EVSE initially	$1,627,550 out of $450,000	Six BYD 200 kW and one Cavotec automated 100 kW charger installed for seven BYD electric trucks, six months of data (May 2020–October 2020)
Idle Reduction Technology (PG&E)	Demonstrate idle-reduction technologies (for transport refrigeration units) and develop a handbook for other fleets based on lessons learned	25 electrified receptacles for eTRU connection (10 at docks, 15 at staging area), 15-17 kW each	$599,675 out of $1,719,400	25 eTRU receptacles installed, nine months of data (January 2020–September 2020)

Source: SDG&E, SCE, PG&E

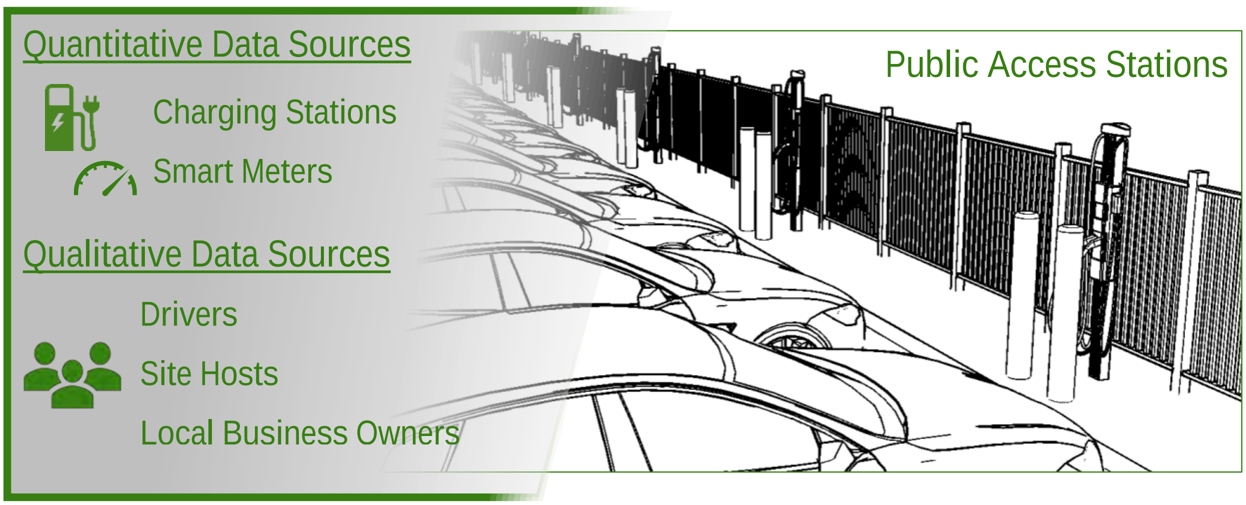
Table 3. Fleet electrification medium- and heavy-duty EV charging infrastructure PRP summary

PRP	Description	Proposed Deployment	Costs to Date & Approved Budget	Status
Fleet Delivery Services (SDG&E)	Support electrification of fleet delivery vehicles by installing, owning, operating, and maintaining the charging infrastructure for up to 90 medium-duty EVs	63 L2 (17 kW) chargers at three UPS locations, 16 L2 (17 kW) chargers at Amazon location	$1,316,472 out of $3,690,749	79 chargers installed, 12 months of data from 15 Amazon EVs (Sep 2019 –Aug 2020), UPS awaiting EV delivery (anticipated Q2 2021)
Green Shuttle (SDG&E)	Charging infrastructure (L2 and/or DCFC) for one or more shuttle companies. May incorporate solar/storage, as well as offering public charging	Two DCFCs (50kW) for San Diego Airport Parking (two EVs), two DCFCs (50kW) for Aladdin (four EVs), and six L2 chargers for Illumina (six EVs)	$1,438,231 out of $3,157,805	Charging infrastructure completed, 9 months of data from SDAP (Dec 2019–Aug 2020), Illumina EVs delivered but not yet used, Aladdin awaiting EVs. No sites with public access, energy storage, or solar energy integration
Charge Ready Transit Bus (SCE)	Make-ready Infrastructure at transit agency sites, plus rebate for charging equipment	Seven depot DCFCs for Victor Valley Transit (seven electric buses), ten depot DCFCs for Porterville (ten electric buses), and 13 depot DCFCs for Foothill Transit (14 electric buses)	$2,087,396 out of $3,978,000	Charging infrastructure completed, 9 months of data from Foothill (Dec 2019–Aug 2020), 13 from Victor Valley (Aug 2019–Aug 2020), 7 from Porterville (Feb 2020–Aug 2020)
Medium/Heavy Duty Fleet Customer Demo (PG&E)	Demonstrate—with utility assistance of make-ready infrastructure and charger rebates—a lower total cost of ownership for MD/HD fleet EVs	Five 60 kW depot chargers, demand management and battery energy storage for existing high-power overhead chargers for San Joaquin Regional Transit District (17 EVs)	$1,021,554 out of $3,355,000	Depot chargers installed, demand management implemented, 24 months of data collected (Oct 2018–Sep 2020), battery storage installation expected in Q2 2021
Electric School Bus Renewables Integration (PG&E)	Deploying make-ready infrastructure, chargers, and control management for electric school buses to test managed charging to consume electricity during peak renewables generation periods	Nine L2 (19kW) chargers and charge management software to integrate onsite renewables	$1,332,369 out of $2,209,500	Charging infrastructure and management software installed, 9 months of data (Feb 2019–Dec 2019), 2 test phases completed and 2 simulated due to inactivity since Mar 2020 pandemic onset

Source: SDG&E, SCE, PG&E

Public access station projects provide data on the electricity dispensed by the installed EV charging infrastructure, many of which are direct current fast chargers (DCFC) at public locations, but do not yield all the data needed to calculate reduced petroleum use. Displaced fossil fuel can be approximated based on utilization of the PRP-deployed stations. Some electric vehicle supply equipment (EVSE) providers may share information about their users, such as an identification number, vehicle type, and zip code of residence, which helps determine the number of different users and their potential routes and destinations. With the known location of the station, it is possible to make some reasonable estimates of which geographical area is benefiting from reduced emissions, but it is not as precise as with a known fleet vehicle. Surveys of users may provide some insights on the PRP's impact on driving patterns and behaviors, including baseline behavior before the charging station was available. A brief summary of public access stations PRPs is presented in Table 4.

Figure 14. Public access station projects



Priority Review Project
Electrify Local Highways (SDG&E)
Urban Charge Ready DCFC (SCE)
Destination Make Ready (BVES)
DCFC Project (Liberty)

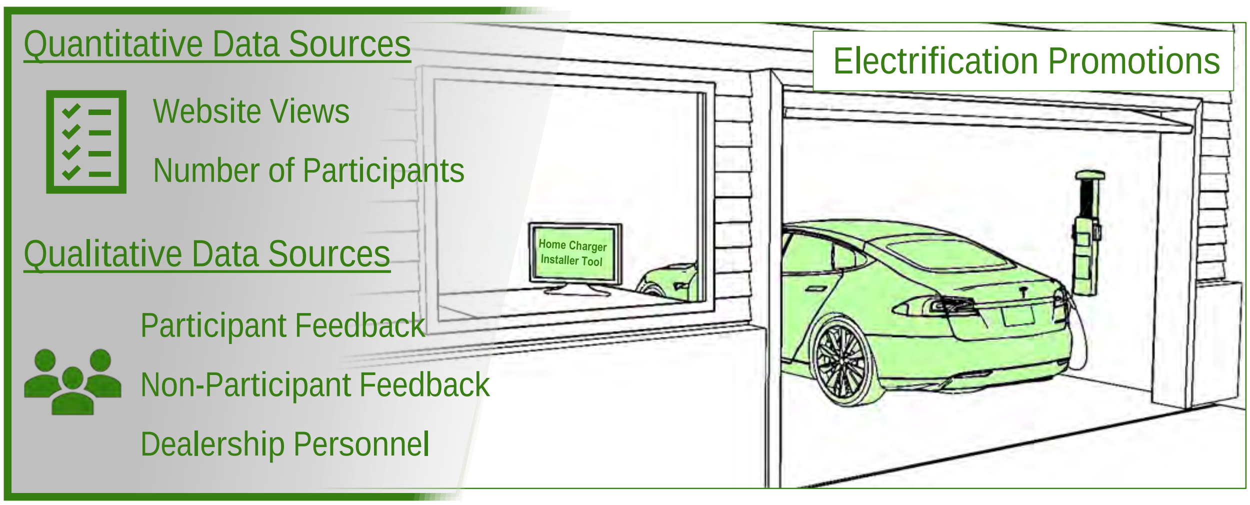
Table 4. Public access stations PRP summary

PRP	Description	Proposed Deployment	Costs to Date & Approved Budget	Status
Electrify Local Highways (SDG&E)	Study the charging patterns from installations, and test the standards for public charging signage, rate display, and general retail EV fuel dispensers. Stations will use a dynamic grid integrated rate.	20 L2 (6.6 kW) and two DCFC (50 kW) chargers each at four Caltrans Park and Ride locations (88 charging ports total)	$2,477,557 out of $4,000,000	Charging infrastructure installed, 7 months of data (Mar 2020–Sep 2020), use significantly impacted by the pandemic travel restrictions (minimal commuting)
Urban Charge Ready DCFC (SCE)	Make-ready Infrastructure and charging station rebate to serve up to 50 new DCFC ports at five locations	Site host agreements for the five selected locations resulted in 14 DCFCs	$1,722,506 out of $3,980,000	Charging infrastructure installed, twelve months of usage data (Oct 2019–Sep 2020), significant activation delay for one site, use impacted by the pandemic travel restrictions (minimal commuting)
Demonstration and Development Program (PacifiCorp)	Offer grant funding for make-ready, hardware, installation and upfront software purchase costs for EV charging stations.	On a quarterly basis for 15 months administer grants for non-residential customers to propose EV charging infrastructure projects	$14,538 out of $270,000	Grant program launched in 2019, only five applications to date with one approved (site under construction, rebate not issued yet)
DCFC Project (Liberty)	Deploy DCFC clusters in sites with high utilization. Procurement, installation, and maintenance of the DCFC stations, as well as the electric infrastructure upgrades and conduit as well as the DCFC charging stations would be covered by the utility	5-9 DCFC sites are expected with one to four dual port stations per location	$125,966 out of $4,000,000	Developed online application and management portal (pre-launch summer, full launch end of 2020). Seven applications received, 1 site selected and in construction. All sites to be constructed by Q3 2024.
Destination Make-Ready Rebate Pilot (BVES)	Rebate for make-ready EV charging infrastructure (for up to 5 L2 chargers per site) with requirement to enroll in a separately metered EV TOU rate when it becomes available	50 L2 charging stations for commercial customers	$75,000 out of $607,500	Contracted with a program implementer, developed program website and materials, launched in Dec 2019 (7 participants interested but no completed applications received in 2020, outreach challenges due to pandemic)

Source: SDG&E, SCE, Liberty, PacifiCorp, BVES

Electrification promotion projects target barriers to EV adoption by private owners, from challenges installing EV home charging solutions to poor dealership experiences when purchasing EVs, so the main data sources are the vendors and participants. While PRP participant data and information about the accomplished effort provide good insights, there are no direct measurements of electricity dispensed to EVs or their operations to calculate direct fuel use reductions or emission benefits. Sales data could potentially indicate whether these PRPs influence the market, but most of these evaluations will rely on surveys and interviews to determine success and the potential for scaling up. A brief summary of electrification promotion PRPs is presented in Table 5.

Figure 15. Electrification promotion projects



Priority Review Project	
Dealership Incentive (SDG&E)	Demonstration and Development Program (PacifiCorp)
Charge Ready Home Installation (SCE)	Residential Rebate Program (Liberty)
Home EV Charger Information Resource (PG&E)	Small Business Rebate Program (Liberty)
Outreach and Education Program (PacifiCorp)	Customer Online Resource (Liberty)

Table 5. Electrification promotions PRP summary

PRP	Description	Proposed Deployment	Costs to Date & Approved Budget	Status
Dealership Incentives (SDG&E)	Education and training for EV salespeople; incentives of $500 split between dealership and salesperson if customer sign up for EV TOU rate	Enroll and train 200 salespeople and issue 1,500 incentives	$757,687 out of $1,790,000	Program run from August 2018 to December 2019: 15 dealerships selected, 92 salespeople trained, 357 incentives issued. Participant survey conducted.
Charge Ready Home Installation Rebate Program (SCE)	Rebates for make-ready and permitting to install home EV Level 2 charging infrastructure. Must enroll in whole-house TOU or install a dedicated EV submeter.	Approximately 5,000 participants	$2,196,106 out of $3,999,000	Program run from May 30, 2018 to May 31, 2019; 2,670 applications approved and processed. Program feedback collected.
Home EV Charger Information Resource (PG&E)	Develop EVSE installation checklist in English, Spanish, and Chinese; develop an enhanced EV information website with an installer tool to help customers find qualified contractors.	Rescoped to reference external EVSE installer selection tools on updated website with checklist for EVSE and contractors	$146,392 out of $185,295	Website enhanced, checklists developed, referenced existing tools and resources. Creating an educational animated video. User feedback collected.
Outreach and Education Program (PacifiCorp)	Test the effectiveness of different education and outreach tactics through four distinct components	(1) customer communications (2) self-service resources/and tools, (3) technical assistance, and (4) community events	$59,252 out of $170,000	Began disseminating resources and conducting outreach in 2019, but pandemic ended in-person outreach events in 2020 (moved to virtual outreach communications)
Residential Charger Installation Rebate (Liberty)	The rebate is designed to incentivize the installation of home EV chargers by offsetting the costs of hardware, permitting, and installation costs	1,000 rebates of $1,500	$23,672 out of $1,600,000	Developed online application and management portal. Final participant program handbook in review. Anticipated activity peak in 2022; final rebates Q2 2023.
Small Business Charger Installation Rebate (Liberty)	Rebates incentivize the installation of EV chargers by providing an offset for the hardware, permitting, and installation costs of the EV charger	100 rebates of $2,500	$16,929 out of $300,000	Developed online application and management portal. Final participant program handbook and marketing strategy in review. Anticipated activity peak in early 2023; final rebates issued in Q4 2023.
Customer Online Resource (Liberty)	Build-out the current website to include a web-based information resource focused on EV-related information–Customer Online Resource portal	Educate customers on EVs, charging requirements, charger locations, rebate programs, and TOU rates	$26,650 out of $240,480	EV savings tool, WattPlan launched on Liberty website at the end of 2019. Ongoing marketing and outreach efforts to encourage customers to use it and learn about residential and commercial rebates.

Source: SDG&E, SCE, PG&E, Liberty, PacifiCorp

Cross-Cutting Research Questions

Each PRP requires slightly different targeted evaluation approaches, and the evaluation includes PRP-specific questions and data collection requirements. However, Figure 16 includes the overarching research questions applicable to all projects, as well as a set of targeted questions that apply to each PRP group. For comparison purposes, these cross-cutting questions are being analyzed across multiple PRPs to draw conclusions about various transportation electrification technologies and approaches to implementing charging solutions.

Figure 16. PRP research questions

For all PRPs

- ✓ What barrier(s) to electrification are being addressed, and what was the PRP's success at overcoming the barrier(s)?
- ✓ What were the net impacts (relative to the no-PRP scenario)?
  - GHG and pollution reduction
  - Fossil fuel displacement
  - Participant changes in cost (if applicable)
- ✓ What were the co-benefits?
  - For disadvantaged communities (DACs)
  - Operations, maintenance, and fuel costs
  - Noise reduction and time savings
  - Health and safety
- ✓ What were the lessons learned?
  - What worked well?
  - How could implementation be improved based on lessons learned?
  - What innovations were made?
- ✓ How could the project be scaled up? Under what timeline?
  - What was the cause of any implementation delays?
  - Can these delays be avoided for future projects?

Fleet Electrification PRPs

- ✓ How did the PRP change electrification within the fleet, and does the customer plan to increase electrification as a result of the PRP experience?
- ✓ Were operations modified to accommodate electrification? Is electrification for the entire fleet feasible?
  - Which vehicles, applications, or routes are best suited for electrification?
  - How should the fleet prioritize future implementation?
- ✓ How does PRP infrastructure utilization or deployment compare with similar fleets?
- ✓ Is the electric transportation equipment reliable? User-friendly?
  - Is near-term reliability a likely indicator of long-term reliability?
- ✓ What were changes to fuel and maintenance compared to the no-PRP scenario?

Public Access Station PRPs

- ✓ What is EVSE infrastructure utilization (DCFC, Level 2), and how does it compare with similar charging stations or locations?
- ✓ Do EV drivers with and without access to home charging use the stations?
- ✓ How do customers find charging stations?
  - Could EV drivers check occupancy prior to arriving or reserve station time?
  - Is there much competition to use these charging stations?
- ✓ How did the stations change driving habits?
- ✓ Is the infrastructure reliable? User-friendly?
  - Are EVs occupying the station longer than necessary and blocking others from charging?
- ✓ Does EV charging station access affect customer decisions to lease or purchase EVs?
- ✓ Did the charging stations increase or decrease use of the parking facility?

Electrification Promotion PRPs

- ✓ What was stakeholder and customer satisfaction with the PRP?
- ✓ Did the PRP change customer awareness and purchasing behavior?
- ✓ What are participants' motivations to pursue electrification?

2.2 Evaluation Approach

The evaluation of each PRP involves specific data collection tasks, identification of data sources, collection of the data, and the analysis to evaluate success. The evaluation requires regular dialogue with the utilities' project managers and the PRP hosts regarding implementation progress and available data, which the evaluation team has facilitated.

2.2.1 Data Sources

Table 6 summarizes the types of data the evaluator is relying on for the evaluation, categorized by the source of each data type—i.e., whether data are gathered by the utilities and implementation partners or by the evaluator via direct PRP interactions and/or from secondary data sources. Data from PRP participants or customers either flow through the utilities or are provided directly to the evaluation team.

Table 6. Example sources of evaluation data

Gathered by Utilities and Implementation Partners	Gathered or Accessed by Evaluator
• Partner/customer/vendor contact information • Advanced metering infrastructure data/submeter data (ideally submetered at charger level) • Vehicle/equipment inventory (project-related and customer total) • Operational changes or project phase testing modifications • Costs (initial and ongoing, for the utility and partner, project elements, and baseline) • Downtime and maintenance/repair of equipment • Electricity rates and costs (project-related and customer total) • Customer surveys conducted by utilities • Data in project dashboards (not accessible to evaluator) • EV charger data (EVSE network service providers)/vehicle telematics (on-board data loggers, fleet dashboard, or vehicle manufacturer)	• In-depth interviews (IDIs) and surveys with project stakeholders • Intercept/online surveys • Data in project dashboards (access provided by PRP vendors) • Market data • Benchmarking (baseline data and for similar technology deployments) • Evaluations or assessments from other deployments or studies related to the PRP

The CPUC Data Collection Template[8] (May 8, 2018 version) includes data fields relevant to analyzing the impacts created by the PRPs, such as charging events, project and electricity costs, equipment specifications, and locations served. The evaluation team worked with the utilities and PRP customers to compile this information as it became available throughout the projects. The types of data available and those relevant for each PRP group differ, as summarized in Table 7.

[8] http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442457045

Table 7. Types of evaluation data by PRP grouping

Fleet Electrification	Public Access Station	Electrification Promotion
Quantitative Data		
• Charging station use • Utility meter data • Facility load data • Vehicle/equipment routes and scheduled operations • Vehicle/equipment telematics or usage (miles or hours) • Maintenance records	• Charging station use • Utility meter data • Vehicle/user information (unique ID, vehicle type, ZIP code if available)	• Website analytics (if available) • Number of participants using the service (rebate or bid tool)
Qualitative Data: IDIs and Surveys of the Following Stakeholder Types		
• Fleet operators • Energy managers • Maintenance personnel • Drivers • Riders • Equipment suppliers	• Drivers • Site hosts • Equipment suppliers	• Website users and participants • Dealership personnel

2.2.2 Data Collection

In general, the data collection within each specific PRP section includes a combination of PRP information (facts and particulars that do not change after implementation or during a test phase), PRP data (updates, findings, and figures that are collectively gathered as the project progresses), market research, IDIs, and surveys. Since PRPs differ, even within a PRP group or within a PRP where there are multiple customers, not all types of data are available for each PRP.

PRP Information

The evaluation team requested key information about the project, technology, and partners during the PRP planning and installation phases. This helped inform the market research, IDIs, surveys, and analysis. Some examples of this information are historical data (used to establish a baseline) on the application that is being electrified, vehicle/equipment functions (routes, duties, etc.), electricity rates, and historical facility electricity and fleet fuel use. Specific to the PRP, the evaluation team collected expenses by the utility and partner (broken out by cost categories), specifications for any project hardware (charging stations, make-ready infrastructure, and vehicles), and details on the structure of the PRP's execution. While some information needed updating based on project changes, most did not change after the 12-month test period begun.

PRP Data

During the 12-month PRP operational data collection period following implementation, some data were collected on an ongoing basis to quantify the vehicle/equipment operations. Depending on the project, these data came from utility meters, charging stations, vehicles/equipment, maintenance records, and customer utility bills. While some of these data streams are duplicative (the utility meter, charging station, and vehicle might all record energy transfer and time for each charging session), having these data resources provides a back-up and can yield additional insights (such as the efficiency losses at each stage). Each source can also provide additional useful data, such as the actual fuel efficiency of a vehicle based on its data; using these data streams produces more accurate results than relying on manufacturer or industry averages. For the Electrification Promotion PRPs, metrics include the number of participants, duration of processes, and total rebates or applications processed.

Market Research

Market research on the technology and application is needed to calculate the resulting emission benefits and to understand the potential for scaling up. Some of this information was collected by the utilities or partners when developing these PRPs or during the decision to implement a transportation electrification solution. The evaluation team also conducted additional research into previous tests and studies that have fuel rates, emission factors, and other information needed to quantify the benefits. The project partners were asked to provide information about their inventory of vehicles or equipment similar to what was electrified under the PRP, assuming those vehicles or equipment could be electrified in the same manner. Where available, similar information from the utilities about this inventory for their entire service territories was used. The evaluation team supplemented this information with market research to understand the potential of scaling up each PRP across the utility service territory and the entire state.

In-Depth Interviews

IDIs are a key aspect of the evaluation. Qualitative information from various stakeholder experiences is invaluable, as these projects involve a variety of new technologies, applications, and decision makers. The evaluation team identified the interviewees and the number of interviews for each PRP, as well as the purpose for each. An experienced member of the evaluation team drafted the interview guide and questions (primarily open-ended and designed to probe various issues), which were reviewed by the respective utility, prior to conducting the interviews.

Surveys

Surveys allow information-gathering from larger populations, such as website users or public access charger users. The evaluation team worked with utilities to identify the population, target sample size, and purpose for each survey. For several PRPs, existing utility or implementer surveys were reviewed and adapted by adding additional, evaluation-specific questions. Surveys were primarily administered online, with in-person intercepts used only when needed. The evaluation team developed draft guides for 1) administering the surveys or 2) adding questions to the utility surveys. The team worked closely with the utilities to finalize the approach.

2.2.3 Analysis and Evaluation Reporting

The evaluation team created preliminary data analysis model to calculate quantitative results to support the PRP evaluations. The data analysis model continued to be refined using PRP data collected from each demonstration. When available, at least two months of operational PRP data, along with the collected PRP information, were entered into the data analysis model to obtain preliminary results. As additional operational data were received, results were updated. When possible, 12 months of operational data was collected. Seasonal shifts in weather may affect heating, ventilation, and air conditioning (HVAC) operations and battery charging efficiency which impacts vehicle or equipment energy use. Data collected during all seasonal variations are critical to assess the overall effectiveness of the PRPs.

As part of the evaluation report, the evaluation team identified PRP co-benefits through IDIs and surveys and, where possible, quantified these benefits. For the fleet electrification projects, the evaluation report shows disadvantaged community (DAC) benefits based on 1) the locations in which the vehicles operate and 2) each location's relationship to DAC boundaries. It was a challenge to accurately predict maintenance savings for the life of the vehicle or equipment, since the PRP demonstration period only covers the first year of operation, when scheduled maintenance is minimal. While noise reduction could be quantified through the collection of decibel measurements operator feedback via surveys was used. Long-term worker health and safety benefits from reduced contact with toxic chemicals such as oils and petroleum fuels are difficult to quantify during the evaluation period, but if such benefits were mentioned during IDIs or surveys, the observations are noted in the report.

For public charging infrastructure projects, specific metrics are used to measure use patterns among the various installations. The evaluation team closely examined electrical power metrics, such as plug-in times and durations, peak power draw, and total energy consumed, to determine system performance along with fuel and emissions offsets.

The team used a combination of information to better understand why charging stations might have different utilization and charging patterns. Also, the team assessed EV and EVSE use and included additional factors in analysis as appropriate, such as population density, geographical region, setting in which the charger was installed, charging station location within a property, cost for charging, presence of signage, and EVSE brand and network. Metrics used in the analysis include time-of-day and day-of-week variations, population density or the type of functions near the installation (residential, commercial, or industrial), parking setting variations (parking garage, open lot, or curbside), location setting variations such as cluster types (e.g., retail, workplace, leisure, or residential), and seasonal variations. Our analyses integrate multiple metrics where appropriate (for example, the time-of-day and day-of-week variations could be determined for different geographical settings). The performance of individual EV charging stations can be compared to the entire group of PRP-funded charging stations to identify which are the best and worst performers. When the PRP scope includes demand response, the analysis includes evaluation of charging events that occur during demand response participation, thereby determining the program's effects on those events or the users' charging experience.

The last step in the evaluation is to draw conclusions based on all data collected and analysis of those data. As appropriate for each PRP and PRP grouping, key performance indicators are assessed to determine the true impacts of those activities and their potential for scaling up. A standard reporting template was used for each PRP grouping but was tailored as needed for each individual PRP as well as the PRP groups to ensure any useful and pertinent information was also evaluated. Evaluation reporting for the individual PRP begun after the data collection and analysis were completed.

2.3 Organization of Report

This final evaluation report documents the PRP accomplishments through September 2020 and highlights any lessons learned based on the input collected for these pilot demonstrations of transportation electrification interventions. For almost all PRPs, this report summarizes the progress from conception to construction/implementation and most PRPs include data or feedback on operations. The final costs incurred by the utilities to complete these PRPs and the final project metrics will be confirmed by the utilities final PRP reports at the conclusion of each pilot.

To the extent possible, each of the following PRP sections (grouped by utility) are organized in a similar manner as shown in Figure 17, although the uniqueness of individual projects will occasionally require deviations to present all information that was collected and analyzed.

Figure 17. Individual PRP section organization

Project Narrative	✓ Overview, Objectives, and Barriers Being Addressed ✓ Sites and Participants ✓ Timeline and Status
Evaluation Methodology (specific to that particular PRP)	✓ Selected Methods and Rationale ✓ Data Sources
Evaluation Findings	✓ Project Baseline ✓ Implementation Process ✓ Costs ✓ Benefits ✓ Operational Impacts of Project Equipment ✓ Stakeholder and Customer Feedback
Conclusions and Recommendations	✓ Successes and Lessons Learned ✓ Scale-up Potential

3. San Diego Gas and Electric Company

3.1 Fleet Delivery Services

3.1.1 Project Narrative

Overview, Objectives, and Barriers Being Addressed

San Diego Gas & Electric (SDG&E) has partnered with delivery service businesses to support the electrification of fleet delivery vehicles by providing electrical infrastructure upgrades and by installing, owning, operating, and maintaining the EV charging infrastructure. California Public Utilities Commission (CPUC) Decision 18-01-024[9] approved $3,690,749 in direct costs for SDG&E to provide charging infrastructure to support up to 90 medium-duty electric delivery vehicles at approximately six locations. The provided charging infrastructure was to be utility owned and used to support regular operation of the electric delivery vehicles. The fleet delivery businesses were responsible for procuring the electric delivery vehicles.

Program fleet delivery partners were to use existing applicable time-varying rates that may include demand charges and encourage off-peak charging which could reduce electric service costs. The fleet partners were to develop a load management plan to efficiently integrate the new vehicle charging loads with SDG&E's grid. This not only benefits the fleet but also generates benefits for all ratepayers through grid optimization.

Fleet delivery trucks are utilized by a wide range of businesses in the goods and services markets for their day-to-day operations and are found throughout SDG&E's service territory, the state of California, the nation, and all around the world.

Fleet delivery trucks are likely good candidates for transportation electrification because they operate in urban centers, have stop-and-go driving cycles, spend a significant amount of time idling, have predictable daily routes, and are centrally maintained and fueled. The goals of the Fleet Delivery Services project were to:

- Prove that regional fleet delivery vehicles can be electrified without impeding their daily missions and operations.
- Determine the charging infrastructure needs for fleet delivery vehicles with regard to utility infrastructure and the associated number of chargers and their power levels.
- Collect data on charging utilization and costs to allow operators to minimize their electric charging costs.
- Analyze data collected with vehicle data loggers to evaluate the vehicles' performance, charging patterns and needs, and impacts on the fleet's overall energy use.

[9] Public Utilities Commission of the State of California, Decision 18-01-024: "Decision on the Transportation Electrification Priority Review Projects," January 11, 2018, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M204/K670/204670548.PDF.

- Assess the grid impacts from the specific fleet demonstration, including impacts at the site and local levels.

Sites and Participants

Recruitment Process

SDG&E secured the participation of the United Parcel Service (UPS) early in the process and included the delivery company as a participant in the original application filing. To maximize the project's reach, the CPUC directed SDG&E to conduct additional outreach when selecting other fleet delivery business partner(s) to identify locally owned, minority-owned business enterprise or woman-owned business enterprise (MBE/WBE) delivery business fleet(s). Two separate fleet delivery forums were held in January and February 2018 to educate customers, vendors, and EV manufacturers about the program. In February 2018, communications were sent to over 125 local businesses to promote the program. Knowing that Amazon is very interested in transportation electrification, SDG&E reached out to company management and informed them of the Fleet Delivery PRP opportunity to fund charging infrastructure for EVs. Amazon often contracts with local small businesses under their Delivery Service Partner program to provide the trucks for local Amazon package deliveries. Amazon would likely have done a local pilot like this eventually, but the PRP accelerated the timeline, enabled electrification of more vehicles than Amazon would likely pilot on their own, and influenced the location of the pilot (a disadvantaged community [DAC] in San Diego). The outreach also resulted in a small local catering company (Brother's Catering) expressing interest in participating in the program, but the caterer decided not to move forward because of vehicle availability, costs, and operational risk.

Participants

SDG&E's primary fleet partner is **United Parcel Service** (UPS). Three UPS locations in the San Diego region (Chula Vista, San Marcos, and San Diego) were intended to operate 60 electric delivery vehicles. Two of the locations (San Marcos and San Diego) are in designated DACs, according to CalEnviroScreen 3.0 for SDG&E territory (not statewide as that only represents about 4 percent of SDG&E customers). SDG&E's original plan was to deploy 20 alternating current Level 2 (L2) charging stations and one direct current fast charger (DCFC) at each UPS location (for a total of 60 L2 charging stations and 3 DCFCs). Based on UPS needs, SDG&E installed only L2 charging stations—33 at the San Diego location and 15 each at Chula Vista and San Marcos. At each location, the project installed one more charging station than the number of EVs in the site's vehicle maintenance area so that they could be charged while they undergo maintenance. The charging stations are 70 A (16.8 kW) **BTC Power** units (EVP-2001-70-W-001). **Greenlots** is the network service provider. A custom solution was designed to position chargers overhead (see Figure 18 through Figure 20) to keep them out of way during vehicle loading while enabling vehicles to be charged. Figure 21 through Figure 23 show the supporting infrastructure that was installed at each of the three UPS sites. UPS proposed to procure 60 Workhorse all-electric E-100 delivery trucks (specifications: 123 kWh battery pack for a range up to 100 miles with a 22-kW onboard charger). UPS has expressed interest in installing energy storage at one location. **Calstart** was to assist UPS with vehicle and charging station data collection and investigate charge management needs. At the time of this report, no vehicles have been delivered, more than a year after the charging installations were commissioned.

Figure 18. UPS BTC Power L2 EVSE from Greenlots

Source: Evaluator team

Figure 19. UPS custom overhead EVSE installation, with a variety of charge session activation options

Source: Evaluator team

Figure 20. UPS San Marcos overhead EVSE installation

Source: Evaluator team

Figure 21. UPS San Marcos EVSE supporting infrastructure

Source: Evaluator team

Figure 22. UPS Chula Vista EVSE supporting infrastructure

Source: Evaluator team

Figure 23. UPS San Diego EVSE supporting infrastructure

Source: Evaluator team

SDG&E has also partnered with a second fleet, **Amazon,** to install charging infrastructure at the company's sorting facility in National City (two different sorting facility locations were initially considered), which is in a DAC. Package delivery is carried out by Amazon-contracted delivery service providers, the majority of which are locally owned small businesses. The delivery service providers are operating the electric delivery vehicles, while Amazon is providing charging at the company facility overnight. A total of 16 L2 charging stations were installed at the Amazon facility. As with the UPS installations, these charging stations are **BTC Power** 70 A units that use **Greenlots** as the network service provider. SDG&E owns the make ready infrastructure and the charging stations. Amazon arranged procurement of 15 **Lightning System** Ford Transit EVs for this project and two delivery service providers operate them. Greenlots provided Amazon a Flex Charge Manager (FCM), a computer running a Linux kernel, to implement load limits on the collective group of chargers (i.e., 0% during on-peak hours, 100% during off-peak hours, or a different percentage during a certain established period). The FCM was expected also to have the capability to modify load limits per day-ahead critical peak pricing events. An in-depth-interview in November 2020 with Amazon staff revealed that the FCM has been installed but was yet programmed for charging management.

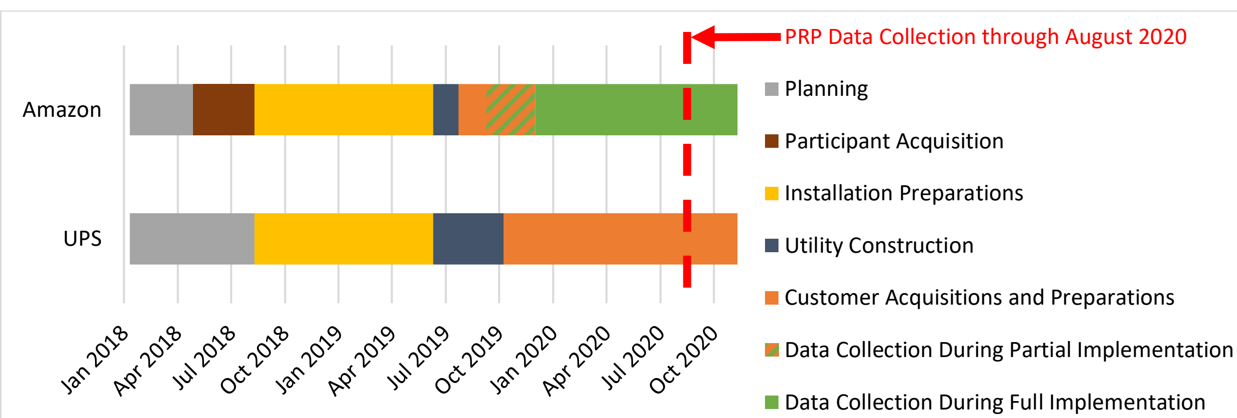
Timeline and Status

Figure 24 presents a timeline summary for the pilot. By September 2018, SDG&E had received all legal documents to proceed with the UPS and Amazon projects. SDG&E construction staff had also completed the site walks, and the initial designs were sent to UPS and Amazon for their review and approval.

Site design approvals, along with the selection of the charging station manufacturer and network service provider by SDG&E, progressed as planned. However, UPS's and Amazon's selection and procurement of EVs took longer than expected owing to unavailability of suitable EV models and delays in available EV production schedules. Therefore, charging infrastructure construction was pushed back slightly to better align with the arrival of the vehicles. Construction started at Amazon in May 2019, and the chargers were commissioned and available for use by August 2019. Amazon's Lightning System EV deliveries started in September 2019, and the last of the 15 trucks was received the first week of December 2019. SDG&E started construction at the UPS Chula Vista facility in May 2019, while work at San Marcos and San Diego facilities started in June 2019. All three sites were commissioned and available for use in October 2019. UPS has not received any electric trucks as of November 2020; delivery is expected in the second quarter of 2021.

When data collection ended in August 2020, there were almost 11 months of operational data (8 months with all vehicles) from the Amazon location.

Figure 24. SDG&E fleet delivery services PRP timeline as of November 2020



Source: SDG&E

3.1.2 Evaluation Methodology

Selected Methods and Rationale

In addition to the evaluation questions that apply to all PRPs and those specific to the Fleet Electrification PRPs, the evaluation questions listed below were examined for this PRP.

- What instructions/training were drivers provided for using the EV charging stations?
- Were operational and technology opportunities to better manage charging identified, how were they implemented, and were they effective?
- What is the appropriate ratio of charging ports to EVs?

The data sources utilized to evaluate this PRP include 1) PRP information from the approved decision, project updates, site visits, and other available documentation, 2) market research on delivery vehicles and early deployment efforts from other similar electrification projects across the country, 3) PRP data from vehicle and charger operations, and 4) in-depth interviews (IDIs) with project partners.

Data Sources

SDG&E provided PRP operational data from the utility service meters (one utility meter at each deployment site for all charging stations at that site) for 15-minute interval data and monthly costs, while network service provider Greenlots provided monthly CSV files for charging station session data. Third-party data loggers for medium-/heavy-duty (MD/HD) EVs were found to be much more expensive than anticipated, so SDG&E is relying on vehicle manufacturer telematics systems for collection of vehicle operational data which should be able to capture the same information. Amazon provided some high-level data on vehicle utilization and maintenance, along with any necessary maintenance of the charging stations.

Some PRP information has been collected through numerous PRP participant interactions: the PRP kick-off meeting (SDG&E and evaluator), quarterly Program Advisory Council (PAC) update meetings, weekly PRP updates (SDG&E and evaluator), site visits (UPS), and other periodic calls or emails. Through these, the evaluation team has the following information from this PRP: charging station hardware specifications, electricity tariff and bill details, some site photos after installation, project costs, and some high-level information on the acquired vehicles and intended use.

The evaluator held IDIs with representatives from the SDG&E PRP management team, SDG&E construction staff, UPS and Amazon to further understand the background of this project and gather lessons learned based on progress to date. Additional IDIs with SDG&E staff, Amazon, and vendors took place in 2020 after the chargers were already operational for some time.

3.1.3 Evaluation Findings

Project Baseline

While the state governments have begun setting mandates on electrifying light-duty vehicles, in June 2020 California Air Resources Board approved the Advanced Clean Trucks Regulation, requiring half of all medium- and heavy-duty vehicles to be zero-emissions by 2030.[10] This regulation is the first of its kind and will require cooperation between manufacturers, fleet owners, and utilities to achieve the mandate.

The electrification of commercial fleets is becoming not only more viable, thanks to market and technology evolution, but also increasingly cost-effective in reducing fuel expenses. EV battery prices have dropped 79% since 2010. On top of that, the energy density of these batteries has increased 5%–7% each year from 2010 to 2017.[11] Along with increased storage and therefore electric range, the added fuel efficiency can improve the economics. Compared to a typical diesel delivery vehicle, an EV's MPG could improve by over 200%, increasing from 7.6 MPG to 24.1 MPGe.[12]

Although the technology continues to improve, there are still significant barriers that need to be addressed for successful implementation. The initial purchase price, adequate charging infrastructure (and power level available), and more vehicle options have each been identified as requirements for fleet electrification. Cooperation and commitment from local utilities, who are needed partners for electricity and infrastructure support, will be important, as electrifying an entire 200- to 300-vehicle fleet could require an order of magnitude more electricity on site than a diesel-operated fleet.[13]

Amazon distribution centers typically support 100–150 different delivery routes per day. There may be different delivery structures for each Amazon distribution center, but they often fall into one of two groups: 1) independent delivery companies that contract with Amazon as well as other companies, and 2) Amazon delivery service partners that are more integrated into Amazon operations. The latter use Amazon-branded vehicles that meet established specifications and may be acquired through exclusive deals set up by Amazon.

The availability of suitable electric delivery vehicles has limited Amazon's pursuit of transportation electrification initiatives in the United States. The parking lot layout at distribution centers can also limit the number of chargers that can be installed. The length of routes also influences which locations are best suited for EVs, as some serve more rural areas that require far more daily miles per route. Amazon selected the National City location because of a good relationship with the landlord, relatively short route lengths, and DAC classification aligned with program requirements. Based on the site layout for the charging infrastructure, only 15 EVs were feasible for this location. Amazon currently uses Ford Transit E250 diesel cargo vans in its National City delivery vehicle fleet.

[10] CARB, *Advanced Clean Trucks Regulation*, August 12, 2020, https://ww2.arb.ca.gov/our-work/programs/advanced-clean-trucks.

[11] Green Biz and UPS, *Curve Ahead: The Future of Commercial Fleet Electrification*, 2018, https://sustainability.ups.com/media/UPS_GreenBiz_Whitepaper_v2.pdf.

[12] National Renewable Energy Laboratory, *Field Evaluation of Medium-Duty Plug-in Electric Delivery Trucks*, December 2016, https://afdc.energy.gov/files/u/publication/field_evaluation_md_elec_delivery_trucks.pdf.

[13] Green Biz and UPS, *Curve Ahead: The Future of Commercial Fleet Electrification*, 2018, https://sustainability.ups.com/media/UPS_GreenBiz_Whitepaper_v2.pdf.

Implementation Process

Customer education to potential future customers through outreach materials and staff interactions will be a key aspect for successful similar future fleet electrification efforts. Very limited EV availability in Classes 2b through 4 is a significant barrier as only a few vehicle products were available. Most fleets see first commercial vehicle deliveries as a significant risk from a reliability perspective, as the vehicles are the core element of their business, and so are waiting to acquire EVs that have been successfully commercialized with a number of fleets. Most discussions with fleet management regarding the possibility of acquiring EVs are at the basic level of whether they can meet requirements and be reliable. Potential early adopters are interested in charging requirements and the impact on electricity rates and costs. Only after these concerns are addressed might fleets be able to calculate the anticipated cost per mile as compared to conventional vehicles. Larger entities' adoption of medium-duty EVs, and the successful integration of these EVs into operations, will help alleviate concerns of businesses that are not first adopters.

Based on this project's experience, SDG&E acknowledges that it is necessary to engage with the customers early and often to understand their intended EV use and any operational constraints that would affect the charger location, charging logistics, and EV operation. This kind of engagement will result in EV charging infrastructure solutions that will enable the customers to take full advantage of EV capabilities and realize maximum benefits of EV operation. While the electrical infrastructure and construction processes were relatively straightforward and did not present any significant challenges, understanding how the fleets will use the vehicles and chargers is important both to the design and to operational cost management. Had SDG&E included a field construction advisor early in the design process to participate in the initial site walk instead of just reviewing the designs, several minor and a few major change orders could have been avoided during the construction period.

As the fleets are starting to operate the vehicles and charging them when needed, the partners are discovering that their charging choices (i.e., plugging them all in at once rather than spreading out their charging or charging during on-peak electricity periods unnecessarily) can have a significant impact on electricity costs. This is new to the fleets, whose priority is to ensure the vehicles are fully charged when needed; this focus does affect the bottom line and is a factor when determining whether EVs can be a cost-effective option. Therefore, it is important for the utility to work closely with the customer, especially during the first few months of EV deployment, to monitor electricity use and suggest strategies for optimizing it (e.g., TOU rates and managed charging).

SDG&E conducted an RFP for the EV service provider in late 2018 and Greenlots was selected. Greenlots provided the networking solution while the chargers were L2 from BTC Power (16.8 kW, 70 A). Amazon later learned that the vehicles were incapable of charging above 6.6 kW due to the on-board charger limitation. Greenlots provided a dedicated representative to manage the charger installations and commissioning for this SDG&E pilot. The representative was very knowledgeable about the chargers and handled charger commissioning and any calls about issues. Amazon noted that charging issues often needed diagnosis to confirm whether they were coming from the vehicle, chargers, or network.

Since Amazon did not initially know which EV model would be acquired, the design placed single-port chargers in the center of the front of each parking space. This placement allowed the most flexibility for the charging cord to reach the vehicle's charging port, regardless of its location.

For each site the PRP required installation of a new utility meter dedicated only to charging stations. Amazon felt it might be more advantageous to add the charging load to an existing meter, given the ability to manage charging demand at the facility level, and would like to see that option in the future.

Although the PRP acquired only 15 EVs, finding a manufacturer with an EV that met Amazon's needs and could be delivered on the PRP timeline was challenging. Since the National City location has very limited parking, only short vehicles can park and charge. Amazon selected Lightning Systems, which has the smallest available package delivery electric vehicle in North America. Lightning Systems also provided a larger battery option (86 kWh) to allow for more route coverage. While the EVs come with only a 6.6 kW on-board charger, they are able to fully charge overnight to meet the needs of single-shift operations of the selected Amazon routes.

Amazon's plan going forward is to include the optional DCFC capability on any EVs deployed in the future as a backup charging option either at their facility or at another available charging location. DCFC is of interest to some fleets, as it provides a redundancy for charging. It provides a fallback in case there are issues with the L2 chargers, or a vehicle does not receive a sufficient charge overnight and therefore needs to be charged quickly in the morning to be able to complete its daily route. Amazon has access to the vehicle's operational information from the Lightning Systems telematics; however, some of the route information and operational performance is considered confidential to their business.

Costs

The approved PRP had an anticipated total direct cost of $3,690,749, consisting of $3,231,963 in capital and $458,786 in expense, as shown in Table 8.

Table 8. SDG&E Fleet Delivery Services PRP proposed costs

	Capital Costs	O&M Expenses	Total PRP Costs
Transformer and Install	$ 248,625	$ 3,731	$ 252,356
Electrical Service	$ 829,323	N/A	$ 829,323
EVSE Costs	$ 1,531,215	$ 35,055	$ 1,566,270
Purchased and Self Developed Software	$ 622,800	N/A	$ 622,800
Measurement and Evaluation	N/A	$ 200,000	$ 200,000
Charging Equipment Maintenance	N/A	$ 15,000	$ 15,000
Billing Support	N/A	$ 80,000	$ 80,000
SDG&E Clean Transportation Project Management	N/A	$ 100,000	$ 100,000
First Year O&M Service Calls	N/A	$ 15,000	$ 15,000
First Year O&M for Charging Equipment	N/A	$ 15,000	$ 15,000
Total Costs	$ 3,231,963	$ 425,000	$ 3,695,749

Source: SDG&E

The estimated total PRP direct costs are $2,407,856 out of a budgeted $3,695,749, as shown in Table 9 (presented in categories reported by the utility).

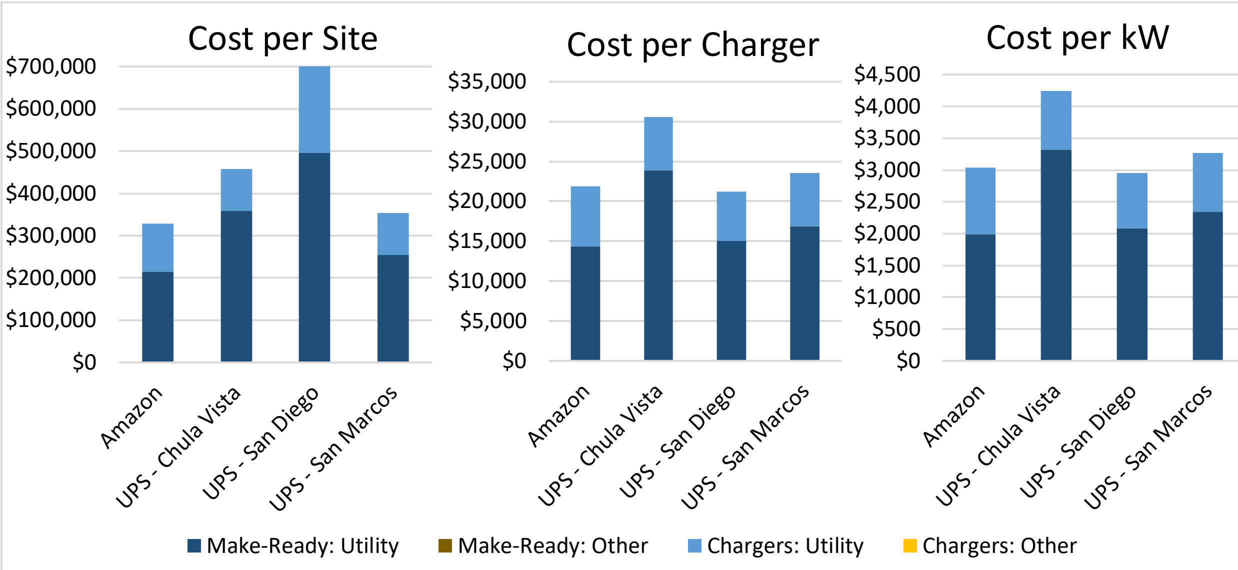
Table 9. SDG&E Fleet Delivery Services PRP estimate at completion (EAC)

	EAC Capital Costs	Budgeted Capital Costs	EAC O&M Costs	Budgeted O&M Costs
Construction	$ 1,322,097	$ 1,356,363	N/A	N/A
Engineering Design	$ 140,648	$ 161,175	N/A	N/A
Chargers, Meter Pedestals, Transformer, and Other Materials	$ 517,955	$ 1,091,625	N/A	N/A
Internal SDG&E Labor (Program Management and Support)	$ 17,161	N/A	$ 97,311	$ 380,001
IT Costs	$ 123,548	$ 622,800	$ 52,738	N/A
Customer Engagement and Outreach		N/A	N/A	N/A
Other	$ 136,345	N/A	$ 52	$ 78,786
Direct Costs	$ 2,257,754	$ 3,231,963	$ 150,102	$ 458,786
Non-Direct Costs (Indirect, AFUDC, and Property Taxes)	$ 416,793	$ 1,811,744	$ 97,229	$ 200,614
Total Costs	$ 2,674,546	$ 5,043,707	$ 247,331	$ 659,401

Source: SDG&E

Figure 25 presents EV charging infrastructure costs for the four sites; separated by make-ready and charger costs which were either paid for by the utility through this PRP or a source of funding “other” than the utility which may be the host site, grants, etc. The costs were highest for UPS San Diego site due to twice the number of chargers installed (33) compared to other sites. On a per-charger and per-kW basis, the costs for UPS Chula Vista site are about 25% higher than the other 3 sites.

Figure 25. SDG&E Fleet Delivery Services electric vehicle charging infrastructure costs



Source: SDG&E

Benefits

As the PRP was originally designed, its estimated benefits were based on the installed charging infrastructure supporting 90 electric delivery vehicles. The PRP's current expected impact is based on 75 electric delivery vehicles. The reduced benefits utilize the factors listed in Appendix A of SDG&E Direct Testimony [pertaining to SB 350 Transportation Electrification Proposals] – Chapter 8 Air Quality Impacts and Cost Effectiveness. The Fleet Delivery Services PRP deployed chargers at four locations to support 75 electric delivery vehicles; however, only one location (with 15 vehicles) could be evaluated fully based on operational data (UPS did not receive and therefore could not operate any EVs during the evaluation period). The key benefits and some contributing factors are outlined in Table 10, with a more detailed description of this benefit analysis in the Appendix.

The pilot demonstration period from November 2019 to August 2020 is used to calculate performance. Baseline delivery vehicles—those replaced by the EVs—used gasoline and were assumed to achieve an industry average fuel economy of 13 MPG (actual customer data was considered business sensitive). Determined on an annual basis, the operations from November 2019 to August 2020 represent 102,339 kWh per year of energy used, with 48,387 kWh (47%) occurring during on-peak hours. Mileage equates to 121,832 total annual miles, which would have required 9,372 gallons of gasoline annually.

During the pilot, the highest utilization month was May 2020. If used as the basis for annual calculations, May usage would result in 216,712 total annual miles. Electrification would save 16,670 gallons of gasoline per year and consume 182,038 kWh annually, with 92,243 kWh (52.9%) on-peak. Fuel cost factors include an average of $3.00 per gallon of gasoline on the West Coast (from the Clean Cities July

2020 Alternative Fuel Price Report[14]) and an average electricity cost of $0.40 per kWh, as observed with the pilot fleet for the demonstration period (large electricity use during on-peak periods).

Table 10. SDG&E Fleet Delivery Services PRP annualized benefits

	Testimony (90 vehicles)	Planned (75 vehicles)	Implemented (15 vehicles)	Optimized (15 vehicles)
Petroleum Reduction	203,000 GGE	169,167 GGE	9,372 GGE	16,670 GGE
GHG Emissions Reduction	894 MT of CO_{2e}	745 MT of CO_{2e}	71 MT of CO_{2e}	124 MT of CO_{2e}
Criteria Pollutant Emissions Reduction	810 kg of NO_X	670 kg of NO_X	87 kg of NO_X 18 kg of SO_X 24 kg of VOC 1,200 kg of CO	155 kg of NO_X 31 kg of SO_X 42 kg of VOC 2,100 kg of CO
DAC Impact	66% (2 of 3 UPS sites), plus same DAC portion with 3 more sites	80% (60 of 75 vehicles have a base location in a DAC)	35% (based on statewide DAC definition)	35% (based on statewide DAC definition)
Grid Impacts / Electricity Consumption	2,946 MWh, with improved net load factor (if charging is properly managed)	2,455 MWh, with improved net load factor	102 MWh, with 47% consumed on-peak	182 MWh, with 53% consumed on-peak
Operational Energy Cost Savings	N/A	N/A	-$13,000 (-$850 per vehicle)	-$23,000 (-$1,550 per vehicle)

Source: Evaluator Calculations

The GHG emission reduction results from the Fleet Delivery Services pilot can be projected for other similar efforts, i.e., potential electric delivery vehicle applications that may replace baseline vehicles of varying fuel types. Projections can consider slightly different baseline vehicle fuel efficiency, as presented in Figure 26, or annual miles traveled, as shown in Figure 27. Impact of the energy cost variability (for both electricity and baseline fuel) on operational energy cost savings is shown in Figure 28. This pilot did not experience operational energy cost savings because of the frequent charging during on-peak periods which was likely needed to achieve full charge overnight. The planned use of the Greenlots' charging management software to avoid on-peak charging to the extent the fleet operation allows could reduce electricity cost per kWh and result in positive operational energy cost savings.

Similar delivery vehicles fit into either the light- or heavy-duty category for the California Low Carbon Fuel Standard (LCFS), which considers 14,000 lbs the threshold. Based on those classes, each kWh could be valued at approximately $0.20 or $0.30 (smart charging pathway) when LCFS carbon credits are sold.

[14] https://afdc.energy.gov/files/u/publication/alternative_fuel_price_report_july_2020.pdf

Figure 26. Delivery vehicle GHG reductions for various baseline fuels by baseline fuel economy

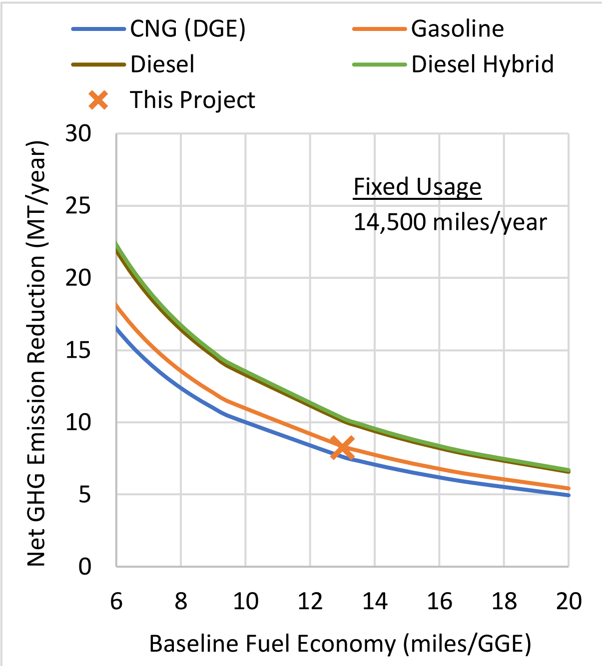
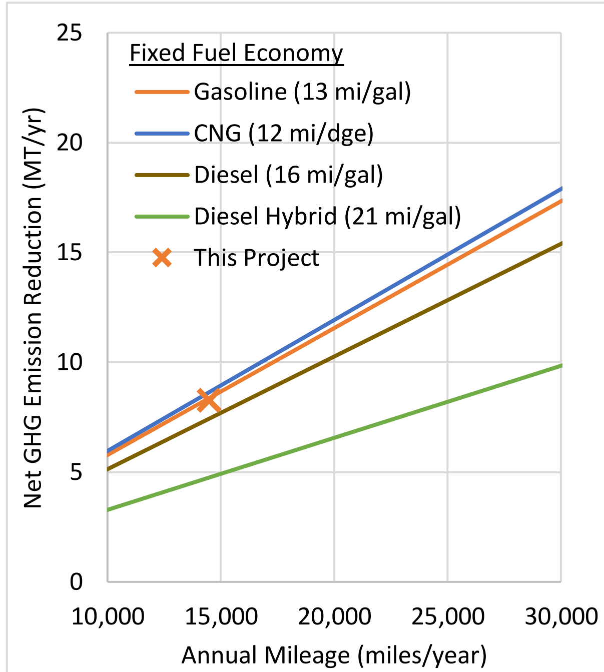
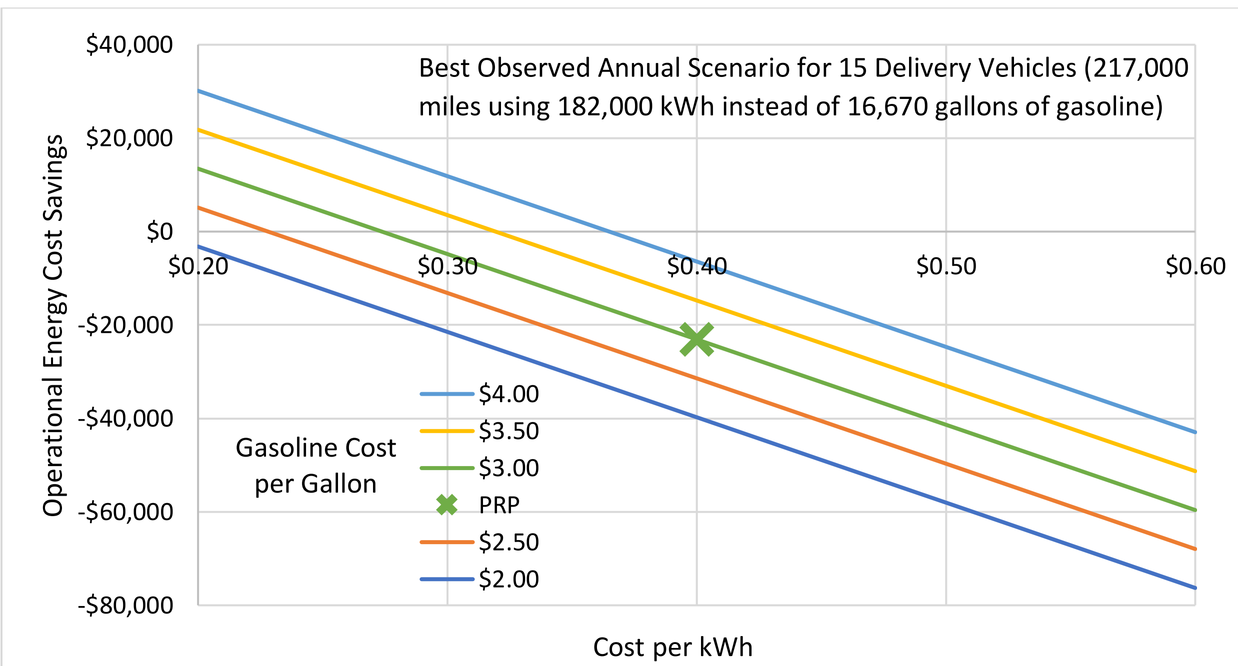


Figure 27. Delivery vehicle GHG reductions for various baseline fuels by annual use



Source: Evaluator Calculations

Figure 28. Annual delivery vehicle operational energy cost savings at various fuel costs



Source: Evaluator Calculations

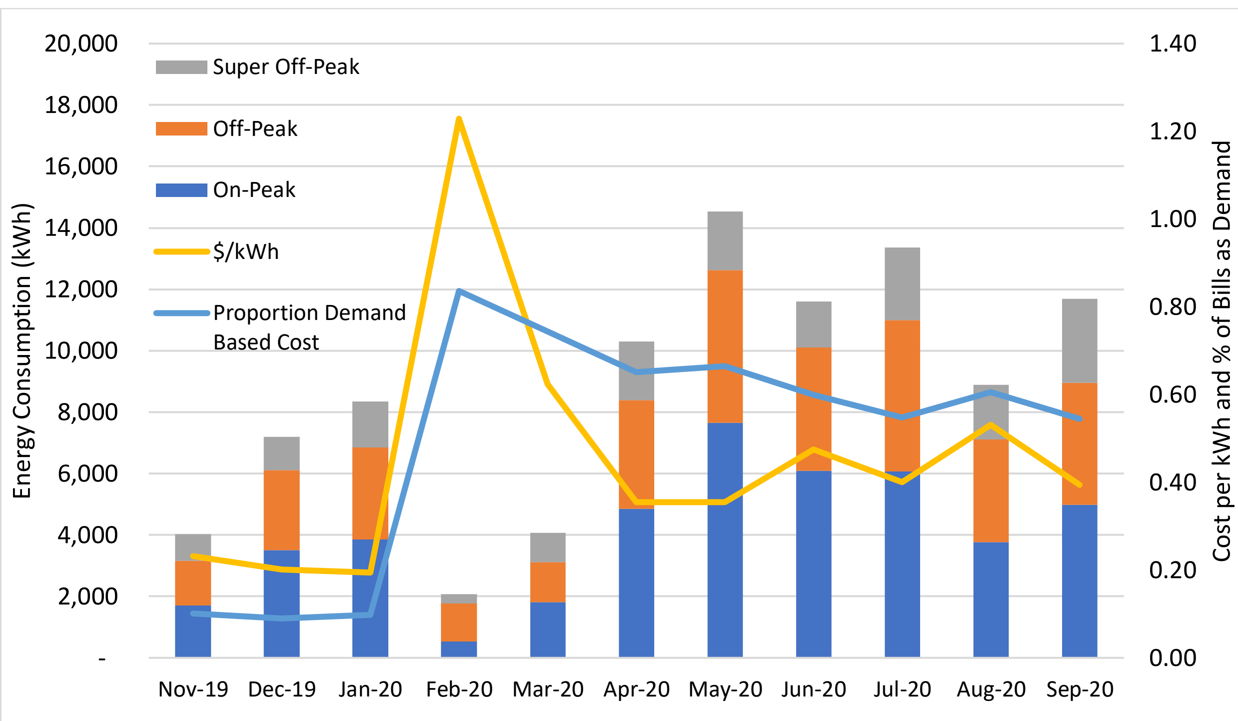
Operational Impacts of Project Equipment

Utility meter data based on charger energy consumption for Amazon site reveals vehicle deliveries ramping up in winter 2019, operations pausing in February 2020 to perform vehicle updates, and from April 2020 on, vehicles consuming approximately 11 MWh (see Figure 29).

Initially, SDG&E assigned Amazon's account to Schedule TOU-M rate for 20–40 kW loads. The rate was changed in late January 2020 to AL-TOU because the load exceeded that threshold. As a result, the average pricing increased from near $0.20 per kWh to over $0.40 per kWh Throughout 2020, demand charges represented 60%–80% of the utility bill. Though the utility provided no communication about this to the customer, the increase likely would have encouraged Amazon to adopt charging management. Doing so may have reduced the average billing cost per kWh nearly $0.15 per kWh. The biggest opportunity for savings at this point appears to be through avoiding charging during the on-peak time period and then reducing non-coincident demand (maximum demand at any time) as much as possible. Compared to TOU-M, AL-TOU does appear to offer lower monthly costs and clear incentives to avoid certain time periods and minimize demand.

AL-TOU is a commercial-industrial rate with two main components: cost per kWh based on time period and cost per kW by maximum exhibited any time and during the on-peak time period. The TOU-M rate exhibits only pricing by kilowatt-hour, with a very minute increase during on-peak.

Figure 29. Utility bill analysis



Source: SDGE

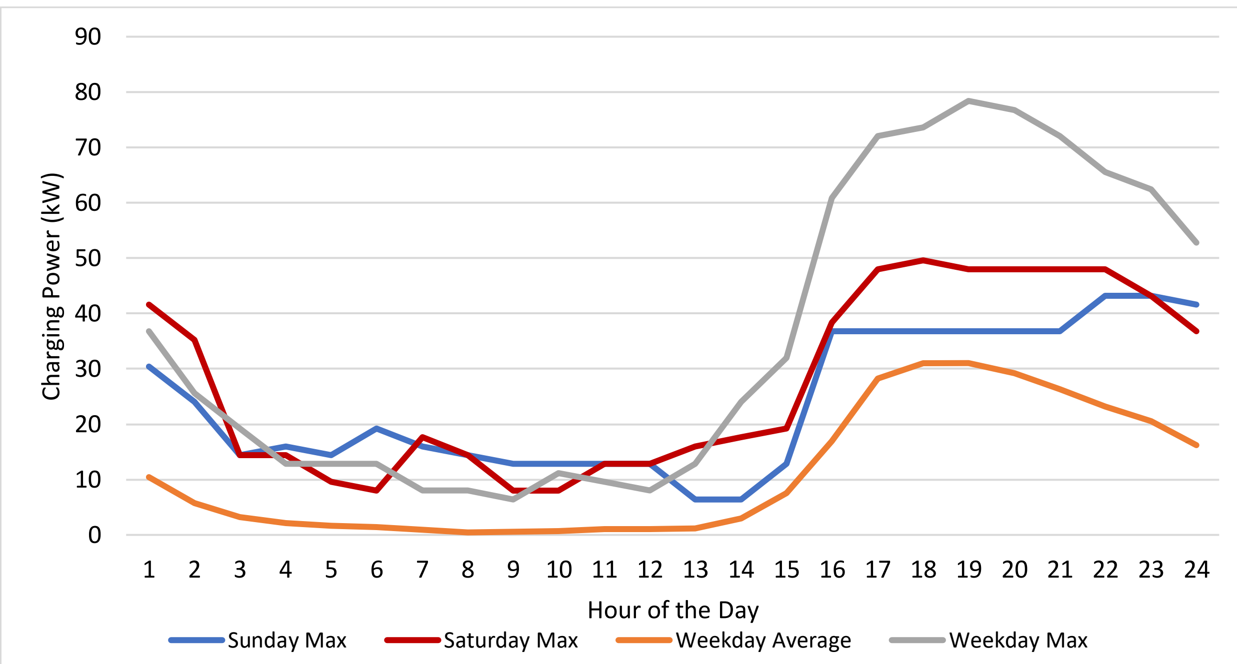
Figure **29** shows a significant proportion of energy being billed at on-peak time periods. AL-TOU costs are much more sensitive to this and utilization rates, which resulted in a nearly 200% increase in average unit costs. A customer can avoid such costs by consuming more for each kilowatt of demand or reducing maximum demand. The structure of this rate provides sufficient encouragement to customers to manage energy consumption, given a proper understanding of the rate and, in the case of fleets, the ability to manage charging through software or otherwise.

As of fall 2020, the CPUC provided a waiver for electric transportation on TOU-M to go beyond the traditional 40 kW maximum threshold. While this rate does communicate a 200% increase in price during the summer on-peak periods, there are two issues:

a. Discontinuity between summer and winter on-peak pricing means any training is likely to be forgotten during the winter.
b. Using only kWh-time-period-based pricing may unnecessarily encourage maximum demand growth that can negatively affect a customer in the future and allows larger utility build-out and rate base, an overall inefficient use of the utility financial mechanism and reward structure.

Amazon confirmed that, in summer and fall 2020, SDG&E reached out to discuss the interim high-power EV tariff (HP-EV TOU) approved by CPUC ruling which removed the load cap for TOU-M; however, as of November 2020, Amazon has yet to return to that rate. SDG&E received CPUC approval of a HP-EV TOU rate in December 2020, which is expected to be implemented January 1, 2022.

Figure 30. Charging trends during the highest usage month (May 2020)



Source: SDGE Meter Data

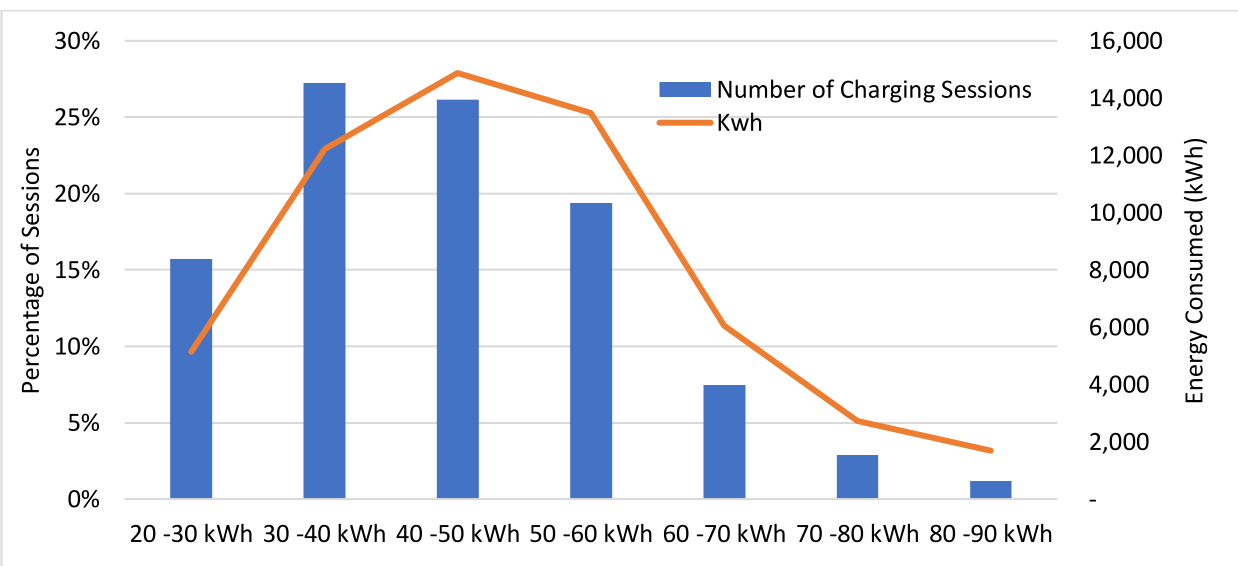
As seen in Figure 30, weekday charging shows consistent trends; however, the weekday maximum is much higher than the weekday average, which may speak to inconsistent use of vehicles. Weekends showed significantly reduced charging. Important to note is that charging appears completed by 3:00 AM, several hours before 7:00 AM when vehicles begin leaving the facility. This may indicate flexibility in charging to suit changing goals or challenges throughout the year, such as lower-cost or lower-carbon-intensity energy. Flexible charging may better avoid on-peak consumption and potentially lower maximum demand. Each delivery fleet has different parking and charging scenarios that will influence charging. One participant fleet located the EVSE at the loading bays, where vehicles can park and charge all night. Another fleet installed the EVSE in the overnight parking lot; vehicles must move from the lot to loading bays before leaving in the morning.

As compared to 75 kW charging seen in Figure 30, slower charging would often suffice to meet even high demand. Average days showed electricity use of 450 kWh, while larger days were close to 600 kWh. The operator has reported high vehicle availability, so presumably 15 vehicles were often in use. As each vehicle would require approximately 40 kWh for the day (600 kWh / 15 vehicles = 40 kWh), a 6.6 kW charger would take approximately seven hours to charge a vehicle. Charging could likely have been extended to lower charging speed, or vehicle charging could have been staggered. A potential switch to the HP-EV rate, when available, will likely alleviate these cost pressures.

In an effort to mitigate risk of draining the batteries before returning to base, daily operations were limited to 60 miles. An unusually high percentage of total recorded charging sessions (40%) resulted in under 20 kWh. The operator reportedly experienced a handful of incomplete charging sessions attributed to over-the-air charger updates which interrupted charging. The operator and vendors were challenged in diagnosing whether the error causes originated from charging software or hardware or the vehicles. The charging session data does not reference a reason for the end of a session like for some EVSPs. However, it is likely that most errors were in 2019 when the average charging session size was only 20%–25% of those in 2020, with the second quarter of 2020 showing the most kilowatt-hours per charging session.

Of non-errored sessions, over 70% ranged from 30–60 kWh (Figure 31). An estimated 30% of the battery state of charge typically remained to buffer heating and cooling needs or unexpected miles traveled. Throughout the project, charging session data represented 92% of the energy tracked and billed by the utility (Figure 32).

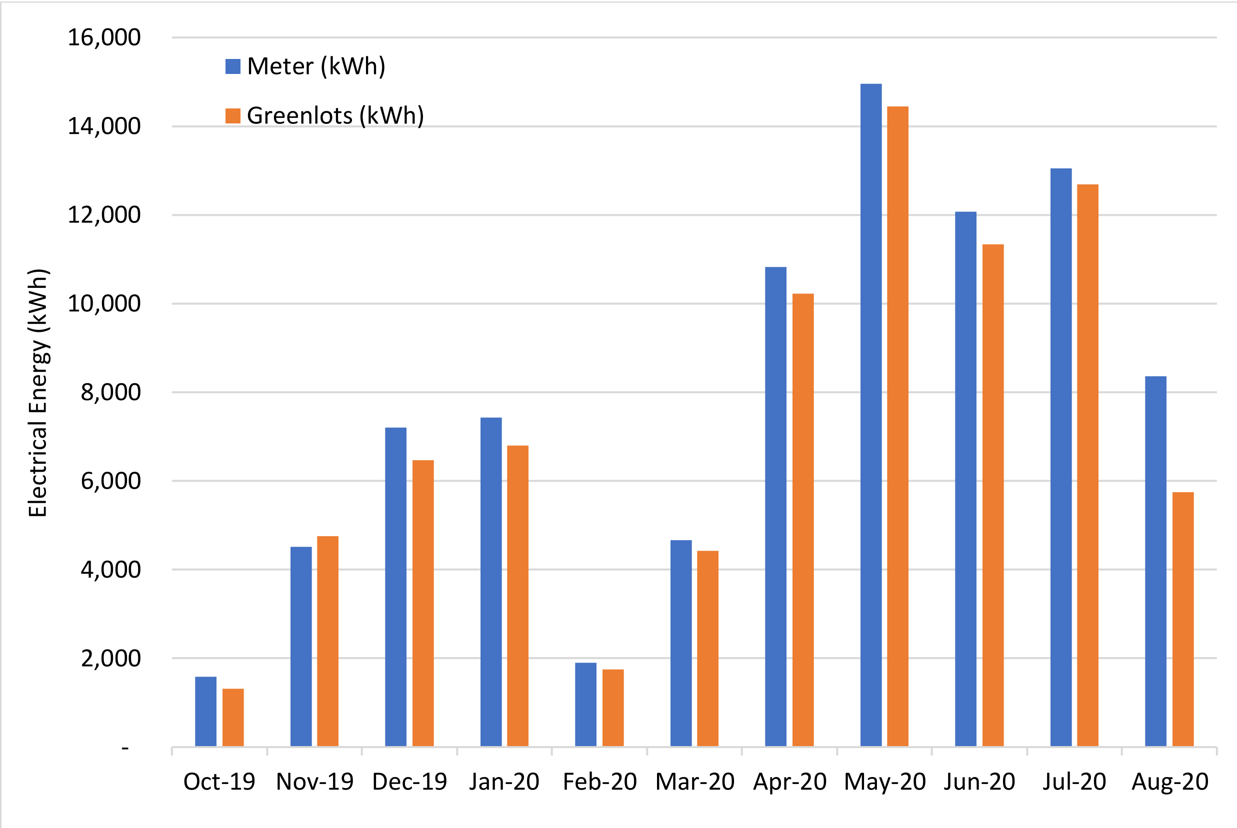
Figure 31. Frequency of charging session energy use



Source: EVSP Charging Session Data

From October 2019 to September 2020 the EV fleet averaged nearly 8,000 miles per month, ranging from a low of 1,000 miles and a high of nearly 15,000 miles. Out of the last 7 months, five of them had more than 10,000 miles. Average monthly miles per vehicle were just over 500 and maximum was nearly 1,700. Individual EV lifetime efficiency ranged from 0.78 to 0.90 kWh per mile, while average vehicle speeds were around 8 miles per hour for one group and 13 miles per hour for the other.

Figure 32. Energy consumption comparison: utility meter vs. charging station



Source: SDGE Meter and EVSP Charging Session Data

Stakeholder and Customer Feedback

One fleet tracked nearly 100,000 miles and more than 100 MWh during the data collection period of this project. The other fleet represented 75% of the charging port installations but had not yet received electric trucks. Feedback pertaining to the initial implementation of this PRP is captured in the Implementation Process section of the Evaluation Methodology. The single participating operator notes the importance of clear and direct communication with all partners on projects such as this. Because the vehicles, EVSE, and charging networks represent relatively new technology, there were situations when charging failed to occur and warnings were not provided to the end user. The EV service provider conducted several over the air updates and on a few occasions that caused chargers to error and become unavailable. The operator noted that $0.40 per kWh, which was the lowest average monthly electricity cost observed during this pilot, will seriously hinder EV fleet deployments. Electricity rates need to be much lower to cover the higher upfront vehicle costs and the cost of charging infrastructure to be competitive with conventionally fueled vehicles.

3.1.4 Conclusions and Recommendations

Findings

SDG&E installed, owns, operates, and maintains 79 L2 charging stations (11 less than proposed in the Decision) for two delivery fleets at four different locations. Total direct PRP costs were $2,407,856 out of the approved $3,690,749. The provided charging infrastructure currently only supports 15 delivery vehicles at one location as the other fleet with three locations is still waiting on vehicles to be delivered. Twelve months of operational data were collected and analyzed. SDG&E has attained relevant installation experience, along with more accurate cost information, to help support electrification of additional delivery fleets (several differences from charging station installations for light duty vehicles). Key findings from this pilot are listed below.

- New products often have low technology readiness. For one fleet, the delivery of the vehicles has been delayed by over a year. The other fleet, in early months, experienced a few charging session faults due to chargers' over-the-air updates, leaving vehicles unprepared for service and the customer unclear as to whether the charging hardware or software or vehicle caused the issue. The early generation of the vehicle's onboard charger technology provided slower charging (6.6 kW) than anticipated (~12 kW). Though this likely benefited the fleet in terms of limiting demand charges on utility bills, faster charging will be necessary for a site with more vehicles or longer routes.
- The restriction imposed by the Decision to only allow new project locations for locally owned MBE/WBE delivery business fleets prevented this PRP from recruiting more participants, despite several outreach methods (forums and direct contact). The final expected number of electric delivery vehicles supported by SDG&E charging infrastructure is only 75 of the initially proposed 90, of which only 15 have been delivered by the end of 2020. Flexibility in pilot and program deployment is essential to allow for accelerated EV adoption.
- There are several reasons for lower PRP costs than approved budget. From budgeted $1M in EVSE and electrical equipment only half of that amount was expended. Charging infrastructure was installed for fewer than expected electric delivery trucks (11 less chargers). Only one additional fleet besides UPS agreed to participate in the PRP (an additional site with 15 chargers would cost up to $500k). Only L2 chargers were installed (DCFC would increase the costs significantly). IT and utility program management costs were a quarter or less than what was budgeted (approximately $750k lower) due to only one fleet receiving vehicles for participation in the PRP.
- For these specific deployments, electric delivery vehicles and fleet operations did not require DCFCs, so only L2 stations were deployed. This may change for longer range electrified delivery vehicles. L2 chargers proved to be adequate for overnight charging with one charger per vehicle ratio. Each location also installed an extra charger in the maintenance facility to support vehicle servicing needs.
- Given the likely electrical infrastructure upgrade requirements for significant fleet electrification, utilities are necessary partners for infrastructure support, as well as charging management plans.
- Charging management plans can help ensure low-cost electricity for transportation while mitigating detrimental impacts to the grid. Neither the utility nor the fleet operator prioritized

the advanced development of a charging management plan, so utility bills were significantly higher than necessary, primarily because of on-peak charging and a higher power-based rate (AL-TOU). Much of the on-peak charging was avoidable, and the use of the AL-TOU rate was no longer necessary once the CPUC provided a waiver allowing SDG&E customers stay on TOU-M even if they exceed that rate's 40 kW threshold. The AL-TOU rate resulted in double the average costs as compared to the TOU-M rate, primarily because of demand charges. AL-TOU makes it harder to achieve least-cost electricity but does offer significant encouragement to minimize demand, if the customer understands the rate and has charging management available. After the evaluator conducted the IDI, the operator became more aware of the benefits of having a charging management plan.

- The PRP experienced $0.40/kWh average electricity costs which resulted in negative operational energy cost savings. On a different utility tariff (e.g., grid integrated rate like green shuttles PRP) and/or with utilization of charging management software, the average electricity costs would be around $0.20/kWh resulting in operational energy cost savings.
- Utilities are learning alongside customers how best to integrate EVs into fleets and operations, as neither utilities nor customers have much experience, though various levels of charge management software do exist and should be utilized when possible.
- Third-party onboard vehicle data loggers were proposed and approved for this pilot to independently monitor vehicle performance. Due to higher-than-expected costs, SDG&E decided to not procure and install third-party dataloggers. Instead, they relied on the fleets to provide vehicle performance data through the vehicle manufacturer telematics systems. This approach resulted in evaluator not having direct access to the vehicle operational data and only receiving it towards the end of the evaluation period.
- Some companies would prefer that future utility transportation projects allow vehicle charging installations on existing utility accounts that supply buildings. This would make it easier for the company to understand the overall site load factor and encourage energy management and demand mitigation across the entire site.
- Key vehicle operational information was collected. Overall vehicle availability for daily service in the fleet was between 80% and 90%. Vehicles consumed an average of nearly one kWh per mile.

Lessons Learned

The following lessons learned were captured during the implementation of this PRP.

- Significantly more effort and investment, as well as improved EV availability and reduced EV costs, will be necessary to sufficiently support locally owned MBE/WBE delivery business fleets to electrify their vehicles. Smaller local companies generally do not have robust financial resources to make investments in new technologies. Further, such businesses often do not have the knowledge or resources to secure the grants necessary to finance this type of effort (upfront costs for electric delivery trucks is a barrier) or the available staffing to navigate the challenges of operating new technology.
- The electric delivery vehicle market is growing and maturing but still has limited product options. Some small manufacturers to first enter the market (e.g., Smith Electric) struggled to succeed and had to cease operations, while other small manufacturers are still struggling to produce vehicles. These PRPs are procuring some of the first production vehicles from the

selected manufacturers, which can have an impact on production and delivery times. Supporting the EV manufacturers, providing a market for their products, and examining vehicle performance will help advance the transition to electric delivery vehicles. Additionally, driving competition by mandating that OEMs sell a percentage of commercial ZEVs to access the CA market would accelerate the transition.

- Utility field construction advisors should be included early in the design process and should participate in the initial site walk to better understand the customer site. Better-prepared advisors can better accommodate the anticipated EV operational needs.
- If charging station installation programs can be made more flexible, customers may prefer to use either new or existing meters—particularly those customers knowledgeable of and actively involved in energy management practices.
- Direct, clear, and routine communication between the utility, customer, and vendor will be necessary for troubleshooting and achieving the lowest cost of electricity possible; costs can be better managed with a clear understanding of rates and a charging management plan. Partners also benefit from developing and jointly reviewing clear agreements on data sharing. The operator was unaware when (or why) the company's electricity rate was changed; knowledge of the change would have influenced company operations.
- A fleet dashboard to confirm vehicles begin and finish charging as planned can help ensure vehicles are ready for service.

Scale-up Potential

There are an estimated 70,000 package delivery trucks within the state of California.[15] It is unclear what percentage have duty cycles similar to fleet operations observed in this PRP, but it is assumed that 50% have daily routines similar to, or less intensive than, this pilot and thus could be electrified. If 35,000 package delivery vehicles in California were converted to electric and have operations similar to the PRP's best observed case, 38,897 million gallons of gasoline could be displaced by 424,755 MWh of electricity (224,567 kWh or 53% on-peak), providing the emissions benefits shown in Table 11.

Table 11. Fleet Delivery scale-up potential annual emissions

	GHG (MT/yr)	SO_x (MT/yr)	NO_x (MT/yr)	CO (MT/yr)	PM (MT/yr)	VOC (MT/yr)
Net Reduction	**289,700**	**73**	**362**	**4,859**	**17**	**97**

Source: Evaluator Calculations

[15] California Hybrid, Efficient and Advanced Truck Research Center. (2013). *Battery Electric Parcel Delivery Truck Testing and Demonstration.* Sacremento, CA: CEC Public Interest Energy Research Program (PIER)

3.2 Green Shuttles

3.2.1 Project Narrative

Overview, Objectives, and Barriers Being Addressed

The San Diego Gas & Electric (SDG&E) Priority Review Project (PRP) filing proposed a partnership with taxi, shuttle, and transportation network companies (TNCs) interested in the electrification of their fleets. SDG&E sought to support them with grid-integrated charging facilities, including direct current fast chargers (DCFCs) and Level 2 (L2) electric vehicle supply equipment (EVSE), and a grid-integrated rate. The California Public Utilities Commission (CPUC) decision approved SDG&E spending up to $3,157,805 for only fixed-route shuttle applications. SDG&E was approved to install solar and energy storage at one project location. The utility was directed to work with the participating shuttle companies to determine whether additional electric vehicle (EV) drivers, such as taxi, vanpool, or TNC drivers, can use the same charging infrastructure. SDG&E offered its new Public Grid Integrated Rate (GIR) at the charging stations it owns. The utility originally proposed to install, own, operate, and maintain up to five grid-integrated charging facilities ("project charging facilities"), which include one DCFC and two L2 EVSEs per facility, to address the fueling needs for the EVs with DCFC capabilities, as well as applications that do not require these capabilities.

The following are key learning objectives of this project:

- Utilization Optimization – The optimal charging facility-to-vehicle ratio to achieve high utilization rates without creating inconvenience for the vehicle drivers.
- Location Optimization – The extent to which charging facility locations for shuttle fleets are easily accessible, convenient, and sufficient in volume and types of chargers to meet the operational requirements of the other potential markets (i.e., taxi, vanpool, and TNC).
- Impact of the GIR – The extent to which the proposed rate works to encourage off-peak charging, as well as the extent to which these operations will have the flexibility to charge during hours with the lowest energy prices.
- EV Adoption – Gathering data to help inform the total cost of ownership for fleet electrification.

The goals of the project are to:

- Partner with two or up to five shuttle companies to purchase 2 or more electric shuttles.
- Enroll shuttle customers in SDG&E's GIR to reduce fueling costs and provide advance notification to facilitating scheduling of charging times during lower-priced, off-peak hours.

The project includes a customer educational component that will help potential participants develop an understanding of the grid, fuel cost savings benefits and advantages of charging off-peak under a grid-integrated rate (where feasible), how the rate works at project charging facilities, SDG&E billing, and other project benefits. Customer engagement for this project includes customer outreach with potential site hosts, outreach through company representatives, and an overarching program-specific communication and education campaign (e.g., using social media, web and web tools, and co-sponsored educational events and collateral).

Sites and Participants

Recruitment Process

SDG&E account executives, shuttle manufacturers, and other resources were used to conduct outreach to potential program participants. In January 2018, SDG&E held an external stakeholder conference for vendors, EV shuttle manufacturers, and local customers that fit the decision requirements. As a result, SDG&E engaged many customers and held serious discussions with 17 customers about the program. Customer operations included schools, workplaces, airport shuttles, and hotel shuttles. Unfortunately, many customers could not participate in the program because:

- The procurement cycle did not align with the program (30%).
- The cost of the electric shuttles was too high (20%).
- The customer operations do not operate on fixed routes (10%).

In addition, some locations have significantly longer conduit and trench lengths than the estimated average in the originally proposed project budgets, which estimated conduit and trench lengths on a per-site basis. The higher project cost excluded some potential customers from participating.

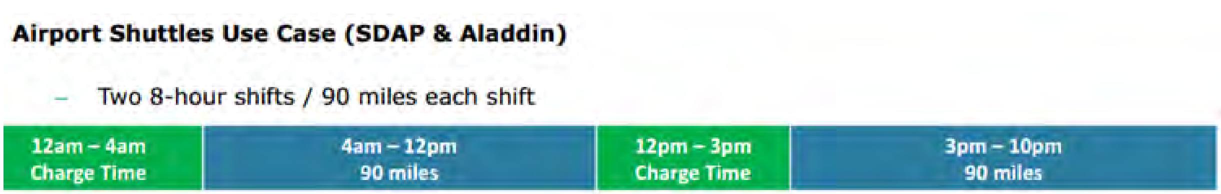
Participants

SDG&E received interest from four fixed-route shuttle companies to help electrify their fleets, including:

- Two offsite airport parking shuttle fleets: San Diego Airport Parking (SDAP) and Aladdin Airport Parking (Aladdin)
- A workplace employee shuttle: Illumina, which has buses operated by ACE Parking
- the San Diego International Airport (SDIA)-operated shuttle fleet

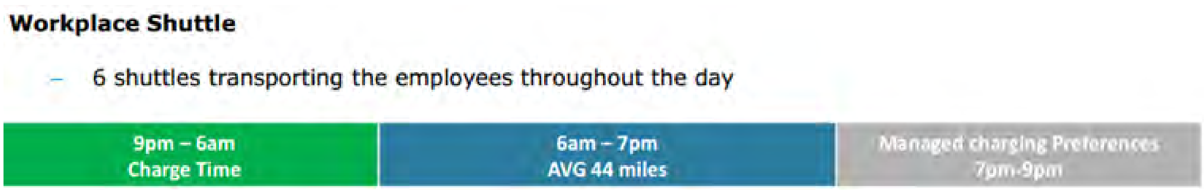
These shuttle fleet project participants indicated that the originally proposed charging infrastructure configuration of two L2 stations and one DCFC per site would not meet their needs. L2 charging stations are not suitable for the airport shuttle operations due to high daily mileage and operational time; multiple DCFCs may be needed. On the other hand, the workplace shuttle operations have lower daily miles and opportunities for longer charging periods outside of the workday, and there is no easy way to rotate the vehicles through a single DCFC, requiring a L2 charging station for every shuttle bus. These use cases are shown in Figure 33 and Figure 34. SDG&E submitted an advice letter to the CPUC in Q1 of 2019 allowing for two DCFCs for three airport shuttle sites, for a total of six DCFCs, and six L2 charging stations at one workplace shuttle site. The CPUC approved the proposed PRP modifications.

Figure 33. SDG&E Green Shuttle airport use case



Source: SDG&E Q4 2018 Program Advisory Council Meeting

Figure 34. SDG&E Green Shuttle workplace use case



Source: SDG&E Q4 2018 Program Advisory Council Meeting

SDAP runs an off-site airport parking facility and shuttles its customers to and from the airport. SDAP is also participating in SDG&E's Power Your Drive Program (ten L2 charging ports were installed). Shuttles operate on an eight-mile loop from the parking facility to the airport and back, which takes approximately 30 minutes. Shuttles operate based on demand; up to four shuttle buses can be running during peak times, and only one runs during off-peak hours. The shuttle buses are minimally operated when the airport is shut down between 12:00 AM and 4:00 AM (although delays or peak days often keep them running until 1:00 AM). In 2015 and 2016, SDAP operated three Zenith EVs with three 14 kW L2 chargers, but the vehicles experienced significant operational issues and could not replace the operation of the diesel shuttles. For this PRP, SDAP acquired two **GreenPower Motor Company** (GreenPower) electric shuttle buses. Two of SDAP's Zenith EVs were repowered with an electric powertrain by Maxwell Vehicles to return them to electric operation. SDG&E approved and SDAP planned to use 50 kW BTC Power DCFCs managed by Greenlots, but the GreenPower electric shuttle's voltage requirements (576 V battery packs) required a change to a 62.5 kW **ChargePoint** CPE 250 DCFC charging station and the ChargePoint network. While SDAP was open to having other fleets use the chargers, SDG&E deemed the site is for private use and will not be publicly available. The ChargePoint CPE 250 DCFC EVSE comes with a 12-foot cord, but SDAP discovered that length is tip to tip; the usable length is made significantly less by the cable positioning around the vehicle and the angle to plug the cord into the vehicle's charging receptacle (see Figure 35, with the EV parked very close to the bollards).

Figure 35. SDAP site with two GreenPower EV Stars

Source: Evaluator Team

Aladdin runs an off-site airport parking garage with 2,100 spaces and shuttles its customers to and from the airport for nearly 200 miles per day per vehicle. The company uses Ford-E450-sized vehicles. In 2011, Aladdin began installing EV charging for customers through the EV Project under ECOtality's

American Recovery and Reinvestment Act grant from the U.S. Department of Energy in 2010. That project installed four L2 charging ports; at around the same time, a series of 120 V plugs were also added for customer charging. In a subsequent project Tesla installed 12 L2 charging ports, of which four were J1772. In 2019, EVgo installed ten –50 kW chargers on a dedicated electric utility service for public use. When looking into vehicles, Aladdin considered Phoenix electric shuttles, but those were too tall to enter their parking garage; the company instead placed an order with Briton for 4 **Lightning System** Ford E450 electric shuttles. To charge these vehicles, SDG&E installed two 62.5 kW **ChargePoint** CPE 250 DCFCs under this PRP. Aladdin has operated two generations of low NOx alternative fuel shuttles as required by the airport, including compressed natural gas (CNG) and propane. The current fleet of eight shuttles is powered by propane and has been more successful than CNG.

Illumina shuttles its employees around the main campus (5200 Illumina Way, San Diego), back and forth to the north campus (4795 Executive Drive, 0.9 miles from the main campus), and back and forth to University Town Center mall (4545 La Jolla Village Drive, 1.3 miles from the main campus). Illumina also participated in SDG&E's Power Your Drive Program where L2 chargers were installed at their parking facilities for workplace charging. **ACE Parking** operates Illumina's shuttle service and placed an order with **Briton** for 6 **Lightning System** Ford E450 electric shuttles for this project. SDG&E installed 6 **BTC Power** 16.8 kW, 70 A L2 charging stations managed by **Greenlots** under this PRP. The site is for private use and will not be publicly available.

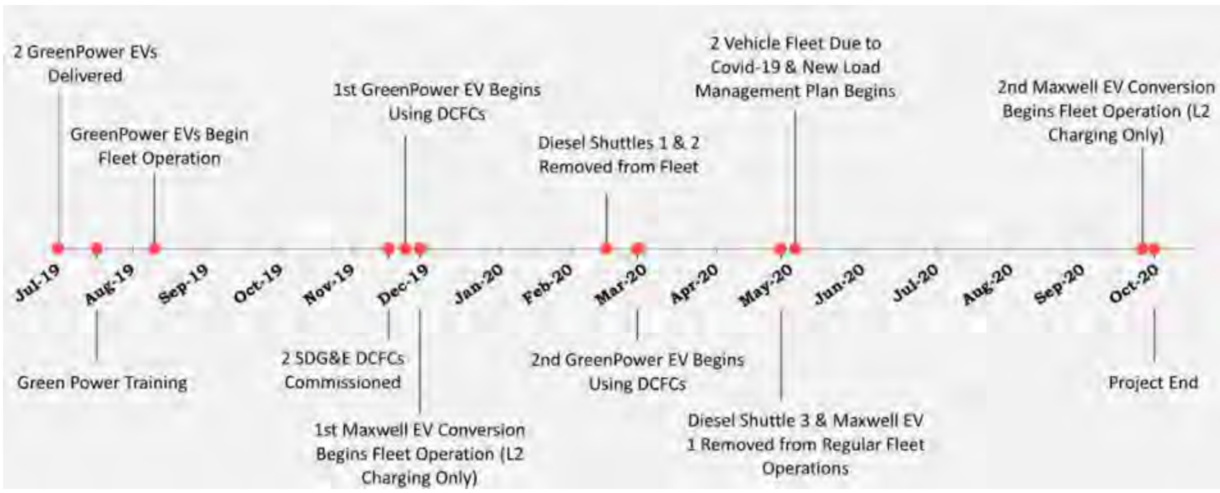
SDIA was working on procuring four electric shuttles for an inter-terminal route and was considered for participation in this PRP. The initial site evaluated by SDG&E for charging infrastructure installation was the current taxi/rideshare/shuttle lot, which intended to be open to other taxi/rideshare/shuttles beyond the new shuttles purchased by SDIA. Unfortunately, this site will undergo major reconstruction soon, so installing charging infrastructure was not feasible. Alternative locations were investigated, but no other suitable options were identified; therefore, SDIA did not participate in the Green Shuttle PRP.

SDG&E investigated potential sites where EV chargers could be integrated with renewable (solar photovoltaic [PV]) energy and an energy storage system (battery) to examine how these technologies can be used to manage energy use and demand charges. SDAP offered the company site to demonstrate the integrated PV and battery system, which would provide a significant opportunity to examine the interaction with electric shuttle bus charging. The utility issued a request for bids to perform the solar and storage installation and integration. Due to high costs and limited potential savings the utility did not pursue this option.

Timeline and Status

SDAP acquired two GreenPower EV Stars in January 2019 and the shuttles were delivered in July 2019. These vehicles initially charged on the SDAP's existing L2 chargers, but the duty cycle requirements (up to 200 miles per day) did not allow for a diesel shuttle to be fully replaced until the DCFCs were commissioned in December 2019. Construction at SDAP was scheduled to begin in May 2019, but when the SDIA site was found infeasible, SDG&E entered into discussions with SDAP about a potential combined DCFC and energy storage system, which delayed the start of construction. However, SDG&E ultimately decided not to change the proposed design. Thus, construction at SDAP started in June 2019 and was completed within two months. When the SDAP charging infrastructure was complete and commissioning was under way, it was discovered that the BTC DCFCs installed were incompatible with the higher voltage (560 V) battery system in the GreenPower EV. The only approved alternative that would meet the PRP timeline was the ChargePoint CPE 250 DCFC as they were the only other approved vendor. Procuring and installing the new chargers took a few additional months. CPE 250 DCFCs allow for a combined output of 125 kW when connected with an optional pairing kit, which SDG&E and SDAP agreed to install at this site. While the construction to accommodate the charger pairing was completed quickly, there was a several-week delay while awaiting delivery of the pairing kit. The entire SDAP pilot timeline is shown in Figure 36.

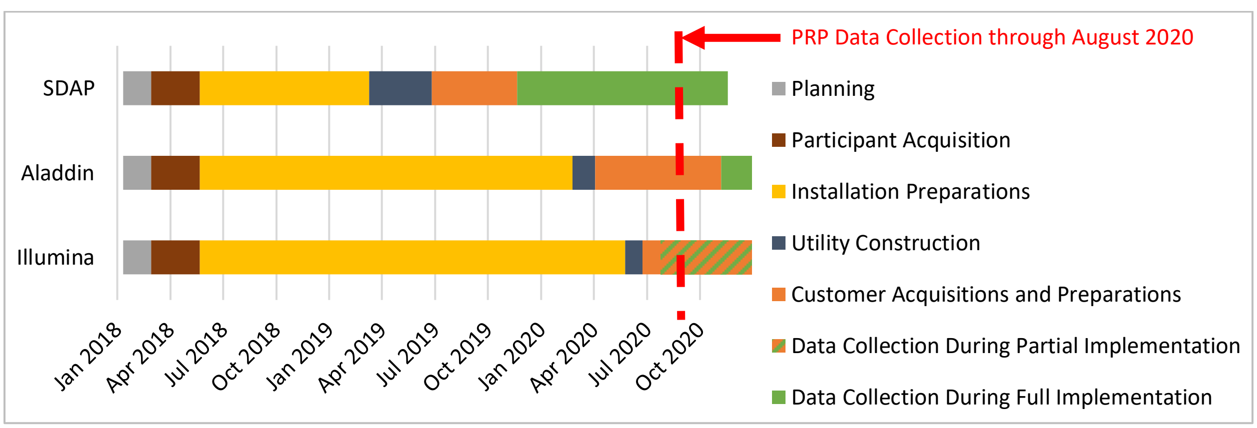
Figure 36. Implementation milestones for SDAP pilot



Source: SDAP

The contract with Aladdin was executed in May 2019, and the contract with Illumina was executed in September 2019. Both organizations experienced delays in acquiring their EVs, and utility construction was pushed back to better align with those procurements. The utility's construction work for Aladdin was done in March and April of 2020, followed by Illumina in May and June. Unfortunately, COVID-19 further delayed EV deliveries; ACE received EVs for Illumina in July but was unable to start operation, and Aladdin did not receive EVs in 2020. As a result, there is no operational data for these two fleets to evaluate in this report. The high-level timeline for all three PRP sites is shown in Figure 37.

Figure 37. SDG&E Green Shuttles PRP timeline as of November 2020



Source: SDG&E

3.2.2 Evaluation Methodology

Selected Methods and Rationale

In addition to the evaluation questions that apply to all PRPs and those specific to the Fleet Electrification PRPs, the evaluation questions listed below will be examined for this PRP.

- What instructions/training were drivers given about using the charging station?
- Were operational and technology opportunities to better manage charging identified, how were they implemented, and were they effective?
- What is the appropriate charging level and ratio of charging ports to vehicles?
- How might the integration of PV and batteries with DCFCs on-site affect this use case? What different charging optimization scenarios were modeled, and what were their outcomes?

The data collection sources utilized to evaluate this PRP include 1) PRP information from the approved decision, project updates, site visits, and other available documentation, 2) market research on shuttle vehicles and early deployment efforts from other similar electrification projects across the country, 3) PRP data from fleet, vehicle, and charger operations, and 4) in-depth interviews (IDIs) with project partners.

Data Sources

SDG&E provided PRP operational data from its utility service meters (one utility meter at each deployment site for all charging stations at that site) for 15-minute interval data and monthly costs (through utility bills). Green Shuttle billing was unique in that details were provided in a standalone spreadsheet noting each hour's pricing and energy consumed. SDG&E and SDAP both provided the evaluator direct access to the charging session data via online ChargePoint portal access which worked very well. SDG&E determined that third-party data loggers for medium- and heavy-duty EVs were much more expensive than anticipated and decided to rely on fleets' third party dataloggers and vehicle manufacturer telematics systems for vehicle operational data. For SDAP's GreenPower EVs, which did come equipped with OEM-provided telematics, this approach failed as the OEM was unable to provide telematics data during the evaluation period. Based on Amazon's experience under SDG&E's Delivery Fleet PRP, Lightning Systems EVs come with an OEM telematics solution which can provide a very rich data set. While such vehicle operational data would add value to the evaluation, unfortunately Aladdin and Illumina did not experience any EV fleet operation during the evaluation period. Project participants provided high-level data on vehicle utilization and maintenance, along with any necessary maintenance on the charging stations. SDAP provided driver logs indicative of typical shifts for the overall fleet.

The evaluator collected PRP information through numerous PRP participant interactions: the PRP kick-off meeting (SDG&E and evaluator), quarterly Program Advisory Council update meetings, weekly PRP updates (SDG&E and evaluator), several site visits, and many periodic calls or emails. Through these, the evaluation team collected charging station hardware specifications, EV specifications, electricity tariff details, construction plans, and project costs. The evaluator held IDIs with representatives from the SDG&E PRP management team and SDG&E construction staff to further understand the background on this project and gather lessons learned based on progress to date. Additional IDIs with the SDG&E staff, project participants, and vendors took place in 2020 during SDAP's EV operation. These IDIs also provided insight into the historical usage of non-EVs in the fleet.

3.2.3 Evaluation Findings

Project Baseline

Promoting the development and use of zero-emission airport ground transportation will help the California Air Resources Board (CARB) achieve the emission reduction strategies outlined in the Mobile Source Strategy, State Implementation Plan, and Sustainable Freight Action Plan. Vehicles such as airport shuttles that operate on fixed routes, have stop-and-go operations, maintain low average speeds, and are centrally maintained and fueled are ideal candidates for targeting zero-emission electric technologies.[16]

The Zero-Emission Airport Shuttle Regulation, which CARB adopted in June 2019, requires that airport shuttle operators transition to 100% zero-emission vehicle (ZEV) technologies. Airport shuttle operators must begin adding zero-emission shuttles to their fleets in 2027 and complete the transition to ZEVs by the end of 2035. The regulation applies to airport shuttle operators that own, operate, or lease nearly 1,000 vehicles at any of the 13 airports regulated under the rule; shuttles with gross vehicle weight ratings of 8,501 or greater that transport passengers to and from the regulated airports; shuttles with fixed routes that stop at rental car facilities, on-airport or off-airport parking, hotels, or other similar locations; and shuttles based within 15 miles of a regulated airport that have round-trip routes of 30 miles or less.[17]

Table 12. Green Shuttle PRP participating fleet summary

Operator	Legacy Shuttles	Fuel	PRP Shuttles	PRP Charging
SDAP	4 Mercedes Sprinter/Ford Transit Vans	Renewable Diesel	2	DCFC (2)
Aladdin	8 Ford E450 Cutaway	Propane	4	DCFC (2)
Illumina	6 Ford E450 Cutaway	Propane	6	Level 2 (6)

Source: SDAP, Aladdin, and Illumina

Before this PRP, SDAP operated four diesel shuttle buses: three Mercedes Sprinters (one 6-cylinder and two 4-cylinder) and one Ford Transit. The company fueled them with renewable diesel to meet SDIA's requirement for alternative-fueled shuttles. They used a retail fueling station 7 miles away and filled the shuttles at least every other day (every day during the busy season). SDAP shuttles accumulate nearly 16,000 miles a month and approached 200 miles a day on the diesel shuttles. SDAP operated Zenith electric shuttle buses in its first attempt to replace the diesel shuttles but experienced many electric powertrain failures. Notably, with both the Zenith and GreenPower Vehicles, L2 charging has proven to be a range limitation. Each EV could only drive up to 100 miles on a full charge and opportunity charging during the day could not add enough range to match the typical diesel daily mileage. With 3 Zenith EV

[16] CARB, *Zero Emission Airport Shuttle webpage*, 2019, https://ww2.arb.ca.gov/our-work/programs/zero-emission-airport-shuttle/about.

[17] California Air Resources Board, *Zero-Emission Airport Shuttle Regulation Factsheet*, 2019, https://ww2.arb.ca.gov/sites/default/files/2019-10/asb_reg_factsheet.pdf.

shuttles in 2016, SDAP was able to achieve 75 percent of monthly miles to be electric but still needed to use diesel shuttles. The company has a maintenance shop across the street with staff who are knowledgeable about EVs. The shop has helped support both the diesel shuttles and the Zenith EVs and can support GreenPower EVs if needed (i.e., no change to current vehicle maintenance operations will be needed).

Electric shuttle bus manufacturers, and therefore EV shuttle options, are currently very limited especially in Class 2b which SDAP operates, and there are not many active demonstrations of the technology. BYD offers a 30-foot electric shuttle bus for sale in North America. Although specific vehicle sales figures are not readily available, BYD is the largest zero-emission bus (ZEB) manufacturer in the world, and its North American operation employs over 750 workers in its 450,000-square-foot manufacturing facility in Lancaster, California. GreenPower Motor Company manufactures and sells five battery electric buses: the EV250 and EV350 transit shuttle bus, the 25-foot EV Star (the EV Star is available in three trim levels, including an ADA accessible version), the EV Star +PLUS (a wider body allowing another aisle of seats) and the BEAST 40-foot school bus. GreenPower also offers a cargo line in each EV Star: a cargo van, a cargo box, and a cab chassis (all are Class 4 trucks). Furthermore, each EV Star is Altoona certified and can be integrated with DCFC and wireless charging. GreenPower has recently deployed an autonomous EV Star in a transit application. The company reports strong sales and earnings, particularly in regard to the EV Star, at least two of which were sold to SDAP. Lightning Systems is a Colorado-based manufacturer of zero-emission all-electric powertrains with offices in Loveland, Colorado, and San Diego, California. Lightning Systems claims to improve a fleet's operating costs while providing safety, environmental responsibility, and advanced technology. The company offers all-electric powertrains for the Ford Transit 350HD passenger and cargo vans, Ford E-450 shuttle bus and cutaway models, Ford F-59 step/food van, Ford F-550 cargo trucks and buses, Chevrolet 6500XD Low Cab Forward model, and 30-foot, 35-foot, and 40-foot transit buses.

Implementation Process

The initial installation design for SDAP incorporated PV and energy storage. SDG&E received two responses to their request for bids to install and integrate these systems, but both companies lacked experience and their quotes were much higher than expected and allocated in the PRP budget. SDG&E explored the option to facilitate this effort using internal staff to design these systems and then investigated the costs for the individual components from known suppliers. Even with this approach, the equipment and installation costs were still very high. SDG&E even considered repurposing older assets to lower costs, but even this approach proved to be costly. SDG&E staff then ran a model to determine the potential impacts of these systems and found very limited electricity savings (~$1,500 per year). According to the utility, the cost differential for this application was so far off that it could not be justified. Instead, SDG&E planned to simulate the expected impacts from PV and energy storage for this DCFC installation and calculate what the benefits would have been if it had been implemented as planned. However, due to limited operation during the COVID-19 pandemic, SDGE did not rerun the model based on actual data.

SDG&E investigated several options for an open access charging station among the potential participants. Several have very complicated parking lot access that would make allowing public access challenging, and most sites rely heavily on the availability of these chargers for shuttle charging, so those locations could not risk having shared chargers. Staff were able to identify a site that could allow public access, but unfortunately, it was the SDIA location that is scheduled to undergo major construction soon. SDG&E has found that many shuttle bus operations are interested in electrification but are unfamiliar with the technology and therefore could not commit to vehicle purchases that aligned with the PRP timeline. However, many of these customers are planning to pursue electrification through SDG&E's Power Your Drive for Fleets program (medium- and heavy-duty standard review project [SRP]). SDG&E has found that, for recruiting new customers, ongoing programs are much more helpful than limited, short-term pilots like the PRP. The latter can work only for those customers who already have plans to electrify their fleets, whereas long-term programs inspire more customers to take the necessary steps toward planning for electrification so that they are ready to install charging stations in the near future. The PRP has created a "pipeline" of potential customers that the SRP can now support.

Costs

The approved PRP had an anticipated total direct cost of $3,157,805, consisting of $2,338,887 in capital costs and $818,918 in expenses, as shown in Table 13.

Table 13. SDG&E Green Shuttle PRP proposed costs

	Capital Costs	O&M Expenses	Total PRP Costs
Transformer and Install	$ 75,100	$ 2,073	$ 77,173
Electrical Service	$ 440,865	N/A	$ 440,865
EVSE Costs	$ 1,317,522	$ 1,845	$ 1,319,367
Purchased and Self-Developed Software	$ 505,400	N/A	$ 622,800
Customer Engagement	N/A	$ 200,000	$ 200,000
Measurement and Evaluation	N/A	$ 410,000	$ 410,000
Billing Support	N/A	$ 80,000	$ 80,000
SDG&E Clean Transportation Project Mgmt.	N/A	$ 100,000	$ 100,000
First-Year O&M Service Calls	N/A	$ 15,000	$ 15,000
First-Year O&M for Charging Equipment	N/A	$ 10,000	$ 10,000
Total Costs	**$ 2,338,887**	**$ 818,918**	**$ 3,157,805**

Source: SDG&E

Although engineering design was not listed as a separate line item in SDG&E testimony it was part of the original estimate. CPUC Energy Division Data Request ED-DR-01-Q2 response shows engineering design was estimated at $109,750, consistent with the budgeted amount in Table 14. The PRP showed that the actual design, engineering, and permitting costs average about $30,000 per site.

The estimated total PRP direct costs are $1,438,231 out of a budgeted $3,157,805, as shown in Table 14 (presented in categories reported by the utility).

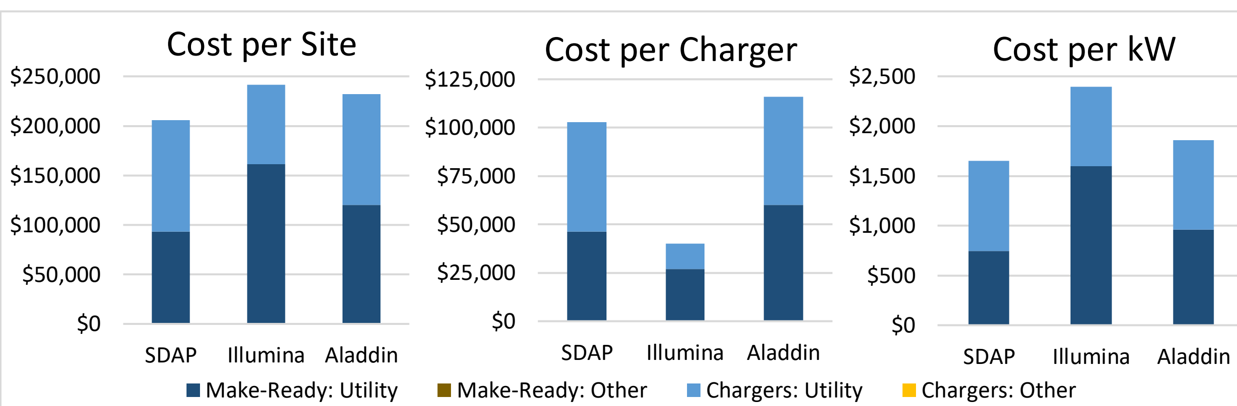
Table 14. SDG&E Green Shuttle PRP estimate at completion (EAC)

	EAC Capital Costs	Budgeted Capital Costs	EAC O&M Costs	Budgeted O&M Costs
Construction	$ 374,201	$ 763,455	N/A	N/A
Engineering Design	$ 106,993	$ 109,750	N/A	N/A
Chargers, Meter Pedestals, Transformer, and Other Materials	$ 305,341	$ 842,882	$ 6,150	N/A
Internal SDG&E Labor (Program Management and Support)	$ 22,445	N/A	$ 130,823	$ 180,000
IT Costs	$ 432,418	$ 622,800	N/A	$ 410,000
Customer Engagement and Outreach	N/A	N/A	N/A	$ 200,000
Other	$ 59,861	N/A	N/A	$ 28,918
Direct Costs	$ 1,301,258	$ 2,338,887	$ 136,973	$ 818,918
Non-Direct Costs (Indirect, AFUDC, and Property Taxes)	$ 267,065	$ 1,372,708	$ 128,938	$ 264,238
Total Costs	**$ 1,568,323**	**$ 3,711,595**	**$ 265,911**	**$ 1,083,156**

Source: SDG&E

The charging infrastructure costs (construction and materials only, not including engineering design) for the three different sites are shown in Figure 38. EVSE costs are shown separate from the make-ready infrastructure upgrade costs. Costs were either paid for by the utility through this PRP or a source of funding "other" than the utility which may be the host site, grants, etc. SDAP and Aladdin had identical chargers installed (two 62.5 kW DCFCs), with one small difference in layout: the SDAP chargers were paired for a maximum power output of 125 kW. Illumina installations included six higher-powered L2 chargers. The utility, under the PRP budget, covered all charging infrastructure costs, including EVSE costs. The utility owns and is responsible for maintenance of all the chargers installed as part of this PRP.

Figure 38. SDG&E Green Shuttle EV charging infrastructure costs



Source: SDG&E

Benefits

The originally designed PRP estimated benefits based on the addition of 4 EV taxis, 4 electric shuttles, and 54 taxis/TNC vehicles. The current expected impact of this PRP is based on 12 electric shuttles. None of the charging infrastructure is accessible by taxis or TNC EVs as originally planned, which would have increased the benefits. In the original PRP plan, benefits were based on the factors listed in Appendix A of SDG&E Direct Testimony [pertaining to SB 350 Transportation Electrification Proposals] – Chapter 8 Air Quality Impacts and Cost Effectiveness. The Green Shuttle PRP deployed chargers in several fleets to support 12 electric shuttle buses; however, only SDAP fleet operation, with 2 electric shuttle buses using 2 DCFCs, could be evaluated as the other fleets did not use EVs during the evaluation period. The key benefits and some contributing factors are outlined below, with a more detailed description of this benefit analysis in the Appendix.

The pilot demonstration period from December 2019 to August 2020 is used to calculate performance. SDAP baseline shuttle buses replaced by the EVs used renewable diesel and had a mean fuel economy of 18.4 MPG. Determined on an annual basis, the operations from December 2019 to August 2020 represent 44,535 kWh per year of energy used, with 6,900 kWh (16%) occurring during the peak hours. Mileage equates to 27,835 miles per year per vehicle (55,669 miles total), which would have required 3,025 gallons of renewable diesel fuel (3,494 gasoline gallon equivalent [GGE]) annually.

The highest utilization month within the pilot was July 2020, which resulted in 96,380 total miles, or 48,190 annual miles per vehicle. Electrification would save 5,238 gallons of renewable diesel (6,050 GGE) per year for two shuttle buses. However, the lower carbon intensity of renewable diesel per 2020 Low-Carbon Fuel Standard (LCFS) there is a slight increase in calculated CO_2 emissions based on July 2020 operations. Operations in January 2020 had lower mileage per vehicle, which would equate to only 23,015 miles per year per vehicle (46,030 total), but on-peak electrical use was much lower, resulting in a favorable CO_2 emissions reduction. Using January as the best observed case for carbon reduction still yields an annual petroleum reduction of 2,502 gallons of renewable diesel, or 2,889 GGE.

Table 15. SDG&E Green Shuttle PRP annualized benefits

	Testimony (4 shuttles and 54 taxis/TNC EVs)	Planned (12 shuttles)	Implemented (2 shuttles)	Best Observed for Carbon Reduction (2 shuttles)
Petroleum Reduction	114,000 GGE	59,000 GGE	3,494 GGE	2,889 GGE
GHG Emissions Reduction	769 MT of CO_{2e}	492 MT of CO_{2e}	-0.7 MT of CO_{2e}	0.9 MT of CO_{2e}
Criteria Pollutant Emissions Reduction	190 kg of NO_x 140 kg of VOC	130 kg of NO_x	110 kg of NO_x 31 kg of SO_x 8 kg of VOC 28 kg of CO	91 kg of NO_x 25 kg of SO_x 7 kg of VOC 23 kg of CO
DAC Impact	SDIA is adjacent to DACs	All three sites are adjacent to DACs around SDIA	0%, adjacent to a DAC only	0%, adjacent to a DAC only
Grid Impacts / Electricity Consumption	996 MWh, with improved net load factor (if charging is properly managed)	152 MWh, with improved net load factor	45 MWh, with 16% consumed on-peak	37 MWh, with 2% consumed on-peak
Operational Energy Cost Savings	N/A	N/A	$ 2,430	$ 1,980

Source: Evaluator Calculations

The GHG emission reduction results from the SDAP pilot can be projected for other potential electric shuttle bus applications that may replace baseline vehicles of varying fuel types. Figure 26 shows results based on slightly different baseline vehicle fuel efficiency; Figure 40 shows results based on annual miles traveled. Impact of the energy cost variability (both for electricity and baseline fuels) on operational energy cost savings is shown in Figure 41. At an average electricity cost of less than $0.20 per kWh, the electric shuttle fleets should realize at least some operational cost savings compared to baseline internal combustion vehicles. EVs should also realize maintenance savings; however, 12 months of operation did not provide enough maintenance records to make a statistically significant comparison. For this PRP, the utility owns the chargers and therefore the resulting LCFS credits. If the fleets were able to monetize the LCFS credits, they could eliminate electricity costs, further improving the total cost of ownership. All three fleets used CARB vouchers for the Hybrid and Zero-Emission Truck and Bus Voucher Incentive Project (HVIP) to cover the incremental costs of the EVs. With the utility covering all charging infrastructure costs and assumed vehicle capital costs on par with baseline, customers in this PRP should be realizing some cost savings, albeit relatively small when not accounting for potential maintenance savings.

Figure 39. Shuttle Bus GHG reductions for various baseline fuels by baseline fuel economy

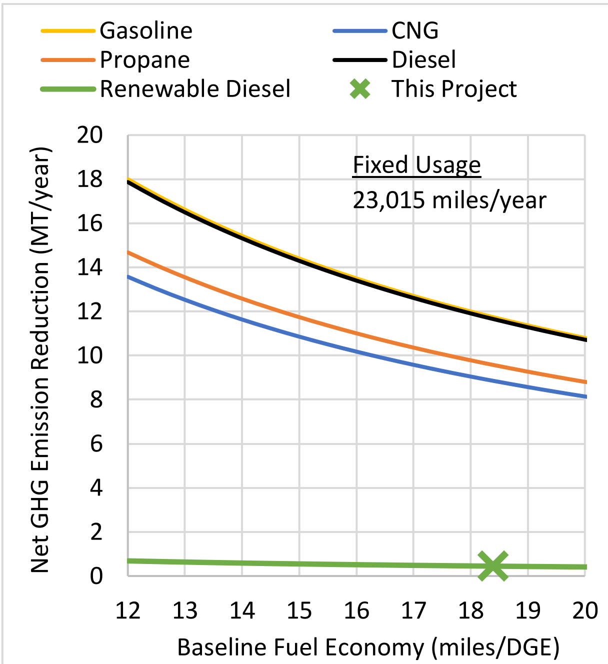
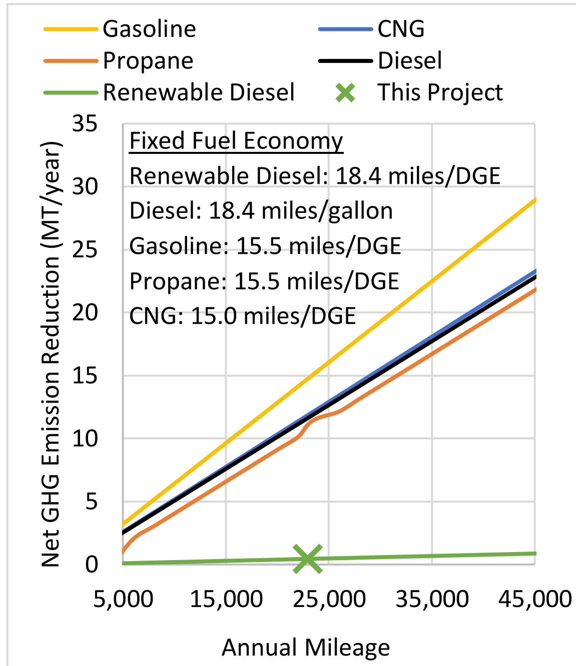
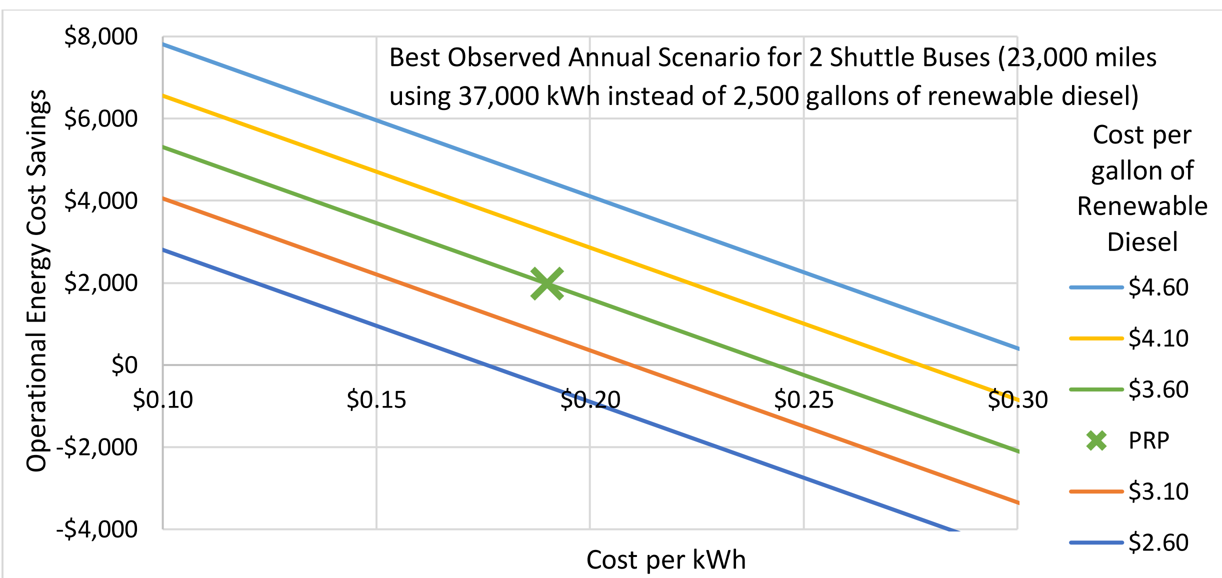


Figure 40. Shuttle Bus GHG reductions for various baseline fuels by annual use



Source: Evaluator Calculations

Figure 41. Annual shuttle bus operational energy cost savings at various fuel costs



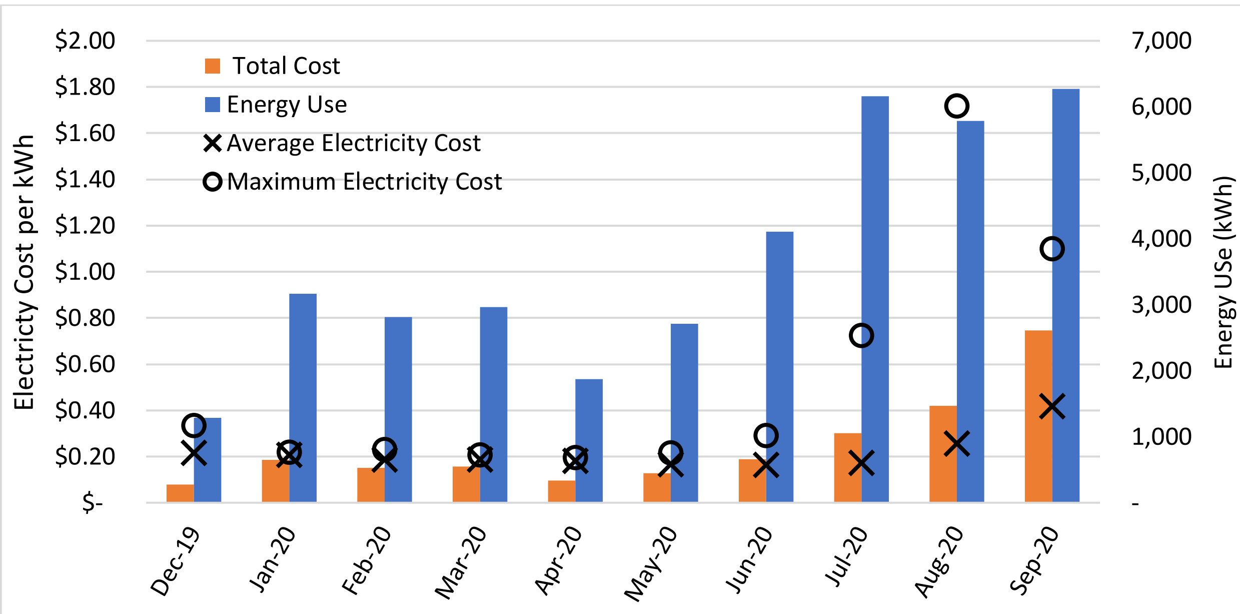
Source: Evaluator Calculations

Operational Impacts of Project Equipment

The utility billing chart in Figure 42 depicts nearly a year of shuttle operations, beginning in December 2019 when the first chargers were installed. The chart includes several months of maximum cost per kilowatt-hour observed each month on the GIR, like those exhibited in summer and fall of 2020. GIR is at times heavily influenced by grid-load forecasting by SDG&E and CAISO. CAISO market day-ahead wholesale energy pricing provides variability year-round, while SDG&E forecasts—both of each distribution circuit (the top 150 annual hours) and of the overall system (the top 200 annual hours)—add substantial costs typically during the hottest hours of the year. This unusual GIR tariff has at times influenced the operator to revert to L2 charging on the preexisting commercial account with a rate that enabled a temporary waiver for EV charging.

Only one electric shuttle utilized DCFC until March when the second shuttle received DCFC capability. March through June operations were heavily impacted by the COVID-19 pandemic (SDAP monthly mileage was down 75%). June shows a significant increase in energy usage as operations begun to recover. Current operations, whose levels are still affected by the ongoing pandemic, appear stable at around 6,000 kWh monthly. Throughout the summer, daily consumption averaged 200 kWh and peaked near 400 kWh, equivalent to two to four full charges based on the larger battery. Charging sessions most often averaged 50 to 60 kW, with fewer than six hours of charging on most days.

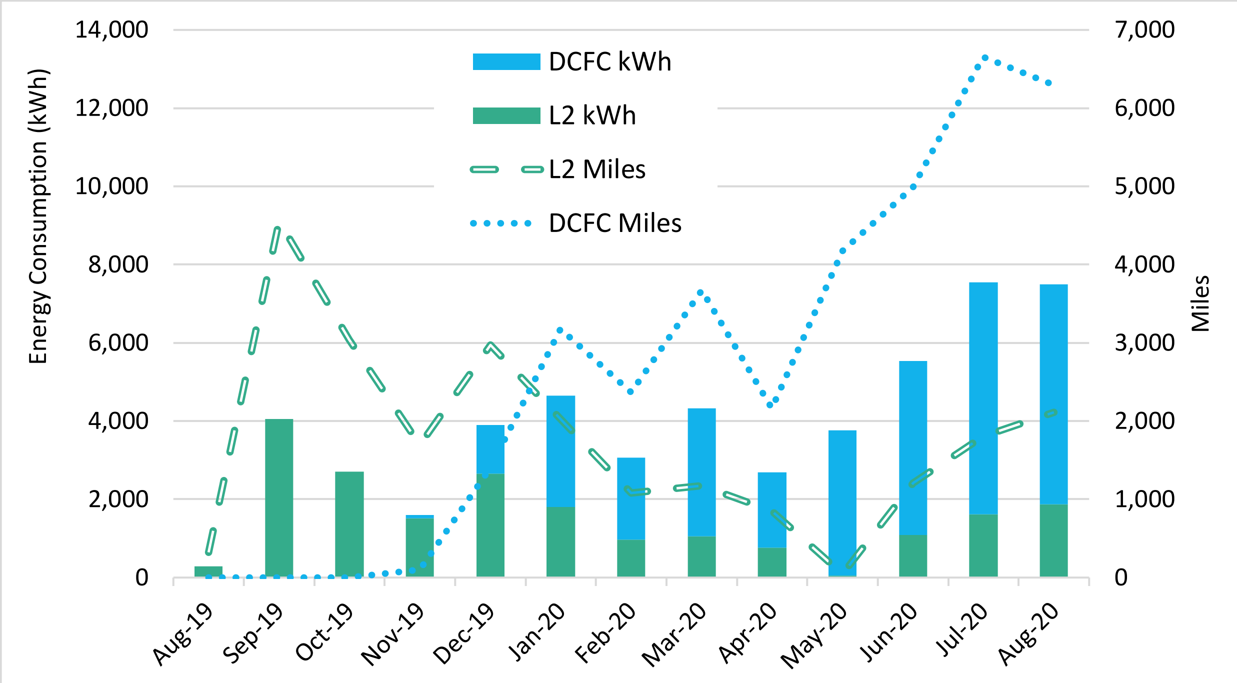
Figure 42. SDAP utility billing



Source: SDG&E Meter Data and Billing Statements

Several years ago, SDG&E submetered SDAP's main account by installing a traditional utility meter in a non-billing format to record the L2 charging in support of the Zenith electric shuttles. Data from the L2 submeter were useful in compiling the electric fleet's total monthly energy consumption shown in Figure 43 to derive fuel economy. The operator relied on L2 charging for GreenPower electric shuttles before the DCFCs were installed and before the second shuttle gained DCFC capability. There was no L2 charging in May 2020 as both GreenPower shuttles were able to use DCFCs and were the only two shuttles in service due to the reduced demand. Maxwell converted shuttle which was received at the same time as DCFCs were commissioned was not able to use DCFCs and was therefore charged by L2 chargers. L2 charging accounted for almost one-quarter of total energy consumption throughout the summer as the fleet reverted to using L2 chargers during the day as part of their load management plan to avoid potential high hourly pricing on the GIR.

Figure 43. Electricity consumption by source and resulting mileage

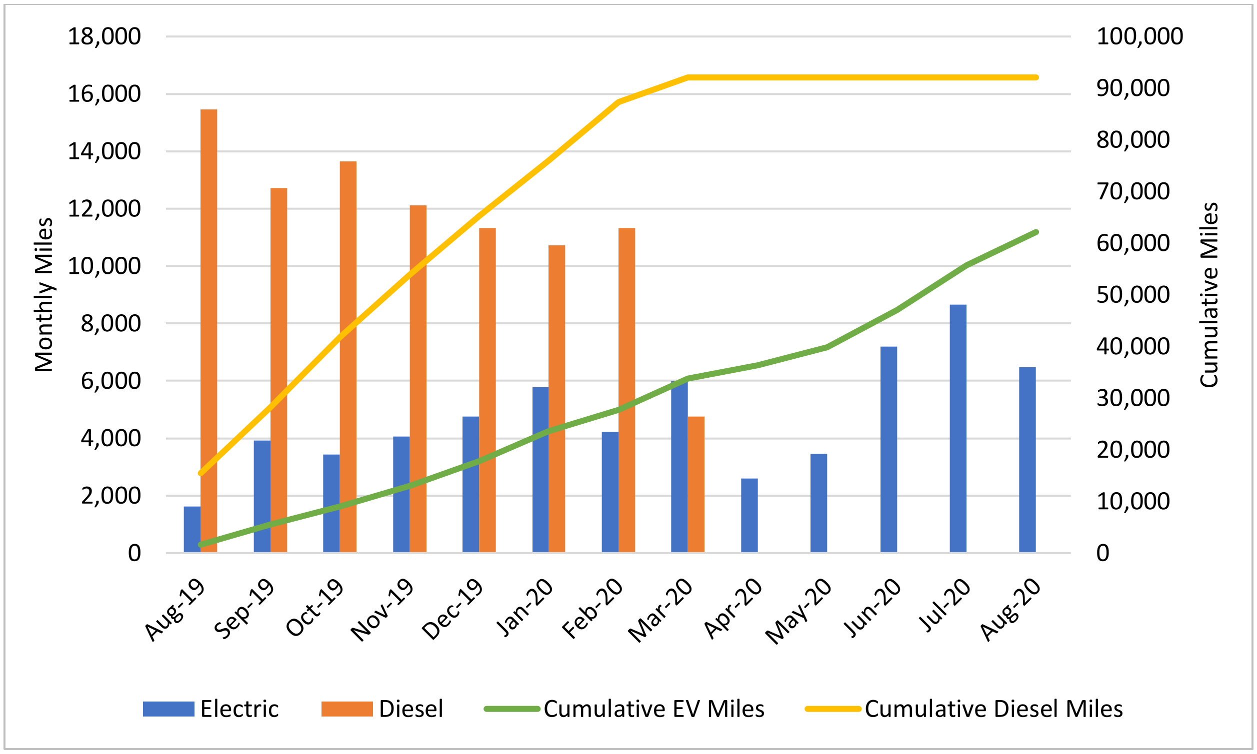


Source: SDG&E Meter Data and SDAP Driver Logs

L2 charging during the summer appears to take place when prices at the DCFC are anticipated to be high (near or over $1.00 per kWh). High prices reflect times when high load is forecasted—an approach similar to the one used to determine the Power Your Drive rate. In Power Your Drive, rates are communicated via the phone app, emails from SDG&E, and the website. The software enables customers to select a maximum price, above which charging will stop. These features were not available to the shuttle operators. The working hypothesis was that such high pricing would encourage operators to charge during off-peak hours, thereby not adding load to the grid. SDAP did try to avoid using DCFCs between 8 AM and 8 PM during the summer months as a 3rd option of their preference in the load management plan that they developed for the PRP. Their first choice was EV service provider (ChargePoint) limiting DCFC charging to only hours during which the cost is below $0.45 per kWh. Their second choice was the EV service provider locking out the chargers during the 8 AM to 8 PM hours during the summer to avoid charging during any potential high-priced hours. While this approach would eliminate any DCFC during high priced hours they would be losing out on significant amount of DCFC and would instead have to rely on slower L2 charging. An email or a text notification from the utility or charger display notification from the EV service provider when the circuit or system events were anticipated or triggered could have been another alternative. Unfortunately, due to ChargePoint's inability to offer TOU or pricing options for fleet charge management on CPE 250 DCFC platform and SDG&E's inability to provide day head pricing to the Green Shuttle customers, SDAP was limited to their 3rd option where SDAP drivers had to avoid using DCFCs during the daytime operation. SDAP did confirm that ChargePoint has notified them that they will be able to implement their preferred option (#1) in 2021. Discussion of the GIR will continue throughout this section.

The SDAP fleet transition from diesel to electric is shown in Figure 44. Total miles traveled is down from 2019 due to the pandemic, but on a per-vehicle basis, the EVs, when coupled with DCFCs, are traveling nearly the same distance as the diesel vehicles, confirming that they are capable of replacing them one-for-one. The highest recorded daily mileage by an electric shuttle with DCFC was 273 miles which significantly exceeds the average diesel shuttle daily mileage of just shy of 200 miles. As of May 2020, SDAP fleet was operating as 100% electric, as all but one diesel shuttle was sold (see Figure 36). July's almost 9,000 miles for 2 EVs exceeds per vehicle monthly total from August 2019 of almost 16,000 miles for four diesel shuttles.

Figure 44. Monthly shuttle miles by fuel type, based on driver logs from August 2019 to August 2020

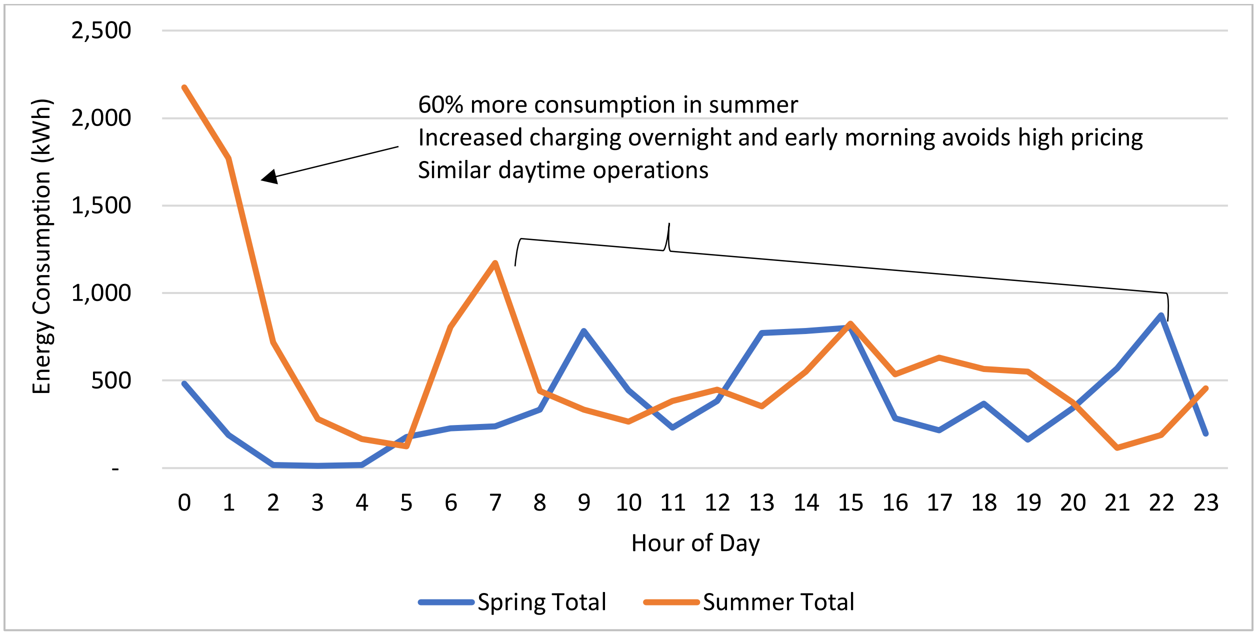


Source: SDAP Driver Logs

California and the San Diego region were unusually hot from mid-July into October 2020. Until that point, the GIR had exhibited prices no higher than $0.35 per kWh. The heat wave brought with it pricing up to $1.80 per kWh. Without available software automation, the operator developed a load management plan that relied on staff avoiding midday opportunity charging for the entire summer. (In November 2020, the EV service provider made a charging management software patch available that will likely be useful in summer 2021.) The mid-day charging ban worked to an extent but proved inconsistent, as the drivers worked in rotation and did not always follow the plan.

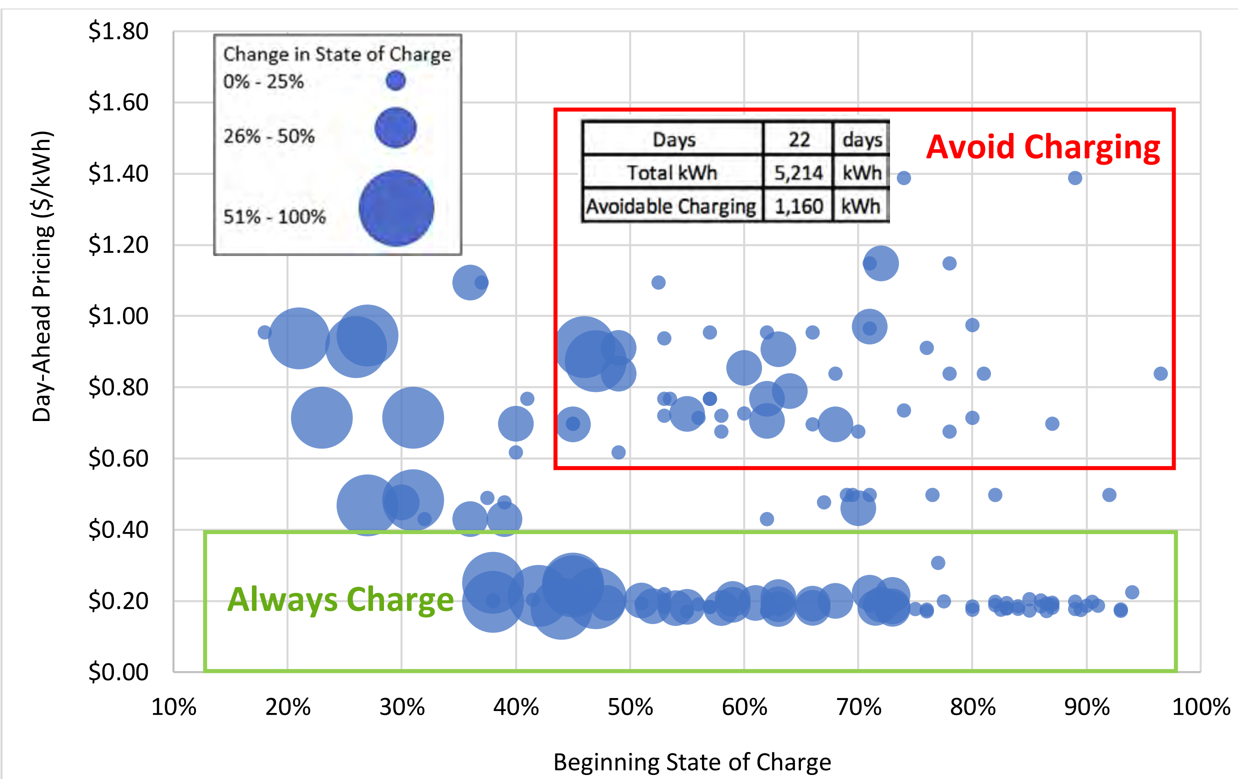
As can be seen in Figure 45, midday charging was relatively constant in the summer, with substantial charging at midnight and just before the mid-day moratorium. Total daily consumption appears consistent once both vehicles start using DCFC. Figure 46 focuses on 22 days with explicitly high pricing. On most of these days, pricing fluctuated, resulting in the highest pricing for only a few hours. Even on these days, there are many hours of lower pricing consistent with the rest of the year (e.g., midnight to 7 AM). Many charging sessions were abbreviated (<25% battery state of charge [SOC] added) and/or took place when the vehicle was already substantially charged (e.g., >50% SOC).

Figure 45. Comparison of total charging trends during spring and summer



Source: SDG&E Meter Data

Figure 46. Load management plan's potential influence on charging variables from high-priced days

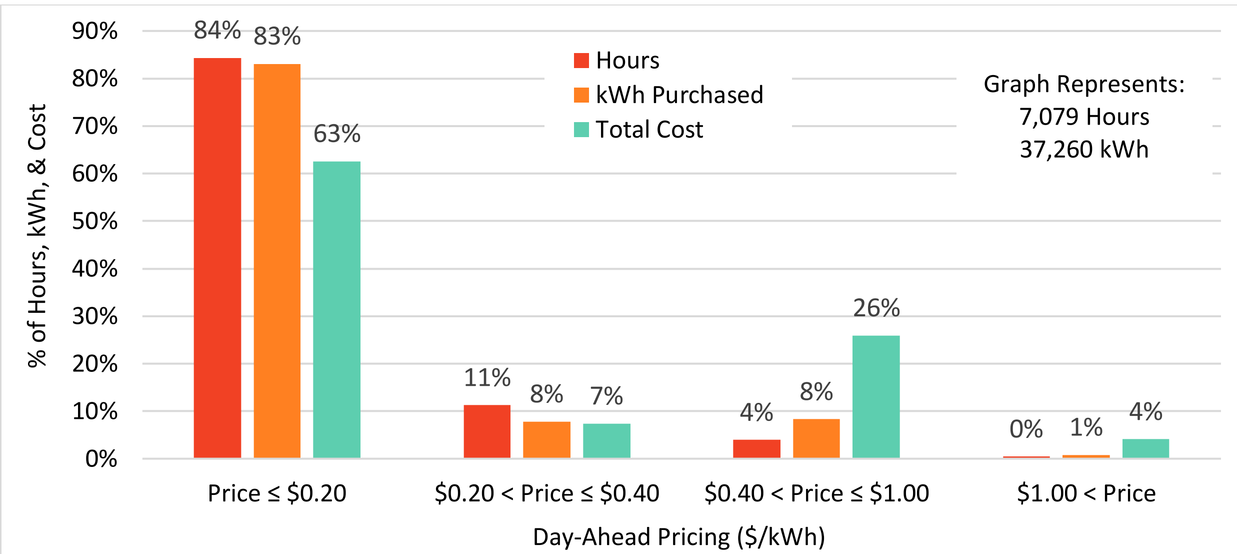


Source: SDG&E Billing Statements and EVSP Charging Session Data

Operators may use this type of assessment to develop employee training or a charging network load management plan. Figure 46 indicates that many charging sessions could have been shifted to lower-cost hours before or after the high-price hours.

Figure 47 shows that less than 10% of energy was consumed during times when prices were over $0.40 per kWh. Those hours represent only 5% of the total operating time yet account for 30% of total costs. Assuming that nearly all this high-priced energy could have been avoided with automation or otherwise (i.e., shifted to times with costs below $0.20 per kWh), nearly 20% of the overall costs could have been saved. The current charging requirement appears flexible enough to avoid high-priced hours, for the most part.

Figure 47. Percentage of hours, energy, and cost from November 27, 2019, to September 17, 2020



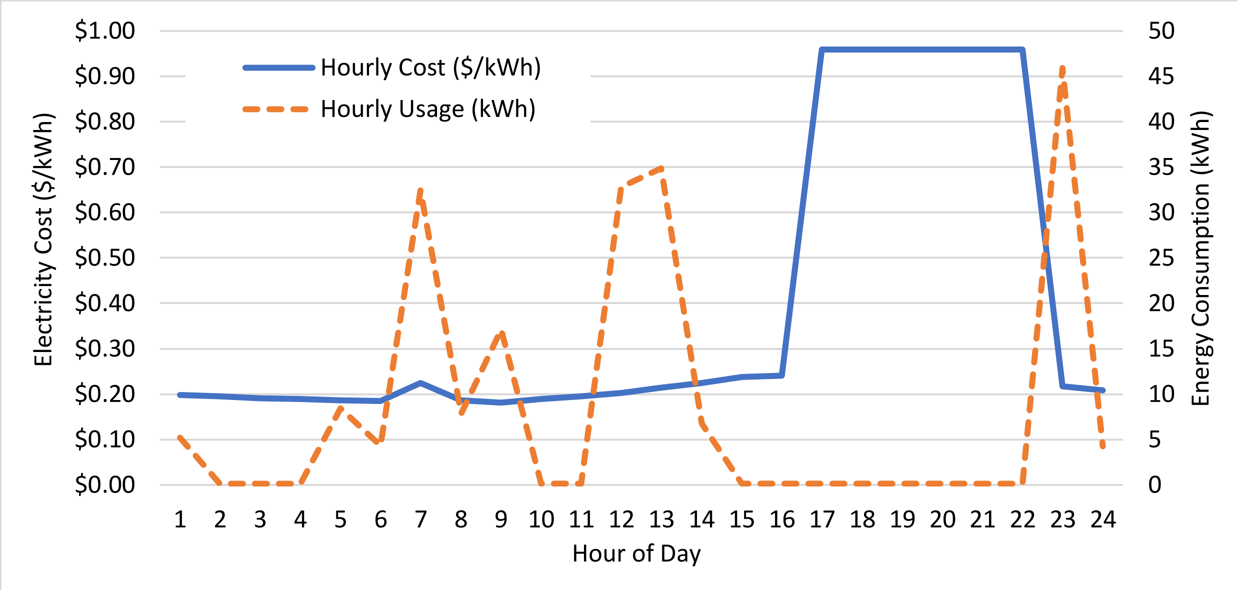
Source: SDG&E Meter Data and Billing Statements

Figure 47 summarizes the results and opportunity for managed charging throughout the lifetime of the project with the following:

- $6,000 spent on 34,000 kWh under $0.40/kWh, for an average of $0.17/kWh
- $2,550 spent on 3,726 kWh over $0.40/kWh, for an average of $0.68/kWh
- $1,900 in excess spending for charging that took place during hours with high pricing

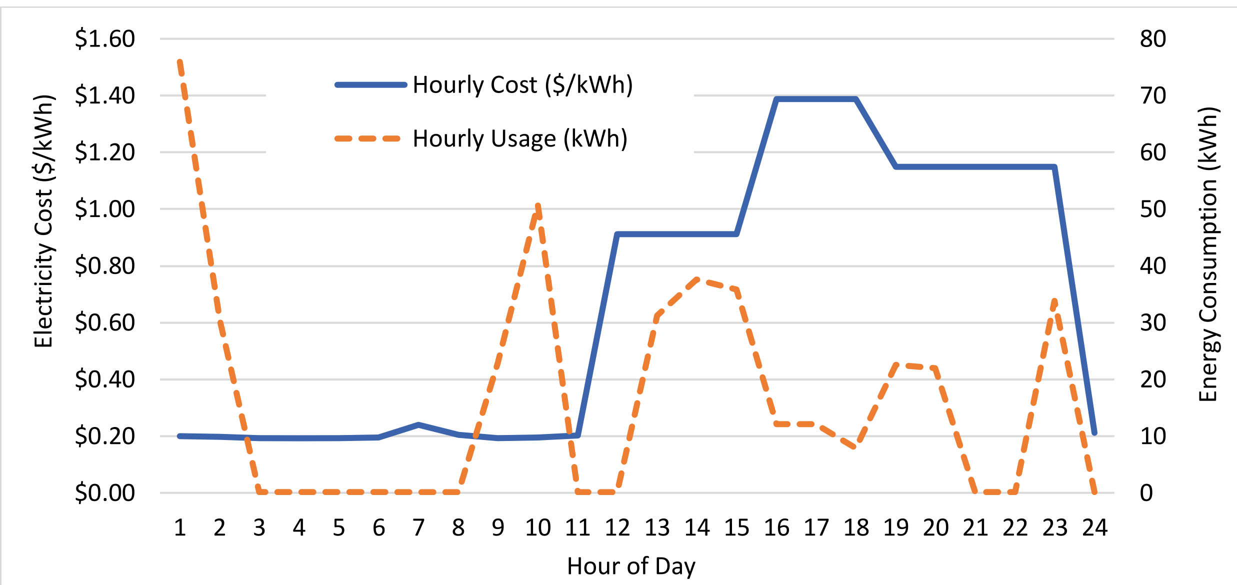
August 15, 2020 was a typical day, with several charging sessions that successfully avoided five hours of high pricing (>$0.90 per kWh) (see Figure 48) indicating optimal charging behavior. On the contrary, August 17, the operator consumed substantial energy at high cost (see Figure 49) indicating charging behavior that should be avoided with charge management. While SDAP did attempt to avoid such charging behavior, relying on drivers to follow specific guidance in addition to focusing on passenger loading and unloading proved unreliable. Even on August 17, the top three hours of high pricing—and possibly more—could have been avoided. On that day, the average battery state-of-charge at the start of a charging session was approximately 70%, suggesting that the highest-cost charging sessions were likely avoidable, at least to some extent. Observed fuel economy and battery capacity indicate that a full charge is expected to last an entire shift.

Figure 48. Example of good charging behavior



Source: SDG&E Meter Data and Billing Statements

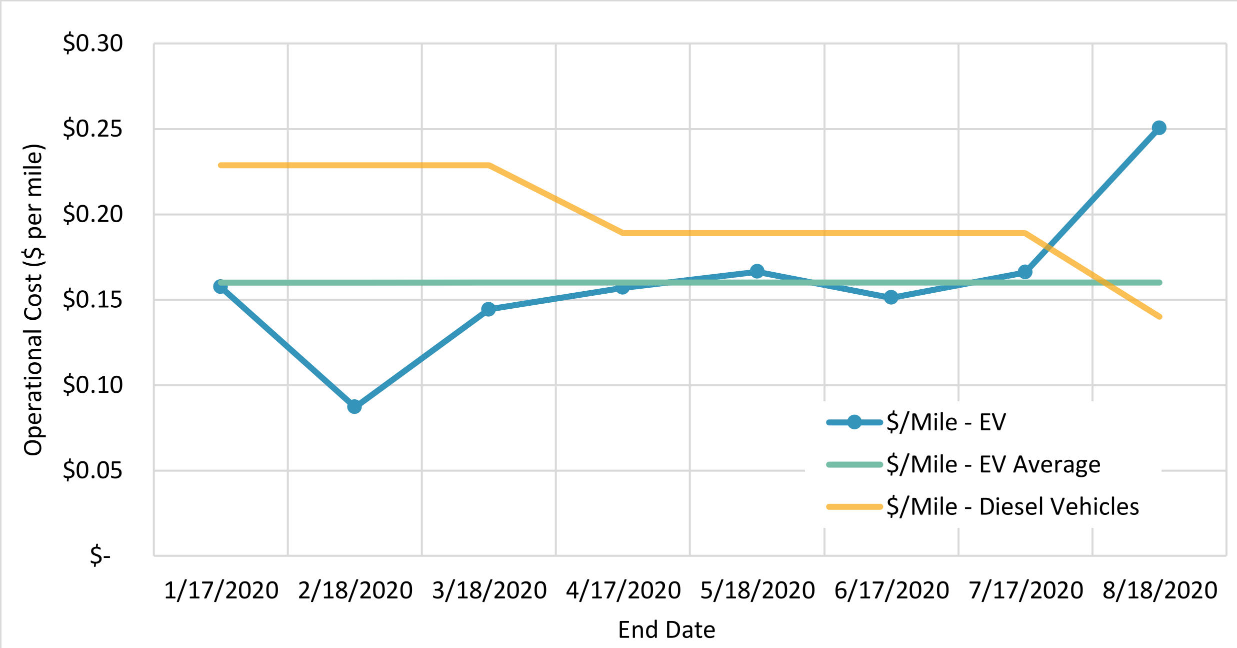
Figure 49. Example of poor charging behavior



Source: SDG&E Meter Data and Billing Statements

Figure 50 compares baseline diesel and EV costs per mile, based on data from driver logs, DCFC utility itemized billing statements, L2 submeter data, and statewide diesel fuel costs for identical dates. The chart shows that SDAP did experience lower cost per mile for EVs during the entire duration except for August 2020 when manual charging management approach failed on several days with high pricing hours, resulting in significantly higher average costs per kWh for the month. The benefits of lower cost per mile for electric vehicles are presented in Figure 50 and Table 15 as annual operational cost savings compared to diesel shuttle baseline.

Figure 50. Monthly costs per mile for EVs versus diesel vehicles



Source: SDG&E Meter Data, Billing Statements, and SDAP Driver Logs

Stakeholder and Customer Feedback

SDAP noted that faster charging allows for vehicles to remain charged and in service for a whole day. On the busiest days, the two electric shuttles charge for six hours apiece; on typical days, they charge for four hours. With DC fast charging the operator confirmed that electric shuttles can meet all of the requirements of their previously used diesel vehicles with fewer maintenance requirements (i.e., brakes, diesel emission control system, powertrain fluids). Additionally, there are driver time savings as they do not have to visit the retail fueling station daily anymore as electric shuttles are charged on site.

While SDAP was very appreciative of the utility support received through participation in the PRP, they expressed disappointment of not being able to pilot integration of PV and batteries as part of their charging solution which was initially proposed under the PRP. While they understand the limited savings potential as modeled by the utility, they believe adding this aspect to the PRP would have evaluated the technical feasibility of this solution that a number of fleets are interested in from operational cost management perspective (to completely avoid charging from the grid during any GIR high-priced hours) as well as resiliency during potential power outages.

While SDAP was eventually able to use DCFCs with their GreenPower electric shuttles, the initial DCFCs installed were unable to charge their EVs due to a lower voltage rating than what vehicles required (oversight due to technical specification details from EV OEM, EV service provider, the fleet and the utility). SDAP mentioned that a broader selection of EV service providers would be beneficial as ChargePoint was their only option that could charge GreenPower vehicles. SDAP mentioned that ChargePoint, unlike Greenlots option, comes with annual networking and service agreement requirements amounting to $3,000 per DCFC which the fleets will be responsible for paying after the first 5 years which are covered by the PRP funding.

SDAP noted a sensitivity to the GIR beyond the pricing itself. During the evaluation, they were unable to receive day ahead pricing information from either the utility or EV service provider to support implementation of their preferred charge management strategies identified in the load management plan that they have developed. Since SDG&E is not publishing day ahead or actual pricing, the fleets can only use similar Power Your Drive day ahead pricing as a proxy by visiting SDG&E website daily. In November 2020, the ChargePoint offered SDAP an option similar to the one available under the Power Your Drive program: charging can be automatically limited based on time of day and published energy price. SDAP requested to avoid charging at prices over $0.45 per kWh which will be implemented in 2021.

In response to high pricing hours within the GIR, the operator has attempted to conduct manual load management. The plan consists of training drivers to avoid charging from 8 AM to 8 PM and relies on employees following various responsibilities. The drivers need to be familiar enough with the EVs to know they can comfortably complete their shifts without running out of charge. Though simple, the strategy was not foolproof, as manual intervention in charging is difficult to achieve consistently. The training began in June and continued through October 2020. Results indicate that approximately 25% of costs could have been avoided with implementation of automated load management software.

3.2.4 Conclusions and Recommendations

Findings

SDG&E spent $1,438,231 of the approved $3,157,805 to install charging infrastructure at three sites: two airport parking sites each had two DCFCs installed and one workplace site had six L2 EVSE installed. Only one of the airport parking sites had active operations with an electric shuttle bus by the end of 2020, but that site provided nine months of data to analyze and tested the Public GIR. None of the three PRP sites were open to external EV drivers such as taxis, vanpools, or TNCs. Solar and energy storage were also not installed at any project location. The one site where these elements had been originally considered was not able to participate in the program because of construction challenges unrelated to this PRP; a backup site was also considered but due to unfavorable economic benefits (as modeled by the utility), the utility decided not to install solar and energy storage. Key findings from this pilot are listed below.

- High-use shuttle bus operations have distinct use cases that dictate specific charging infrastructure, and it did not make sense to install both L2 chargers and DCFCs at each location. Airport parking fleet operators required 2 DCFCs to support operation of 2 to 4 electric shuttles with daytime opportunity charging. The workplace charging site only needed L2 chargers, one for each electric shuttle, for overnight charging.
- Most shuttle bus companies have private facilities that are not equipped to allow other EVs to charge at company sites. The decision approved consideration of the PRP sites for use by external users. One site did express potential interest, but the utility decided not to pursue it due to the rate and billing limitations.
- Electric shuttle bus options, especially in Classes 2–4, are very limited, and there can be long lead times for procurement. All three participating fleets encountered challenges finding

suitable vehicles and getting EV manufacturer commitments for meeting PRP timeline for vehicle delivery. Only one fleet received EVs and used them in service before the end of 2020.

- Shuttle bus operators have established replacement and procurement cycles. The offer of charging infrastructure was not enough of an incentive for companies to commit quickly to purchasing electric shuttle buses, if they did not already have plans to do so.
- There are several reasons for lower PRP costs than approved budget. From budgeted $750k in construction costs and $850k in EVSE and electrical equipment only half and a third of those amounts were expended, respectively. Charging infrastructure was installed for fewer than expected shuttle bus sites (3 out of 5). An additional site, similar to the three PRP participants, would cost up to $250k). IT costs were less than a half than what was budgeted (approximately $600k lower) due to only one fleet receiving vehicles for participation in the PRP.
- The EVs, when coupled with DCFCs, traveled nearly the same distance as the diesel vehicles, confirming that they are capable of replacing them one-for-one. The highest recorded daily mileage by an electric shuttle with DCFC was 273 miles which significantly exceeds the average diesel shuttle daily mileage of 200 miles. The EVs also demonstrated that based on the highest usage month they are capable of matching the diesel annual mileage (50,000+).
- The benefits in Table 15 for this PRP were significantly lower than expected primarily due to only 2 EVs out of 12 expected being used. Additionally, the 2 EVs were compared to baseline vehicles that used renewable diesel fuel with very low carbon intensity.
- Limitations to charging speed may be found in any one component, such as a charging cord, on-board charger for L2, or vehicle power inlet cabling, especially in early-production vehicles.
- Direct access to the charging session data via EV service provider’s online portal provided evaluation team ability to continually follow the fleet operation and follow up with the utility and the fleet on any operational interruptions or anomalies. Charging session data from DCFCs included starting and ending state of charge information which provided additional insights in support of managed charging.
    - Recommendation: Direct access to EV service provider’s online portal should be provided to the third-party evaluator where possible. This would allow real time and unlimited access to the charging session data for performance monitoring. Potential data handling issues associated with multiple party involvement are avoided. Utility staff are not taxed with ongoing data requests.
- Third-party onboard vehicle data loggers would be ideal for independently monitoring vehicle performance, but they were cost-prohibitive, according to the utility. The PRP has instead relied on the fleets to provide vehicle performance data through use of OEM telematics or manual log entries which did not prove to be very reliable. While Lighting Systems telematics hold promise, their EVs were not deployed during the evaluation; telematics on GreenPower shuttles were unable to provide any operational data for evaluation (although SDAP did pursue this option).
    - Recommendation: CARB requires EV manufacturers to provide EV telematics for HVIP grant reporting. Utilities could include a similar requirement for fleet participants, thereby facilitating less cumbersome data collection and more accurate data for reporting and evaluation.

- While SDG&E does not yet offer a commercial EV charging rate (a proposed decision on high-powered EV rate is pending as of end of 2020 and interim TOU rate with minimal demand charges is available to fleets) GIR rate resulted in the lowest electricity cost per kWh ($0.20/kWh) among the five SDG&E charging infrastructure PRPs.
- A load management plan was developed by a participating fleet, but only a rudimentary option was able to be implemented. The resulting manual process can be effective for periods of time; however, September average electricity costs doubling from $0.20 to $0.40 per kWh indicates a significant opportunity for automated charge management approach. From a fleet perspective this resulted in the only month where the operational cost per mile exceeded that of the diesel baseline, significantly impacting the business case for electrification of this application.
    - Recommendation: while not demonstrated in this PRP during the evaluation period, automated charging management software solutions should be strongly encouraged (based on time of use or energy cost signal) to reduce electricity costs per kWh for the fleet customers to improve the fleet electrification economics and minimizing grid impacts by shifting charging to more-grid friendly times.
- The annual DCFC networking and maintenance fees result in additional cost for the operators. While the PRP covered these costs for the 5-year duration of the pilot, these costs will be borne by the fleet operators afterwards and therefore will negatively impact cost per mile.
    - Recommendation: for smaller size fleets with less daily miles traveled per shuttle bus, non-networked chargers could reduce operating costs. To avoid on-peak charging, fleets would likely need to implement some kind of charge management technology (lower cost off-the-shelf technologies should be explored if/when available).
- All three participating fleets have converted or are in process of converting to 100 percent electric as a result of the experience with this PRP. SDAP will operate 4 electric shuttles in 2021 supported by the two DCFCs installed under this PRP; once their campus opens after the pandemic, Illumina will have all 6 electric shuttles in operation supported by 6 L2 chargers installed under this PRP; and Aladdin will receive 4 additional DCFCs and 4 more electric shuttles (total of 6 DCFCs and 8 shuttles) under SDG&E's Power Your Drive for Fleets program in 2021.

Lessons Learned

The following lessons learned were captured during the implementation of this PRP.

- Medium-duty EVs in smaller market segments, such as shuttle buses, are often supplied by several smaller manufacturers that are attempting to fill a market need. (More established manufacturers target larger market segments.) The specifications of these EVs may be unique to each manufacturer and components might be sourced from light- or heavy-duty electrification suppliers; therefore, it is critical to verify compatibility with the planned EVSE, especially as vehicles move to batteries above 500 V. Fleets are not always aware of inter-operational aspects of batteries and chargers; utilities' confirming compatibility can avoid mismatched purchasing. Personnel with backgrounds in fleet management and EV technology will have increasing value to utilities as part of their technical advisory services to ensure customer satisfaction with future TE programs.

- The integration of a PV and battery system with EV charging could be a valuable solution to managing electrical demand. While PV is a mature technology that has been widely deployed, integration with battery system and EV operations is new. The significant costs and technological challenges associated with implementation were likely key reasons for the limited response SDG&E received to its request for bids. Given the current costs and risks, SDG&E decided instead to model this solution. Should this approach prove valuable with a positive return on investment within the ten-year charger life, a future deployment (outside of the PRP) may be warranted.
- PV and energy storage technologies are well developed, and their application to supporting grid services has been proven. However, integration with EV charging is entirely new, and no off-the-shelf system exists (except for limited applications of an off-grid PV, battery, and L2 charger system). On their own, these components need to be optimized to provide a positive return on investment, and the complexity of combining these into one solution adds costs and challenges to the optimization strategy for maximizing benefits.
- The ChargePoint CPE 250 DCFC EVSE comes with a 12-foot cord, but SDAP discovered that length is tip to tip; the usable length is significantly less due to the cable positioning around the vehicle and the angle to plug the cord into the vehicle's charging receptacle (see Figure 35, with the EV parked very close to the bollards). For fleet applications, especially if chargers are selected before exact vehicle specifications might be available (i.e., location of the charging port) longer charging cords should be specified (at least 18 if not 20+ feet long).

Scale-up Potential

Within the state of California, there are many shuttle buses in use but fewer applications like those in this PRP with a vehicle of similar size. Recent CARB estimates are that there are 686 buses of similar size across the 13 California airports.[18,19] Scaling the existing vehicles at 50,000 miles per year using January operational data from this PRP as a baseline provides the results shown in Table 16.

Table 16. Scale-up potential annual emissions

	Fuel (GGE)	GHG (MT/yr)	SO_X (MT/yr)	NO_X (MT/yr)	CO (MT/yr)	PM (MT/yr)	VOC (MT/yr)
Net Reduction	2M	670	19	68	17	4	5

Source: Evaluator Calculations

[18] California Air Resources Board, "Proposed Zero-Emission Airport Shuttle Regulation," February 21, 2019, https://ww3.arb.ca.gov/board/books/2019/022119/19-2-6pres.pdf.

[19] California Air Resources Board, "Public Hearing to Consider the Proposed Zero-Emission Airport Shuttle Regulation, Staff Report; Initial Statement of Reasons," December 31, 2018. https://ww3.arb.ca.gov/regact/2019/asb/isor.pdf.

3.3 Airport Ground Support

3.3.1 Project Narrative

Overview, Objectives, and Barriers Being Addressed

California Public Utilities Commission (CPUC) Decision D18-01-024 approved $2,839,738 for San Diego Gas & Electric (SDG&E) to encourage, support, and accelerate electrification of ground support equipment (GSE) at San Diego International Airport (SDIA), also known as Lindbergh Field. SDG&E proposed to retrofit 16 existing GSE-specific 36-48 volt charging ports (Phase 1), then consider increasing the number of electric GSE charging ports at SDIA by up to 45 (Phase 2). This PRP is helping to incorporate additional electric charging load from electric GSE in a manner that mitigates impacts to the grid. This project was conceived with coordinating charging with SDIA's 5.5 MW photovoltaic (PV) system to the fullest extent possible, such as time periods to charge or not. A major component of this project is SDG&E's data collection and analysis to better understand GSE charging load patterns and support electric GSE, as well as the related impacts of conversion from internal combustion engine GSE to electric GSE.

As of 2018,[20] one quarter of GSE at SDIA (174 of 687) were electric. This PRP includes approximately 20% of the entire 2018 electric fleet. From 2006 to 2014, SDIA has seen an increase in the electric GSE fleet that could have been much larger. The technical maturity and operational capabilities of electric GSE on the market allow for higher penetration than had been implemented at SDIA. The most recent electric GSE charging port was installed at SDIA in 2013. SDG&E's project removes the barriers of construction and electric GSE charger procurement from multiple airport tenants that operate at SDIA.

Electric GSE tracked within this project include baggage tractors and cargo belt loaders but could still support pushback tractors, forklifts, and other equipment, given market availability (see Figure 51 for example GSE) so long as vehicle battery packs are below 96 V.

[20] San Diego International Airport Clean Transportation Plan, pg. 44 (of 72), https://www.san.org/Portals/0/Documents/Environmental/2020-Plans/2020_Carbon-Transportation-Plan-min.pdf.

Figure 51. A variety of available electric GSE charging at a California airport

Source: Evaluator Team

SDG&E installed two load research meters and selected networked chargers to closely track consumption patterns and allow for future managed charging and grid integration. Upon collection of data, SDG&E and other partners better understand the increased load resulting from the adoption of electric GSE, the time of day of the additional charging load, and potentially the appropriate ratio of charging ports to vehicles. With this analysis and knowledge, SDG&E can better collaborate with SDIA and airport tenants to operate and charge electric GSE at times that are beneficial rather than detrimental to local distribution circuits and the electric grid in general.

Sites and Participants

Recruitment Process

SDG&E worked closely with SDIA during the application process. The strategy around the GSE electrification project was based on a collaborative effort with SDIA. As part of Phase 1, SDG&E was authorized to retrofit existing ports. After conducting outreach to SDIA tenants, including locally owned and minority-owned businesses, SDG&E selected American Airlines as the candidate for those retrofits because the airline's existing charging equipment was outdated and less efficient and provides no data to help guide users as to when they need to charge.

In November 2018, SDG&E spoke at the monthly airlines meeting at SDIA. SDG&E reviewed the project's goals, presented Phase 2 electric vehicle supply equipment (EVSE) installation potential, and asked the airlines to respond to a survey. The survey was designed to gather information about the airlines' different needs, barriers, and goals related to electrifying their GSE fleets in the future. Survey results showed that infrastructure, procurement cycles, and available electric GSE were the main barriers. SDG&E and SDIA plan to work with SDIA's tenants to pursue funding sources for new electric GSE, as described in SDG&E's application and supporting testimony. These efforts contribute to the Phase 1 goal, which is to understand whether there is a need for further charging infrastructure at SDIA.

Participants

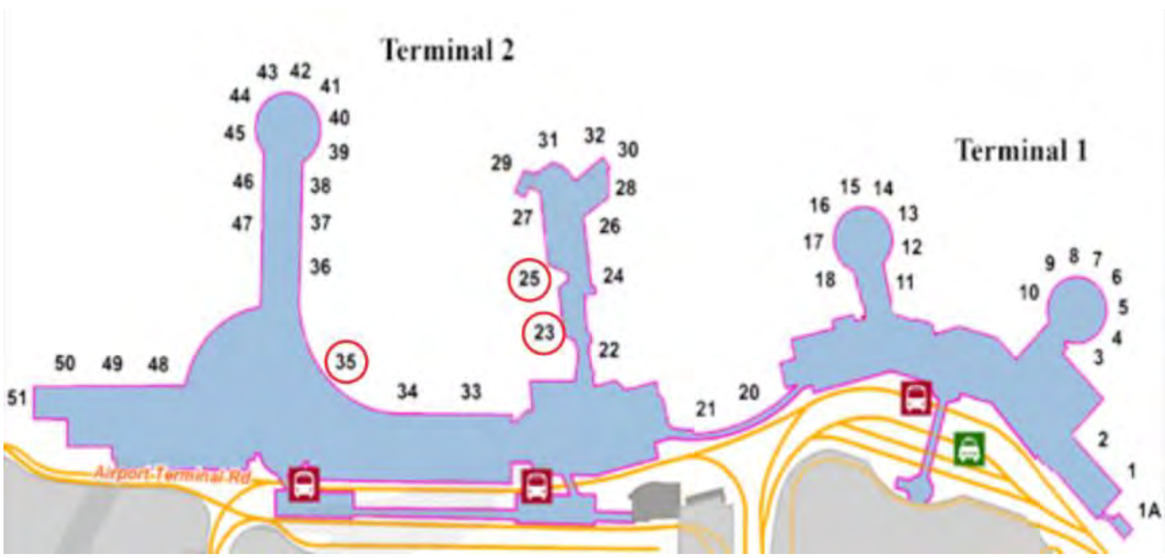
In Phase 1 of this PRP, the objectives were to install, own, operate, and maintain 16 charging ports and the necessary equipment for **American Airlines** to efficiently integrate with the grid at the **SDIA**. Charger locations are listed in Table 17 and shown on the SDIA map in Figure 52.

Table 17. Banks of chargers at SDIA for SDG&E Airport GSE PRP

Terminal 2 Location	Configuration	Ports
Gate 23	3 dual-port chargers	6
Gate 25	3 dual-port chargers	6
Gate 35	2 dual-port chargers	4

Source: SDG&E

Figure 52. SDIA gate map



Source: SDIA

Figure 53 shows one of the charger sites with three dual-ports. These existing charger retrofits allow for the introduction of new features such as data collection, ability to charge vehicles of various voltage and amp-hour configurations, and faster charging. Load research meters were installed for each bank of chargers. Although there was some uncertainty regarding the reliability of the devices and their ability to communicate effectively from the restricted airside of the facility, they did, in the end, appear reliable. The EVSE provider (**Webasto**) was also able to provide charging session data reliably once integrated to their network.

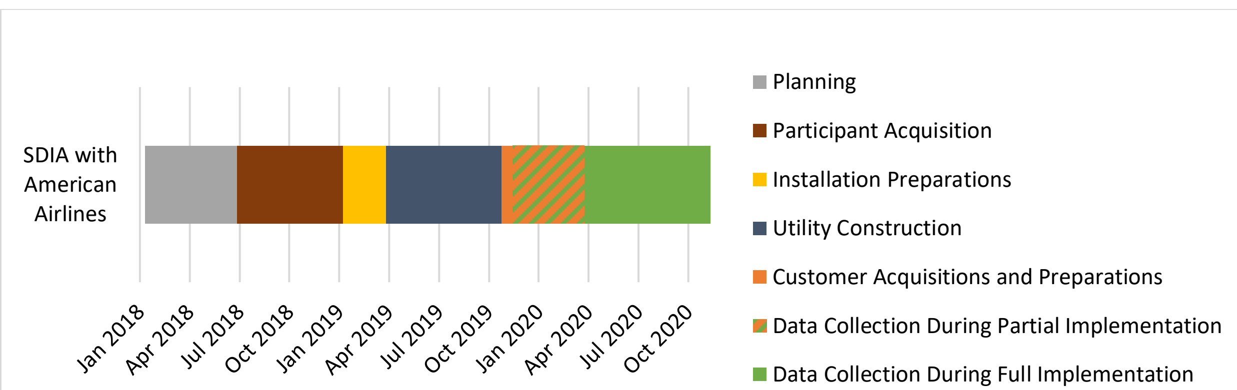
Figure 53. Three installed chargers

Source: SDG&E PAC presentation 10.16.20

Timeline and Status

Figure 54 shows the PRP timeline. It took several months to work through contractual concerns over ownership (SDG&E owns the electric vehicle [EV] chargers) and liability. Unfortunately, that process delayed the potential start of construction until June. As June began a busy time of the year for SDIA and American Airlines, construction did not actually begin until September 2019, and the charging stations were energized and commissioned in November 2019. One charger was damaged soon after commissioning, and its repair took several months, so there was a significant delay before full operations could be analyzed.

Figure 54. SDG&E Airport GSE PRP timeline as of October 2020



Source: SDG&E

3.3.2 Evaluation Methodology

Selected Methods and Rationale

In addition to the evaluation questions that apply to all PRPs and those specific to the Fleet Electrification PRPs, the evaluation questions listed below were examined for this PRP.

- Were opportunities to better manage charging for least-utility cost or more reliable operations identified, how were they implemented, and were they effective?
- To what extent integration of charging with the SDIA solar array and any battery storage was possible, and what impact would that have on the electrical grid?
- What is the appropriate ratio of charging ports to electric GSE?

The data collection sources utilized to evaluate this PRP include 1) PRP information from the approved decision, project updates, and other available documentation, 2) market research on ground support equipment and early deployment efforts from other similar electrification projects across the country, 3) PRP charging session data specific to vehicle and charger operations and utility meter data, and 4) in-depth interviews (IDIs) with project partners.

Data Sources

The Webasto charging stations collect session data tied to vehicles (but derive 15-minute interval energy data from sessions) to track utilization using cloud-based access. SDG&E installed two check meters (conventional utility meters but not used for billing purpose) to collect energy usage for the installed chargers. Electricity costs were simulated based on electricity data since these charging stations are not on a separate SDG&E service. SDIA has a single SDG&E meter, and the chargers and the supporting infrastructure are installed behind that meter. At the time of this report, the fleet was unavailable for an interview. Therefore, no high-level data on electric GSE utilization and maintenance were provided.

The evaluator collected PRP information through numerous PRP participant interactions: the PRP kick-off meeting (SDG&E and evaluator), quarterly Program Advisory Council update meetings, weekly PRP updates (SDG&E and evaluator), and other periodic calls or emails. Through these, the evaluation team received details about the charging station hardware characteristics, electricity tariff information, project costs, and list of equipment using the charging stations. Construction site plans and designs and historical use of similar conventional equipment were not available.

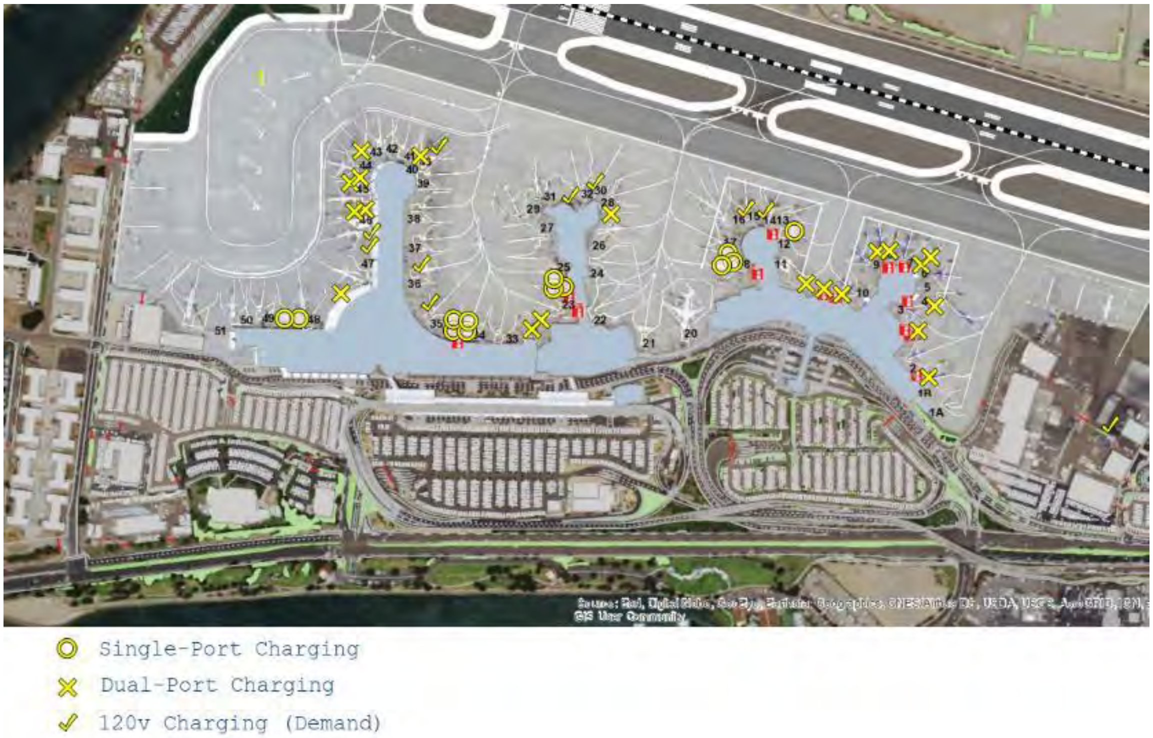
The evaluator held in-depth-interviews (IDI) with representatives from the SDG&E PRP management team and construction staff to further understand the background of this project and gather lessons learned based on progress to date. Additional IDIs with SDG&E staff, SDIA staff, and vendors took place in 2020 as charger use began.

3.3.3 Evaluation Findings

Project Baseline

The electrification of GSE is an especially attractive option for airports across the globe. Electrified GSE offers fuel security to airports that are already vulnerable to the price volatility of petroleum, as well as lower maintenance costs and better performance. SDIA's electric charges before the PRP are shown in Figure 55.

Figure 55. SDIA airside GSE charging – preexisting infrastructure inventory (November 8, 2016)



Source: SDIA

The number of airports electrifying GSE has been increasing over the last decade. SDIA hosts 840 GSE of which 27% are electric. Many of the pre-PRP chargers are an older version of what this project used (supporting a single fleet). Other chargers are similar to what this project replaced; fixed-voltage (e.g., 36 volts), non-communicating or programmable, lead-acid chemistry only, and lower powered. In 2016, 22 major airports had major electrified GSE projects in place.[21] More recently, John F. Kennedy International Airport and Jet Blue installed 118 charging ports for the baggage tugs and belt loaders that have been electrified.[22] The availability of GSE is also improving: as of 2017, there were eight manufacturers providing various electrified GSE for airport applications. According to the Global Airport Ground Support Vehicles Market Forecast, the GSE market is anticipated to grow over 7% between 2019 and 2024. This report states that electrified GSE will play a key role during this growth period, particularly for baggage tugs and tractors.[23]

[21] National Renewable Energy Laboratory, "Electric Ground Service Equipment at Airports," NREL/FS-5400-70359, Golden, CO, 2017.

[22] Business Wire, "Jet Blue Introduces Largest Electric Ground Service Equipment," Berkshire Hathaway, September 26, 2019. https://www.businesswire.com/news/home/20190926005676/en/JetBlue-Introduces-Largest-Electric-Ground-Service-Equipment.

[23] Business Wire, "Global Airport Ground Support Vehicles Market, Forecast to 2024," Berkshire Hathaway, December 2, 2019, http://www.digitaljournal.com/pr/4523881#ixzz68g8F6FSQ.

Implementation Process

SDG&E has encountered challenges in the PRP due to restrictions on how much access and control SDG&E has on the airside of the terminal. This was anticipated, but issues continue to arise. This factor may restrict SDIA participation in the SDG&E Medium- and Heavy-Duty SRP. The goal for Phase 1 is to utilize the collected charging session data and develop a business cases for GSE electrification on behalf of at least the operator, airport and utility. A positive business case result would be the best justification to promote electrification to other tenants at this airport and elsewhere. By the time this report was written, SDG&E had notified the California Public Utilities Commission (CPUC) that the project would not conduct Phase 2; installation of 45 new charger installations meant to directly enable at least 90 new electric GSE.

After the new Phase 1 chargers were installed, the airport did not immediately remove the outlets that were previously used for charging. This ended up being very helpful when one of the charging stations was damaged by GSE. Other SDG&E installed chargers remained operational while one underwent repairs.

SDG&E initially experienced challenges acquiring data from these chargers prior to a successful network connection. Collecting data required a site visit to manually download it which proved difficult due to restricted access on the terminal. SDG&E now realizes that, for projects that require data collection, some sort of enforcement is needed to ensure data flows. It is also important to select technology with an established remote data access (ideally through a variety of communication means in case circumstances, such as limited cellular reception, render one approach infeasible).

SDIA inspectors were always available during construction and were helpful in addressing questions regarding special construction manuals and standards that needed to be met (a requirement that was not discussed during the planning and design review). The delays were encountered due to decision making cycles within SDIA management around designs and construction; every issue needed to be documented in detail, and confirmation that it had been addressed was required.

Costs

The approved PRP had an anticipated total direct cost of $2,839,738, consisting of $2,405,598 in capital and $434,140 in expense, as shown in Table 18.

Table 18. SDG&E Airport GSE PRP proposed costs

	Capital Costs	O&M Expenses	Total PRP Costs
Transformer and Install	N/A	N/A	N/A
Electrical Service	$ 912,333	N/A	$ 912,333
EVSE Costs	$ 1,493,265	$ 22,140	$ 1,515,405
Purchased and SD Software	N/A	N/A	N/A
Measurement and Evaluation	N/A	$ 200,000	$ 200,000

	Capital Costs	O&M Expenses	Total PRP Costs
Billing Support	N/A	$ 80,000	$ 80,000
SDG&E Clean Transportation Project Management	N/A	$ 100,000	$ 100,000
First-Year O&M Service Calls	N/A	$ 22,000	$ 22,000
First-Year O&M for Charging Equipment	N/A	$ 10,000	$ 10,000
Total Costs	$ 2,405,598	$ 434,140	$ 2,839,738

Source: SDG&E

The estimated total PRP direct costs are $835,859 out of the budgeted $2,839,738, as shown in Table 19 (presented in categories reported by the utility). No additional costs are anticipated. The utility submitted a Tier 2 advice letter in mid-2020 to CPUC turning down Phase 2, and the installation of 45 additional chargers would have made up the bulk of anticipated costs.

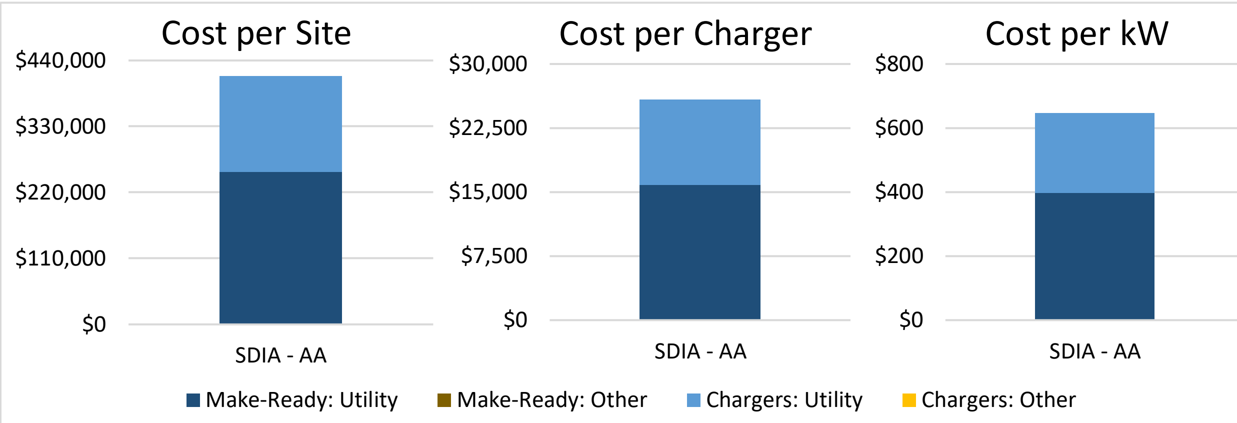
Table 19. SDG&E Airport GSE PRP estimate at completion (EAC)

	EAC Capital Costs	Budgeted Capital Costs	EAC O&M Costs	Budgeted O&M Costs
Construction	$ 167,214	$ 1,101,258	N/A	N/A
Engineering Design	$ 58,186	$ 89,100	N/A	N/A
Chargers, Meter Pedestals, Transformer, and Other Materials	$ 246,884	$ 1,215,240	N/A	N/A
Internal SDG&E Labor (Program Management and Support)	$ 15,289	N/A	$ 111,967	$ 380,000
IT Costs	$ 123,548	N/A	N/A	N/A
Other	$ 112,772	N/A	$ 12	$ 54,140
Direct Costs	$ 723,880	$ 2,405,598	$ 111,979	$ 434,140
Non-Direct Costs (Indirect, AFUDC, and Property Taxes)	$ 109,995	$ 1,145,923	$ 112,843	$ 191,676
Total Costs	$ 833,875	$ 3,551,520	$ 224,822	$ 625,816

Source: SDG&E

The charging infrastructure costs (construction and materials only, not including engineering design) are shown in Figure 56, separated by make-ready and charger costs which were paid for either by the utility through this PRP or a source of funding "other" than the utility, which may be the host site, grants, etc. The utility, under the PRP budget, covered all charging infrastructure costs, including charger costs. The utility owns and is responsible for maintenance of all the chargers installed as part of this PRP.

Figure 56. SDG&E Airport GSE charging infrastructure costs



Source: SDG&E

Benefits

The planned/anticipated benefits in Table 20 reflect the PRP's (never conducted) Phase 2 benefits resulting from the electrification of 90 airport GSE (17 belt loaders, 47 baggage tractors, 9 forklifts, and 17 push back tugs) enabled by the installation of 45 new charging stations. The 16 retrofitted charging ports in Phase 1 are only upgrades to existing chargers that support current electric GSE, so no net emissions benefits would be realized unless new charger access or data enable increased utilization (there was no evidence of this in the limited pilot). Phase 1 collected and analyzed data from existing operations for a better understanding of electric GSE impacts. This project generates data via two utility-grade meters and telematics between the chargers and vehicles. The data may provide value to the airport and the operator regarding charging management or general operations.

The pilot demonstration period from December 2019 to August 2020 is the basis for calculating performance. Conventional gasoline baggage tugs achieve a mean fuel economy of 1.5 gallons per hour. Determined on an annual basis, the operations from December 2019 to August 2020 represent 73,693 kWh per year of energy used, with 12,164 kWh (17%) occurring during the peak hours. The electrical consumption equates to 9,826 total hours of operations per year for the 31 GSE that used these chargers, which would have required 14,739 gallons of gasoline annually. The highest utilization month within the pilot was January 2020. Extrapolating this usage across 12 months gives usage of 95,951 kWh per year, with 18,518 kWh (19%) of the electricity being consumed on-peak. This equates to annual usage of 12,879 hours of GSE use, which would have consumed 19,318 gallons of gasoline.

Table 20. SDG&E Airport GSE PRP annualized benefits

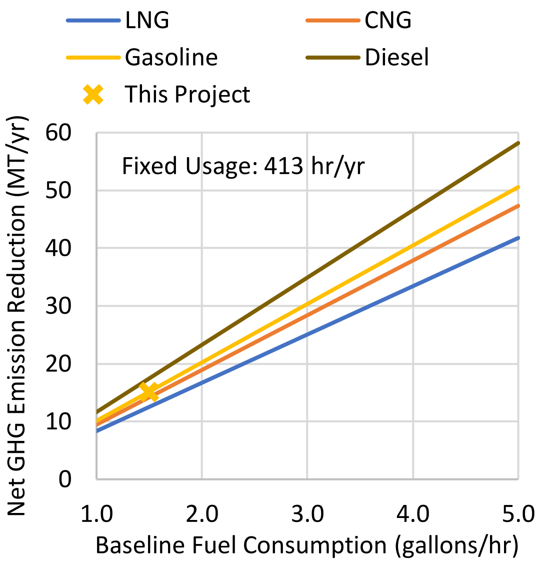
	Testimony (15 updated chargers and 45 new chargers for 90 new eGSE)	Planned (Phase 1–15 charger retrofits to support existing eGSE)	Implemented (16 new charging ports to support 31 eGSE)	Best Observed (16 new charging ports to support 31 eGSE)
Petroleum Reduction	281,000 GGE	None	14,739 GGE*	19,318 GGE*
GHG Emission Reduction	1,174 MT of CO_{2e}	None	358 MT of CO_{2e}*	470 MT of CO_{2e}*
Criteria Pollutant Emission Reduction	7.33 MT of NO_X 3.57 MT of VOC	None	159 MT of CO* 1.9 MT of NO_X* 297 kg of VOC* 116 kg of SO_X* 16 kg of PM*	209 MT of CO* 2.5 MT of NO_X* 389 kg of VOC* 152 kg of SO_X* 20 kg of PM*
DAC Impact	SDIA is not in a DAC	SDIA is not in a DAC	SDIA is not in a DAC	SDIA is not in a DAC
Grid Impacts / Electricity Consumption	4,164 MWh, with improved net load factor (if charging is properly managed)	1,481 MWh, with improved net load factor	74 MWh, with 84% consumed off-peak	96 MWh, with 81% consumed off-peak
Operational Energy Cost Savings	N/A	N/A	$ 17,700 ($ 570 per vehicle)	$ 32,600 ($ 1,050 per vehicle)
***No net benefits due to pre-existing eGSE were observed. Net benefits shown are theoretical, based on a potential gasoline baseline vehicle replacement with similar operation to the ones observed in this program, such as was anticipated for Phase 2.**				

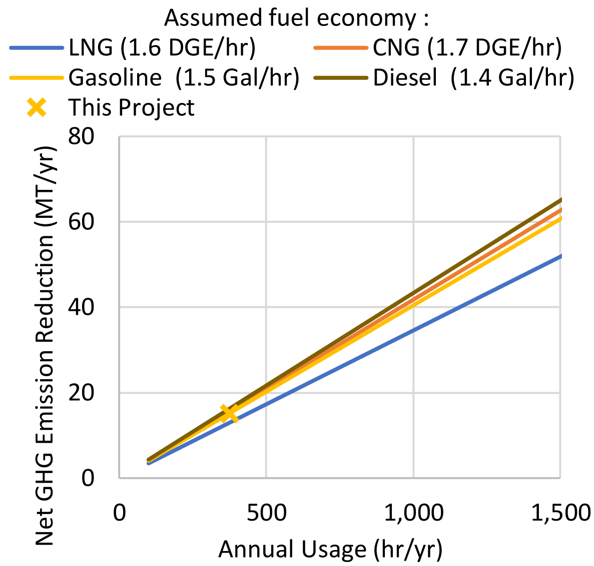
Source: Evaluator Calculations

The estimated benefits were based on key assumptions of fuel type, efficiency, and annual mileage. Figure 57 and Figure 58 present likely greenhouse gas (GHG) emission reductions from other popular fuels for use in airport GSE as well as the sensitivity to the hourly fuel consumption (Figure 57) and annual use in hours (Figure 58).

Figure 57. Airport GSE GHG reductions by baseline fuel consumption

Figure 58. Airport GSE GHG reductions by annual use

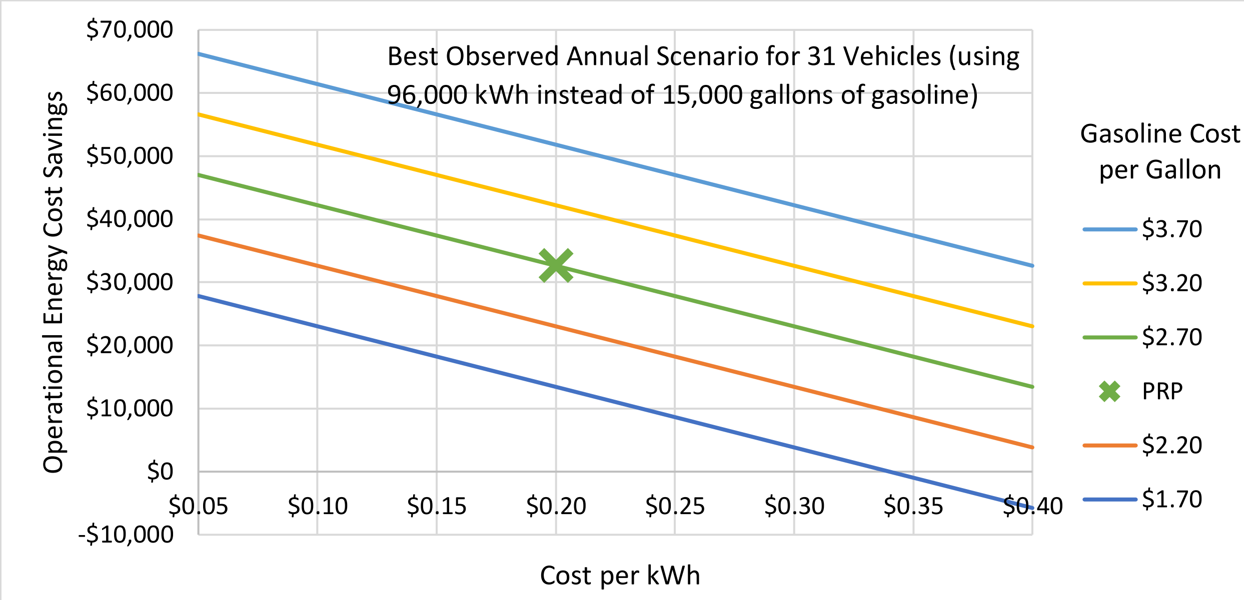




Source: Evaluator Calculations

Actual utility bills from the airport were not shared. The rate is assumed to be AL-TOU with energy costs ranging from \$0.10 to \$0.15 per kWh and demand costs of \$17 to \$28 per kW. Large customers often have transmission-level prices that can be lower due to bulk-rates and owning their infrastructure. Further nuance to cost analysis can be customers with direct access, when they can procure their own energy while still paying the utility for use of the grid. Cost savings were determined using the average observed electricity cost of \$0.20 per kWh and average off-road gasoline price of \$2.70 per gallon determined from published retail gasoline prices excluding federal and state taxes. Figure 59 shows the sensitivity of operational energy cost savings based on varying electricity and gasoline fuel costs.

Figure 59. Airport GSE operational energy cost savings at various fuel costs

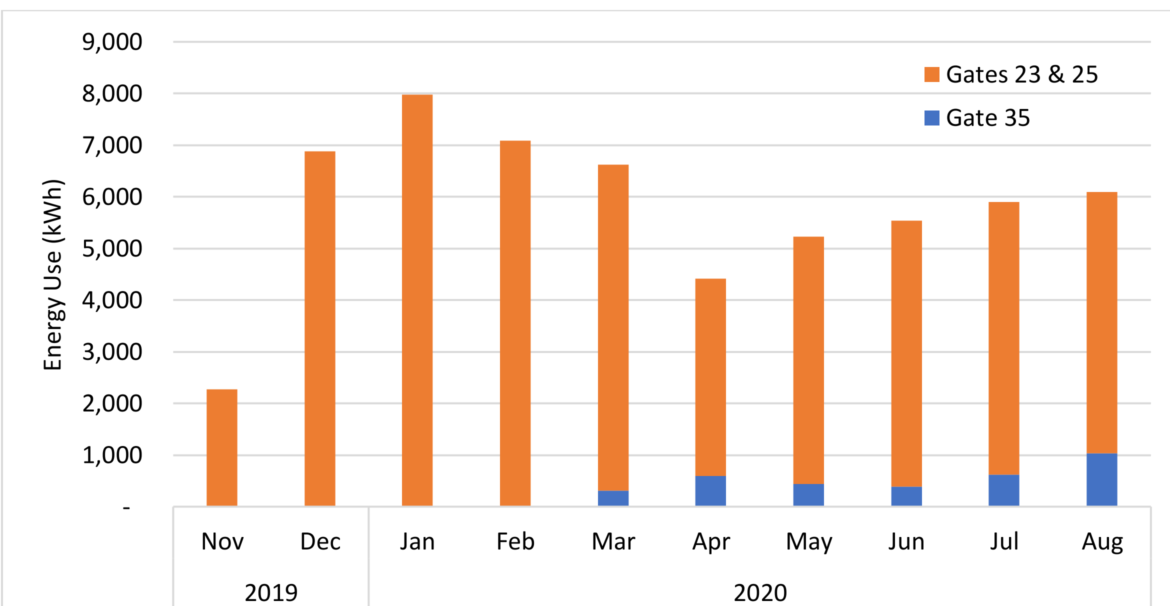


Source: Evaluator Calculations

Operational Impacts of Project Equipment

Figure 60 shows the PRP chargers' monthly electricity consumption. As the operator had electric GSE in use prior to this project, the chargers began typical operation right away. November 2019 low usage is due to commissioning the chargers toward the end of the month. Total consumption dropped noticeably at the pandemic's onset (April 2020), then ramped up again through August, the last month of meter data collection. January 2019 consumption was highest, likely because of the holidays.

Figure 60. Charging consumption (kWh) recorded by two non-billing utility meters

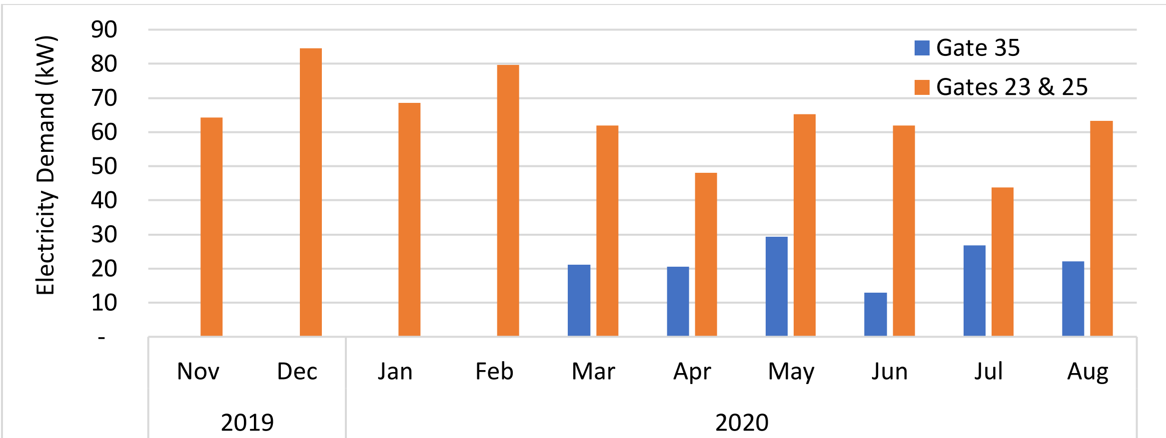


Source: SDG&E Meter Data

As more chargers came online, maximum power draw did not increase significantly (see Figure 61).

- Three dual-port chargers were commissioned at Gate 23 from November 21–26, 2019.
- Three dual-port chargers were commissioned at Gate 25 on February 25, 2020. March 2020 shows an increase in demand. A single meter tracks electricity consumption for Gates 23 and 25.
- Two dual-port chargers were recommissioned at Gate 35 on May 28, 2020. May creates a new peak demand. A single meter tracks electricity consumption for Gate 35.

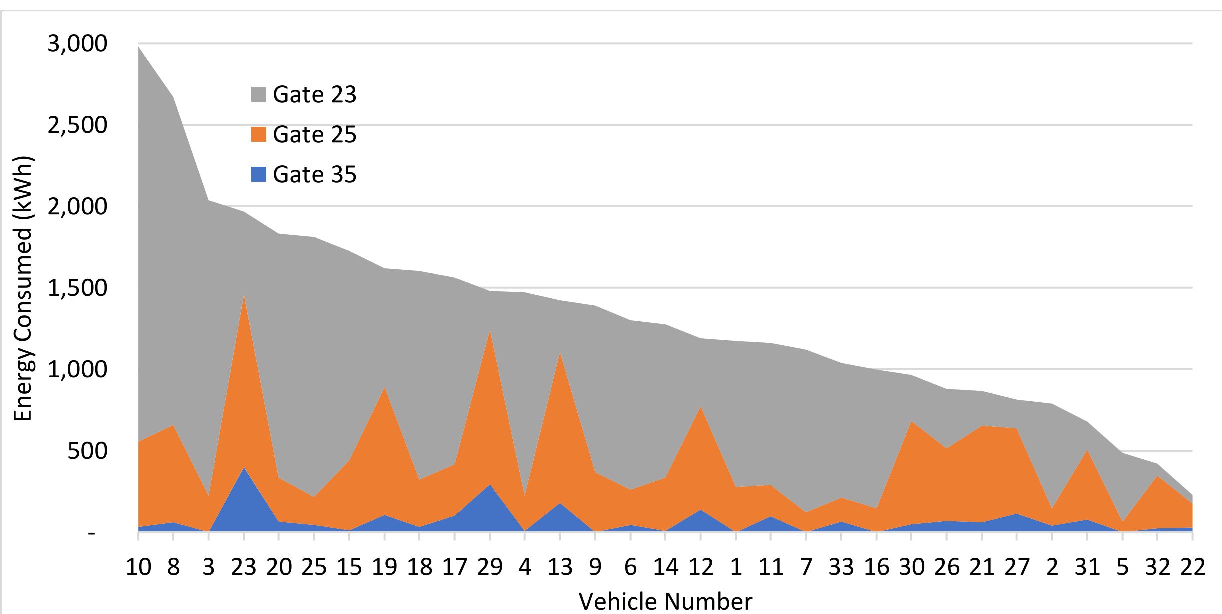
Figure 61. Charging power (kW) recorded by two non-billing utility meters



Source: SDG&E Meter Data

All GSE using the PRP chargers were either baggage tugs or belt loaders, with the energy consumption nearly proportional to each segment's size. Most vehicles fueled at multiple chargers and gates, with the chargers at gates 23 and 25 being used most, as shown in Figure 62. By February 2020, 31 vehicles had recorded usage on at least one of the new chargers.

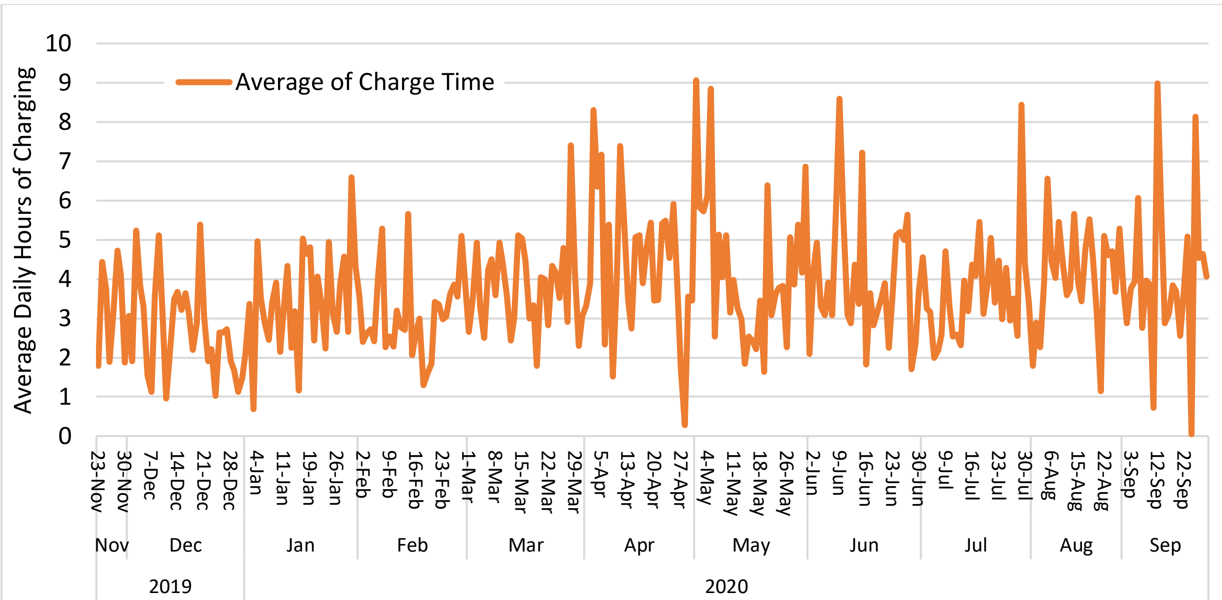
Figure 62. Energy consumption by gate and vehicle using Webasto data (November 2019–September 2020)



Source: EVSP Charging Session Data

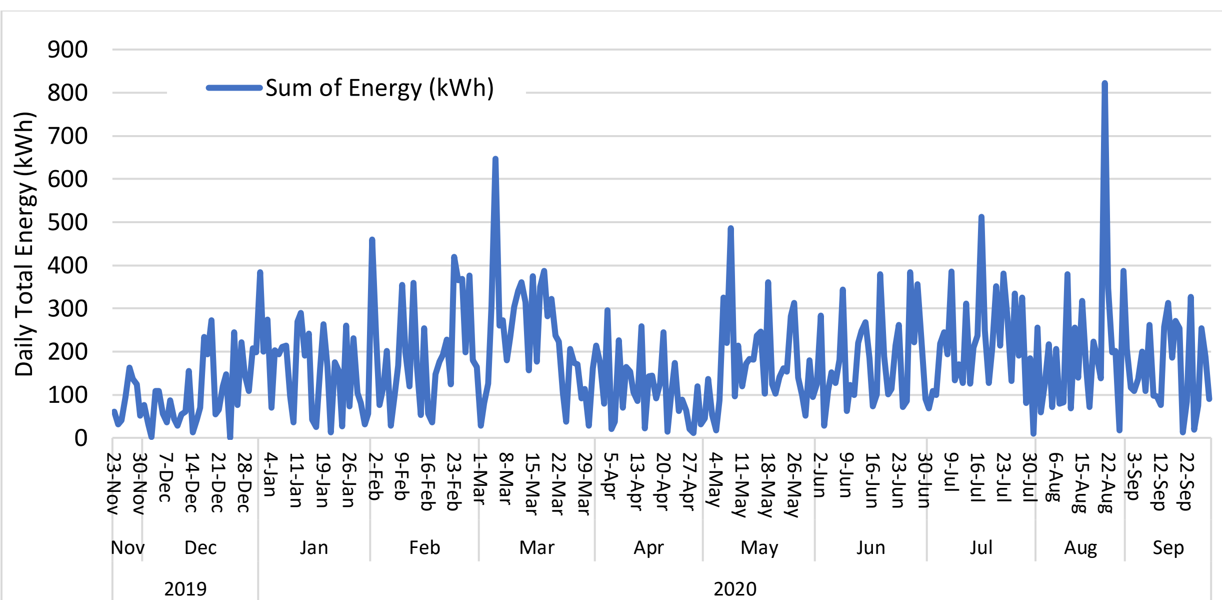
Figure 63 and Figure 64 indicate significant variation in energy consumption across the charger fleet every few days. The mean daily energy use is 160 kWh, while the average is 330 kWh. In terms of utilization, each charger provides energy to vehicles on average for less than five hours a day. On most days, most chargers have ample time remaining to support more vehicles. Based on vehicle type and battery size, a considerable amount of charging can take place during the super-off-peak time period. Some charging is likely flexible enough to be part of a charging management plan that incorporates relatively real-time needs.

Figure 63. Average charging time per charger



Source: EVSP Charging Session Data

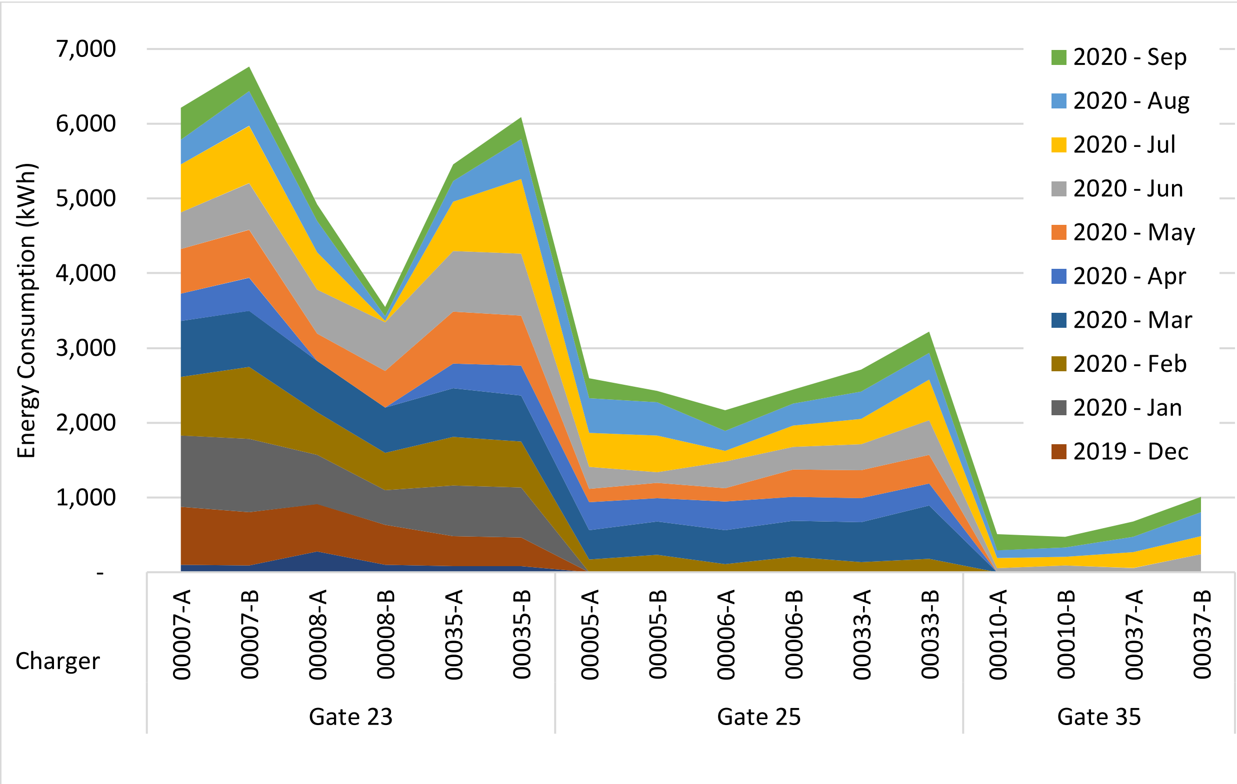
Figure 64. Daily total installation energy use (kWh)



Source: EVSP Charging Session Data

As seen in Figure 65, the chargers at Gate 23 were heavily used before the others were commissioned, and over time, usage is becoming more evenly distributed as other chargers became available.

Figure 65. Trends by gate and charger

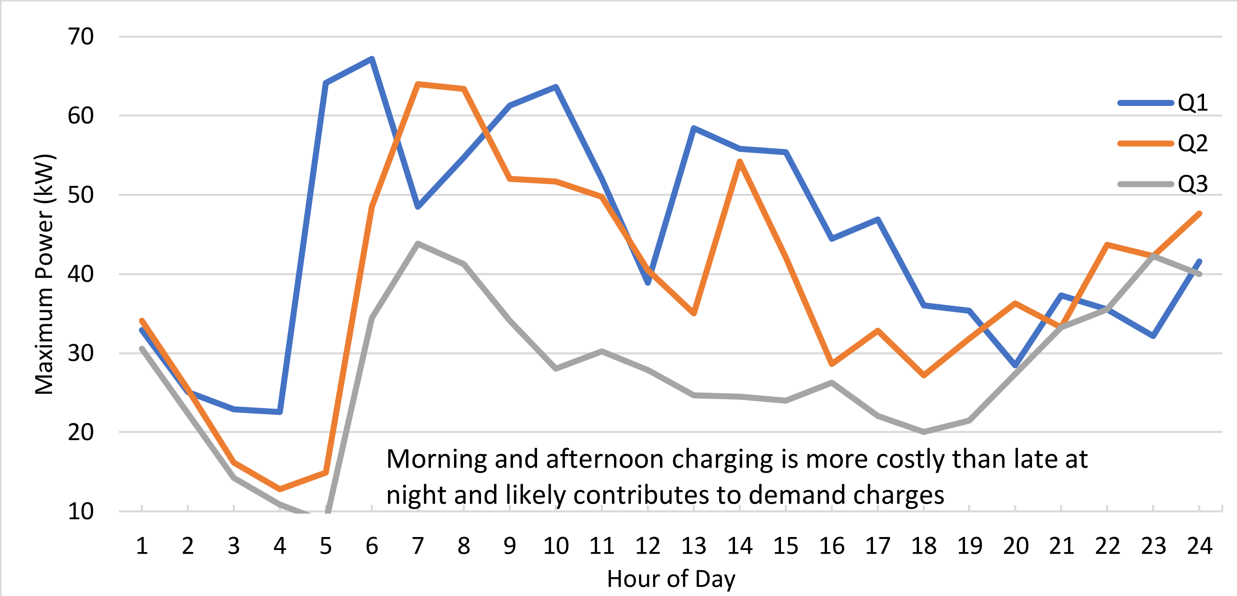


Source: EVSP Charging Session Data

Figure 66 represents the maximum demand experienced at each hour of the day during any given quarter. Actual monthly load curves are similar in shape. The first and second quarters of 2020 show substantial charging from 5:00 AM to 10:00 AM and 1:00 PM to 4:00 PM. There was less overall charging in the third quarter of 2020, with peaks around 7:00 AM and 11:00 PM. The early morning timing likely coincides with other loads as the airport opens operations in the morning, leading to a deleterious effect on monthly and annual demand charges. With just over two vehicles for each charging port in this pilot, the morning and afternoon peaks may each represent half the fleet plugging in.

Through data collected within this pilot, the evaluator asserts that each charger should be occupied each night, whether with vehicles chosen randomly or prioritized based on highest consumption or operational need. This would enhance confidence to GSE operators that vehicles are fully charged and ready vehicles to start the day. The airport may consider reducing maximum power available from the chargers between 5:00 AM and 9:00 PM to mitigate demand charges, if doing so does not hinder operations. As lithium batteries replace lead-acid batteries (currently used in these GSE to our knowledge), the ability for a single charge to last throughout the day will increase.

Figure 66. Maximum charging power (kW)



Source: EVSP Charging Session Data

Billing

Though this airport's existing energy bills incorporate eGSE charging, historical bills were not available to the evaluator. However, using data from the utility load research meters, Webasto charging sessions and estimated billing as described by SDIA representatives, the eGSE billing impacts have been estimated and indicates the value of a charging management plan.

Scaling up the recorded maximum non-coincident and peak time demand (kW) from this project would indicate that the total electric GSE fleet represents about 500 kW in demand. At current AL-TOU (time of use) tariff costs, this may account for summertime monthly demand charges ranging from $10,000 to $20,000 per month. There is also opportunity to shift nearly 30% of on-peak energy costs at approximately $0.05 per kWh. However, energy consumption is rather low compared to maximum demand, which leads to low load factors. Demand charges are estimated to account for nearly 95% of GSE-related utility billing costs.

SDG&E developed a load management plan for the airport, taking into account onsite solar generation and historical billing details. It highlights that mid-day and the middle of the night are low-cost time periods for charging. The airport reviewed the plan with the operator but has not been able to confirm if the operator has been able to implement the plan's suggestions.

Stakeholder and Customer Feedback

- Despite some challenges with various contract aspects, parties moved forward to complete Phase 1.
- Airlines consider GSE to be expensive and long-life equipment. The pandemic made replacing working equipment more difficult, which played a part in the decision against moving forward with Phase 2 (the installation of 45 new charging ports). Upcoming California Air Resources

Board regulations and updates to the Low Carbon Fuel Standard for zero-emission GSE will likely drive airlines' investment in that equipment.

- Airport management said that working with the utility was a positive experience and hopes to leverage subsequent programs to further electrify airside and other transportation needs.
- Ownership and liability concerns arose with the airport, potentially due to the complicated relationship with a separate owner (SDIA) and operator (American Airlines).
- As some operators have used electric GSE for many years, coordinating to change their charging habits is a long-term process. The true cost of energy is not historically billed or communicated to operators and therefore is not influencing charging behaviors currently.

3.3.4 Conclusions and Recommendations

Findings

SDG&E spent $835,859, out of $2,839,738 approved, in direct costs to retrofit 16 existing GSE charging ports. Nine months of charging session data were collected to analyze the performance of charging 31 existing electrified GSE (no data was available on the equipment itself). SDIA was interested in having additional charging ports installed to electrify more GSE, but they were unable to move forward with Phase 2 of the PRP due to the COVID-19 pandemic. Due to significantly reduced operations, their tenants (airlines) postponed capital expenditures including purchase of new electric GSE which was a Phase 2 requirement. Key findings from this pilot are listed below.

- Approximately 30% of the approved budget was spent in Phase 1 to install 16 charging ports. Construction spending was 15% of the approved budget, right in line with 15% of the charging ports installed (16 out of 61 across both Phases). EVSE and electrical equipment costs represented 20% of the approved budget, indicating that based on the average cost of $25,000 per port as observed in Phase 1, insufficient funding remained to deploy 45 additional charging ports in Phase 2. A third of the project management and two thirds of the engineering design budgets were spent in Phase 1, additionally confirming that Phase 2 would not be able to support many more than 30 or so additional chargers.
- The utility check meters and the chargers remotely provided reliable data for the majority of the project. This was a concern initially due to the restricted access to and potentially limited cellular service on the airside of the terminal where the chargers were installed.
- Based on the observed operations and assumed fuel costs, operational energy cost savings of approximately $1,000 per year per electrified GSE are expected (see Figure 59).
- Charging sessions are relatively short, suggesting that the charging load of the vehicles in this pilot and potentially others, could be managed and vehicles successfully charged during low-cost hours. Regular charging appears to take place in the early morning, which likely has negative billing impacts. The load management plan developed by the utility suggested shifting some of this charging to overnight or during the day because of the PV system. While billing data was not available for SDIA, due to a single meter for the whole airport, charging management can likely lead to utility bill savings.
    - Recommendation: Share data between airport and fleets for better understanding of operational impacts on costs and opportunities for reducing costs without impacting operational readiness.

Lessons Learned

The following lessons learned were captured during the implementation of this PRP.

- The timeline for this PRP was significantly extended. Participation agreement between the utility and the SDIA took nearly a year to execute. Additional delays were encountered due to decision making cycles within SDIA management around designs and construction; every issue needed to be documented in detail, and confirmation that it had been addressed was required.
- SDG&E encountered challenges due to restrictions on how much access and control they have on the airside of the terminal. This was anticipated to some extent, but it impacted construction, charger maintenance and repair, and data collection. It is critical to have reliable equipment.
- Many initial EV deployments do not include redundancy in charging equipment, but this can be key to project success because the vehicles rely on functioning chargers for continued operation. After the PRP chargers were installed, the airport did not immediately remove the outlets that were previously used for GSE charging. This ended up being very helpful when one of the charging stations was damaged by GSE as they could continue to charge with the old outlet.
- It is important to select technology with an established remote data access capability. SDG&E initially faced a challenge in acquiring data from the chargers as the EV service provider did not yet have remote data collection capability. Collecting data via site visits to manually download it would not be feasible due to restricted access on the terminal. To alleviate the potential challenges with remote EV service provider data access, SDG&E decided to install utility meters in non-billing mode as check meters. This allowed the utility to receive energy consumption data from the bank of chargers that the meter was connected to just like from any of their other billing meters. This approach proved to work very well and allowed for validation of the EV service provider data which was collected remotely and provided via their online portal.

Scale-up Potential

As of 2018, there were over 3,500 petroleum fueled GSE at California airports. All could likely be converted to electric with little to no negative effects on performance.[24] There are already over 1,300 electric GSE in the state (~27% of all GSE). Of the petroleum fueled GSE, 533 are either baggage tractors or belt loaders using gasoline similar to GSE in this project.[24] Converting these vehicles to electric would result in the benefits shown in Table 21. Additionally, there are 409 diesel baggage tugs and belt loaders. Their emissions profiles would be different but would likely have a similar scale of reductions.

Table 21. Airport GSE scale-up potential annual emissions

	GHG (MT/yr)	SO_X (MT/yr)	NO_X (MT/yr)	CO (MT/yr)	PM (MT/yr)	VOC (MT/yr)
Net Reduction	8,353	3	43	3,587	0.4	7

Source: Evaluator Calculations

[24] California Air Resources Board, "Public Workshop to Discuss the Zero-Emission Airport Ground Support Equipment," June 6, 2018. https://ww2.arb.ca.gov/sites/default/files/2020-06/GSE%20Workshop%20Presentation%20-%20June%206.pdf.

3.4 Port Electrification

3.4.1 Project Narrative

Overview, Objectives, and Barriers Being Addressed

There are some grant-funded deployments of transportation electrification technologies within the San Diego Unified Port District ("Port District") tidelands, but none have load research meters that allow utilities to analyze how grid integration for the medium- and/or heavy-duty (MD/HD) electric vehicle (EV) and electric forklift market segment can be implemented and optimized. SDG&E was approved to spend $2,405,575 to install, operate, maintain, and own EV charging infrastructure, load research meters, and data loggers for 30–40 installations within the Port District tidelands. The original intent was that each charging infrastructure installation supporting grant-funded MD/HD EVs or electric forklifts could include a combination of some or all of these funded components.

The primary goal of this project is to obtain a consumption, charging, and operational dataset to facilitate development of an optimized grid integration solution for electrification of MD/HD vehicle and forklift applications. Load research meters will collect consumption and charging data to evaluate energy consumption relative to time and demand. Data loggers will provide operational data such as operation-specific and EV-specific charging patterns. This information will aid in determining how to optimize grid integration, as well as electric fuel economy, to determine optimal vehicle energy storage size and electric vehicle supply equipment (EVSE) power level.

Sites and Participants

Recruitment Process

In conjunction with filing the application, San Diego Gas & Electric (SDG&E) provided support and technical expertise to the Port of San Diego and the San Diego Port Tenants Association for several transportation electrification grant applications that would benefit various port tenants. Upon approval of this Port Electrification priority review project (PRP), SDG&E targeted the tenants, including locally owned and minority-owned businesses, that would be recipients of grant-funded medium-duty and heavy-duty (MD/HD) vehicles and electric forklifts, to provide charging infrastructure support. Additionally, SDG&E conducted outreach through various channels, including presentations at the Port of San Diego maritime meetings, San Diego Port Tenant Association board meeting and funding presentations, and the Regional Energy Working Group. The smaller tenants were much more hesitant to try new technologies, and it was difficult for them to understand the economics of electrification (costs, rates, etc.). Interest is starting to grow among the port tenants now that they see what the PRP participants have done and learned from their experience.

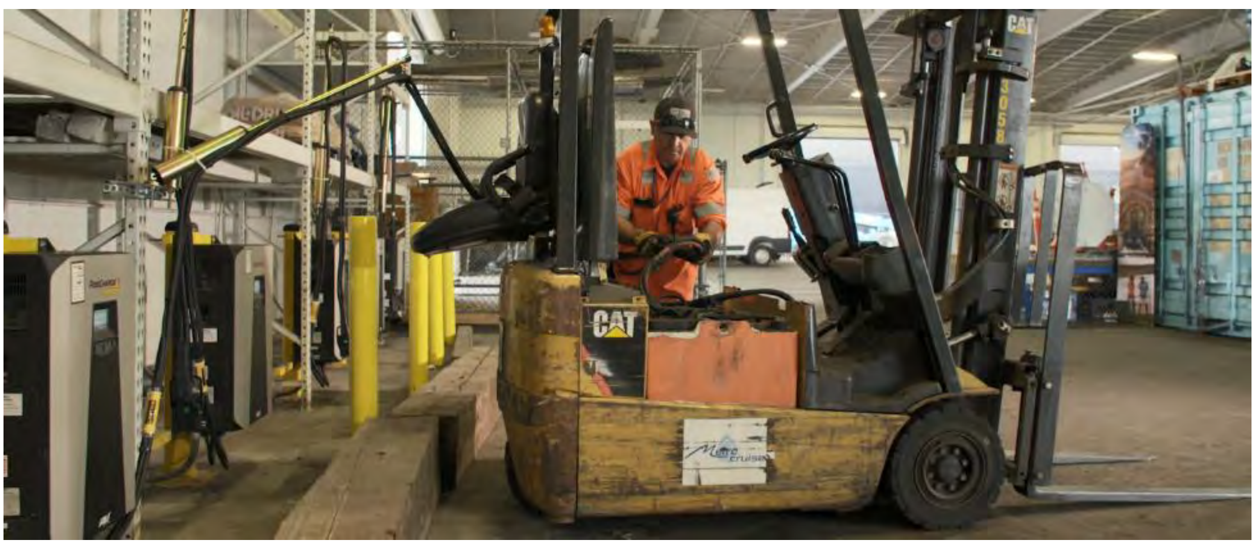
Ten port tenants applied to participate in the program. While SDG&E had a targeted list of port tenants who were designated as recipients of grant-funded vehicles, timing was an issue. A total of 20% of the tenants received their vehicles prior to PRP approval and chose to install the infrastructure on their own (they were content with a simpler and more temporary charging solution for the duration of the grant, which was typically one year, rather than signing a contract to commit to the infrastructure for five years). Another 20% of the tenants chose to install the infrastructure outside of Port Tidelands, making them ineligible for the program. The biggest obstacle was negotiating with the customers on signing an easement/license agreement, resulting in 30% of customers opting out of the program. There is additional complexity for all the customers because they are tenants of the port and therefore do not have jurisdiction of the land.

Participants

This PRP was conducted with Port District tenants. SDG&E has pursued installations with four participants: Port of San Diego Cruise Ship Terminal, Pasha Automotive (Pasha), Dole Foods, and Four Seasons. The Port of San Diego Cruise Ship Terminal and Pasha were onboard early in the PRP because they already had plans underway to install charging infrastructure and either had, or had already ordered, electric equipment/vehicles.

The **Port of San Diego B Street Cruise Ship Terminal (Metro Cruise)** uses forklifts that transfer food and goods on and off cruise ships docked at the terminal. Metro Cruise had previously acquired the nine electric forklifts. These were charged by regular building electrical outlets, which provided no capability to monitor or optimize the charging behavior. **Webasto** (formerly AeroVironment) PosiCharge ProCore™ 10 kW chargers were installed by SDG&E under this PRP for the Port of San Diego. SDG&E owns and maintains the chargers while Metro Cruise uses them for their forklift operation. Metro Cruise also has five smaller electric carts (jack pallets), which have their own chargers, but these did not qualify for the SDG&E PRP and were installed separately by Metro Cruise.

Figure 67. Metro Cruise Webasto chargers and electric forklift



Source: Port of San Diego

Pasha, which imports over 400,000 vehicles annually, transfers new vehicles between the Port District, where they arrive on a ship, to a satellite storage location in Otay Mesa, California. Pasha acquired two **BYD** electric drayage trucks and one **BYD** electric yard tractor through a California Energy Commission (CEC) grant. While they have used several small electric forklifts, these BYD trucks are Pasha's first real EVs. Through the CEC project, **Carbon BLU** instrumented the three trucks with dataloggers to report on utilization. The vehicles require proprietary BYD chargers. Three different chargers were installed by SDG&E (power levels of 40, 80, and 100 kW) because the drayage trucks are different generations of designs and the yard tractor has a different charger (100 kW) because of its very different duty cycle. The chargers came with the trucks and were paid for by the CEC grant. They were installed on the Port property, with Pasha owning and operating the chargers while SDG&E maintains the make-ready infrastructure.

Figure 68. Pasha's electric drayage trucks and yard tractor

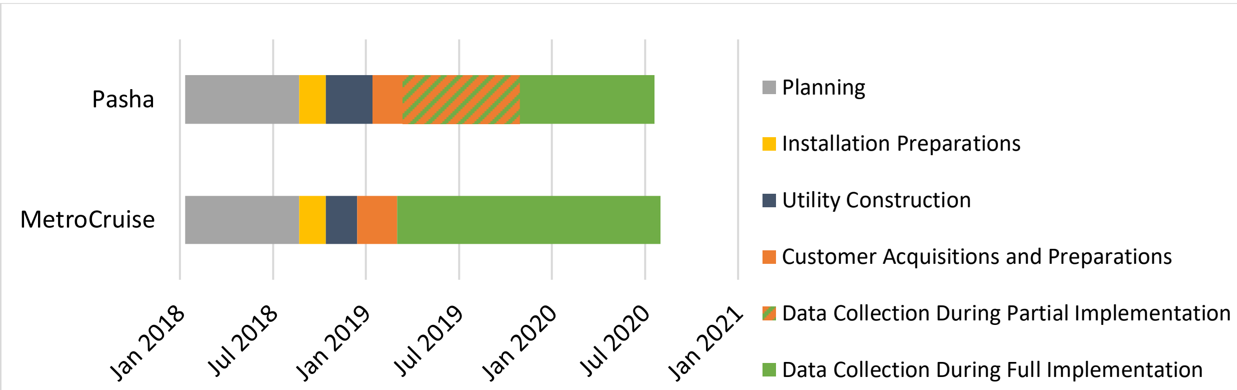
Source: Evaluator Team

Dole Food Co. (Dole) is one of the Port District's largest tenants, bringing in approximately 50,000 refrigerated containers a year. Dole was conducting a year-long test of two **Transpower** demonstration electric trucks for its operations to determine how they work, and the company was considering purchasing 30 electric trucks if the test was successful. During this demonstration, Dole used only temporary chargers for the vehicles, and after a few months in operation, the vehicles were returned to Transpower because the cost to retain the vehicles was higher than Dole was willing to invest. Dole also received two electric yard tractors from BYD in August 2018 for a 12-month demonstration project. The tractors, just like the Pasha one, were equipped with a 217-kWh battery pack powering a 180-kW motor, which delivers 1,106 lb-ft (1,500 N·m) of torque for 10+ hours of operation. Uncertain electrification plans beyond the CEC demonstration projects, both of which were short-term, and challenges associated with addressing the legal risk factors stalled the negotiation process with SDG&E, resulting in Dole being unable to participate in this PRP. **Four Seasons** (for which Dole would also be the customer of record) conducts similar activity at the Port District and was also looking to pilot one **Transpower** electric truck. After several months of discussions, Four Seasons was unable to sign a contract for reasons similar to Dole.

Timeline and Status

The installation at the Cruise Ship Terminal was completed by the end of 2018, but the chargers were not commissioned until March 4, 2019, when they started to be used in regular operations (see Figure 69). The Pasha installation was completed in January 2019 (there were some weather delays) and commissioned on March 15, 2019. Negotiations with Dole lasted a number of months but ended in November 2019 without a signed participation agreement. Contract discussions with Four Seasons, who expressed interest in the program, also did not result in a contract. The EVs and EVSE at the Cruise Ship Terminal were available for operational data collection for more than a year for this evaluation, but there were significant durations when the equipment was not used. While this is typical for cruise ship operators due to summer offseason, it was especially pronounced during the COVID-19 pandemic which essentially halted all cruise ship activity. The Pasha infrastructure was monitored for 17 months following commissioning, but Pasha's truck usage was sporadic and mostly limited to a single electric truck because of operational challenges and technical issues with the vehicles. In August 2020, Pasha decommissioned the chargers temporarily to move them to a more convenient location and the re-installation should be completed early 2021.

Figure 69. SDG&E Port Electrification PRP timeline as of November 2020



Source: SDG&E

3.4.2 Evaluation Methodology

Selected Methods and Rationale

In addition to the evaluation questions that apply to all PRPs and those specific to the Fleet Electrification PRPs, the evaluation questions listed below will be examined for this PRP.

- Did some EVs, equipment, or charging equipment perform better than others?
- Would similar supporting electrical infrastructure at other locations in the Port District be more expensive? Is there a limit to the available power?
- Could these electrification efforts be economically feasible without the grants for the vehicles/ equipment and SDG&E support?
- Were opportunities to better manage charging identified? If so, were they implemented, and were they effective?

The data collection tasks utilized to evaluate this PRP include 1) PRP information from the approved decision, project updates, site visits, and other available documentation, 2) market research on port vehicles and early deployment efforts from other similar electrification projects across the country, 3) PRP data from vehicle and charger operations, and 4) in-depth interviews (IDIs) with project partners.

Data Sources

SDG&E provided PRP operational data from its utility service meters (one utility meter at each deployment site for all charging stations at that site) for 15-minute interval data and monthly costs (through utility bills). Metro Cruise charging station session data (not 15-minute interval data) is retrieved manually (via Bluetooth) during periodic site visits (Webasto is developing a remote, cloud-based data access, but it is still not available).

Pasha's BYD chargers do not have the capability to track session data. Data logging of the Pasha vehicles was conducted for the CEC grant. This was facilitated by a third-party vendor that was not scheduled to share a complete set of data until the 12-month demonstration was completed. Unfortunately, when the vendor decided to process the data which needed to be manually downloaded from vehicle dataloggers, there was no usable information due to an installation error. The dataloggers were reinstalled for the CEC grant purpose but no data from Pasha's EVs was available for this evaluation.

The evaluator collected PRP information through numerous PRP participant interactions: the PRP kick-off meeting (SDG&E and evaluator), quarterly PAC update meetings, weekly PRP updates (SDG&E and evaluator), site visits, and other periodic calls or emails. Multiple IDIs were also administered with representatives from the SDG&E PRP management team, SDG&E construction staff, Port District, Metro Cruise, Pasha, BYD, and Webasto to further understand the background on this project, discuss the findings from the data analysis, and gather lessons learned.

3.4.3 Evaluation Findings

Project Baseline

Metro Cruise operates nine electric forklifts, several pallet jacks and golf carts to serve loading and unloading needs of large cruise ships that dock at the port. These use 36- to 48-volt batteries approaching 40 kWh capacity. Several cruise ship operators have San Diego-based ships that will go on multi-day cruises and return to San Diego, where they need to unload waste generated from the prior excursion and load supplies for the next one. The loading and unloading requires several back-to-back eight-hour shifts over the course of a few days. This typically occurs over the weekend, followed by several days before servicing the next ship. The summer is off-season with next to no charging; however, the chargers themselves always consume a small amount of standby energy. Metro Cruise was operating propane forklifts to support these services prior to acquiring electric forklifts a few years ago. Between then and this project, the fleet has used slower, non-programmable chargers that do not collect any data. Historic forklift energy use was not understood because the electric circuit was feeding several loads at the terminal including another operator's forklift fleet.

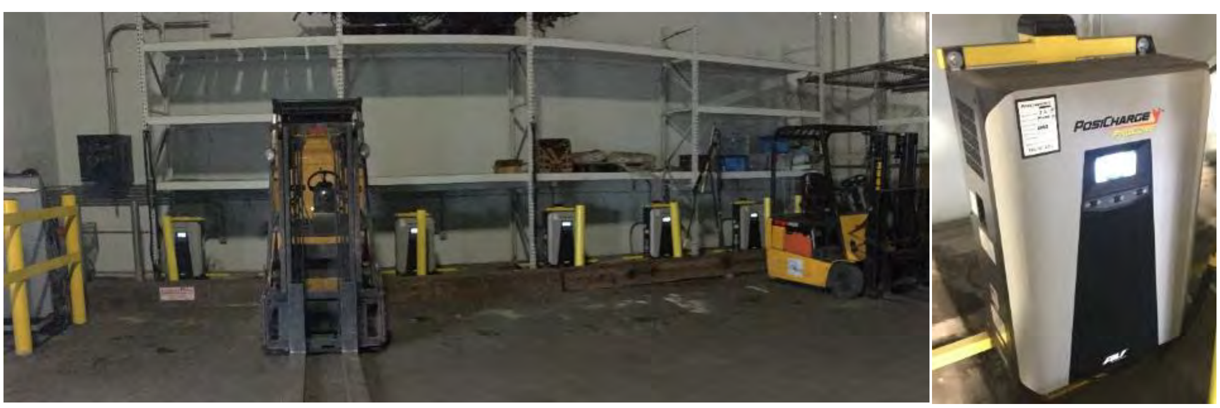
Pasha operates an 18-hour shift per day with its drayage trucks, while the use of a yard tractor depends on the vessel(s) in port, which may require several eight-hour shifts in a row. EV utilization was impacted by the drivers' perception of the convenience to operate the EV on the roll-on/roll-off (RORO) cargo ship as well as charging. The first-generation BYD drayage truck has a smaller battery which limits this operator to a single 42-mile round trip to the storage facility before the truck needs to recharge for the second trip. The second-generation BYD drayage truck can complete two of these 42-mile round trips on a single charge. Since this truck entered service at the end of Q3 2019, the first-generation truck was not utilized anymore due to range limitation. The utilization of the second-generation truck is reflected directly in the utility meter consumption data as the yard tractor was not utilized anymore after intermittent use over the first six months. Pasha had similar-sized, Class 8 diesel trucks operating in the fleet prior to demonstrating electric trucks. The company is using this project to determine where EVs can meet operational requirements and with what internal adaptations. Pasha recognizes that battery technology will need to improve, and vehicle acquisition costs decrease before electrifying the entire drayage truck operation, which primarily consists of regional- and long-haul trucks that can travel nationwide. However, this specific “drayage shuttle” application is a good starting point to test electric technology and work through some early adoption challenges.

Implementation Process

SDG&E and participants for this PRP were able to use some strategic contracting strategies to simplify the process. SDG&E used participation (licensing) agreements rather than easements to expedite the contracting process, which was modeled after SDG&E’s Power Your Drive Program. The Port District was also able to execute a simplified contract that did not have as many requirements because their agreement is for less than five years (it would have otherwise needed to follow a more complicated process with additional approvals). However, even despite these simplified contracting processes, certain clauses in the agreement needed to be discussed at length before execution. This included indemnity and risk, particularly what happens to the equipment after five years and who can claim the environmental credits.

Design specifics can be complicated for certain locations and customers that have complex management structures or approval chains. Trenching is a concern for projects at the port because of the thickness of the concrete, which makes construction more difficult and costly. In addition, construction could involve digging up hazardous materials, which would require costly mitigation strategies. Installations that do not require trenching are ideal and significantly lower cost. For example, the Metro Cruise installation (Figure 70) needed only duct work (bollards needed to be anchored to the pavement), no trenching, which simplified the construction. These projects can serve as a model for others to replicate and have provided valuable experience for SDG&E. However, based on the two implemented projects and several others that were considered for this PRP, every charging station installation will have unique aspects that will require custom design and construction to some extent.

Figure 70. Metro Cruise charging infrastructure



Source: Evaluator Team

For Pasha’s project, while the availability of electric Class 8 trucks is limited, the CEC grant further restricted the selection of electric truck manufacturers to BYD and Transpower. The PRP does not provide funding for EVs, but they are a requirement for customers to participate in the project. As a result, grant is often used to cover the vehicle cost; however, that can result in procurement of larger and less available vehicles. While the manufacturers consider these EVs commercial models, they are often very early in production, and customers often consider them to be demonstration vehicles since they have not been deployed in significant numbers and are likely to experience some operational issues. The BYD electric trucks came with their own proprietary charger (which differed based on the version of the truck and date acquired), so Pasha did not have a choice; however, it is advantageous to use the vehicle manufacturer approved charger to minimize potential interoperability issues. Pasha chargers were installed next to the transformer to minimize the trenching (Figure 71). Once the chargers were installed, the customer realized that they were facing away from the vehicles which was not expected. It was also determined that longer charging cables were needed to reach charging receptacles on the trucks. Due to internal business requirements, Pasha relocated the chargers in the second half of 2020. Pasha contracted with SDG&E to decommission the chargers, install the necessary make ready infrastructure at two new locations, and re-install the chargers, all outside of the scope of the PRP and at their own cost. The new location for the yard truck charger is in its maintenance area, closer to the ship berth. Pasha anticipates that this location, which will be much more convenient than the initial location at the other end of the terminal, will result in increased usage.

Figure 71. Pasha charging infrastructure

Source: Evaluator Team

If SDG&E had been allowed to proceed with the company's interpretation of the approved PRP scope in the Decision (fund and collect information from data loggers and research load meters without installing new charging infrastructure), the PRP could have monitored the demonstration vehicles at Dole (and possibly other Port District tenants that received EVs under the CEC grant) and gathered more EV charging and utilization data. However, because of the CPUC's interpretation of the Decision, dataloggers and research grade load meters could only be used alongside charging stations installed under new electric service accounts under this PRP.

Costs

The approved PRP had an anticipated total direct cost of $2,405,575, consisting of $1,840,575 in capital and $565,000 in expense, as shown in Table 22.

Table 22. SDG&E Port Electrification PRP proposed costs

	Capital Costs	O&M Expenses	Total PRP Costs
Electrical Service	$ 849,570	N/A	$ 849,570
EVSE Costs	$ 991,005	N/A	$ 991,005
Purchased and Self Developed Software	N/A	N/A	N/A
Measurement and Evaluation	N/A	$ 150,000	$ 150,000
Education and Outreach	N/A	$ 110,000	$ 110,000
Billing Support	N/A	$ 80,000	$ 80,000
SDG&E Clean Transportation PM	N/A	$ 200,000	$ 200,000
First-Year O&M Service Calls	N/A	$ 15,000	$ 15,000
First-Year O&M for Charging Equipment	N/A	$ 10,000	$ 10,000
Total Costs	**$ 1,840,575**	**$ 565,000**	**$ 2,405,575**

Source: SDG&E

Little to no costs were associated with design, engineering, and permitting. SDG&E had originally estimated these costs would be less than $10,000 per site in concurrence with using existing electrical services (some estimates did not even account for any additional costs for this). SDG&E learned that the actual design, engineering, and permitting costs average about $30,000 per site. The total PRP direct costs are $645,787 out of the $2,405,575 budget, as shown in Table 23 (presented in categories reported by the utility).

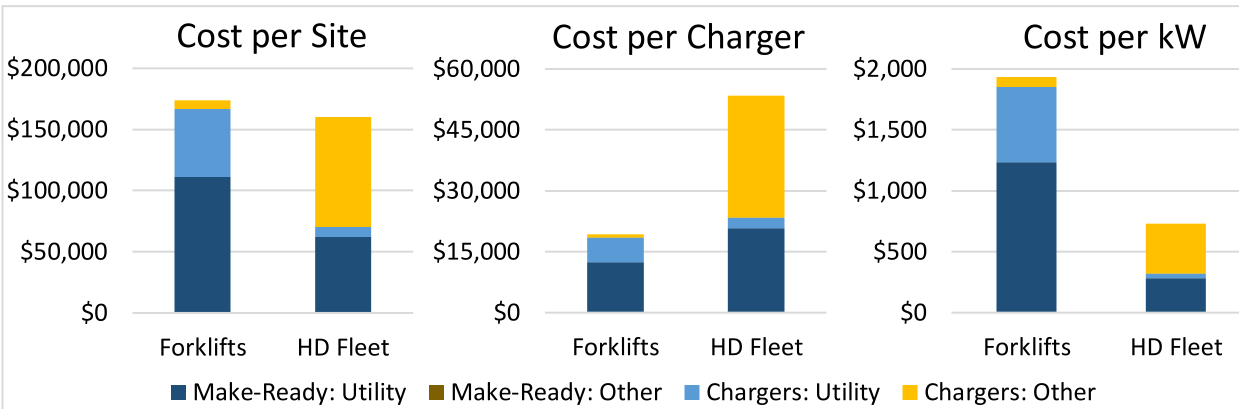
Table 23. SDG&E Port Electrification PRP estimate at completion (EAC)

	EAC Capital Costs	Budgeted Capital Costs	EAC O&M Costs	Budgeted O&M Costs
Construction	$ 173,260	$ 966,045	N/A	N/A
Engineering Design	$ 104,544	N/A	N/A	N/A
Chargers, Meter Pedestals, Transformer, and Other Materials	$ 63,923	$ 874,530	N/A	N/A
Internal SDG&E Labor (Program Management and Support)	$ 12,408	N/A	$ 126,804	$ 280,000
IT Costs	$ 123,548	N/A	N/A	$150,000
Customer Engagement and Outreach	N/A	N/A	$ 4,050	$ 110,000
Other	$ 37,215	N/A	$ 35	$ 25,000
Direct Costs	$ 514,898	$ 1,840,575	$ 130,889	$ 565,000
Non-Direct Costs (Indirect, AFUDC, and Property Taxes)	$ 180,559	$ 986,166	$ 127,831	$ 253,717
Total Costs	**$ 695,457**	**$ 2,826,741**	**$ 258,720**	**$ 818,717**

Source: SDG&E

Figure 72 shows the PRP costs (construction and equipment/materials only) for each site, per individual charger, and also per kW of charging capacity installed. Costs are separated by make-ready and charger costs which were either paid for by the utility through this PRP or a source of funding "other" than the utility which may be the host site, grants, etc. Pasha's BYD chargers were paid for by the CEC grant, and SDG&E covered the installation costs. The CEC grant for $900,000 covered the three EVs and chargers (charger costs are estimated at $30,000 each). For the Cruise Ship Terminal, SDG&E covered all the costs associated with EV charging infrastructure; Metro Cruise paid for the charging port adapters ($800 each) which were required to charge the forklifts.

Figure 72. SDG&E Port Electrification electric vehicle charging infrastructure costs



Source: SDG&E

Benefits

The Port Electrification PRP contains two distinct pilots, one uses medium-duty forklifts in limited weekly duty cycles for the Cruise Ship Terminal operations entirely within the port property. The other pilot involves heavy-duty truck operations moving cargo within the port as well as back-and-forth to offsite locations. The key benefits and some contributing factors are outlined below, with a more detailed description of the benefit analysis included in the Appendix.

The analyzed data for the electric forklifts includes a period of performance from March 2019 to February 2020, during which 13,877 kWh of energy were consumed, with 5,266 kWh (38%) occurring during the on-peak hours. Based on the estimated hours of use, which varied from 624 hours for the highest utilized forklift to 128 hours for the lowest, forklift efficiency (total use in hours divided by the total energy in kWh) ranged from 4.1 kWh per hour for the larger forklifts to 2.6 kWh per hour for smaller ones. In this particular pilot, the electric forklifts were already acquired and in operation for several years resulting in no actual fuel and emissions benefits. However, within the industry, most forklifts are fueled by propane (especially for any indoor operation) which is therefore used as a baseline for the benefits shown in Table 24 which a project like this would achieve annually. If the electric forklifts had replaced propane forklifts, this project would have displaced 819 gallons of gasoline equivalent energy (GGE) use annually.

Table 24. Cruise ship operation annual emissions

	GHG (kg/yr)	SO_x (kg/yr)	NO_x (kg/yr)	CO (kg/yr)	PM (kg/yr)	VOC (kg/yr)
Propane	7,258	-	25.24	93.91	0.65	-
Electric	3,065	1.04	3.38	2.80	0.58	0.57
Net Reduction	**4,193**	**-1.04**	**21.86**	**91.11**	**0.07**	**-0.57**
% Reduction	**58%**	**-**	**87%**	**97%**	**11%**	**-**

Source: Evaluator Calculations

The best observed operations for this pilot were in October 2019, with an estimated 168 hours of operation across all 9 forklifts. This would have required 2,184 gallons of propane per year for 9 forklifts or 1,655 GGE. Annualized electric equivalent use would be 27,726 kWh, doubling the electricity used for the full pilot's period of performance (largely because it doesn't account for an offseason experienced by this operator). Forty-seven percent of the utilization occurred during on-peak times, with an annualized 12,948 kWh of the utilization occurring between the hours of 4 and 9 PM.

Table 25. Best observed cruise ship operation annual emissions

	GHG (kg/yr)	SO_x (kg/yr)	NO_x (kg/yr)	CO (kg/yr)	PM (kg/yr)	VOC (kg/yr)
Propane	14,676	-	51.04	189.91	1.31	-
Electric	6,858	2.07	6.75	5.60	1.15	1.13
Net Reduction	**7,819**	**-2.07**	**44.29**	**184.31**	**0.16**	**-0.09**
% Reduction	**53%**	**-**	**87%**	**97%**	**12%**	**-**

Source: Evaluator Calculations

The GHG emission reduction results from the Metro Cruise pilot can be projected for other potential electric forklift applications that may replace baseline forklifts of varying fuel types and with slightly different baseline vehicle fuel efficiency or annual use.

Figure 73. Forklift GHG reductions for various baseline fuels by fuel economy

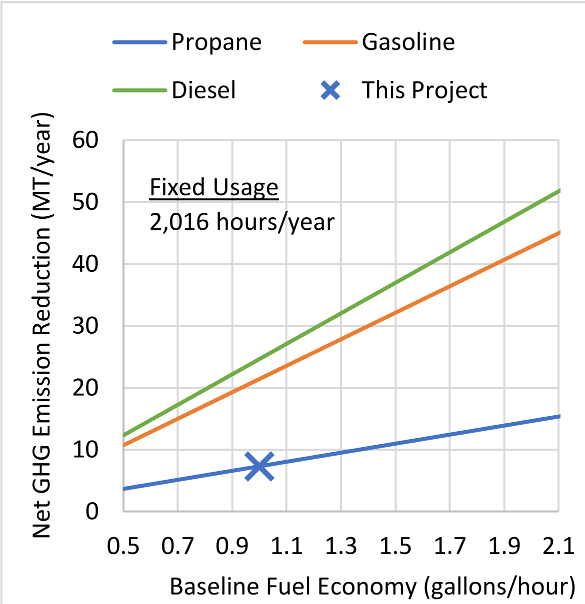
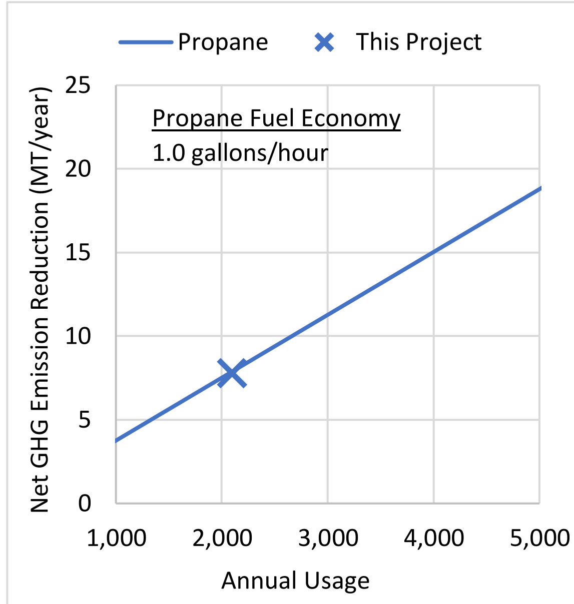


Figure 74. Forklift GHG reductions by annual use



Source: Evaluator Calculations

In the port truck pilot, the larger battery electric truck (ETRK-200 with 409 kWh versus ETRK-100 with 207 kWh and the yard truck at 217 kWh) proved to be the only vehicle fit for regular use. It achieved an efficiency of 2.87 kWh per mile during a period of consistent use during the performance period. This vehicle replaced a diesel Class 8 truck with an estimated fuel economy of 5.4 miles per gallon (MPG) on the same route. The period from September 2019 to May 2020 is used for the pilot's primary performance results. Extrapolating the ETRK-200's performance during the pilot to an annual scale, the one vehicle uses 22,167 kWh per year of energy, with 11,693 kWh (53%) occurring during the on-peak hours. This equates to a baseline annual utilization of 7,724 miles per year which translates to 1,430 gallons of diesel fuel consumption for the baseline truck. The best observed operations for this pilot were in May 2020 which would result in 18,731 annual miles, requiring 2,341 gallons of diesel for the baseline truck and 53,758 kWh (29,047 kWh, 54% on-peak) for the electric truck.

The anticipated benefits from the SDG&E Testimony in Table 26 were calculated based on 13 EVs (modeled as forklifts) replacing diesel, gasoline, and propane vehicles. As planned, the number of EVs supported by this PRP's charging infrastructure is nine electric forklifts (which were already electric so there is no net PRP benefit for those) and three MD/HD electric trucks (using calculation factors from the fleet delivery vehicles as a similar application used in the Testimony). As implemented, only one MD/HD electric truck experienced regular use and therefore is the only one providing benefits compared to the baseline vehicles.

Table 26. SDG&E Port Electrification PRP annualized benefits

	Testimony (13 Forklifts)	Planned (3 MD/HD EVs)	Implemented (1 MD/HD EV)	Best Observed (1 MD/HD EV)
Petroleum Reduction	38,000 GGE	6,767 GGE	1,652 GGE	4,000 GGE
GHG Emissions Reduction	228 MT of CO_{2e}	30 MT of CO_{2e}	11 MT of CO_{2e}	26.5 MT of CO_{2e}
Criteria Pollutant Emissions Reduction	1,000 kg of NOx 490 kg of VOC	27 kg of NOx	32 kg of NOx 4 kg of VOC 11 kg of CO	78 kg of NOx 10 kg of VOC 27 kg of CO
DAC Impact	Majority of the Project is in a DAC	The HD site is in SDG&E DAC	100%	100%
Grid Impacts / Electricity Consumption	344 MWh, with improved net load factor (if charging is properly managed)	98 MWh, with improved net load factor	22 MWh, with 47% consumed off-peak	54 MWh, with 46% consumed off-peak
Operational Energy Cost Savings	Not listed	N/A	-$5,000	-$14,000

Source: Evaluator Calculations

The GHG emission reduction results from the Pasha pilot can be projected for other potential electric drayage truck applications that may replace baseline vehicles of varying fuel types and with different baseline vehicle fuel efficiency or annual use. The results of these sensitivity analyses are shown in Figure 75 and Figure 76.

Figure 75. Drayage truck GHG reductions for various baseline fuels and fuel economy

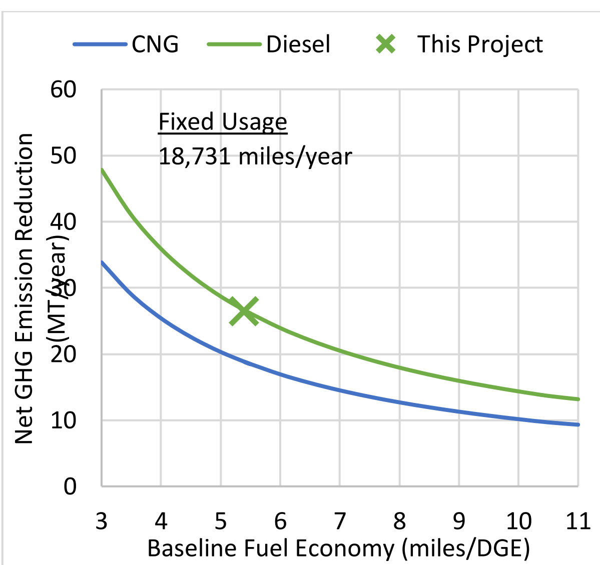
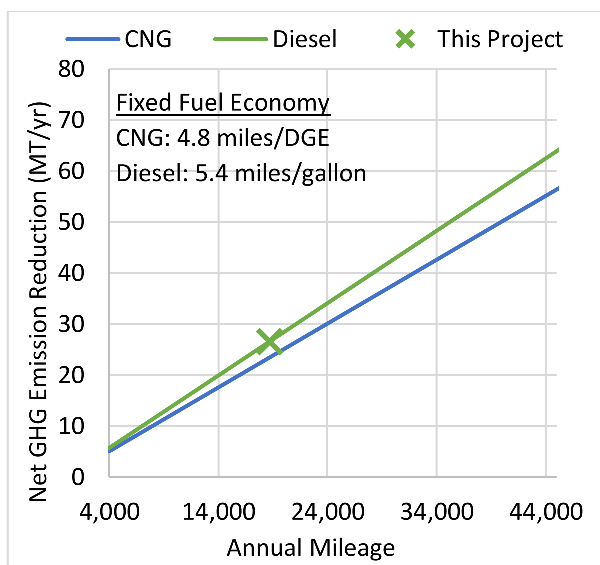


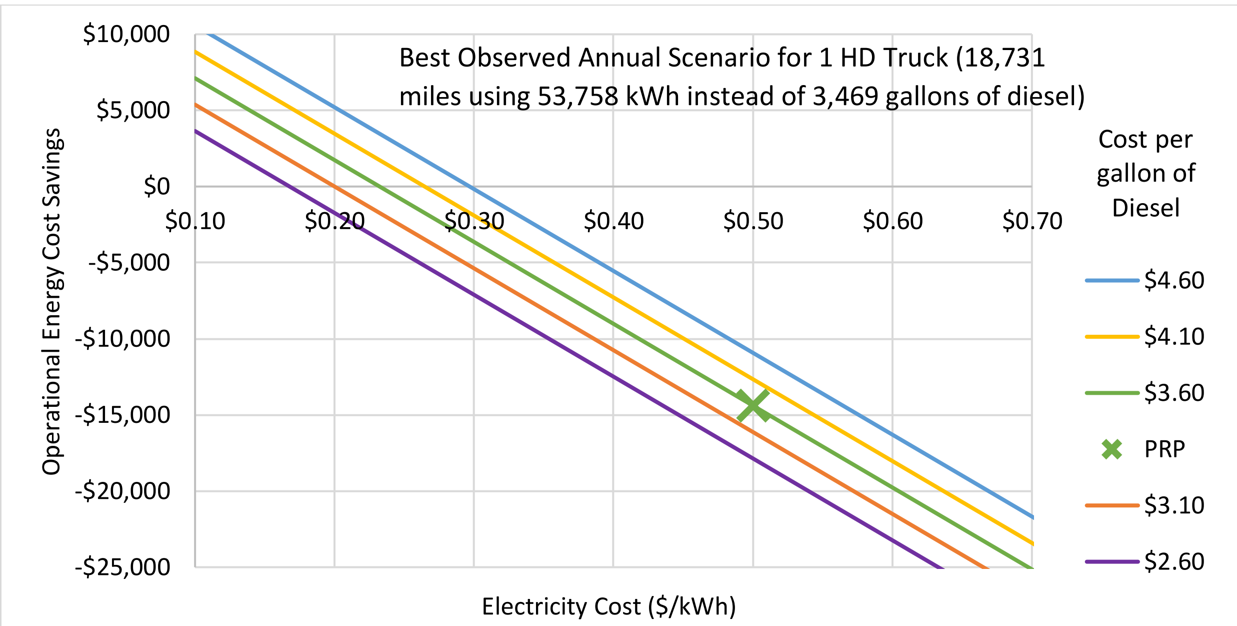
Figure 76. Drayage truck GHG reductions for various baseline fuels by annual use



Source: Evaluator Calculations

Figure 77 shows how the operational energy cost vary with cost of energy for electric truck compared to the baseline diesel vehicle. To realize any operational energy cost savings, the average electricity price would need to be $0.20 per kWh or less depending on the diesel fuel costs ($0.15 per kWh for Pasha). Since Pasha owns the chargers, they are entitled to LCFS credits which would reduce the fuel costs. Based on 2019-2020 average LCFS credit price of $200 per metric ton, Pasha could expect to receive about $0.26 per kWh in credits (assuming 5% transaction and management fee, 5 energy efficiency ratio for HD EV, and carbon intensity of 82.92 g CO_2e per mega Joule for California average grid electricity used as a transportation fuel in California in 2020).

Figure 77. Annual HD truck operational energy cost savings at various fuel costs



Source: Evaluator Calculations

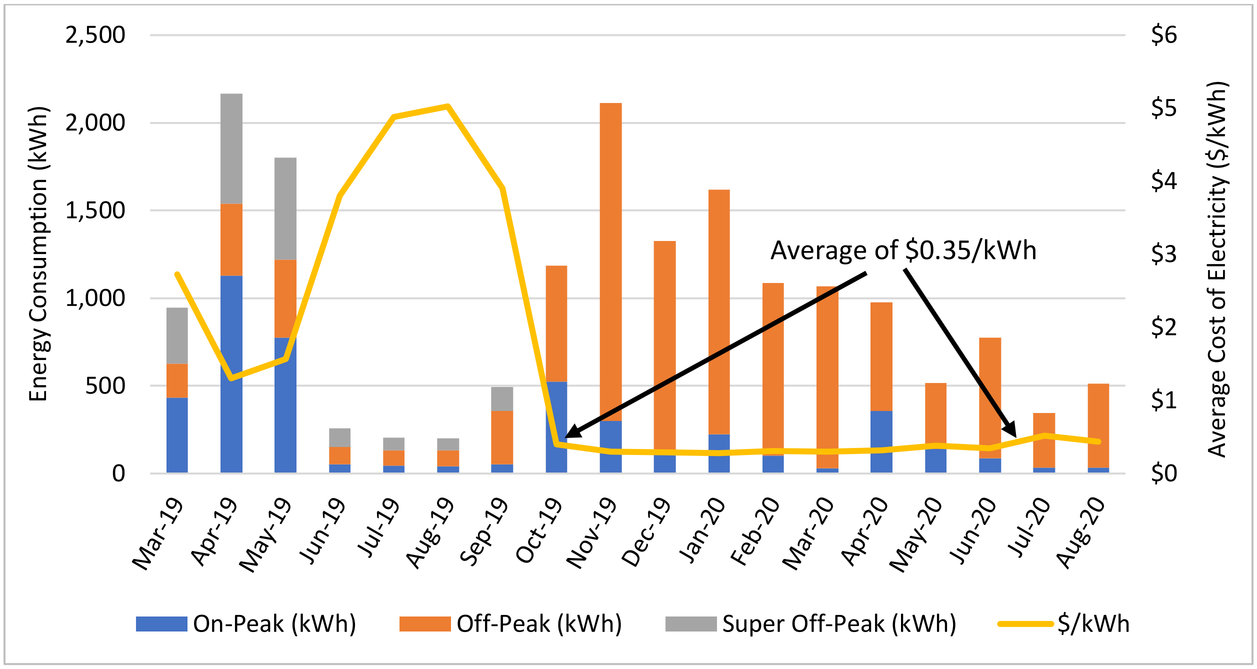
Operational Impacts of Project Equipment

Initial operations data from Metro Cruise (Webasto charger manual session data retrievals and utility bills) and Pasha (utility meter data and bills) provided some insight into operations, although the periodic use of the EVs resulting from vehicle technology limitations (Pasha) and off-season and COVID-19 pandemic related cruise schedules (Metro Cruise) affected the amount of data available for analysis.

Forklifts

For the forklifts, April, May, and November 2019 were the highest energy consuming months on record with around 2,000 kWh each. A considerable amount of charging took place between 4 and 9 PM, although much of that was off-peak during the weekends. Over the lifetime of the project, as of the end of May 2020, nearly 18 MWh have been consumed while a typical year is estimated at just over 13 MWh based on the 12-month billing period from March 13, 2019 through March 14, 2020. As these forklifts have been in operation for several years, the operation is believed to be fairly mature with little increase due to learnings associated with this PRP.

Figure 78. Forklift utility bills



Source: SDG&E Billing Data

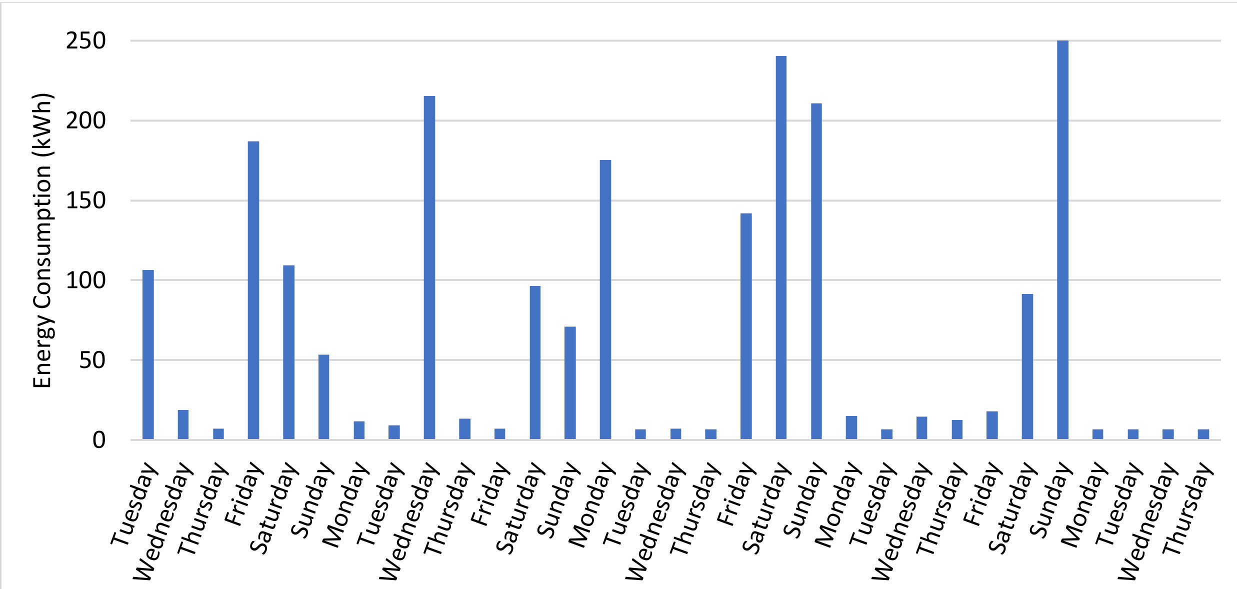
The electric account for this project was initially billing on AL-TOU, a large commercial rate. That rate is heavily influenced by maximum demand and volume of energy consumed. While the energy cost was relatively low ($0.09/kWh to $0.13/kWh), the demand fees (on-peak and non-coincident) on AL-TOU were as high as $41.65/kW. In the off-season months with no charging activity, the monthly electric charges were largely comprised of non-coincident demand charges ($21.43/kW to $24.23/kW) which were based on 50 percent of the maximum demand over the past 12 months. In October 2019, per request of the Port and after working with SDG&E account manager to find a more suitable rate, the rate was changed to TOU-A which provides a relatively flat pricing regardless of demand or total consumption. Figure 78 shows the pricing volatility this operation was subject to before the rate change; on TOU-A rate the pricing has been relatively consistent around $0.35 per kWh over the last 11 months.

Achieving similar pricing per kWh on AL-TOU as TOU-A may have been possible but would be challenging. To do so, more than 2,000 kWh would need to be consumed each month and at least two charging management strategies would need to be implemented through the charger management software application:

- Completely avoid on-peak time period to reduce maximum demand costs of $17.42/kW
  - Possible with blocking 4–9 PM weekday charging via software application
- Limit maximum charging demand across all 9 chargers to no more than 10 kW
  - Possible with derating power of each charger to 1 kW if all are connected at the same time; however, not practical as overnight charging might not fully charge the battery at that rate
- Include golf cart charging to increase consumption and therefore utilization rate

Utility meter data shows that the cruise ship terminal operates predominantly on weekends. The energy consumption for operational days typically ranges between 50 and 250 kWh as shown in Figure 79. Highest energy use days consume almost three times the average daily energy use.

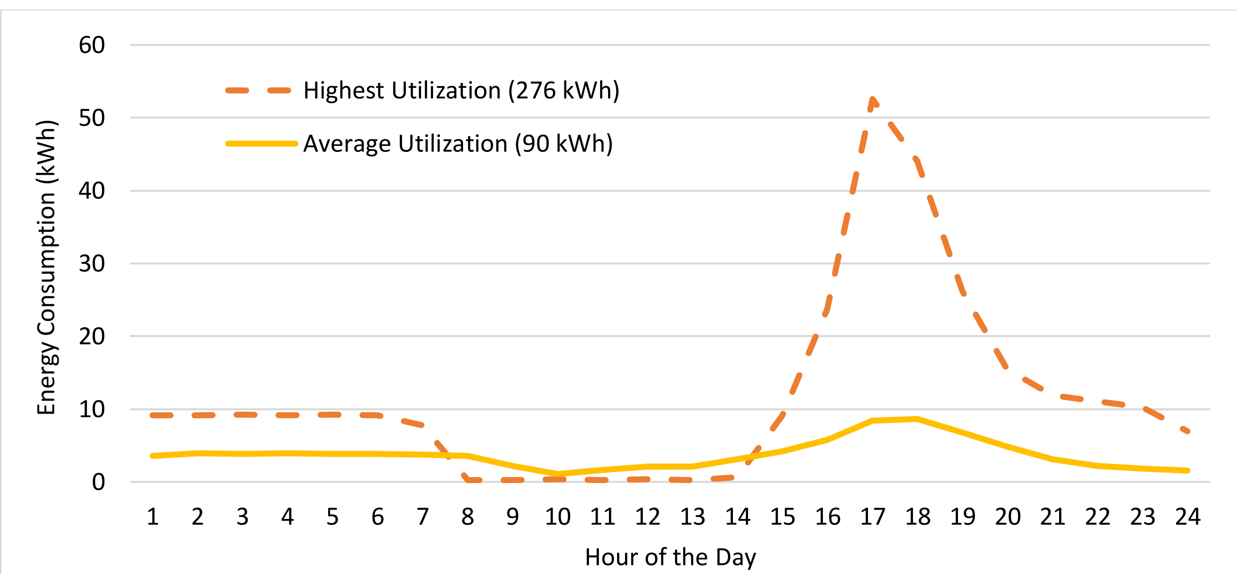
Figure 79. Daily forklift charging energy consumption for October 2019



Source: EVSP Charging Session Data

As Figure 80 shows, charging typically begins by 3 PM and is nearly completed by 8 PM, nearly fully aligned with the on-peak time period, depending on which rate the account is on. Forklifts typically begin use by 7 AM.

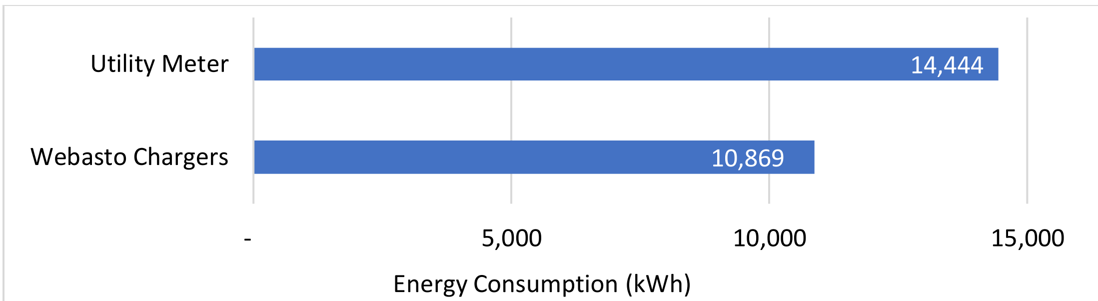
Figure 80. Hourly forklift energy consumption



Source: SDG&E Meter Data

Though the chargers collect data they record differently from the utility meter due to line losses and their own energy consumption. Figure 81 shows that the chargers recorded approximately 75% of what the utility meter reports. Note that the date ranges below do not include the off-season. This is because the chargers would have continued to consume energy while in stand-by mode despite almost no forklift usage. The chargers consume close to 10 kWh daily (about 1 kWh per day each) in stand-by mode. During the 2019 off-season this amounted to billing for approximately 250 kWh each month when there were no charging events.

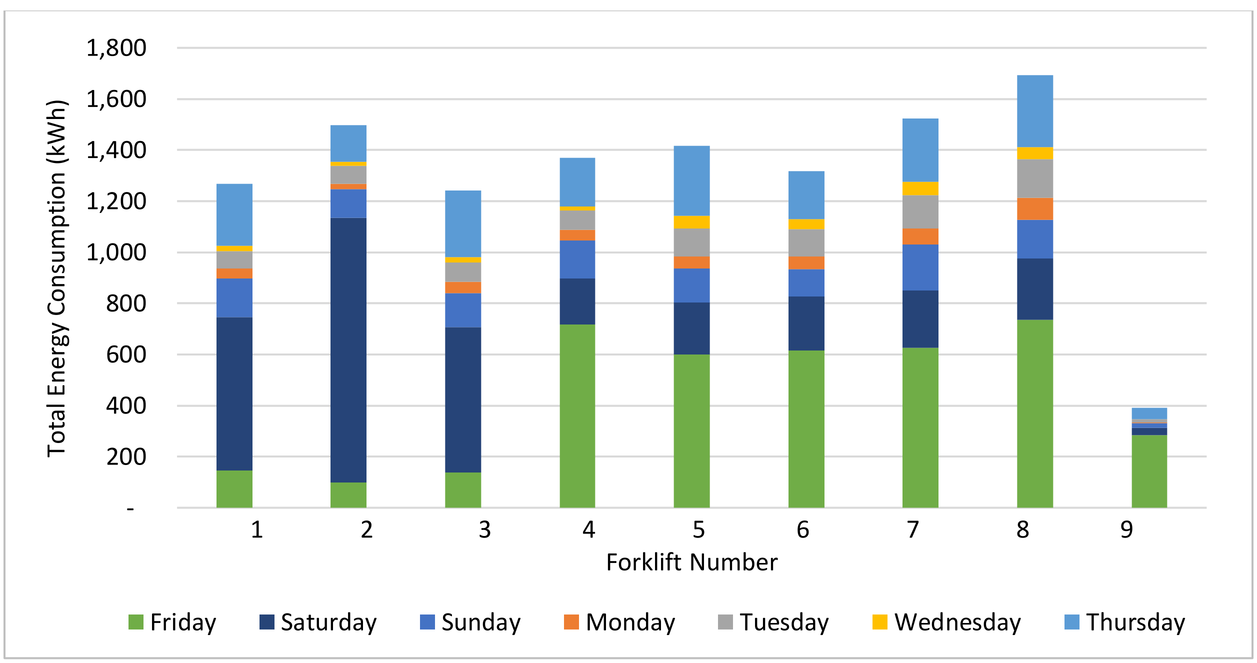
Figure 81. Energy consumption comparison between utility meter and EVSP (on-season only)



Source: SDG&E Meter Data and EVSP Charging Session Data

Webasto chargers record charging session summaries but do not provide hourly charging intervals. The charging session data provides useful insights on charging behavior. For example, the forklift charging is alternated between Fridays and Saturdays. This pattern may indicate that forklifts do not necessarily need a dedicated charger, as long as there is enough access to reach available chargers.

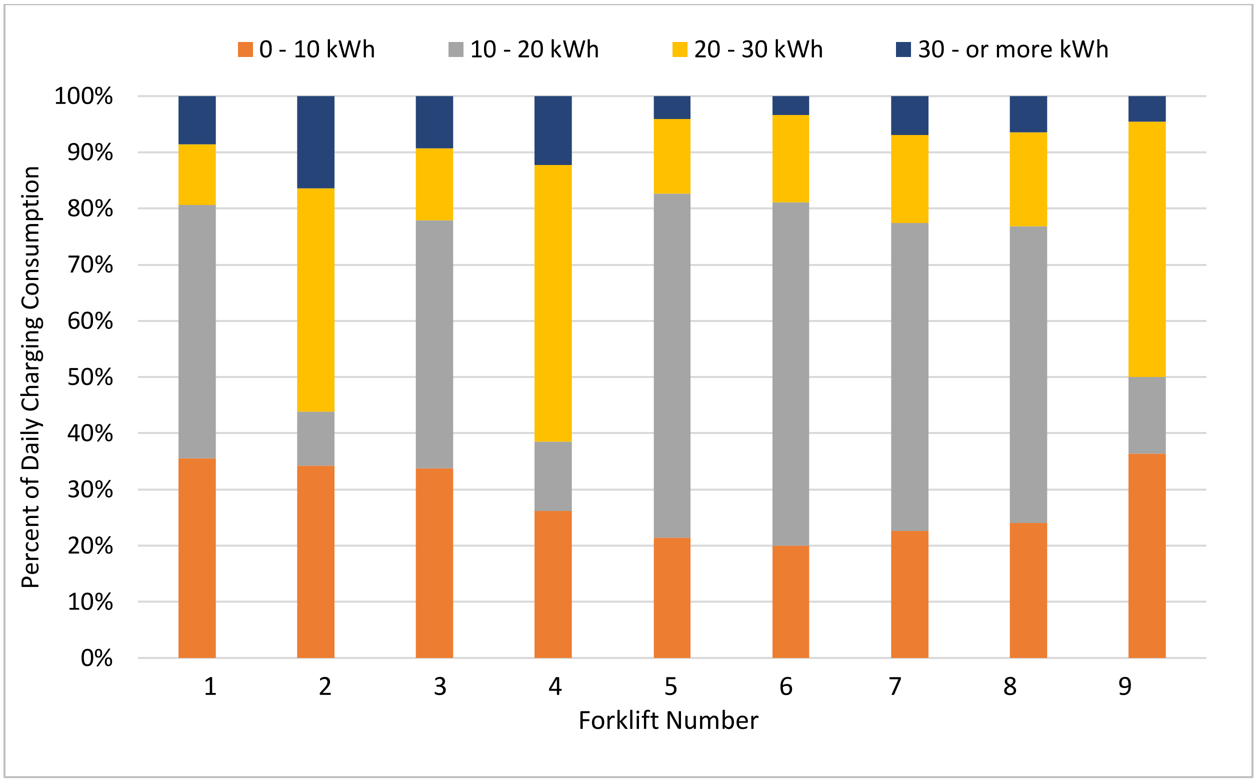
Figure 82. Consumption by forklift for each day of the week (March 2019–July 2020)



Source: SDG&E Meter Data

The average charging session delivered 17.5 kWh. Metadata used by Webasto to manage charging shows forklift number 4 (Friday operations) and 2 (Saturday operations) are equipped with larger battery packs than others. Though these two have nearly double the quantity of charging sessions over 20 kWh, their overall energy consumption closely matches the rest of the fleet at approximately 1,400 kWh during the study period.

Figure 83. Frequency of daily charging consumption (March 2019–July 2020)



Source: EVSP Charging Session Data

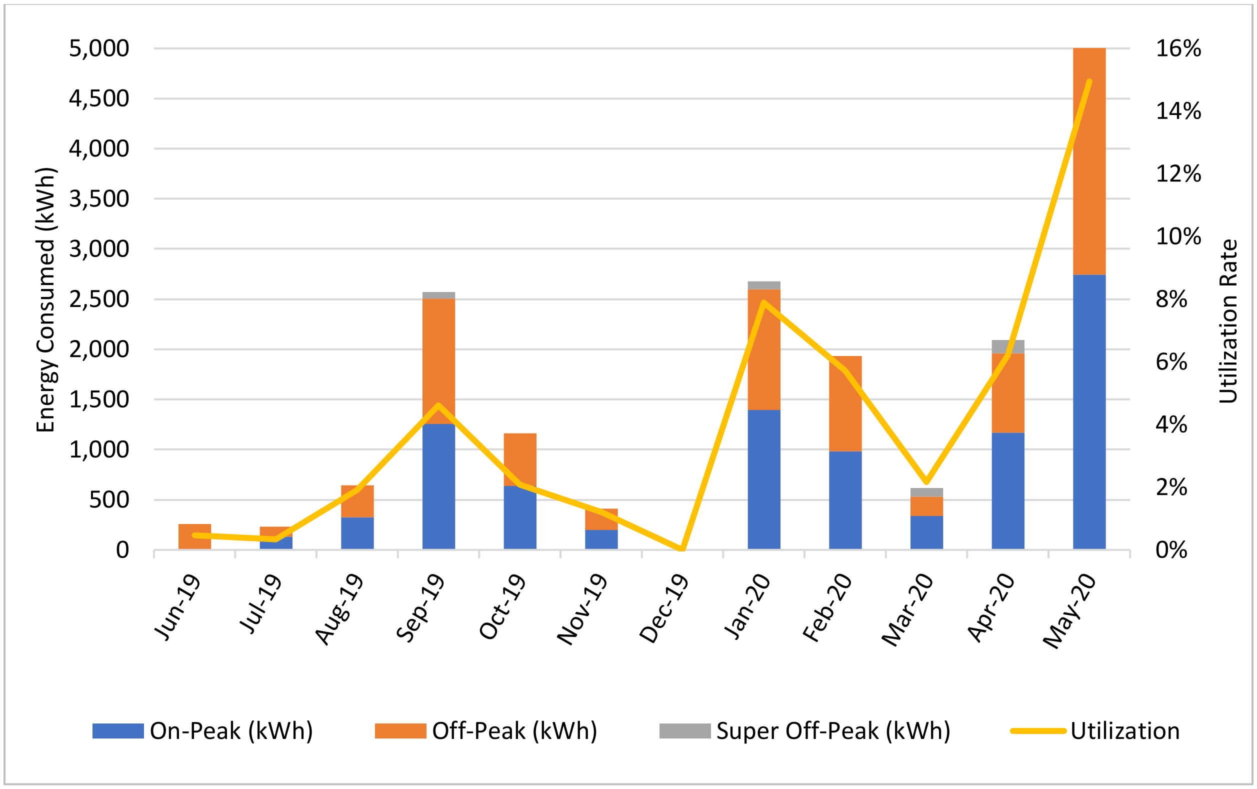
In August 2020, per Port request based on consultation with Metro Cruise and review of Evaluator's charging session analysis, Webasto programed the forklift chargers during a site visit to delay charging until off-peak. Due to the ongoing pandemic, the effects of this change were not observed during the data collection period. Ordinarily, this along with slower charging at lower maximum demand or higher utilization would have resulted in a lower overall cost per kilowatt-hour.

Heavy-Duty Trucks

The BYD chargers installed for charging Pasha's trucks are non-networked and have no energy management features. Lack of networking ability resulted in no charging session data collected directly from the chargers. Lack of energy management features resulted in significant on-peak charging of Pasha's trucks as they were typically plugged in at the end of the shift between 1 and 4 PM. From the 3 EVs operated by Pasha, the long-range drayage truck accounted for about 80 percent of the consumed energy.

As Figure 84 shows, May 2020 was the highest month of drayage truck use during the 15 months of data collection. More than 5 MWh of electricity was consumed for vehicle charging, resulting in 1,550 miles traveled by the long-range electric drayage truck. This EV accounted for all energy use with an average consumption of 3.25 kWh per mile based on utility meter data. The total electricity consumption for all 3 EVs through May 2020 was nearly 18 MWh with drayage truck averaging just under 3 kWh per mile in 2020. Utilization rate as shown presents the ratio of the average power demand and maximum demand.

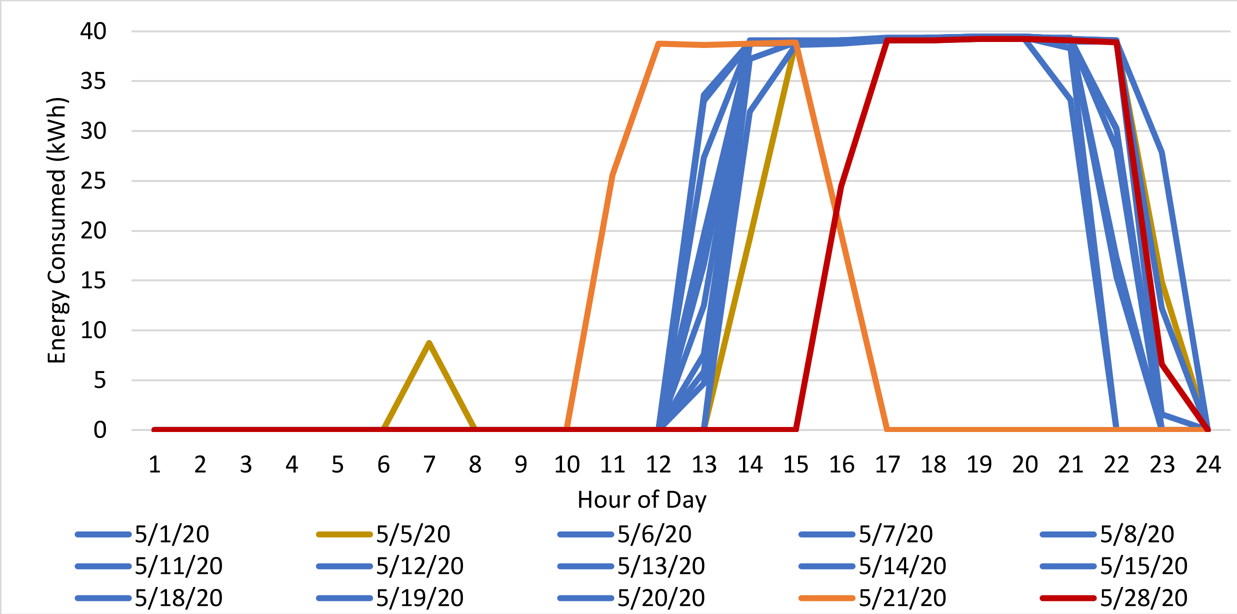
Figure 84. HD fleet utility bills



Source: SDG&E Billing Data

During May 2020, daily electricity consumption averaged 350 kWh resulting in just over 100 miles driven. Each operating day in May, the charging begun at the end of the shift around 1 PM, continued through the on-peak period and finished by 11 PM as shown in Figure 85. The charging rate during this 10-hour period was consistently around 40 kW. Delaying the charging would likely still enable a full charge before the beginning of the shift around 7 AM the next morning and lower the on-peak demand. However, the charger does not provide any ability to manage charging.

Figure 85. HD fleet daily charging load curves



Source: SDG&E Meter Data

The combination of early EV technology, COVID-19 pandemic, and daily routes driven by customer needs resulted in sporadic usage of long-range electric drayage truck (5,153 miles and 373 hours), limited use of short-range electric drayage truck (1,581 miles, 207 hours, all during first 6 months before the long-range truck was delivered) and minimal use of the yard tractor. Limited EV use and the fact that Pasha's EV charging service account was under a large commercial rate (AL TOU), identical to Metro Cruise's initial one, their energy costs per kWh were very high (highest observed of any PRP). The biggest contributor to that was high demand cost ($41.65 per kW during on-peak time in the summer) and their reoccurrence (50 percent of maximum kW demand over the past 12 months regardless of monthly usage). Lowest observed costs were for the highest usage month in May 2020 ($0.52 per kWh). Electricity costs were below $1 per kWh for only one other month ($0.89 per kWh in January 2020). With significant truck use and not exceeding 40 kW demand (maximum rate of the BYD charger for drayage trucks) Pasha could see average monthly rate in the 30-cent per kWh range. As part of the relocation of chargers, Pasha will be moved to SDG&E's interim rate (TOU-M with minimal demand charges of only $2 per kW) until the HP EV rate for commercial EV charging is available (CPUC decision is pending). This change should result in significantly lower average electricity costs which directly impacts the cost per mile.

Stakeholder and Customer Feedback

Forklifts

Both the Port (as a landlord) and the forklift operator (as a tenant) have had a good experience with the installation of the utility owned chargers and make-ready infrastructure. The Port was in the process of issuing an RFP for installing the charging infrastructure to serve the forklifts that their tenant already operated before their relocation on the Cruise Ship Terminal. The utility covered all of the infrastructure and charger costs and construction was relatively quick and smooth as no trenching, only above ground conduit, was needed.

The forklift operator previously used five chargers that came with the forklifts to charge all 9 forklifts. Higher power and dedicated chargers for each forklift not only simplified and speed up the charging operation but also potentially extended the lifetime of the batteries due to automatic equalization charges. The operator has to order and purchase custom charger adapters that were $800 each as the charger connectors did not match those on the forklifts.

Before the PRP, the forklift operator was only billed for a portion of the total building electricity costs (split proportionally among 3 tenants) and did not have any energy consumption data available for its operation. While initial electric bills were very high due to demand charges, the average monthly rate was significantly reduced by Port negotiating with the utility to switch to a more appropriate rate.

While the PRP chargers came with networking capability and energy management features it took 18 months after commissioning to program the chargers to delay charging to off-peak time periods. The remote charger accessibility for charging session data download has been delayed to the first quarter of 2021 (2 years after charger commissioning).

Heavy-Duty Trucks

The heavy-duty truck operator also had a good experience working with the utility as part of this PRP. The utility managed the planning, design, and installation of the fleet owned chargers and utility owned make ready infrastructure. Location of the chargers next to an existing transformer minimized the trenching and resulted in a relatively quick and cost-effective construction.

The operator’s only surprise was that the chargers were installed facing away from the trucks. The location of the yard tractor’s charger proved to be inconvenient as it was on the opposite end of the terminal compared to where the tractors are parked and operated.

This was the first EV experience for the fleet operator and the EVs and chargers were fully covered by the CEC grant. The 3 EVs were not intended to be a direct replacement for diesel vehicles but solely for the operator to gain experience with electrification to aid in achieving their sustainability goals. The operator observed and reported several technology limitations:

1) The shorter-range drayage truck did not meet the minimum range needed. It was unable to consistently reach 80 miles between charges with 10 percent state of charge remaining. This range is needed to complete two consecutive drayage shuttle trips without charging.
2) The yard truck lacked functionality and ergonomics to operate onboard a roll-on roll-off cargo ship. The operation requires numerous adjustments of the fifth wheel height to account for angle of the ramp during the ingress and egress of the ship. The electric tractor requires shifting into neutral to adjust the fifth wheel height, whereas the conventional truck can do so while in gear. This causes not only inconvenience and delays, but also safety concerns among the drivers. Additionally, the seat or cab design does not allow swiveling like some conventional trucks do, therefore limiting the ability to maneuver the truck in tight areas on the ship.

The fleet operator did experience success with using the longer-range drayage truck for operating on the drayage shuttle route. As part of a different grant, they accepted another identical drayage truck that was placed in service toward the end of 2020, allowing them to fully electrify the drayage shuttle route by replacing two diesel class 8 trucks previously used for this operation.

3.4.4 Conclusions and Recommendations

Findings

SDG&E spent $645,787 in direct costs, out of $2,405,575 approved, to install, operate, maintain, and own EV charging infrastructure for nine forklift chargers and three BYD electric trucks (not owning the chargers as they were covered by a CEC grant) at two separate locations within the Port District. This was well short of the target, but still provided SDG&E additional experience in installing EV charging, along with more accurate cost information. This experience will help SDG&E and the Port to support future electrification of Port District tenants' cargo handling equipment and vehicles. From an infrastructure standpoint, the PRPs were successful in implementing smart meters and charging equipment that helped monitor charging activity. This insight helped the participants better manage the costs of charging and provides an opportunity to reduce their cost of ownership. The PRP did not fund any vehicle telematics devices to collect data on vehicle operations because they were already installed for another project on the BYD electric trucks or not compatible with the forklifts. Other findings include:

- Port operations and tenant locations regularly change to accommodate consumer trends and the always-changing import/export businesses. This concerned several port tenants that were uncomfortable committing to the program requirements, and even one of the participants, Pasha, needed to relocate the chargers (at the company's expense) because of tenant changes.
- Several port tenants park vehicles overnight at their off-site location because of space constraints at the port. Since the PRP requirement was to install charging stations within the port tidelands, these tenants were unable to participate. Even if they could accommodate parking the vehicles at the port to charge overnight, drivers might have to be shuttled back to the warehouse at the end of their shift to retrieve their personal vehicles.
- Third-party onboard vehicle data loggers would be ideal for independently monitoring vehicle performance, but the utility found them cost prohibitive in the case of Pasha though Metro Cruise required them for charging. Instead, the project had to rely on Pasha to provide vehicle performance data through other means such as vehicle maintenance records and third-party dataloggers collecting data for other grant reporting purposes. These options were not successful at providing additional data due to complications and issues.
- The PRP participants, both Pasha and the Port District had a very positive experience with SDG&E installing the charging infrastructure under this PRP. Both participants had experience with similar efforts that required coordinating with contractors and the utility, and both stated that SDG&E made the installation process relatively smooth. The PRP participants noted that SDG&E's communication regarding the construction and installation was very good and resulted in minimal impact on terminal operations.
- Utility bills for Metro Cruise and Pasha revealed at times very high costs per kilowatt-hour delivered to the EVs during months with very low utilization before switching to a rate that

eliminated demand charges. The chargers are designed to accommodate high utilization of these vehicles by providing shorter charging times but if not managed can also result in high demand costs. Even during low utilization periods, when a faster charge is likely unnecessary, the equipment was still drawing the maximum charge level and triggering high demand costs.

- As early adopters, all PRP participants (utility, Port, fleet operators, and the evaluator) would have benefitted by regular (i.e., quarterly) check-ins after charger commissioning to review charger utilization, energy billing, and load management plans. This would encourage charger utilization, appropriate billing rates, and data collection to help inform and develop load management plans. Any issues or challenges with the charging equipment or EVs could also have been discussed and addressed during these meetings as appropriate.
- While HD truck chargers did not experience significant usage, valuable insights were gained by their participation. Many trucks of this type do operate in Southern California and the data collected is likely relevant. This project did provide insight on fuel economy and charging patterns that heavy-duty trucks experience. Larger battery capacity to provide a longer range between charges was critical for supporting fleet's operation and even longer range would be needed to electrify more of their trucks that serve a broader region. The OEM provided chargers resulted in more than 9 hours of charging needed on average to fully charge the batteries. Faster charging would likely be necessary in some scenarios and in many cases, a dedicated charging port per truck may be required.
- Operational behaviors, such as limitations as to when the vehicles are plugged in (which for some Port District tenants with union labor might be the responsibility of someone other than drivers) can also affect the cost effectiveness of electrification. Such operations rarely account for higher on-peak costs for electricity or accommodate the staggering of charging across a longer period.
- For operational energy cost savings, average monthly EV charging costs need to be at or below twenty cents per kilowatt hour. For a total cost of ownership benefit of EVs compared to baseline vehicles, LCFS credits are needed in addition to the utility provided make ready infrastructure and chargers, and vehicle incentives or grants to cover the incremental vehicle costs. Maintenance savings of EVs cannot be determined based on a limited duration data collection during the PRP.

Lessons Learned

The following lessons learned were captured during the implementation of this PRP.

- Communication with all relevant parties is important with diverse projects like these. The forklift operator had little contact with the utility in regard to how rates work and charge management functionality of the chargers. Nearly a year and a half into the project the chargers were finally programmed to avoid on-peak charging and could have been used to limit maximum demand.
- Construction projects at the Port can be very challenging and costly. Concrete can be several feet deep, which complicates trenching, so it was essential to identify sites that required minimal or no trenching to align with the approved budget. The estimates also failed to account for environmental costs, which for one potential project was forecasted to be around $150,000 due to the hazardous risk of the site; the cost precluded the site from participating in the PRP.

- Evaluating in-use performance of EVs in a new application for 12 months will most likely produce less than 12 months of operational data because of unexpected issues. Early commercial vehicle deployments tend to experience reliability issues, resulting in vehicle downtime to facilitate repairs. Deploying all of the EVs in regular operation can take from a couple of weeks to several months, as the fleet needs to adapt driving and charging operations to accommodate EVs.
- Utilities should require as part of their contract agreements with the customers that they provide vehicle utilization data (at a minimum hours or miles on a regular basis – monthly at least for each vehicle) to meet CPUC data collection template requirements and provide the necessary data for program evaluation (cost per mile is a key metric in EV's total cost of ownership). Most if not all EVs have diagnostic ports available for collecting electronic data via telematics. While not every EV comes with a telematics option, installing an aftermarket datalogger, albeit typically with upfront and monthly recurring costs, would save the fleet manual reporting requirement and provide much more reliable data. Counting on third-party data collection agreements for meeting specific grant requirements does not always provide the needed data nor deliver it on a timely basis. It is also critical to test the data collection approach soon after deployment to verify it is functioning properly.
- Charging equipment designed for certain fleet applications, including the port tractors and forklifts within this project, is not equipped with robust data collection capabilities. The Webasto chargers could not measure interval power being dispensed and instead estimated it during post-processing which revealed inaccuracy as compared to the utility meter data. Webasto is developing remote capability to retrieve data from their chargers, but while expected to be available during this demonstration, it has been postponed to 2021, requiring site visits to download the collected data. The BYD chargers for the port tractors had no monitoring capabilities and there are no plans to have that on these chargers which were early models designed for these specific truck models. BYD has developed a partnership with Amply that could provide monitoring, data collection, and managed charging capability but that would come at an additional cost and was not yet available during this PRP.

Scale-up Potential

Many forklifts exist within the Port district as well as warehousing and distribution facilities throughout this region. SDG&E's Power Your Drive for Fleets (Standard Review Project) provides funding for several hundred forklift chargers. Though operations will vary greatly by industry, charging technology is moving in a direction that can help integrate the forklift's electric consumption to times of the year and day exhibiting the least demand on the grid. Feedback consisting of maximum demand and total consumption can help operators and their industry partners identify how best to charge the forklifts compared to simply plugging in at the end of the shift. Electric forklifts of 10,000 lbs., 20,000 lbs., and above are coming to market that will see much different usage than exhibited in this project.

According to recent CEC reports, there are approximately 100,000 forklifts in the state of California.[25] Assuming these follow the national sales trends over the past 10 years,[26] 37,000 of those forklifts will be internal combustion based. If half of these (18,500) were converted to electric, the benefits shown in Table 27 could be achieved as well as a petroleum reduction 3.4 million GGE.

Table 27. Forklift scale-up potential annual emissions

	GHG (MT/yr)	SO_x (MT/yr)	NO_x (MT/yr)	CO (MT/yr)	PM (MT/yr)	VOC (MT/yr)
Net Reduction	**16,070**	**Negligible**	**91**	**379**	**0.3**	**Negligible**

Source: Evaluator Calculations

Heavy-duty trucks are less pervasive in this region compared to the other parts of the state but have a marked impact throughout the Port, including several US NAVY bases and the US-Mexico border crossing. At this time, fleet operators are more likely to augment than replace their conventional trucks with EVs due to the nascency of the technology for this application and relatively short driving ranges. Forthcoming generations with more range will allow the EVs to operate in place of conventional trucks more often.

Scale-up of this project may be challenging due to acceptance rates; however, as electric class 8 trucks become more widely available, battery capacity increases, as well as charging rates, the opportunity is quite significant. A drayage truck able to travel 150 miles daily (200-mile total range) could serve this purpose well as long as the owner/operators were willing to adapt their operations to accommodate a stop for on route charging. Alternatively, drayage trucks with 250-mile range between charges would be needed. It was not apparently clear how many drayage trucks exist within the state of California; however, given an estimated 12,000 active at the San Pedro Ports,[27] it is likely that there are upwards of 30,000 active drayage trucks in the state. An estimate of 5,000 of these are likely to have duty cycles favorable towards electrification today, with the remaining 25,000 developing as battery pack sizes increase and charging times and costs decrease. With a fleet of 5,000 drayage trucks, the benefits shown in Table 28 could be realized as well as a petroleum reduction of 17.3 million GGE.

Table 28. Drayage truck scale-up potential annual emissions

	GHG (MT/yr)	SO_x (MT/yr)	NO_x (MT/yr)	CO (MT/yr)	PM (MT/yr)	VOC (MT/yr)
Net Reduction	**132,713**	**14**	**390**	**136**	**7**	**48**

Source: Evaluator Calculations

[25] California Energy Commission, “Zero Emission Forklifts,” accessed November 2020, https://ww2.arb.ca.gov/our-work/programs/zero-emission-forklifts/about.

[26] Industrial Truck Association, “United States Factory Shipments,” accessed November 2020, https://www.indtrk.org/wp-content/uploads/2019/02/United-States-Factory-Shipments-Table-2018.pdf.

[27] Tetra Tech/Gladstein, Neandross & Associates, “San Pedro Bay Ports Clean Air Action Plan,” May 2020, https://cleanairactionplan.org/documents/final-drayage-truck-feasibility-assessment.pdf/.

3.5 Electrify Local Highways

3.5.1 Project Narrative

Overview, Objectives, and Barriers Being Addressed

The 2016 Governor's Zero-Emission Vehicle (ZEV) Action Plan tasked California's Department of Transportation ("Caltrans") with installing DCFCs at some of its locations throughout the state. Caltrans' 2016 Sustainability Implementation Action Plan prioritized the installation of electric vehicle (EV) charging stations on Caltrans-owned park-and-ride facilities, as these locations are good for both long-duration parking and charging, as well as quick stops for DCFC use. Caltrans District 11 did not have the means or necessary expertise to own, operate, and maintain EV charging stations and determined that a third-party end-to-end solution could be the best option for providing a positive customer experience. Caltrans has concerns about the availability of resources to oversee such an effort and has not been able to find the right charging installation programs that would provide an end-to-end solution through a third party, which could take on the installation, ownership, customer service, billing, maintenance, and operations efforts altogether.

San Diego Gas & Electric (SDG&E) was approved to spend $4,000,000 to install, own, maintain, and operate 80 Level 2 (L2) and 8 DCFCs at four Caltrans-owned park-and-ride locations for this priority review project (PRP). As part of this collaboration, Caltrans would provide land rights, parking spaces, and expertise to help streamline the design, permitting, and installation efforts. SDG&E will study charging patterns and share the usage data for modeling charging infrastructure at these park-and-ride locations. SDG&E will also test time-of-use (TOU) pricing in the public domain, as well as test the standards for public charging signage, rate display, and general retail EV fuel dispensers. This will be the first time that SDG&E will test how to easily communicate a TOU rate to the public at a charging station.

Sites and Participants

Recruitment Process

SDG&E worked closely with Caltrans District 11 during the application process for this PRP. Most of the sites were identified prior to the application, and SDG&E collaborated with Caltrans on site design and permitting. This PRP had a set charging station deployment goal with a specific partner and was not established as a project that would recruit additional partners or solicit participation by small, locally owned, minority-owned, and women-owned businesses.

Participants

Caltrans supports more than 60 park-and-ride locations in the San Diego region and owns 33 of these locations. Of the 33 state-owned park-and-ride locations, Caltrans initially identified four locations for this project, each located within or adjacent to a DAC:

- Pala: Located across the freeway from a large DAC at the northwest corner of the I-15 freeway and Highway 76 in northeastern San Diego county
- Oceanside Transit Center: Located across the street from a DAC at 235 South Tremont Street in Oceanside (northwestern San Diego county)

- National City: Located within a DAC at 2300 Sweetwater Road in National City (just south of downtown San Diego)
- Chula Vista: Located on Palomar Street within a DAC off the I-805 freeway in Southern San Diego county

Figure 86. SDG&E Electrify Local Highways installation sites

Source: SDG&E

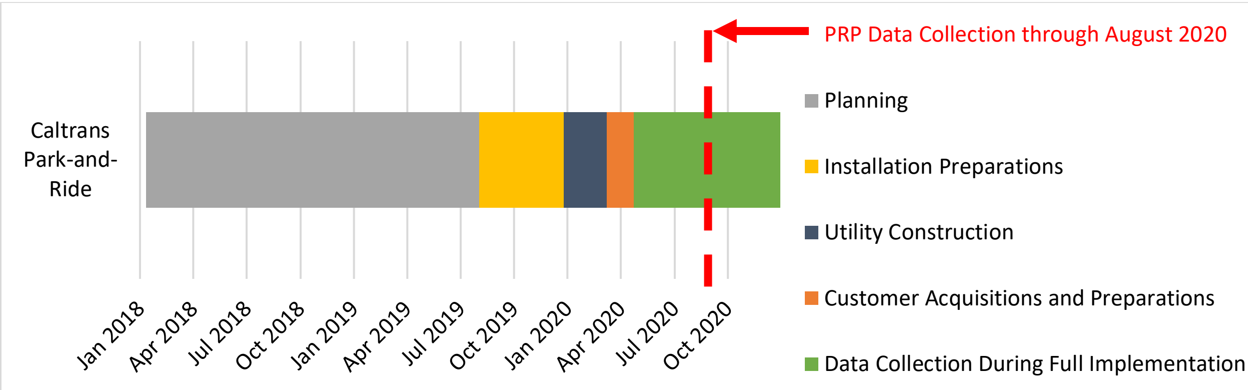
The sites in National City and Ch ula Vista remained in the project implementation plans, but Pala was replaced by a park-and-ride at 13516 Camino Canada in El Cajon off I-8, and the Oceanside location was moved from the Transit Center to a nearby park-and-ride at 1928 South Moreno Street off I-5. Each of these park-and-ride sites are located along major freeways within SDG&E's territory, as well as within or adjacent to DACs.

ChargePoint was selected to provide the EVSE and the network services following the completion of DCFC meter testing requirements. Twenty 7.2 kW L2 stations and two 62.5 kW DCFCs (compatible with the CHAdeMO and Combined Charging System ["CCS"] standards) were installed at each site. SDG&E is working with skilled contractors (affiliated with the International Brotherhood of Electrical Workers) for the installation and maintenance of the charging equipment.

Timeline and Status

Figure 87 shows the PRP timeline. The project had delays for various reasons, and construction did not begin until November 2019. SDG&E had to perform penetration (security) and meter testing on the DCFCs to ensure they would meet requirements, and a contract was executed with ChargePoint in April 2019. The longest delay was contracting land rights with Caltrans, which required involvement of several internal departments. During the process, Caltrans brought up questions about the site designs, with specific concerns about complexities and potential disruption to operations. Securing the necessary permits was also more complicated than anticipated, particularly for the National City site, which required more extensive trenching to bring power to the charger location.

Figure 87. SDG&E Electrify Local Highways PRP timeline as of October 2020



Source: SDG&E

3.5.2 Evaluation Methodology

Selected Methods and Rationale

In addition to the evaluation questions that apply to all PRPs and those specific to the Public Access Station PRPs, the evaluation questions listed below will be examined for this PRP.

- How do customers respond to TOU pricing?
- Given the high-occupancy vehicle (HOV) incentive for EVs, will EV drivers still be motivated to come to the park and ride?
- How does utilization compare between the L2 and DCFC?
- Is EV occupancy of the charger after being charged preventing others from accessing the charging stations?
- Do some sites perform better than others, and if so, what was the reasoning behind the difference?

The data collection sources utilized to evaluate this PRP include 1) PRP information from the approved decision, project updates, site visits, and other available documentation, 2) market research on DCFCs and early deployment efforts from other similar electrification projects across the country, 3) PRP data from charger operations, 4) in-depth interviews (IDIs) with project partners, and 5) surveys with vehicle drivers.

Data Sources

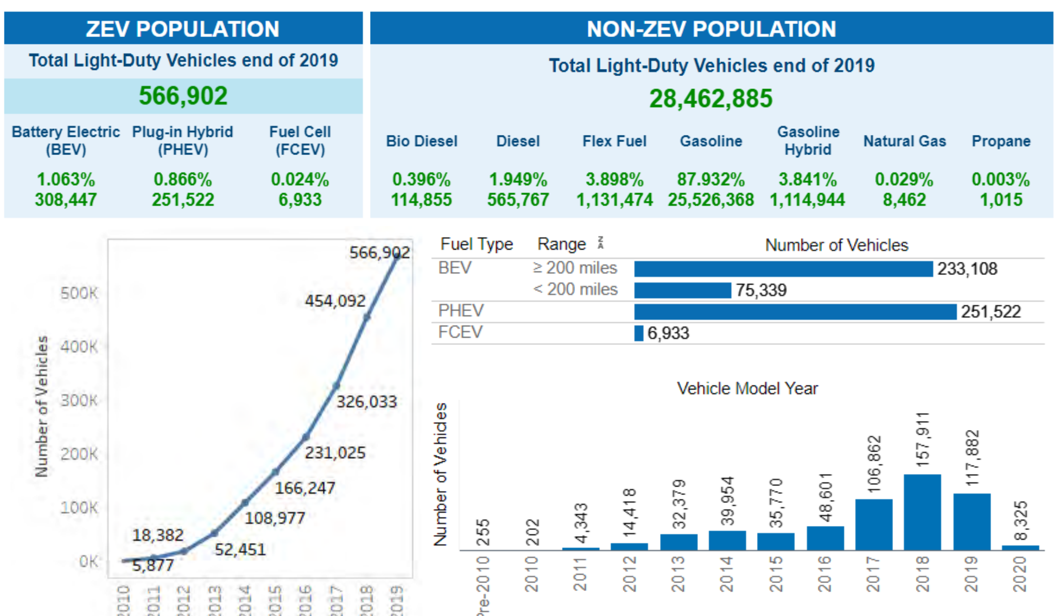
SDG&E provided 15-minute interval data from its utility service meters (one utility meter at each deployment site for the 20 L2 and one for 2 DCFC charging stations at that site) and monthly electricity costs. Charging station session data was also provided by SDG&E through direct access to the ChargePoint (the network service provider) online portal. The evaluator collected PRP information through numerous PRP participant interactions: the PRP kick-off meeting (SDG&E and evaluator), quarterly PAC update meetings, weekly PRP updates (SDG&E and evaluator), site visits, and other periodic calls or emails. Through these, the evaluation team collected charging station hardware specifications, EV specifications, electricity tariff details, construction plans, and project costs. The evaluator held initial IDIs with representatives from the SDG&E PRP management team and SDG&E construction staff to further understand the background on this project and gather lessons learned during the planning and construction phases. Additional IDIs with SDG&E staff, Caltrans, and ChargePoint took place in 2020 after all four sites were commissioned. A survey of the EV drivers was conducted in collaboration with SDG&E and ChargePoint to gauge customer satisfaction.

3.5.3 Evaluation Findings

Project Baseline

After the initial 2016 ZEV Vehicle Action Plan was announced, Governor Brown raised the bar and increased the target number of ZEVs on the road and public EVSE across the state with the 2018 update. This increased the initial 1.5 million ZEV goal by 2025 to 5 million by 2030 and calls for 250,000 public charging stations by 2025 with at least 10,000 being DCFC.[28] Since 2012, ZEV adoption in California has continued to increase as shown in Figure 88.[29] To reach the 2030 vehicle goals, however, ZEV adoption will need to increase significantly with ZEV portion of new sales reaching 40% of the market share.

Figure 88. CEC zero-emission vehicle statistics



Source: California Energy Commission

[28] 2018 Zev Action Plan Priorities Update, Governor's Interagency Working Group on Zero-Emission Vehicles, http://www.business.ca.gov/Portals/0/ZEV/2018-ZEV-Action-Plan-Priorities-Update.pdf.

[29] California Energy Commission (2020). California Energy Commission Zero Emission Vehicle and Infrastructure Statistics. Data last updated August 28, 2020. Retrieved November 27, 2020 from https://www.energy.ca.gov/zevstats.

There are an estimated 27,000 public chargers (L2 and DCFC) and 39,500 shared private chargers in California as of end of August 2020 as shown in Table 29.[29] Nearly 5,000 public DCFCs have been installed, which accomplish about half of the State's 2025 goal.

Table 29. CEC EV charger statistics

Charger Type	Public	Shared Private	Grand Total
Level 1	329	166	495
Level 2	22,531	38,949	61,480
DCFC	4,818	550	5,368
Total	27,678	39,665	67,343

Source: California Energy Commission

Implementation Process

Three of the four sites did not have any existing charging infrastructure. One site was recently constructed and was built with make-ready upgrades by a contractor hired by CalTrans. This was done prior to the commencement of this PRP. Unfortunately, the make-ready infrastructure that was installed would not meet the needs of the chargers (inadequate capacity) and had to be replaced. Traffic control costs may be much higher than the $2,000 planned budget for the National City site as the site required paving and striping on a county road. This site also had complications with the right-of-way permit. The National City site is unique as the construction is planned in Caltrans, National City, and the San Diego County right-of-way (trenching across Sweetwater road).

Each Electrify Local Highways PRP site consists of 250 kW of charging capacity with 20 ChargePoint L2 EVSE at 6.6 kW each and two ChargePoint DCFC at 62.5 kW with both CHAdeMO and CCS connectors.

Oceanside

Figure 89 and Figure 90 show the EV charger installations at Oceanside Caltrans park and ride location. The two DCFCs are accessible from the two assigned parking spaces. However, each charger can be accessed by both stations which provides some redundancy in case one unit becomes inoperable. Shifting the DCFCs approximately three feet further from the curb would have enabled access by four parking spaces accommodate vehicle turnover. The charging cords for the 20 L2 EVSE can reach 22 parking spaces, but those two extra spaces are not currently labeled for charging use. Station signage is the same for all charging spaces regardless of whether it is in front of a DCFC or L2 station. Updating DCFC parking space signage to "Parking only while charging; 1-hour limit" would enforce the short duration nature of use for those which may be helpful in managing the charging assets as usage increases (ensuring a day-long commuter does not park there to charge). Strategically, L2 EVSE are placed between parking spaces on both sides, but that can lead to uncertainty over which charging cord the EV driver should select and may result in some spaces not having an accessible charging cord when several EVs are parked next to each other.

Figure 89. Path of trenching from power source to switchgear and to the chargers

Source: Evaluator team and Google Maps

Figure 90. Row of chargers, with DCFCs at one end where better positioning could have increased access by four parking spaces

Source: Evaluator team

National City

Figure 91 and Figure 92 show the EV charger installations at National City Caltrans park and ride location. This installation design has a dual cord EVSE in between every other parking space. There are two nearby shopping centers that may be visited while drivers charge their EV at the DCFC which may result in higher usage and warrant parking access for more spaces that can access charging cords.

Figure 91. Satellite image of National City site, switchgear location, and trenching path

Source: Evaluator team and Google Maps

Figure 92. DCFCs on dedicated parking spaces and dual-port L2 stations between parking spaces with signage at each space

Source: Evaluator team

Chula Vista

Figure 93 and Figure 94 show the EV charger installations at Chula Vista Caltrans park and ride location. This parking lot has varying terrain and the construction appears located in the flattest area to avoid breaking and repairing hardscape. The trenching design utilized existing unpaved areas to avoid rework in the lot. L2 EVSE are arranged in two rows; each supplied by a trench of approximately 175 feet in length. A third trench around 100 feet feeds the two DCFCs in a different parking row where they can be accessed from three parking spaces. If the chargers were moved over a few more feet and separated, they could have been accessed by a fourth or even fifth parking space to support more frequent vehicle charging turnover. This location is next to a series of fields, in between two schools, and adjacent to a neighborhood. Activities in this area may align well with L2 charging durations or generate demand and congestion for the DCFCs. The dual-port L2 EVSE are installed between every other parking space. For the same distance of trenching as the two one-sided parking rows where the L2 stations are installed, these could have been placed between two head-to-head parking rows with access from both sides to potentially double the current charging access (so someone arriving mid-day could potentially disconnect a fully-charged EV that might remain connected the entire day while the driver is at work.

Figure 93. Satellite image of chula vista site with trenching path (orange) and an alternative trenching route to head-to-head parking rows (blue)

Source: Evaluator team and Google Maps

Figure 94. One of the L2 EVSE rows at Chula Vista

Source: Evaluator team

El Cajon

Figure 95 and Figure 96 show the EV charger installations at El Cajon Caltrans park and ride location. All EVSE at this site are in the middle of the parking lot in head-to-head parking rows. The main trench measures approximately 125 feet while L2 power supply branch is 150 feet and the DCFC power supply branch measures 50 feet. The DCFC cords may stretch to reach five parking spaces with two EV-charging reserved, two ADA designated, and a fifth with no designation at this time. However, due to the charging cord length it is difficult to reach each parking spot comfortably and requires strategic parking of the vehicle based on where the charging port is located. If each DCFC was installed evenly in the middle of four parking spaces, these two stations could have reached eight total spaces enhancing vehicle charging turnover. There is a single L2 EVSE supporting two ADA spaces that may reach two more spaces depending on the EV model. An adjacent L2 EVSE supports a dedicated charging space but could reach another that is currently not labeled for charging use. The row of 18 L2 EVSE between head-to-head parking rows can stretch to reach a total of 21 parking spaces.

If all chargers were placed one row further in the parking lot with both L2 EVSE and DCFCs between separate parking spaces, six more parking spaces could have accessed the same number of L2 stations and three more parking spaces could have accessed the DCFCs. Overall trenching length would have been similar as it would have not required a trench back to the first row for the ADA-accessible chargers (they could have been in this same row). However, the site design has the best layout out of all four to provide the most parking spaces with access to charging. Cords that reach more parking spaces generally provide more EV miles of charging because cords can be swapped once one vehicle is fully charged, or others can park in a DCFC adjacent space to start charging as soon as the first EV driver is finished.

Figure 95. Satellite image of El Cajon site with trenching path (orange) and an alternative trenching route to support greater parking space access to chargers (blue)

Source: Evaluator team and Google Maps

Figure 96. Row of L2 EVSE with DCFCs (ADA L2 EVSE in the background)

Source: Evaluator team

The charging fee structure for these sites is identical and is related to the cost of energy at the time of use. It will vary during winter and summer months according to Table 30. ChargePoint adds a 5% service fee as they are a customer of record (receiver of the utility bills).

Table 30. Charging station fees (2020)

Time Period	Winter Cost	Summer Cost
12 am – 6 am	$0.20033 per kWh	$0.19951 per kWh
6 am – 4 pm	$0.30523 per kWh	$0.35071 per kWh
4 pm – 9 pm	$0.31396 per kWh	$0.59326 per kWh
9 pm – 12 am	$0.30523 per kWh	$0.35071 per kWh

Source: PlugShare

Costs

The approved PRP had an anticipated total direct cost of $4,000,000, consisting of $3,309,212 in capital and $690,788 in expense, as shown in Table 31.

Table 31. SDG&E Electrify Local Highways PRP proposed costs

	Capital Costs	O&M Expenses	Total PRP Costs
Transformer and Install	$ 147,000	$ 3,316	$ 150,316
Electrical Service	$ 559,372	N/A	$ 559,372
EVSE Costs	$ 1,757,728	$ 32,472	$ 1,790,200
Purchased and SD Software	$ 845,112	N/A	$ 845,112
Customer Engagement	N/A	$ 200,000	$ 200,000
Measurement and Evaluation	N/A	$ 250,000	$ 250,000
Billing Support	N/A	$ 80,000	$ 80,000

	Capital Costs	O&M Expenses	Total PRP Costs
SDG&E Clean Transportation PM	N/A	$ 100,000	$ 100,000
First-Year O&M Service Calls	N/A	$ 15,000	$ 15,000
First-Year O&M for Charging Equipment	N/A	$ 10,000	$ 10,000
Total Costs	$ 3,309,212	$ 690,788	$ 4,000,000

Source: SDG&E

The estimated total PRP direct costs are $2,477,557 out of the budgeted $4,000,000, as shown in Table 32 (presented in categories reported by the utility).

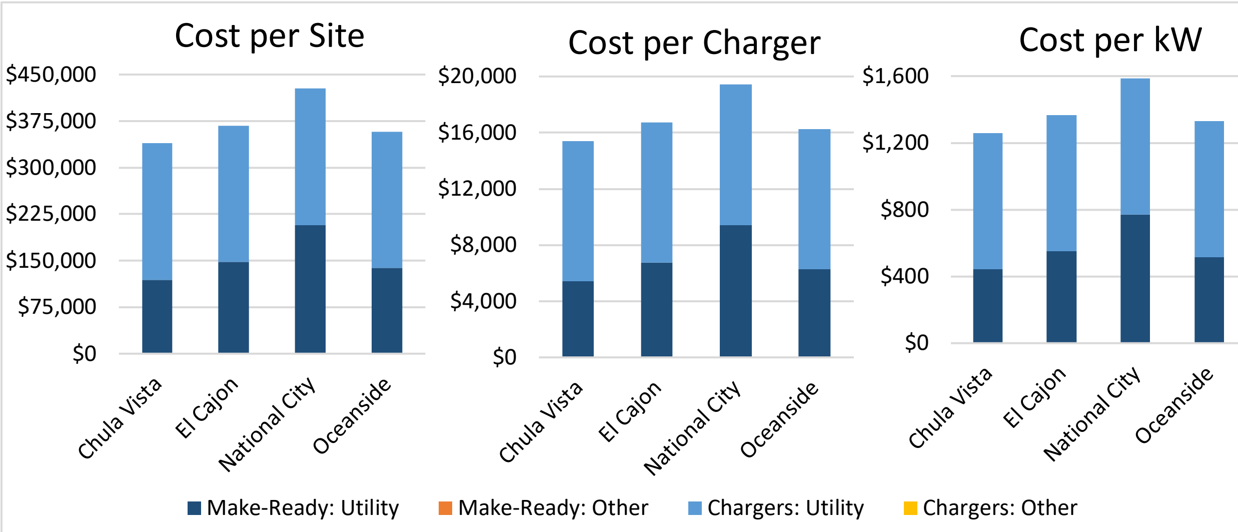
Table 32. SDG&E Electrify Local Highways PRP estimate at completion (EAC)

	EAC Capital Costs	Budgeted Capital Costs	EAC O&M Costs	Budgeted O&M Costs
Construction	$ 612,992	$ 1,285,097	N/A	N/A
Engineering Design	$ 199,287	$ 134,600	N/A	N/A
Chargers, Meter Pedestals, Transformer, and Other Materials	$ 878,884	$ 1,044,403	N/A	N/A
Internal SDG&E Labor (Program Management and Support)	$ 48,821	N/A	$ 203,524	$ 180,000
IT Costs	$ 432,418	$ 845,112	N/A	$ 250,000
Customer Engagement and Outreach	N/A	N/A	N/A	$ 200,000
Other	$ 101,525	N/A	$ 106	$ 60,788
Direct Costs	$ 2,273,927	$ 3,309,212	$ 203,630	$ 690,788
Non-Direct Costs (Indirect, AFUDC, and Property Taxes)	$ 372,350	$ 1,812,703	$ 197,654	$ 246,693
Total Costs	$ 2,646,277	$ 5,121,915	$ 401,284	$ 937,481

Source: SDG&E

Figure 97 shows the total capital costs, cost per charger, and cost per kW of installed charging capacity for each of the four sites. Costs are separated by make-ready and charger costs which were either paid for by the utility through this PRP or a source of funding "other" than the utility which may be the host site, grants, etc. As expected, due to a more complex location, National City cost is about 20% higher than the other sites. As the number and power rating of the chargers does not differ among the sites, all three graphs show the same trend. Utility covered all charging infrastructure expenses.

Figure 97. SDG&E Electrify Local Highways EV charging infrastructure costs



Source: SDG&E

Benefits

SDG&E's initial estimate of vehicle usage for each Caltrans site is one charge per day for L2 charging stations (supporting a mix of 60% battery electric vehicles and 40% plug-in hybrid electric vehicles), and five charging sessions per day for each of the DCFC (all battery electric vehicles), which is a total of 120 vehicles charged per day among the four sites. The anticipated benefits from the testimony are the same as planned since the same number of charging stations was deployed. The key benefits and some contributing factors are outlined below, with a more detailed description of this benefit analysis in the Appendix. Operational cost savings are based on an average of $3.00 per gallon of gasoline and a sum of fees collected from each charging event.

This PRP includes four separate public charging station locations. Two of these, Chula Vista and National City are in a DAC according to CalEnviroScreen 3.0 using the SDG&E territory determination. It was also determined that 46% of the top 20 driver ZIP codes were defined as DACs based on SDG&E territory determination. Since there is no tracking of where the EVs that charge at these stations drive, based on this information, 50% of the emission benefits can be attributed to disadvantaged communities. The other two sites are adjacent to a DAC and EV drivers living in or near a DAC also regularly drive in areas adjacent to a DAC, so an additional 25% of this PRPs benefits are estimated to occur adjacent to a DAC.

The pilot demonstration period from May 2020 to September 2020 is used to calculate performance. Light-duty EVs charging at these sites achieve an average efficiency of 3.46 miles per kWh while equivalent internal combustion engine vehicles have an average fuel economy of 24.9 MPG.[30]

[30] Internal combustion engine vehicle efficiency same as used in the Electric Vehicle-Grid Integration Pilot Program ("Power Your Drive") Ninth Semi-Annual Report of San Diego Gas & Electric Company (https://www.sdge.com/sites/default/files/regulatory/R.18-12-006%20Ninth%20Oct%202020%20PYD%20Final%20Report%2010%2014%202020.pdf), October 14, 2020.

Determined on an annual basis, the charging stations dispensed 48,940 kWh per year which corresponded with utility supplied electricity of 56,780 kWh per year, with 14,00 kWh (25%) occurring during on-peak hours. This resulted in 169,300 electric miles for which internal combustion engine vehicles would have consumed 6,800 gallons of gasoline, which is therefore saved.

Several factors limited utilization of these charging station during the demonstration period, so the best observed analysis looked at the busiest week for an individual location for each type of charging (DCFCs and L2 EVSE). For L2 EVSE potential use, the busiest week still only had 3 chargers used at any one time (which was only for 1 hour during the entire week), so the busiest week was scaled up by 6.67 (20 chargers total / 3 chargers used at once). Combining these best performances for DCFCs and L2 EVSE results in 929 events per week dispensing 7,220 kWh. Annually this equates to 375 MWh of electricity dispensed (393 MWh of supplied electricity with 20% on-peak) supporting 1,299,000 electric miles which would have consumed 52,200 gallons of gasoline. Table 33 presents the annualized benefits.

Table 33. SDG&E Electrify Local Highways PRP annualized benefits

	Testimony/Planned (80 L2 + 8 DCFC providing 120 charge events per day)	Implemented (80 L2 + 8 DCFC providing 10 charge events per day)	Best Observed (80 L2 + 8 DCFC providing 133 charge events per day)
Petroleum Reduction	23,000 GGE	6,800 gallons of gasoline	52,200 gallons of gasoline
GHG Emissions Reduction	155 MT of CO_{2e}	65 MT of CO_{2e}	518 MT of CO_{2e}
Criteria Pollutant Emissions Reduction	10 kg of NO_X 20 kg of VOC	49 kg of NO_X 68 kg of VOC 548 kg of CO 13 kg of SO_X 5 kg of PM	388 kg of NO_X 522 kg of VOC 4,212 kg of CO 104 kg of SO_X 40 kg of PM
DAC Impact	2 sites within a DAC and 2 sites adjacent to a DAC	50% within a DAC, an additional 25% likely adjacent to a DAC	50% within a DAC, an additional 25% likely adjacent to a DAC
Grid Impacts / Electricity Consumption	211 MWh, with improved net load factor (if charging is properly managed)	57 MWh, with 25% consumed on-peak	393 MWh, with 20% consumed on-peak
Operational Energy Cost Savings	N/A	\$2,370 for Drivers (\$0.65 per charge event)	\$31,800 for Drivers (\$0.66 per charge event)

Source: Evaluator Calculations

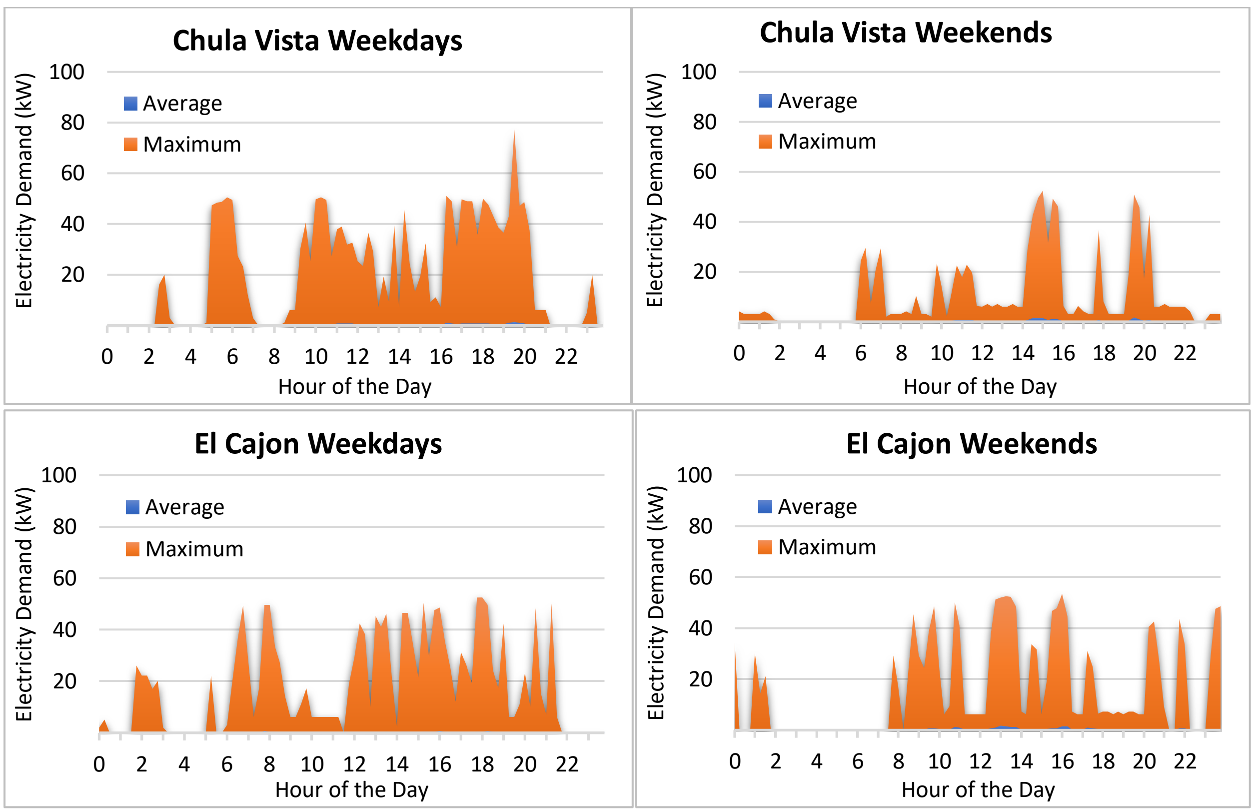
Operational Impacts of Project Equipment

Overall use of EVSE at the four charging sites was low during the data collection period (May 1 through September 30, 2020). DCFCs across all four sites were connected to vehicles less than 2% of the time and averaged only five charging events per week. L2 EVSE had their ports connected to vehicles for less than 1% of the time and averaged only one charging event every three weeks. Low use can undoubtedly be attributed to dramatically reduced driving (especially by commuters who would be expected to primarily use L2 EVSE) due to the COVID-19 pandemic and its resulting stay-at-home orders.

Demand Curves

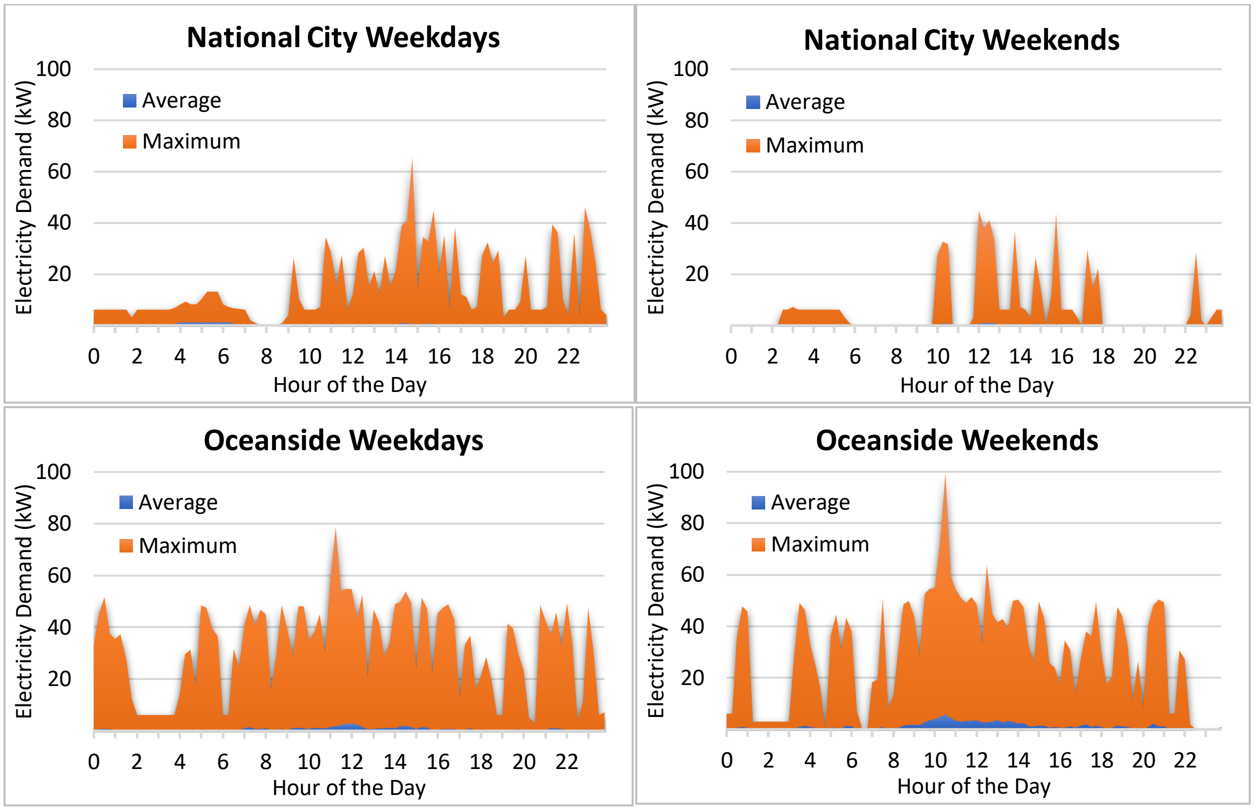
Each Electrify Local Highway PRP site has a total installed charging capacity of 257 kW (two 62.5 DCFCs and twenty 6.6 kW L2 EVSE). An analysis of the utility meter 15-minute interval demand data from July 6 to August 30 showed that most demand peaks for these sites hit approximately 50 kW. Chula Visit reached 76 kW, El Cajon 52 kW, National City 65 kW, Oceanside 77 kW all during one weekday fifteen-minute period. The highest demand occurred at Oceanside (94 kW) during one weekend fifteen-minute period. The average demand is barely visible on the charts in Figure 98 and Figure 99 as utilization is infrequent and inconsistent during this time period.

Figure 98. Electricity demand curves for Chula Vista and El Cajon (July 6–August 30, 2020)



Source: SDG&E Meter Data

Figure 99. Electricity demand curves for National City and Oceanside (July 6–August 30, 2020)



Source: SDG&E Meter Data

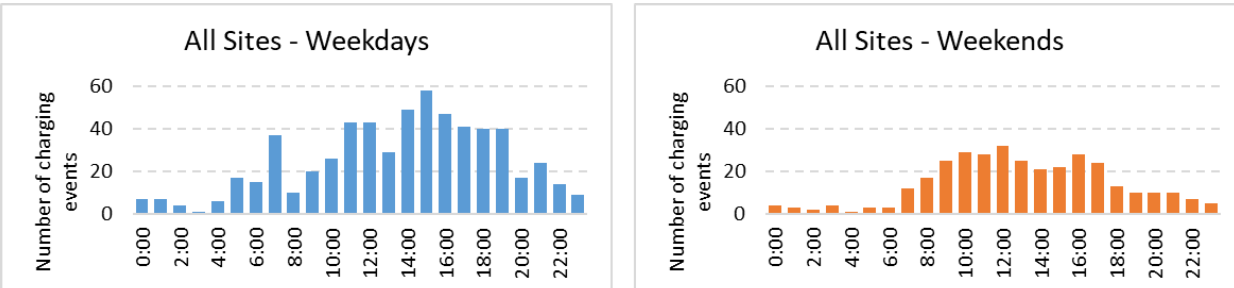
There are some differences in the maximum electricity demand between weekdays and weekends at these sites, but the demand is strongly influenced by DC fast charging events that occur sporadically almost any day of the week.

The four charging sites have vastly more capacity than has been used to date. However, the question that policy makers and regulators face is not what charging demand relative to capacity has been, but what it will be in the future. To establish expectations for future charger utilization and estimate how much existing capacity might be used, user charging behavior must be examined.

DCFC Usage

DCFC usage showed some variation relative to time of day, as shown in Figure 100. Session start time peaked during the 3 PM hour on weekdays and at noon on weekends but was fairly uniform between 11 AM and 7 PM on weekdays and between 9 AM and 5 PM on weekends. Drivers also often started charging events during the 7 AM hour on weekdays, presumably as part of the morning commute or prior to starting a shift for professional drivers, but this was not a dominant trend. Charging sessions were less common, in the late evenings and less so after midnight; however, DCFCs were used at all hours of the day. Overall, use of these DCFCs relative to time of day was consistent with use profiles observed in the EV Project.[31]

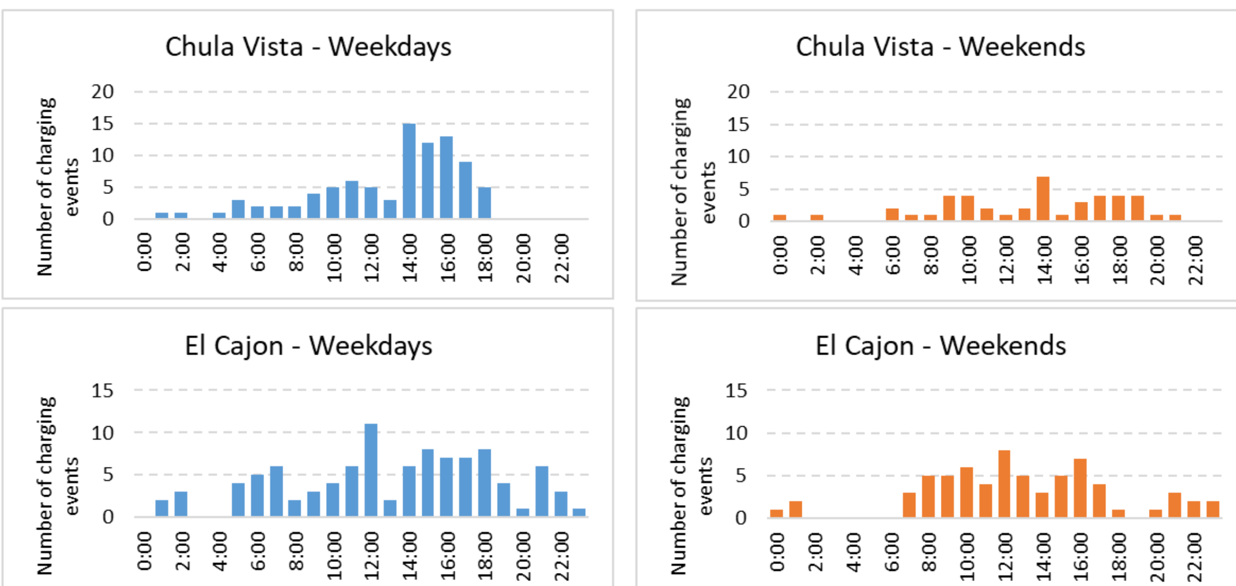
Figure 100. Time of day at the start of DC fast charging events (all sites, entire reporting period)



Source: EVSP Charging Session Data

Viewing the distribution of DC fast charging session start times for each site separately (Figure 101 and Figure 102) makes it easier to see three distinct periods of high use: early-morning (5 AM–8 AM), mid-day (9 AM – 1 PM), and afternoon (2 PM – 7 PM). Chula Vista peaks in the afternoon, El Cajon peaks at mid-day, National City peaks in the early-morning and afternoon, and Oceanside peaks at mid-day and again in the afternoon period.

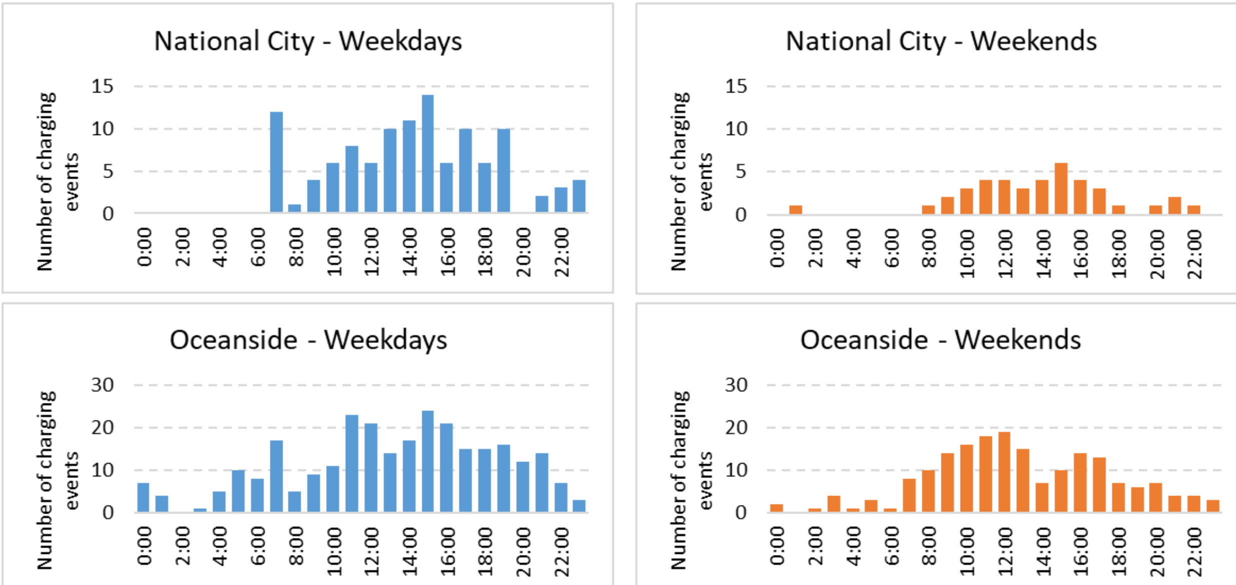
Figure 101. Time of day at the start of DC fast charging events (Chula Vista and El Cajon, entire reporting period)



Source: EVSP Charging Session Data

[31] See EV Project Electric Vehicle Charging Infrastructure Summary Report, January 2013 through December 2013

Figure 102. Time of day at the start of DC fast charging events (National City and Oceanside, entire reporting period)



Source: EVSP Charging Session Data

Charging sessions ranged from a minute to over five hours, with a median duration of 24 minutes. The two inner quartiles ranged between 16 and 40 minutes. This was consistent across all four sites.

DC fast charging power tapers off as battery state of charge (SOC) increases past about 80%. Therefore, viewing the breakdown of charging events relative to their ending SOC can be helpful. Users ending charging sessions when SOC is below 80% are more focused on time—getting in and out quickly—whereas users ending charging sessions when SOC is greater than 80% are more likely to be interested in maximizing their range replenished through charging. Figure 103 provides this breakdown by site. It shows that most users charged beyond 80% SOC, which can be considered "full" charges, but more users at El Cajon and Oceanside ended charging sessions with SOC below 80%. In Figure 104, each vertical line represents the change in SOC during an event. Ordered based on the ending SOC shows many events ending right at 80% and another grouping at 90%, but overall a wide range of starting and ending SOC.

Figure 103. Fraction of full and partial DC fast charging events by site

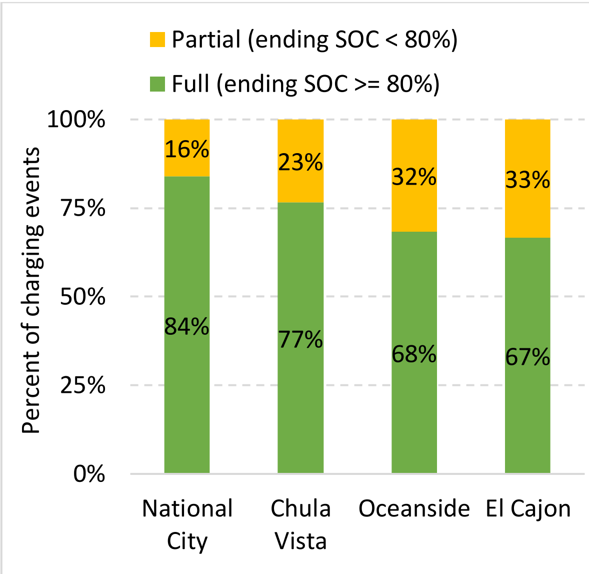
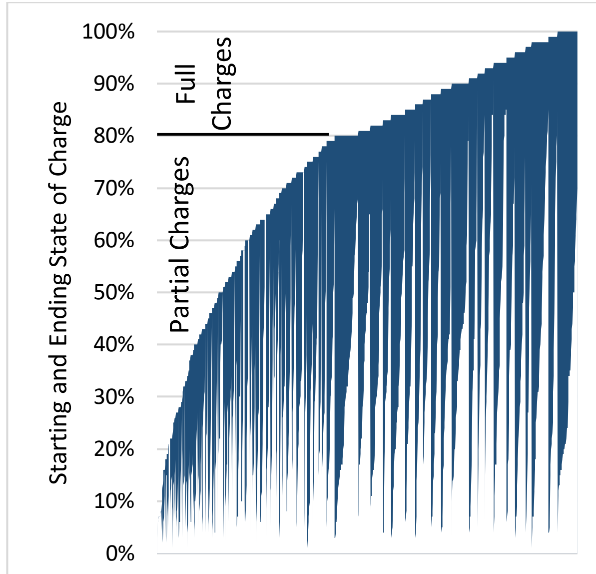


Figure 104. Change in SOC per DC fast charging event ordered by ending



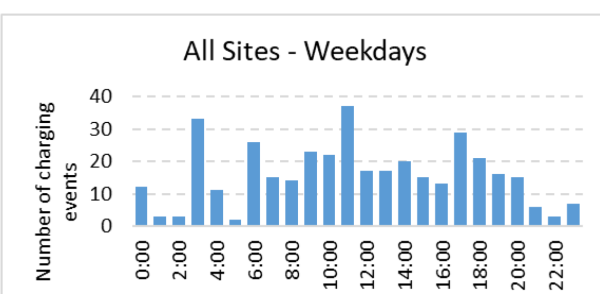
Source: EVSP Charging Session Data

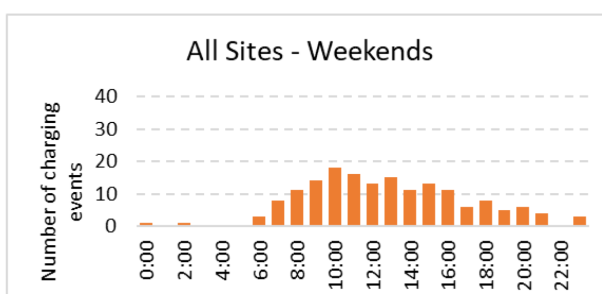
There were 265 distinct users who charged their vehicles with a DCFC at any of the four sites during the reporting period. However, only 20 vehicles charged more than 10 times. Most users (62%) only charged once during the 5 months. The most frequent user conducted 44 charging events between June and August. Sparse use of DCFCs by most drivers indicates that few users were reliant on these four charging sites as their primary sources of charging (or if they were, they drove very little during the reporting period). Examination of charging by the most frequent users found that most used DCFCs across a range of times on both weekdays and weekend days. Only one user showed a consistent pattern of charging only in the early morning and afternoon periods, with charges in both periods on two days.

L2 EVSE Usage

L2 EVSE were used during all hours of the day during the reporting period. The most popular time to plug in on weekdays was during the 11 AM hour. The peak at 3 AM on weekdays is attributed to a single user who often charged at the National City and Chula Vista sites in the early morning.

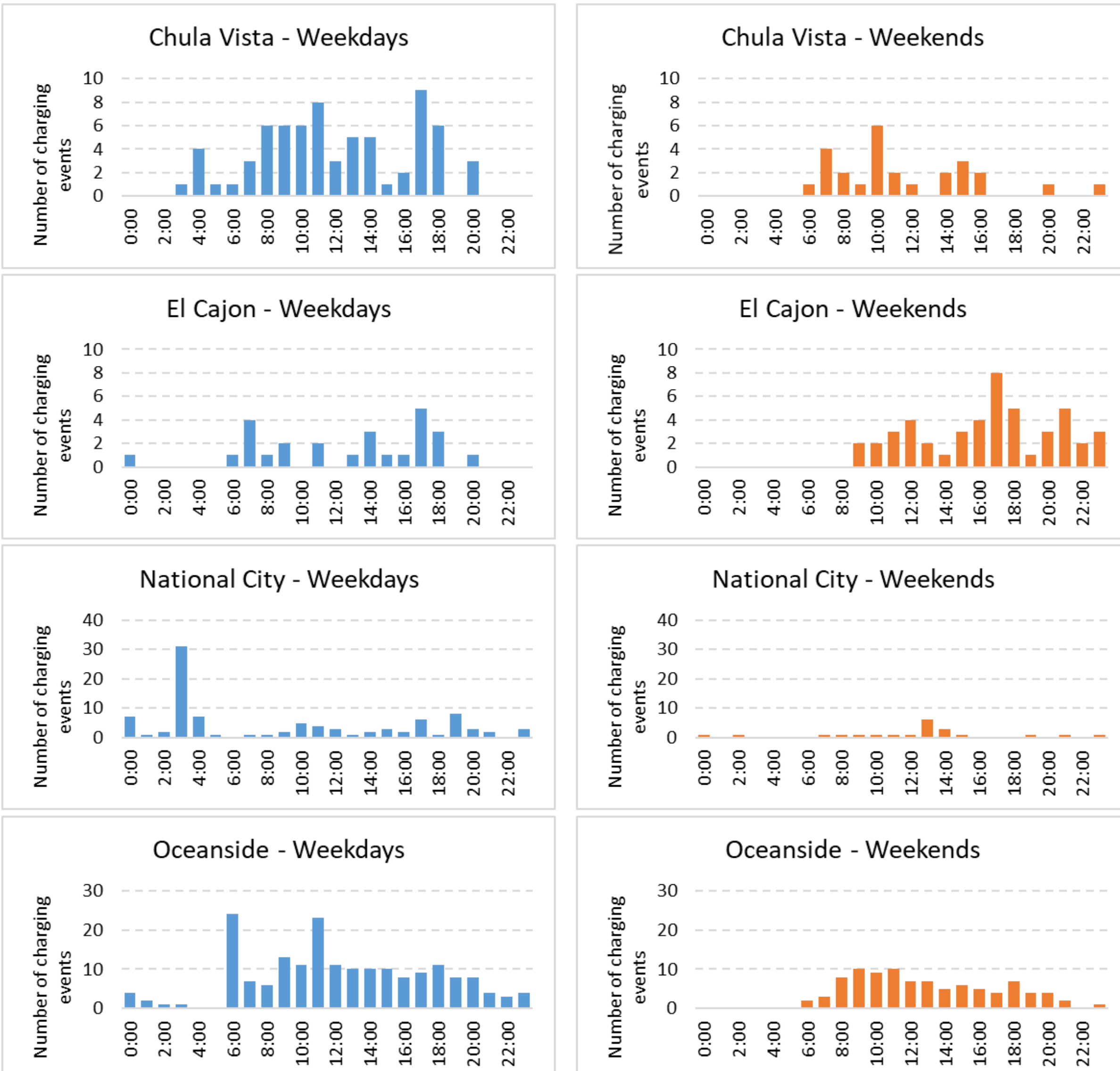
Figure 105. Time of day when L2 EVSE users started charging sessions (all sites, entire reporting period)





Source: EVSP Charging Session Data

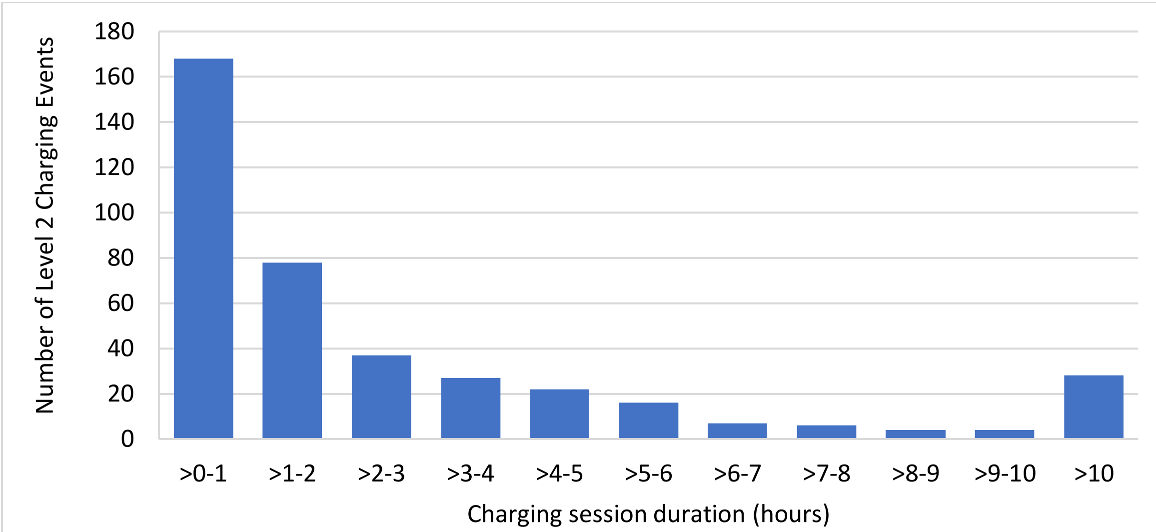
Figure 106. Time of day when L2 EVSE users started charging sessions (each site, entire reporting period)



Source: EVSP Charging Session Data

The 6 AM and 5 PM hours were the next most popular times to plug in. Many morning plug-in times are consistent with the expectation that EV drivers would use the sites as park-and-ride lots, leaving their vehicles plugged in while they traveled by another mode to work. However, inspection of session data found that only five of 138 L2 users were connected for more than 8 hours when plugging in before noon, such that these users could be considered commuters. These sessions amounted to only 9% of all events, and only two users were responsible for two thirds of these 8+ hour events. The vast majority of users charging at L2 EVSE during the reporting period did not seem to use the sites as conventional park-and-ride commuter lots. Figure 107 shows the distribution of weekday charging session duration, which can also be considered dwell time at the sites. The median session duration on weekdays was 1.25 hours.

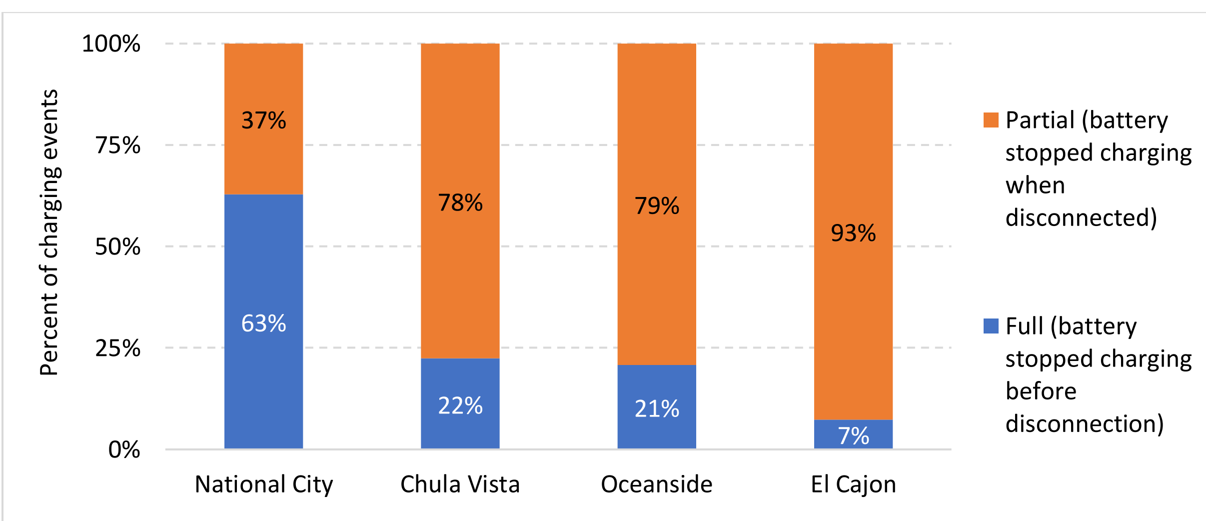
Figure 107. Distribution of charging session duration (i.e., time the vehicle spent connected to the EVSE per charging session) for L2 EVSE (all sites on weekdays, entire reporting period)



Source: EVSP Charging Session Data

Another way of looking at user dwell time at L2 EVSE is to compare the number of charging sessions that were full versus partial charges. For L2 charging, a full charge is one where power stops flowing (i.e., the battery stops charging) before the user disconnects the vehicle. Figure 108 shows the split of full and partial L2 charges at each site on weekdays throughout the entire reporting period. Users at National City site had a much higher percentage of full charges than at other sites. Inspection of session data found that full charges were performed by only 6 of 27 weekday users, and most of the full charges were performed by the user that plugged in between 3 AM and 5 AM. This user was one of the few that exhibited commuting behavior (and one of the two users responsible for most of the 8+ hour charging sessions that started in the morning). The other five users responsible for the full charges at National City site almost always stayed connected for less than three hours.

Figure 108. Fraction of full and partial L2 weekday charging events by site

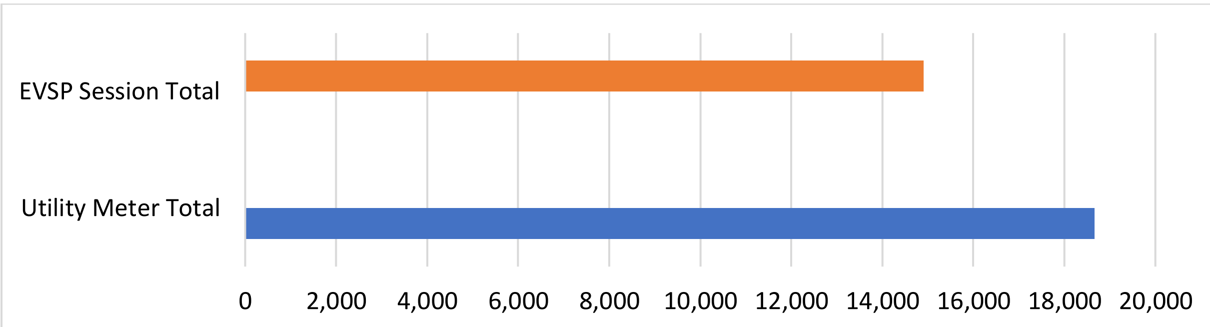


Source: EVSP Charging Session Data

Utility and EVSP Metering

Electricity dispensed to users is tracked by the EVSP and recorded as charging sessions. Electricity supplied to the chargers at the site is metered by the utility and captured through 15-minute interval data. Analyzing the totals from each of these sources between May 1 and August 30, 2020 there was a 20% difference as shown in Figure 109.

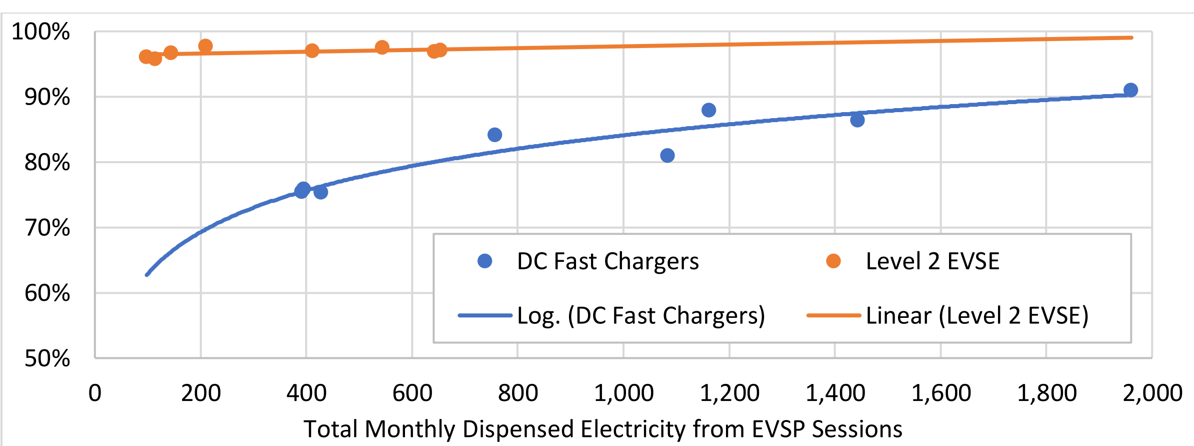
Figure 109. ELH electricity totals (May 1 to August 30, 2020)



Source: SDG&E Meter and EVSP Charging Session Data

Some difference in measurements is expected because of varying degrees of accuracy by the meters and it might be possible a few charging sessions were inadvertently left out due to some that extended before or after this time period. However, this would not typically account for a 20% difference. Taking a closer look at the data by charger type (since the DCFCs and L2 EVSE each had their own meter) from Oceanside and Chula Vista where more charging occurred, some key observations emerge as shown in Figure 110. While the difference between the L2 EVSE sessions and utility meter electricity totals is consistently low at 3% for both sites at any amount of total monthly dispensed electricity, the difference between the DCFC session and utility meter electricity totals decreases (leading to a higher percentage of alignment) as more electricity is dispensed monthly. Further analyzing the DCFC utility meter data when not charging a 140-watt stand-by power draw for two DCFCs emerges. Since this is a fixed amount during no charging, as more charging occurs there is better alignment between the session and utility meter data.

Figure 110. Alignment of charging session and utility meter electricity data

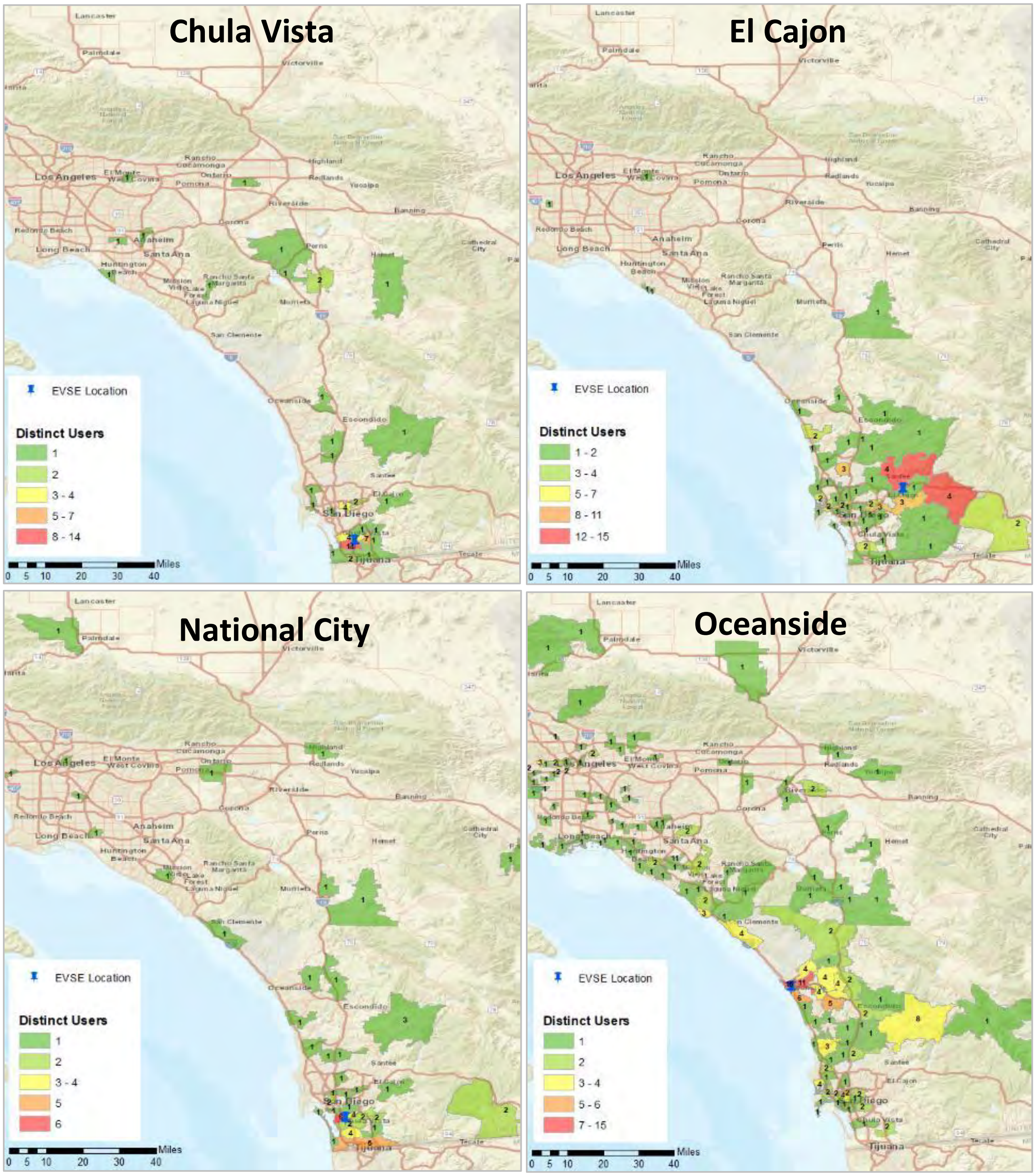


Source: SCE Meter and EVSP Charging Session Data

Geographic Distribution of L2 EVSE and DCFC Users

Users from a wide range of ZIP codes charged at the four PRP sites. Chula Vista, El Cajon, and National City served mostly local drivers, whereas Oceanside served both local and regional drivers. Figure 111 shows the geographic distribution of drivers that charged at each site during the reporting period.

Figure 111. Distribution of user ZIP codes charging per site during the reporting period



Source: Esri ArcGIS and EVSP Charging Session Data

Participant Survey

A five-minute online user survey was provided to EV drivers that charged at these sites to explore several topics—whether access to public charging stations impacts a customer's decision to lease or purchase an EV, whether EV drivers with and without access to home charging use public stations, and how (if at all) the stations changed driving habits—as well as to assess and document the user's experience. ChargePoint issued the survey directly to users of the PRP stations within SDG&E's territory (321 total unique users of the PRP stations between July 1, 2020 and October 26, 2020). ChargePoint sent out email invitations via Survey Monkey to the target audience, taking a census approach. The survey was closed two weeks after the email invitation was sent, with two reminders issued during this period.

There were 39 survey respondents for which ChargePoint shared anonymized summary statistics. The evaluation findings for the SDG&E EV charging station public access survey are presented by topic area:

- Charging station user experience and satisfaction
- Purchasing motivation and the impact of public charging station access
- Charging station usage and driving habits

User Experience and Satisfaction

Of all survey respondents, only 68% (n=26) remembered using a public charging station within the last four months. The largest percentage of respondents (37%; n=14) reported charging at Oceanside, followed by National City (18%; n=7), El Cajon (16%; n=6), and Chula Vista (11%; n=4). Three respondents (shown in Table 34) reported having used more than one public charging station location in last four months which is why the total of individual sites exceeds the total that remembered using one of these public charging stations. One-third of respondents (32%; n=12) said they have not used any of the listed public charging stations in the last four months, despite the sample data indicating that all customers had used at least one charging station since July.

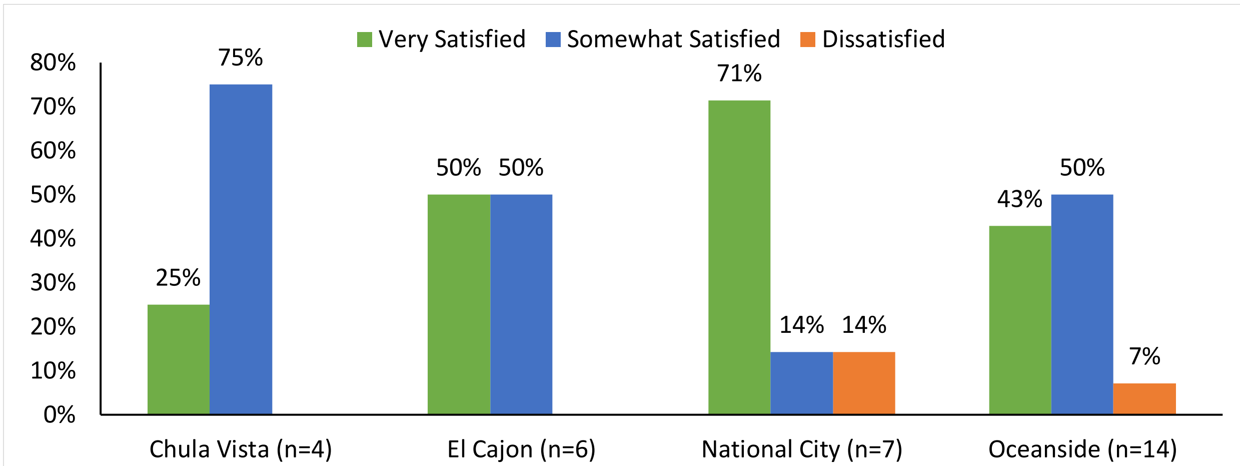
Table 34. Respondents who frequented multiple charging stations

Charging Location	Respondent 1	Respondent 2	Respondent 3
Chula Vista	X	X	X
El Cajon	X	X	-
Oceanside	-	X	X
National City	X	-	-

Source: SDG&E Public Access Survey Question 5. "At which of the following site have you charged your EV in the past four months? Select all that apply."

Of those respondents stating they have used public charging in the past four months, 92% (n=24) rated themselves as either *very satisfied* (50%) or *somewhat satisfied* (42%) with their charging station experience. Two respondents (8%) rated themselves as *dissatisfied*. Figure 112 shows respondent satisfaction with their overall experience broken out by charging station location. Oceanside and National City both had one respondent express dissatisfaction with their overall experience at that location, with both respondents citing the pricing for EV charging as their reason for dissatisfaction.

Figure 112. Respondent satisfaction by charging station



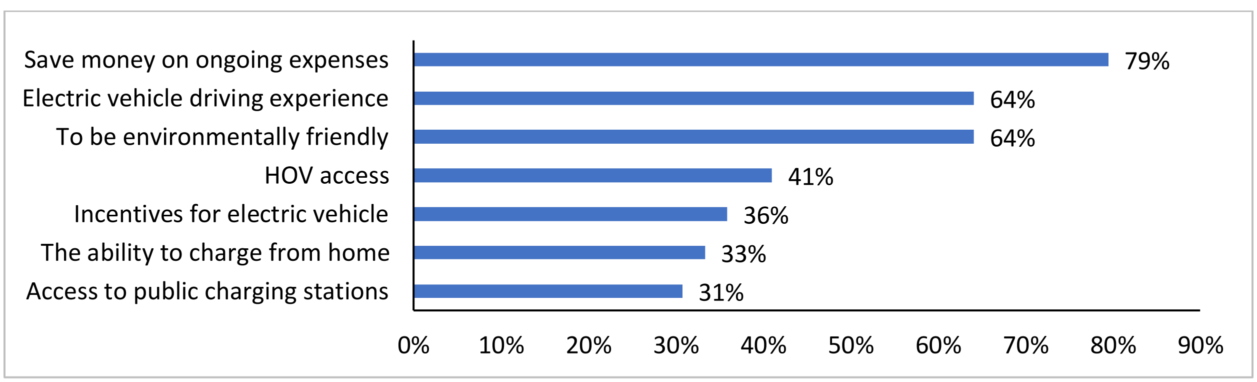
Source: SDG&E Public Access Survey Questions 5 and 6. "At which of the following site have you charged your EV in the past four months? Select all that apply." (n=38) and "How satisfied were you with your overall experience at the site(s) you've visited?" (n=26)

Additional feedback on driver reactions to these charging locations can be found on PlugShare, a user-based charging locator website or app. Most like these locations. All seem to quickly recognize the TOU pricing, noting that it is a good deal at certain times, but could be expensive at other times. Specific comments can be found in the Appendix.

Purchasing Motivations and Impact of Public Charging Station Access

Respondents could select multiple responses from seven options provided for their purchasing or leasing motivations. Most respondents (79%; n=31) were motivated by saving money, closely followed by the positive driving experience and by the desire to be more environmentally friendly (64% each; n=25). Figure 113 shows the remaining breakdown of motivations for purchasing or leasing an EV.

Figure 113. Motivations for purchasing or leasing an EV



Source: SDG&E Public Access Survey Question 1. "What motivated you to purchase or lease an electric vehicle?" (Multiple responses allowed; n=39)

Table 35 shows the breakdown of respondents' home parking situation compared to their motivations to purchase or lease an EV. The proportions of motivation responses are similar to the averages shown in Figure 113, particularly for users living in a single family with parking due to a high percentage of respondents (78%) falling into this category. Of note, 50% (n=1) of single-family residents without parking and 40% (n=2) of multifamily residents with parking said access to public charging stations was a motivation to purchase or lease an EV.

Table 35. Motivations for purchasing or leasing an EV by parking situation

Motivations to Purchase or Lease and EV	Single Family with Parking (n=28)	Multifamily with Parking (n=5)	Single Family without Parking (n=2)	Multifamily without Parking (n=1)
Save money on ongoing expenses	79%	80%	100%	100%
Electric vehicle driving experience	68%	40%	50%	0%
To be environmentally friendly	64%	60%	50%	0%
High-occupancy vehicle lane access	50%	40%	0%	0%
Incentives for electric vehicle	43%	40%	0%	0%
The ability to charge from home	43%	0%	0%	0%
Access to public charging stations	29%	40%	50%	0%

Source: SDG&E Public Access Survey Questions 1 and 11. “What motivated you to purchase or lease an electric vehicle?” (n=39) and “Please select the parking situation that most reflects your home.” (n=36)

The respondents who selected access to public charging stations as a motivation to purchase or lease an EV then rated that influence. All respondents rated public charging station access as either *very influential* (n=7) or *somewhat influential* (n=4). Respondents answered what specifically about having access to public charging stations influenced their decision to purchase or lease an EV. The top influencer was the convenience of public charging stations, cited by all respondents (n=11; Table 36).

Table 36. Public charging influencing factors by influential level

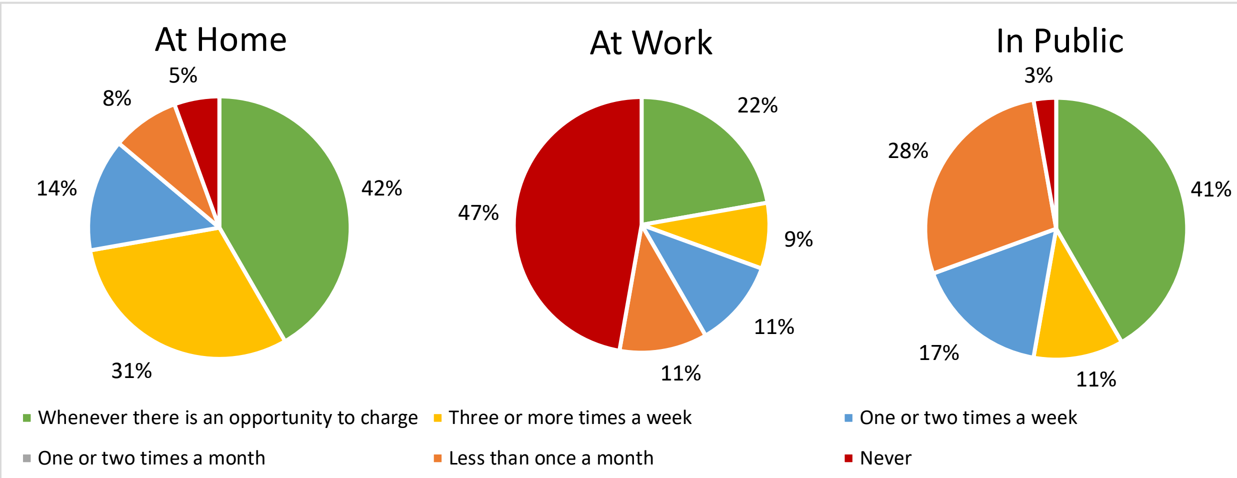
Key Public Charging Station Influences	Very Influential (n=7)	Somewhat Influential (n=4)	Total (n=11)
Public charging is convenient	7	4	**11**
There is sufficient charging at my workplace	5	2	**7**
The price of the charging session	4	2	**6**
I do not have the ability to charge at home	1	0	**1**

Source: SDG&E Public Access Survey Questions 3 and 5. “How influential was access to public charging stations on your decision to purchase or lease an electric vehicle?” (n=11) and “What about access to public charging stations influenced your decision to purchase or lease an electric vehicle?” (Multiple responses allowed; n=38)

Charging Station Usage and Driving Habits

At home, most respondents charge “whenever there is an opportunity to charge” (n=15) or “three or more times a week” (n=11). Almost half of the respondents don’t do any charging at work (n=17) and those that do charge at work, do so at varying frequencies. The survey targeted EV drivers that used the public PRP charging stations, but the frequency of how often these respondents use public charging differed significantly. While 41% charge in public “whenever there is an opportunity to charge” (n=15), 28% charge in public "less than once a month" (n=10) with the others falling somewhere in between. Figure 114 shows the breakdown of stated charging frequencies at home, at work, and in public.

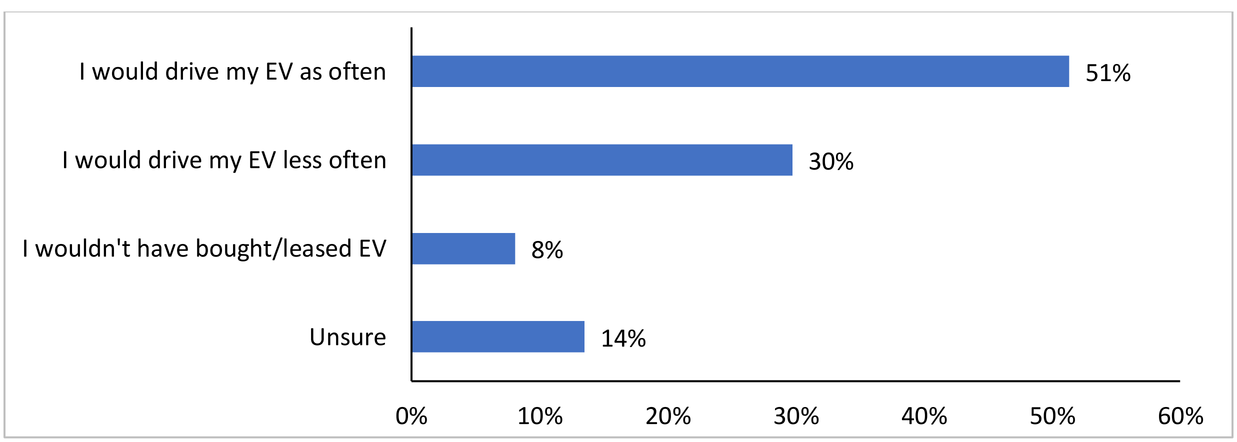
Figure 114. Charging habits by frequencies and location



Source: SDG&E Public Access Survey Question 10. "How frequently do you typically charge your electric vehicle at home, at work, and at public charging stations: never, less than once a month, one or two times a month, one or two times a week, three or more times a week, or whenever there is an opportunity to charge?" (n=36)

Regarding the impact of respondents' EV driving habits because of the PRP public access charging stations (Figure 115), over half (51%; n=19) said they would drive their EV as often as they currently do if these stations were not installed. However, three respondents (out of 36) said they would not have purchased or leased an EV if public charging stations had not been installed. Eleven respondents (all of which previously indicated they have a home charger) said they would drive their EV less often if these PRP chargers were not available and five of those had previously indicated that access to public charging stations influenced their decision to purchase or lease an EV.

Figure 115. Change in driving habits if EV public access charging stations were not installed



Source: SDG&E Public Access Survey Question 8. "How influential was access to public charging stations on your decision to purchase or lease an electric vehicle?" (n=38)

3.5.4 Conclusions and Recommendations

Findings

SDG&E executed this PRP as designed with four park-and-ride charging station installations each having 20 L2 EVSE and 2 DCFCs at only 62% of the originally proposed costs ($2,477,557 out of $4,000,000). Minor challenges with contracting, EVSP arrangements, and permitting caused project delays, but otherwise did not impact the outcomes. Data collection was successful through the EVSP and utility, with direct access to the EVSP portal granted to provide some additional project data such as driver ID, driver zip code, and state of charge information. Less than 12 months of operational data were collected due to the timing of the charger commissioning and this evaluation report. The demonstration period coincided with significant driver behavior changes because of COVID-19 pandemic. Further collection and analysis of charging station data over the next several years will provide additional insights to the PRP findings, but preliminary answers to some of the research questions are included below.

What barriers to electrification are being addressed, and what was the PRP's success at overcoming them?

- Caltrans had not found a good solution for installing charging infrastructure at their park-and-ride locations until this PRP. This PRP successfully deployed charging infrastructure at four different locations and establishes a model for additional installations.

What is EVSE infrastructure utilization (DCFC, L2), and how does it compare with similar charging stations?

- Utilization of the L2 EVSE was extremely low (less than 1%), but this is a larger than usual installation with 20 L2 EVSE at one site and COVID-19 pandemic significantly disrupted commuting patterns which these chargers were designed to support. Across the entire demonstration period for all sites, DCFC use was also low (about 2%), but it has significantly increased over time and for certain locations (Oceanside reached 6% during a week in September 2020). The DCFC utilization over the project period was similar to the SCE PRP Urban DCFC pilot at 2.5%, but that project saw a higher best utilized week at 24%.

Is the infrastructure reliable? User-friendly?

- While the charging stations have not had a lot of use or been in operation for a long time, to date there have been no reported maintenance issues. No major concerns on using the chargers were captured by the user survey, although a few noted relatively high electricity cost.

Are EVs occupying the station longer than necessary and blocking others from charging?

- This is certainly not a concern for the L2 EVSE but may become an issue for DCFCs at some point. Currently, even for the most utilized station during the demonstration period, the two DCFCs were only both in use 1% of the time.

Does EV charging station access affect customer decisions to lease or purchase EVs?

- Based on the user survey, 8% of the users stated they would have not leased or purchased an EV if public charging was not readily available, and access to public charging stations was a motivating factor to lease or purchase an EV for 31% of the survey respondents.

Do some sites perform better than others, and if so, what was the reasoning behind the difference?

- L2 EVSE utilization was very low for all sites, but slightly higher for Oceanside. Oceanside also experienced as much DCFC use as the other three sites combined. While Chula Vista, El Cajon, and National City park-and-ride locations were used primarily by local drivers, Oceanside is on the Los Angeles freeway which attracted drivers from the counties around Los Angeles. Oceanside location also has some commercial retail, residences, and school fields nearby. The other three park-and-ride lots are more isolated and require drivers to cross busy roads to get to another destination if leaving their car while charging.

Lessons Learned

The following lessons learned were captured during the implementation of this PRP:

- All make-ready charging infrastructure for future charging station installations should be upsized to account for larger power supplies and properly protected to ensure longevity.
- Trenching lengths between transformers and charging stations, along with the quantity of parking spaces within a reasonable reach of the charging cable varies by site. Greater access to chargers allow the next vehicle to charge at a staging space to more quickly start a charge after the current one ends, or in some cases may enable the driver of the second vehicle to disconnect the charging cord from an unoccupied fully-charged vehicle to begin their own charge. This higher access could potentially lead to more electric miles delivered at busy charging sites.
- While access to public charging stations impacts a customer's decision to purchase or lease an EV, other factors are more significant. Access to public charging stations was a motivating factor for about one-third of respondents, while other factors—such as saving money, the EV driving experience, and the environmental impact—were key motivation factors for more than two-thirds of respondents to purchase or lease an EV. Those who indicated public charging stations were a motivating factor cited the convenience and availability of public charging in the workplace as the most influential factors, and less frequently mentioned the electricity pricing and lack of ability to charge at home.
- Access to public charging stations may impact driver behavior. One-third of respondents would drive their EV less if access to public charging stations was not available. As for how their EV driving habits would change if public charging stations were not installed in the locations they have frequented, 51% (n=19) said they would drive their EV just as often, while 30% (n=11) said they would drive their EV less often. Additionally, 8% (n=3) said they would not have purchased or leased an EV: two of these respondents have dedicated parking at their residence while the third respondent does not have dedicated parking.
- Station users are highly satisfied with their public charging station experience. Respondents rated their satisfaction with their overall experience at public charging stations. Overwhelmingly, 92% of respondents (n=24) who indicated having used a public charging station in the past four months rated themselves as either very satisfied (50%) or somewhat

satisfied (42%). Two respondents rated themselves as dissatisfied, both listing "pricing" as the driver of their dissatisfaction.

Scale-up Potential

California's goal to expand the use of light-duty EVs will require significantly more charging stations. Many current EV owners have the ability to charge at home, but as ownership expands and diversifies this will change. Public charging options will be needed as the primary source of electricity for some EV owners, while others will rely on these stations for long distance travel. Caltrans park-and-ride locations are likely ideal opportunities for charging stations because a lot of vehicles already use them for parking on a regular basis. Most of these locations are also near major highways which is a useful location for DCFCs that support longer distance travel by EVs. Given Caltrans desire to fulfill the goals outlined in the Governor's Office ZEV Action Plan, interest in others to owning and operating charging stations, Caltrans' dissatisfaction with the current third-party end-to-end solutions on the market, and the potential to install many charging stations at these large parking lots, utility support and ownership of these installations as implemented in this PRP is a viable solution.

3.6 Dealership Incentives

3.6.1 Project Narrative

Overview, Objectives, and Barriers Being Addressed

SDG&E's Dealership Incentives Priority Review Project (PRP) involved enrolling electric vehicle (EV-battery electric vehicle [BEV] and plug-in hybrid electric vehicle [PHEV]) dealership staff in an educational training and certification program and incentivizing trained staff to sell more plug-ins. SDG&E selected Plug-In America (PIA), a plug-in vehicle advocacy organization to implement the program through a competitive solicitation. PIA offered the turnkey program PlugStar to achieve several PRP goals:[32]

- Increase plug-in vehicle sales
- Provide dealerships in SDG&E's territory with the opportunity to participate
- Emphasize plug-in vehicle sales in disadvantaged communities (DACs)
- Educate dealerships and their salespeople on the benefits of driving electric and utility resources
- Encourage new EV owners to sign up for SDG&E's residential EV time-of-use (EV-TOU) rates

Through PlugStar, PIA worked with new car dealerships and shoppers to incentivize plug-in vehicle sales over an internal combustion engine vehicle by addressing three barriers:

- ***Low retail satisfaction:*** PlugStar improved the plug-in vehicle buying experience by informing shoppers through a shopping assistant website and by educating dealership staff on meeting the needs of plug-in vehicle buyers.
- ***Poor salesperson knowledge of driving electric:*** PlugStar provided training for dealership staff as well as a plug-in vehicle sales tool. The trainings differed from original equipment manufacturer product trainings by addressing larger issues in the plug-in vehicle ecosystem, such as charging, rates and incentives.
- ***Low commissions and profits ($150 to $200) on plug-in vehicles relative to extra work required:*** PlugStar provided a bonus of $500 per plug-in vehicle sold (split between the dealership and the trained salesperson) at participating San Diego–area dealerships. Sales by untrained staff at certified dealerships resulted in an incentive of $125 for the salesperson and $125 for the dealership. Enrolled dealerships also participated in SDG&E's promotional events to drive plug-in vehicle sales.

In 2019, the PlugStar program was offered in several market areas (Los Angeles, St. Louis, New Jersey, San Diego, Sacramento, and Boston). Only San Diego, the market included in this PRP, and Sacramento offered dealership incentives; the other markets provided educational services only. SDG&E began

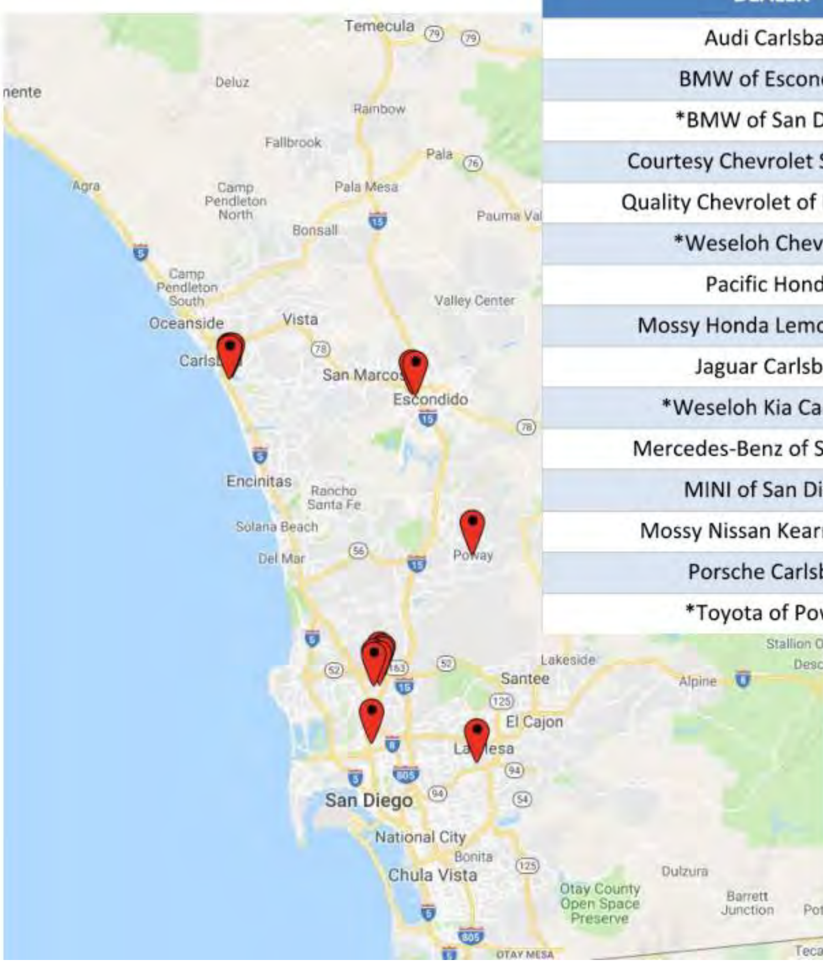
[32] These barriers and goals are from SDG&E's application for approval of SB 350 Transportation Electrification Proposals, accessed December 6, 2019. https://www.sdge.com/sites/default/files/Direct%2520Testimony%2520Chapter%25203%2520-%2520Priority%2520Review%2520Projects.pdf

PlugStar as a pilot, which ran from August 31, 2018 through January 31, 2019. SDG&E incorporated lessons learned from the pilot into the full program, which operated through the end of 2019.

Sites and Participants

PIA recruited dealerships, including several with whom they had existing relationships, and conducted outreach through trade associations, vehicle manufacturers, and other channels. PIA received 47 dealership applications for the PlugStar program, then used a formal selection process based on two criteria: (1) whether the dealership had existing plug-in vehicle inventory and access to on-site charging infrastructure and (2) the dealership's commitment to plug-in vehicles. PIA accepted five dealerships for the initial pilot and 10 additional dealerships for the full-scale program using this formal selection process (for 15 total), maximizing program funding. Figure 116 shows the locations of participating dealerships.

Figure 116. Locations of participating PlugStar dealerships



DEALER
Audi Carlsbad
BMW of Escondido
*BMW of San Diego
Courtesy Chevrolet San Diego
Quality Chevrolet of Escondido
*Weseloh Chevrolet
Pacific Honda
Mossy Honda Lemon Grove
Jaguar Carlsbad
*Weseloh Kia Carlsbad
Mercedes-Benz of San Diego
MINI of San Diego
Mossy Nissan Kearny Mesa
Porsche Carlsbad
*Toyota of Poway

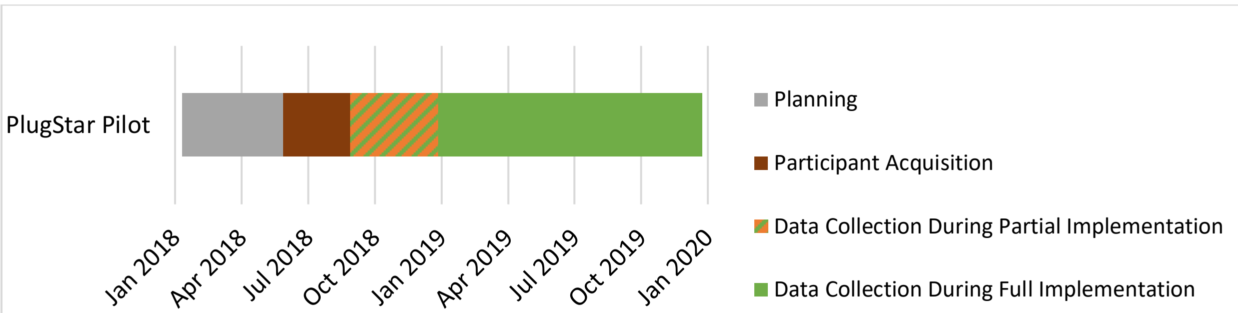
* These dealerships participated in the initial pilot phase.
Source: SDG&E Q1 2019 Programs Advisory Council Meeting

Recruiting dealerships near DACs was one of the program goals, but PIA noted in an interview that a more comprehensive strategy for helping plug-in vehicle purchasers in DACs would be to provide options to purchase used plug-in vehicles, since many members of these communities have lower budgets and often look to the secondary market. PIA emphasized that the secondary market presents even greater barriers for shoppers and would benefit from future support (note that this PRP is focused entirely on new plug-in vehicle sales).

Timeline and Status

Figure 117 illustrates the timeline for the PlugStar pilot with details for each activity in the text below.

Figure 117. PlugStar pilot timeline



Source: SDG&E

California Public Utilities Commission (CPUC) Decision 18-01-024[33] approved the SDG&E Dealership Incentives PRP in January 2018. In response to concerns submitted by The Utility Reform Network, the CPUC modified SDG&E's proposed program by requiring the plug-in vehicle buyer or lessee to enroll in an EV-TOU rate before the dealership incentives could be paid.

During the pilot phase, it was apparent that this mandated modification caused a delay in the incentive processing and significantly limited the number of claims paid (as only 16% of claims were approved through January 2019).[34] Some customers were ineligible for EV-specific rates because they live in a multi-unit dwelling and some faced higher costs with the EV-TOU rate than with other available rates, such as those through California Alternate Rates for Energy or the Family Electric Rate Assistance program. Because these and other similar factors are beyond the control of car dealers and salespeople, it would not be appropriate or possible for dealer program participants to advise plug-in vehicle buyers or lessees on which utility rate would be most beneficial. PIA further commented that "… the TOU requirement created uncertainty around whether a dealer's effort would be rewarded, thereby reducing the impact of the incentive. Moreover, due to the highly individualized nature of home energy use and costs, dealers are not able to guarantee savings but rather must connect the customer with the utility to

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[33] Public Utilities Commission of the State of California. January 11, 2018. Decision 18-01-024: "Decision on the Transportation Electrification Priority Review Projects." http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M204/K670/204670548.PDF

[34] Ultimately, 33% (24 out of 73) of pilot period claims were paid out by the end of 2019 due to further TOU review.

make such a determination. Lastly, SDG&E, as well as utilities throughout the state, were already embarking on shifting customers to TOU rates."

Due to these limitations, SDG&E filed a Tier 2 advice letter[35] in February 2019, waiving the requirement that customers enroll in an EV-TOU rate before paying the dealership incentive. The CPUC issued Resolution E-5006 on August 1, 2019, approving this and a few other modifications, including a modified customer release form for reaching out to purchasers or lessees for evaluation and education follow up. The modification was intended to emphasize to plug-in vehicle buyers and lessees the need to contact SDG&E to discuss whether an EV-TOU rate would be beneficial. Just as before the Tier 2 advice letter, SDG&E used the customer information to contact the buyers and lessees and discuss electricity rates. Although applied to purchases starting March 14, 2019, the EV-TOU rate waiver was not formally approved until the release of Resolution E-5006. More than two-thirds of the program period had elapsed before this issue was addressed.

In Resolution E-5006, the CPUC stated concerns that this change to the PRP might not serve the interests of ratepayers, as plug-in vehicle charging without enrollment in an EV-TOU rate "could cause adverse grid impacts and ultimately increase peak load, resulting in additional ratepayer costs." As such, the evaluation team examined whether SDG&E is following up with plug-in vehicle purchasers to conduct education about EV-TOU rates.

3.6.2 Evaluation Methodology

The evaluation team worked with PIA to deploy interviews and surveys to stakeholders. In addition, the team purchased new vehicle sales data to assess PRP attribution to determine whether there was market lift in San Diego and Sacramento, the areas where a dealership incentive program was implemented.

The evaluation team performed several data collection activities:

- Interviewed SDG&E and PIA staff in 2019.
- Worked with PIA to develop questionnaires for dealerships and plug-in vehicle purchasers or lessees. Since PIA has relationships with these entities and planned to gather data from them during January and February 2020, the evaluation team collaborated on these data collection efforts to minimize the burden on customers and dealership participants. PIA interviewed dealership staff in person or sent questions via email when a visit was not possible and managed an online survey with plug-in vehicle buyers and lessees during winter 2019/2020 who signed a consent form at the time of their plug-in vehicle purchase.
- Reviewed PRP activity data provided by PIA after the close of the program.
- Reviewed PIA-provided PlugStar.com website use and traffic data, including data on online profile creation.

[35] Public Utilities Commission of the State of California. August 8, 2019. "Advice Letter 3344-E." http://regarchive.sdge.com/tm2/pdf/3344-E.pdf

- With PIA, purchased new vehicle sales data that allowed for a market lift analysis comparing participating and nonparticipating dealership plug-in vehicle sales in the periods prior to and during program operation.

Implementation Process

PIA's dealership recruitment strategy was to get buy-in from management by engaging them through trusted channels, such as auto manufacturers and trade associations. PIA provided trainings as either a three-hour multi-dealership session or a one-hour session at a single dealership's location. The program required at least two sales staff to attend the three-hour session to become a certified plug-in vehicle specialist.

Once a participating dealership's staff completed training, it could submit claims for any plug-in vehicle sold. Plug-in vehicle buyers and lessees would sign a consent form during the transaction to provide their contact information to SDG&E. SDG&E staff said the utility's customer call center would follow-up with the buyers and lessees and send promotional emails about EV-TOU rates.

Communication of Program Goals and Expectations to PIA

The PRP had a cap on the number of available incentives for 1,500 plug-in vehicle sales. PIA indicated that while achieving 1,500 sales was an ambitious goal for the 15 recruited dealerships, the dealerships may have been able to achieve this result "absent the insertion of an EV-TOU [rate] requirement" with the PlugStar training and incentive program.

Furthermore, per PIA it was not clear at the outset of the program that the EV-TOU rate adoption was the CPUC's key metric for gauging success. After discussion with the CPUC in early 2019, PIA took several actions to support EV-TOU rate adoption:

- Amended the customer release form to emphasize TOU rates (see the original and modified customer release forms in Figure 118 and Figure 119, respectively)
- Implemented an EV Customer Support Program call center, which provided general information on TOU rates and directed customers to SDG&E for more information
- Advised on specific activities for the program and SDG&E to take more proactive steps to convert buyers
- Worked with SDG&E to file an advice letter with the CPUC to waive the program-hindering requirement of using the EV-TOU rate
- Provided more detailed training on TOU rates for dealers
- Updated PlugStar.com with detailed rate information, including for TOU rates
- Provided TOU rate collateral to dealers for their information and to hand to customers

Figure 118. Original customer release form excerpt

With your purchase or lease today, Plug In America, a national not-for-profit leading America's transition to cleaner electric transportation, invites you to a complementary (free) one-month enrollment in the PlugStar Customer Support Program to assist you with all of your electric car and charging needs.

PlugStar is a partnership between Plug In America, local electric utilities and area dealers to support electric car customers to help you get the most out of electric driving. Benefits of enrollment include:

- Phone and email support from EV experts
- Confidence choosing the right charging equipment and charging networks for your needs
- Access to qualified electricians with experience assisting EV customers

Source: PIA

Figure 119. Modified customer release form excerpt emphasizing TOU rates

Congratulations! We at Plug In America, the nation's leading not-for-profit voice of electric car drivers, are thrilled that you chose to drive electric. We want to make your EV ownership experience the best it can be. This includes taking advantage of San Diego Gas & Electric's (SDG&E) Time-of-Use rates for EV drivers.

Time-of-Use rates provides price signals to homeowners to shift energy use from peak hours to off-peak hours. Electric vehicle owners may benefit from these rate plans if they charge their vehicles overnight when electricity cost is the lowest.

Cost to Fully Charge at Home*

$5.40	$33.60
Best Rate	Highest Rate

**Calculation is based on charging an EV with 240 miles of range with an efficiency of 3 miles/kWh. Comparison uses SDG&E's EV-TOU-5 (Summer 2019) Super Off-Peak rate with SDGE TOU-DR1 (Standard 2019) On-Peak rate. Actual cost will vary.*

Source: PIA

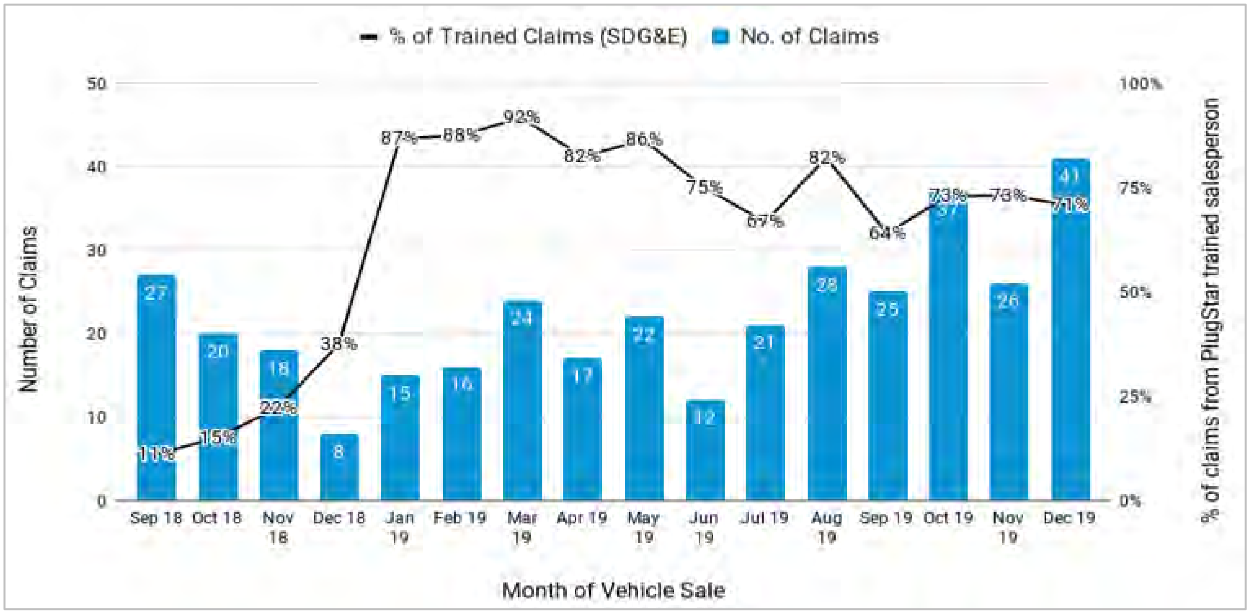
3.6.3 Evaluation Findings

Incentive Claims Awarded

In 2019, two areas provided a PlugStar program with dealership incentives: San Diego (through this PRP) and the Sacramento area (which includes Sacramento, Placer, and Yolo counties). Sacramento's implementation of PlugStar provides a useful comparison to the PRP efforts in San Diego. Unlike the initial design of the PRP, the program in Sacramento did not require customers to adopt an EV-TOU rate for the dealership to receive the $300 incentive,[36] where $200 was for the PlugStar-trained salesperson and $100 was for the dealership. The Sacramento program incentive was slightly lower than that for the San Diego program, which provided $250 for the PlugStar-trained salesperson and $250 for the dealership. In both programs, since January 2019, claims submitted by PlugStar dealerships for sales by untrained salespeople received only half the incentive amount. As a result of the program policy change, the percentage of claims from PlugStar-trained salespeople rose dramatically in January 2019 (Figure 120 shows this data for San Diego and Figure 121 shows the data for Sacramento).

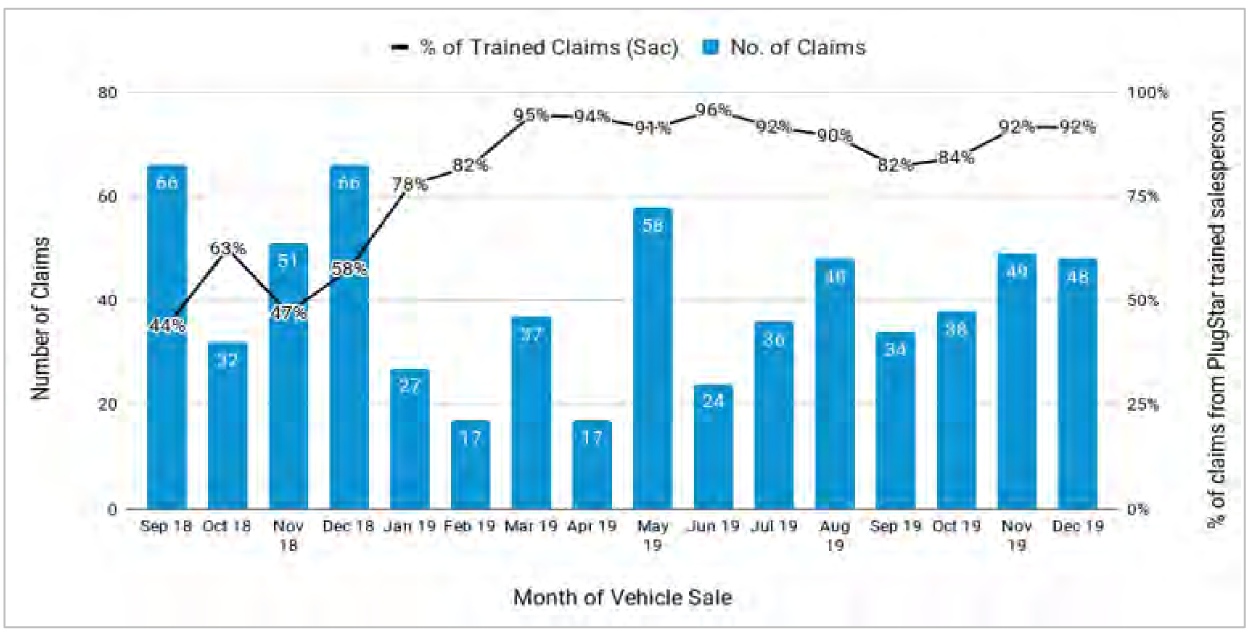
[36] In September 2018, the Sacramento incentive was doubled (to $600), leading to a high number of claims in Sacramento for that month.

Figure 120. Total and percentage of claims submitted by PlugStar-trained salespeople – San Diego



Source: PIA

Figure 121. Total and percentage of claims submitted by PlugStar-trained salespeople – Sacramento



Source: PIA

Figure 122 shows monthly PlugStar claims activity in Sacramento and San Diego. Sacramento, despite having less than half the market size of San Diego and offering a smaller incentive, had nearly twice the claims of San Diego. The removal of the EV-TOU rate requirement in San Diego after August 2019, when the resolution was approved, coincided with slightly higher claims during October through December 2019 compared to the first half of 2019. This data suggests that the EV-TOU rate requirement did result in lower program activity. The claims in the Sacramento area for those months were still higher; however, the San Diego trained dealer claim rate from September through December 2019 was on par with Sacramento.

Figure 122. Comparison of PlugStar activity in Sacramento versus San Diego

Source: PIA

Table 37 shows a comparison of PlugStar program activity and regional characteristics from the U.S. Census Bureau for Sacramento and San Diego counties. Most claims in Sacramento (77%) and San Diego (65%) were submitted by PlugStar-trained sales staff. Although Sacramento had far greater numbers of claims on an absolute basis, the average number of claims submitted by each PlugStar-trained sales staff is similar in both regions. PIA believes the number of claims per PlugStar-trained sales staff could be increased with improved marketing, driving more shoppers to participating dealerships.

Table 37. Comparison of program activity and region characteristics

Source	Metric	Sacramento	San Diego
PIA	Claims (September 2018 through December 2019)	648	357
	Trained Claims	498	232
	Untrained Claims	150	125
	Participating Dealerships	19	15
	Trained Staff	208	92
Calculated	Trained Staff per Dealership	11	6
	Claims per Dealership	34	24
	Average Claims Submitted by Each Trained Staff	2.4	2.5
U.S. Census Bureau	County Median Household Income	$60,239	$70,588
	Mean Travel Time to Work (minutes)	26.9	25.7
	Percentage with High School Diploma or Higher and 25+	87%	87%
	Population July 1, 2018	1,540,975	3,343,364

Source: PIA

The Sacramento area has a greater number of PlugStar-trained sales staffs per participating dealership than San Diego. While there are many factors that could contribute to this difference, PIA theorizes that there is less interest in PlugStar training at San Diego dealerships due to “a much longer history of unpredictability, and therefore unreliability, in payment of the dealer incentive claim” as a result of the EV-TOU rate requirement. Participating Sacramento dealerships received incentives on a consistent basis because incentives were not dependent on the customer signing up for the EV-TOU rate. In turn, the Sacramento dealership sales teams requested and received more PlugStar training. PlugStar training rates were double in Sacramento (at 11 staff per dealership versus six per dealership in San Diego), and a much larger number of sales staff were PlugStar-trained overall (208 versus 92).

Both regions have similar mean travel times to work and similar levels of educational attainment, while the median household income is slightly higher in San Diego. The population of San Diego county is more than twice that of Sacramento county, so there is a potential for twice as much program activity.

Project Baseline and Market Lift

The evaluation team completed a baseline and market lift analysis using market data from Cross-Sell, an automotive market data and reporting resource.[37] The baseline period was August 2016 through December 2017 (17 months) and the program period was August 2018 through December 2019 (also 17 months). While the results presented above were based on the number of incentives claimed by dealership staff, the market lift analysis attempted to measure the program impact by the total vehicles sold.

For a variety of factors, including the mix of OEMs represented in the program, the challenges of the EV-TOU requirement, and economic variances, the evaluation team found the market lift analysis results to be inconclusive for PlugStar in San Diego County. Details on the market lift analysis methodology and results are provided in the Appendix.

Costs

The PRP had an anticipated total direct cost of $1.79 million (for all operation and maintenance expenses). Of that, $750,000 was reserved for incentives, and the remaining budget was allocated for program education, outreach, and SDG&E program management. The actual PRP direct costs totaled $757,687, or 42% of the budget, as shown in Table 38.

[37] Cross-Sell. Accessed December 2020. https://www.cross-sell.com/

Table 38. SDG&E dealership incentives PRP costs

	Actual Costs	Approved Budget
Customer Engagement and Outreach	$641,261	$1,675,000
SDG&E Program Management and Support	$116,427	$115,000
Direct Costs	$757,687	$1,790,000
Non-Direct Costs (Indirect, Allowance for Funds Used During Construction, and Property Taxes)	$119,975	$351,786
Total Costs	**$877,661**	**$2,141,786**

Source: SDG&E

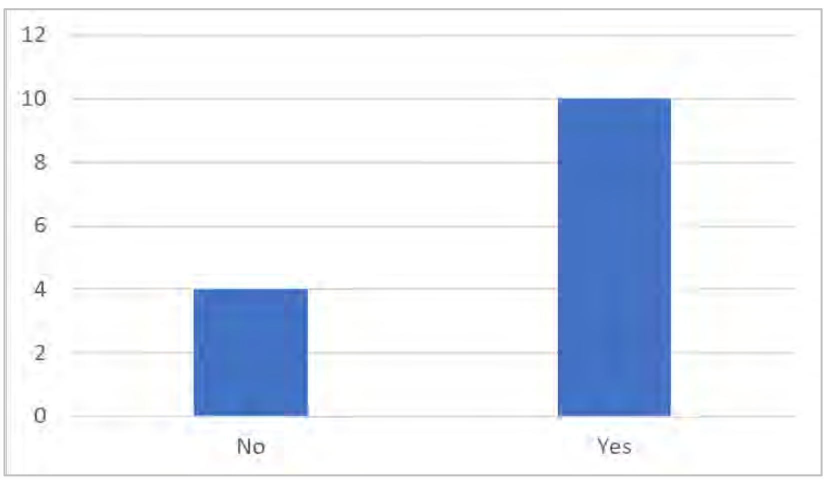
Plug-In Vehicle Purchaser Feedback

Plug-In Vehicle Buyer Survey Results

Between November 2019 and January 2020, 14 San Diego buyers responded to PIA's invitation to take an online survey. PIA sent the survey to 154 recent plug-in vehicle buyers on November 8, 2019, with 53 from San Diego.

When asked, "Is this your first plug-in electric vehicle?" most buyers in San Diego indicated this is their first plug-in vehicle (Figure 123).

Figure 123. First plug-in electric vehicle?



Source: Evaluator Survey

When asked what type(s) of vehicles they were considering for purchase, most plug-in vehicle buyers had considered a plug-in vehicle and four of 14 had considered a conventional non-plug-in vehicle. Buyers who considered a non-plug-in ultimately choose a plug-in for various reasons:

- Lower cost of ownership
- Reduced carbon emissions
- Better performance
- Discounts or incentives that lowered the cost for plug-ins

The primary reason participants selected the dealership where they purchased their plug-in was the availability of the model they wanted, cited by nine of 14 buyers. Buyers also said the competitive pricing and convenient location were major factors. A couple plug-in vehicle buyers indicated that customer service was a factor in their selection of dealership. The survey also asked about the average daily miles traveled, shown in Table 39.

Table 39. San Diego vehicle miles traveled

"How many miles on average do you drive per day with your electric vehicle?"	Percentage of Respondents
25 miles or less	36%
26 to 50 miles	50%
51 or more miles	14%

Source: Evaluator Survey

Of the 14 San Diego buyers, eight recalled that the salesperson mentioned a special utility rate plan for plug-in vehicle drivers. Nine buyers said they contacted their utility for more information about the EV-TOU rate plan.

Dealership Review Survey

PIA deployed an online dealership review survey from August to October 2019. The survey received 12 reviews for PlugStar dealerships in San Diego, with an average rating of 4.75 out of 5 stars, all from plug-in vehicle buyers or lessees. Four of 12 customers said they switched to an EV-TOU rate plan after interacting with the dealership; the other eight customers did not switch to the EV-TOU rate for various reasons:

- Already on a rate plan that costs less to charge (two responses)
- Waiting for SDG&E to contact them to discuss EV-TOU rate options (two responses)
- Needs to further investigate the EV-TOU rate plan
- Not interested in charging at home
- Does not pay the power bill
- Served by a community choice aggregator with no available EV-TOU rate

PIA also sent the dealership review survey to their larger email list to obtain dealer reviews from non-PlugStar dealerships. The average PlugStar dealership rating from this group in both San Diego and Sacramento was 4.6 out of 5 stars (32 respondents), higher than the national non-PlugStar dealer rating of 3.5 (86 respondents).

Anecdotal Evaluation Team Member Experience

To augment the dealership review survey results, in May 2019 an evaluation team member had direct experience in leasing a plug-in vehicle from a participating PlugStar dealership and signing the consent form to share contact information with SDG&E. This allowed the team to further evaluate the sales process and other program aspects.

An SDG&E representative called the team member in October 2019 about switching to an EV-TOU rate but was brief and referred the team member to the SDG&E website for more information. When the team member asked whether SDG&E offered tools to help customers determine whether they would save money under various EV-TOU rates based on their previous 12 months of usage, the SDG&E representative said no such tools were available.

PlugStar.com Web Traffic

PlugStar.com offers information to support plug-in vehicle buyers in their shopping experience, with a list of available makes and models, a vehicle cost calculator with incentives included, energy provider rates and plug-in vehicle charging utility bill cost calculations, a list of locally trained plug-in vehicle dealerships, and more. Table 40 shows the PlugStar.com site traffic by month.

San Diego is one of the most highly trafficked pages on PlugStar.com (including traffic from Sdge.PlugStar.com). PIA collects data on customer visits to PlugStar.com from the customer release form signed during the sales process. In San Diego, about 12% of plug-in buyers visited PlugStar.com prior to purchasing a plug-in from a PlugStar dealership between August 31, 2018 and October 31, 2019.

Table 40. PlugStar website traffic (program areas)

Month	San Diego	Sacramento
September 2018	532	399
October 2018	386	389
November 2018	370	397
December 2018	631	550
January 2019	495	478
February 2019	782	508
March 2019	787	614
April 2019	983	1,063
May 2019	1,358	1,089
June 2019	1,244	1,060
July 2019	673	747
August 2019	779	725
September 2019	949	803
October 2019	866	1,248
Cumulative	**10,835**	**10,070**

Source: PIA

Dealership Feedback

PIA interviewed nine dealerships in San Diego in January and February 2020, after the program had concluded. All nine dealerships rated the PlugStar program as a “5 out of 5” (the best possible rating). All dealerships agreed that the PlugStar program resulted in selling more plug-in vehicles:

- Staff increased their confidence in selling plug-ins
- Management stocked more plug-ins
- Plug-in vehicle customers were more satisfied
- Dealerships can now sell plug-ins faster

Nearly all the respondents said the incentive was the right amount to influence management to stock more plug-in vehicles. Dealers expect staff who attend the training to become an internal plug-in vehicle sales champion, or at least be better positioned to respond to customers’ needs when opportunity arises. All the participating sales staff (100%) would recommend the training to others.

EV-TOU Rate Requirements

The original goal of the PRP was to increase plug-in vehicle purchases in SDG&E territory through sales staff and dealership incentives, and by educating dealership staff and customers. The EV-TOU rate requirement in Decision 18-01-024 was intended to support cost savings for plug-in vehicle drivers and contribute to favorable net grid impacts for the utility. Unfortunately, this added a complication to the PRP’s planned activities, placing a particular burden on salespeople. Based on interviews with SDG&E and PIA staff, there are several reasons it is not desirable to have salespeople explain the EV-TOU rate to shoppers and to require plug-in vehicle buyers to switch to this electricity rate in order to receive an incentive:

- Some shoppers do not plan to or are unable to charge plug-in vehicles at their residence.
- Some shoppers do not have an SDG&E account because someone else pays for their electricity.
- Dealerships do not want to assume liability for providing plug-in vehicle buyers with incorrect information, such as which rates would save them money or which buyers are eligible for which rates.
- Rates are complex and difficult for salespeople to understand and explain to customers.
- Per SDG&E analysis, not all plug-in vehicle buyers would benefit from switching to an EV-TOU rate plan.

In July 2020, SDG&E said just 59 of 343 program plug-in vehicle purchasers[38] (17%) were on an EV-TOU rate.

Since SDG&E has specialized staff who consult with their customers about the best rate plan, the utility could assume this role from dealership staff and offer to review customer bill data to provide pricing

[38] SDG&E could not retrieve account information for 14 plug-in vehicle purchasers.

comparisons of different rate structures and highlight potential cost savings from switching to the EV-TOU rate.

3.6.4 Conclusions and Recommendations

There were several positive outcomes from the Dealership Incentive PRP indicating that the lack of well-trained EV salespeople is still a barrier towards EV adoption. The structure of PIA's PlugStar program directly helps address this barrier. With the California-wide launch of Clean Fuel Rebate program where a utility provides a $1,500 rebate for a purchase or lease of a new EV it does not seem appropriate for utilities to use ratepayer funds in the future to incentivize dealers for EV sales. The appropriate utility role, as SDG&E feedback and future plans suggest, is to continue engaging with local dealerships that sell EVs and coordinate marketing and outreach efforts. As part of the coordination, the utilities should provide the information resources and conduct outreach activities to inform and encourage EV drivers to switch to EV-TOU rates to save on energy cost, minimize adding peak load to the electric grid, and reduce GHG emissions.

There are several key dealership incentive program findings, in addition to the lessons learned that were shared throughout this chapter:

- Dealerships in SDG&E's territory signed up for and participated in the PlugStar program, displaying an understanding of the need to learn about EVs and a desire to increase their EV sales.
- Dealers can be trained and motivated via monetary reward to deliver simple, distilled messages to customers about the potential to save money through enrolling in an EV-TOU rate. Beyond this, the highly individualized nature of household energy use makes it most appropriate for SDG&E to follow up with customers about whether an EV-TOU rate would result in savings and the amount of that saving.
- Based on the positive feedback in dealership staff surveys and customers' high rating of participating dealerships, the education goals of the PRP were achieved.
- Participating dealership staff indicated that management stocked more plug-in vehicles and can sell plug-in vehicles faster as a result of the program.
- Although SDG&E followed up with plug-in vehicle buyers, stakeholder feedback indicates there was a lag in follow up and that the information provided was generic and typically directed customers who sought more information to the SDG&E website.
    - **Recommendation**: SDG&E should augment the plug-in buyer outreach (which includes point-of-sale/glovebox materials) by also running eligibility checks for EV-TOU rates and by providing customized analyses of each plug-in buyer and lessee's usage under their existing rates compared to the EV-TOU rate. This would identify customers who would benefit financially from switching, who could be sent personalized postcards or emails explaining how changing their rate plan could result in savings, along with steps on how to switch to the EVTOU rate.
    - **Recommendation**: Take advantage of the PlugStar.com and sdge.plugstar.com portals to provide prospective plug-in buyers with personalized estimates of EV-TOU rate savings. The portal currently uses default EV off-peak rates for the user's zip

code to determine the cost of charging. However, it does not calculate the cost difference between the EV-TOU rate and the non-EV-TOU rate.

- The market lift analysis of the impact from the PlugStar program on new plug-in vehicle sales in San Diego County is inconclusive. There are many factors involved with comparing the market lift between different baseline and program periods. In addition to the mix of OEMs represented in the program and the challenges of the EV-TOU requirement, other non-quantifiable factors may be responsible for the lack of lift.
- Tying the EV-TOU rate requirement directly to the salesperson incentive substantially hindered program performance in San Diego compared to Sacramento, which did not have the EV-TOU rate requirement and was able to achieve greater total claims with lower incentive levels. This requirement may need to be modified before attempting to scale up the program.
    - **Recommendation:** Consider exceptions for customers who aren't qualified to adjust their rate.
    - **Recommendation:** Require that the salesperson provide customers with information on the EV-TOU rate and sign customers up to speak with their utility about the rate, but not withhold the incentive based on whether the customer actually switches rates.
    - **Recommendation:** Shift the burden of switching customers to the EV-TOU rate to the utility, since there are specialized utility staff who consult with their customers about the best rate plan. Utilities could offer to review customer bill data to provide pricing comparisons of different rate structures and highlight potential cost savings from switching to the EV-TOU rate.
    - **Recommendation:** Provide an additional incentive to dealership staff if a customer switches to the EV-TOU rate.
- The program trained 92 salespeople in San Diego compared to 208 salespeople in Sacramento. The results in Sacramento suggest that the program may have achieved higher training rates in San Diego had the EV-TOU rate requirement not been added, which likely caused uncertainty around customers signing up for the rate. This must be resolved because to improve the dealership experience, staff must be trained to educate customers about the benefits of plug-in vehicles.
- Carefully consider the program design requirements set by CPUC decisions, while well-intentioned, for possible negative impacts on program effectiveness. Instead of prescribing specific requirements, state expectations of what would constitute success (such as increasing plug-in vehicle sales while avoiding peak grid load increase due to plug-in charging) and allow the program implementers to determine how to best proceed.
- PIA amended processes to improve program delivery once becoming aware of CPUC concerns, as such emphasizing TOU rates in the customer release forms, providing more detailed training on TOU rates for dealers, and implementing a call center.
- Programs targeted to DACs will need to support secondary market transactions, since many members of these communities have lower budgets and often look to the secondary market.
- To continue engagement with the region's dealerships, SDG&E plans to launch the SDG&E Dealer Partner Network in Q1 of 2021. The SDG&E Dealership Partner Network will be comprised of new car dealers that are driving the adoption of electric vehicles in the San

Diego region. SDG&E will support participating dealers with the tools and resources they need to increase EV sales and provide a positive customer experience.

- Salespeople of participating dealers will have instant access to resources to answer questions regarding:
  - Current federal, state, and local EV incentives
  - SDG&E EV Time-of-Use Rate Plans
  - Charging and qualified electrician resources
  - EV Cost Savings
- Participating dealers will have the opportunity to:
  - Attend special events (i.e., press and media launches, ride and drives, award ceremonies)
  - Advise on future SDG&E marketing and outreach programs and events focused on increasing EV sales
  - Receive EV customer leads
  - Be recognized as an automotive leader and innovator in the San Diego community

4. Southern California Edison

4.1 Port of Long Beach Rubber Tire Gantry Crane

4.1.1 Project Narrative

Overview, Objectives, and Barriers Being Addressed

SCE was approved to spend $3,038,000 on the Port of Long Beach (POLB) Rubber Tire Gantry (RTG) Crane Electrification Pilot which will deploy make-ready infrastructure to serve nine cranes at Stevedoring Services of America (SSA) Marine Terminal J. SCE will design, install, own, and maintain the electric infrastructure, including two new distribution substations that will serve nine new electric motorized RTG cranes.

The pilot supports the state's Sustainable Freight Strategy to "reduce diesel particulate matter (PM) and criteria pollutant emissions from compression ignition mobile cargo handling equipment that operates at ports and intermodal rail yards in the state of California." Electrifying RTG cranes will improve air quality and reduce greenhouse gas (GHG) emissions for the communities surrounding the port, which are mostly disadvantaged communities (DACs). RTG cranes are the second-largest source of NOx emissions at the terminal, and the technology could have a significant impact on emissions if adopted by other port operators in California.

Traditional RTG cranes have electric lift and propulsion drives, with electric energy generated by on-board diesel reciprocating engines. SCE's proposed project will support a customer pilot for a grid-connected electric conversion system that removes the diesel engine and adds power transformation and electronics fed by a motorized electric cable mechanism. The cable connects to a stationary grid-connect mechanism that allows the RTG crane to disconnect from the cable when it needs to transfer to the maintenance area (using power from a temporary mobile battery system). The grid-connection mechanism ties to a high-voltage utility connection (4,000 V).

Sites and Participants

The project supports SSA Marine Terminal J at the POLB in accelerating the conversion of the port's current RTG cranes to electric power by deploying the electric infrastructure necessary to serve the new electric RTG (eRTG) cranes. The PRP was designed specifically for this application and customer, with no additional recruitment of participants planned.

Participants

Southern California Edison (SCE) is providing the electrical infrastructure to support the eRTG cranes, and the **POLB** secured funding for the eRTG cranes through part of a $9.7 million grant from the California Energy Commission (CEC), as well as port money and in-kind contributions from the private sector. Converting an RTG from diesel power to electricity costs about $585,000. SCE's estimated cost for the make-ready infrastructure to support the nine RTGs is $3,038,000, or $337,556 per RTG. **M.S. Hatch Consulting** is supporting the POLB on the RTG conversion project by collecting performance data and conducting analysis for the final CEC grant report. As SCE is not providing a rebate for the charging equipment in this PRP, **SSA Marine** will qualify vendors, products, and services.

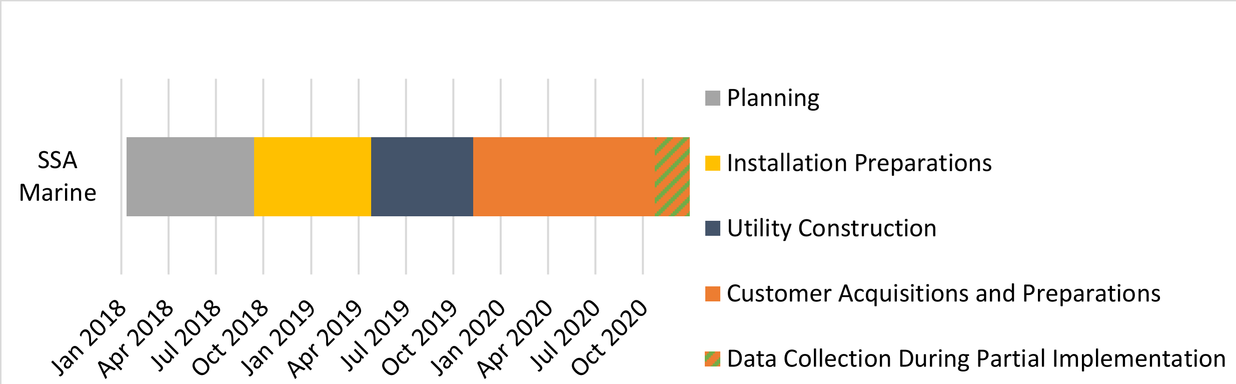
SSA Marine has enlisted technology vendor **Cavotec** to support conversion of nine diesel–electric RTG cranes by removing the on-board diesel engines—which generate electricity for the electric lift and propulsion drives—and replacing them with a grid-connected electric conversion system. The system will enable disconnection from the grid and, by use of a container with an electrochemical battery pack, enable block changing during normal operations and easy movement to the maintenance area when needed. A single battery container will be used to support transfer of all nine cranes; it will be stored and charged by the maintenance area and delivered to the cranes by a yard truck. SSA Marine will connect the eRTG cranes to the grid at SCE's four 4,000 V termination points.

Timeline and Status

SCE estimated the PRP portion of this project (supporting electrical infrastructure) would take approximately 12 months to complete. The pilot began in Q1 2018, with the following key milestones as of November 2020:

- Final engineering design for SCE's new and upgraded infrastructure was completed and received approval for construction (Q2 2018).
- The POLB issued the Harbor Development Permit (November 2018).
- Wharf 66/12 kV Substation upgrades were completed (Q4 2018).
- SCE completed all its civil construction (Q1 2019).
- The POLB installed the switchgear pads on the north side, and SCE completed the placement of their electrical equipment (Q3 2019).
- South-side switchgear pads and SCE electrical equipment were installed (October 2019).
- All switchgear and equipment disconnects were energized (November 2019).
- The battery pack to move the eRTG to the maintenance area arrived (January 2020).
- Trenching for the cable was completed (February 2020).
- The first eRTG conversion was completed (May 2020).
- The guidance system was installed and successfully tested (October 2020).
- First eRTG commenced operation (November 2020); remaining 8 to be converted in 2021.

Figure 124. SCE POLB RTG crane PRP timeline



Source: POLB CEC grant monthly meetings

4.1.2 Evaluation Methodology

Selected Methods and Rationale

In addition to the evaluation questions that apply to all PRPs and those specific to the Fleet Electrification PRPs, the evaluation questions listed below will be examined for this PRP.

- Did the technology (container with a battery pack) adequately accommodate moves among the berths?
- Was there wear in the cables or other issues that might limit the eRTG crane's useful life as compared to traditional diesel-powered ones?
- Could this be economically feasible without the CEC grant and SCE support?

The data collection tasks utilized to evaluate this PRP include 1) PRP information from the approved decision, project updates, site visit, and other available documentation, 2) market research on RTGs and early deployment efforts from other similar electrification projects across the country, and 3) in-depth interviews (IDIs) with project partners (SCE, POLB, SSA Marine, Cavotec, and M.S. Hatch Consulting).

Data Sources

The evaluator collected PRP information through numerous PRP participant interactions, including a PRP kick-off meeting (SCE and evaluator), quarterly SCE Transportation Electrification Program Advisory Committee meetings, periodic PRP updates (SCE and evaluator), monthly CEC project updates, site visit, and other periodic calls and emails. Through these interactions, the evaluation team obtained a data collection plan for the CEC project funding the electric conversion of the RTGs, infrastructure and eRTG specifications, electricity tariff details, project costs, historical RTG use, and pictures of the site and equipment.

Expected PRP operational data for this project included utility service meter 15-minute-interval data (one meter for all nine RTG connections), power quality analyzer data for individual eRTG tests, monthly electric consumption data for each converted RTG, monthly facility electricity bills, periodic hour-meter readings for the eRTGs, and their maintenance records. However, since the eRTGs had not been put into service during the PRP evaluation, none of these data were available. Therefore, the analysis of benefits was based on past performance and other relevant research, including:

- POLB: Electric Vehicle Blueprint, Identify and Plan for a Zero-Emissions Future (2019)
- Papaioannou et al.: Analysis of energy usage for RTG cranes (2016)
- Electric Power Research Institute, Inc. (EPRI): Evaluation of Electric Rubber-Tired Gantry Cranes at the Port of Savannah (2014)
- Knight et al.: A Consumption and Emissions Model of an RTG Crane Diesel Generator (2011)
- EPRI: Electric Cable Reel Rubber-Tired Gantry Cranes: Costs and Benefits (2010)
- California Air Resources Board (CARB): Zero- and Near Zero-Emission Freight Facilities Project Methodology for Determining Emission Reductions and Cost-Effectiveness (2018)

The evaluator held an IDI with POLB representatives to further understand the background of this project and gather lessons learned. IDIs with the SCE construction manager, SCE project and account managers, and SSA Marine were also held. An operator survey was planned after several months of operation but was not conducted since the first eRTG just entered service as of writing of this report.

4.1.3 Evaluation Findings

Project Baseline

The RTGs take deliveries of containers from yard tractors and place them into stacks in the container yards, where they await delivery to on-road trucks. Currently, most RTG cranes at the POLB are configured with a diesel-fueled engine, driving an electric generator, which powers the RTG crane's propulsion and lift functions. Each RTG burns approximately 10 gallons of diesel fuel per hour during about 2,000 hours of service each year. RTG cranes comprise 5% of the total heavy-duty equipment operating at the POLB; however, because of the engine sizes and operating schedules, they represent approximately 20% of the POLB cargo-handling equipment emissions. RTGs have a useful life of about 30 years. There are 64 RTG cranes at the POLB, and they represent a significant source of criteria pollutant emissions. The mean annual NOx emissions from these 64 cranes are 111 tons. The mean PM emissions are about 2 tons. The mean carbon dioxide equivalent (CO_2e) emissions for the 64 cranes are 11,776 tons.

Implementation Process

The POLB's zero-emissions goal stems from influence of both local and state entities. The port wants to be ready when requirements are in place to mandate zero-emissions equipment. They also try to secure grants and outside funding to help tenants address higher costs, while also providing assistance as needed. It is necessary to secure support for larger-scale demonstrations that really test the equipment in revenue service to determine its durability. Projects such as this PRP aim to prove out the use of these technologies so others will have more confidence adopting them. SCE support for this eRTG project came after the POLB received the CEC award; however, discussions between SCE and the POLB on this project begun during the CEC grant application. This RTG conversion project might not have happened without SCE funding, or it would have had to be scaled down significantly. SCE's support was critical to the success of the overall project to electrify the RTGs.

To support the eRTG crane project, SCE upgraded existing facilities and installed the following new equipment and supporting infrastructure:

- New 12 kV circuit (Beluga 12 kV) out of wharf substation
- One pad-mount capacitor bank
- Conduit and cable
- Four new 12 kV/4 kV distribution substations
- Four 2,500 kVA 12 kV/4160 V transformers
- Pad-mounted switches
- New vaults
- All supporting civil and foundation structures

The new distribution substation (yellow rectangle in Figure 125) transforms the 12 kV to 4 kV and then distributes the 4 kV circuits to four termination points—one for each RTG stacking run—for a total of four 4 kV termination points (yellow squares with red dots in Figure 125).

Figure 125. Pier J eRTG crane project site layout

Source: POLB

This PRP was highly dependent on the POLB and SSA Marine's onsite work to electrify the RTG cranes. SSA Marine relies on the RTG cranes during their everyday operation and needed to ensure that everything was ready for the conversion before taking them out of service. The Cavotec parts for the conversion came from overseas and took several months to arrive. The system requires that the electrical connection cable be laid in a trench resulting in a clearance of only a few inches for the crane during movement to prevent wear on the cables during coil reel movement. To protect the cables, SSA Marine needed an automatic steering system. The system was intended to be laser-based until testing identified issues with general accuracy and maintenance of reflective tape on the ground. The team then pursued a solution using proximity sensors that read a 1" wide steel bar on the ground for the entire container stack distance.

After SCE infrastructure was completed, work began on cutting the approximately 7,000 feet of linear trenching needed to support all RTG cranes on the terminal. This effort took several months and was completed in February 2020. Before converting the first RTG, the battery system had to be procured and brought onsite to enable RTG movement independent of the power cable system if needed. The battery system arrived in March 2020. Once all supporting components were in place and SSA Marine had completed a mock-up of the conversion (discovering that a larger enclosure would be needed), the conversion of the first RTG crane to electric started in mid-November 2019 and major systems were completed by May 2020. The first unit was tested in limited service in November 2020. After several weeks of successful operation of the first eRTG conversion, the second RTG would be taken out of service to be converted.

Figure 126. Linear trench being cut and configured for the connection cable

Source: POLB

Figure 127. Enclosure removed from RTG crane engine compartment to begin conversion

Source: POLB

A guidance system was needed to assist the automated steering system. A Cyth laser guidance system was tested during the summer and fall 2020. It required reflective tape on the ground, which did not withstand the port environment well. The tape was replaced with reflective paint. The system was first tested with a diesel RTG, which required a good deal of fine tuning that could be done only once per week when operations were minimal. After several months, the performance was deemed sufficient to start testing on the eRTG. Unfortunately, when moving at faster speeds, there were deviations in the steering (it was not correcting itself fast enough), which brought the electric reel system uncomfortably close to the container stacks. The reel was moved back two feet to provide more clearance; however, reliability continued to be a concern for the laser guidance system, and a decision was made in October 2020 to consider alternatives. SSA staff designed their own guidance system using proximity sensors which they use for multiple application on the terminal. This system was successfully tested in and the first eRTG commenced limited service in November 2020.

Each subsequent eRTG conversion is expected to take less time and potentially as little as six weeks to complete. Each will occur sequentially so that only one crane would be taken out of service at one time to minimize the impact on terminal operation.

One of the key challenges for customers electrifying their fleets is the initial research and project development phase. During the project development phase, the collaboration among the POLB, SSA

Marine, Cavotec, and SCE contributed significantly to a successful project kickoff and continued into the execution phase. However, the newness of this technology made it challenging to acquire the desired components for all nine cranes in a timely manner.

This project and other electrification projects from SCE demonstrate a clear path that customers can take not only to collaborate with their local utilities but also to engage with equipment providers to create an outcome that is beneficial for business, the environment, and the community. Ports outside of SCE's service territory have been in contact with the POLB on the strategies leveraged to allow for duplication of efforts at their respective facilities. SSA Marine has implemented similar emission reduction strategies at its terminal in Oakland where they converted several RTGs to hybrid electric by installation of a smaller diesel engine (150 hp) and a battery pack.

Costs

The proposed total cost for the PRP make-ready infrastructure provided by SCE was $3,038,000. This comprises capital costs entirely, as SCE does not capture the site assessment, design, and permitting costs for the utility side, only for the customer side. Additionally, the POLB covered the cost of switchgear and installation for the eRTG project (~$2.84 million) and overall has spent much more in match funding (CEC grant requirement) than anticipated. SSA Marine out-of-pocket costs would include only the guidance system; in case of the laser-guided option, costs would be significantly higher than the proximity sensor alternative that was implemented. As of November 2020, the SCE-incurred final PRP costs totaled $2,322,934 (not including the POLB-covered costs), as shown in Table 41.

Table 41. SCE POLB RTG Crane PRP nominal costs as of November 2020

Cost Category	Actual Costs	Budgeted Costs
Site assessment, design, and permitting	N/A	N/A
Rebate amount paid	N/A	N/A
EVSE procurement	N/A	N/A
EVSE installation	N/A	N/A
Make-ready infrastructure (utility side)	$2,322,934	$3,038,000
Make-ready infrastructure (customer side)	N/A	N/A
Other construction costs	N/A	N/A
Project management	N/A	N/A
Customer outreach (labor)	N/A	N/A
Outreach and education materials	N/A	N/A
Other program costs	N/A	N/A
Total Costs	$2,322,934	$3,038,000

Source: SCE

Benefits

This project offers many potential environmental benefits. The Assigned Commissioner's Ruling recognizes the potential for improvement in this transportation segment, stating, "Mobile emission sources at ports and truck stops located in the service territories of the large three electric utilities are a concentrated source of emissions that could be well served with targeted programs." Accelerating transportation electrification adoption at the POLB improves air quality and reduces GHG emissions for all neighboring communities. These communities immediately surrounding the POLB are considered DACs, as defined by the California Environmental Protection Agency.

Since there were no eRTG operational data available, the following benefits are projected based on market information and estimates similar to the calculations conducted for the testimony and CEC grant application. These results are likely feasible since the electrical power system is replacing a diesel generator that previously powered the RTGs and will not have battery capacity limitations since the RTGs are connected directly to the utility grid. The only potential difference from current operations might be in maintenance; electrical components that are replacing the diesel generator should require much less maintenance resulting in cost savings.

The baseline fuel for the RTGs is diesel, and each of nine 1,000 HP RTGs operates between 750 hours and 3,772 hours per year, according to emission inventories.[39,40,41] Emission factors presented in Table 42 were determined based on the same emission inventories.

Table 42. Diesel baseline emissions factors determined using port emissions inventory

GHG (g/kWh)	SO_x (g/kWh)	NO_x (g/kWh)	CO (g/kWh)	PM (g/kWh)	VOC (g/kWh)
762	0.072	8.38	1.23	0.2	0.1

Source: 2019 POLB Emissions Inventory

While GHG emissions from electricity consumption are typically calculated per hour of operation based on low-carbon fuel standard (LCFS) values, no actual operational data were available, and therefore a GHG factor of 298.4 grams per kWh was used as the average of all LCFS values for 2020.

Annual hours are modeled as 1,800 hours and are based on the average of the nine cranes as reported over the past three years in emission inventories.[39,40,41] Fuel consumption was modeled at 12 gallons per hour based on a load factor of 20% and correlation of fuel use information. While SSA Marine mentioned fuel use as low as 9.5 gallons per hour, emission inventories and published data implied a higher use rate. With 1,800 hours at 12 gallons per hour, 194,400 gallons of diesel fuel (224,540 gasoline gallon equivalent [GGE]) would normally be consumed across the nine RTGs per year. On an energy

[39] Starcrest Consulting Group, LLC, "Port of Long Beach: Air Emissions Inventory - 2017," Starcrest Consulting Group, LLC, Long Beach, 2018.

[40] Starcrest Consulting Group, LLC, "Port of Long Beach: Air Emissions Inventory - 2018," Starcrest Consulting Group, LLC, Long Beach, 2019.

[41] Starcrest Consulting Group, LLC, "Port of Long Beach: Air Emissions Inventory - 2019," Starcrest Consulting Group, LLC, Long Beach, 2020.

basis, this fuel use translates to 149 kW during each hour of operation. Studies show a significantly lower energy consumption for electric conversions than for diesel units, owing to efficiency gains (a diesel RTG consumes three times as much energy as an eRTG).[42] Using this ratio, it can be expected that the converted cranes will consume 49 kW on average during operation, for a total use of 795 MWh per year across the nine RTGs. Table 43 presents annual emissions and emission reductions, based on the determined hours and energy consumption.

Table 43. Port RTG expected operation annual emissions

	GHG (MT/yr)	SO_x (kg/yr)	NO_x (kg/yr)	CO (kg/yr)	PM (kg/yr)	VOC (kg/yr)
Diesel	1,839	19	19,168	2,968	58	120
Electric	237	60	194	161	33	33
Net Reduction	**1,601**	**(41)**	**18,974**	**2,807**	**25**	**87**
% Reduction	**87%**	**N/A**	**99%**	**95%**	**42%**	**73%**

Source: Evaluator Calculations

While no actual operation was observed, SSA Marine indicated that RTGs are used 72 hours per week (five 8-hour day shifts and four 8-hour evening shifts). Across an entire year (50 weeks), this utilization would result in 3,600 annual hours of operation for each of the cranes. Table 44 shows the annual benefits if this level of utilization was experienced across an entire year, which would save 389,000 gallons of diesel fuel annually, or 449,000 GGE per year. The total electric use would be 1,591 MWh per year.

Table 44. Port RTG high utilization operation annual emissions

	GHG (MT/yr)	SO_x (kg/yr)	NO_x (kg/yr)	CO (kg/yr)	PM (kg/yr)	VOC (kg/yr)
Diesel	3,677	38	38,337	5,936	116	240
Electric	475	119	388	321	67	65
Net Reduction	**3,203**	**(81)**	**37,949**	**5,614**	**49**	**175**
% Reduction	**87%**	**N/A**	**99%**	**95%**	**42%**	**73%**

Source: Evaluator Calculations

The RTGs do not leave the port terminal, and therefore their entire operation is directly adjacent to a DAC, according to CalEnviroScreen 3.0. The POLB is not part of a census district, so the RTGs do not operate within a DAC.

Table 45 presents the summary of expected benefits for this PRP. The first column lists the expected benefits mentioned in the SCE PRP application testimony; the second column lists anticipated benefits included in the POLB CEC grant application. The last two columns include the benefits expected from normal- and high-use scenarios as described in the paragraphs above.

[42] Electric Power Research Institute, "Electric Cable Reel Rubber-Tired Gantry Cranes: Costs and Benefits," EPRI, Palo Alto, 2010.

Table 45. SCE POLB RTG Crane PRP benefits summary

	Testimony (9 RTG Cranes)	CEC Application (9 RTG Cranes)	Projected (9 RTG Cranes) Normal Use	Projected (9 RTG Cranes) High Use
Petroleum Reduction	180,000 gallons[a]	N/A	194,400 gallons of diesel	389,000 gallons of diesel
GHG Emissions Reduction	1,890 MT of CO_{2e}[b]	1,140 MT of CO_{2e}	1,601 MT of CO_{2e}	3,203 MT of CO_{2e}
Criteria Pollutant Emissions Reduction	N/A	24,000 kg of NO_X 400 kg of PM 1,400 kg of ROG	19,000 kg of NO_X 25 kg of PM 2,800 kg of CO 87 kg of VOC	38,000 kg of NO_X 50 kg of PM 5,600 kg of CO 175 kg of VOC
DAC Impact	POLB is adjacent to DACs	POLB is adjacent to DACs	POLB is adjacent to DACs	POLB is adjacent to DACs
Grid Impacts / Electricity Consumption	N/A	N/A	795 MWh, with 6% consumed on-peak	1,591 MWh, with 12% consumed on-peak
Operational Energy Cost Savings	N/A	N/A	$342,900	$686,120

Source: Evaluator Calculations

[a,b] Evaluator calculations based on data included in SCE's testimony

The GHG emission reduction results from the POLB eRTG pilot can be projected for other potential RTG applications that may replace diesel RTGs with slightly different fuel efficiency or annual use (see Figure 128 and Figure 129). Expected annual operational energy cost savings are presented in Figure 130. While no operational data was available for this report, SSA Marine is expected to realize electricity costs between 8 and 32 cents per kWh, based on the EV-TOU-9 rate. The electricity costs between 8 AM and 4 PM are 7 cents per kWh in the winter (eight months) and 10 cents per kWh in the summer (four months); between 4 PM and 9 PM, electricity costs are 25 cents per kWh in the winter and 41 cents per kWh in the summer. Assuming a 5-to-4 ratio of day to evening shifts (according to SSA Marine), the expected average annual cost of electricity, with applicable taxes and fees, would be about 18 cents per kWh. Comparing eRTG and diesel RTG operational energy costs, based on an SSA Marine-reported cost of $2.50 per gallon for off-road diesel fuel in 2020, $343,000 of annual savings can be expected.

Figure 128. eRTG GHG reductions by baseline fuel economy

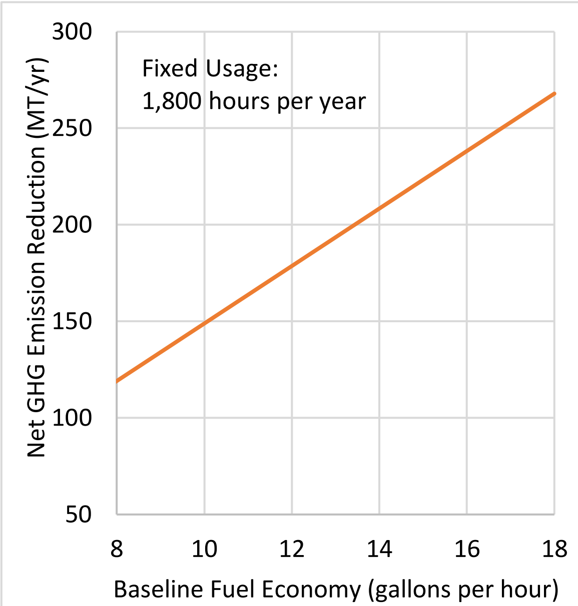
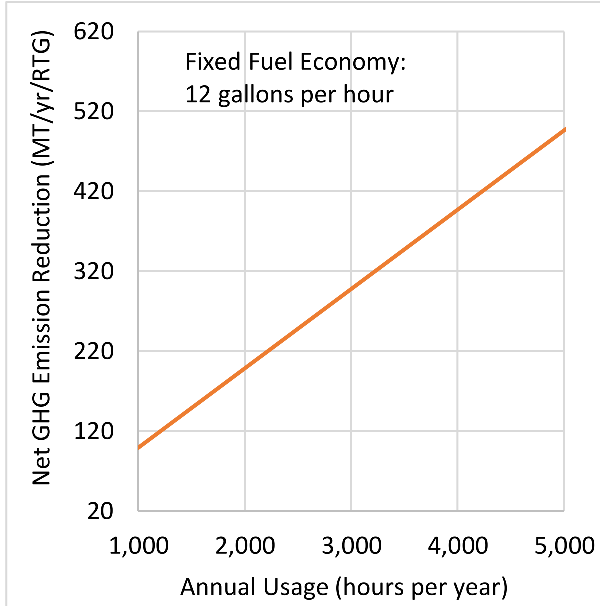
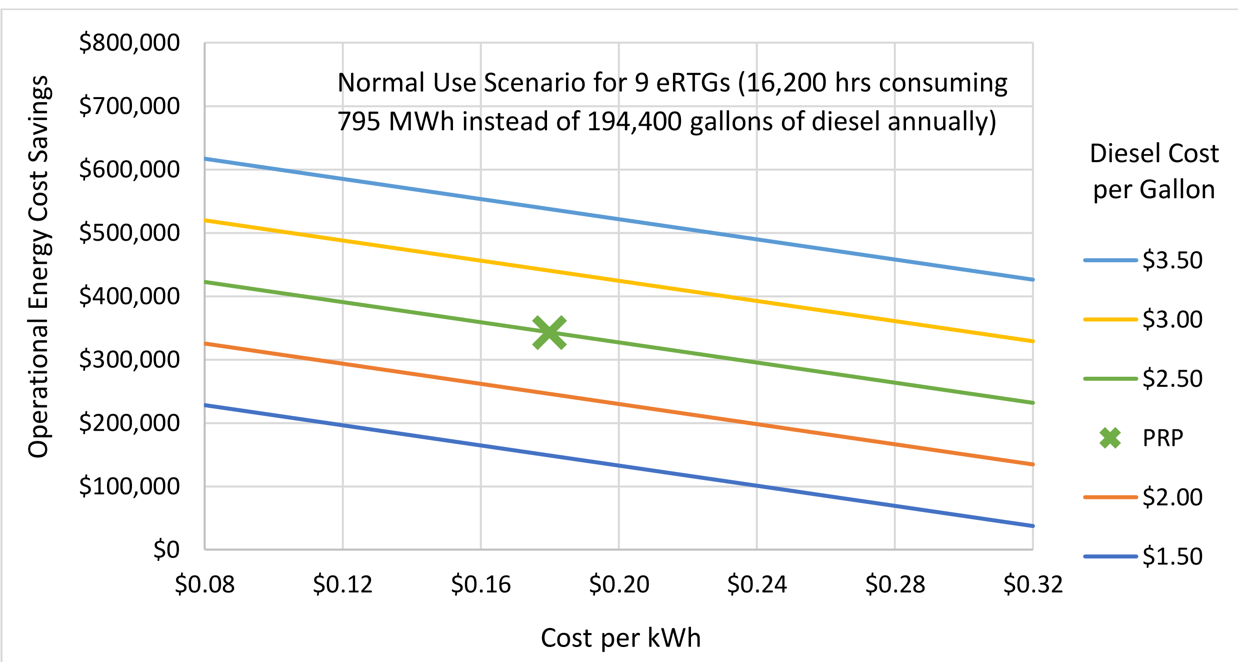


Figure 129. eRTG GHG reductions by annual use



Source: Evaluator Calculations

Figure 130. Annual eRTG operational energy cost savings at various fuel costs



Source: Evaluator Calculations

Stakeholder and Customer Feedback

SSA Marine reports that crane operators have appreciated the benefits of removing the noise and emissions typically associated with their working environment. Performance with grid-power is better than with the gensets and speed has since been decreased. The grid-sourced power may provide quicker feedback than the generator system.

Despite the emissions and costs savings, SSA Marine indicated that they would not do another project like this unless zero-emission regulations require it. Their reasons include the following:

- It took a very long time to get approval and funding and to complete permitting (well over two years).
- Terminal space is very expensive, and tenants need it for containers instead of electrical infrastructure (four distribution pads take up a significant footprint).
- Installing electrical gear on a working terminal is very challenging, as it affects busy terminal operation.
- The conversion and testing timeline is sensitive to both the terminal workload and the successful development of the first unit.
- Installing the trench and protective rubber (Panzor style) belt was difficult and time-consuming (e.g., it required deep and far concrete-cutting), which resulted in significant cost.
- SSA Marine has experienced 90 percent fuel use reduction with a hybrid RTG (150 HP generator and a battery system) conversion in Port of Oakland operation. That project exceeded expectations, in part due to energy generation that is captured by the batteries as cargo containers are lowered. The Bay Area Air Quality Management District grant allowed for 13 RTG hybrid conversions, which SSA Marine mechanics did themselves relatively quickly, and no outside permitting was required. Port of Oakland SSA Marine is considering a fell cell option to replace the batteries, as those RTGs have limited remaining useful lives (up to year 2030 as it was a retrofit).

4.1.4 Conclusions and Recommendations

Findings

SCE spent $2,322,934 of the $3,038,000 to install make-ready infrastructure that will serve nine RTG cranes. The conversion of the RTG cranes to electric was significantly delayed so no data was collected on operations during the evaluation period. Therefore, most of the key findings below are related to the implementation of the electrical infrastructure and eRTG conversion.

- Customers tend to be very cautious when working on equipment that is critical to their operations. While SSA Marine might have been able to accelerate the project timeline by doing multiple actions in parallel (procuring the conversion components, installing the switchgear pads, ordering the battery module, and cutting the trenches), management chose to verify each activity was completed before progressing to the next.
- Though new eRTGs are available, this operator chose to modify current units because of their long service lives. Despite advance planning, the retrofit process required much more time and

problem solving than anticipated, resulting in significantly delayed benefits compared to the infrastructure completion.

- Port terminal space is very expensive. Using it for electrical infrastructure subtracts from tenant revenue.
- Bringing additional power for eRTGs to the terminal caused significant disruptions to tenant operations.
- Because of timing issues, implementation complexity, and costs experienced with RTG electrification, the terminal operator is considering alternative options (such as hybrid systems or fuel cells) for reducing RTG emissions to meet any upcoming zero-emissions regulations.
- While emissions reductions and operational energy cost savings are projected to be significant, the capital infrastructure and RTG conversion costs are significant as well. Replacing internal combustion gensets with electrical components is expected to result in maintenance savings but quantifying these savings will take several cranes operating for over a year.

Lessons Learned

The following lessons learned were captured during the implementation of this PRP.

- Undertaking a significant project such as this one requires grant funding from different sources but acquiring and managing the funding tend to lengthen the project timeline.
- Permitting requirements for infrastructure upgrades add additional time to the implementation, whereas equipment conversion can be handled by the terminal operator.
- Lengthy construction on an active terminal causes logistical challenges for tenant operation.
- Because of the unique nature of cargo-handling terminal equipment, terminal operators can often come up with practical technology solutions instead of relying on complex and expensive solutions (e.g., proximity sensors vs. laser guidance systems).
- Phasing in a project of this complexity or coordinating with other terminal development plans could reduce the risk to rate payers.
- Port Terminals are subject to severe use and ground markings such as the reflective tape initially used by the guidance system are subject to premature failure.

Scale-up Potential

SSA Marine operates a total of 15 RTG cranes at the POLB and 28 RTG cranes statewide (including the Port of Los Angeles and the Port of Oakland). There are 357 RTGs in the state of California between Ports and Rail yards.[43] A successful demonstration could create opportunities to introduce eRTG cranes and subsequent significant reduction in emissions in California. Of the 357 RTGs in the state of California, 272 RTGs are at ports[43]; they range in size but have an average of 690 HP. If the benefits from the nine RTGs were achieved across the entire state fleet, with the average horsepower of 690 and

[43] California Air Resources Board, "OFFROAD2017," Sacramento, California.

annual usage of 1,800 hours per crane, the emission benefits shown in Table 46 could be expected, along with savings of 4.7 million gallons of diesel fuel.

Table 46. RTG scale-up potential annual emissions

	GHG (MT/yr)	SO_x (MT/yr)	NO_x (MT/yr)	CO (MT/yr)	PM (MT/yr)	VOC (MT/yr)
Net Reduction	**34,392**	**N/A**	**396**	**59**	**0.5**	**1.8**

Source: Evaluator Calculations

4.2 Port of Long Beach Terminal Yard Tractors

4.2.1 Project Narrative

Overview, Objectives, and Barriers Being Addressed

The Port of Long Beach (POLB) Clean Air Action Plan (CAAP) sets aggressive goals to accelerate transportation electrification technology development. To help drive the transition to zero-emissions, the port proposed that all terminal equipment must be zero-emissions by 2030. Through this pilot, SCE was approved to spend $450,000 deploying the electric infrastructure necessary to serve charging stations for new electric yard tractors, which move intermodal containers around the facility. To accommodate the originally proposed load for 24 charging points, SCE needed to upgrade its distribution infrastructure, including additional pad-mounted switches, capacitor bank, and transformers. SCE is designing, deploying, and maintaining—and now owns—this electric infrastructure. However, SCE is not establishing technical requirements on charging equipment, as the utility is not providing a rebate to cover these costs.

The objectives of the pilot are to demonstrate proposed vehicles/technologies for 12 months, convene a Zero-Emission Port Workforce Development group to improve existing workforce development and training programs in support of port equipment electrification, and establish the proposed technologies as cost-competitive purchase options through development of estimates of future costs versus baseline technology costs. The project also supports the state's Sustainable Freight Strategy to reduce diesel particulate matter (PM) and criteria pollutant emissions from compression-ignition mobile cargo-handling equipment that operates at ports and intermodal rail yards by demonstrating the feasibility of replacing diesel drive tractors with electric drive tractors.

Sites and Participants

Recruitment Process

The PRP was specifically developed and approved to deploy make-ready infrastructure that serves the **International Transportation Service, Inc. (ITS) Terminal**'s fleet of yard tractors, currently fueled by diesel engines. The ITS Terminal has a fleet of approximately 130 diesel-powered yard tractors at the POLB and plans to expand it in the near future. The ITS Terminal has two areas where yard tractors are parked; the main area accommodates more than 100 tractors, and a second, smaller area accommodates 24 tractors. ITS management selected this second area on the west side of Pier G for the pilot because of its proximity to the pier's electrical substation. The PRP supports the first phase of a two-phase plan to install some initial chargers as a test. If proven successful, a Phase 2 plan will target up to 80 more chargers.

Participants

The POLB has received funding from the California Energy Commission (CEC) for twelve pre-commercial terminal yard tractors. However, the funding does not cover the supporting electric infrastructure, so this PRP will provide that for the project. Initially, during the timeline of this PRP, ITS is deploying seven **BYD Motors Inc. (BYD) electric yard tractors,** six **BYD chargers**, and one smart **charger from Cavotec**. SCE will deploy infrastructure to serve up to 20 terminal yard tractor charging stations. The additional five electric yard tractors in the CEC project will be demonstrated at Long Beach Container Terminal (LBCT), which is not associated with SCE's PRP. LBCT terminal recently underwent a significant renovation and therefore has sufficient electrical capacity to support installation of the EV chargers; therefore, not requiring any SCE upgrades.

Figure 131. BYD model 8T electric yard tractor, BYD 200 kW charger, and Cavotec automated charger arm

Source: BYD (left and middle pictures) and Cavotec (right)

Six of the new battery electric yard tractors will use 200 kW charging stations from BYD. These high-power chargers will enable ITS to overcome one of the key barriers to widespread market adoption of zero-emissions technologies: the ratio of charge time to operating time. With a lower-power charger, ITS might be forced to limit use of the new yard trucks to a single shift per day—a condition that would be considered a failure right from the very start of the project. By deploying 200 kW chargers, ITS anticipates being able to charge between shifts or opportunity charge so yard trucks can be operated two shifts per day, meeting the real-world minimum requirements of the marine terminal. One BYD yard tractor includes compatibility with an innovative and automated "smart" yard tractor charging system from Cavotec to support a more convenient large-scale charging system that is necessary to transition the POLB fleet to zero-emissions.

To serve the estimated load for the 20 charging ports (200 kW each), SCE is upgrading its distribution infrastructure, including additional pad-mounted switches, a capacitor bank, and transformers. SCE is responsible for the planning, design, and construction of the make-ready electrical infrastructure at both the utility side and customer side for the ITS demonstration. The following equipment and supporting structures are included in SCE's design:

- Two sets of pad-mounted equipment (PME): (PME 10 and PME 9)
- Two 3,000 A meter switchgear
- Pad-mounted 12 kV capacitor bank
- Two 2,500 kVA 12 kV/480 V transformers
- Distribution conduit and cable
- All supporting civil and foundation structures
- Protective bollards surrounding all newly installed infrastructure

- 480 V charging station infrastructure terminating in seven fused service disconnect make-ready positions
- Ducts and structures to support an additional 13 future electric vehicle supply equipment (EVSE) installations

The customer-side electrical infrastructure is being constructed by one of SCE's approved general contractors under SCE's supervision. The POLB provided connection to the service disconnects, EVSE units, EVSE foundations, and additional impact protection for the Cavotec charger. The POLB has a consultant, **Starcrest Consulting Group, LLC**, overseeing the data collection requirements for the CEC grant.

Timeline and Status

Figure 132 presents the timeline for this pilot. SCE estimated that designing and deploying the infrastructure for this project would take about 12 months. SCE's installation of the electrical infrastructure under this PRP ultimately took approximately 18 months, with the following major milestones:

- The PRP was implemented in first quarter (Q1) 2018, following the California Public Utilities Commission (CPUC) decision in January 2018.
- Final engineering design for SCE's make-ready infrastructure was completed in Q4 2018.
- The POLB and ITS reviewed and approved the design plans in November 2018.
- The POLB issued the Harbor Development Permit for construction in November 2018.
- The plans were submitted to the City of Long Beach Building & Safety Bureau for review and permitting in November 2018.
- Construction of the electrical infrastructure was completed in Q1 2019, with structural, fire, and electrical approvals of completion received by the end of March 2019.
- The electrical infrastructure was energized following the installation of the chargers in Q3 2019.

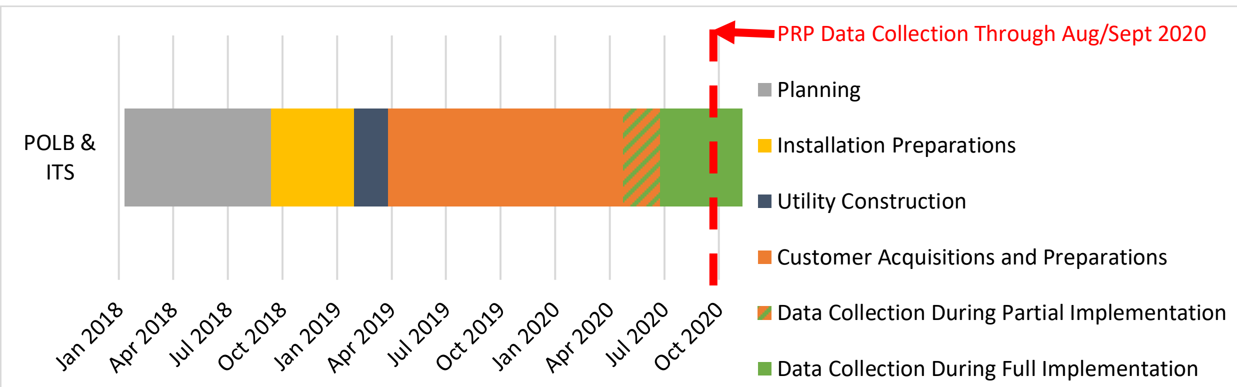
While this PRP was strictly supporting SCE electrical infrastructure at the POLB for this ITS yard tractor demonstration, the project's impacts are not realized until the equipment is fully operational. Future SCE transportation electrification projects may involve charging equipment installation, so there is value in observing the process at ITS through the CEC grant.

BYD brought the first demonstration yard tractor to ITS in May 2019 to conduct maintenance personnel training. ITS took delivery of the first four BYD yard tractors on May 17, 2019 including one with the Cavotec funnel (which guides the automated charger arm) installed. There was miscommunication on the required height of the automated charger arm, which created multiple interactions about the tractor funnel's specifications and later some adjustments to the height of the charger itself (ultimately, the height of the mounting pad had to be increased). Neither BYD nor Cavotec chargers were listed by a Nationally Recognized Testing Laboratory (NRTL). As a result, BYD pursued onsite TÜV SÜD product certification for the six BYD chargers, and Cavotec pursued ETI Conformity Services Field Evaluation for the Cavotec charger.

The initial inspections of both listed several concerns: the enclosure did not meet National Electrical Manufacturers Association (NEMA) 3R requirements, some individual electrical components and cables were not NRTL-listed, and some electrical components were not rated to meet the potential power levels. In addition to finding solutions to these issues, ordering the replacement parts, properly installing them, and follow-up inspections were required that necessitated the coordination of the inspector, equipment manufacturers, the POLB, and ITS.

This additional effort resulted in an 8-month delay (chargers were first installed in August 2019 and final permit approvals to begin in service operation were received in April 2020). Primary reason for the delay were EVSE issues identified during field certification inspection that needed to be addressed prior to approval. Secondarily, location of safety barriers (i.e., bollards, k-rail) and safety clearance issues hampered the start up. In parallel, ITS expressed concerns about the weight of the charging cords and potential tripping hazard if left on the ground, which triggered an investigation into cable racks or a tether system. There were also significant complications in charging a BYD tractor with the manual BYD chargers due to software issues that caused numerous charging errors. The smart charger also experienced software interface issues with BYD yard truck system. Unfortunately, software modifications were delayed due to the COVID-19 pandemic (BYD software engineer was quarantined in China).

Figure 132. SCE POLB terminal yard tractor PRP timeline



Source: POLB CEC Grant Weekly Construction Meetings

4.2.2 Evaluation Methodology

Selected Methods and Rationale

In addition to the evaluation questions that apply to all PRPs and those specific to the Fleet Electrification PRPs, the evaluation questions listed below will be examined for this PRP.

- Did electric yard tractors and charging equipment perform as expected?
- How did the automated charger use compare to other chargers? What were the benefits, and were there any downsides to the automated charger use?
- Would similar supporting electrical infrastructure at other locations in the port be more expensive? Is there a limit to the available power?
- Could this be economically feasible without the grants for the tractors and SCE support?

The data sources used to evaluate this PRP include 1) PRP information from the approved decision, project updates, site visits, and other available documentation, 2) market research on yard tractors and early deployment efforts from other similar electrification projects across the country, 3) PRP data from vehicle and charger operations, and 4) in-depth interviews (IDIs) with project partners.

Data Sources

The evaluator collected PRP information through numerous PRP participant interactions: a PRP kick-off meeting (SCE and evaluator), quarterly Program Advisory Council (PAC) update meetings, periodic PRP updates (SCE and evaluator), weekly PRP construction calls, biweekly CEC grant data collection calls, site visits, and other periodic calls or emails. Through these interactions, the evaluation team collected 1) the data collection plan for the CEC project that funded the electric yard tractors, 2) electric yard tractor characteristics and hardware specifications, 3) details from other electric yard tractor efforts at the POLB through the CEC grant, and 4) a National Renewable Energy Laboratory (NREL) study in support of the POLB Port Community Electric Vehicle Blueprint. The PRP participants also provided additional information on project costs, pictures from the site, all specifications for the charging stations, and historical yard tractor use.

PRP operational data for this project includes 15-minute interval data from the utility service meters (two meters, each supporting a bank of 10 charger connections with all 7 EVSE installed on one meter), charging session data from the automated Cavotec charger, yard tractor data from GeoTab telematic devices (expanded to all tractors), and operational data and anecdotal insights from ITS.

The evaluator held an IDI with a representative from the POLB to further understand the background on this project and gather lessons learned to date. Additional IDIs with the SCE construction team, SCE project managers, vendors, and operators were held in 2020 as the yard tractors were added to revenue service.

4.2.3 Evaluation Findings

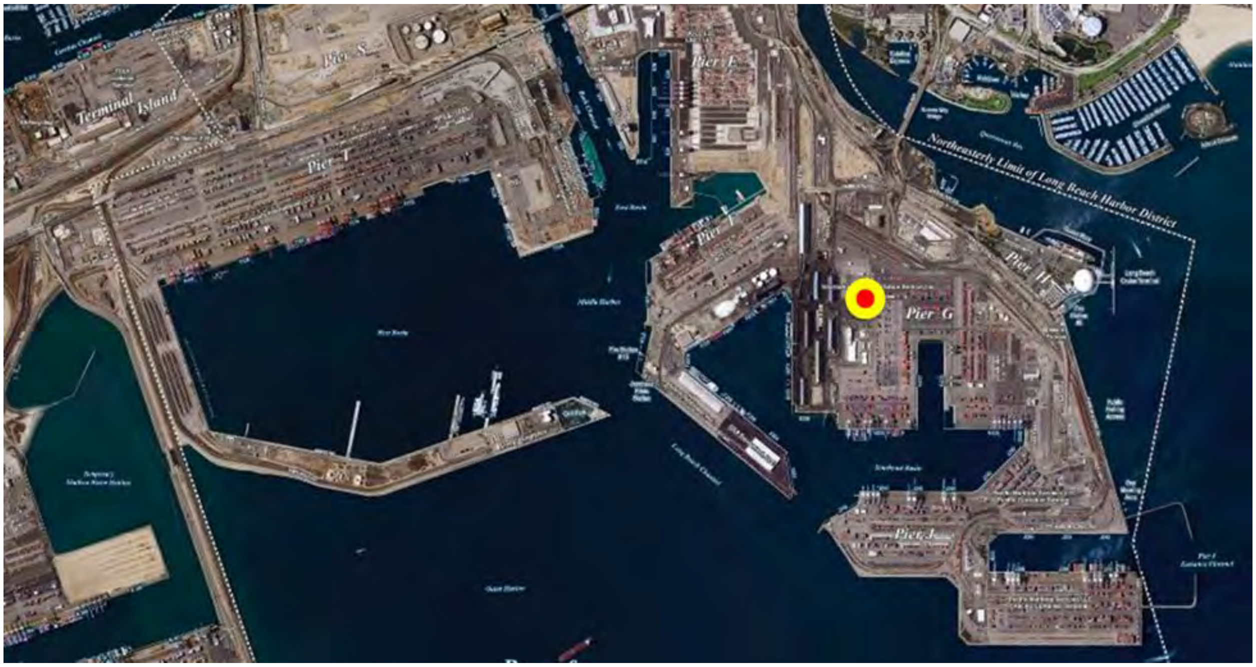
Project Baseline

At the POLB, yard tractors—which may also be referred to as terminal tractors, utility tractor rigs, yard trucks, yard goats, or yard hostlers—are the most common cargo-handling equipment used in on-terminal container movement. According to the 2019 Air Emissions Inventory,[41] yard tractors account for approximately 46% of total cargo-handling equipment at the POLB. The total number of yard tractors operated within the port exceeds 700 vehicles. Over 80% of these yard tractors are currently equipped with non-road diesel engines, making them high polluters.

Yard tractor activities in marine terminals generally fall into three main categories: ship work, rail work, and dock work. Ship work involves the loading and unloading of containers onto and from container vessels. Rail work comprises loading and unloading containers to and from cargo trains, while dock work consists of moving containers within a terminal yard, such as the consolidation of containers (sometimes referred to as housekeeping).

This project is driven by the POLB's CAAP goals to go to zero-emissions, which is influenced by expected state and local regulations on this topic. Working toward these goals will require significant equipment replacement and upgrades in partnership with terminal operators. The operators believe it's necessary to demonstrate zero emission technologies to better determine if such technologies will work for port operations/environment, can pull the needed loads, and are durable enough to meet demanding port duty cycles. There have been smaller, short-term demonstrations, but this is the first time a project of this scale will enter revenue service with the intention of the deployed technologies staying with the terminal operator for their lifetime. Such projects are needed to bring technologies closer to commercialization for other operators to adopt and to quantify the business case for electrification.

Figure 133. POLB Pier G electric yard tractor project site location



Source: POLB

Implementation Process

The pilot's ongoing success was a direct result of the collaboration between all the partners and stakeholders during the development stage. The execution of large-scale electrification projects with multiple stakeholders across a number of industries can be challenging. Early collaboration is critical to success. The POLB began its electrification plan with a goal to ensure that all stakeholder groups were involved in developing the pilot execution plan. This ensured that all parties were aware of the timeline during each planning stage.

Procuring the electric yard tractors and installing the charging equipment was beyond the scope of SCE's PRP, but these efforts have a significant impact on the success of the overall goal to deploy transportation electrification technology for emission reductions. Majority of complications and delays were attributed to the availability of the cutting-edge technologies selected for this demonstration pilot. The process undertaken to field-certify the charging stations revealed NRTL listing requirements and short circuit current rating (SCCR) capacity issues that necessitated modifications to the already installed equipment. In addition to the time for identifying a solution, ordering replacement components, and performing the modifications, there are added complications for scheduling and site access because the equipment was already at the customer location. The POLB would require that, for future installations, any certifications are done prior to installation to minimize work and disruptions at the customer site.

Another concern discovered post-installation was that the charging cable weight was difficult for the equipment operators to handle and could pose a tripping hazard. As charging power increases, the cords quickly become heavy and difficult to maneuver, particularly if liquid cooling is required (in this case, it was not). The length of charging cord based on the charger positioning and location of the charging port on the vehicle may also affect its weight. Some form of cable support was necessary for this installation (and will likely be needed for many similar installations). The POLB also noted that the electrical infrastructure, charging stations, and protective bollards took up more space than initially anticipated, which presented equipment parking site configuration layout challenges. Several concrete pads were also very large and posed potential tripping hazards, so post-construction modifications were necessary.

The POLB also noted that it would be helpful to determine roles and responsibilities for each project team member early in the project. Regularly held calls helped work through any confusion or concerns, but concerns could have been addressed more easily if roles and responsibilities were clarified at the beginning of the project. The POLB also suggested binding agreements with all project stakeholders and equipment end users for similar future projects.

Figure 134. Cavotec automated yard tractor charger

Source: POLB

Figure 135. One of six BYD yard tractor chargers

Source: POLB

Costs

The approved total PRP cost (which is made up entirely of capital expenses) was $450,000. The PRP costs as of November 2020 totaled $1,627,550 (which may not include all participant costs), as shown in Table 47, based on data available to SCE.

Table 47. SCE POLB terminal yard tractor PRP nominal costs as of November 2020

Cost Category	Actual SCE Costs	Budgeted SCE Costs
Site Assessment, Design, and Permitting	$ 41,298	N/A
Rebate Amount Paid	N/A	N/A
EVSE Procurement (Subject to Change)	N/A	N/A
EVSE Installation (Subject to Change)	N/A	N/A
Make-Ready Infrastructure (Utility Side)	$ 733,071	$ 450,000
Make-Ready Infrastructure (Customer Side)	$ 853,181	N/A
Other Construction Costs	N/A	N/A
Project Management	N/A	N/A
Customer Outreach (Labor)	N/A	N/A
Outreach and Education Materials	N/A	N/A
Other Program Costs	N/A	N/A
Total Costs	$ 1,627,550	$ 450,000

Source: SCE

The forecast for the customer-side construction costs was inadvertently omitted from the initial application and therefore will not be included for recovery as part of this pilot. The customer-side construction costs of approximately $900,000 and utility-side of nearly $300,000 were recorded to Shareholder Operations and Maintenance (O&M) account. The assumptions used for the original $450,000 forecast for the utility-side construction costs were based on single-meter switchgear and standard installation conditions using PVC (polyvinyl chloride) conduit between all SCE structures. Cost overruns were primarily due to the following:

- Load requirements on the customer side required that two-meter switchgear be installed, as opposed to the single-meter switchgear in the original assumptions.
- Customer-imposed space constraints and an asphalt cross-section that was substantially thicker than expected (up to 3 feet of concrete instead of 1 foot on as-built plans) resulted in higher-than-anticipated construction labor costs.
- More expensive concrete cable trenches had to be custom-built at the site because of tighter-than-expected equipment placement, which made traditional conduit placement from transformers to the meter switchgear impossible.

Benefits

The pilot integrated seven yard tractors into the operator's existing port diesel fleet and seven EV chargers. The key benefits and some contributing factors are outlined below and shown in Table 48, with a more detailed description of the benefit analysis included in the Appendix.

The calculated average diesel fuel consumption rate for the single baseline yard tractor is 2.7 gallons per hour. The pilot's primary performance results were based on the period from May to October 2020 (excluding 36 days when data appeared to be erroneous and could not be validated). During the May–October period, only five of the seven electric yard tractors were regularly used. Extrapolating the electric yard tractor performance during the pilot to an annual scale, the vehicles use 158 MWh per year of energy, with 16,500 kWh (10%) occurring during on-peak hours. This equates to a baseline annual utilization of 6,300 hours, which translates to 17,000 gallons of diesel fuel consumed for the baseline vehicles. The best observed operations for this pilot were during a week in September 2020; using data from this week translates to 12,700 annual hours of operation, requiring 34,200 gallons of diesel for the baseline vehicles and 317 MWh (with 34 MWh [11%] of that use during on-peak hours) for the electric yard tractors. Fuel cost savings calculations used average fuel prices of $2.00 per gallon of off-road diesel as provided by ITS and $0.20 per kWh of electricity determined from utility bills.

Table 48. SCE POLB terminal yard tractor PRP annualized benefits

	Testimony (24 Charging Ports)	Planned (7 Charging Ports)	Implemented (5 Yard Tractors)	Best Observed (5 Yard Tractors)
Petroleum Reduction	N/A	N/A	17,000 diesel gallons	34,200 diesel gallons
GHG Emissions Reduction	N/A	N/A	177 MT of CO_{2e}	356 MT of CO_{2e}
Criteria Pollutant Emissions Reduction	3,712 kg of NO_X 54 kg of PM[a]	1,083 kg of NO_X 16 kg of PM	409 kg of NO_X 11 kg of PM 52 kg of VOC 155 kg of CO	821 kg of NO_X 22 kg of PM 103 kg of VOC 310 kg of CO
DAC Impact	POLB is adjacent to DACs	POLB is adjacent to DACs	100% of emission benefits are DAC adjacent	100% of emission benefits are DAC adjacent
Grid Impacts / Electricity Consumption	N/A	N/A	158 MWh, with 10% consumed on-peak	317 MWh, with 11% consumed on-peak
Fuel Cost Savings	N/A	N/A	$2,400 ($480 per vehicle)	$5,000 ($1,000 per vehicle)

Source: SCE Testimony and Evaluator Calculations

[a] Evaluator calculations based on data included in SCE's testimony

The best observed greenhouse gas (GHG) emission reduction results from the POLB Yard Tractor pilot can be projected for other potential yard tractor applications that may replace baseline diesel yard tractors with slightly different baseline fuel efficiency or annual use. The results of these sensitivity analyses are shown in Figure 136 and Figure 137.

Figure 136. Yard tractor GHG reductions for various baseline fuels and fuel economy

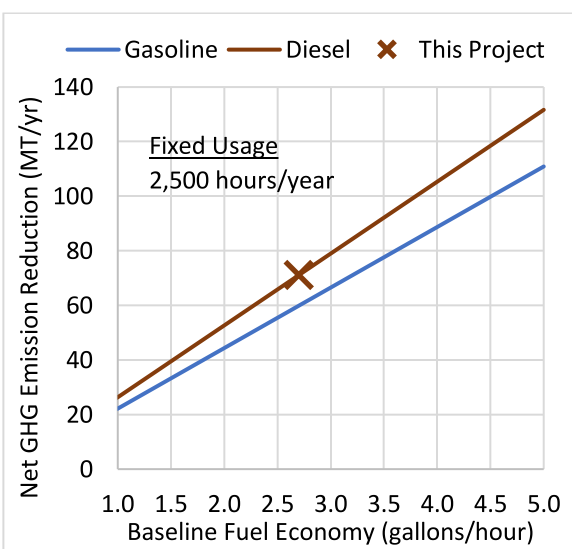
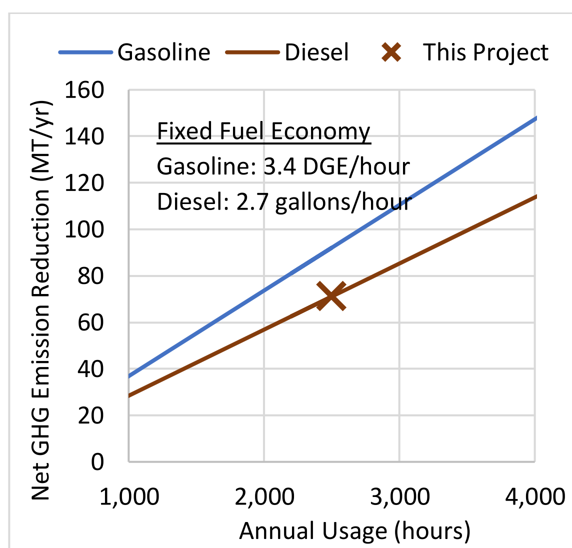


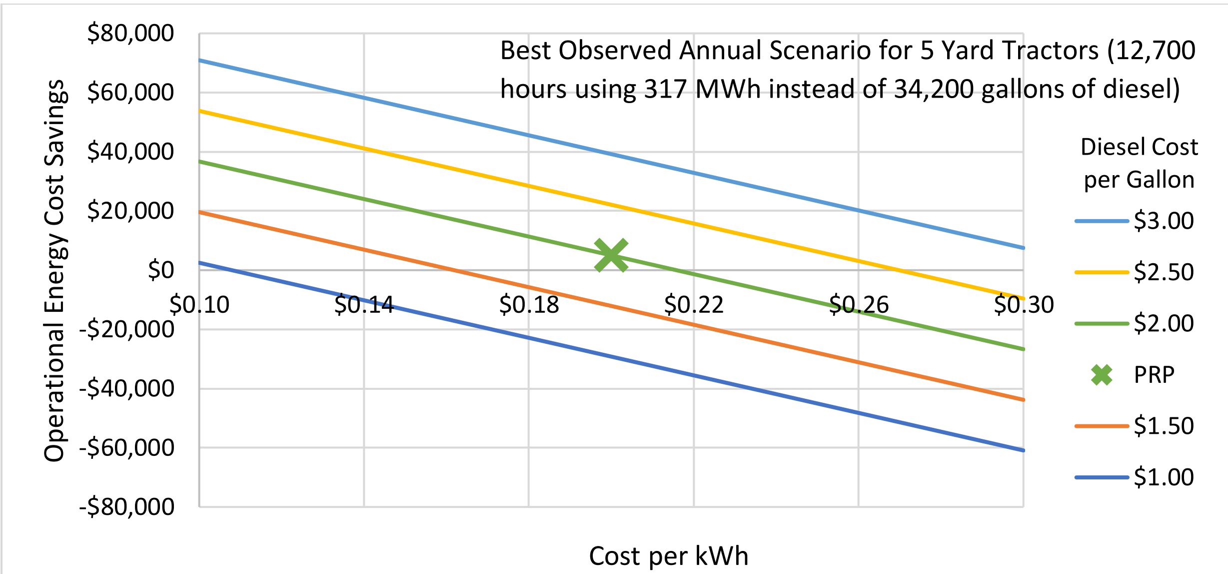
Figure 137. Yard tractor GHG reductions for various baseline fuels by annual use



Source: Evaluator Calculations

Figure 138 shows how the operational energy cost varies with the cost of energy for an electric yard tractor compared to the baseline diesel vehicle. While the fleet realized some operational energy cost savings (less than $500 per year per vehicle), they could be magnified significantly when accounting for potential low carbon fuel standard (LCFS) credits which would eliminate electricity costs. The challenge might be that the port owns the chargers and therefore the fuel credits associated with their use.

Figure 138. Annual yard tractor operational energy cost savings at various fuel costs



Source: Evaluator Calculations

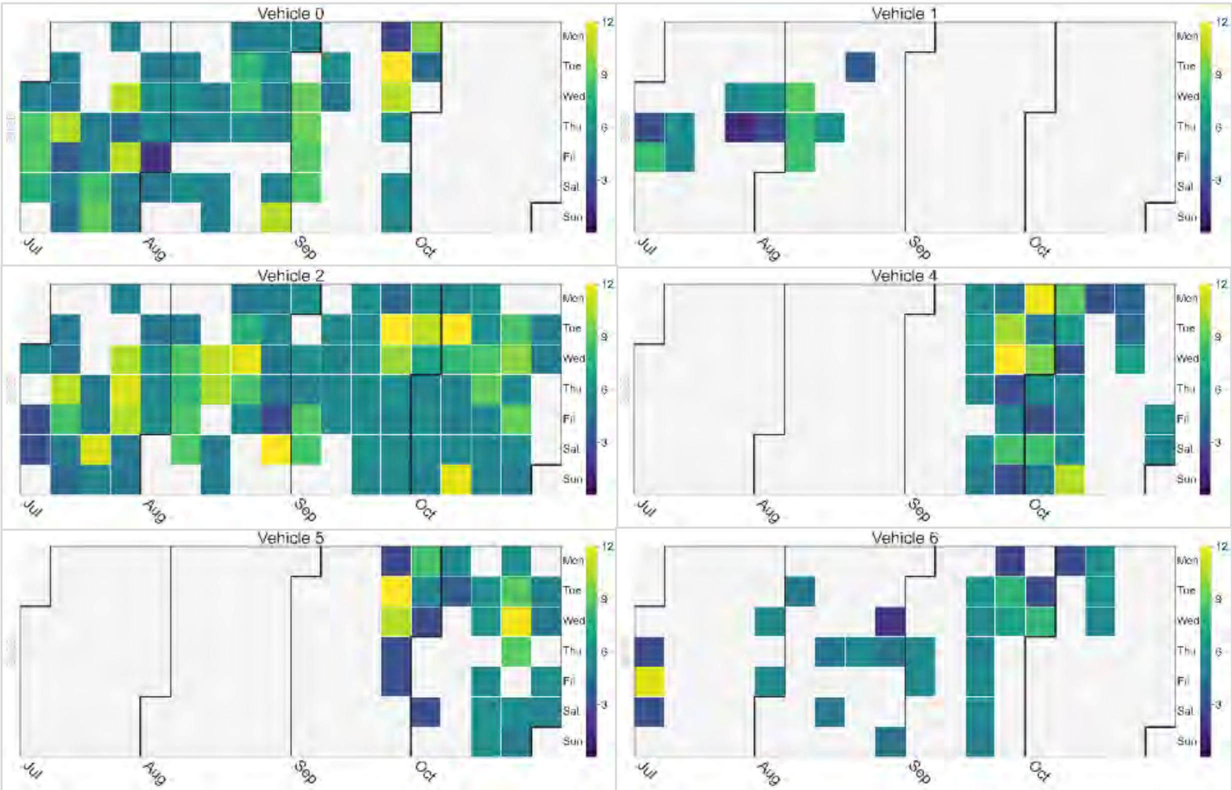
Operational Impacts of Project Equipment

Electric yard tractor testing comprised three primary phases:

1) Electric Yard Tractor Acceptance Testing – completion of specified testing parameters (completed in Q2 2019 by BYD in Lancaster, California)
2) Controlled On-Terminal Testing – completion of typical single-shift duties (completed in May through August 2020 at ITS Pier J, POLB terminal)
3) Revenue On-Terminal Demonstration – typical operations for 6 to 12 months (started September 2020 at ITS Pier G, POLB terminal)

Figure 139 shows utilization of the yard trucks beginning in July 2020, after on-board data loggers were installed. Each colored block represents one day of operation. The color scale to the right of each chart indicates hours of operation for each day. From the first phase, electric vehicles 0 and 2 show consistent usage since starting operation. Though also deployed in the first phase, vehicle 6 shows much less usage, generally because of a lack of driver availability. Vehicle 6 was the single unit using a charger with an automated connector. Vehicle 1 has been primarily out of service. Vehicles 3, 4 and 5 were placed into service in September as phase two of the vehicle deployment. Vehicle 3 had data logging issues and no data was available; according to ITS, its operation matches those experienced by vehicles 4 and 5.

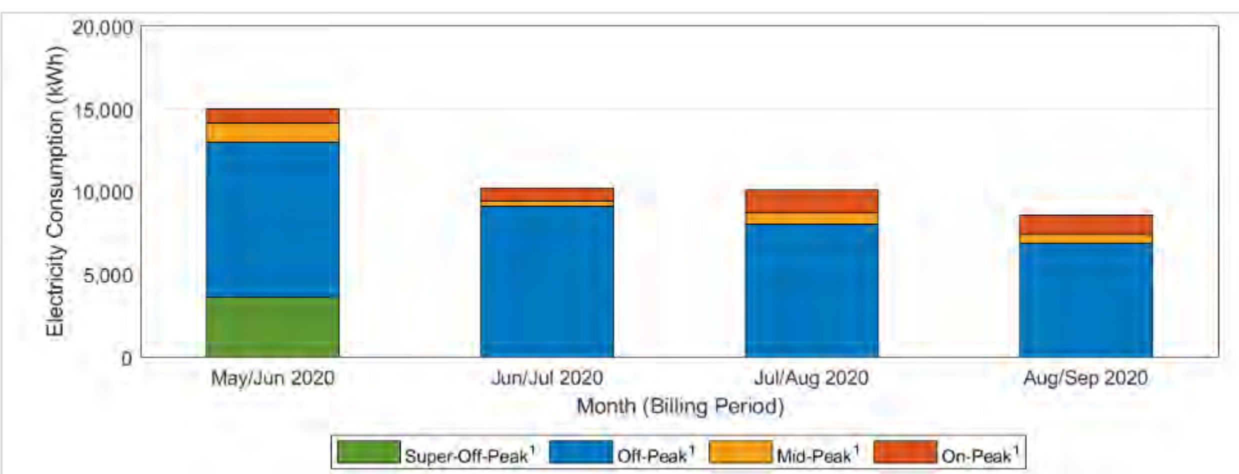
Figure 139**. Vehicle phase-in trending via telematics**



Source: BYD vehicle telematics

Whether energy consumption is looked at on the basis of utility billing cycle or calendar-month, the project is using over 10 MWh of electricity most months. Despite frequent opportunity charging around noon during breaks and between shifts prior to 4:00 PM (off-peak and super-off-peak hours), some energy consumption takes place during the on-peak time period (4:00 PM–9:00 PM), as seen in Figure 140.

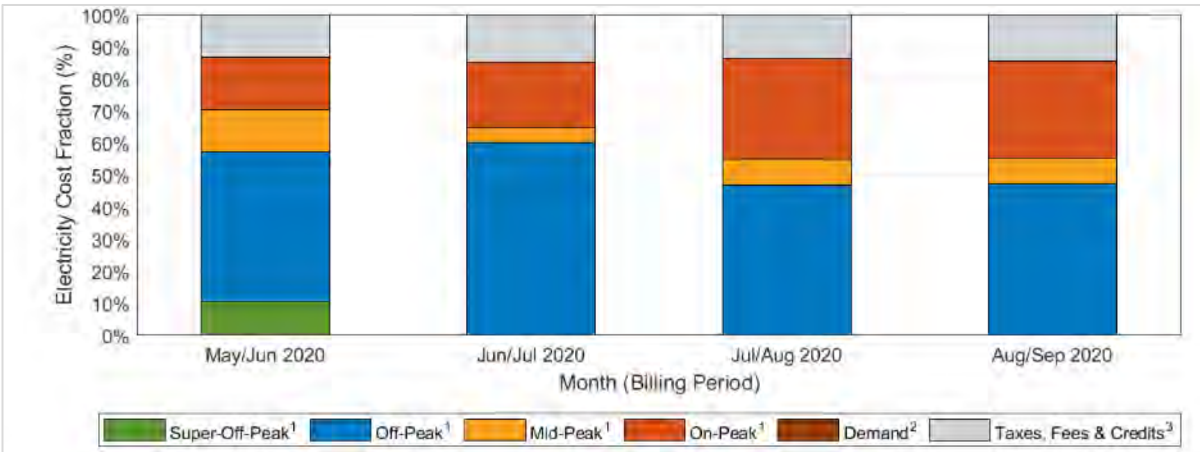
Figure 140**. Terminal yard tractor fleet energy consumption (SCE TOU-EV-8 tariff)**



Source: SCE Meter Data

However, despite relatively low on-peak consumption, the high pricing of on-peak electricity led to on-peak usage's accounting for approximately 30% of total billing costs during summer months, as seen in Figure 141. The utility bills reflect overall electricity prices of \$0.18–\$0.22 per kWh. For three-quarters of the time period studied, the trucks were used for only a single shift per day, so even more of the on-peak and mid-peak charging could have been shifted to lower-cost off-peak or super-off-peak time periods. Having software available to implement a charging management plan would have facilitated such a strategy.

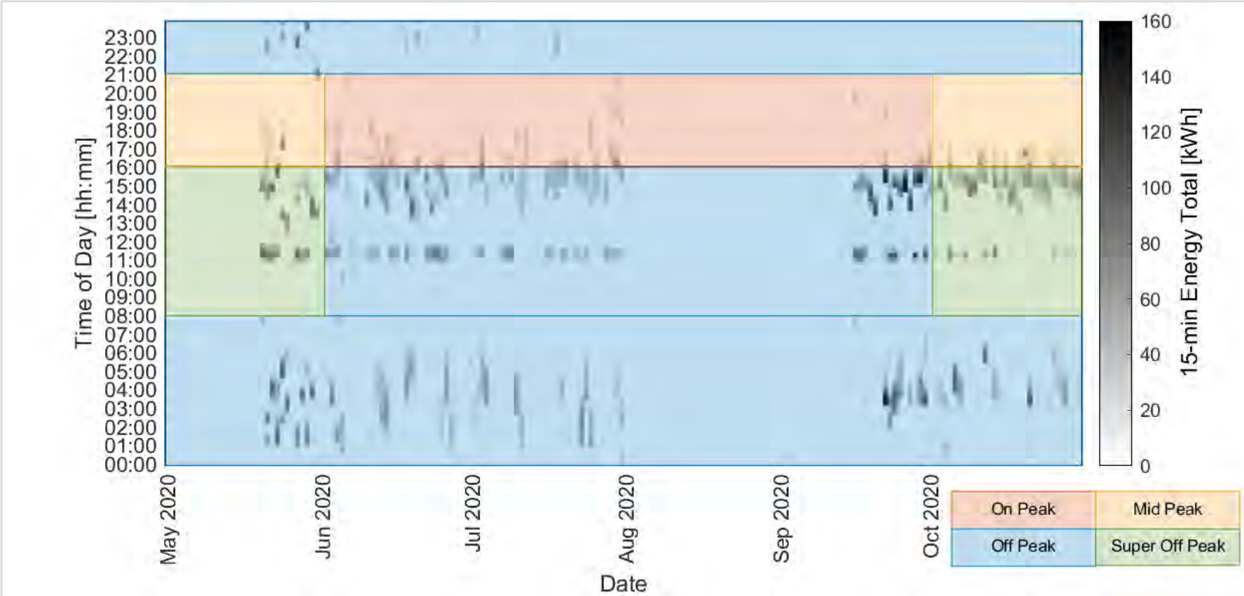
Figure 141. Electric utility billing components



Source: SCE Billing Data

Figure 142 shows the EV fleet charging behavior during rail operation as recorded by the utility meter. There is consistent charging during the midday break and after completion of the first shift. There appears to be flexibility in the schedule to end charging at 4:00 PM, avoiding expensive on-peak charging while still completing a second shift, given effective opportunity charging during breaks. However, majority of operations end at 5:00 PM requiring on-peak charging with higher costs. Figure 142 excludes utility meter data during August and the beginning of September, as there were irregularities in the data during these months. Vehicle telematics data from this time period were valid and are used elsewhere in the analysis.

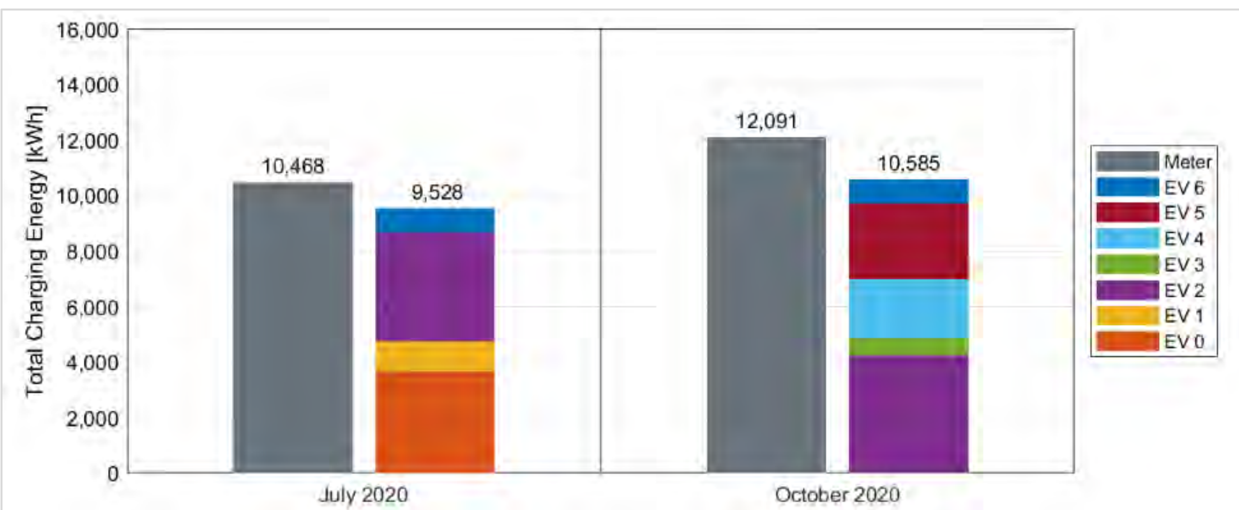
Figure 142. Charging trends for rail operation



Source: SCE Meter Data

July and October were the two months with the most complete data sets from the utility meter and the electric yard tractor telematics. The telematics system captured close to 90% of the energy recorded by the utility meter, which is expected due to efficiency losses of the chargers. July and October data show that four or five of the seven vehicles had variable operation.

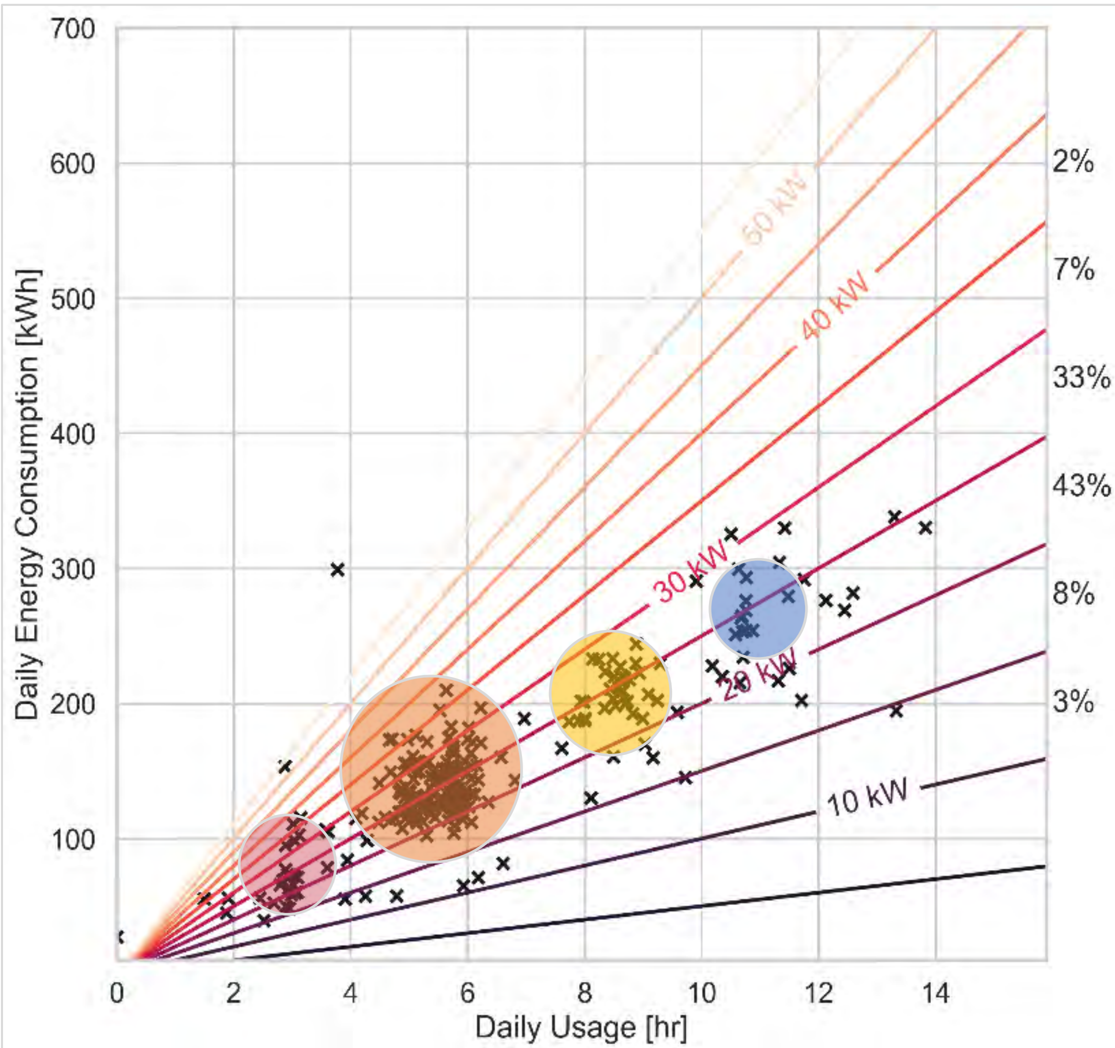
Figure 143. Energy consumption: utility meter vs. vehicle telematics



Source: SCE Meter and BYD Vehicle Telematics Data

The electric yard trucks typically consumed 20–30 kW during operation, as shown in Figure 144. Based on the battery capacity of the electric yard trucks, this consumption aligns with 7–10 hours of run time. Relatively fast charging (one to two hours) can typically maintain battery state-of-charge over 33%, as shown in Figure 146. The COVID-19 pandemic necessitated additional time for cleaning between shifts (extended from 1 hour to 2), which resulted in longer charging durations. A post-pandemic environment may result in deeper battery discharge if this break gets shortened. Figure 144 also suggests that while phasing in the yard trucks, most days saw six hours of operation, while a number of days experienced around eight and eleven hours. Though this type of operation is focused on operational hours, typical daily driving for rail operations was 40–60 miles, with more recent usage reaching close to 100 miles per day.

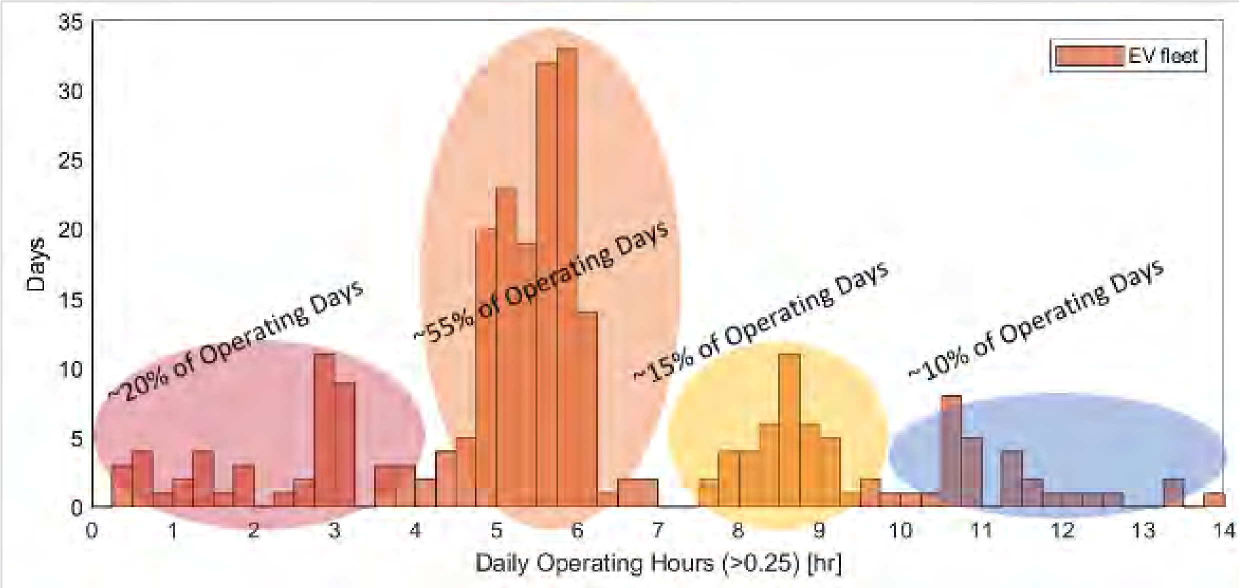
Figure 144. Daily operational time and consumption rate for rail operation



Source: BYD Vehicle Telematics

Figure 145 focuses more closely on the distribution of daily hours of the rail operation. On nearly half of the days, vehicles operate for less than seven hours, which is small enough that their charging could fully take place during the cheapest time periods without compromising vehicle readiness.

Figure 145. Frequency of daily rail operations

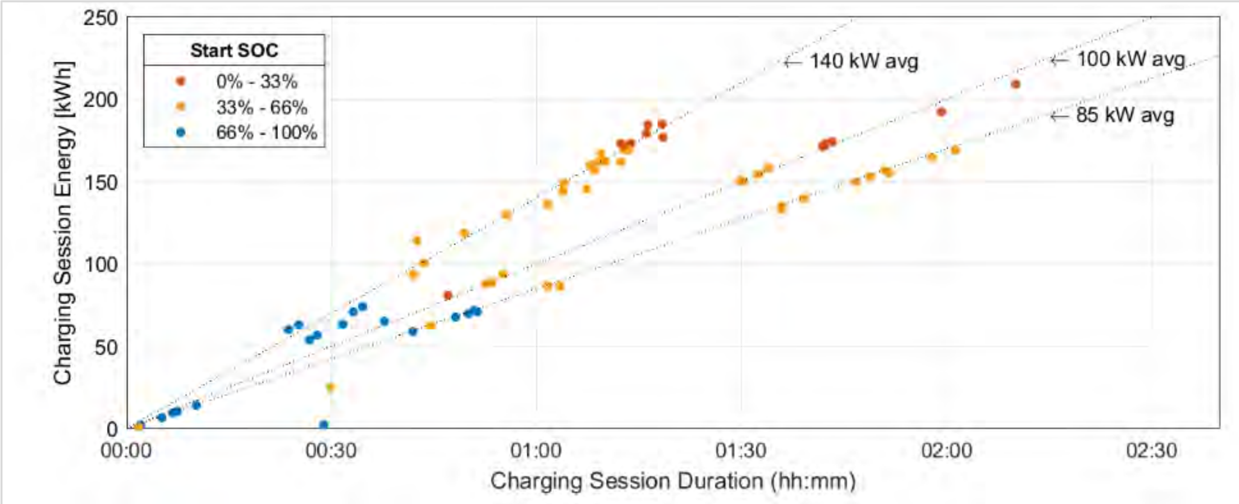


Source: BYD Vehicle Telematics

Figure 146 displays the charging sessions for the month of October 2020; charging session state-of-charge data from GeoTab vehicle dataloggers provided by BYD became available this month. The data shows that most of the time, vehicles maintain at least one-third of their charge while operating. Such evidence suggests that the vehicles have under-utilized operating range and that current charging during the highest-cost time period may be avoidable. Once demand charges are phased back in, avoiding this time period will likely be more important.

Charging sessions shown below reflect average charging power of 80–100 kW using single charging ports on the vehicle and, with two ports, average approximately 140 kW and peak at 175 kW, as recorded by telematics. During the first two months of deployment, charging sessions were ending prematurely. To troubleshoot, the terminal operator began using only a single charging port to charge the trucks. Subsequent software updates corrected the issues and allowed for dual-port charging. Three average power charging trends appear in Figure 146 based on a charging session data.

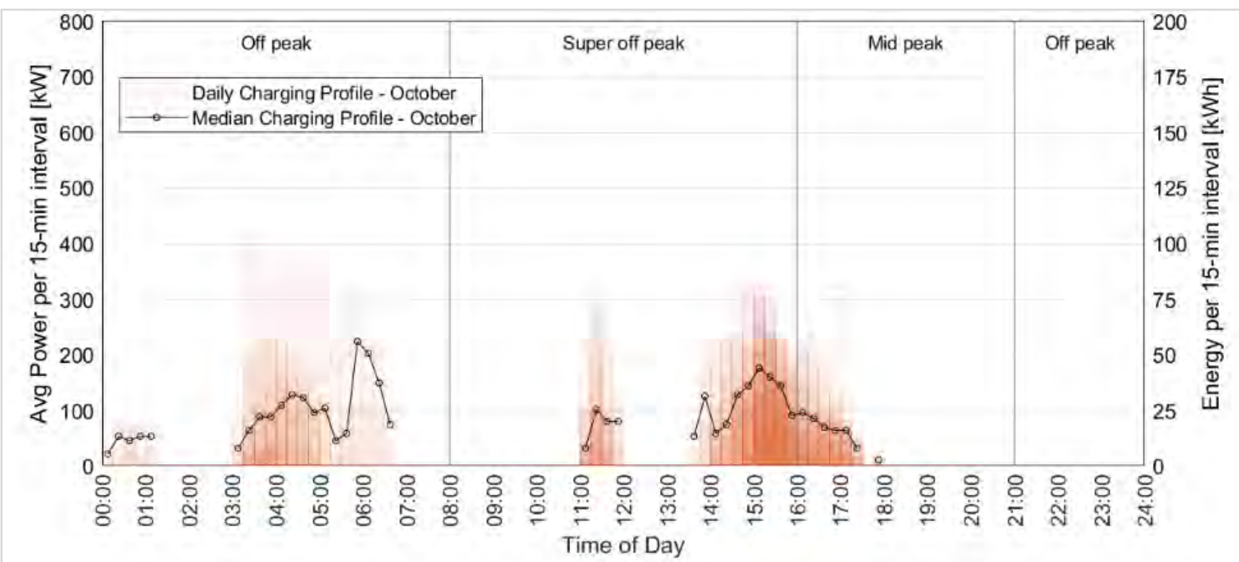
Figure 146. Charging trends (October 2020)



Source: BYD Vehicle Telematics

Up to four trucks were operating on any given day in October. On-peak charging reached 400 kW with charging levels commonly around 200 kW during the afternoon between shifts. Trucks appear to use nearly a full charge, representing around 200 kWh, each full shift, with the busiest days consuming over one MWh. Using an average of 235 kWh daily per truck, the EV fleet would use close to 30 MWh per month.

Figure 147. October 2020 frequency of charging power for the rail operation



Source: SCE Meter Data

Detailed interval data from the utility meter help show the regularity of terminal operations for the entire EV fleet. The typical schedule of charging and driving time can be summarized as follows:

- Trucks begin operating by 8:00 AM.
- A one-hour break occurs around noon.
- Charging takes place between the end of the first shift and the start of the second shift at 6:00 or 7:00 PM.
- A one-hour break occurs before midnight.
- Trucks return to chargers at 3:00 AM.

Stakeholder and Customer Feedback

ITS started deploying electric yard tractors in their marine terminal operation in May 2020, and through November, they averaged approximately 11,400 kWh monthly while still ramping up vehicle utilization. Feedback pertaining to the initial implementation of this PRP is captured in the Implementation Process section of the Evaluation Methodology.

The operator experienced a smooth construction experience with the utility. Installation and powering charging equipment had challenges. Challenges with NRTL field certification and initial vehicle charging caused significant delays of full deployment. The operator is very interested in monitoring energy consumption and tracking operational costs compared to baseline to assess the business case. The operator experienced challenges accessing the utility account for meter data and was billed on a different rate than expected for the first few months (SCE rebilled them on TOU-EV-8 rate). The operator expressed satisfaction in general with ability of electric yard tractors and installed charging infrastructure to meet their most demanding use case (rail application). Several equipment challenges were experienced as mentioned in the findings section below. As of the writing of this report, it appears that no review has been conducted that would facilitate using least-cost energy.

4.2.4 Conclusions and Recommendations

Findings

SCE spent $1,627,550, of the approved $450,000 to install make-ready charging infrastructure for 7 POLB installed chargers (six 200 kW BYD and one 100 kW Cavotec) that are supporting 7 ITS owned and operated BYD electric yard tractors. The installed utility make-ready charging capacity is sufficient to power 13 additional EVSE. Nearly 5 months of limited use data was collected from the operation of 7 yard tractors in ITS service. Over 10 MWh of electricity was consumed most months. SCE's construction of the electrical infrastructure to charge the yard tractors was straightforward and completed in a timely manner, once the design was approved and permits were secured. Technical issues with the chargers and tractors caused project complications and delays; such issues are beyond the project scope. Other findings from the project include the following:

- The project costs exceeded the approved budget by nearly $1.2M. The original project was estimated at $450,000 without considering the customer-side construction costs. Once the project planning commenced, a $1.1M estimate for the customer make-ready infrastructure was developed for a $1.55M total utility investment. The utility-side improvements exceeded the original estimate, but SCE was able to value engineer the customer-side to keep the overall project scope at $1.63M, exceeding the updated estimate by only 5%. The approximate overage of $1.2M was recorded to the Shareholder O&M account and not billed under the PRP. The assumptions used for the original $450,000 forecast for the utility-side construction costs were based on single-meter switchgear and standard installation conditions using PVC conduit between all SCE structures. Cost overruns of $300,000 on the utility-side make-ready were primarily due to space constraints resulting in more expensive concrete cable trenches that had to be custom-built at the site and substantially thicker concrete than expected that had to be cut through.

- It is important to determine and clearly define roles and responsibilities for each project team member early in the project to avoid potential complications. Where possible, binding agreements should be secured with all project stakeholders and equipment end users.
- Electrical infrastructure and charging equipment can require significant space and need ample protection, which can be a challenge for the site configuration layout. The layout must also consider driver behavior, such as parking orientations, to minimize disruptions to current operations.
- The combination of battery capacity, speed of charging, and ability to charge between shifts and during breaks has proven sufficient to keep trucks operating in regular service. In some instances, charging management software may reduce on-peak consumption, as well as maximum power demand.
- The automated charging was part of CEC grant technology demonstration and as such experienced commissioning and charging reliability challenges. Limited pool of trained drivers for automated charging contributed to infrequent use.
- These particular EV are still evolving to meet U.S. market needs, such as reliable ancillary items (e.g., the mechanics of doors, switches, and knobs). Trucks can still operate despite those issues, but drivers will often report the vehicles to maintenance for issues in lieu of operating them. In terms of ergonomics, some shorter drivers find the fit inconvenient due to a protective panel around the steering column, which further limits the driver pool. Another terminal reports the inability to swivel the seat severely limits the vehicle's usefulness for that terminal's particular operation.
- Policy development is important to ensuring enough longshoremen drivers are willing and able to use demonstration trucks with which they are not familiar.
- Tracking cost of operations across multiple work order systems (e.g., manufacturer and operator) can be complicated and not all of the necessary details are always included to assess maintenance costs.
- The electric yard trucks consumed 20–30 kW during operation, resulting in 7–10 hours of run time. One to two hours of charging between the shifts can typically maintain battery state-of-charge over 33%. The typical daily driving for rail operations was 40–60 miles, with a high of 100 miles per day.
- The utility bills reflect overall electricity prices of $0.18–$0.22 per kWh on a commercial EV-TOU rate. Despite a relatively low on-peak consumption, the high pricing of on-peak electricity led to on-peak usage's accounting for approximately 30% of total billing costs during summer months.

- While the fleet realized some operational energy cost savings (less than $500 per year per vehicle), they could be magnified significantly when accounting for potential LCFS credits which could eliminate electricity costs. The challenge might be that the port owns the chargers and therefore the fuel credits associated with their use.

Lessons Learned

The following lessons learned were captured during the implementation of this PRP.

- Field certification of charging equipment that is not already NRTL-listed can add significant complications to a project. The initial inspection may uncover issues that require correction, which would likely delay project completion by several months. For cutting-edge transportation electrification technology, this step is sometimes unavoidable but should be limited to projects classified as pre-commercial demonstrations (which the CEC grant supported), not commercial deployment programs.
- Utility needs to account for the customer-side infrastructure costs and include them as part of their initial estimates when supporting grant funded demonstration projects. The forecast for the customer-side construction costs was inadvertently omitted from the initial application and therefore was not included for recovery as part of this pilot. The customer-side construction costs of approximately $900,000 were recorded to Shareholder O&M account.
- Early commercial product challenges (EVs and EVSE) contributed to sporadic and low utilization rates for much of the relatively short data collection period.
- These trucks support railroad operations, which the operator considers a heavier duty cycle than supporting the cargo ships. Cargo ships represent the majority of operations, and this project suggests that at least this particular vehicle and charging combination (charging that can be completed in 1-2 hours) can have significant impacts on diesel fuel consumption at ports.
- Charging management technology would have lowered fuel costs by avoiding charging during the on-peak time period.

Scale-up Potential

In 2020, there were 2,276 diesel port yard tractors and 592 rail yard tractors across the state of California.[44] Scaling the benefits of the best observed operations of these yard tractors across the entire state fleet of 2,868 trucks would be expected to result in the emission benefits shown in Table 49, along with a 19.6 million gallon reduction in the diesel fuel use.

Table 49. Yard tractor scale-up potential annual emissions

	GHG (MT/yr)	SO_X (MT/yr)	NO_X (MT/yr)	CO (MT/yr)	PM (MT/yr)	VOC (MT/yr)
Net Reduction	204,202	25	471	178	13	59

Source: Evaluator Calculations

[44] California Air Resources Board, "EMFAC 2017 v1.0.3," accessed 2020, https://arb.ca.gov/emfac/emissions-inventory.

4.3 Electric Transit Bus Make-Ready Program

4.3.1 Project Narrative

Overview, Objectives, and Barriers Being Addressed

SCE was approved to spend up to $3,978,000 in deployment costs to serve up to 20 charge ports and customer rebates to offset the costs of qualified charging equipment and installation.

Electric bus technology is maturing, with several companies offering a range of commercially available vehicles suited to the needs of transit agencies, with Society of Automotive Engineers standard-based charging systems. However, there are costs and complexities associated with electric buses. From siting and deploying charging infrastructure to operational impacts (e.g., downtime for charging and training maintenance technicians), transit agencies must overcome new challenges when they convert to operating electric buses.

The Electric Bus Make-Ready Program, also known as the Charge Ready Transit Bus Program, will deploy make-ready infrastructure to serve charging equipment for electric transit buses operating in SCE's service territory. SCE will also provide a rebate to participating customers to help offset the cost of the charging equipment and its installation. The program will encourage system safety and reliability, as SCE will work closely with participating customers to site, size, and deploy electric infrastructure in accordance with SCE's transmission and distribution standards and applicable building and electrical codes, using licensed contractors. The objective is to help transit agencies expand the number of electric buses in operation in SCE's service territory.

SCE will target transit agencies operating in its service territory and solicit them for participation in the program through SCE's business customer division. The program was open on a first-come, first-served basis to non-residential customers that meet the following requirements:

- Qualify as a government transit agency,
- Own or lease the participating site, or be the customer of record associated with the premises meter (likely the property management company or the building owner or tenant), where the charging equipment for the buses would be deployed,
- Provide agreement by the participating site's owner to grant SCE appropriate real property rights and continuous access to the customer participant site infrastructure,
- Acquire at least one new electric or plug-in hybrid bus used to provide transit service to the public,
- Commit to and provide acceptable proof of qualified charging equipment and vehicle purchase (together with actual pricing information) prior to deployment by SCE,
- Agree to take service on an eligible time-of-use (TOU) rate, and
- Agree to participate in the pilot for its entire duration, including maintaining the charging equipment in working order and participating in surveys and data collection.

Sites and Participants

Recruitment Process

An informational session was conducted on May 21, 2018, to solicit feedback from transit agencies and equipment providers on the program. The Electric Bus Make-Ready Priority Review Project (PRP) pilot was then launched on June 4, 2018. The Pilot fact sheet, participation informational package, and program application were made available online for viewing and download. Applicants were instructed to fill out the application and submit via email. The SCE business customer division's account managers were also available to guide the applicants through the submission process.

Figure 148. SCE factsheet pages for the Electric Transit Bus PRP

Source: SCE Charge Ready Website

The Electric Bus Make-Ready Pilot received six applications. All program applicants submitted proposals for in-depot charging stations. The number of ports per site in applications ranged from 3 to 14. SCE reviewed the applicants' proposed site, number of charging ports requested, proposed charging equipment, and presence of disadvantaged community (DAC) routes. Site visits were performed to obtain cost estimates for installing infrastructure at the site. The customers were also required to submit information about its EVSE network and equipment providers to ensure that they meet the program's technical requirements.

Three Pilot applications did not advance; one was withdrawn by the customer citing procurement timing and two were rejected due to charging equipment not meeting the SB350 safety requirements. In one of the rejected applications because the applicants' charging equipment for Complete Coachworks buses did not meet technical requirements and could not be changed. The other rejected applicant planned to acquire 14 electric BYD buses but would have to make bus modifications to enable use of ChargePoint stations as originally proposed BYD chargers are not NRTL-listed. This applicant as well as the one that withdrew their application may apply to Charge Ready Transport, SCE's standard review program.

Participants

The Electric Bus Make-Ready Program resulted in agreements with three transit agency customers with a collective total of 30 ports supporting 31 electric buses.

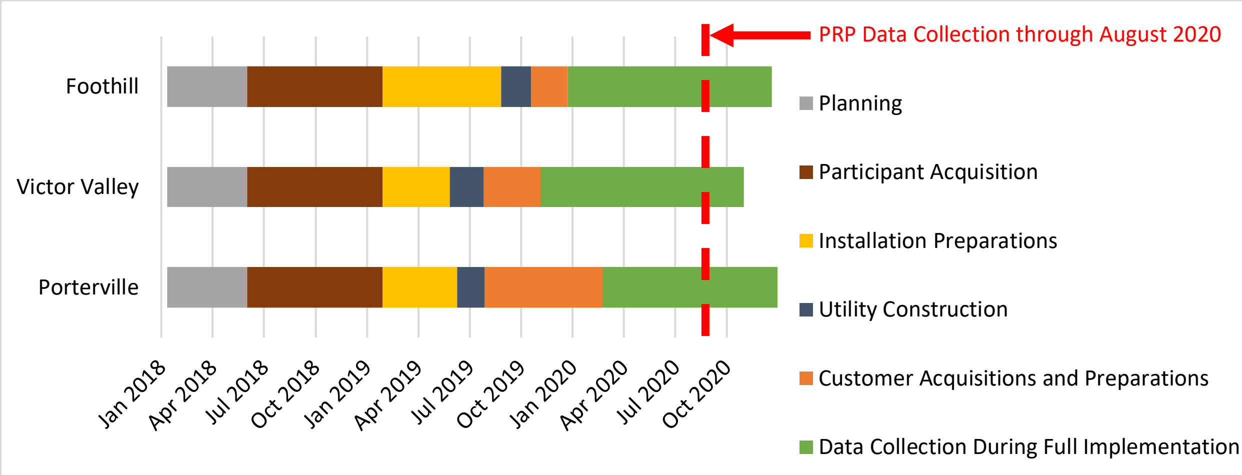
- **Fleet 1 – Victor Valley Transit Authority** acquired its first battery electric buses to move forward on the agency's commitment to operate an all-electric fleet by 2040. Victor Valley deployed seven 40-foot **New Flyer** Xcelsior XE model buses that are charged by seven 62.5 kW **ChargePoint** DC chargers.
- **Fleet 2 – Porterville Transit** has a fleet of 20 buses. **GreenPower Motor Company** delivered 10 **GreenPower** EV350 40-foot zero-emission all-electric transit buses in 2019 for deployment on all nine Porterville Transit routes. Ten 200 kW **BTCPower** DC chargers were installed at the main depot.
- **Fleet 3 – Foothill Transit** has a fleet of 373 buses (33 battery electric, 340 compressed natural gas [CNG]); the fleet has plans to convert to zero emission buses in order to meet California Air Resources Board (CARB) Innovative Clean Transit (ICT) regulation. The first deployment of electric buses was in 2010 (first fast-charge electric bus line in the United States), with a fleet of extended-range electric buses added in 2017 and two all-electric double-decker buses in 2021. Infrastructure installed to support 14 new **Proterra** electric buses consists of twelve 60 kW Proterra DC chargers and one 125 kW Proterra DC charger.

Timeline and Status

SCE estimated that the Pilot would take approximately 12 months from launch to completion. Following the CPUC decision in January 2018, SCE launched the program on June 4, 2018, and executed agreements with the three eligible transit agencies in the fourth quarter of 2018. Electrical infrastructure designs were completed in the first quarter of 2019, with design approvals by the participants and local permits obtained in the second quarter of 2019. SCE completed the make-ready at Porterville and Victorville in the third quarter of 2019 and completed the make-ready at Foothill in early fourth quarter of 2019. In addition to acquiring the electric buses, individual participants were also responsible for completing the installation of the charging stations (part of the customer scope):

- Victor Valley's charging infrastructure was installed and operational by the end of September 2019. Two New Flyer electric buses had been delivered by then and the remaining five were placed into service by November 2019.
- Porterville received all ten GreenPower electric buses by October 2019, but the completed installation of the charging stations did not occur until February 2020 in conjunction with the parking lot re-pavement.
- Foothill commissioned their depot charging station installation in December 2019. Their long-range Proterra electric buses were received earlier and utilized the existing overhead and maintenance facility chargers.

Figure 149. SCE Electric Transit Bus Make-Ready PRP timeline



Source: SCE

4.3.2 Evaluation Methodology

Selected Methods and Rationale

In addition to the evaluation questions that apply to all PRPs and those specific to the Fleet Electrification PRPs, the evaluation questions listed below will be examined for this PRP:

- Did some electric buses or charging equipment perform better (e.g., fewer issues, easier to use, more useful features) than others?
- Could operations have benefited from on-route charging or faster charging?

The data collection tasks utilized to evaluate this PRP include 1) PRP information from the approved decision, project updates, and other available documentation, 2) market research on transit buses and early deployment efforts from other similar electrification projects across the country, 3) PRP data from vehicle and charger operations, and 4) in-depth interviews (IDIs) with project partners.

Data Sources

The evaluator collected PRP information through numerous PRP participant interactions: PRP kick-off meeting (SCE and 3rd party evaluator), quarterly PAC update meetings, periodic PRP updates (SCE and 3rd party evaluator), site visits, and other periodic calls or emails. Through these, the evaluation team collected electric bus characteristics and hardware specifications, project costs, station characteristics, site layout, construction updates, and electricity tariff details.

PRP operational data sources for this project include utility service meter 15-minute interval data, charging station session data, monthly facility electricity bills, bus telematics, operational summaries, and maintenance records. The evaluator also facilitated IDIs with the SCE construction team, SCE project manager, participating transit agencies, and vendors after construction was completed and the electric buses were placed into revenue service. Close out IDIs were conducted with SCE project manager and participating transit agencies at the end of the data collection period.

4.3.3 Evaluation Findings

Project Baseline

As of December 2018, approximately 12,000 transit buses were in operation throughout California, an inventory that has remained relatively constant over the past decade. Public and contract bus service employment has decreased over the same period, down to about 22,100 in 2016 compared to 26,200 in 2006. Ridership over the period from 2007 to 2017 decreased from 1,000,300,000 to 802,900,000.[45]

Effective October 1, 2019, the Innovative Clean Transit regulation is part of a statewide effort to reduce emissions from the transportation sector. The regulation, a replacement of the Fleet Rule for Transit Agencies (S.2023), mandates that each of the state's public transit agencies submit a rollout plan to CARB to transition to an all-ZEB fleet by 2040. Starting in 2029, all transit agencies will be able to purchase only zero-emission buses. Rollout plans are due July 2020 for large transit agencies and July 2023 for small agencies; each of which is to have 25% ZEB three years later. As of December 2018, eight of the ten largest transit agencies in the state were operating ZEBs.[46] The regulation's mandate to transition to an all-zero-emission transit system is projected to dramatically increase the inventory of ZEBs from an estimated 153 at the time of passage to 1,000 buses in 2020.[47]

Several bus manufacturers are offering electric models, with some recent companies being formed to serve this market exclusively. New Flyer offers CNG, hydrogen fuel cell, and battery electric buses in its Xcelsior line, introduced in 2010, with the battery electric model introduced in 2012 and commercially available in 2014. New Flyer has provided buses to transit fleets across North America, with 1,600 ZEBs in service as of December 2019.[48] Proterra, originally headquartered in Colorado, moved to South Carolina in 2010 and then expanded to the City of Burlingame, California, in 2015 when the CEC awarded the company a $3 million grant to fund the design, development, and construction of the company's battery electric transit bus manufacturing line. Proterra reports sales of more than 800 ZEBs to 100 communities across 43 U.S. states and Canadian provinces.[49] Chinese electric bus manufacturer BYD has a U.S. manufacturing facility in Lancaster, California. BYD reports having nearly 40,000 ZEBs in service around the world, with the vast majority of those sales in China.[50] The company reported sales of about 722 ZEBs in the United States as of May 2018, with anticipated growth to 1,500 annually in subsequent years.[51] GreenPower Motor Company is a Canadian ZEB manufacturer with manufacturing

[45] California Transit Association, *Interactive Repository of Facts and Figures on California Public Transit*, 2019, https://caltransit.org/about/transit-data/.

[46] CARB, *Innovative Clean Transit*, accessed 2019, https://ww2.arb.ca.gov/our-work/programs/innovative-clean-transit/about.

[47] CARB, *California Transitioning to All-electric Public Bus Fleet by 2040*, 2019, https://ww2.arb.ca.gov/news/california-transitioning-all-electric-public-bus-fleet-2040.

[48] New Flyer Industries Canada ULC, "About Us," accessed 2019, https://www.newflyer.com/company/about/.

[49] Proterra, "Our Story," 2019, https://www.proterra.com/company/.

[50] BYD North America, "About BYD," 2019, https://en.byd.com/about/.

[51] Green Biz, *The World's Biggest Electric Vehicle Company You've Never Heard Of*, 2018, https://www.greenbiz.com/article/worlds-biggest-electric-vehicle-company-youve-never-heard.

facility in Porterville, California. GreenPower offers five models of battery electric transit buses, along with electric school buses and shuttle vehicles.[52] GreenPower is a relatively small manufacturer compared to New Flyer, Proterra, and BYD, but the company increases the electrified options in an industry segment that is projected to grow significantly over the next decade.

Implementation Process

The Electric Bus Make-Ready Program had a short timeline between the decision approving the program, program launch, and the need to enroll customers and complete construction before program closure. Electric transit buses have a long procurement timeline, often 12–18 months from when a new electric transit bus is first ordered to its delivery. While many of SCE's transit agency customers were interested in participating in the program, their procurement schedules did not all align with the PRP's aggressive timeline. In addition, some potential transit agency customers have electrification goals that exceed the budget of the Electric Bus Make-Ready Pilot and were aware of the upcoming SCE larger scale MDHD program that was pending CPUC approval at the time (Charge Ready Transport).

Because of nascent and rapidly changing nature of the transit bus EVSE market, some EVSE providers could not meet the Pilot technical requirements mandated by SB350, such as the requirement that the equipment be recognized by a NRTL. This resulted in delays to qualify the applicant, as SCE needed to work with the applicant's EVSE provider to explain the purpose behind the requirements listed in the Pilot's technical requirements document.

Figure 150. Victor Valley Transit Authority charging station installation

Source: SCE

SCE developed an EVSE Technical Requirements Document instead of an approved product list as there were not many commercially available charging stations dedicated for bus charging at the time of PRP development and launch. This document was available as part of the original customer collateral online and through SCE account managers. SCE staff met with applicants and their EVSE providers to discuss products and review the PRP EVSE technical requirements. SCE was open to customers and vendors submitting new products for approval under their qualified product list process. One transit agency selected an EVSE and signed the contract with SCE, but it was discovered that the EVSE was not NRTL-

[52] Greenpower, Inc. (2019) LINK: https://www.greenpowerbus.com/news/

listed as required by the SB350 Safety Checklist, and the application was withdrawn. Field certification was permitted by SCE, but this can be costly and time consuming.

No significant issues arose during the design and construction process that would require scope-of-work changes. A minor field change occurred when Foothill requested one higher-power charger (125 kW) to replace two lower power units (62.5 kW) to charge two double-decker electric buses from Alexander Dennis with Proterra electric drive and battery. The change request was made late in the construction process, but SCE managed to accommodate it without any significant delays. SCE construction costs came in as expected within the original estimates. Due to the need for field certification of the higher-powered charger because it was not NRTL certified, the SCE charger rebate was not processed until 9 months after the chargers were commissioned and NRTL field certification was obtained.

Victor Valley installed a self-contained EVSE unit with DC power and dispenser combined. Porterville and Foothill installed power control cabinets with remote dispensers. Foothill already had an on route high-power overhead charger on transit Route 291, and the customer installed an overhead gantry charging system at the bus depot based on the make-ready provided by SCE. The overhead gantry charging system has control cabinets on the ground on one side with chargers suspended above the buses and potential for addition of solar panels. The Foothill installation includes a distribution line extension that will allow for future growth. The Porterville installation includes a distribution line extension with additional capacity to accommodate a subsequent deployment.

Costs

The approved PRP had an anticipated total cost of $3,978,000, consisting of $2,731,000 in capital and $1,247,000 in expense. The PRP costs as of November 2020 totaled $2,087,396 (which may not include all participant costs), as shown in Table 50, based on data available to SCE.

Table 50. SCE Electric Transit Bus Make-Ready PRP nominal costs as of November 2020

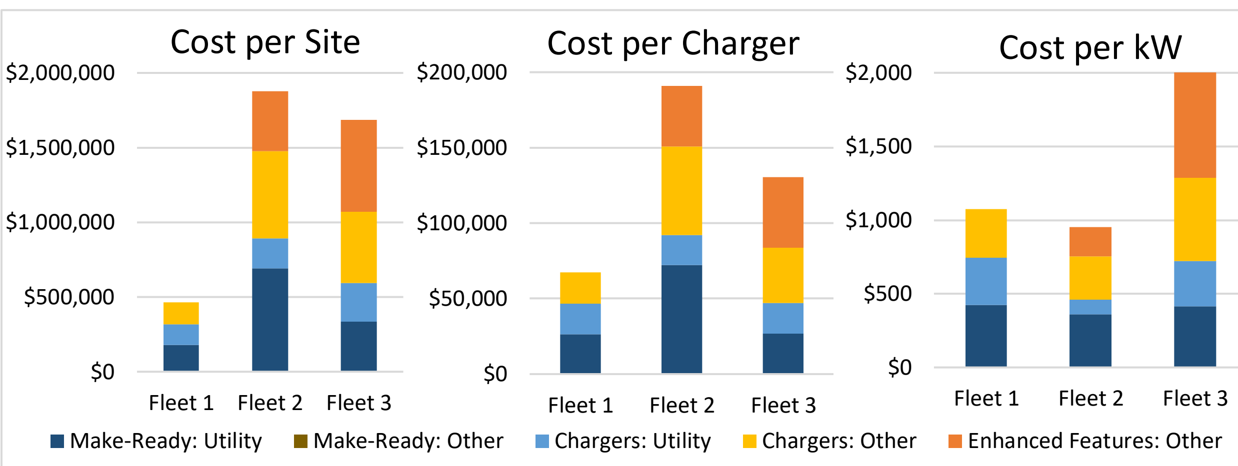
Cost Category	Actual SCE Costs	Budgeted SCE Costs
Site assessment, design, and permitting	$ 120,992	N/A
Rebate amount paid	$ 600,000	$ 900,000
EVSE procurement	N/A	N/A
EVSE installation	N/A	N/A
Make-ready infrastructure (utility side)	$ 740,312	$ 939,575
Make-ready infrastructure (customer side)	$ 463,967	$ 1,647,425
Other construction costs	N/A	N/A
Project management	$ 103,875	$ 406,991
Customer outreach (labor)	N/A	N/A
Outreach and education materials	$ 58,268	N/A
Other program costs	N/A	$ 84,009
Total Costs	$ 2,087,396	$ 3,978,000

Source: SCE

Site assessment, design, and permitting was budgeted under the customer-side capital expense for make-ready infrastructure. The O&M non-labor and contract costs were budgeted under other program costs. SCE provided a rebate for the chargers and installation ($20,000 per charger) which required justifications of costs equal to that of the rebate amount paid. Most sites submitted costs in excess of the rebate amount for additional work associated with this project, but in some cases these costs may not be comprehensive and in other cases include site enhancements that may not be required for other installations (but chosen by these sites to support the electrification of their buses). Fleet 2 redeveloped their parking lot for ease of access to the chargers and upgraded their electrical system to integrate solar generation (the structure, photovoltaics, and their installation were not included in these costs). Fleet 2 also has higher power chargers which cannot be fully utilized by the current electric buses but might be by future ones. Fleet 3 installed an overhead structure to integrate their charging for ease of access.

Table 53 presents EV charging infrastructure costs for the three sites. Only make ready charging infrastructure and charger rebates are included from the utility budget along with the balance of charger costs and appropriate portion of the enhanced features that were part of the charger installation. Costs were either paid for by the utility through this PRP or a source of funding "other" than the utility which may be the host site, grants, etc. The costs were the highest for Fleet 2 site as it has the largest power capacity. The same site also had the highest cost per charger as their chargers were three times as powerful as at the other two sites. On a per kW basis, Fleet 3 site had the highest costs as their overall power capacity was relatively high while their charger power level was lower than Fleet 2 and very close to that of Fleet 1.

Figure 151. SCE Electric Transit Bus Make-Ready PRP infrastructure costs



Source: SCE

Benefits

The Electric Transit Bus Make-Ready PRP contains three distinct pilots. Foothill Transit received charging infrastructure make-ready and station rebates for 13 chargers (twelve 62.5 kW and one 125 kW) to support 14 new electric buses, along with a few older electric buses previously acquired. Victor Valley Transit received charging infrastructure make-ready and station rebates for seven chargers (all 62.5 kW) to support seven new electric buses. Porterville Transit received charging infrastructure make-ready and station rebates for ten chargers (all 200 kW) to support ten new electric buses. The key benefits and some contributing factors are outlined below, with a more detailed description of this benefit analysis in the Appendix.

All three fleets replaced CNG baseline buses with an average efficiency of 3.88 miles per diesel gallon equivalent (DGE) of CNG for Foothill, 3.71 miles per DGE for Victor Valley, and 4.17 miles per DGE of CNG for Porterville. Electric bus efficiency for these fleets was 1.85 kWh per mile (Foothill), 1.99 kWh per mile (Victor Valley), and 2.11 kWh per mile (Porterville). The fleets operate on fixed routes that are partially within a DAC. Based on route analysis, the electric buses supported by the PRP charging infrastructure operate 43% of the time in a DAC for Foothill, 22% of the time in a DAC for Victor Valley, and 57% of the time in a DAC for Porterville for an overall PRP average of 40%. The selected evaluation period for each fleet excludes some initial months of much lower use during start-up operations for these electric buses. Extrapolating the electric bus performance during this period to an annual scale, results in the values in Table 51 for each fleet.

Table 51. Transit fleet demonstration period results

Fleet	Evaluation Period	Annual Electricity Consumed	Percentage of Peak Electricity Use	Annual Mileage	DGE of CNG Saved
Foothill	Jan-Aug 2020	860,256 kWh	5%	464,789	119,668
Victor Valley	Jan-Aug 2020	521,169 kWh	1%	261,369	70,450
Porterville	Mar-Aug 2020	378,984 kWh	3%	179,613	43,073

Source: SCE Meter Data and Transit Fleet Telematics

The best observed month of performance for each fleet with the highest monthly mileage was also extrapolated to an annual scale, resulting in the factors presented for each fleet in Table 52.

Table 52. Transit fleet best observed period results

Fleet	Highest Mileage Month	Annual Electricity Consumed	Percentage of Peak Electricity Use	Annual Mileage	DGE of CNG Saved
Foothill	June 2020	1,138,774 kWh	5%	615,270	158,412
Victor Valley	February 2020	634,811 kWh	0%	318,360	85,811
Porterville	March 2020	568,776 kWh	1%	269,562	64,643

Source: SCE Meter Data and Transit Fleet Telematics

The anticipated benefits from the Testimony in Table 53 were calculated based on new charging infrastructure supporting 20 electric buses that replaced diesel vehicles. As planned, 31 electric buses were supported by this PRP's charging, so the anticipated benefits were scaled up. All 31 electric bus deployments occurred in this PRP, but they replaced baseline CNG vehicles which had lower emissions than the anticipated diesel baseline buses.

Table 53. SCE Electric Transit Bus Make-Ready PRP annualized benefits

	Testimony (20 ports/buses)	Planned (30 ports & 31 buses)	Implemented (31 buses)	Best Observed (31 buses)
Petroleum Reduction	150,000 diesel gallons[a]	232,500 diesel gallons	233,191 DGE of CNG	336,143 DGE of CNG
GHG Emissions Reduction	1,600 MT of CO_{2e}[b]	2,480 MT of CO_{2e}	916 MT of CO_{2e}	2,535 MT of CO_{2e}
Criteria Pollutant Emissions Reduction	8,000 kg of NO_X 130 kg of PM[c]	12,400 kg of NO_X 202 kg of PM	3,136 kg of NO_X 101 kg of PM 34,766 kg of CO 1,292 kg of VOC 388 kg of SO_X	4,149 kg of NO_X 132 kg of PM 46,031 kg of CO 1,711 kg of VOC 511 kg of SO_X
DAC Impact	Designed to maximize electric transit bus routes in a DAC	Fleet locations in a DAC for all three transit partners	40% in a DAC, remainder adjacent to a DAC	40% in a DAC, remainder adjacent to a DAC
Grid Impacts / Electricity Consumption	N/A	N/A	2,660 MWh (97% off-peak)	2,342 MWh (97% off-peak)
Operational Energy Cost Savings	N/A	N/A	-$21,359 (-$689 per bus)	$196,624 ($6,343 per bus)

Source: Evaluator Calculations

[a, b, c] Evaluator calculations based on data included in SCE's testimony

The best observed GHG emission reduction results from these electric bus pilots can be projected for other potential electric transit applications that may replace baseline vehicles of varying fuel types and have slightly different baseline vehicle fuel efficiency (shown in Figure 152) or annual use (Figure 153).

Figure 152. Transit bus GHG reductions for various baseline fuels by fuel economy

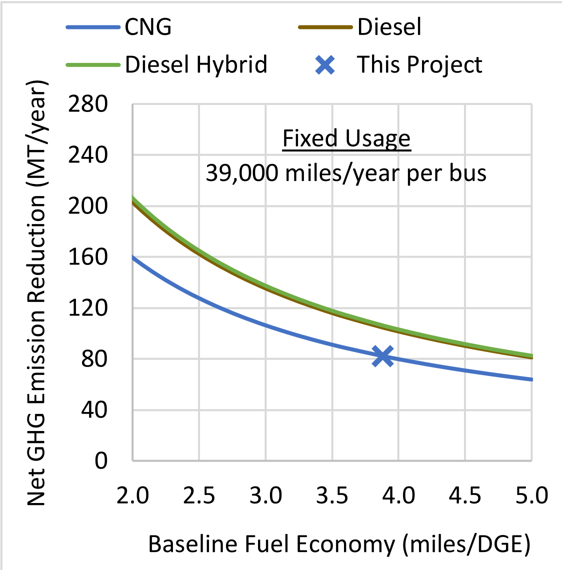
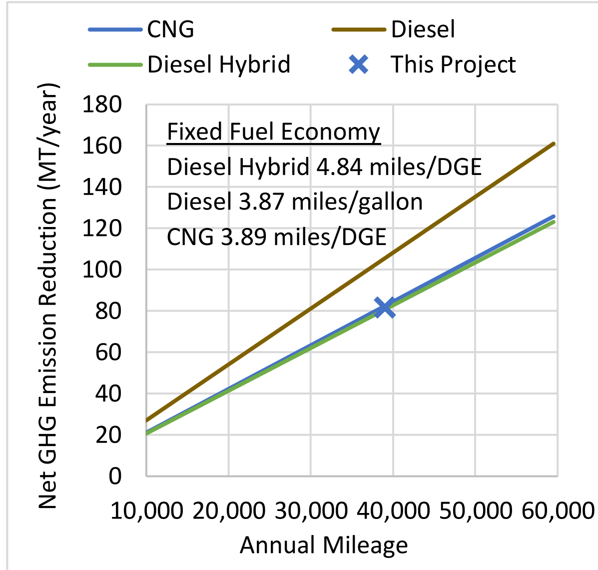


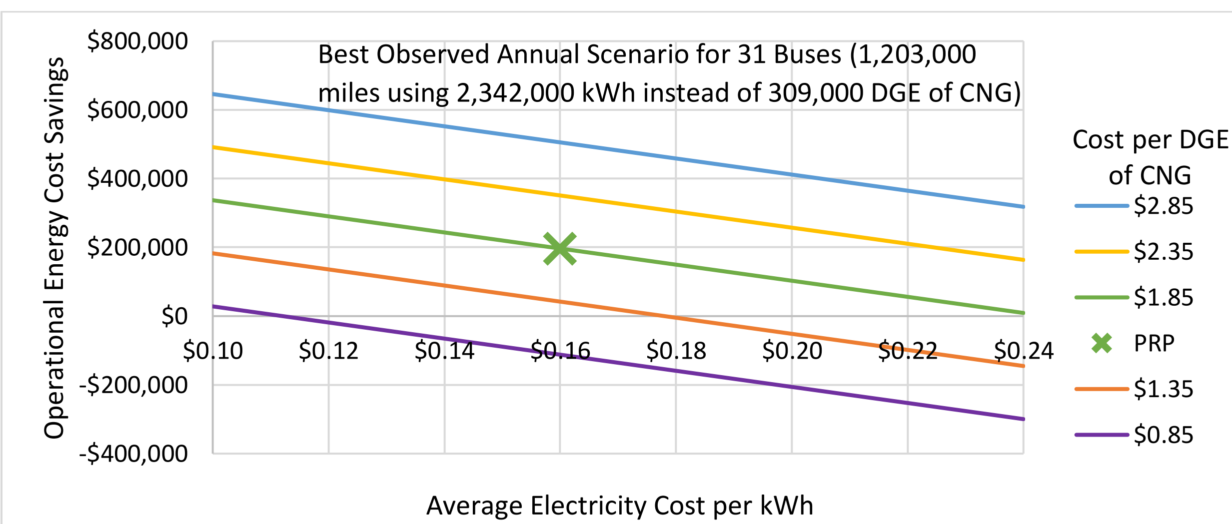
Figure 153. Transit bus GHG reductions for various baseline fuels by annual use per bus



Source: Evaluator Calculations

The fuel cost savings sensitivity analysis to the CNG fuel price and electricity price is shown in Figure 154. It shows that electric buses at current average electricity rate would realize fuel cost savings even at lower CNG fuel prices. While the annual savings per bus of just over $6,000 does not seem very significant, acounting for CARB LCFS credits could result in significantly larger savings. At 26 cents per kWh LCFS credit for heavy-duty EVs, the savings would increase by more than three times to approximately $26,000 per year for each bus. This figure does not include any maintenance savings which would also be expected but could not be quantified due insufficient maintenance records available during the less than 12-month operational data collection period.

Figure 154. Annual transit bus operational energy cost savings at various fuel costs



Source: Evaluator Calculations

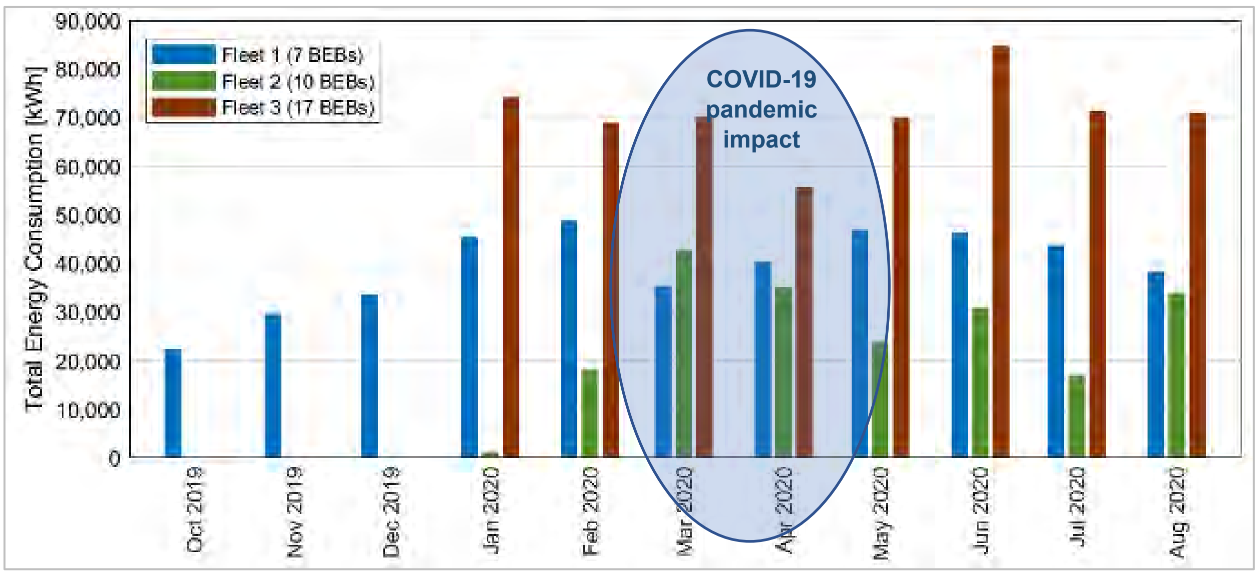
Operational Impacts of Project Equipment

This section presents overall PRP data summary and provides a breakdown for each fleet. Specifically, monthly energy use, miles driven, electricity costs, charging demand, vehicle and charger efficiency, and operational costs per mile are presented.

General State of the Fleets

All three fleets used electric buses consistently from the start based on charging energy consumed after the chargers were commissioned. Two fleets experienced significant reductions in service due to the COVID-19 pandemic as they shifted service to weekend schedules throughout March and April, as evident by lower energy use in Figure 155.

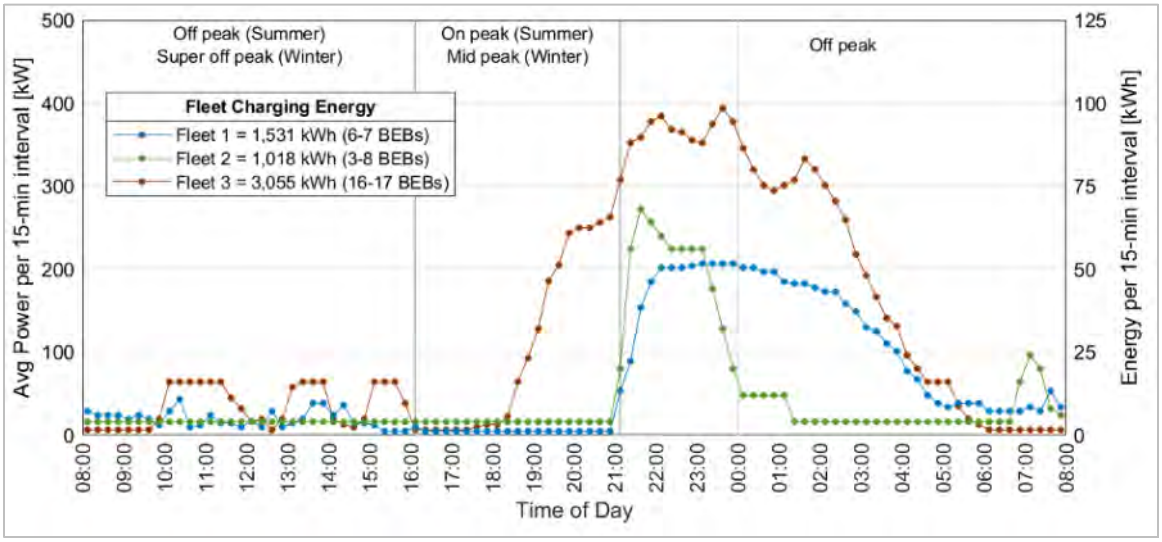
Figure 155. Transit fleet electricity use (charger commissioning to end of data collection)



Source: SCE Meter Data

Figure 156 portrays the charging load profiles for the three fleets during the last 4 months of data collection to capture the mature or steady-state operation. The weekday median curves indicate charger utilization of 13, 5 and 15 hours per day for fleets 1, 2 and 3 respectively. Two of the fleets routinely operated all their electric buses, while one fleet had a significant portion of their buses out of service due to repairs for nearly the entire data collection period. The median curves reach peak power of 50, 28 and 46 percent of the total capacity for fleets 1, 2 and 3 respectively. For Fleet 2, the power capacity is based on the maximum available charging power of the vehicle, while for the other two fleets it is based on the charger power level.

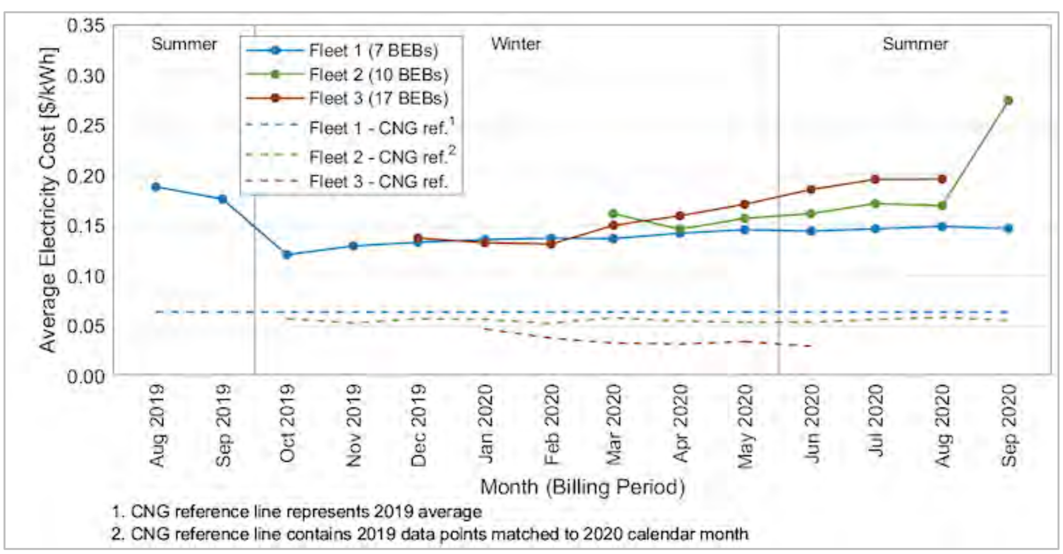
Figure 156. Weekday median charging load profiles (May through August 2020)



Source: SCE Meter Data

All three fleets experienced similar electricity costs per kWh, around 16 cents or about $6 per DGE, as shown in Figure 157. Fleet 1 implemented a managed charging strategy through the EVSP software to avoid charging during on-peak time (between 4 and 9 PM). The result was lower cost per kWh compared to those experienced by the other two fleets, especially during the summer season where on-peak pricing was significantly higher. Fleet 2 managed to avoid charging during the on-peak period for the first 3 months of the summer, but their manual approach was not effective in September due to staffing constraints, resulting in significant cost increase. The baseline, CNG fuel costs are also included in Figure 157, showing relative consistency as well, just under $2 per DGE. Compared on an equivalent energy basis (per DGE), the electricity cost is about 3 times the cost of the CNG.

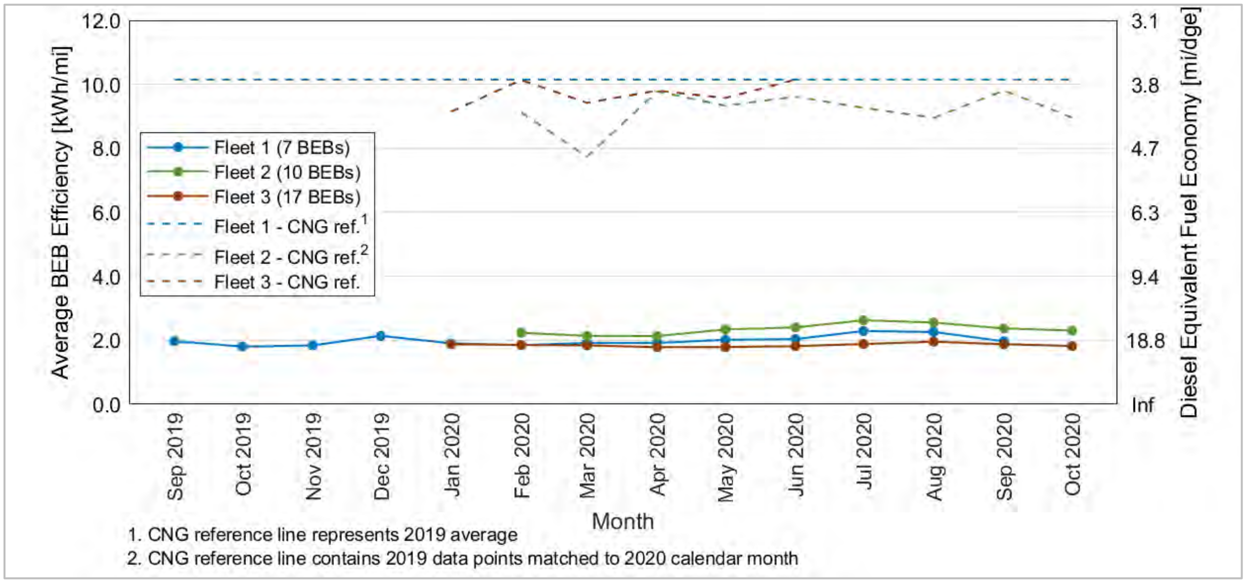
Figure 157. Monthly electricity and CNG fuel cost comparison



Source: SCE Billing Data and Transit Fleets

Despite low resolution of the vertical axis in Figure 158, it is evident that all three fleets experienced an increased electricity consumption per mile and respective energy cost during the summer. The former is attributed to air-conditioning load needed to keep the bus passengers comfortable, while the latter is also impacted by the higher summer energy rates. Comparing fuel economy on an energy equivalent basis (in terms of DGE), electric buses are nearly five times as efficient as CNG buses.

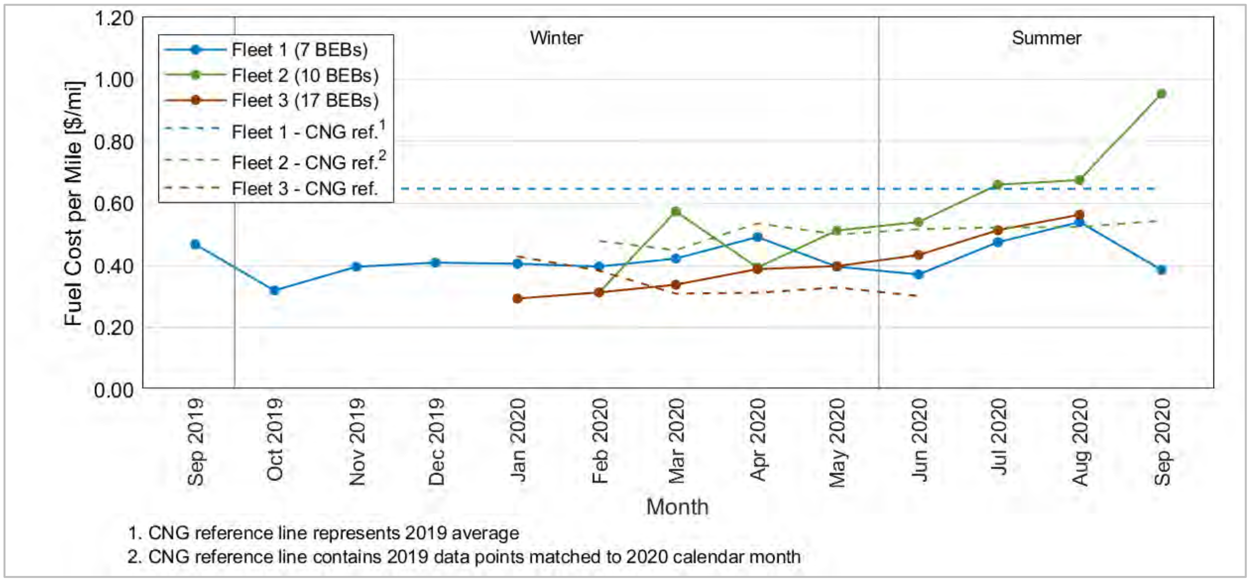
Figure 158. Electric and baseline bus efficiency trends and comparison



Source: Transit Fleets Telematics

Combining electricity costs with bus energy efficiency or fuel economy, the fuel cost per mile is presented for electric and CNG baseline buses in Figure 159. Two of the fleets show increasing costs of electricity per kWh during the summer and each used a significant amount of on-peak energy. One of the fleets charges overnight at a depot in addition to fast charging on-route which includes demand charges (from another utility). Throughout the data collection period, the fleets' energy efficiency ranged from 1.8 to 2.5 kWh per mile. Higher fuel consumption is due to heating loads in the winter and cooling in the summer. Fleet 1 has the most effective bus charging management approach and highest CNG fuel cost per mile, resulting in operational fuel savings of nearly 30 percent. Fleet 3 has the lowest electricity cost per mile but also the lowest CNG cost per mile, negating any operational fuel savings. Fleet 2 experienced operational fuel savings during a couple of winter months, but higher energy use and electricity rates during the summer resulted in negative savings.

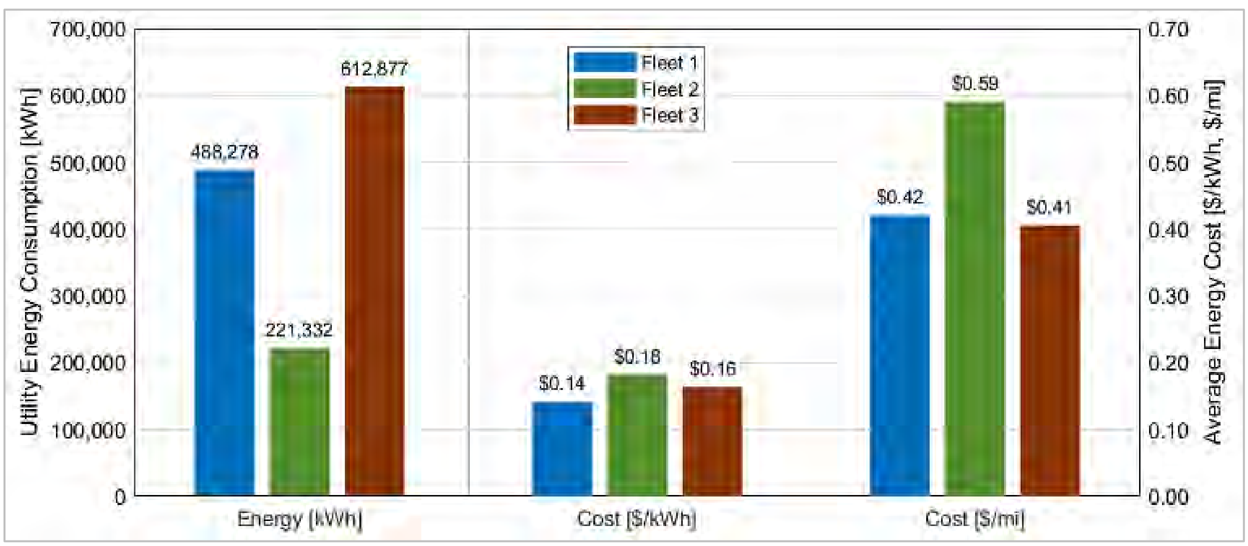
Figure 159. Cost per mile trends for electric and baseline buses



Source: SCE Billing Data and Transit Fleets Telematics

Figure 160 summarizes and compares the total energy use, costs per kWh and per mile for all three participating fleets. More than 1.3 GWh of electricity were consumed during the data collection period for this PRP. The participating fleets have experienced the lowest cost per kWh of any of the PRP participants. The two larger fleets (1 and 3) achieved remarkably similar costs per mile while the smaller fleet costs were almost 50% higher.

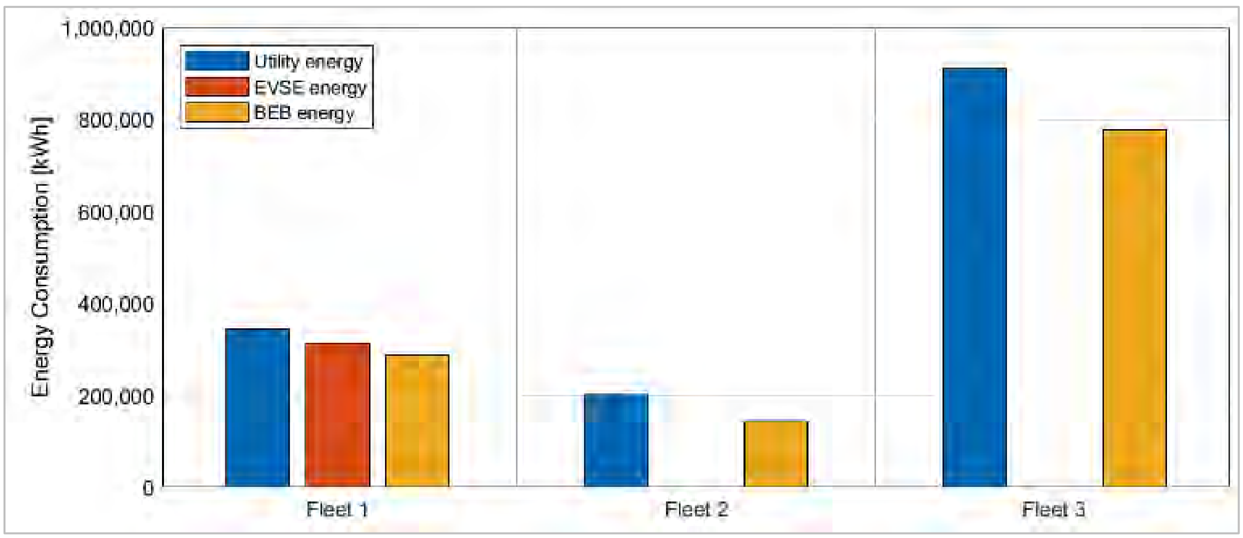
Figure 160. Project energy use and cost comparison summary



Source: SCE Meter and Billing Data and Transit Fleets Telematics

Electrical energy use was tracked via several different means, including utility meter, charger, and on-board vehicle dataloggers. Vehicle manufacturers advertise vehicle energy efficiency in terms of electricity consumed by the vehicle to travel a certain distance. While that metric can be helpful to fleets, their true costs are based on the electricity measured by the utility meter. Since these two electricity use numbers can be significantly different depending on the energy losses of the charger, Figure 161 compares the electricity consumption measured by the utility meter, EVSE and the vehicle datalogger. As expected, the utility meter for each fleet provides the highest number which according to utility metering standards is accurate to a half of a percent. The EVSE number does not account for any energy used by the charger and on-board datalogger number does not accounts for any charging efficiency loses. EVSE number was only readily available for one fleet that was using networked chargers. A second fleet attempted to capture EVSE charging session data; however, they used different charger hardware and back office software vendors and experienced challenges in extracting charging session data. The difference between the utility meter and on-board datalogger energy consumption is between 15 and 20 percent. This means that up to 20% of the energy that the fleet is paying for does not make it into the vehicle battery and therefore cannot be used to operate the bus.

Figure 161. Energy consumption (January–August 2020) comparison as measured by different sources



Source: SCE Meter, EVSP Charging Sessions and Fleet Telematics Data

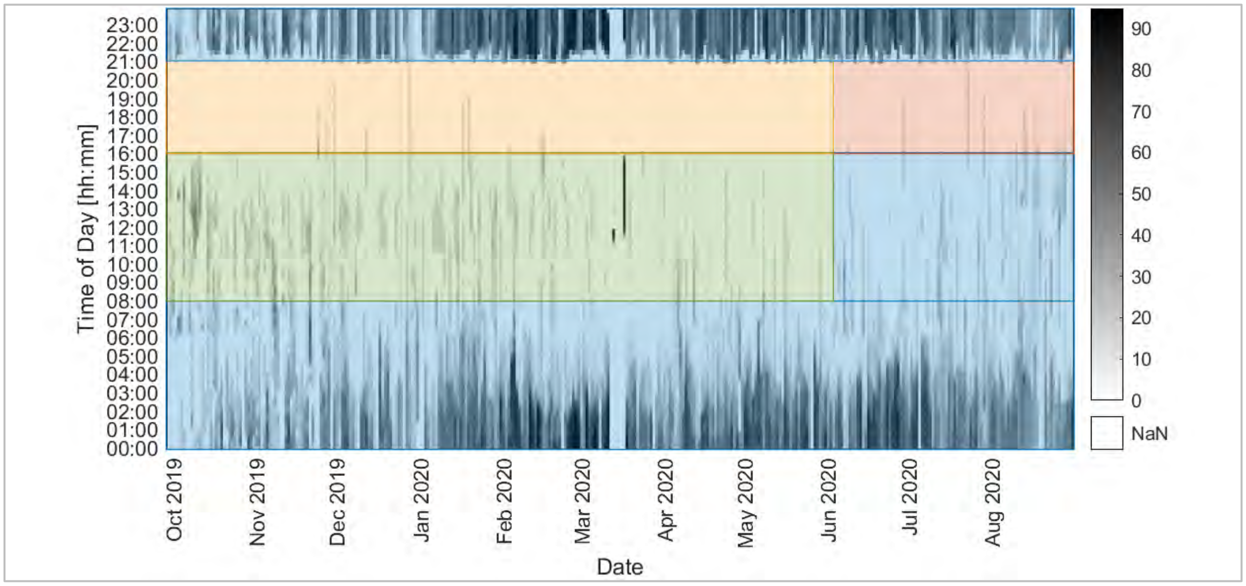
Operational Nuances

This section provides additional insights on individual fleet experiences with electric buses that help address the research questions for this PRP.

Fleet 1 (Victor Valley)

Fleet 1 is the only operator whose EVSE vendor provided charging management option. ChargePoint CPE 250 DCFC was designed primarily for public charging of light-duty vehicles. ChargePoint used it in this project as one of their first transit fleet applications. According to the fleet, they were very responsive to their needs to develop a charging management system. ChargePoint used TOU option to setup a period of no charging between 4 and 9 PM to avoid higher cost of electricity. While this was a good starting point, they needed to adapt their software to allow the buses that are connected to the charger before 4 PM to charge until that time, then stop and not charge until 9 PM, and then automatically start charging beyond that time until full charge is reached. As a result of this implementation, Figure 162 shows a very successful history of avoiding charging during on-peak time period (orange area during the winter, and red during the summer); whereas the other two fleets relied on staff management of charging operations and experienced charging during on-peak time and correspondingly higher costs per kWh. It is also noteworthy that Fleet 1 charged some during the super off-peak period between 8 AM and 4 PM during the winter early in the project.

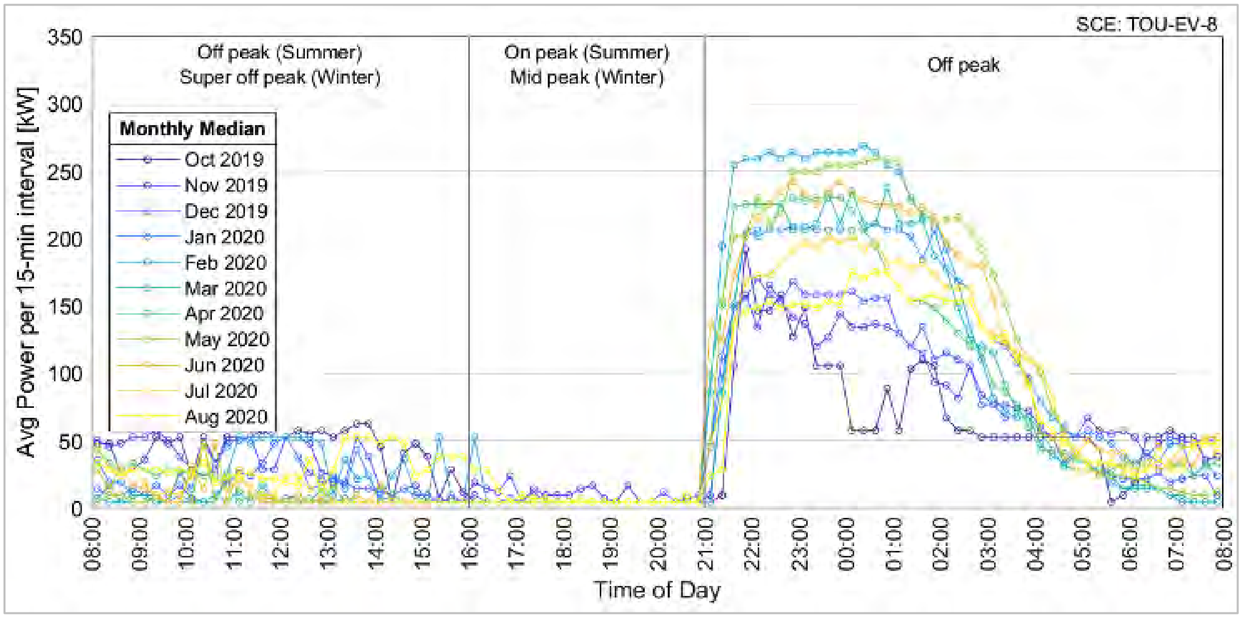
Figure 162. Transit bus Fleet 1 charging trends by time of day and date (15 minute - kWh)



Source: SCE Meter Data

Monthly site load shapes are shown in Figure 163 for the data collection period. Each month in 2020 has a similar load shape but peak demand varies. The observed peaks are between 200 and 250 kilowatts while the fleet has shifted their operations during the COVID-19 pandemic. Installed chargers have a capacity of 438 kW; however, make-ready infrastructure (not including the transformer) was reported to be designed for charging 40 buses. The chargers are rated for 62.5 kW each; however, that rating can be utilized only with vehicles that have 800 V batteries. New Flyer buses operate at 650 volts which limits their charging closer to 50 kW. The fleet is planning to install another identical charger for a total of 8 as well as charger pairing kits to combine the charging current of two chargers to increase bus charging speed (up to 125 kW).

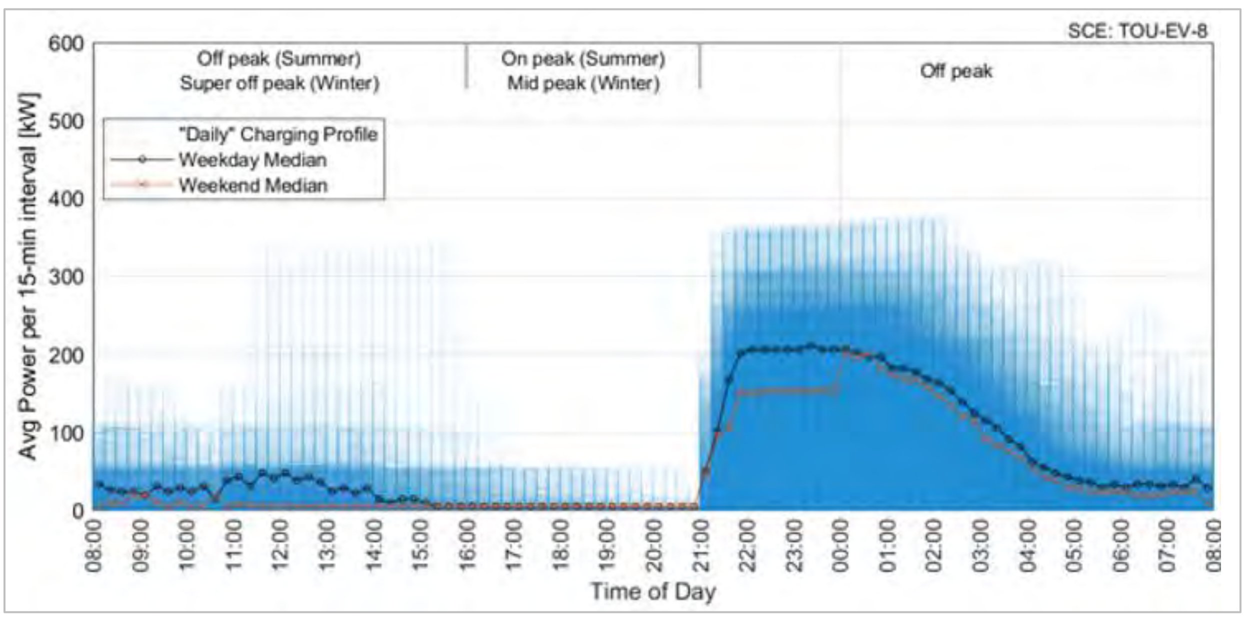
Figure 163. Transit bus Fleet 1 monthly average demand curves



Source: SCE Meter Data

The cloud chart in Figure 164 indicates that peak demand reached maximum available capacity on a regular basis during 9 PM to 3 AM (about 370 kW as it is limited by bus battery voltage).

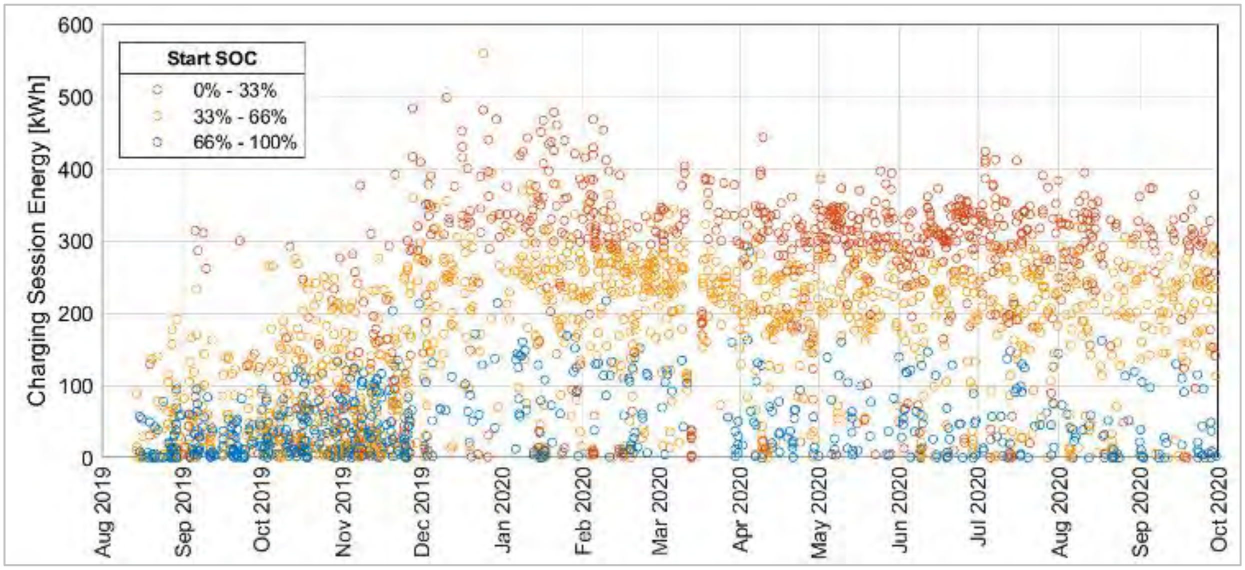
Figure 164. Transit bus Fleet 1 maximum charging power



Source: SCE Meter Data

Figure 165 presents the monthly history of the energy dispensed during each charging session. The state of charge (SOC) at the start of the charging session is also shown by the color of the symbols. After the initial few months of electric bus operation, deeper battery discharges are observed, indicating increased fleet comfort to driving more miles in a day. COVID-19 pandemic operational impacts have reduced frequency of charging sessions with more than 400 kWh and resulted in more shallow charging from March 2020 on. Most charging sessions delivered between 200 and 350 kWh resulting in 100 to 140 miles of driving daily during the pandemic (60 to 125 miles daily was frequently observed prior to the onset of the pandemic but mature operation was not yet achieved). Total daily consumption ranges between 1,500 and 2,000 kWh.

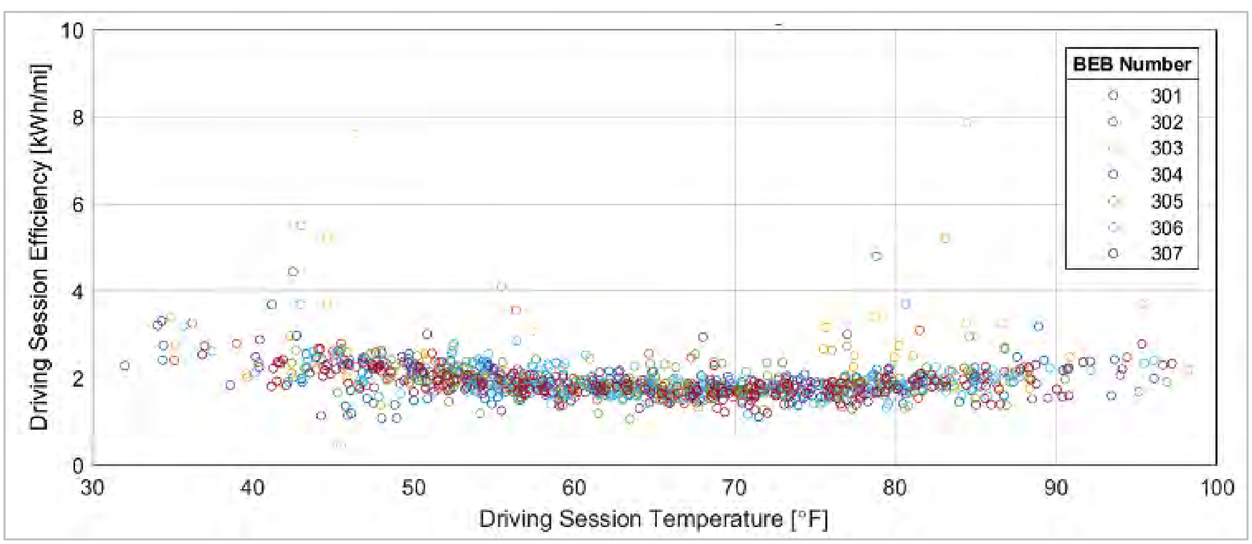
Figure 165. Transit bus Fleet 1 depth of charge



Source: Fleet Telematics Data

Figure 166 shows seasonal variation in electric bus energy efficiency. Most efficient bus operation (1.7 kWh per mile) was observed during mild temperature (60-75 degrees Fahrenheit). While average efficiency was close to 2 kWh per mile for most of the data collection period, it did increase to 3 kWh per mile on a few days with average temperatures either below 40 or above 90 degrees Fahrenheit.

Figure 166. Transit bus Fleet 1 trip ambient temperature effect on fuel economy



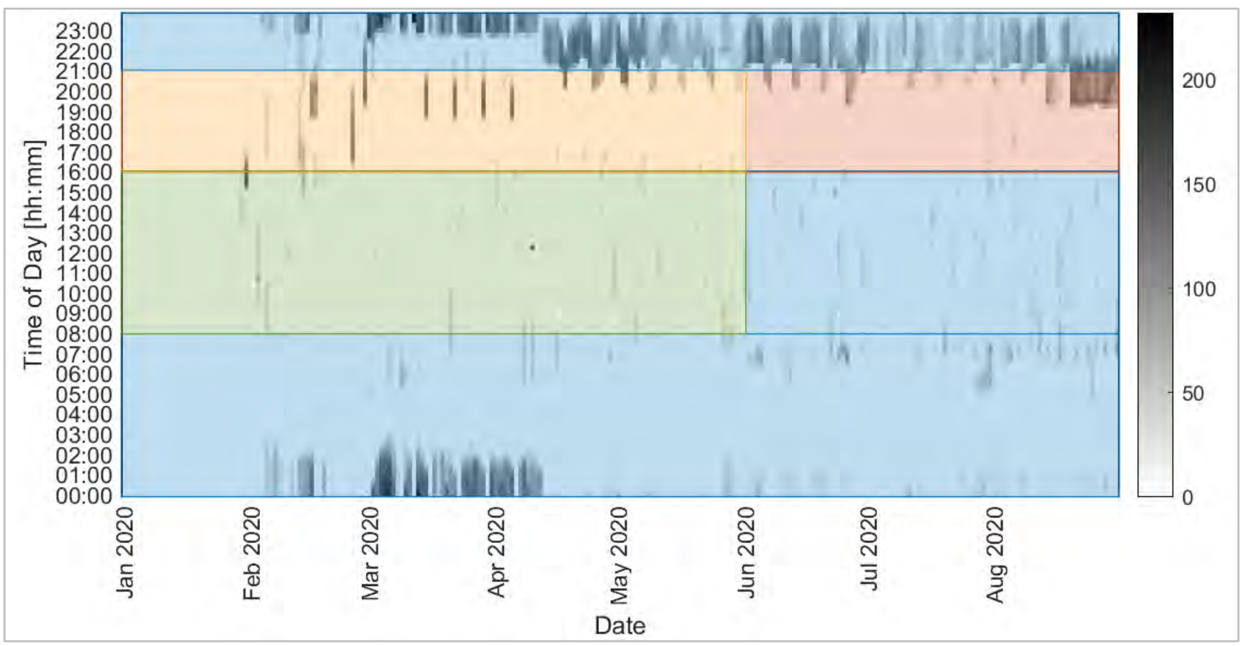
Source: Fleet Telematics Data

Fleet 2 (Porterville)

Fleet 2 did not have any charging management software available during the data collection period. From the start, the fleet made a good effort to avoid on-peak charging as evidenced by minimal black traces in yellow and red parts of the chart in Figure 167, indicating bus charging during on-peak time. Because of the manual charging approach, they did charge during mid-peak on the weekends in the spring. Staff challenges lead them to simply plug in at the end of shifts in the second half of August which significantly increased their electricity costs.

As a relatively small transit fleet, Fleet 2 is co-located with other municipal fleets. This presents a potential opportunity for electrification of other vehicles that could use the same chargers during the day (i.e., school buses). This would only be possible if the transit operator does not use the chargers during that time. This approach would increase charger utilization while taking advantage of the low-cost electricity during the supper off-peak time period (between 8 AM and 4 PM each day during the winter).

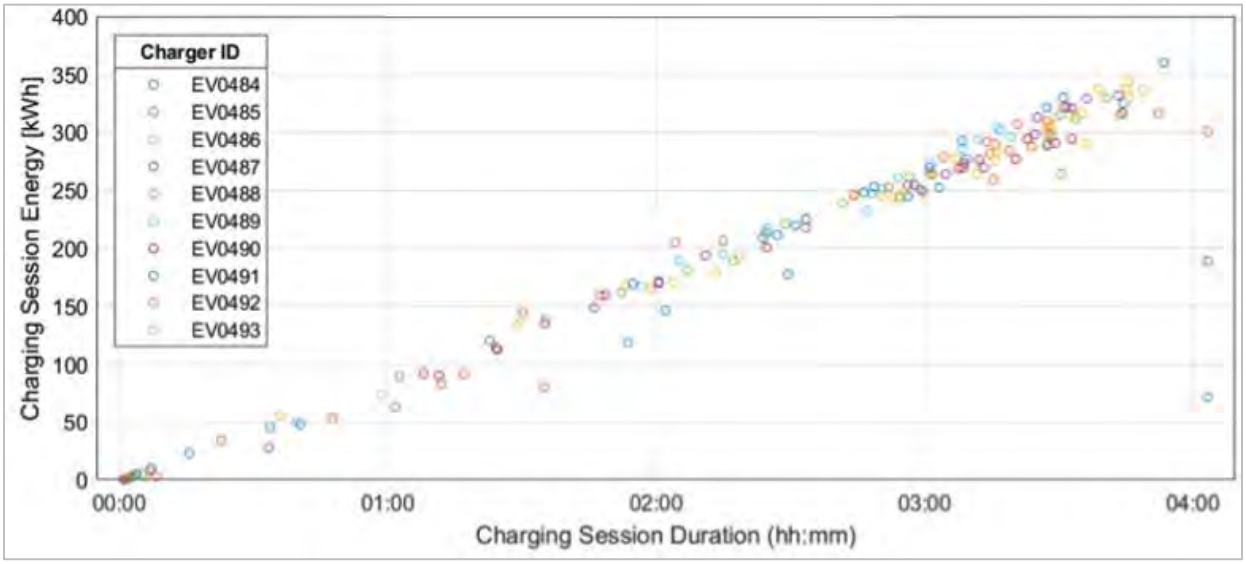
Figure 167. Transit bus Fleet 2 charging trends by time of day and date (15 minute – kWh)



Source: SCE Meter Data

As shown in Figure 168, Fleet 2 averaged 75 kW (slope of the line in the chart) over most charging sessions with the majority of charging events consuming between 250 and 350 kWh. The charging ports were able to only deliver 100 kW due to the maximum charging rate allowed by the bus despite the 200-kW nameplate rating of the chargers. Telematics data shows most daily trip distances of 80 to 90 miles with 40 to 60 percent of battery state-of-charge typically replenished each day. Energy consumption of 2.25 kWh per mile was observed on average with the highest in the summer and the lowest in the spring, reflective air-conditioning loads during hot months.

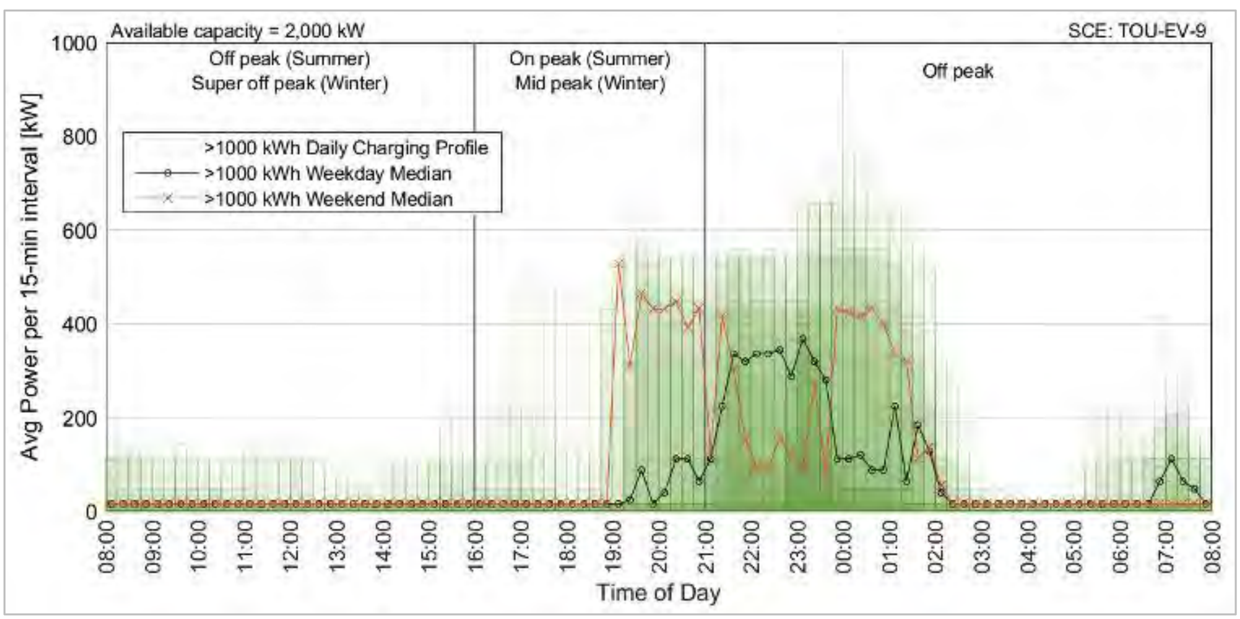
Figure 168. Transit bus Fleet 2 charging duration and energy use



Source: EVSP Charging Session Data

Their average 15-minute demand of 350 kW between 9 PM and midnight indicates four buses charging concurrently on most days. Offering fewer routes during the pandemic has likely enhanced up-time which the operator anecdotally reports to be typically six to seven buses out of the ten in the fleet for most of 2020. Varying color transparency of the cloud chart in Figure 169 indicates frequent demand near 500 kW and infrequent beyond 600 kW (peak just over 800 kW) for days with more than 1,000 kWh of energy dispensed. A peak of 850 kW at midnight indicates that all ten buses were likely plugged at least once.

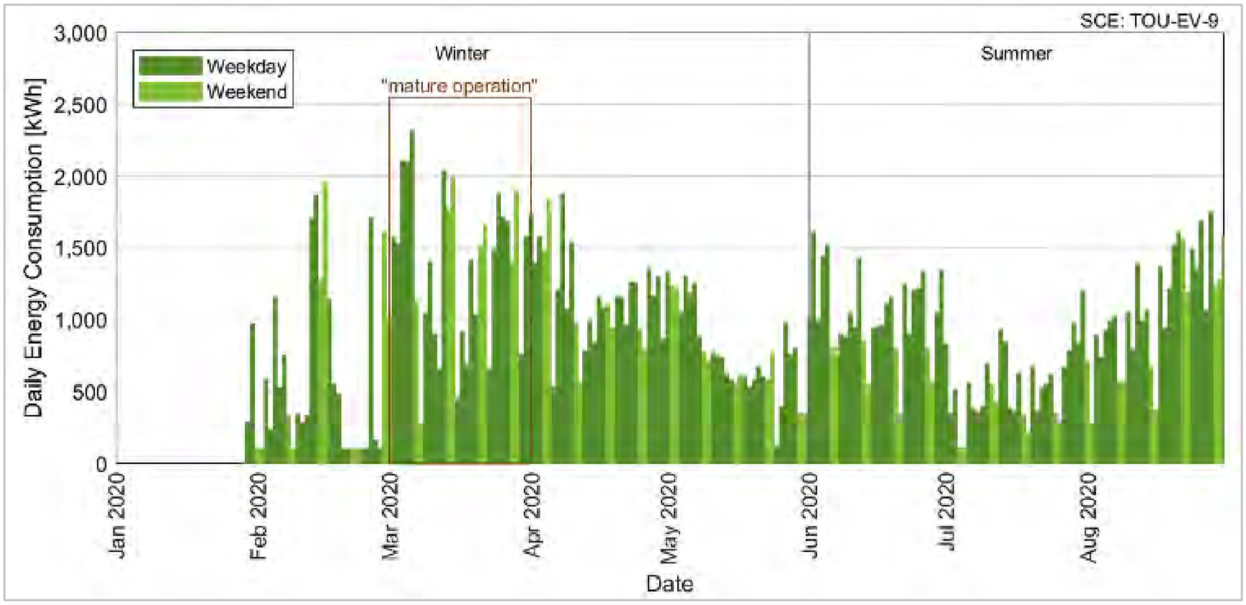
Figure 169. Transit bus Fleet 2 charging trends on high use days



Source: SCE Meter Data

The variation in the daily energy consumption shown in Figure 170 indicates varying bus availability and operation. The largest daily consumption of 2,300 kWh was observed in early March during the ramp up stage but has not exceeded 75 percent of that (1,700 kWh) since COVID-19 pandemic begun. According to the fleet, normal (pre-COVID-19 pandemic) operation should result in larger daily consumption than has been observed to date assuming all ten buses would be used.

Figure 170. Transit bus Fleet 2 daily charging energy use

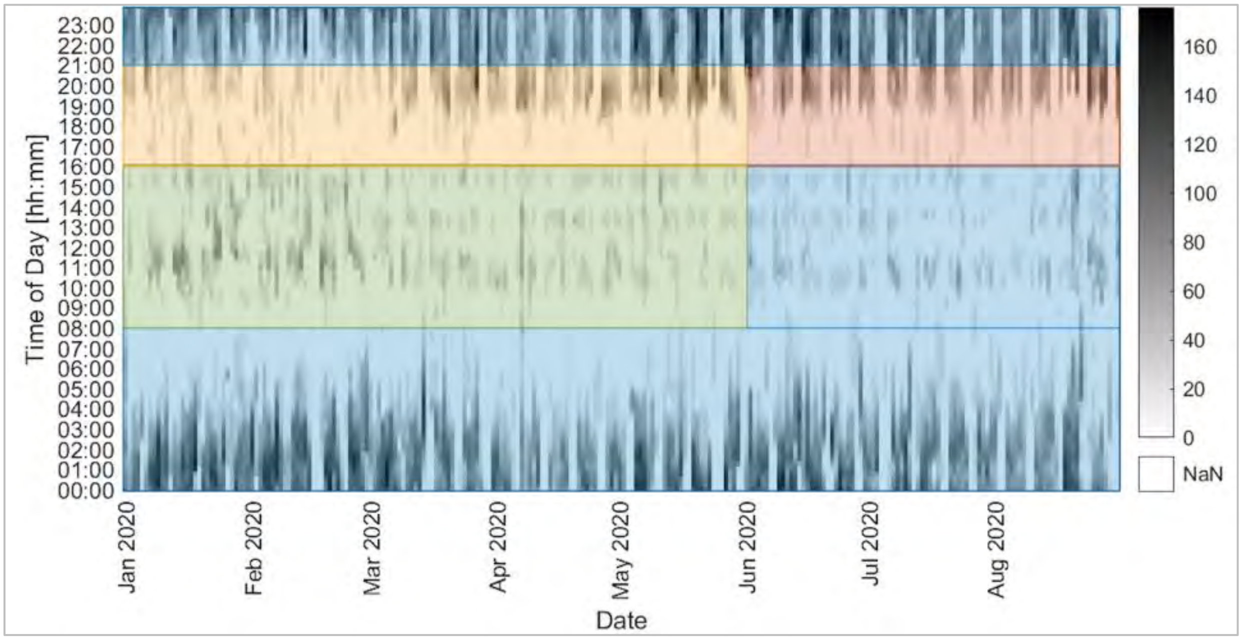


Source: SCE Meter Data

Fleet 3 (Foothill Transit)

Fleet 3 charged their buses at the depot with the chargers installed under this PRP while they also utilized on-route, high-power chargers installed previously. They have nearly a decade of experience with electric buses in contrast to the other two fleets which had none before the PRP. This fleet has the largest number of overall buses and maintained consistent electric bus operation throughout the COVID-19 pandemic.

Figure 171. Transit bus Fleet 3 charging trends by time of day and date (15 minute – kWh)



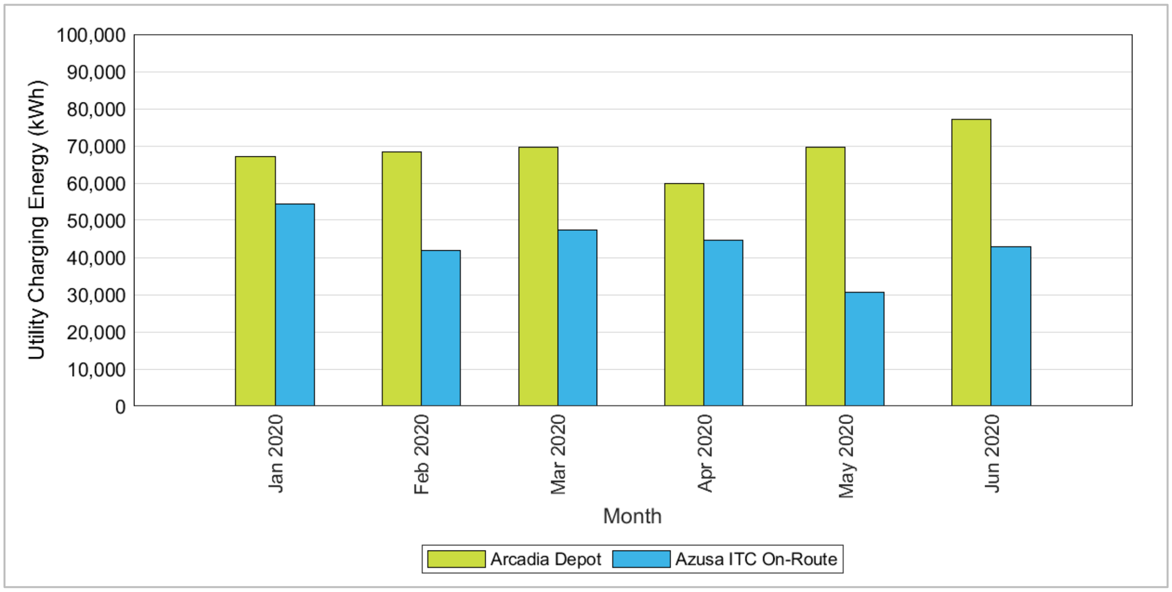
Source: SCE Meter Data

Figure 171 shows that Fleet 3 utilized depot chargers throughout the day with most of the charging occurring between 6 PM when buses return to the depot and can be connected to the charger after inspection and cleaning and 4:30-5 AM when the buses start leaving the yard. They were able to take some advantage of low-cost charging during the winter (green part of the chart) but also charged during the on-peak time consistently (yellow and red parts of the chart).

The on-route charging appeared to average up to 175 kW as compared to the 60 kW in-depot chargers. Bus telematics provided state-of-charge details for charging sessions. While in service, on-route charging maintained at least 33% of battery capacity at the end of the day; depot charging on the other hand often showed buses returning at much lower state-of-charge. This may indicate that with on route charging capability and with available software, the operator could ride through demand response events or even target low carbon intensity energy during various times of the year.

As Figure 172 indicates, about 60 percent of total charging energy was dispensed by the depot chargers with the balance provided by the on-route chargers. The on-route chargers are used to enable electric buses to complete a 220-mile or more daily route while the depot chargers typically only provide enough range to serve a 150-mile route. The powerful on-route chargers suggest that there might be a possibility to shift charging to an extent for lowering the cost of electricity or make up for offline equipment in case of failure.

Figure 172. Transit bus Fleet 3 charging at depot and in-route

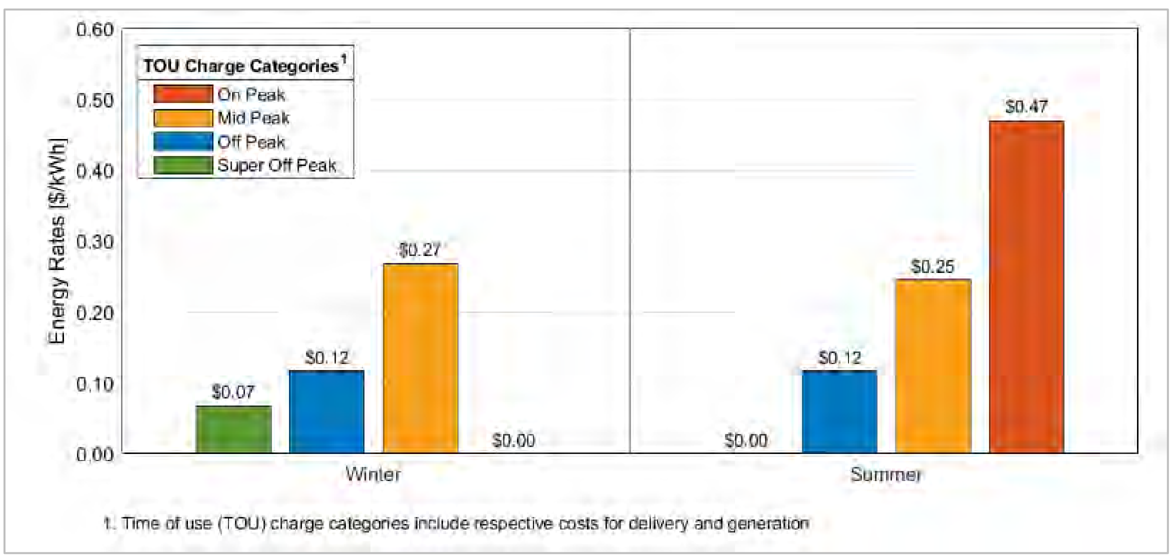


Source: SCE and Azusa Power and Light Meter Data

Utility Billing

SCE was the only utility that had available commercial EV charging rates in 2019 when most fleet PRP charging commenced. EV-TOU-7 rate is available for small sites based on charging capacity (less than 50 kW), EV-TOU-8 is for medium sites (between 51 and 500 kW), and EV-TOU-9 is for large sites (greater than 500 kW). A convenience of these commercial EV rates (shown in Figure 173) is that fleets only need to schedule charging to avoid high-cost periods. In addition to time-relevant costs per kWh, monthly service fees vary by rate and service voltage; $130 to $480 typically and for 50,000 volts or higher, $1,770.

Figure 173. Southern California Edison EV rate energy costs



Source: SCE

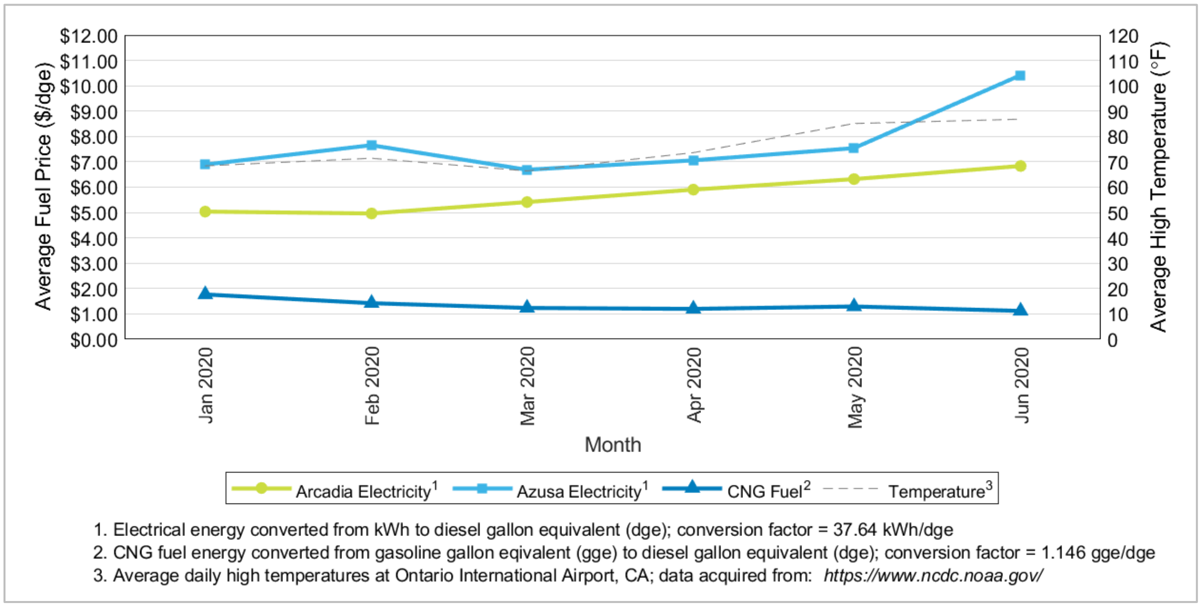
As facility demand charges will be phased back in starting in 2024, in addition to scheduling charging, fleets will also need to consider reducing charging power to minimize electricity costs. By then, charging management software will likely be more readily available from EVSPs. Only Fleet 1 had software available during the data collection period and this resulted in the lowest costs per kWh of the three fleets as well as across all the PRPs.

The lowest cost on commercial EV rate is between 8 AM and 4 PM in the winter ($0.07 per kWh); a time when buses are generally operating and not able to charge. This may provide an opportunity for transit agencies to consider use of stationary batteries. They could improve load factor by charging them during low-demand and low-carbon intensity times (per CARB LCFS smart charging electricity for transportation pathway) that can reduce peak loads and provide resiliency in case of power shut off or equipment failure. Because of this potential, transit charging locations may be an opportunity to anchor local micro-grids.

Based on the current rates, high summer on-peak rates ($0.47 per kWh) have a disproportionate impact on the total cost of utility bills. This poses a challenge to fleet electrification as potential benefits cannot be realized without charging management. Larger fleets with multi-shift staff have more flexibility to manually address this challenge by staff plugging in vehicles after 9 PM than smaller fleets do. During the data collection period, fleets were significantly more focused on ensuring the electric buses operate reliably than achieving the lowest possible cost. After achieving a stable and reliable electric bus operation, fleets shifted focus to bus charging logistics. Only after that was addressed, the fleets started looking at the cost of operation and potential ways to lower it.

While Figure 174 shows the cost comparison of monthly utility electricity rates for two different utilities (SCE for the Arcadia and Azusa Power and Light for the Azusa locations) the benefit of SCE's commercial EV rates is evident (between 15 and 35 percent lower). In comparison, the baseline CNG fuel on energy equivalency can be still significantly lower (between 65 and 85 percent). While only 6 months of data is presented in the chart, it is evident that there is a seasonal variability (indicated by the average high temperature) in the energy cost for both electricity and natural gas.

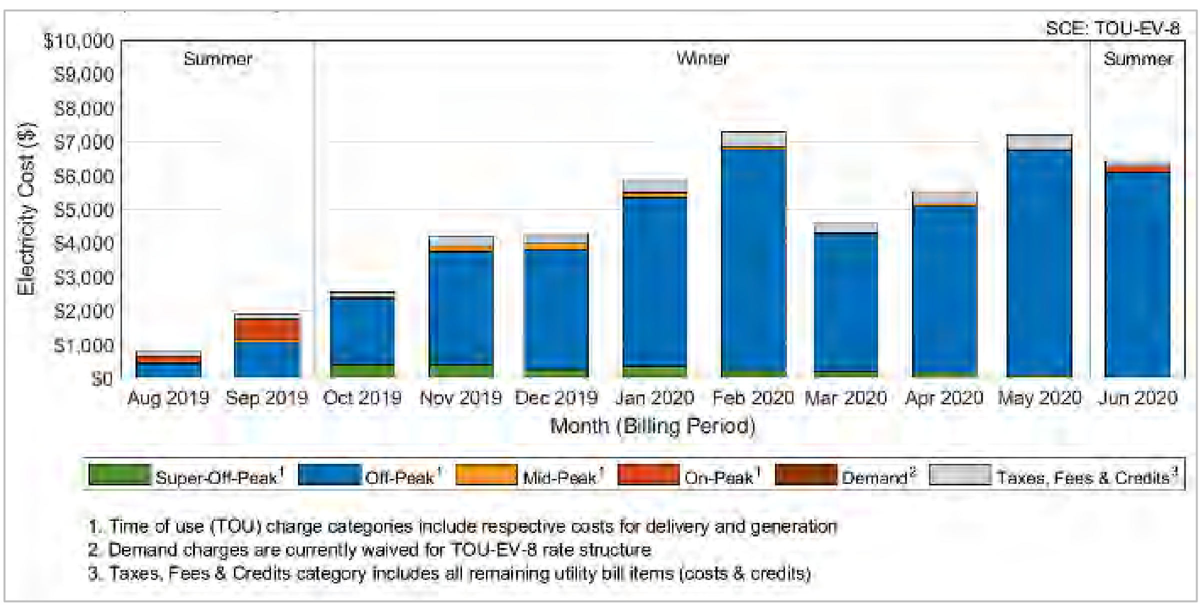
Figure 174. Comparing electricity costs from two utilities with CNG baseline



Source: SCE and Azusa Power and Light Billing Data and Fleet CNG Costs

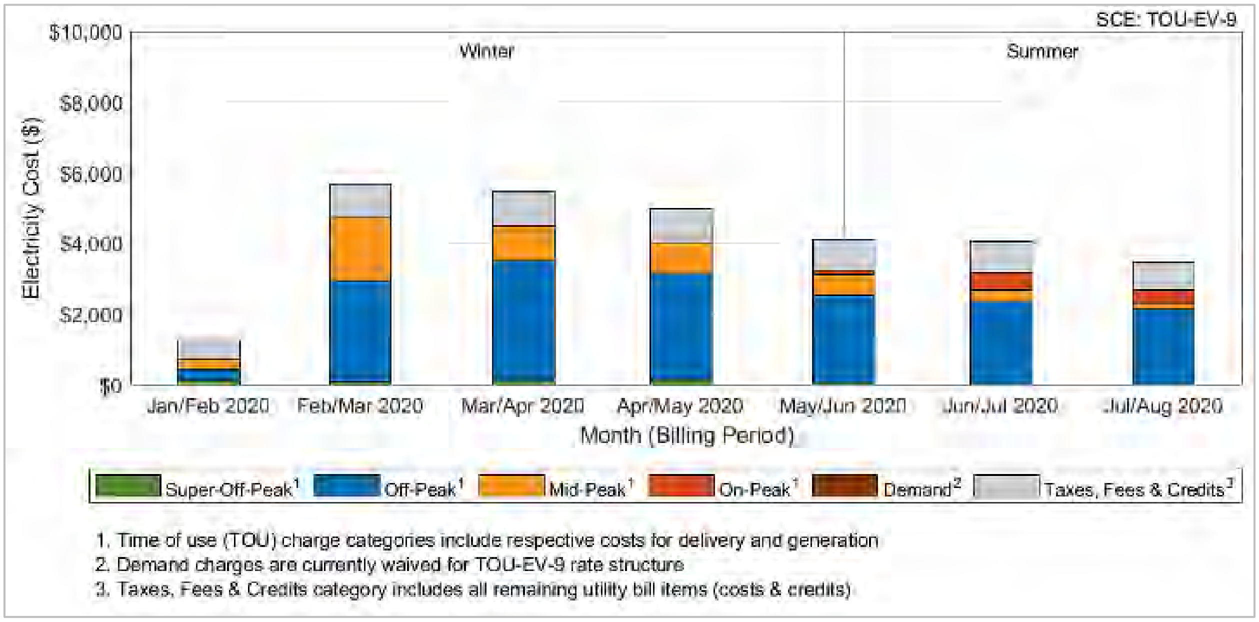
For relative comparison, actual fleet monthly utility electricity costs are presented in the following three figures. Of note are summer on-peak charge contributions to overall costs; they are most significant for Fleet 3 as shown in Figure 177. Fleet 2 was initially on a TOU-GS-1-E rate for the first 9 months through the middle of April 2020 and then switched to TOU-8-D for May and June 2020. After discovery of the incorrect rate during 3rd party evaluator operational performance summary presentation to the fleet, SCE rebilled the fleet on their commercial EV-TOU-9 rate. This resulted in 70% savings to the fleet primarily due to absence of demand charges on commercial EV rate.

Figure 175. Transit bus Fleet 1 monthly utility billing cost breakdown



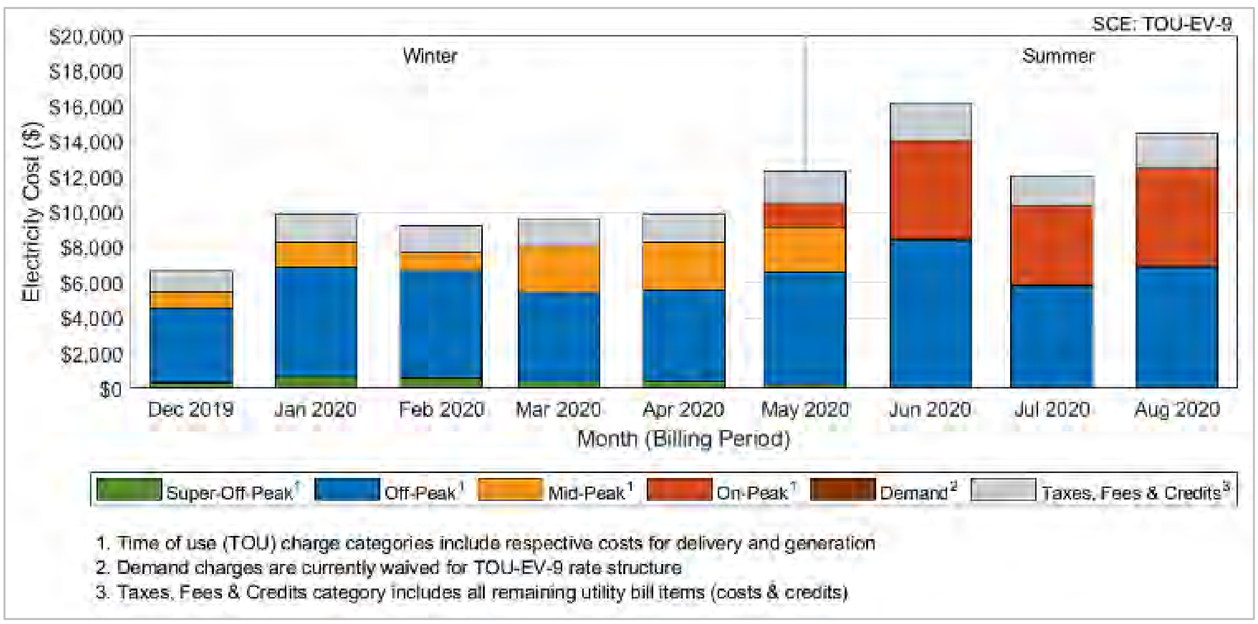
Source: SCE Billing Data

Figure 176. Transit bus Fleet 2 monthly utility billing cost breakdown



Source: SCE Billing Data

Figure 177. Transit bus Fleet 3 monthly utility billing cost breakdown



Source: SCE Billing Data

Stakeholder and Customer Feedback

All three fleets were pleased with SCE's coordination of site design and construction of make ready infrastructure. They commented on flexible designs to accommodate their needs for placement of make ready infrastructure and timely and efficient construction schedules. In addition, they were very interested in the new rates due to the recent removal of demand charges for a period of five years.

Fleets reported that they have gained experience with current electric bus technology with overnight depot charging. They have been able to successfully operate electric buses on routes less than 150 miles per day. Two of the three fleets indicated that they began exploring hydrogen fuel cell bus alternatives for routes above 150 daily miles as the current electric bus technology would require high-power, on-route charging in addition to the depot chargers or electric bus batteries with 600+ kWh capacity which some OEMs are working on. To convert their whole fleet to zero emission buses in the next 10 to 20 years to meet CARB ICT regulation, transit fleets would need to make significant investments in on-route chargers in addition to depot chargers which would significantly increase the charging infrastructure cost. Longer range electric buses would help as well, but there is beginning to be a limit to how much added weight in batteries should be put into a bus and how expensive that might make it. Two participating fleets have a significant number of routes with 150 to 300 miles per day and in a unique case as many as 500 miles. That said, two of the fleets have already signed agreements for SCE's Charge Ready Transport program to install additional chargers for expanding their electric bus fleets, indicating satisfaction with experience gained from this PRP. Fleet 1 is adding charging at a main transit center which will extend electric bus operation to longer routes around that location. They see potential that placing chargers at this site will also influence another transit agency that operates in that area to adopt electric buses sooner. They have also identified that the same chargers can support their non-revenue fleet, such as the vehicles used for driver shift changes. Fleet 2 is adding twelve 50-kW chargers to support addition of a dozen of Lightning Systems shuttles for their paratransit operation at the same location. They are also considering installing two chargers at a transit depot to support a longer route that serves a Native American reservation.

While two fleets reported relatively high electric bus availability, one fleet commented on daily bus availability as an issue. Reasons they listed were technology challenges associated with early production models from a startup OEM (battery management and electric drive components as well as non-electric component issues).

Fleets also highlighted the lack of charger management solutions at the beginning of the PRP to help them schedule charging and manage electricity costs. One of the fleets did express satisfaction with the managed charger software solution that was implemented during PRP demonstration. Two of the other fleets did express some interest in charging management solutions after reviewing the charging session summaries and electricity costs.

All three fleets expressed some disappointment by the observed daily miles from the electric buses as they fell short of their expectations. Bus OEMs advertised ranges of around 200 miles per day which can be expected based on larger than 400 kWh nominal battery capacities and energy consumption of 2 kWh per mile. However, when factoring in actual usable battery capacity (in some cases less than 80 percent of nominal capacity), seasonal temperature variations impact on energy consumption (up to 30 percent), and the fact that fleets need to take buses out of service when SOC falls below 20 percent to ensure buses can make it back to the depot at the end of the day (in some cases bus power gets de-rated below 20 percent SOC and it goes into a limp-home mode), the effective daily miles with only depot charging are closer to 130.

Two fleets reported that actual charging power is lower than expected. In one case, this was due to the lower electric bus battery voltage than what is needed for full power capability of the charger, resulting in a 20% decrease from charger power rating. In the other, it was due to the maximum vehicle charging power limitation (charging coupler and battery management system). This resulted in a little disappointment for the fleet, as they installed charging infrastructure capacity of 200 kW, but due to the vehicle limitation, they can only charge at 100 kW (50%). Lower-power chargers would likely be significantly cheaper without impacting the charging time.

4.3.4 Conclusions and Recommendations

Findings

SCE spent $2,087,396 out of the approved $3,978,000 PRP budget to install charging infrastructure (30 chargers) for three transit agencies, supporting a total of 34 electric buses. All transit agencies received make-ready charging infrastructure from SCE up to a charger disconnect and a $20,000 rebate for each charging port they installed. At least 7 months of in-use operational data was collected for each of the three fleets, with one of them providing 13 months of data. Data and demonstration insights were collected from all pilots which help SCE and others better understand the potential electrification opportunities and challenges. Key findings from this PRP are:

- The make-ready construction planning, design, and execution went smoothly, with only a minor field change order to add a higher power charger. Construction durations were within expected timelines. The infrastructure installation process was similar to the DCFC PRP, as comparable charging equipment is being used.
- Make-ready costs were well within the approved budget as only 53 percent of the allocated budget was used. As proposed, the utility anticipated higher infrastructure costs as they did not yet have much experience with infrastructure installations at bus yards. The PRP filing estimated 20 ports at $900,000 but during the program development stage (after the Decision), the program structure was adjusted to lower the rebate amount in anticipation of possibly more sites. Due to most applicants not having qualified charging equipment and challenges of receiving electric buses in a timeframe to participate in the PRP, only 3 sites ended up participating in the pilot. SCE make-ready costs per site were between $200,000 and $800,000. While more than the anticipated number of chargers were installed (30 vs. 20), the rebate cost was only two-thirds of the approved budget ($600,000 vs. $900,000). The largest difference was in the customer side make-ready costs where less than $500,000 was spent out of more than $1.6M approved. Project management labor accounted for only one quarter of the budgeted project management cost.
- The program experienced a challenge in qualifying charging equipment proposed by the applicants. Because of the rapidly changing nature of the transit bus EVSE market, some EVSE providers could not meet the program's technical requirements, such as NRTL certification.
- This PRP provided the make-ready charging infrastructure capacity only for the number of EVSEs to be immediately installed by the three transit customers. Future electrification plans were discussed with the customers to understand their potential make-ready charging infrastructure needs. Each project incorporated enough capacity to roughly double charging power; however, additional transformers and switch gear or their upgrades would be required.
- Transit fleet electrification represents an interesting and significant opportunity for the electric grid due to often a relatively large installed facility charging capacity (kW), long daily operations in many territories and role as a public service. Software will help fleets adjust their charging

profile throughout the year to accommodate seasonal changes in pricing that will help them achieve lower cost, target low carbon intensity times, or provide revenue by charging other nearby fleet vehicles where appropriate or through ancillary grid services.

- This PRP experienced the lowest electricity cost ($0.16 per kWh) for one of the pilot sites which resulted in significant energy cost savings throughout the year. The other two fleets had higher baseline fuel (CNG) costs which meant they could experience cost benefits for some months of the year. While maintenance savings associated with electric buses are also expected compared to internal combustion engine buses, these operational savings combined might not be sufficient for a positive total cost of ownership when considering the additional capital expenses of electric buses and chargers. Therefore, it is important to note that statewide vehicle purchase incentives (CARB HVIP), charger incentives (utility make ready programs), and fueling credits (CARB LCFS) are needed to continue supporting the transit bus sector for a successful transition to ZEVs over the next decade to meet CARB ICT regulation.

Lessons Learned

The following lessons learned were captured during the implementation of this PRP.

- When performing site design for these PRP installations, SCE learned that there were developments or bus retrofits occurring, or in the design phase, at some customer facilities related to their conventional buses. In some cases, these activities directly interfered with the proposed EV deployment. For future infrastructure programs, a question about current and planned facility upgrades or retrofits should be included in the program participation package.
- Commercial readiness of electric buses varies by vehicle manufacturer. Fleets should do their due diligence before committing to a product and utilities can share experiences of other fleets.
- Chargers can be used with multiple buses, and even support non-revenue vehicles. Duty cycle and charger layout should be properly understood to plan the deployment to prevent the need for buses to charge during on-peak periods.
- Chargers with software management capability can significantly reduce on-peak electricity use.
    - Fleets should consider investing in software to administer charging management that will result in lower electricity costs and enhance consistency as opposed to relying on staff to plug in and avoid on-peak charging.
- Charging power is limited by the lowest common denominator of EVSE, electric vehicle battery voltage or charging capability (whichever is lower is maximum) and is not always clearly explained/advertised. Fleets should always double check relevant vehicle and equipment specifications.
    - One fleet learned that their chargers only produced peak power with batteries of higher nominal voltage than what their buses had. This resulted in 15 percent lower charging power than expected.
    - Another fleet learned that their electric buses had limiting charging power capability which resulted in only being able to charge at 50 percent of their charger power rating.
- Specified battery capacity multiplied by the advertised bus efficiency does not always equate to expected range.

  - Seasonal changes impact range because of heating and air conditioning needs of electric buses.
  - Fleets are not comfortable operating the electric buses below 20% SOC (some buses experience derated power).
  - Without adjusting routes, electric buses are limited to shorter routes (<150 miles per day) unless they utilize high cost on-route chargers or mid-day charging.
- Fleets pay for electricity based on utility meter use, not just the electricity consumed by the bus while driving which could be up to 20 percent lower due to charger efficiency and other losses. Therefore, for cost tracking or comparison, cost per mile needs to be based on utility meter bills.
- Utility account managers should review the rate on new transportation electrification accounts to ensure appropriate billing.
- Periodic (i.e., quarterly) review of fleet operational performance (utility meter, charging session, and billing data) with participating fleets identified low utilization and high electricity cost which were both promptly addressed by changing charging behaviors to increase project benefits.
- Electric bus charging energy costs can be lower or similar to CNG; however, significant savings were not observed without LCFS credits which these transit fleets are eligible for as they own the chargers.
- Commercial EV rates result in relatively low cost per kWh (adding facility demand charges in the future could significantly increase the costs).

Scale-up Potential

There are many transit bus fleets operating in California, all of which are required to convert 100 percent of their buses to zero emissions by 2040 to meet CARB's Innovative Clean Transit regulation (starting with only zero emission bus purchases by 2029). Transit buses with large battery packs are commercially available and could potentially meet half of fleets' daily use patterns with depot charging. CARB recently estimated that 12,000 buses across the state could be electrified.[53] Scaling the best observed annual benefits from the 31 electric buses supported by this PRP to 12,000, the benefits shown in Table 54 could be realized as well as a 120 million DGE of CNG reduction in petroleum use.

Table 54. Transit bus scale-up potential annual emissions

	GHG (MT/yr)	SO_x (MT/yr)	NO_x (MT/yr)	CO (MT/yr)	PM (MT/yr)	VOC (MT/yr)
Net Reduction	**981,306**	**198**	**1,606**	**17,818**	**51**	**662**

Source: Evaluator Calculations

[53] California Air Resources Board, "California transitioning to all-electric public bus fleet by 2040," December 14, 2018, https://ww2.arb.ca.gov/news/california-transitioning-all-electric-public-bus-fleet-2040.

4.4 Urban DC Fast Charging Clusters

4.4.1 Project Narrative

Overview, Objectives, and Barriers Being Addressed

Direct current fast charger (DCFC) installations to date tend to support long-distance travel near highways. (Approximately 75% of the DCFC stations in Southern California Edison's [SCE's] territory are located within 0.5 miles of a major highway.) Many residential customers do not have access to overnight off-street parking or home charging, and DCFCs in urban areas could help such a customer adopt an EV and quickly charge it near his or her home. Lack of overnight or home charging is especially problematic for customers in multi-unit dwellings (MUDs), who could benefit from this pilot. DCFCs located in densely populated areas away from highway corridors could also prove useful for EV drivers participating in rideshare programs.

Through the Urban DCFC Clusters Pilot, SCE was approved to spend $3,980,000 for deploying and operating five DCFC sites, clustered in urban areas. Selected sites could install up to five dual-port charging stations, for up to 50 DCFC ports total. SCE is installing and maintaining make-ready SCE-owned infrastructure at participating customer sites. Participating customers select DCFC charging stations qualified by SCE and receive a rebate to cover the base cost of charging stations deployed through the pilot, including hardware and installation. Approved vendors, which were selected through a request for proposals and equipment qualification process, include MaxGen (using ABB hardware and Greenlots for networking), Greenlots (using one of several hardware options and the company's network), and ChargePoint (using its own hardware and network). Participating customers are required to provide public access to the charging stations deployed through the pilot but can determine EV charging fees at their discretion.

Sites and Participants

Recruitment Process

For the Urban DCFC Clusters Pilot participants, SCE targeted non-residential customers likely to meet the pilot's requirements. SCE's business customer division reached out to these customers through low-cost channels such as emails and other customer communications. SCE also solicited expertise and proposals from electric vehicle (EV) service providers on potentially eligible sites. Non-solicited customers also had the opportunity to apply to the pilot, which SCE promoted on its website. The website's Charge Ready landing page was one of the main resources for potential customers to learn about this pilot and submit their applications. The landing page provided potential customers with a participation package and fact sheet that explained the overall pilot and provided copies of the application, easement template, and program agreement. Eligible site host customer requirements included the following:

- Be a non-residential customer.
- Own or lease the participating site or be the customer of record associated with the premises meter where the charging stations will be deployed.

- Provide an agreement by the participating site's owner granting SCE appropriate real property rights and continuous access to the customer participant site infrastructure that is to be installed, owned, and maintained by SCE.
- Identify a site in or near (< 1.5 miles) a disadvantaged community (DAC) with MUDs nearby.
- Commit to and provide acceptable proof of qualified charging station purchase, and price paid, prior to SCE deployment.
- Agree to take service on an eligible time-of-use (TOU) rate and participate in applicable demand response (DR) program(s).
- Agree to participate in the pilot for five years, including maintaining the charging stations in working order.
- Contract with a qualified EV charging network service provider to provide transactional data to SCE.

The pilot received 50 applications from 18 unique customers. To determine the most qualified candidates for the pilot, SCE developed quantitative scoring criteria (up to 1.0 point for each of the following for a maximum score of 4.0), based on 1) the site's proximity to a DAC, 2) EV adoption in the selected area, 3) population density, and 4) proximity to MUDs. Results from the initial selection process to rank customers who applied to the pilot were as follows:

- 12%, or 6 sites, were located outside DAC areas and were not eligible to participate.
- 26%, or 13 sites, scored <3 and were deemed less than ideal to participate.
- 8%, or 4 sites, withdrew from the pilot.
- 54%, or 27 customers, met the scoring criteria.

Of the 27 customer sites passing the initial selection process, 16 customer sites were selected for the feasibility analysis, which included preliminary engineering to determine feasibility of the site, develop conceptual drawings, and estimate the project cost. To further narrow the list and identify the top five sites to participate in the pilot, SCE performed a qualitative review of each site, examining (a) distance from major freeways (further is better, as many DCFC charging stations are located along highways), (b) site cost, (c) permitting requirement(s), (d) ease of construction, and (e) need for ADA requirements.

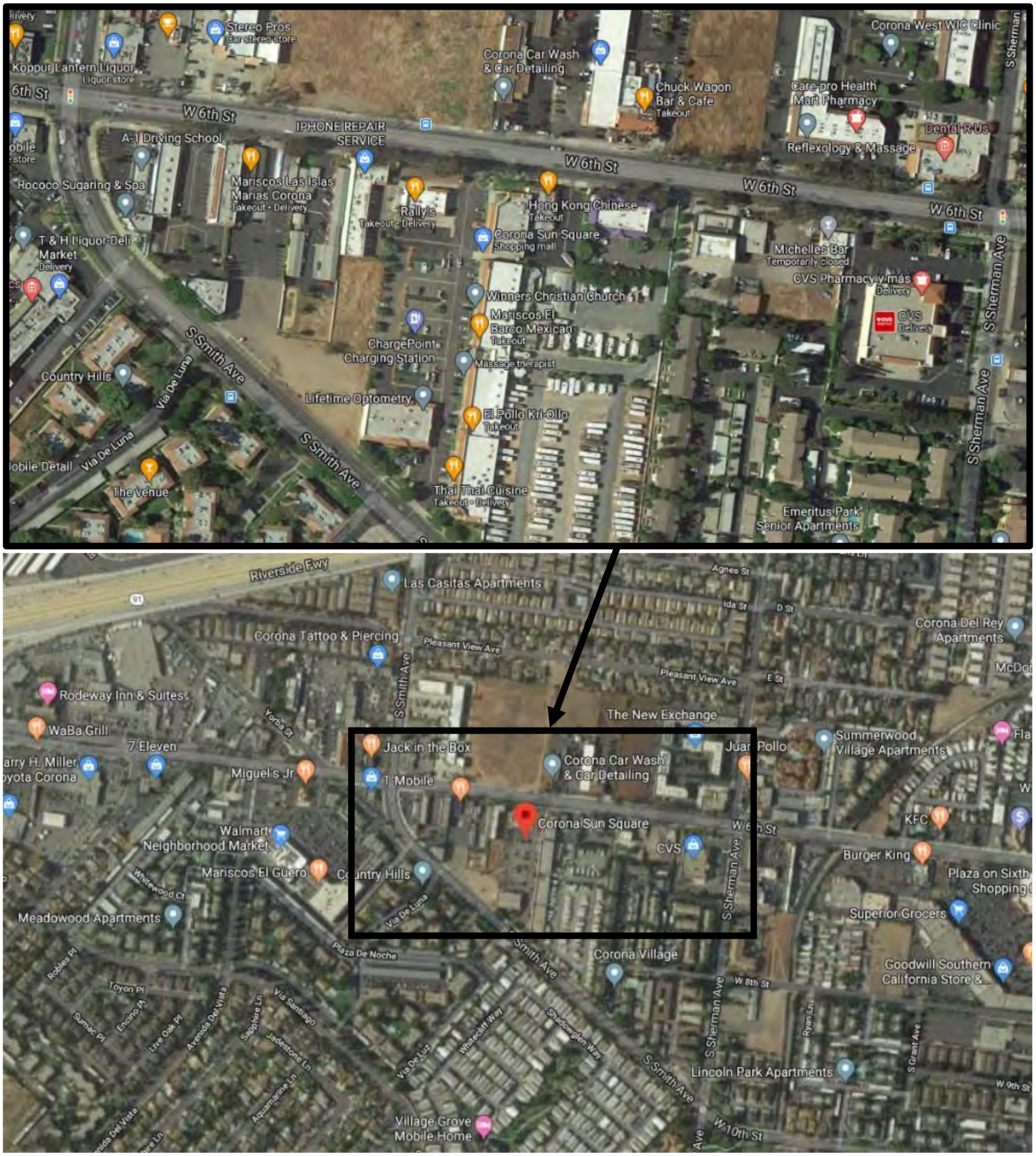
Participants

SCE selected five sites for participation in this priority review project (PRP). Three sites selected the 62.5 kW, and two sites selected the 50 kW **ChargePoint** DCFC (CPE 250) for installation. Two locations are shopping centers, and the other three are stand-alone businesses close to other shopping centers and retail businesses. A total of 14 DCFCs were installed among these five locations.

SCE provided the infrastructure to the make-ready position. For the DCFC project, the make-ready is a service disconnect adjacent to each electric vehicle supply equipment (EVSE) power cabinet. The customer scope was installing the EVSE and any required conduits/wiring/mounting fixtures and connecting to the energized service disconnect provided by SCE.

Corona Sun Square, at 1380 West 6th Street in Corona, has several nearby MUD neighborhoods, including Meadowood Apartments, Las Casitas Apartments, Village Grove Mobile Home, Lincoln Park Apartments, Summerwood Village Apartments, and Corona Del Rey Apartments. Nearby retail outlets include Walmart Neighborhood Market, CVS, and several restaurants.

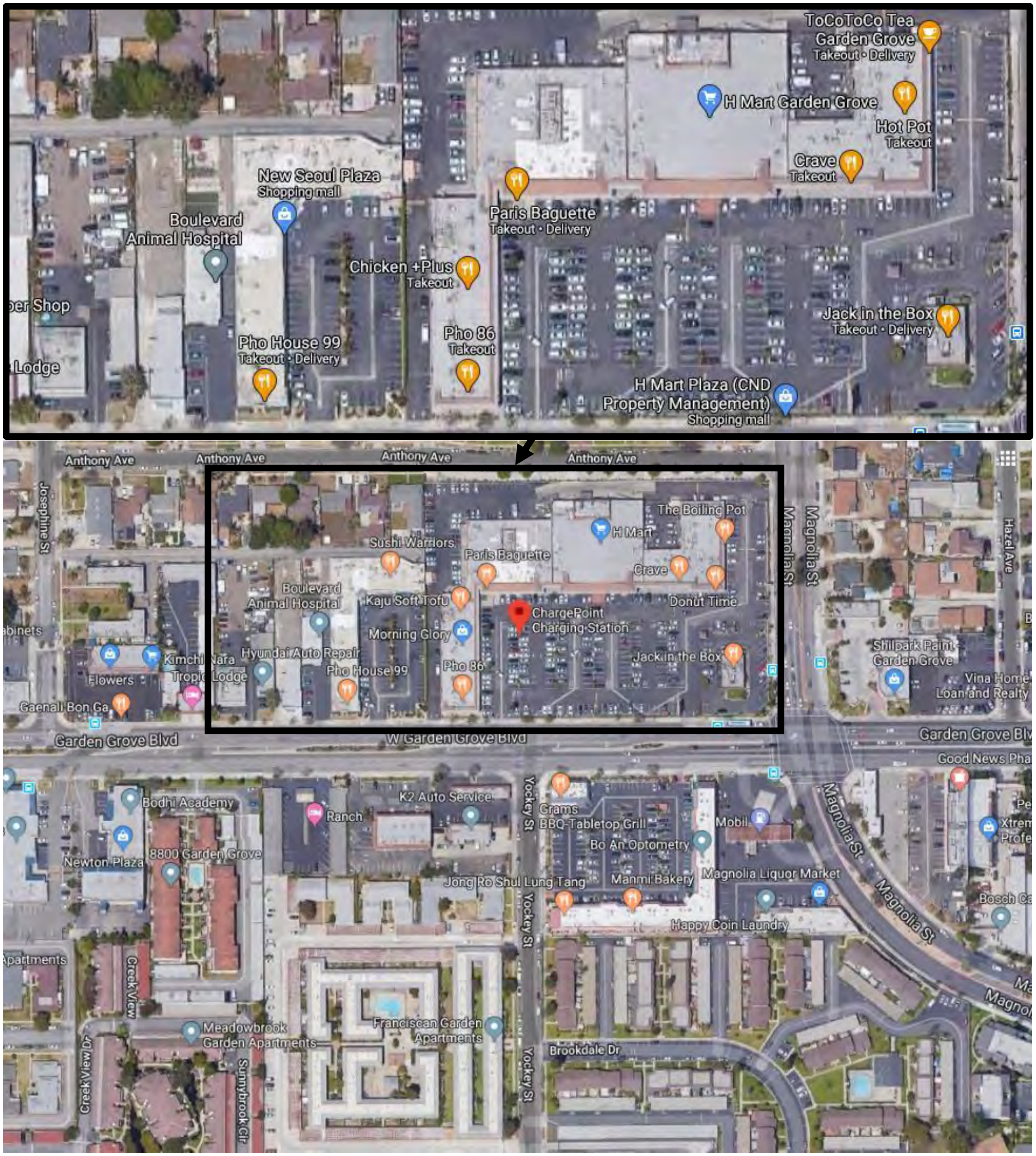
Figure 178. Map of Corona Sun Square and surrounding area



Source: Google Maps

H Mart center in Garden Grove, owned by Global Partnership, LLC and located at 8901 Garden Grove Boulevard in Garden Grove has 21 restaurants and retail shops, such as Paris Baguette, an international premium bakery–café chain, and Kaju Soft Tofu, a Korean comfort food restaurant. Nearby MUD neighborhoods include Meadowbrook Garden Apartments, Franciscan Garden Apartments, and Walden Apartments. Nearby retail outlets include H Mart, an Asian grocery store, and several other restaurants.

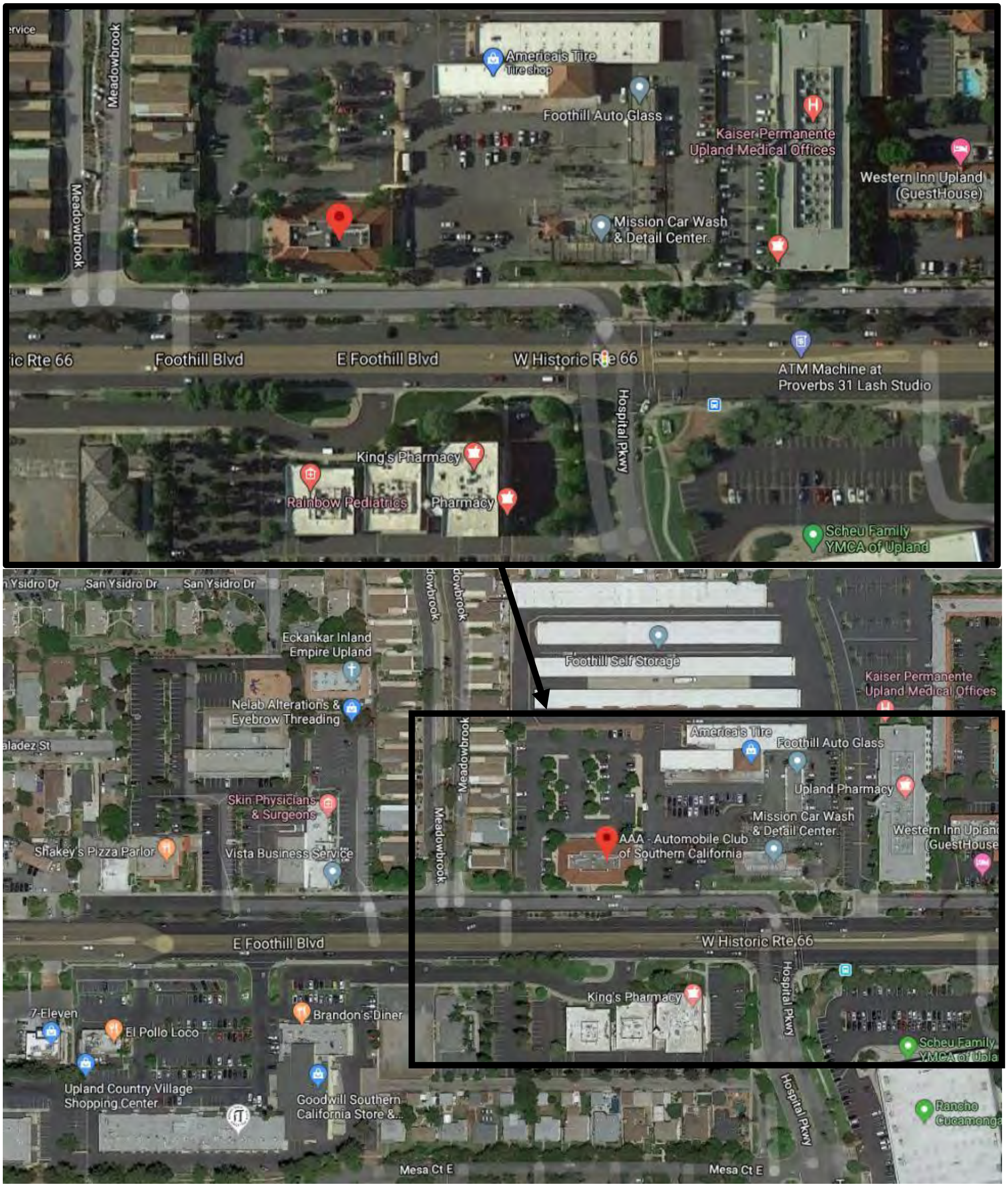
Figure 179. Map of H Mart center in Garden Grove and surrounding area



Source: Google Maps

AAA – Automobile Club of Southern California, at 1021 East Foothill Boulevard in Upland, has a nearby Upland Meadows mobile home park. Nearby retail outlets include King's Pharmacy and a few restaurants. A YMCA is located across the street.

Figure 180. Map of AAA in Upland and surrounding area



Source: Google Maps

A second **AAA – Automobile Club of Southern California** location, at 18642 Gridley Road in Artesia, has nearby MUD complexes on 186th Street and a large mall across the street, with several restaurants in the area.

Figure 181. Map of AAA in Artesia and surrounding area

Source: Google Maps

A 7-Eleven convenience store at 806 Indian Hill Boulevard in Pomona has several restaurants nearby. Nearby MUD neighborhoods include Pama Management, Keystone Court Apartments, Vista del Cielo Apartments, and San Antonio Vista Apartments.

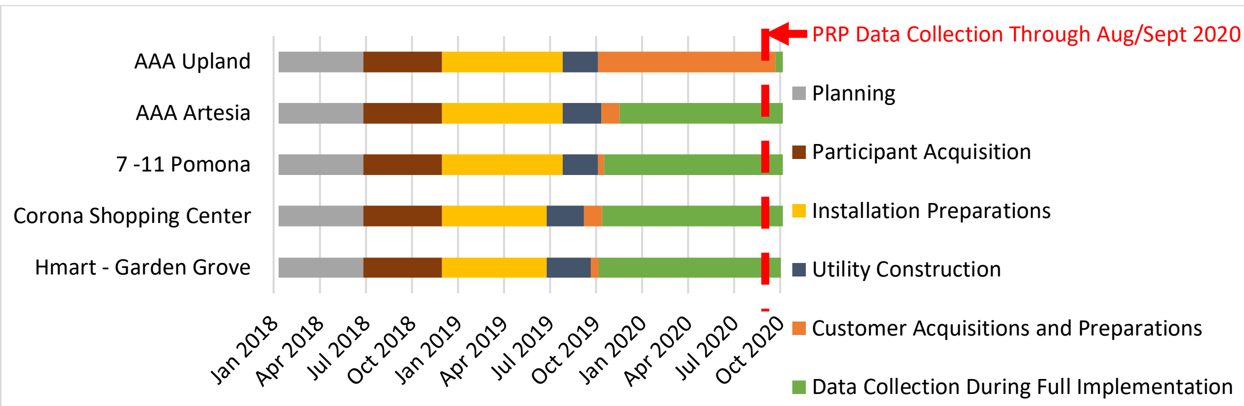
Figure 182. Map of 7-Eleven in Pomona and surrounding area

Source: Google Maps

Timeline and Status

SCE launched the Urban DCFC Clusters Pilot on June 29, 2018. The application and site selection were completed by November 2018. All five site assessments were conducted by February 2018. The design and permitting phase began after each site host provided proof of EVSE procurement. After the final design was reviewed and approved by the pilot participant, SCE submitted the design to the authority having jurisdiction (AHJ) for review and permitting. SCE also submitted the easement agreement to each pilot participant for execution prior to starting construction. Obtaining design approval and securing permits took 3–4 months for these five sites. Construction began in June 2019 and took six weeks or less per site. The customers and their contractors began EVSE installation after SCE completed the make-ready infrastructure and released the site. The first location was energized in October 2019, and all five were operational by early December 2019. The AAA Upland site experienced significant delays in registering the charger with ChargePoint, which restricted use of the station until October 2020.

Figure 183. SCE Urban DCFC Clusters PRP timeline



Source: SCE

4.4.2 Evaluation Methodology

Selected Methods and Rationale

In addition to the evaluation questions that apply to all PRPs and those specific to the Public Access Station PRPs, the evaluation questions listed below will be examined for this PRP.

- Does the rebate cover all eligible costs?
- Did applicants who were not selected continue with EVSE installation?
- Are utilization patterns different in the urban setting from those for highway installations?
- Did some sites perform better than others, and what was the reasoning for any differences?
- Did the sites' participation in DR benefit the utility? Did it negatively affect the customers?

The sources for data collection used to evaluate this PRP include 1) PRP information from the approved decision, project updates, site visits, and other available documentation, 2) market research on DCFCs and early deployment efforts from other similar electrification projects across the country, 3) PRP data from charger operations, 4) in-depth interviews (IDIs) with project partners, and 5) surveys with vehicle drivers.

Data Sources

PRP operational data sources for this project include utility service meter 15-minute interval data, charging station session data, and some monthly facility electricity bills. Some PRP information has been collected through numerous PRP participant interactions: PRP kick-off meeting (SCE and evaluator), quarterly Program Advisory Committee update meetings, periodic PRP updates (SCE and evaluator), site visits, and other periodic calls or emails. The evaluator facilitated IDIs with the SCE construction team and SCE project manager. A survey of the EV drivers was conducted in collaboration with SDG&E and ChargePoint to gauge customer satisfaction.

4.4.3 Evaluation Findings

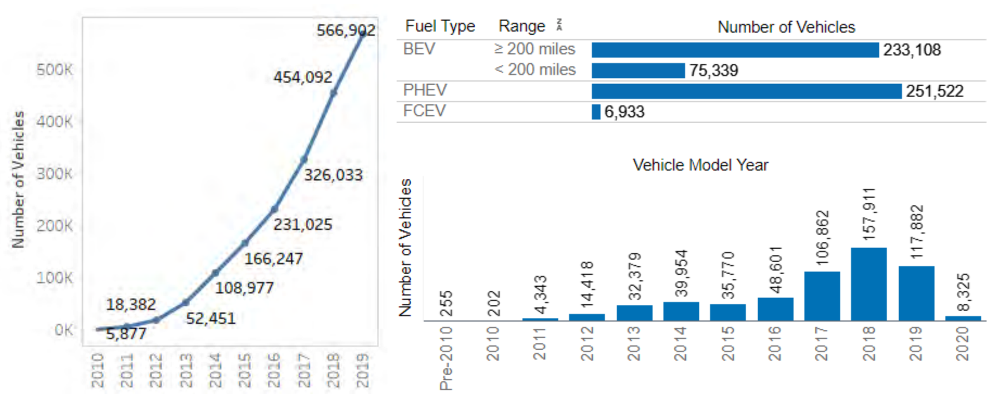
Project Baseline

After the initial 2016 Zero-Emission Vehicle (ZEV) Action Plan was announced, Governor Brown raised the bar and increased the target number of ZEVs on the road and public EVSE across the state with the 2018 update. This increased the initial 1.5 million ZEV goal by 2025 to 5 million by 2030 and calls for 250,000 public charging stations by 2025 with at least 10,000 being DCFC.[54]

Since 2012, ZEV adoption in California has continued to increase, as shown in Figure 184.[55] To reach the 2030 vehicle goals, ZEV adoptions will need to increase significantly, with the ZEV portion of new sales reaching 40% of the market share.

Figure 184. California ZEV statistics

ZEV POPULATION			NON-ZEV POPULATION						
Total Light-Duty Vehicles end of 2019			Total Light-Duty Vehicles end of 2019						
566,902			28,462,885						
Battery Electric (BEV)	Plug-in Hybrid (PHEV)	Fuel Cell (FCEV)	Bio Diesel	Diesel	Flex Fuel	Gasoline	Gasoline Hybrid	Natural Gas	Propane
1.063% 308,447	0.866% 251,522	0.024% 6,933	0.396% 114,855	1.949% 565,767	3.898% 1,131,474	87.932% 25,526,368	3.841% 1,114,944	0.029% 8,462	0.003% 1,015



Source: California Energy Commission

[54] 2018 Zev Action Plan Priorities Update, Governor's Interagency Working Group on Zero-Emission Vehicles, http://www.business.ca.gov/Portals/0/ZEV/2018-ZEV-Action-Plan-Priorities-Update.pdf.

[55] California Energy Commission Zero Emission Vehicle and Infrastructure Statistics, California Energy Commission, data last updated August 28, 2020, https://www.energy.ca.gov/zevstats.

There are an estimated 27,000 public chargers (Level 2 and DCFC) and 39,500 shared private chargers in California as of September 30, 2020, as shown in Table 55.[29] Nearly 5,000 public DCFCs represent about half of the state's 2025 goal.

Table 55. California zero-emission charger statistics

Charger Type	Public	Shared Private	Grand Total
Level 1	329	166	495
Level 2	22,531	38,949	61,480
DCFC	4,818	550	5,368
Total	27,678	39,665	67,343

Source: California Energy Commission

Implementation Process

SCE originally planned for up to ten DCFCs at each site (up to a total of 50 ports); however, most of the applications asked for two or four ports because of a reluctance to lose parking spots. To electrify two ports, site hosts might need to give up three or four existing parking spots (since one spot must be ADA compliant). Retail customers requested only two ports, as they were unable or unwilling to allocate more than two or three parking stalls for the pilot. Customers that owned or managed the property were able to allocate more stalls but still typically requested only four ports.

Another issue SCE discovered along the way was that since many of the applicants were tenants, SCE needed to work with the property owner to obtain an easement to install the make-ready infrastructure and maintain the equipment and service line. This added an additional step in securing the agreements, if all went well. Some customers were not able to obtain the necessary approval from the property owners or property managers for their sites to participate in the pilot. Three sites withdrew from the pilot during the agreement stage because the property owners refused to sign the pilot agreement and were unwilling to provide the required easements.

A senior director of Energy, Engineering and Store Planning for the 7-Eleven convenience store giant provided a testimony of successful customer partnership: "Our collaboration with SCE through Charge Ready is a win–win for everyone. Fast chargers mean added convenience for EV drivers who visit our store and cleaner air for the surrounding community."[56]

According to the SCE construction manager, there were no surprises during the design and construction phases beyond the minor field changes that are normal for construction scope. Construction costs were within expected budget, and SCE construction of each site was completed in six weeks or less.

[56] Paul Griffo, "EV Drivers Can Now Get a Fast Charge With a Slurpee at Pomona 7-Eleven," *Energized by Edison*, November 21, 2019, https://energized.edison.com/stories/ev-drivers-can-now-get-a-fast-charge-with-a-slurpee-at-pomona-7-eleven.

Corona Sun Square installed four 50 kW CPE 250 DCFCs. The Corona Sun Square project utilized an existing transformer. The voltage of the existing transformer (208 V) was not correct for selected DCFC installation; thus, the EV infrastructure includes a 208 V to 480 V step-up transformer. The charging fee, which is set by Corona Sun Square, was $0.50/kWh from July 2019 to January 2, 2020; $0.55/kWh from January 3, 2020, to July 5, 2020; and $0.25/kWh plus $5.00/hour after the first two hours of use after July 6, 2020. (Since that time, only two charging events have been more than two hours in length.)

Figure 185. Corona Sun Square DCFC installation

Source: Evaluator team

Global Partnership, LLC in H Mart center in Garden Grove installed four 50 kW CPE 250 DCFCs from ChargePoint. The four chargers are lined up in head-to-head parking in adjacent parking spaces. Four parking spots have access in one row and five parking spots on the other. Trenching goes from the end charger location to the corner in between the two sections of restaurants to reach the electrical supply. The businesses use 208 V-3 phase power, which is run to a transformer providing 480 V-3 phase to the chargers. SCE held a plug-in ceremony on October 17, 2019, at the H Mart center in Garden Grove. The initial charging price was $0.25/kWh, set by Global Partnership, LLC, and changed to $0.30/kWh on April 10, 2020.

Figure 186. H Mart center in Garden Grove

Source: Evaluator

One **AAA – Automobile Club of Southern California** location, at 1021 East Foothill Boulevard in Upland, installed two 62.5 kW DCFCs from ChargePoint (CPE 250). The AAA Upland site utilized the existing transformer structure but required a new upsized transformer (300 kVA, from 12 kV to 208 V). The AAA does not charge a fee for charging. The SCE scope for make-ready and customer scope for EVSE installation was completed in November 2019. The two stations were installed shortly thereafter but were not fully set up with ChargePoint, so after the first four uses (the initial number allowed by any ChargePoint station until it is fully registered with ChargePoint), the stations were not available until September 2020, when the next charging event was recorded.

The chargers are installed in a median with parking on both sides. Under many circumstances, such an arrangement can double the access to charging. At this location, a wide median of seven feet and short cords limits access to two parking spaces. Three additional feet of trenching could have placed the non-ADA charger to reach an additional parking space on one side. If both chargers were placed centrally in the median, four parking spaces could have access. The length of cord (12 feet) on this charger model has shown access limitations in several PRPs.

Figure 187. AAA DCFC installation in Upland

Source: Evaluator team

The second **AAA – Automobile Club of Southern California** location, at 18642 Gridley Road in Artesia, installed two 62.5 kW DCFCs from ChargePoint (CPE 250). The AAA Artesia site required installation of a new dedicated 480 V transformer and structure. The SCE scope for make-ready and customer scope for EVSE installation was completed in November 2019, and the station was activated by the end of that month. AAA did not charge a fee for use of this station. Two parking spots have reasonable access. If the chargers were moved over ten feet (1.5 parking spaces), two more parking spots could have access for low additional cost.

Figure 188. AAA site in Artesia with two DCFCs installed

Source: Evaluator team

A 7-Eleven convenience store at 806 Indian Hill Boulevard in Pomona installed two 62.5 kW ChargePoint Express 250 DCFCs with a pairing kit that allows both stations to share the total input power. This means that if only one charger is in use, it can provide up to 125 kW for an EV capable of this higher power charging rate. The charging stations are the very first to be owned, operated, and branded by 7-Eleven. 7-Eleven and SCE held a plug-in ceremony on November 21, 2019, to celebrate the project's completion. The charging costs are set by the 7-Eleven for energy use on a variable rate throughout the day (see Table 56). Additionally, a parking fee of $0.10 per minute for the first hour and $0.15 per minute thereafter applies. The maximum parking fee is $75 per session (this fee was lower prior to December 1, 2019).

Table 56. 7-Eleven DCFC energy costs as of November 2020

Time Period	Station Energy Cost
12 am – 8 am	$0.41/kWh
8 am – 4 pm	$0.41/kWh
4 pm – 9 pm	$0.55/kWh
9 pm – 12 am	$0.41/kWh

Source: PlugShare

Figure 189. 7-Eleven DCFC installation in Pomona

Source: Evaluator team (December 2019)

Costs

The approved PRP had an anticipated total cost of $3,980,000, consisting of $3,788,000 in capital and $192,000 in expense. The PRP costs as of November 2020 totaled $1,722,506 (which may not include all participant costs), as shown in Table 57, based on data available to SCE.

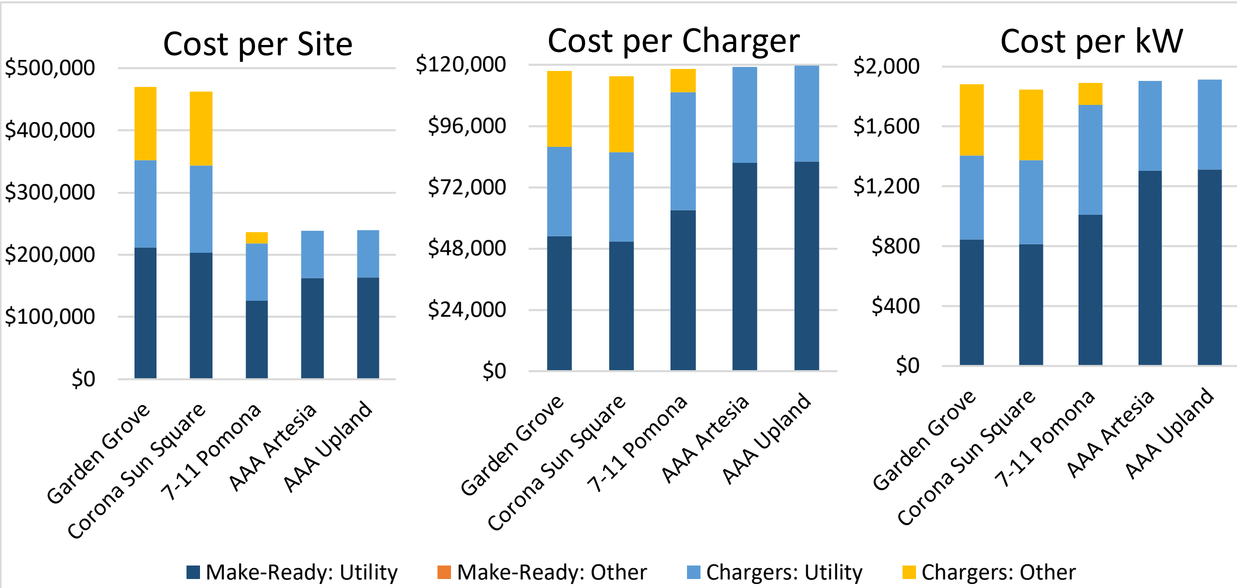
Table 57. SCE Urban DCFC Clusters PRP nominal costs as of November 2020

Cost Category	Actual SCE Costs	Budgeted SCE Costs
Site assessment, design, and permitting	$ 189,191	N/A
Rebate amount paid	$ 522,620	$ 1,495,000
EVSE procurement (subject to change)	N/A	N/A
EVSE installation (subject to change)	N/A	N/A
Make-ready infrastructure (utility side)	$ 235,187	$ 525,625
Make-ready infrastructure (customer side)	$ 633,302	$ 1,489,016
Other construction costs	N/A	N/A
Project management	$ 133,579	$ 395,526
Customer outreach (labor)	$ 0	N/A
Outreach and education materials	$ 8,627	N/A
Other program costs	N/A	$ 74,833
Total Costs	$ 1,722,506	$ 3,980,000

Source: SCE

Site assessment, design, and permitting was budgeted under the customer-side capital expense for make-ready infrastructure. Operations and maintenance non-labor and contract budget was budgeted under other program costs. Customers were responsible for the cost to acquire, install, and maintain the EVSE, including energy cost and network communications for up to five years. The pilot provided a rebate to offset the base cost of the EVSE and installation only ($35,000 for 50 kW DCFC and $46,000 for 62.5 kW). Customers set the rate that drivers pay to use the charging stations.

Figure 190. SCE Urban DCFC Clusters EV charging infrastructure costs



Source: SCE

Benefits

The pilot provides new charging options in certain urban areas for EV drivers. The pilot also offers potential environmental benefits. It aims to increase EV adoption, which potentially increases alternative fuels, improves air quality, and reduces greenhouse gas (GHG) emissions. No specific emission reductions or other benefits were stated in the testimony. The key benefits and some contributing factors are outlined below, with a more detailed description of this benefit analysis in the Appendix. Operational cost savings are based on $3.00 per gallon of gasoline and a sum of fees collected from each charging event.

This PRP includes five separate public charging station locations. Two of these, Corona Sun Square and 7-Eleven, are in a DAC, according to CalEnviroScreen 3.0, while the two AAA locations are directly adjacent to a DAC. Using the average energy dispensed per charging event and average efficiency for EVs in this region, a traveling area around the charging station location was determined and an average of 15% of it was calculated to be in a DAC.

The pilot demonstration period from February 2020 to September 2020 is used to calculate performance. Light-duty EVs charging at these sites achieve an average efficiency of 3.34 miles per kWh while equivalent internal combustion engine vehicles have an average fuel economy of 24.9 miles per gallon (MPG).[57] Determined on an annual basis, the charging stations dispensed 65,430 kWh per year

[57] Internal combustion engine vehicle efficiency same as used in the Electric Vehicle-Grid Integration Pilot Program ("Power Your Drive") Ninth Semi-Annual Report of San Diego Gas & Electric Company (https://www.sdge.com/sites/default/files/regulatory/R.18-12-006%20Ninth%20Oct%202020%20PYD%20Final%20Report%2010%2014%202020.pdf), October 14, 2020.

which corresponded with utility supplied electricity of 87,700 kWh per year, with 8,500 kWh (10%) occurring during on-peak hours. This resulted in 219,000 electric miles for which internal combustion engine vehicles would have consumed 8,800 gallons of gasoline, which is therefore saved.

Several factors limited utilization of these charging station during the demonstration period, so the best observed analysis looked at the busiest week for an individual location. The best charging performance was at AAA Artesia in September with 63 events per week dispensing 1,250 kWh. Annually this equates to 456 MWh of electricity dispensed (466 MWh of supplied electricity with 12% on-peak) supporting 1,520,000 electric miles which would have consumed 61,100 gallons of gasoline.

Table 58. SCE Urban DCFC Clusters PRP annual benefits

	Testimony (up to 50 DCFC ports)	Implemented (14 DCFC ports providing 12.6 charge events per day)	Best Observed (14 DCFC ports providing 63 charge events per day)
Petroleum Reduction	N/A	8,800 gallons of gasoline	61,100 gallons of gasoline
GHG Emissions Reduction	N/A	80 MT of CO_{2e}	592 MT of CO_{2e}
Criteria Pollutant Emissions Reduction	N/A	62 kg of NO_X 87 kg of VOC 706 kg of CO 17 kg of SO_X 6 kg of PM	453 kg of NO_X 611 kg of VOC 4,934 kg of CO 121 kg of SO_X 46 kg of PM
DAC Impact	DAC sites prioritized	43% of DCFCs installed in a DAC, 15% electric miles from charging traveled within a DAC	43% of DCFCs installed in a DAC, 15% electric miles from charging traveled within a DAC
Grid Impacts / Electricity Consumption	N/A	88 MWh, with 10% consumed on-peak	466 MWh, with 12% consumed on-peak
Operational Energy Cost Savings	N/A	$13,600 for Drivers ($2.96 per charge event)	$95,000 for Drivers ($4.13 per charge event)

Source: Evaluator Calculations

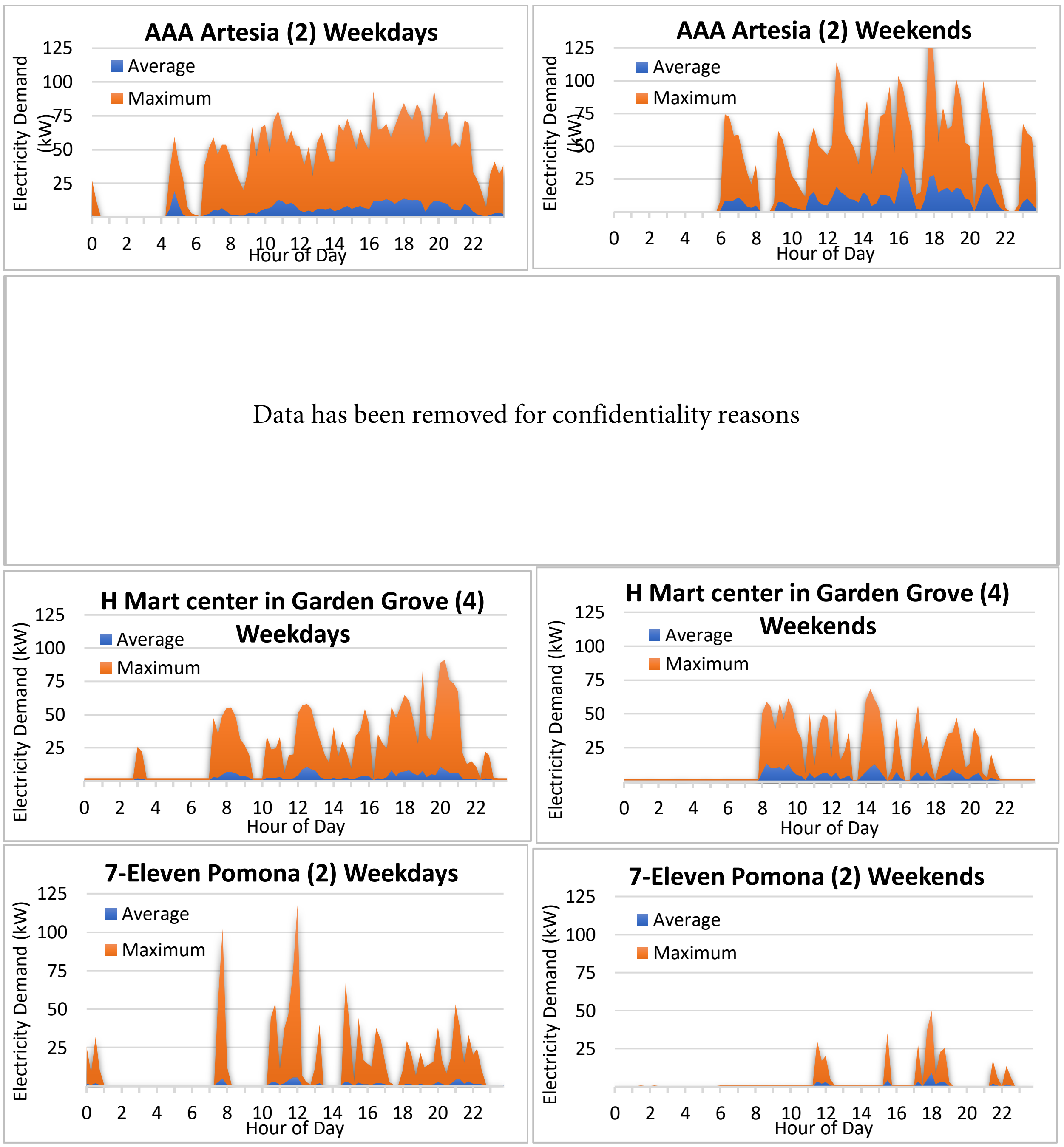
Operational Impacts of Project Equipment

Overall use of EVSE at the four charging sites (AAA Upland was not operational during this time) was low during the data collection period (February 1 through September 30, 2020). DCFCs across all four sites were connected to vehicles approximately 2.5% of the time and averaged only seven charging events per week. Low use can undoubtedly be attributed to dramatically reduced driving due to the COVID-19 pandemic and its resulting stay-at-home orders.

Demand Curves

Three Urban DCFC Clusters PRP sites have a total installed charging capacity output of 125 kW (two 62.5 DCFCs), while two have 200 kW (four 50 DCFCs). An analysis of the utility meter 15-minute interval data from September 2020 showed that most demand peaks for these sites were well below their capacity (Figure 191). The average demand is low because utilization is infrequent and inconsistent across this time period. AAA Upland is not included because there was no charging activity.

Figure 191. Electricity demand curves for each site (with 2 or 4 DCFCs) (September 1–30, 2020)



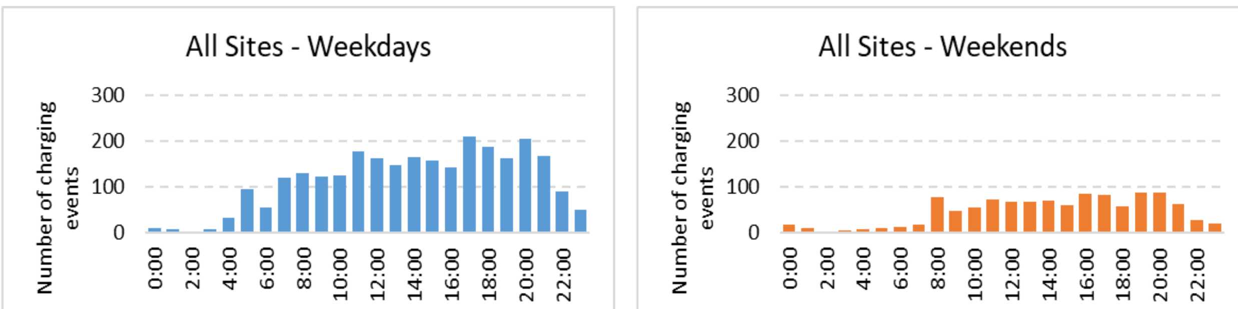
Source: SCE Meter Data

The five charging sites have vastly more capacity than has been used to date. However, the question that policy makers and regulators face is not what charging demand relative to capacity has been, but what it will be in the future. To establish expectations for future charger utilization and estimate how much existing capacity might be used, user charging behavior must be examined.

Charger Usage

Charger usage showed some variation relative to time of day, as shown in Figure 192. Session start time peaked during the 5 PM hour on weekdays and between 7 and 9 PM on weekends but was fairly uniform between 11 AM and 9 PM on weekdays and weekends. Charging sessions were less common in the late evenings and less so after midnight, but chargers were used at all hours of the day. Overall, use of the chargers relative to time of day was consistent with use profiles observed in the EV Project.[58]

Figure 192. Time of day at the start of DCFC events (all sites, entire reporting period)

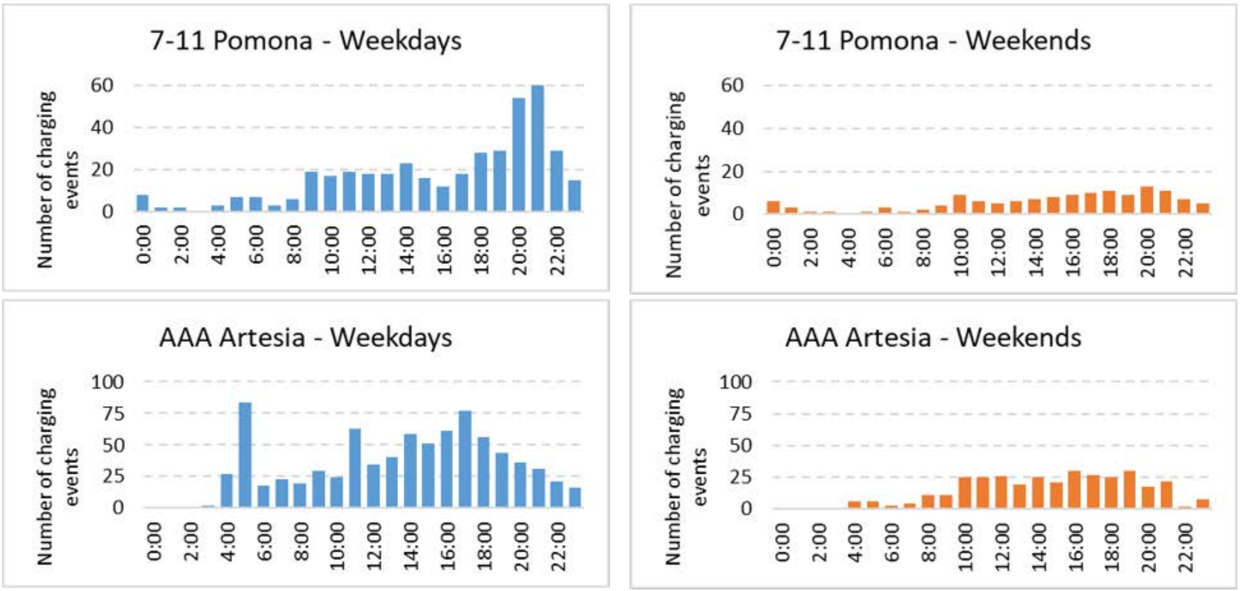


Source: EVSP Charging Session Data

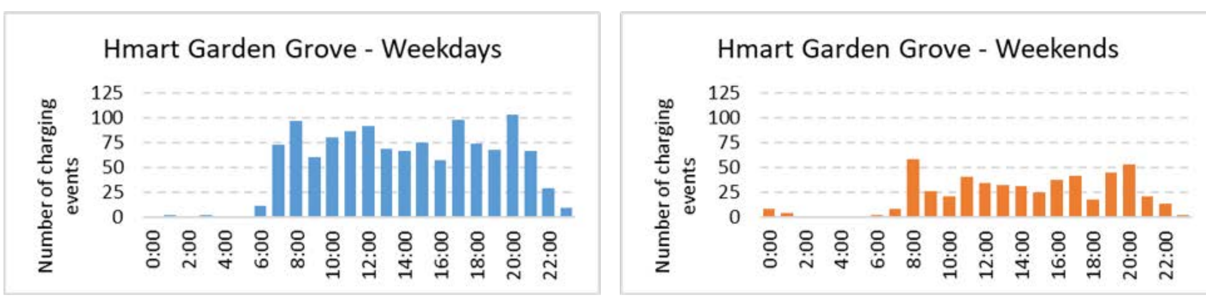
Viewing the distribution of charging session start times for each site separately (Figure 193) makes it clear that different sites experienced different periods of high use on weekdays. The Pomona site was most popular between 8 PM and 10 PM. The Artesia site peaked in the early-morning (5 AM), mid-day (11 AM), and evening (5 PM). The Corona site use was similar to Artesia but saw more significant and protracted mid-day use. The Garden Grove site had fewer early-morning users but more consistent use throughout the rest of the day on weekdays.

[58] See EV Project Electric Vehicle Charging Infrastructure Summary Report, January 2013 through December 2013

Figure 193. Time of day at the start of DCFC events (each site, entire reporting period)



Data has been removed for confidentiality reasons

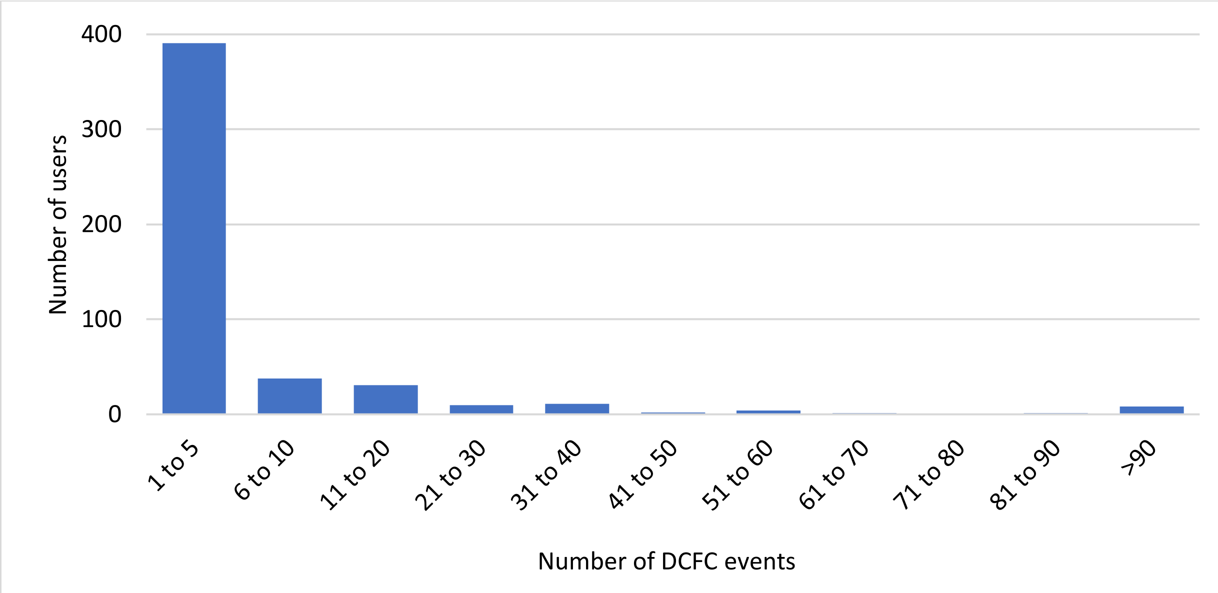


Source: EVSP Charging Session Data

Charging sessions ranged from a minute to over 6 hours, with a median duration of 25 minutes. The two inner quartiles ranged between 16 and 42 minutes.

There were 497 distinct users who charged their vehicles at these sites from October 2019 to September 2020. However, only 68 users (14%) charged more than ten times. Half of the users only charged once. Figure 194 provides the overall distribution of charging events per user.

Figure 194. Distribution of number of charging events per user (any site, October 2019–September 2020)



Source: EVSP Charging Session Data

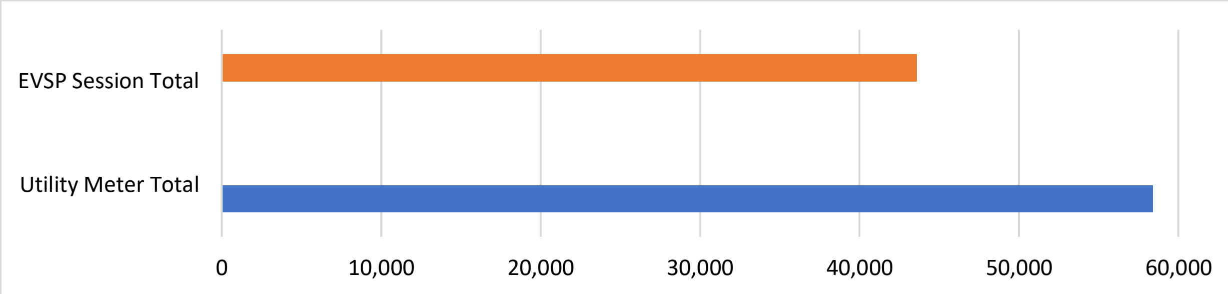
The most frequent user conducted 228 charging events between November 2019 and September 2020. This user performed between 13 and 33 charges each month, suggesting that the DCFCs at these sites were a primary source of charging for this user. The top ten most frequent users charged at one of the sites at least every third day, on average. Several of these users charged twice a day, including one user who charged twice a day on 23% of the days between their first and last charges from October 2019 to September 2020. However, there was no distinct day or time of day that the most frequent users charged at the DCFCs.

The 7-Eleven DCFC installation included a pairing kit which linked the power of the two chargers together and could provide up to 125 kW of charging power instead of up to 62.5 kW from a single charger. While there are few EVs on the market that can take advantage of this higher power, the 7-Eleven DCFCs recorded 38 charging events that had a maximum demand over 62.5 kW. Seventeen of these were noted as a Hyundai Ioniq Electric which maxed out at 68.2 kW, but there were also several others with max demand between 70 and 90 kW and 5 charging events over 100 kW maximum demand (115 being the highest individual charging event demand recorded).

Utility and EVSP Metering

Electricity dispensed to users is tracked by the EVSP and recorded as charging sessions. Electricity supplied to the chargers at the site is metered by the utility and captured through 15-minute interval data. Analyzing the totals from each of these sources between February 1, 2020 and September 30, 2020 for the four sites with charging activity there was a 25% difference as shown in Figure 195.

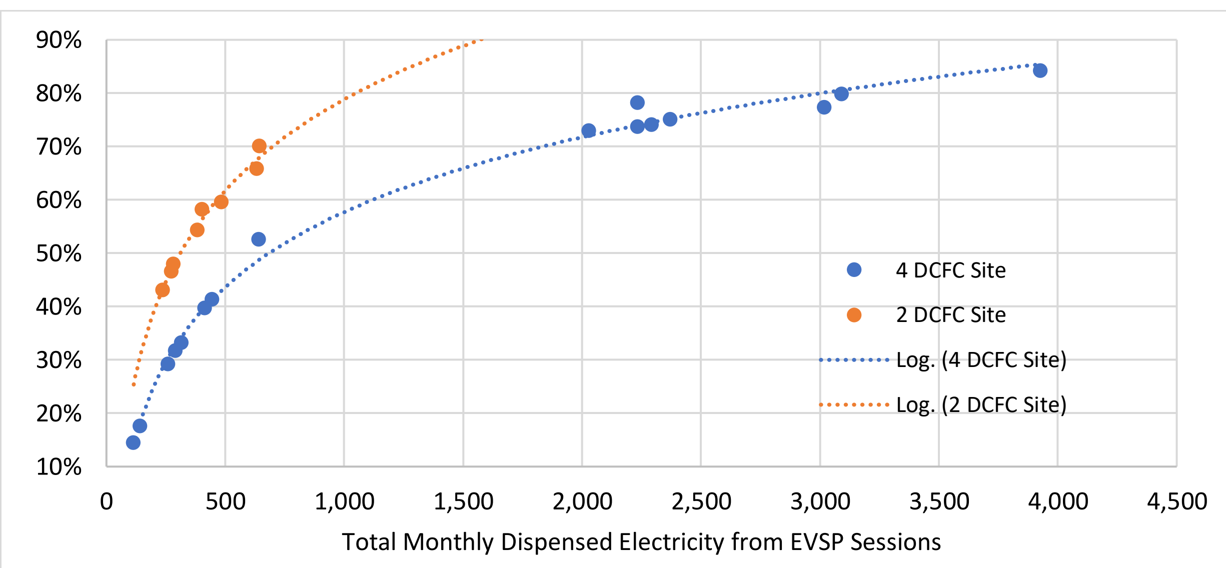
Figure 195. Electricity totals from the four active sites (February 1–September 30, 2020)



Source: SCE Meter and EVSP Charging Session Data

Some difference in measurements is expected because of varying degrees of accuracy by the meters and it might be possible a few charging sessions were inadvertently left out due to some that extended before or after this time period. However, this would not typically account for a 26% difference. Taking a closer look at the data (see Figure 196), the difference between the DCFC session and utility meter electricity totals decreases (leading to a higher percentage of alignment) as more electricity is dispensed monthly. Further analyzing the DCFC utility meter data when not charging various stand-by power draws emerge from these charging stations. At one site with 4 DCFCs, the stand-by power draw is a constant 1 kW which consumes about 720 kWh per month even if no charging occurs. At another site with 4 DCFCs, the stand-by power draw is 1.2 kWh every 1.5 hours which consumes about 600 kWh per month even if no charging occurs. At a site with 2 DCFCs, the stand-by power draw can be as low as constant 400 Watts which consumes nearly 300 kWh per month even if no charging occurs. At another site with 2 DCFCs, the stand-by power draw is 1.2 kWh every 2.5 hours which consumes about 350 kWh per month even if no charging occurs. Since this stand-by energy is a fixed amount whenever there is no charging taking place, as more charging occurs there is less stand-by time and more actual power draw due to charging sessions which results in better alignment between the session and utility meter data.

Figure 196. Alignment of charging session and utility meter electricity data



Source: SCE Meter and EVSP Charging Session Data

Participant Survey

A five-minute online user survey was provided to EV drivers that charged at these sites to explore several topics—whether access to public charging stations impacts a customer's decision to lease or purchase an EV, whether EV drivers with and without access to home charging use public stations, and how (if at all) the stations changed driving habits—as well as to assess and document the user's experience. ChargePoint issued the survey directly to users of the PRP stations within SCE's territory (277 total unique users of the PRP stations between July 1, 2020 and October 26, 2020). ChargePoint sent out email invitations via Survey Monkey to the target audience, taking a census approach. The survey was closed two weeks after the email invitation was sent, with two reminders issued during this period.

There were 41 survey respondents for which ChargePoint shared anonymized summary statistics. The evaluation findings for the SCE DCFC public access survey are presented by topic area:

- Charging station user experience and satisfaction
- Purchasing motivation and the impact of public charging station access
- Charging station usage and driving habits

User Experience and Satisfaction

Of all survey respondents, only 85% (n=35) remembered using a public charging station within the last four months. The largest percentage of respondents reported charging at AAA Artesia (n=20), followed by H Mart center in Garden Grove (n=9), 7-Eleven (n=7), Corona Sun Square (n=7), and AAA Upland (3). Five respondents (shown in Table 59) reported having used more than one public charging station location in last four months which is why the total of individual sites exceeds the total that remembered using one of these public charging stations. Fifteen percent of respondents (n=6) said they have not used any of the listed public charging stations in the last four months, despite the sample data indicating that all customers had used at least one charging station since July.

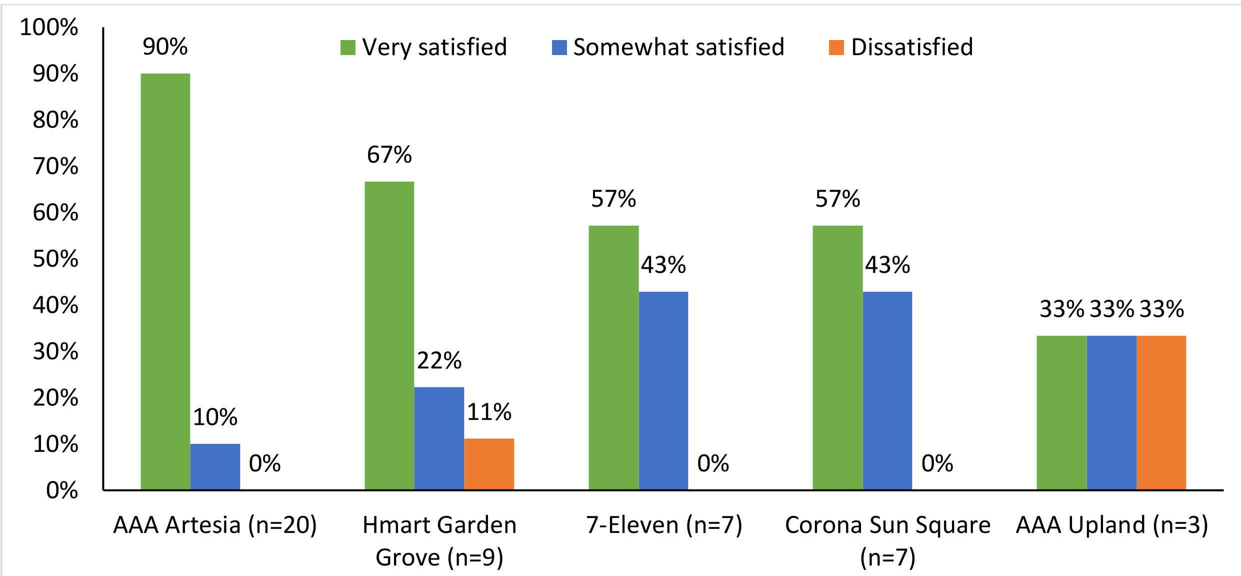
Table 59. Respondents who frequented multiple charging stations

Charging Location	Respondent 1	Respondent 2	Respondent 3	Respondent 4	Respondent 5
AAA Artesia	X	X	X	-	-
H Mart center in Garden Grove	X	X	X	-	-
7-Eleven	X	X	-	X	X
Corona Sun Square	X	X	-	X	X
AAA Upland	X	X	-	-	-

Source: SCE Public Access Survey Question 4. "At which of the following site have you charged your EV in the past four months? Select all that apply."

Of those respondents stating they have used public charging in the past four months, 94% (n=33) rated themselves as either *very satisfied* (74%) or *somewhat satisfied* (20%) with their charging station experience. Two respondents (6%) rated themselves as *dissatisfied*. Figure 197 shows respondent satisfaction with their overall experience broken out by charging station location. The H Mart center in Garden Grove and AAA Upland locations both had one respondent express dissatisfaction with their overall experience at that location. The respondent who used the H Mart center in Garden Grove location had difficultly charging their EV, while the respondent who used the AAA – Upland location cited pricing as the main driver for their dissatisfaction (which doesn't make sense because the site was free, but this was the response given).

Figure 197. Respondent satisfaction by charging station



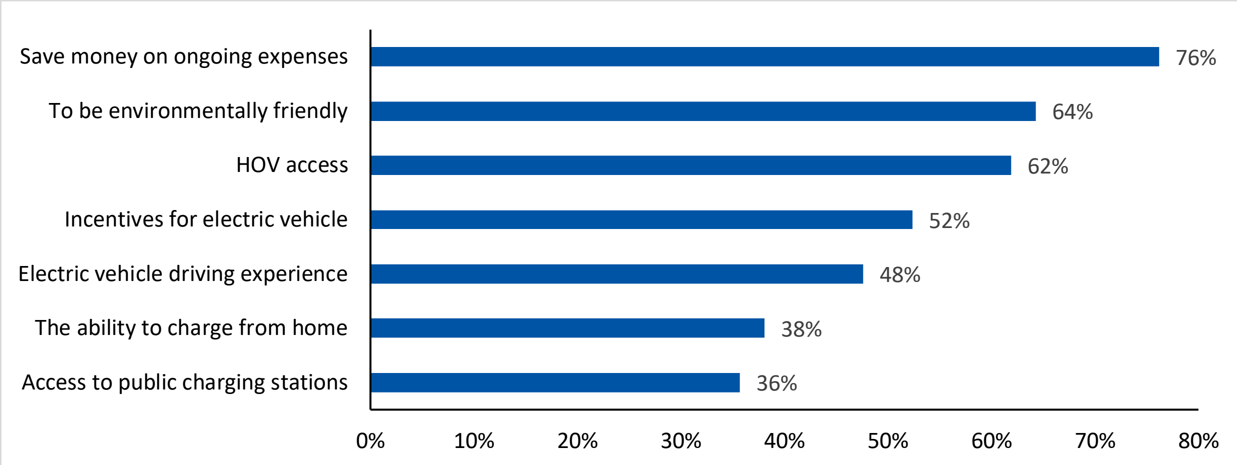
Source: SCE Public Access Survey Questions 4 and 6. "At which of the following site have you charged your EV in the past four months? Select all that apply." (n=41) and "How satisfied were you with your overall experience at the site(s) you've visited?" (n=35)

Additional feedback on driver reactions to these charging locations can be found on PlugShare, a user-based charging locator website or app. The feedback indicates that most users like and appreciate the DCFCs at these locations. Price is mentioned as a concern at the more expensive locations, while the free ones get rave reviews. A few times when the stations were not working properly are noted and several users experienced much slower charging at the AAA Artesia site in November.

Purchasing Motivations and Impact of Public Charging Station Access

Respondents could select multiple responses from seven options provided for their purchasing or leasing motivations. Most respondents (76%; n=32) were motivated by saving money, closely followed by a desire to be more environmentally friendly (64%; n=27) and high-occupancy vehicle lane access (62%; n=26). Figure 198 shows the remaining breakdown of motivations for purchasing or leasing an EV.

Figure 198. Motivations for purchasing or leasing an electric vehicle



Source: SCE Public Access Survey Question 1. "What motivated you to purchase or lease an electric vehicle?" (Multiple responses allowed; n=42)

Table 60 shows the breakdown of respondents' home parking situation compared to their motivations to purchase or lease an EV. The proportions of motivation responses are similar to the averages shown in Figure 198, particularly for users living in a single family with parking due to a high percentage of respondents (84%; n=32) falling into this category.

Table 60. Motivations for purchasing or leasing an electric vehicle by parking situation

Motivations to Purchase or Lease and EV	Single Family with Parking (n=32)	Multifamily with Parking (n=4)	Single Family without Parking (n=1)	Multifamily without Parking (n=1)
Save money on ongoing expenses	81%	75%	100%	100%
Electric vehicle driving experience	50%	75%	0%	100%
To be environmentally friendly	72%	50%	100%	0%
High-occupancy vehicle lane access	66%	50%	100%	100%
Incentives for electric vehicle	59%	25%	100%	0%
The ability to charge from home	44%	25%	0%	0%
Access to public charging stations	38%	25%	100%	0%

Source: SCE Public Access Survey Questions 1 and 11. "What motivated you to purchase or lease an electric vehicle?" (n=40) and "Please select the parking situation that most reflects your home." (n=38)

The respondents who selected access to public charging stations as a motivation to purchase or lease an EV then rated that influence. Nine of these respondents rated access to public charging as *very influential* and five rated access as *somewhat influential*. Respondents answered what specifically about having access to public charging stations influenced their decision to purchase or lease an EV. The top influencer was the convenience of public charging stations, cited by 12 respondents (Table 61).

Table 61. Public charging influencing factors by influential level

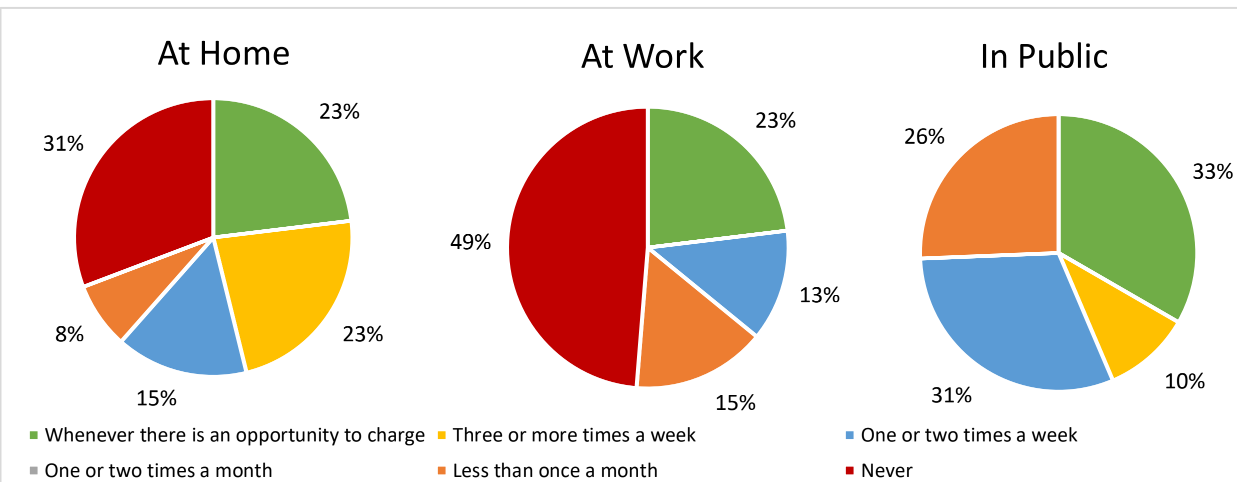
Key Public Charging Station Influences	Very Influential (n=9)	Somewhat Influential (n=5)	Total (n=14)
Public charging is convenient	9	3	**12**
There is sufficient charging at my workplace	2	3	**5**
The price of the charging session	4	1	**5**
I do not have the ability to charge at home	2	1	**3**
Availability of public charging	1	0	**1**

Source: SCE Public Access Survey Questions 2 and 3. “How influential was access to public charging stations on your decision to purchase or lease an electric vehicle?” (n=15) and “What about access to public charging stations influenced your decision to purchase or lease an electric vehicle?” (Multiple responses allowed; n=14)

Charging Station Usage and Driving Habits

At home, most respondents never charge (n=12), but those that do charge “whenever there is an opportunity to charge” (n=9) or “three or more times a week” (n=9). Almost half of the respondents don’t do any charging at work (n=19) and those that do charge at work, do so at varying frequencies. The survey targeted EV drivers that used the public PRP charging stations, but the frequency of how often these respondents use public charging differed significantly. While 33% charge in public “whenever there is an opportunity to charge” (n=13), 31% charge in public “one or two times a week” (n=12) and 26% charge in public “less than once a month” (n=10). Figure 199 shows the breakdown of stated charging frequencies at home, at work, and in public.

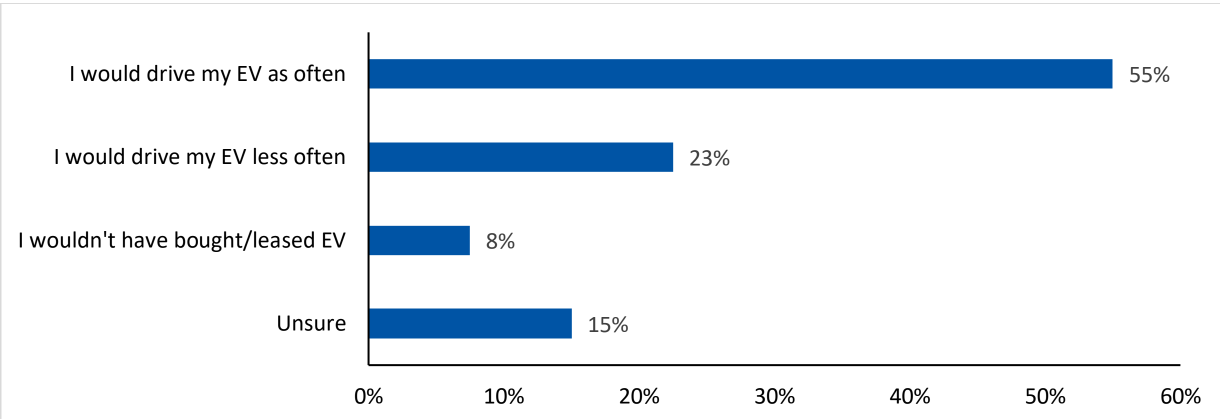
Figure 199. Charging habits by frequency and location



Source: SCE Public Access Survey Question 10. “How frequently do you typically charge your electric vehicle at home, at work, and at public charging stations: never, less than once a month, one or two times a month, one or two times a week, three or more times a week, or whenever there is an opportunity to charge?” (n=39)

Regarding the impact of respondents' EV driving habits because of the PRP public access charging stations (see Figure 200), over half (55%; n=22) said they would drive their EV as often as they currently do if these stations were not installed. However, three respondents said they would not have purchased or leased an EV if public charging stations had not been installed. Nine respondents (all but one of which previously indicated they have a home charger) said they would drive their EV less often if these PRP chargers were not available and five of those had previously indicated that access to public charging stations influenced their decision to purchase or lease an EV.

Figure 200. Change in driving habits if EV public access charging stations were not installed



Source: SCE Public Access Survey Question 8. "How influential was access to public charging stations on your decision to purchase or lease an electric vehicle?" (n=40)

4.4.4 Conclusions and Recommendations

Findings

SCE supported the installation of DCFC stations at five sites as designed. However, none of the selected sites or any that applied were willing to install ten DCFCs at their location. Therefore, instead of 50 DCFCs initially anticipated, only 14 were installed. The reduced number of chargers is reflected in the spent budget as only 45% of the original budget was used. While the spending doesn't fully align with the proportion of DCFCs installed versus anticipated, economies of scale resulting from up to 10 chargers per site were not possible.

- Recommendation: for a similar program in the future SCE could consider targeting a total number of ports without defining the number of sites. This will allow the program flexibility to maximize the budget and support increased adoption with more sites and the potential for higher port count.

Minor challenges with contracting, EVSP arrangements, and permitting caused project delays, but otherwise did not impact the outcomes. All of the required data from the EVSP and utility was obtained; however, there were significant delays in obtaining some of the data.

- Customer billing data was provided in October 2020, but one customer chose not to provide it. Billing analysis showed that one site was on an incorrect billing rate resulting in electricity bills double of what they should have been (billing was corrected for this customer account).

  - Recommendation: as part of the participation agreement customers should be required to share electricity billing data with 3rd party evaluator to support evaluation of costs. SCE has since corrected customer program participation agreements in their current pilots and programs to require customers to share billing data.

- Charging session data was provided in October 2020 (it was requested to be sent on a monthly basis as soon as the stations were committed in November 2019) because of delays in ChargePoint providing data to SCE. Having direct access to the EVSP online portal would allow collection of additional charging session data such as driver ID, driver ZIP code (to support DAC attribution), and EV battery state of charge.

  - Recommendation: as part of the participation agreement customers should be required to grant the utility and 3rd party evaluator access to their charging session data directly from their EVSPs online portal to avoid delays in receiving data. Additionally, utilities should require all EVSPs as part of their approved product list for transportation electrification programs to enable the utility and 3rd party evaluator to view and download program participants charging session data directly from their online portals based on signed customer participation agreements.

Less than 12 months of operational data were collected due to the timing of the charger commissioning. The data collection period coincided with significant driver behavior changes because of the COVID-19 pandemic. Further collection and analysis of charging station data over the next several years would provide additional insights to the PRP findings, but preliminary answers to the research questions are included below.

What barriers to electrification are being addressed, and what was the PRP's success at overcoming the barriers?

- This PRP was successful at attracting numerous potential site hosts (although they were all interested in less than the anticipated 10 DCFCs per site) that were near MUD communities, and most were in or near a DAC. The incentive to provide make-ready charging infrastructure and a rebate that often covered the full cost of the chargers and their installation attracted interest and seemed to be appreciated by the site hosts. Charger utilization is increasing and will likely continue to after the pandemic, resulting in increasing number of electric miles. Users are generally satisfied with the installations, particularly the free ones. Based on the survey responses three users (8%) would not have purchased or leased an EV without having access to public DCFCs and one user (3%) is living in a MUD without access to charging.

What is EVSE infrastructure utilization, and how does it compare with similar charging stations?

- Across the entire demonstration period for all sites, DCFC use was low (about 2.5%), but has significantly increased over time such as at AAA Artesia which reached 24% during a peak week in September. The DCFC utilization over the project period was similar to the SDG&E Electrify Local Highways PRP (2 DCFCs at 4 park and ride sites) at 2%; however, its peak week only reached 14%.

Do EV drivers with and without access to home charging use the stations?

- Based on survey responses, 31% of the respondents don't charge at home likely because they do not have home charging. In addition, about 16% of the respondents don't reside in a single-family home with a dedicated parking space. Access to public charging stations has an impact on driver behavior as 23% (n=9) of the respondents rive said they would drive their EV less often if access to public charging stations were not available.
- A significant number of BEV models do not have DCFC capability and PHEVs, most often also without DCFC capability, are a significant portion of the plug-in electric vehicle market. In this regard a rather large number of EV drivers were unable to participate in or benefit from this pilot.
    - Recommendation: to make these or similar future charging sites available to a broader EV community addition of Level 2 charging ports should be considered where appropriate to provide broader benefits.

Is the infrastructure reliable? User-friendly?

- While the charging stations have not had a lot of use or been in operation for over a year, to date there have been no reported maintenance issues. No major concerns with charger use were captured by the user survey, although a few commented on charging fees.
- Station users are highly satisfied with their public charging station experience. Overwhelmingly, 94% of respondents (n=33) were satisfied (74% very and 20% somewhat satisfied) with only two respondents dissatisfied due (one citing difficulty charging their EV and the other pricing).

Are EVs occupying the station longer than necessary and blocking others from charging?

- All charging sites reported a bit longer average connection times for EVs than their actual duration of charging. This is atypical of DCFCs where users often disconnect before reaching a 100% state of charge because the charging rate decreases significantly above 80%. Since these stations were installed, only 74 of 3,990 charge events (2%) lasted over 2 hours, with 6 events over 4 hours and one lasting over 6 hours. While 11 of the charge events lasting over 2 hours were actually charging the whole time, most vehicles are charging very slowly at that point and are likely unnecessarily occupying a station. In contrast, only 4 of the charge events over 2 hours were at sites that implemented additional time-based fees. This shows the effectiveness of time-based fees at keeping vehicles from congesting access to chargers at these locations. This method is used at other public DCFC and Level 2 charging sites and could be a strategy implored to a greater extent. Even if sites wished to continue offering charging for free, a nominal fee per hour starting after 1 hour would encourage those drivers to move on and make the charger available for others. For reference, only the largest EV batteries approach 100 kWh for which a full charging session may take nearly two hours at 50 kW or just over an hour at 100 kW.

Does EV charging station access affect customer decisions to lease or purchase EVs?

- Based on the user survey, 8% (n=3) of the users would have not leased or purchased an EV if public charging was not readily available (all three have dedicated parking at home). Access to public charging stations was a motivating factor to lease or purchase an EV for 36% of the survey respondents. They cited the convenience of public charging and the availability of public charging in the workplace as the most influential factors.

Do some sites perform better than others, and if so, what was the reasoning behind the difference?

- The H Mart center in Garden Grove site dispensed the most energy to date. This is likely due to its location in a more affluent neighborhood, in proximity to many shops and restaurants, and nearby access to Interstate 5. However, AAA Artesia dispensed more energy per DCFC (2 at this site compared to 4 at H Mart center in Garden Grove) and has surpassed the total charging electricity delivered over the past three months. This can be attributed to free charging that AAA offers which several users regularly take advantage off.

Lessons Learned

The following lessons learned were captured during the implementation of this PRP.

- Since many of the applicants for the pilot were tenants, SCE needed to work with the property owner to obtain an easement to install the make-ready infrastructure and maintain the equipment and service line. This added an additional step in securing the agreements, if all went well. Some customers were not able to obtain the necessary approval from the property owners or property managers for their sites to participate in the pilot. Three sites withdrew from the pilot during the agreement stage because the property owners refused to sign the pilot agreement and were unwilling to provide the required easements.
    - Recommendation: For similar future efforts, SCE should consider doing additional outreach to target property owners and property management companies of retail shopping centers. By targeting both property owners/management and retail businesses, SCE would likely see fewer rejections for qualified sites and an increase in adoption and higher numbers of ports at these locations.
- Most site hosts in retail venues nearby MUDs are not interested in installing more than 2 to 4 DCFCs as they take up valuable parking spaces. Retail customers requested only two ports, as they were unable or unwilling to allocate more than two or three parking stalls for the pilot. Customers that owned or managed the property were able to allocate more stalls but still typically requested only four ports. To electrify two ports, site hosts may need to give up three or four existing parking spots (since one spot must be ADA compliant).
- Activating the charging station with the EVSP and ensuring it shows up as available on their app should be a requirement before issuing a rebate. This approach would likely have motivated AAA Upland to address the activation issue several months earlier while the site was commissioned but not available for use.
- Periodic review (i.e., quarterly) of the new EV charging site host performance data (between the SCE account manager and site host representative) during the first year of operation can help ensure utilization of the charging infrastructure (preventing stranded assets) and lower the electricity cost (appropriate rate and time of use). Both of these factors are critical for maximizing the benefits for the utility and the EV drivers.
- Trenching lengths between transformers and charging stations, along with the quantity of parking spaces within reasonable reach to a charging cable vary by site. Greater access to

chargers where the cord reaches multiple parking spaces allows the next vehicle to stage and more quickly start a charge after the current one ends, or in some cases may enable the driver of the second vehicle to disconnect the charging cord from an unoccupied fully-charged vehicle to begin their own charge. This approach could potentially lead to more electric miles enabled at busy charging sites. Some DCFC models provide multiple cords that can share power as one charging station ramps down. This function will likely develop further as a means to preserve electrical capacity and enhance electrical load factor.

Scale-up Potential

California's goal to expand the light duty EV market will require significantly more charging stations. Many current EV owners can charge at home, but as ownership expands and diversifies this will change. Public charging options will be needed as the primary source of electricity for some EV owners, while others will rely on these for longer distance travel. While the survey provided some insights into who is using these DCFCs, it was limited by the few responses that could be collected over a short time frame, and a small subset of the EV market comprising only all-electric, DCFC capable vehicles. It was also not possible to link the respondents to a user ID in the charging session database which would have given further insights to regular users of these stations. Therefore, it is hard to fully understand how much these stations influenced more electric miles driven or impacted EV adoption, particularly for MUD residents which were being targeted with these installations. It will likely take years for the influence of public DCFCs to encourage significant EV adoption by drivers that can't charge at home. Even so, survey evidence suggests that demographic was served by these stations. Also, based on the utilization, particularly from the stations with a charging fee (in which drivers are typically paying higher fees than they would by charging at home), there is a clear demand for public DCFCs in locations like these.

4.5 Charge Ready Home Installation Rebate Program

4.5.1 Project Narrative

Overview, Objectives, and Barriers Being Addressed

Southern California Edison (SCE) staff designed the Charge Ready Home Installation Rebate Program (CRHIRP) to help new electric vehicle (EV) drivers offset the electrical and permitting costs of installing an alternating current Level 2 (L2) home electric vehicle supply equipment (EVSE) (commonly referred to as a "charging station"). Eligible electrical costs included the installation of a new 240 V circuit and breaker, along with a new or upgraded electrical panel if needed but excluded the cost of the L2 charging station itself.

Staff identified a lack of access to reliable daily charging stations as a key barrier to EV adoption.[59] By lowering the cost of installing L2 home charging stations, the CRHIRP should encourage more residential customers to purchase EVs. Staff also sought to learn about L2 home charging needs, costs associated with home EV infrastructure upgrades, customer behavior after installing L2 home charging, and customer satisfaction with residential TOU rates.

Through the CRHIRP, SCE offered two levels of rebates to eligible customers. To be eligible for either rebate, customers had to be California-registered EV drivers who purchased or leased an EV listed on the High-Occupancy Vehicle (HOV) Eligibility List[60] within six months prior to submitting their rebate applications. In addition, customers had to have a dedicated parking space for the vehicle. Finally, for either rebate, customers had to provide copies of all required permits obtained and receipts for the installation of the charging station by an electrical contractor with a C-10 license or licensed electrician. Finally, each customer had to agree that SCE may complete random spot checks at the customer residence to confirm that the work was performed.

Once eligible, SCE customers could apply for one of two rebates:

- **$500** for customers who enrolled in SCE's whole-home time-of-use (TOU) program.
- **$1,500** for customers who installed a meter specifically for the EV charging station to participate in SCE's TOU-EV-1 rate (applied only to the EV charging) for at least 24 months.

SCE contracted with a third-party administrator, the Center for Sustainable Energy (CSE, or the Center), to manage application processing, rebate distribution, major marketing activities, customer support, and an online application portal. CSE provided regular updates to SCE (weekly during the launch and beginning of the program, then biweekly thereafter) regarding program participation statistics throughout the priority review project (PRP) duration (May 2018–May 2019).

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[59] "Charge Ready Home Installation Rebate Pilot 2018 Interim Report." Issued January 31, 2019, by Anna Valdberg and Andrea L. Tozer, attorneys for Southern California Edison Company.

[60] The HOV Eligibility List can be found on https://ww2.arb.ca.gov/carpool-stickers. Note: electric bikes, motorcycles, scooters, and neighborhood vehicles are not eligible for the rebate.

Participation

Recruitment Process

Because CSE also manages the Clean Vehicle Rebate Project (CVRP),[61] staff easily cross-promoted CRHIRP to CVRP participants who opted in to receive more information about EV rebates. Each of these opt-in CVRP participants received at least one email about the CRHIRP. Over the course of the CRHIRP period, 57% (26,709 out of 45,697)[62] of opt-in CVRP participants opened these emails, and 676 submitted rebate applications. The Center considered the email outreach to be the single most successful recruitment process for the CRHIRP.

As another primary CRHIRP marketing strategy, CSE staff set up information booths at local events within SCE territory where potential EV owners were likely to attend. These events included auto shows, home improvement shows, large community events or festivals, and Earth Day events. In particular, the Center prioritized events that would have attendance by a higher proportion of residents living in disadvantaged communities (DACs). At each of these events, CSE staff held conversations with individuals in English and Spanish and distributed program materials. By the end of the program period, CSE marketed at 71 events, 56% (40 out of 71) of which were in DACs.

In addition to managing the direct email outreach to CVRP participants and attending local events, CSE also conducted outreach to electricians, labor unions, car dealerships, automakers, and DAC property managers. Outreach also included focused targeting of car dealerships within DACs. Overall, CSE staff found these initiatives to be less effective. CSE staff also reported that DAC property managers indicated that their residents had higher-priority concerns than EV adoption.

Finally, SCE completed some minor outreach through its general marketing efforts to promote EV adoption and installation of home charging stations.

Participants

In total, SCE received 4,128 applications over the course of the program period. The applications for the increased $1,500 rebate closed on February 28, 2019, because SCE discontinued the TOU-EV-1 rate. Participants already enrolled in the rate will continue to be enrolled for the duration of their agreements (24 months). CSE approved 2,670 of those applications, providing a 65% approval rate. A total of 17% (713 out of 4,128) of the applications were considered ineligible, and 18% (745 of 4,128) were cancelled by customers.[63] Applicants reported average permit costs of $191 and average installation costs of $1,190. Other application details—including DAC status, resident type, and EV make—are presented in Figure 201 below.

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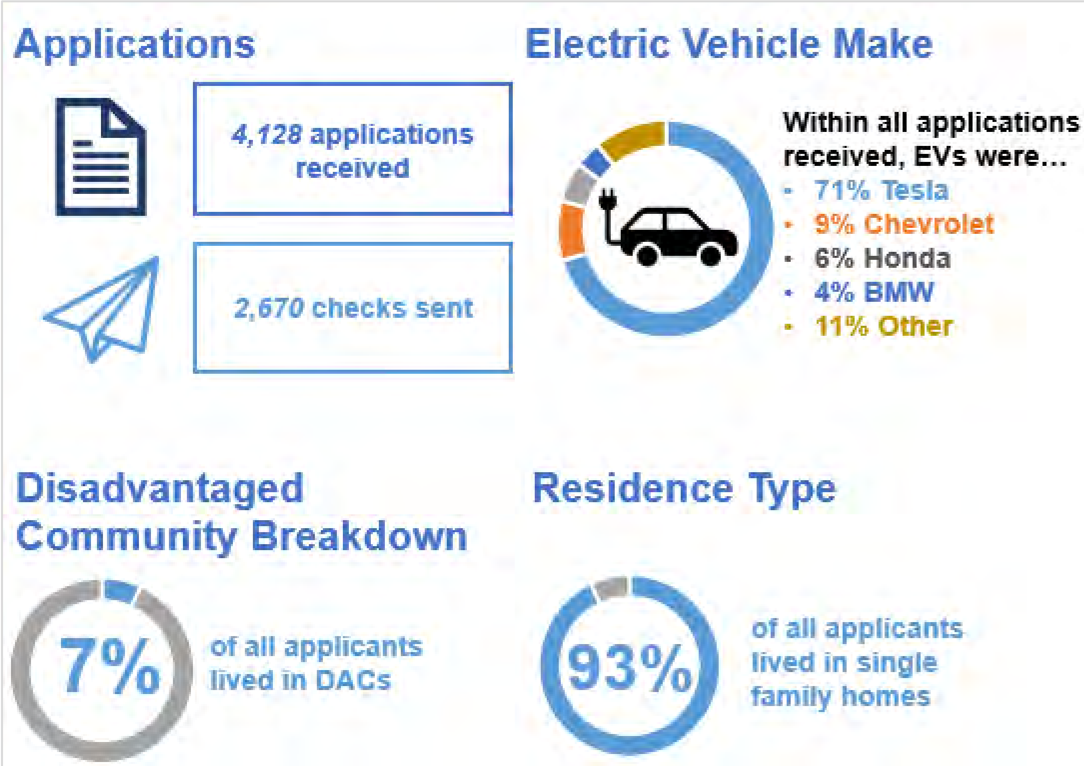
[61] The CVRP allows California residents to receive up to $7,000 for the purchase or lease of a new eligible zero-emission or plug-in hybrid light-duty vehicle (https://cleanvehiclerebate.org/eng).

[62] Source: CSE Marketing tracking data.

[63] Metrics are as of August 30, 2019.

Figure 201. Participant and application data



Source: CSE Final Dashboard (Application) Data. Percentages do not add up to 100% because of rounding.

Timeline and Status

The CPUC approved the CRHIRP in January 2018. In March 2018, SCE contracted with CSE to develop the marketing plan, application processing operations, website, and online application portal. The online application portal opened to the public on May 30, 2018, and the pilot accepted applications through May 29, 2019. The pilot was completed in early 2020 when the final participant checks were cashed and any unclaimed rebates returned.

4.5.2 Evaluation Methodology

Selected Methods and Rationale

In addition to the evaluation questions that apply to all PRPs and those specific to the Education and Outreach PRPs, the evaluation questions listed below will be examined for this PRP.

- Are customers aware of permitting requirements?
- At what stages do customers drop out, and what causes customer attrition during the application process?

The data collection sources utilized to evaluate this PRP include 1) PRP documents and application dashboard data, 2) SCE and implementer interviews, and 3) the SCE participant survey.

Data Sources

The evaluator collected PRP information through numerous interactions, including the PRP kick-off meeting, quarterly PAC update meetings, and other periodic calls or emails. In addition, the evaluation team examined the following data sources: application dashboard data (e.g., days accrued between steps taken in the application process and the number of applicants at each stage), presentations and interim reports, marketing activities executed by the third-party administrator, and the SCE participant survey results.

The evaluator also conducted IDIs with representatives from the SCE PRP management team and the implementer to further understand the background on this project, identify roles and responsibilities, assess stakeholder (SCE and implementer) experience in program delivery, and gather lessons learned.

4.5.3 Evaluation Findings

The evaluation findings presented in this interim report are based on the SCE and CSE staff interviews, SCE administered participant survey, and program document and data review.

Implementation Process

To execute the program, CSE managed the marketing, application, and rebate distribution processes with SCE assistance and oversight. CSE created the program webpage and custom online application. The Center also processed the submitted applications and verified that all eligibility requirements were met before issuing the rebate check. If an applicant failed to provide any information, CSE staff followed up to notify the applicant about what was missing and to offer help, if needed.

CSE provided biweekly status updates to keep SCE up to date on the program's progress. To provide transparent data to SCE, CSE staff members developed the program's online dashboard, which delivered key information to SCE. SCE staff could access the dashboard on demand to view details about the number of applications at each stage (e.g., approved, check sent, canceled), average processing times, residence types, percentage of DAC participants, and types of vehicles.

Overall, CSE staff indicated that program implementation went well. However, extensive application requirements caused delays throughout the implementation process. SCE considered all application requirements necessary to ensure participant safety and legality during the installation of the L2 charging stations. However, SCE staff recognized that the six-month time limit to submit an application following an EV purchase or lease may have limited the number of eligible participants, given that an individual may need more time to determine whether he or she needs or wants a home charging station.

The application required six to nine separate documents (depending on applicable requirements such as Homeowners' Association (HOA) approval), with specific details for each kind of document. For example, the invoice from the electrician had to have the C-10 license number listed. This delayed applications for some applicants who had to request new invoices from their electricians. Similar problems arose for individuals who did not need permission from their HOA or housing jurisdiction to install the charger but were still required to provide formal documentation of HOA exemption. Occasionally, an applicant had charging station costs embedded in the price of the vehicle and was unable to provide a separate receipt for the cost of the charging station. SCE staff noted that these application requirements may have also contributed to the program's higher-than-expected drop-out rate (18%, 745 out of 4,128). Anecdotally, CSE and SCE staff reported receiving feedback from customers who chose not to participate because they did not use C-10 licensed electricians or did not have the proper permits to install their L2 charging stations.

Additionally, the application required that customers enroll in an active TOU rate plan. This meant that a participant could not complete the application until his or her bill reflected the TOU rate. The delayed application submission combined with some SCE processing staff limitations (including waiting for the TOU rate to be in effect) to cause a one- to two-month delay in application approval.

Costs

Comparison of Actual and Forecast Costs

The approved PRP had an anticipated total cost of $3,999,000. The final PRP costs totaled $2,096,597, as shown in Table 62, based on SCE data. The outreach and education materials category includes O&M non-labor and third-party administrator contract cost.

Table 62. Final SCE Charge Ready Home Installation Rebate program PRP costs

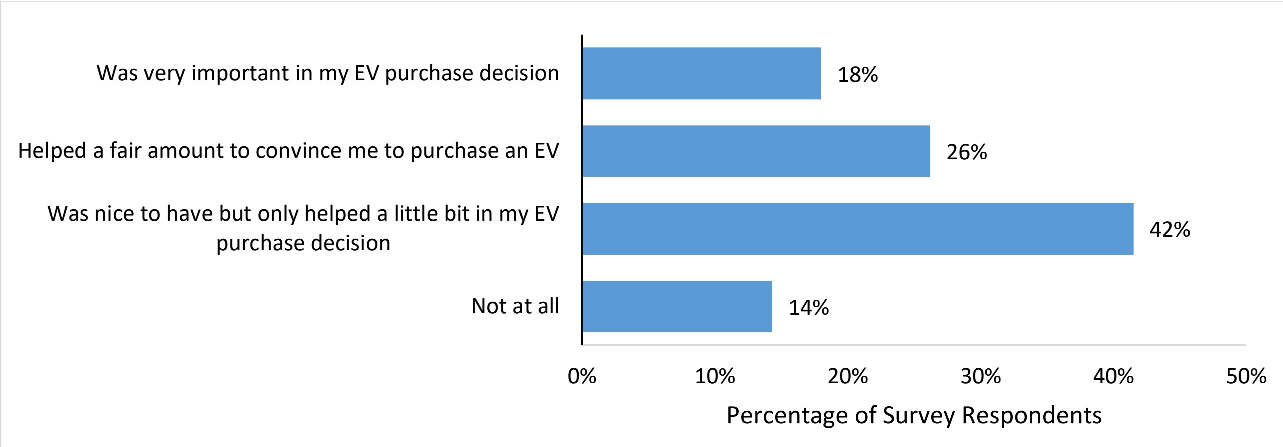
Cost Category	Actual SCE Costs	Budgeted SCE Costs
Site assessment, design, and permitting	N/A	N/A
Rebate amount paid	$1,399,033	$2,880,000
EVSE procurement (Subject to change)	N/A	N/A
EVSE installation (Subject to change)	N/A	N/A
Make-ready infrastructure (utility side)	N/A	N/A
Make-ready infrastructure (customer side)	N/A	N/A
Other construction costs	N/A	N/A
Project management	$83,765	$262,068
Customer outreach (labor)	N/A	N/A
Outreach and education materials	$613,799	$856,932
Other program costs	N/A	N/A
Total Costs	$2,096,597	$3,999,000

Stakeholder and Customer Feedback

Addressing Customer Barriers to Electrification

SCE and CSE staff reported that the program was successful at overcoming the cost barrier for installing charging infrastructure. Two data sources support their statement. In the rebate application, 70% (2,661 out of 3,785) of all applicants who answered the question indicated that the rebate **had an influence** on their decision to purchase an EV.[64] In the survey, 44% (474 out of 1,072) of respondents indicated the rebate **was important to** their decision to purchase an EV. (Note the different population and different wording and see Figure 202 for the survey question results.)

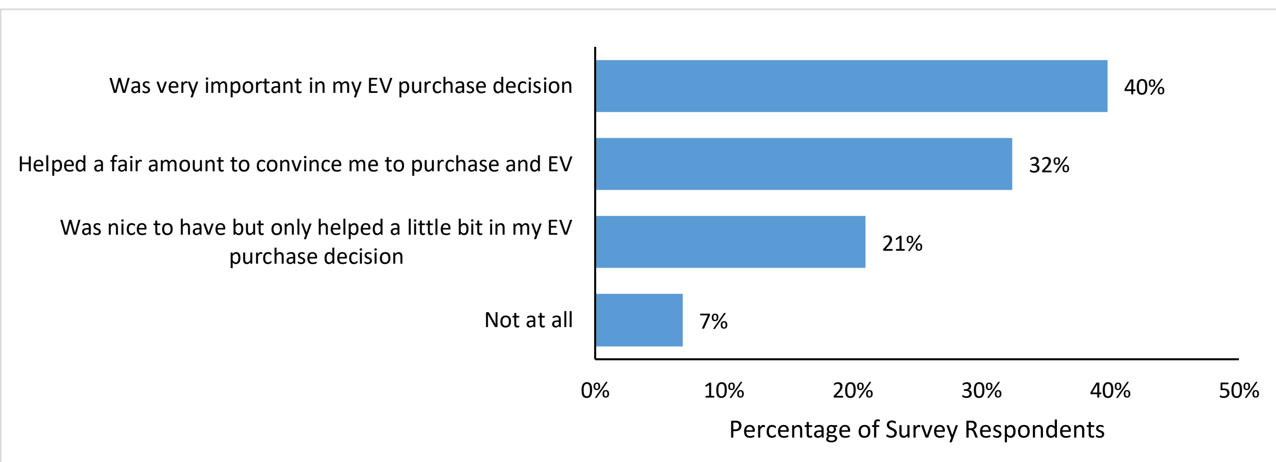
Figure 202. Rebate influence on EV purchase



Source: Participant Survey Question 6: "How much did this rebate influence you to purchase an electric vehicle?" (n= 1,072)

Unless otherwise noted, the remainder of the statistics provided in this section refer to responses from the participant surveys. A total of 93% of survey respondents (998 out of 1,071) indicated that the program had at least some influence over their decision to install an L2 home charging station (Figure 203).

Figure 203. Rebate influence on L2 charger purchase



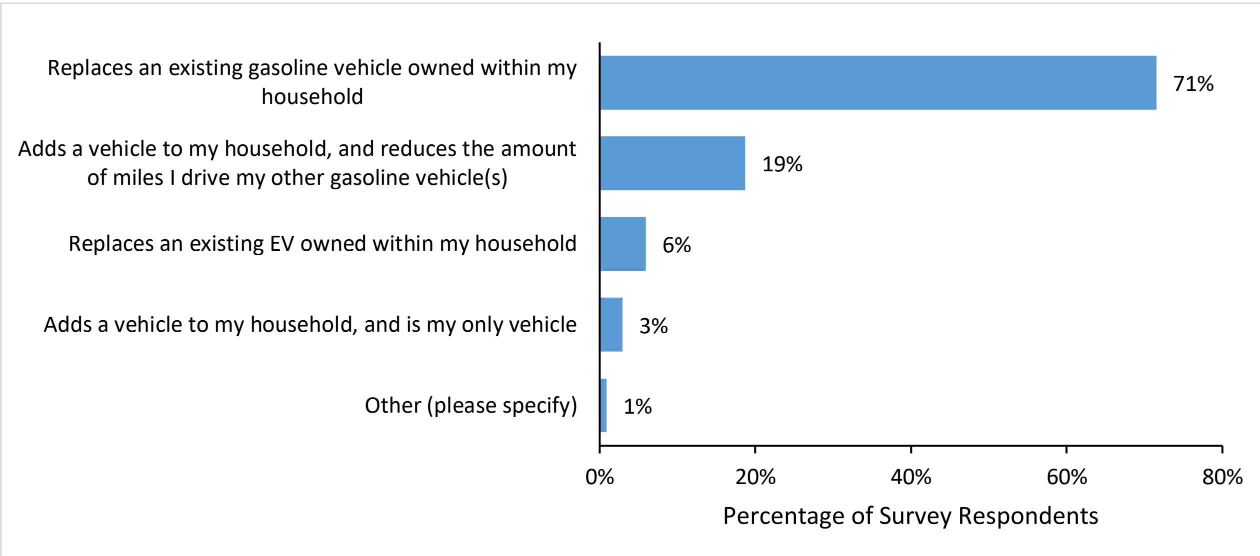
Source: Participant Survey Question 7: "How much did this rebate influence you to install an L2 home charging station?" (n=1,071)

[64] As noted above, the applicants include successful rebate recipients, dropouts, and ineligible customers.

Perceived Net Impacts

As shown in Figure 204, survey respondents commonly reported that they replaced an existing gasoline vehicle (71%, 627 out of 877) or added an EV to the household (19%, 164 out of 877), which reduces the number of miles they drive in their other vehicle(s) fueled by gasoline. Three of the eight survey respondents who answered *Other* to this question already had at least one EV and were adding another.

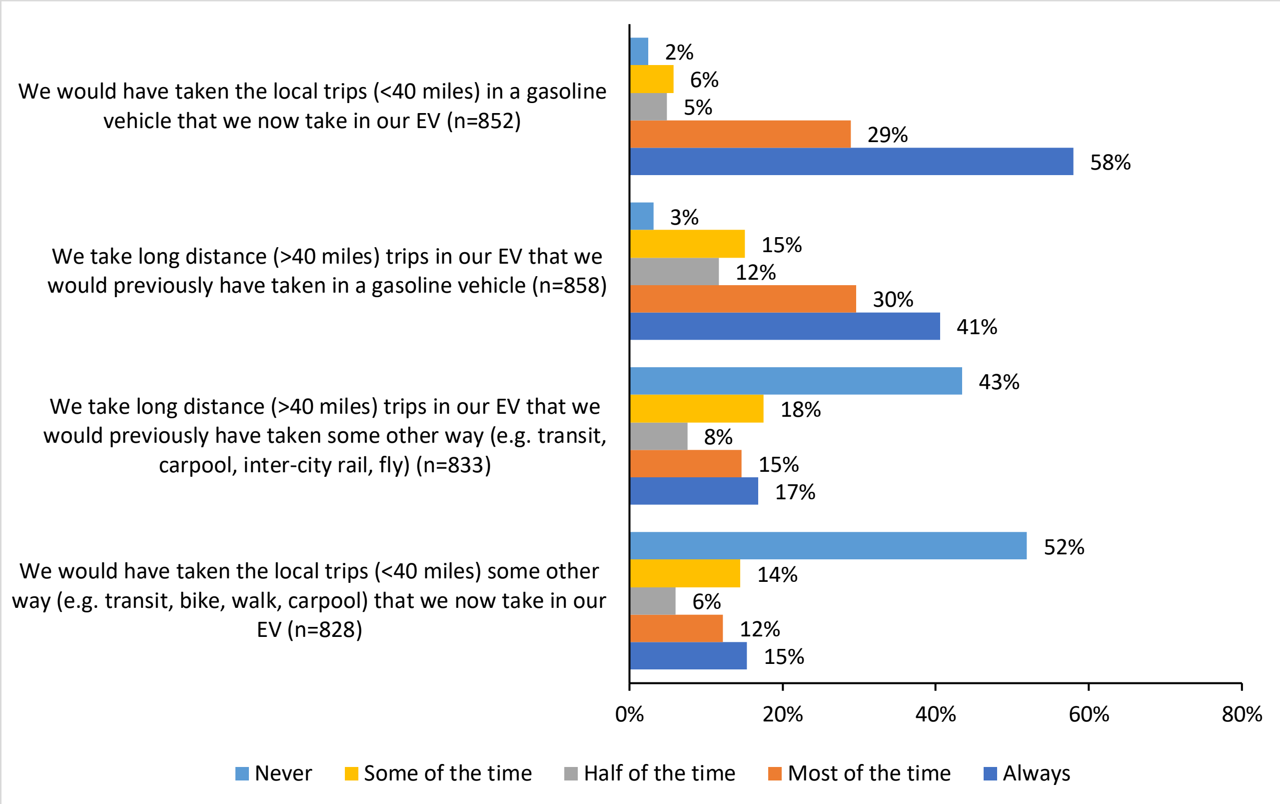
Figure 204. EV purchase description



Source: Participant Survey Question 26: “Which of the following best describes your EV purchase?” (n=877)

Many survey respondents reported that they always take their EVs on local (58%, 494 out of 852) or long-distance (41%, 348 out of 858) trips that they would have previously taken in their gasoline vehicles. In addition, customers indicated to SCE and CSE staff that increased flexibility and convenience in charging (being able to charge at home with the L2 charging station) has allowed them to use their EVs more often. However, as shown in Figure 205, many survey respondents also indicated they used EVs for local or long-distance trips that they previously would have taken using another mode of transportation, such as walking, biking, public transit, carpool, or flying, which may have either a positive or negative emissions impact.

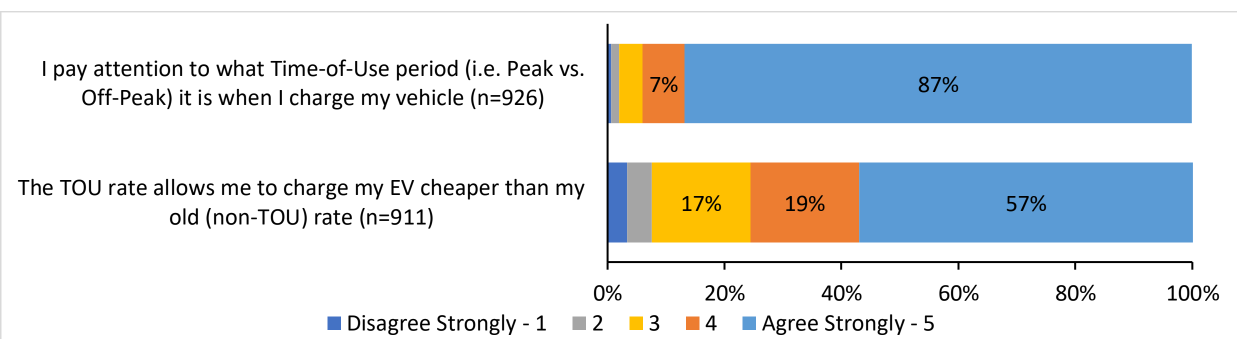
Figure 205. EV influence on travel behaviors



Source: Participant Survey Question 27: "How often are the following statements true about your household travel?"

Installing an L2 charging station can affect a customer's charging and driving habits. Because the program requires the applicant to enroll in a TOU rate, charging timing and cost can also change. Most survey respondents (57%, 520 out of 911) strongly believed that enrolling in the TOU rate allowed them to charge their EVs for less than under their old non-TOU rate. Additionally, survey respondents reported that they pay attention to the TOU period (on-peak versus off-peak) when they charge their EVs (94%, 803 out of 926; Figure 206).

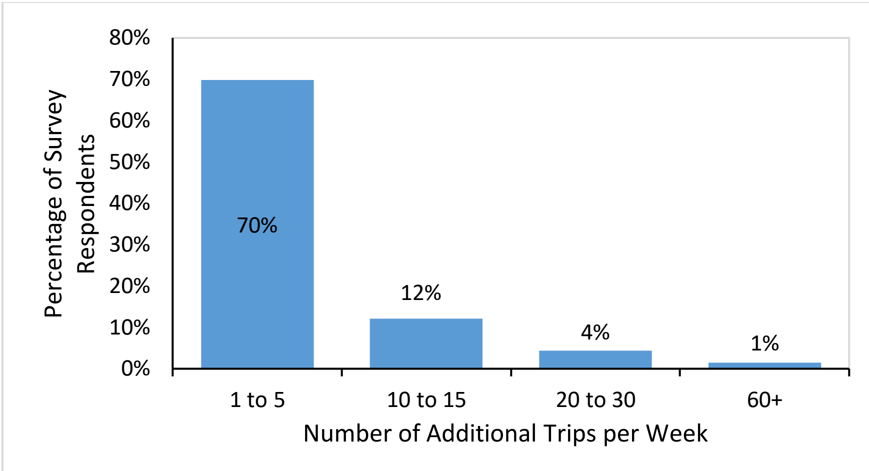
Figure 206. Charging and cost changes from TOU rate



Source: Participant Survey Question 11: "Please rate how much you agree or disagree with each of the following statements about the Time-of-Use (TOU) rate you are on."

Most survey respondents reported taking an increased number of trips in their EVs after installing their L2 charging stations (52%, 447 out of 862). Of those who increased the number of trips, most added one to five additional EV trips (70%, 283 out of 405) per week (Figure 207).[65,66]

Figure 207. Number of additional trips per week



Source: Participant Survey Question 31: "How many additional trips in your electric vehicle per week do you take now? Please enter a numerical response." (n=405)

Perceived Co-Benefits

SCE staff, CSE staff, and survey respondents all recognized that the program promoted several co-benefits, such as lowering the cost of installing a charging station, imparting education about at-home charging, and providing the convenience of charging at home.

Within the application, applicants were asked to identify one factor that described why they acquired EVs. Figure 208 shows that most applicants wanted to save money on fuel costs (32%, 1,278 out of 3,995) or decrease their environmental impacts (29%, 1,159 out of 3,995). Note that this statistic is associated with the overall applicant pool, rather than the survey respondents.

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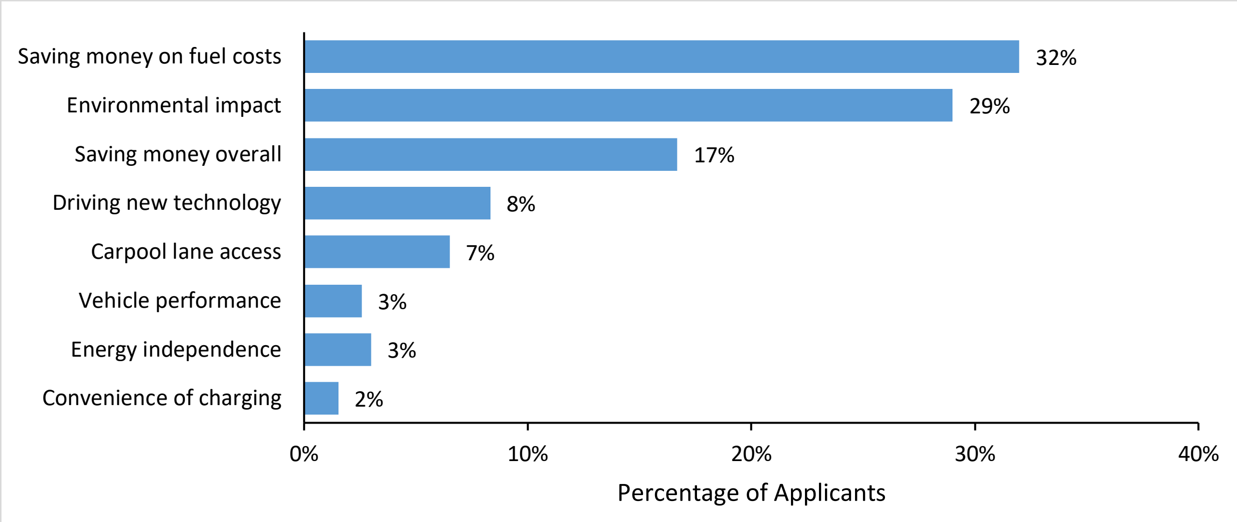
[65] Though this question was only asked to individuals who indicated they take additional trips in their EVs, when asked to specify, 25 (6%, 25 out of 430) indicated they take zero additional trips. These individuals have been excluded from the total numbers and percentages in the text above.

[66] Six individuals noted that they take more than 60 additional trips per week. The evaluation team hypothesizes these individuals could be drivers for ride-share services.

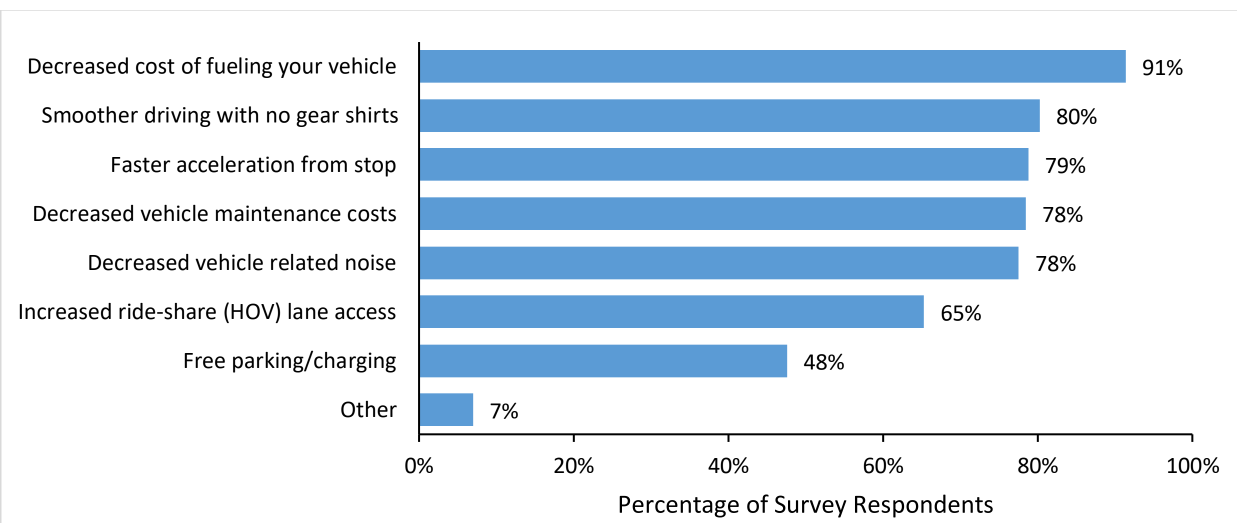
Figure 208. Motivation for purchasing an EV



Source: Application Data (n=3,995)

Survey respondents reported the benefits they experienced from a list of seven co-benefits that could result from purchasing an EV (Figure 209). Most survey respondents experienced six of the seven: decreased fuel costs (91%, 806 out of 882), smoother driving with no gear shifts (80%, 708 out of 882), faster acceleration from stop (79%, 695 out of 882), decreased vehicle maintenance costs (78%, 692 out of 882), decreased vehicle-related noise (78%, 684 out of 882), and increased ride-share lane access (65%, 577 out of 882). "Other" reported benefits included increased safety or advanced technology features (19 survey respondents), better overall driving experience (17 survey respondents), creating less pollution/having a positive environmental impact (16 survey respondents), and fewer trips to gas stations (9 survey respondents).

Figure 209. Benefits experienced as a result of EV purchase



Source: Participant Survey Question 28: "Have you experienced any of the following as a result of purchasing your electric vehicle?" (n=882, multiple responses allowed)

In addition to participant co-benefits, SCE staff designed the program to prioritize benefits to individuals living in DACs. The PRP had a goal of 50% of the rebate funds going toward applicants in DACs. To achieve this, CSE staff prioritized DAC marketing tactics, including attending events with English- and Spanish-speaking staff and talking to businesses, property managers, and contractors within DACs. Despite these efforts, only 7% (278 of 4,128) of all applications came from individuals living in DACs. SCE and CSE staff found that many individuals within DACs live in MUDs. These individuals often do not have dedicated parking spaces or may not pay their electric bills directly, both of which were requirements for rebate eligibility. Additionally, CSE staff received feedback from DAC property managers indicating that "residents have bigger problems than EVs."

Stakeholder Experience

CSE staff expressed an overall positive experience working with SCE staff. Additionally, Center staff appreciated that SCE was open and receptive to feedback and solicited input, as appropriate, throughout the program period.

However, in their final lessons learned memo, CSE staff identified some program challenges, such as difficulty transitioning applicants to the TOU rate, especially the TOU-EV-1 rate, which was discontinued in the middle of the program. CSE reported that it was difficult to provide customers with accurate status updates regarding their TOU rates because the Center did not have a specific point of contact at SCE for such questions and because the Center did not have direct access to customer data. Additionally, CSE indicated that information relayed to customers about the program's timeline and requirements was sometimes "lost in translation" with the SCE customer call center. In an attempt to minimize the impact of this "translation" issue, SCE staff instructed customer call center employees to refer customers inquiring about application requirements directly to CSE.

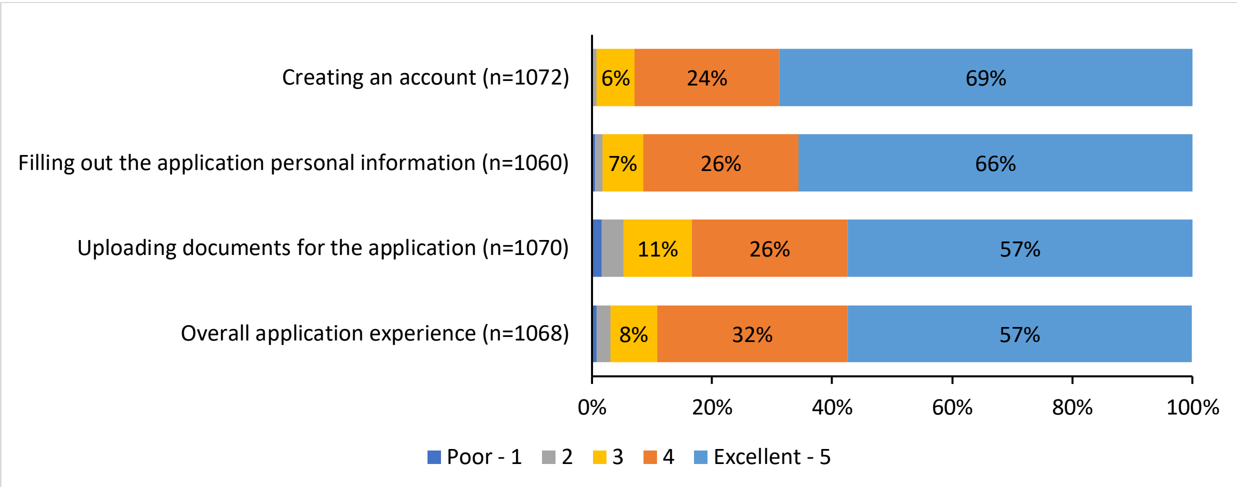
Customer Program Experience

Overall, from the perspectives of CSE and SCE staff, as well as from the survey respondents themselves, customers were generally satisfied with the program. However, CSE staff reported that the permitting process often confused applicants. Requirements from cities and towns could be unclear, and CSE had limited resources to help assist applicants from all the numerous jurisdictions. Additionally, issues with inconsistent invoicing and receipts from car dealerships and electricians, permission inquiries to HOAs, and lag time for TOU rates to go into effect made it difficult for applicants to complete their applications in a timely manner. It should be noted, however, that most of the applicants with whom CSE staff directly interacted were more likely to be the ones with problems because those were the applicants reaching out to CSE for assistance.

Survey respondents answered several questions about their satisfaction with the program and individual components of the program on a scale of *1* (*poor*) to *5* (*excellent*). Most survey respondents reported having a positive experience with the program overall (92%, 1,030 out of 1,128). A small minority of the dissatisfied respondents cited specific drivers of their dissatisfaction, the most common being the complexity of the application process (14 survey respondents). Other issues stemmed from customer service (8 survey respondents), lengthy rebate delivery time (5 survey respondents), length of time to switch to the TOU (2 survey respondents), and an increase in the electricity bill since the start of program participation (1 survey respondent).

Within the application process, most survey respondents had an excellent experience creating an account (69%, 738 out of 1,072), filling out the application with personal information (66%, 695 out of 1,060), uploading documents for the application (57%, 614 out of 1,070), and the overall application experience (57%, 612 out of 1,068) (see Figure 210).

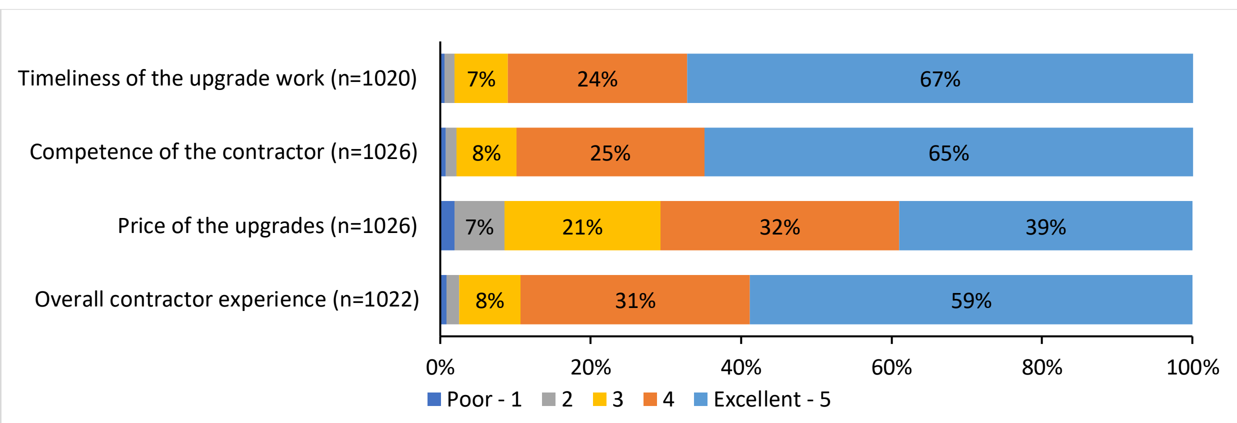
Figure 210. Participant experience with application



Source: Participant Survey Question 2: “How would you rate the following aspects of applying for the rebate?”

The majority of survey respondents also found most aspects of their electrical upgrade contractor experience to be *excellent*: timeliness of the upgrade work (67%, 686 out of 1,020), competence of the contractor (65%, 667 out of 1,026), and overall contractor experience (59%, 601 out of 1,022); however, respondents did identify some room for improvement with price (Figure 211).

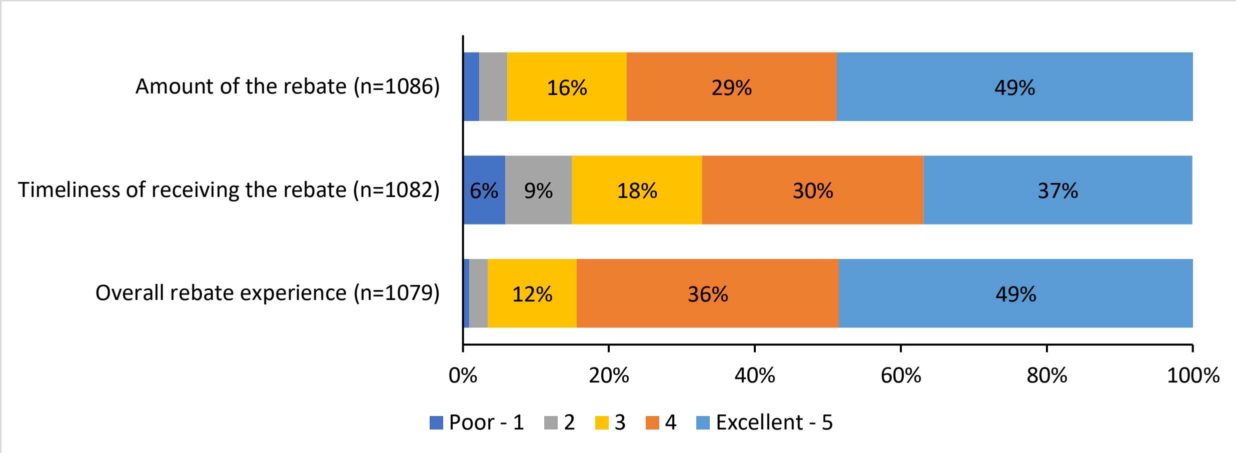
Figure 211. Participant experience with contractor



Source: Participant Survey Question 3: “How would you rate the following aspects of your electrical upgrade contractor experience?”

In addition, survey respondents reported as *excellent* the amount of the rebate (49%, 530 out of 1,086) and the timeliness of receiving the rebate (37%, 398 out of 1,082). Overall, almost half of survey respondents (49%, 523 out of 1,079) had an *excellent* rebate experience (see Figure 212).

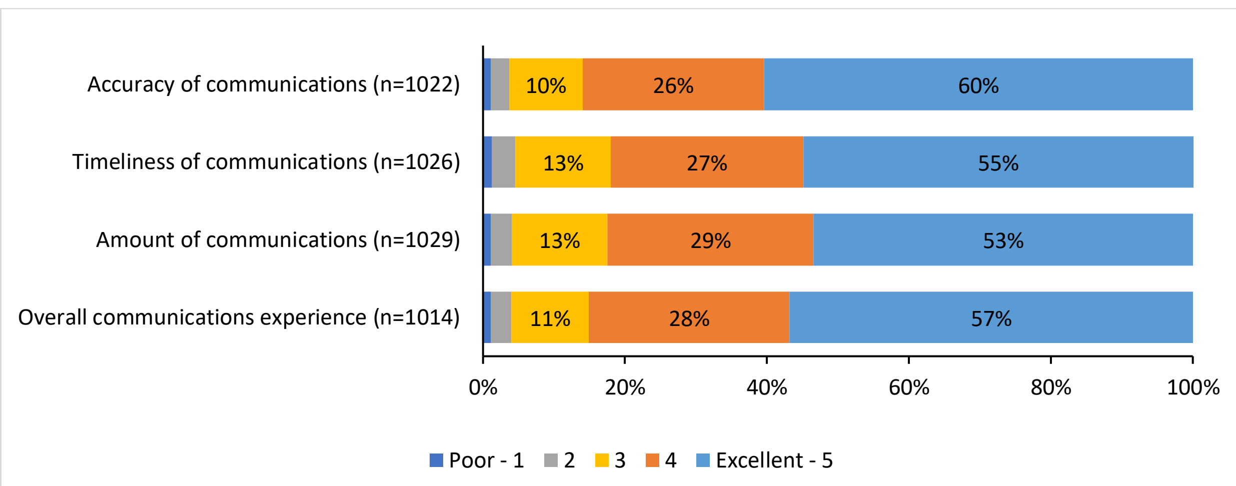
Figure 212. Participant experience with rebate



Source: Participant Survey Question 4: “How would you rate the following aspects of the rebate itself?”

More than half the survey respondents found all aspects of the communication process to be *excellent*: accuracy of communications (60%, 617 out of 1,022), timeliness of communications (55%, 564 out of 1,026), amount of communications (53%, 550 out of 1,029), and the overall communications experience (57%, 576 out of 1,014) (see Figure 213). Additionally, the majority of survey respondents had *excellent* experiences with SCE’s customer service (60%, 353 out of 588).

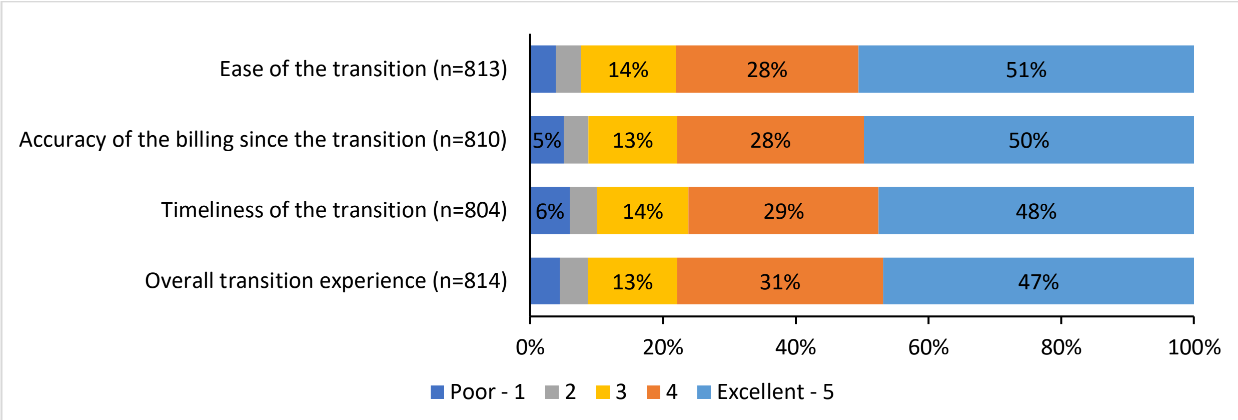
Figure 213. Participant experience with communications



Source: Participant Survey Question 5: “How would you rate the communications throughout the process?”

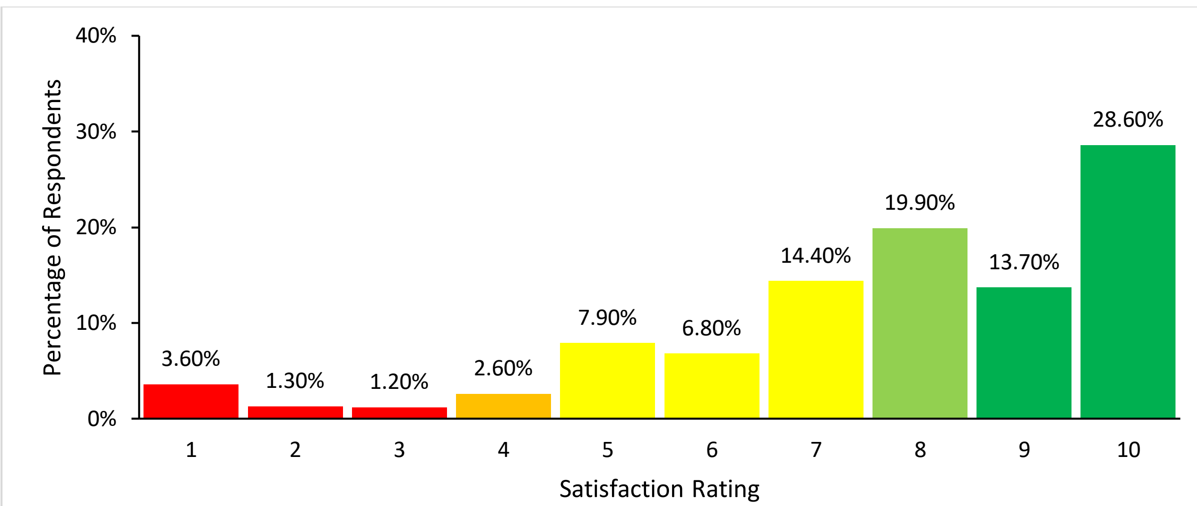
Most survey respondents transitioned to the TOU rate as a part of the application process. Of those that did transition, 51% (411 out of 813) had excellent experiences with the ease of transition and the accuracy of billing after the transition (50%, 403 out of 810). Many survey respondents also had excellent experiences with the timeliness of the transition (48%, 382 out of 804) and the overall transition experience (47%, 381 out of 814) (see Figure 214). Overall, survey respondents reported being satisfied with their TOU rates, with 62% (601 out of 967) providing a rating of 8 or higher on a scale of 1 (*extremely dissatisfied*) to 10 (*extremely satisfied*) (see Figure 215).

Figure 214. Participant experience with TOU transition



Source: Participant Survey Question 14: "How would you rate the following aspects of the transition to a Time-of-Use rate (TOU) as part of the rebate process?"

Figure 215. Overall participant satisfaction with TOU rate



Source: Participant Survey Question 15: "Overall, how would you rate your satisfaction with the Time-of-Use rate plan your household is on?"

Finally, most survey respondents reported that it was easy to find a qualified electrician to install the charging station (70%, 638 out of 908) and complete the permitting process (58%, 524 out of 901). However, when asked what SCE could do to help address their difficulties with these aspects of the program, 30% (65 out of 218) of survey respondents complained that city permitting is an arduous, expensive process that is not always necessary when work is done by a licensed electrician, and they requested relaxed permitting requirements. A total of 14% (30 out of 218) of survey respondents indicated that providing a preferred list of contractors by area would have been helpful when they were looking for trustworthy electricians. Finally, some individuals with HOAs would like to see more flexible HOA requirements (14%, 31 out of 218). CSE staff and eight survey respondents noted that HOAs were often confused by survey respondents' requests because charging stations were installed inside garages, where HOAs typically do not have jurisdiction. Some survey respondents provided feedback on other aspects of the program, such as providing better program communication (12%, 27 out of 218), improving the TOU rate (11%, 25 out of 218), increasing the amount of the rebate (5%, ten out of 218), delivering the rebate faster (4%, eight out of 218), or making it easier to upload the application (2%, four out of 218).

Overall, the responses to these questions show that most survey respondents responded positively to each aspect of the program evaluated (more than 50% giving a 4 or 5 out of 5 rating), including their experience with the application process, their electrical upgrade and contractor experience, the rebate process, SCE communications through the process, the TOU rate transition, and the program overall.

4.5.4 Conclusions and Recommendations

Findings

Throughout the PRP, SCE and CSE staff identified successes and critical lessons that may be applied to similar future endeavors. These successes and lessons are presented below with supporting findings and recommendations.

- Although customers who successfully completed the rebate process were generally highly satisfied with the program, the necessary requirements may have limited participation. In particular, some application requirements were challenging for participants to complete correctly and for the implementer to monitor. For example, requiring documented proof of a waiver for HOA permission or city permitting created roadblocks for applicants who did not need those documents. Other documentation, such as a separate receipt for the charging station or C-10 license numbers on electrician invoices, caused problems for applicants who needed special invoices printed for the program. In addition, both CSE and SCE staff reflected that the six-month time restraint on purchase/lease date of a new EV may have limited participation because it can take EV adopters more time to understand their charging needs.
- ***Recommendation:*** If SCE explores a similar program in the future, the utility might consider structuring requirements in a simpler format. For example, individuals who do not have HOAs or whose cities do not require permits to install an L2 charger could potentially click a box on the application form and sign to confirm, relieving SCE of any liability while also reducing application processing time. Similarly, if the C-10 license number of the electrician is not already on the invoice, an applicant could include this number on the application form itself. Finally, because this program is not rebating the cost of the charging station, requiring proof of the charging station cost may not be necessary, especially as applicants are required to submit other forms of proof of the charging station installation, such as a photo and receipt for the infrastructure work.
- Despite regular communication between CSE and SCE staff, program requirements (e.g., TOU rate) necessitated the need for greater coordination within SCE departments, as well as with CSE. During the program, SCE and CSE staff met at least biweekly to review program status, and SCE and CSE staff both expressed general satisfaction with the communication throughout the process. However, both also noted that there were times that additional up-front planning and coordination were needed. For example, CSE was not able to successfully engage stakeholders such as electricians or MUD managers, who could have become champions for the program. There were also several unforeseen issues with validating applicants' TOU rates during the process, causing delays in application processing time. For example, the TOU-EV-1 rate ended in

the middle of the program, which led to internal SCE misunderstandings about how soon an applicant had to switch to a TOU-EV-1 rate before the rate was shut off to any additional SCE customers. CSE also noted a disconnect in the information that applicants were receiving from SCE call center staff, though SCE did make efforts to minimize this issue by directing applicants to contact CSE directly.

- ***Recommendation*:** If offering a similar future program, SCE may consider designing a marketing strategy that includes more lead time to meet with key stakeholders—such as electricians, MUD property managers, and city officials who will be helping applicants with their permits—before program launch. Educating these stakeholders to encourage them to become "champions" of the program could help increase participation while simultaneously making it easier for applicants to complete the process.
- ***Recommendation*:** If offering a similar future program, SCE may explore greater internal coordination within the departments at SCE (such as the rates, information technology, and program departments) when there are program processes (such as the validation of customers switching to a TOU rate) that depend on the efforts of multiple departments. This coordination may also include any future third-party administrator who will be working with customers individually to ensure that all data request, or status update, needs are being met.
- The program successfully reduced barriers to EV adoption by providing a financial rebate for home charging infrastructure, which resulted in positive impacts for participants. However, as currently designed, MUD residents continued to face challenges with L2 charging station installations. The program successfully encouraged the installation of home charging stations and spurred residential customers to purchase EVs, as evidenced by the 70% (2,661 out of 3,785) of all applicants who indicated that the rebate had an influence on their decision to purchase an EV. Additionally, participant feedback corresponded with SCE and CSE staff feedback, indicating that participants now benefit from more flexible, convenient charging in their homes. The program, as piloted, also helped confirm that at-home charging is actively desired by EV owners. However, the implementer struggled to engage individuals living in DACs and/or MUDs, despite targeted marketing efforts. With the program requiring an applicant to have a dedicated parking spot for the EV for 24 months and to switch to a TOU rate, two items that many MUD residents cannot ensure, most of the individuals in DACs or MUDs who might have been interested in buying EVs were ineligible for this program. Additionally, despite having Spanish-speaking individuals at marketing events and Spanish turnkey documents, there was not a Spanish language option for the application itself.
- ***Recommendation*:** If offering a similar future program, SCE may want to explore alternative requirements and/or engagement approaches in the program design to address MUD and DAC customer barriers and speak to key participant motivations.
- **Marketing effectiveness may be enhanced through more robust tracking**. Although CSE documented several marketing and outreach efforts (including sending out CVRP emails, attending events, and visiting car dealerships), other efforts did not appear to be tracked. In particular, conversations or meetings with other key stakeholders—such as MUD property managers or electricians—were not tracked with sufficient detail to be thoroughly reviewed.

- ***Recommendation*****:** The program should include metrics for all marketing and outreach strategies and evaluate effectiveness to ensure marketing investment focuses on the most effective strategies.

Scale Up

Although SCE staff indicated that they do not intend to scale up this program, they will continue to support EV adoption through other initiatives and incorporate lessons learned from this program. If SCE considers launching a similar program in the future, educating key players who would play crucial roles in the program (such as electricians and city permitting offices) may ease the path for customer participation.

5. Pacific Gas and Electric

5.1 Electric School Bus Renewables Integration

5.1.1 Project Narrative

Overview, Objectives, and Barriers Being Addressed

The purpose of the Electric School Bus Renewables Integration pilot was to work with a school district to understand the feasibility and impact of integrating electric school buses into their operations and aligning vehicle charging with renewable energy generation. The objectives of this project were (1) to demonstrate reduced total cost of ownership (TCO) by minimizing infrastructure and fuel costs and (2) to demonstrate the ability of electrified school bus fleets to support the integration of renewable generation from both on-site and grid resources.

Electrified transportation is a promising approach to address the glut of electricity supply at midday from solar generation and subsequent ramping needs in the afternoon as solar production decreases. The duty cycle of school buses, with their predictable routes and midday break period, is well-suited to match this supply curve. Though the pilot was envisioned and designed prior to the June 2020 release of the *Final Report of the California Joint Agencies Vehicle-Grid Integration Working Group*, the structure and goals of the PRP directly relate to investigating several of the priority vehicle grid integration use-cases identified in that report:[67]

- Customer cost management
- Commercial sector demand charge management (an important type of customer cost management for commercial applications)
- Use-cases for vehicle locations with daytime charging abilities
- Vehicle types with excess battery capacity relative to duty cycle, such as school buses
- All system and customer applications that defer charging away from on-peak periods

The Electric School Bus Renewables Integration pilot explored whether a school district could respond to signals from the Excess Supply Demand Response Pilot (XSP),[68] how participation in various load management protocols affected the school's transportation operations, and whether the program incentives could result in valuable compensation that would encourage shifts in charging patterns

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[67] California Joint Agencies Vehicle-Grid Integration Working Group. June 30, 2020. *Final Report*. California Public Utilities Commission DRIVE OIR Rulemaking (R.18-12-006). https://gridworks.org/wp-content/uploads/2020/09/GW_VehicleGrid-Integration-Working-Group.pdf

[68] XSP tests the capabilities of price-responsive demand-side resources to shift or increase load as a service to the grid during times of anticipated excess supply of renewables generation or negative wholesale energy prices. Depending on market conditions, participants may be asked to increase their usage during certain hours of the day (https://www.pge.com/en_US/large-business/save-energy-and-money/energy-management-programs/energy-incentives.page).

aligned with grid conditions and needs. The pilot also explored optimization approaches for a site that had its own on-site renewable generation.

The PRP project team, which included Pacific Gas and Electric Company (PG&E), Olivine, Inc., the site host, and vendors, designed the Electric School Bus Renewables Integration pilot to address several barriers to the widespread adoption of school bus electrification. These barriers included uncertainty around the technological readiness of vehicles (in terms of capacity, range, torque, and other factors) and charging equipment (in terms of software and hardware configuration, communication with charge management system, and ease of use). A common challenge to electrification is that school district staff may have insufficient technical expertise to make informed decisions related to procuring and implementing novel renewable and electrified transport infrastructure. There is also the question of whether school bus fleets have enough operational flexibility and economic incentive to adjust their loads dynamically and to strategically integrate renewable energy generation.

Sites and Participants

Site Host

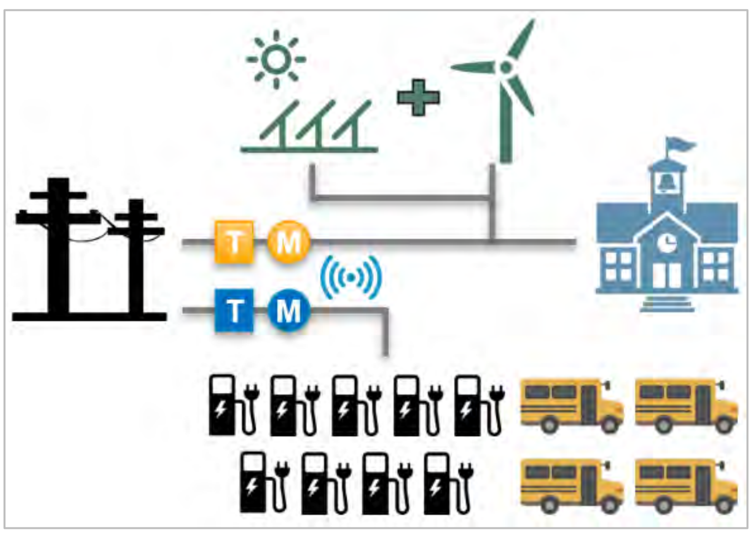
The site host in this priority review project (PRP), Pittsburg Unified School District (PUSD), serves over 11,000 K–12 students at 13 school sites in the San Francisco Bay Area. The District currently operates a fleet of 30 buses including 10 Type D (large) diesel school buses, 14 Type A (smaller) propane-fueled buses dedicated to transporting special education students, three gasoline buses, two Lion Type C electric buses, and two Blue Bird Type D electric buses. Under typical District operations (pre-COVID-19 pandemic), buses are used daily for students to commute to and from school, as well as for student activities such as athletic events and field trips. PUSD did not have electric buses or on-site renewables before initiating this pilot, though the District had secured grant funds for the acquisition of electric buses. The bus selection and procurement processes were not part of the PRP.

PUSD had initially planned to procure electric vehicles across four manufacturers (Lion Electric Company, GreenPower, Blue Bird Corporation, and TransTech) to allow for comparison. PUSD first procured two Lion buses in March 2018. These are 64-passenger versions of the LionC, a Type C school bus. When the District decided to procure these Lions, this was the only available model that had been approved by California Highway Patrol. PUSD also has two Blue Bird electric buses: the first was delivered at the end of September 2019 and the second was delivered in January 2020. These vehicles are the 78-passenger Blue Bird model T3RE 3904, a Type D school bus. After procuring its first Blue Bird, the District concluded that the Blue Bird models best suit its needs because they have a larger student capacity and longer range than the other models under consideration, which are characteristics that allow for greater operational flexibility. As of August 2020, PUSD does not have immediate plans to procure additional battery electric buses.

The electrical infrastructure associated with this PRP is located in the single bus yard at 3200 Loveridge Road (Pittsburg, California), adjacent to the District’s main high school and nutrition services department and next to an elementary school. PG&E installed nine Clipper Creek CS-100 chargers[69] on the site, located behind a locked gate that can be accessed only by PUSD staff. PUSD bus drivers are expected to plug in the electric buses when they park on the site. Thus, there is no need for payment processing capabilities, enabling PUSD to select non-networked chargers. District staff were also very cost-conscious during the procurement process, which was a primary reason for their interest in avoiding the ongoing network costs associated with networked chargers. Given that many other districts may also opt for low-cost chargers, this site provides extra value by partnering with vendors to test the concept of managed charging with low-cost, non-networked chargers paired with a networked charger controller. Another unique aspect of the site is that PUSD built a learning center for students to engage with the project. The District's experience with this learning center may provide useful insights to PG&E going forward.

The on-site renewables generation projects were not part of the PRP, but they were integrated into the project design and planning. The District now has 160 kW of solar and 40 kW of wind generation installed. These resources are integrated behind the facility's meter, while the EV chargers are installed on a separate, dedicated meter. Because PUSD subscribes to the net metering aggregation program offered under PG&E's NEM2A tariff, PUSD is awarded credits for excess on-site generation at the facility meter. These credits are then applied to the District's electric bill based on the proportional consumption recorded by facility and EV meters. This enabled the District to generate renewable energy credits that could be used to serve its new electric bus load, with the aim of reducing electricity costs and greenhouse gas (GHG) emissions. An overview diagram of PUSD's on-site energy resources is provided in Figure 216.

Figure 216. Diagram of PUSD on-site energy resources



Source: PG&E Clean Transportation Program Advisory Council Meeting slides

[69] Although PUSD currently only operates four electric buses, the District was planning to procure nine battery electric school buses in the near term as of the initiation of the PRP, so PG&E installed nine chargers to meet this projected need. PUSD remains committed to long-term fleet electrification.

Implementers and Additional Vendors

Several parties in addition to PUSD were involved in the project who have provided engineering, installation, charging services, and equipment. Electric vehicle supply equipment (EVSE) was provided by Clipper Creek, while Liberty Plugins provided a hardware/software solution that controls all the Clipper Creek chargers with a networked charger controller. Olivine's E-Fleet charge management system gathered charging and bus telematics data, optimized charging schedules, and enabled grid integration.

PUSD needed these additional charge management services and the networked charger controller because the non-networked chargers alone could not have been used for energy optimization and renewables integration. PUSD and PG&E identified key requirements for PRP performance against which they evaluated nine potential solutions. After the vendors made product presentations, PUSD and PG&E selected Olivine and Liberty Plugins. Although Olivine and Liberty Plugins responded to the solution separately, PUSD believed the best value would come from an integrated solution that involves both vendors:

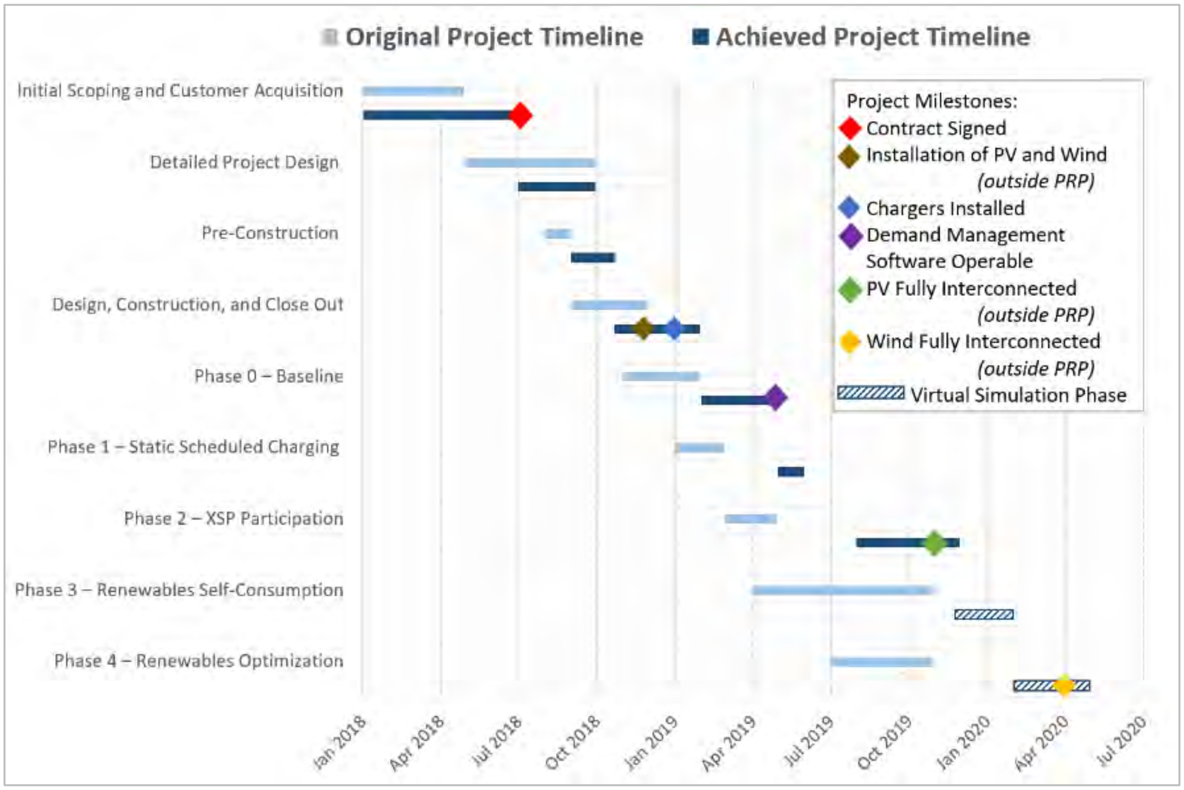
- Liberty Plugins was selected for the load management system because of its certification through the open automated demand response (OpenADR) 2.0b protocol (which demonstrates that they can receive and act upon OpenADR messages), as well as because of its cost-competitiveness and experience working on medium-duty and heavy-duty vehicle projects with Clipper Creek chargers.
- Olivine, Inc., was selected for its software-as-a-service that integrates with Liberty Plugins to provide an energy optimization platform. Olivine was also selected for its experience administering PG&E's XSP, as well as for its OpenADR 2.0b experience (as a demand response platform provider), cost-competitiveness, and incorporation of user interface components desired by PUSD (such as a web widget).

Timeline

Original Planned Timeline

Figure 217 illustrates the original timeline (pale blue fill) and the achieved timeline (medium blue fill) for the PUSD PRP. The divergence in timing reflects a variety of disruptions and challenges, many of which were unforeseeable by PG&E or the site host. The activities shown in Figure 217 are detailed below.

Figure 217. PUSD Priority Review Project timeline



Source: PG&E

Initial Scoping and Customer Acquisition

PG&E began recruiting potential district partners in January 2018. PG&E aimed to partner with a school bus district that already had an electric bus or had received grant funding and was in the process of purchasing an electric bus. By engaging both internal (PG&E's Business Energy Solutions team) and external (A-Z Bus Sales) partners, PG&E was able to identify districts that met these criteria.[70] PG&E's project manager invested significant time and effort to generate partner leads and identify a site host.

In addition to the clear requirements for participation in the program, several characteristics of the PUSD made them an especially attractive partner. First, PG&E was encouraged by the attitude of stakeholders at the School District, who work within a culture that celebrates innovation and who exhibit an eagerness to share insights and learnings. Second, the School District was clear on their own operational constraints, which suggests that they share PG&E's goal of achieving meaningful integration of the electric school buses into their operations. In addition, the District was already planning to acquire buses from a variety of original equipment manufacturers (OEMs) and was already planning for on-site renewables, both characteristics enabled the exploration of interesting questions in the pilot.

[70] See a more detailed description in PG&E's *Interim Priority Review Report*, available online: http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=285086006.

The decision makers at PUSD were motivated to participate in this project because it aligns with the values of their community. They are interested in improving air quality because they recognize the relationships between air quality, student respiratory health, and school attendance. PUSD aims to be a green innovation leader when serving the community. While the leadership expressed interest in capturing any potential savings the project may generate, finances were not a driving motivation for pursuing the project.

PUSD rose to the top of the list of potential partners and PG&E and PUSD began serious conversations about the project in April 2018. However, the project could not commence until the contract received approval from the PUSD school board, which meets only once or twice per month. The school board approved the project in mid-June, somewhat behind the target in the original timeline.

Design, Construction, and Close Out

The original timeline for the PUSD PRP design and construction period was planned to allow for one calendar year of data collection and for determining lessons learned prior to project completion at the end of 2019. Construction included procuring and installing nine 19 kW Clipper Creek CS-100 chargers. This involved putting in a new transformer, switchboard, and electrical conduit. The project also included laying conduit for cables that would carry data from chargers to the Liberty Plugins Hydra charge management system.

Initially the Lion buses were charged on 7.2 kW AC Level 2 chargers that had been installed previously to serve the District's light-duty EVs. With the commissioning of the Clipper Creek chargers that were installed as part of this PRP in January 2019, all electric buses are now served by the 19 kW AC Level 2 chargers that are paired with load management software and energy optimization services.

External factors caused notable delays during the construction phase. The date on which the PRP was scheduled to be energized was pushed back three months when PG&E resources were redirected to fire restoration efforts following the Camp Fire. Despite setbacks, all PRP construction activities were closed out and chargers were operational as of January 12, 2019.

The on-site renewables generation projects are not part of the PRP, but their progress affected the test phases described below. Both the solar and the wind systems were installed in the spring of 2019 but faced interconnection delays. Because of concerns about exceeding the hosting capacity on the existing PG&E transformer, only five photovoltaic inverters, accommodating approximately 130 kW AC, were connected on a conditional Permission to Operate as of August 1, 2019. The remaining 30 kW AC inverter was connected as of December 3, 2019, once these concerns were resolved. The 40 kW AC wind energy system faced interconnection delays because of an issue with certifying its inverters and was interconnected on April 23, 2020.

Pilot Test Phases

PG&E planned four test phases to investigate a series of research questions that stemmed from the PRP goals. Because the PRP objectives included understanding the level of sophistication of charge management that can be achieved even when employing lower-cost charging hardware, the tests' complexity increased sequentially. Phase start and end dates were designed to align with PG&E billing months, in order to facilitate cost comparisons between phases.

Phase 0 – Baseline (conducted January through April 2019): Once the chargers were installed and commissioned, the uncontrolled charging phase commenced. Buses began charging immediately upon being plugged in, with no application of any load management practices. The purpose was to set a baseline against which to measure performance during the subsequent phases.

Phase 1 – Static Scheduled Charging (conducted May 2019): This phase was used to test the integration of the Olivine and Liberty Plugins systems. Olivine's software platform managed bus charging according to static schedules that were designed to align with the time-of-use (TOU) off-peak period of 9:30 PM to 8:30 AM. During this phase, the primary goal was to ensure that bus energy needs were met while minimizing electricity costs, and to further analyze the opportunity for charge flexibility in a real-world environment.

Phase 2 – XSP Participation (conducted August through November 2019): This phase was used to add demand response functionality. The approach tested PUSD's ability to dynamically shift load to instances of consumption that would provide higher value to the grid, such as when there is excess wholesale electricity supply. These load-shift events were announced at 5 p.m. on the day prior to each event, triggering a signal to the charge management software, which directed an adjustment to the static charging schedule that was otherwise followed.

Phase 3 – Renewables Self-Consumption (demonstrated early December 2019 through January 2020 and modeled): This phase focused on adjusting the charging schedules to optimize consumption from the on-site renewable generation based on dynamic signals from the facility meter. Olivine automatically monitored real-time facility meter data and signaled buses to charge for the next 30 minutes when there was excess generation at the facility above a preset threshold in the prior 30 minutes. This approach was instituted to accommodate for delayed interactions between the buses and charging hardware and to avoid start-up of charging when excess generation was brief. This optimization retained the overarching goal of minimizing PUSD's electricity bill.

Phase 4 – Renewables Optimization (demonstrated February through April 2020 and modeled): This phase combined the previous two phases to assess the bill impact of both charging during periods of excess on-site renewable generation and also responding to XSP events. In addition, because the phase was conducted as a simulation, this allowed for flexibility to also assess the potential bill impacts of the PG&E Commercial Business Electric Vehicle Rate.

Notably, the Phase 2 testing period was originally scheduled for the end of the 2018-2019 school year. However, because the Phase 1 test ended on May 31, the start of Phase 2 needed to be delayed three months due to summer break. This delay reflects how the unique operational characteristics of schools may constrain project implementation timelines. Likewise, the testing and refinement of protocols may require extra time because of the annual school year cycle, since fleet operations are substantially different during summer and holiday months.

Transition to Virtual Phases

Two unforeseeable disruptions caused further delays of project implementation in the 2019-2020 school year: a ransomware attack during the school's 2019-2020 winter break and a school closure due to the

COVID-19 pandemic. While the ransomware attack did not affect the basic functioning of the EVSE and its ability to deliver energy to the buses, it did prevent data collection efforts of the real-time facility meter data because the site's wireless internet connection was interrupted. The collection of bus telematics, charging, and utility meter data was not impacted because they were delivered over alternative communication networks not dependent on the district's internet connectivity.

In addition to the effects of the ransomware attack, the inability to control charging of the Blue Bird buses and the lack of Lion bus use were the reasons that PG&E moved to virtual models for Phase 3 and Phase 4 of the project (discussed in the section, "*What were the Operational Impacts on the Fleet and its Staff?*"). Meanwhile, the school continued to use existing electric buses as feasible, performing on-site renewable self-consumption prior to the outage and resuming when data collection was restored in early February 2020. XSP signals were reintroduced in early February as part of Phase 4 activities and the school operated under typical schedules until the COVID-19 pandemic forced school closure for the remainder of the 2020 academic year.

5.1.2 Evaluation Objectives and Data Sources

Objectives and Research Questions

The theory of change of the PRP is based on the premise that school districts and other capital-constrained fleets procure non-networked chargers because they are low-cost. However, these low-cost chargers cannot control charging activity and therefore cannot prioritize charging during low-cost hours. This means, without additional systems, low-cost, non-networked chargers are expected to result in higher fueling costs compared to networked chargers. By developing a charge management system that incorporated non-networked chargers, the PRP aimed to lower the upfront cost of charging infrastructure and demonstrate ways to minimize fuel costs through the various charging approaches tested. In turn, applying the learnings from the project was anticipated to result in additional fleet electrification by the district and/or by other school districts. In these ways, the focus of the PRP is on enabling industry capabilities and providing proof of concept, with a lesser emphasis on measurable impacts such as overall cost savings or GHG reductions.

For this PRP, in addition to the research questions that apply to every fleet electrification PRP, the evaluation team sought to understand the challenges and innovations associated with implementing charge management, minimizing customer bills, providing grid services, and optimizing both on-site and grid-generated renewable energy. The evaluators investigated this by answering the following research questions:[71]

- What were the operational impacts on the fleet and its staff?
- What were the cost impacts to the fleet?

[71] This list is aligned with the intended evaluation objectives, though it diverges slightly from the original wording of the research questions in our evaluation plan. The relative importance of each question became clearer over the course of the project, and some questions were streamlined and consolidated for improvement in the organization of the evaluation report and for drawing emphasis on the most important questions. The full list of original evaluation questions can be found in the Evaluation Plan for California IOU Transportation Electrification PRPs.

- What was the District's overall satisfaction with the PRP?
- What is the potential for scale-up in the fleet?
- How, if at all, did the PRP change electrification within the fleet?
- What were the net energy and emissions impacts (relative to the no-PRP scenario)?
- What were the co-benefits? And how did these impacts accrue in disadvantaged communities (DACs)?
- How did PG&E project costs compare to expectations?
- How did the performance vary between test phases?
- What innovations were achieved?

Among these questions, the highest priority ones were related to the feasibility and cost-effectiveness of implementing charge-control mechanisms with low-cost, non-networked chargers. The evaluation team collected data as described below in order to address these priority questions and this theory of change.

Data Sources and Collection Challenges

The evaluation team conducted two in-depth interviews with PG&E and PUSD staff to better understand the decision-making process and reasoning behind this project. The evaluators performed the first interviews following the installation of the nine depot chargers to collect lessons learned on the implementation process and early operations. The evaluation team also interviewed Olivine staff about integrating the load management software and about the energy optimization process. The evaluators interviewed each of these entities again at the end of the project. The evaluation findings in this report draw substantially upon these interviews.

The evaluation team also assessed quantitative data to estimate project impacts and analyze usage patterns and costs related to the PRP. These include maintenance and fuel data, mileage records, operational details such as bus assignments to routes, PG&E electricity bills, PG&E meter interval data, PG&E's costs to implement the PRP, equipment out-of-service dates, and bus geographic location data.

The evaluation team conducted market research of comparable fleets throughout the duration of the PRP. Resources discussing the state of electric school bus technology, literature detailing TCO estimates, analyses of vehicle fuel economies and emissions, and other relevant references provided a baseline and context for the fleet primary data collected as part of the evaluation. The evaluation team navigated several data collection challenges throughout the PRP, which are detailed in Table 63.

Table 63. Data collection challenges and resolutions

Item	Issue	Result/Resolution
Maintenance costs of buses	**Low precision on maintenance cost data.** Because PUSD does not track labor hours or materials at the vehicle level, the evaluation team could not precisely identify how maintenance costs have changed with the introduction of electric buses.	PUSD staff provided generalized estimates that described maintenance costs for diesel buses. The evaluation team also used maintenance costs for electric buses at a neighboring fleet with similar vehicle characteristics.
Mileage records	**Records of the miles driven by Blue Birds was incomplete.** PUSD does not record vehicle odometer readings on a regular basis. The Geotab telematics system was intended to provide details on miles traveled, but these were not installed on the Blue Birds until 1-2 months after the buses had been introduced into fleet operations.	PUSD provided an odometer reading for each bus as of August 10, 2020. The difference between these readings and the number of miles logged in the Geotab data was used to estimate miles covered by the Blue Bird buses prior to installation of the Geotab telematics.
Charger-level interval usage data	**Data from the Liberty Hydra system was incomplete for chargers 3, 4 and 5, in part due to issues metering the higher-power draw of the Blue Bird buses.**[a] The Liberty Hydra system was expected to enable collection of 15-minute interval data on the activity of individual chargers. This data was also envisioned to inform Olivine's optimized charge management.	The evaluation team relied on meter data that encompasses activity across all the active charging stations but does not allow for disaggregation to study activity at individual chargers. Olivine developed a state of charge model based on telematics data and demonstrated vehicle efficiencies.
Driver survey	**Due to operational impacts of the COVID-19 pandemic, the driver survey was cancelled.** The evaluation team would have used the survey to collect information on the perceptions of co-benefits, differences between driving an electric bus and a conventional bus, satisfaction with new electric buses, charging protocols, and necessary changes to driver behavior.	PUSD staff provided the needed insights during interviews.

[a] In December 2019 Olivine noticed that some charging session data for chargers 3, 4, and 5 was not getting reported from the Liberty Hydra system, potentially starting late October or early November 2019. Liberty deployed a fix at the beginning of May 2020 and executed tests to validate the fix in June 2020; No discrepancies in the data have been documented since this fix was implemented.

Source: PG&E, PUSD

5.1.3 Evaluation Findings

This section is organized around the priority evaluation questions articulated above, grouped into three main categories: (1) the impact from the fleet perspective, (2) the immediate impact from a societal perspective, and (3) the project legacy.

High-Level Quantitative Summary

Table 64 presents a summary of annualized program benefits are calculated in comparison to the performance characteristics typical of the industry and of PUSD's diesel Type D bus fleet. Each column represents different assumptions:

- *As Anticipated* uses annual mileage the same as the District's diesel buses (e.g., the electric buses were supposed to perform as a one-for-one replacement of conventional buses). Emissions reductions per mile are calculated using the average kWh per mile and emissions per kWh observed in Phase 1 (static charging schedule), for lack of a specific forecast provided at the outset of the pilot.
- *As Implemented* uses annualized values for each of the above factors reflective of the actual performance documented over the course of the entire pilot.
- *Best Observed* uses annualized values for each of the above factors reflective of the actual performance documented in February 2020, a month of high utilization and high efficiency.

Notably, *As Anticipated* is not a project target, rather what could be expected based on full utilization of the buses. As explained elsewhere in this report, numerous factors limited utilization during the project period. The assumptions underlying this table are described in more depth in the sections "What were the Net Energy and Emissions Impacts (Relative to the No-PRP Scenario)?" "What were the Cost Impacts to the Fleet?," and "What were the Co-Benefits? And How Did these Impacts Accrue in Disadvantaged Communities?"

Table 64. Annualized program benefits

	Anticipated	As Implemented	Best Observed
Assumptions	4 concurrent buses 40,000 total miles 2.61 kWh/mile	1-3 buses concurrent 3,572 total miles 2.96 kWh/mile	2 concurrent buses 9,630 total miles 2.54 kWh/mile
Petroleum Reduction (gallons diesel)	8,000	714	1,926
Avoided GHG Emissions (tonnes CO2e)	83.6	6.3	20.1
Avoided SO2 (kilograms)	9.1	Negligible	2.2
Avoided NOx (kilograms)	199.4	17.5	48.2
Avoided CO (kilograms)	72.5	6.2	17.6
Avoided PM10 (kilograms)	4.6	Negligible	1.1
Avoided VOC (kilograms)	24.9	2.2	6.0
Impact to DACs (% miles within DAC)	88.6%	88.6%	88.6%
O&M and Fuel Cost Savings [a] ($)	$23,981	($1,128)	$3,905
Other Co-Benefits		Reduced ambient noise	Reduced ambient noise

[a] Calculations are based on maintenance characteristics of industry baseline ($0.88/mile)

Source: Evaluator Calculations

Results Observed to Date: Fleet Perspective

This section addresses whether the project affected the fleet's ability to perform its core functions, satisfied fleet and stakeholder needs, and demonstrated the technological readiness and TCO benefits of electric school buses deployed with an integrated charge management system.

What were the Operational Impacts on the Fleet and its Staff?

Despite initial challenges, once integrated into regular operations the vehicles performed reliably. PUSD staff did not report any instances of an electric bus being unable to complete an assignment due to running out of energy along the route. Likewise, once energized and commissioned, the EVSE was never out of service, meaning that it was capable of delivering charge at any time the fleet wished.[72] Additionally, there were no reported instances of power outages affecting bus operations. Because this project involved deploying nascent technologies in novel applications, the PRP project team anticipated that issues with project equipment might introduce complications to operations. Some characteristics of the selected equipment disrupted operations in unanticipated ways, as described below and summarized in Table 65 at the end of this section.

To support integration of PRP-related equipment into fleet operations, PUSD conducted training for staff related to the vehicles and charging infrastructure. PUSD requires that drivers be proficient with any type of bus they are assigned to drive, and they therefore invested an estimated $10,000 in staff training. This included training on the electric bus data display, acceleration and regenerative braking, and operation of the electric doors. Despite this training, some drivers are not proficient in air brakes and are not assigned to electric buses. PUSD noted that it would have liked to have representatives from Blue Bird and Lion visit and describe the driving process and eco-driving techniques. Overall, the electrification strategy has not caused operational hardship for the fleet.

The charge management component of this PRP did not cause adverse operational impacts to the fleet. However, the fleet was not able to operate the charging protocols the way PG&E and PUSD originally hoped since the default bus battery management systems are not designed to enable intermittent delivery of power. This capability is central to implementing managed charging, where the power flow to the battery cycles on or off depending on the signal from the charge management system, even as the physical connection to the charger is unaltered. For both bus types, the bus battery management systems were set to stop the power flow between the bus and the charger if no power was delivered over a factory-specified number of minutes. For example, if a bus was plugged in to a charger at 4 PM, but charging was not scheduled to begin until 9 PM, the bus battery management system would electrically disconnect a short time after 4 PM because no electricity was being delivered, and would not be able to accept electricity at the beginning of the scheduled charging period at 9 PM unless the electrical connection was reestablished by physically un-plugging and re-plugging the bus. For Lion buses, the PRP project team developed a workaround by using a trickle charge of 1.3 kW to keep the bus from electrically disconnecting but were unable to identify a solution for the Blue Bird buses. This issue

[72] While the EVSE core charging function was reliable, control and reporting systems were not always operational, as described above.

meant that the fleet was unable to implement a managed charging protocol for the Blue Bird buses during the PRP.

Another challenge was that the two Lion buses are smaller (64 passenger) than the District's diesel vehicle fleet buses (72 passenger) and do not have enough seating capacity to be heavily incorporated into the District's regular routine. Because of driver shortages, the District tended to send out its larger vehicles to serve more students on a single trip. Additionally, the District had not gained enough comfort with the electric bus ranges to use these buses for longer field trips or athletic events that were farther away. While the electric buses did not perform poorly, the low usage impacts TCO, as the additional upfront cost of the electric buses was not being offset by substantial fuel cost savings. School districts are first and foremost concerned with serving their operational needs, which may not allow for the needed flexibility in route assignment or charging patterns to optimize costs.

The project also faced setbacks due to bus delivery delays and bus malfunctions. The first Blue Bird bus was scheduled for delivery in August 2019 but was not available until mid-fall. There were also maintenance issues, which included a door problem with one of the Lions and HVAC issues on both the Lions. The door issue went unresolved for three to four months, leaving only one bus available to participate in test Phase 1. While this issue was simple to resolve once finally addressed, PUSD was frustrated with the manufacturer's customer service. The HVAC issue required both Lions to be brought to Sacramento for repairs; one was repaired from early September to November 2019 and the other is expected to be sent for repair soon. While repairing the first bus, the Sacramento maintenance shop did not have an appropriate charger on the site to keep the bus powered on for maintenance and diagnostics. The workaround involved towing the bus across Sacramento multiple times. The Blue Bird bus was also sent to Sacramento for a repair in December. These problems reflect two themes that may carry over to similar contexts:

- Vehicle technicians and maintenance workers are still developing familiarity with electric buses.
- The industry is experiencing growing pains as manufacturers transition from focusing on sales to meeting the service needs of customers with vehicles in operation.

Troubleshooting processes throughout the project resulted in novel conversations and solutions among various industry actors. For example, addressing the problems posed by the default settings of the bus battery management systems involved significant engagement on the part of the PRP project team and both OEMs. After facing challenges with the Lions, Olivine preemptively joined a conversation with the Blue Bird technical sales representative to discuss the PRP's planned charge management activities. Later, after the Blue Bird bus battery management system issue was identified, Olivine had extensive conversations with Blue Bird engineers to collaboratively search for solutions. Although no solution was identified during the PRP period, PUSD's efforts to implement a charge management configuration for this new vehicle segment jump-started the identification of issues and search for solutions.

Table 65. Summary of issues with project equipment and associated resolution

Issue	Result/Resolution
Low usage because of limited passenger capacity in Lion buses	Blue Bird buses selected for subsequent procurements have larger capacities and are likely to integrate better into normal fleet operations.
Mechanical issue with Lion bus door	This issue was resolved after three to four months through collaboration with Lion's customer service.
HVAC system on Lion bus did not function properly and the remote repair shop lacked appropriate infrastructure to charge the battery	This issue was resolved after about two months at the repair shop in Sacramento and towing the bus to a facility with adequate charging equipment.
The ability to support delayed charging was not included in original bus specifications	For the Lion buses, the PRP project team developed a workaround using a trickle charge to keep the bus from electrically disconnecting. No solution has been found for the Blue Bird buses.

Source: PUSD

What were the Cost Impacts to the Fleet?

Overall, PUSD attained cost savings from its participation in the PRP relative to a no PRP scenario. This is because the upfront costs of electric school buses were reduced substantially by grant and rebate funds. The School District did not need to invest in project infrastructure costs and also received a grant of $1.12 million from the Bay Area Air Quality Management District to support its purchase of the vehicles themselves, which could not be applied to purchase of diesel buses. However, the District is responsible for ongoing operational costs associated with the project. This section details actual operational costs throughout the project period and then describes what TCO could be expected based on actual and optimal operational data, relative to the fleet's diesel baseline.

Under certain conditions, the project generated notable operational cost savings for the fleet. The program benefits presented in Table 66 suggest the potential for saving of almost $25,000 per year if performance were akin to that modeled in the *Anticipated* scenario. Further calculations indicate that, if annualized operations were to reflect the *Best Observed* performance, operating just two electric buses would generate almost $4,000 in annual savings relative to providing the same service with diesel buses. On the other hand, the *As Implemented* scenario indicates that the actual operational cost for the electric school buses was about $1,000 greater than it would have been for comparable service from conventional diesel buses. Although the electric buses exhibited per-mile savings on fuel and maintenance costs, in the scenario with low utilization, these per-mile savings are insufficient to offset fixed EVSE networking fees.

Table 66. Annualized program operational cost savings

	Anticipated	As Implemented	Best Observed
Assumptions	4 concurrent buses 40,000 total miles 2.61 kWh/mile	1-3 buses concurrent 3,572 total miles 2.96 kWh/mile	2 concurrent buses 9,630 total miles 2.54 kWh/mile
Fuel Savings	$12,081	$814	$3,545
EVSE Network Fees	($3,300)	($3,300)	($3,300)
Maintenance Savings[a]	$15,200	$1,357	$3,659
Total	**$23,981**	**($1,129)**	**$3,905**
[a] Calculations are based on maintenance characteristics of industry baseline ($0.88/mile)			

Source: Evaluator Calculations

Due to the installation of on-site renewables and application of the NEM2A tariff, electricity costs have been quite low. In the period since billing was initiated and through June 29, 2020, the EVSE meter incurred $1,128 in electricity costs.[73] The other primary operational cost related to the PRP is the $275 per month network fee for the Liberty Hydra system. This flat fee is paid by PUSD for its use of a single Hydra smart controller, which can support up to 10 buses.

The TCO analysis detailed in Table 67 presents a wholistic picture of the cost profiles of different bus types from the perspective of the PUSD fleet at end-of-life vehicle replacement. The analysis uses industry standard data, actual fleet characteristics, and observed performance capabilities to illustrate TCO assuming the electric buses attain annual mileage and lifetimes equivalent to their diesel counterparts. The "As Implemented" and "Best Observed" variations illustrate the effect of vehicle energy efficiency (kWh/mile) on TCO calculations. To develop the cost per vehicle estimates, the evaluation team amortized capital and certain operational costs across the number of vehicles served. For instance, since only two buses were operating during the majority of the PRP timeline, half the site's $275 per month networking fee was assigned to each bus. But since the infrastructure and chargers installed through the PRP will eventually support 9 buses (assuming the fleet procures one bus for every charging port), each electric bus was only assigned one ninth of total site costs for equipment procurement and installation.

Overall, equipment rebates and vehicle grants are central to achieving cost-parity from the perspective of the fleet. When these are in place, the ongoing costs of electric school buses are projected to be lower than costs for their diesel counterparts due to the lower per-mile costs of fuel and O&M activities. Calculated savings are greater still when vehicle usage is higher and NEM2A credits are generated at the site, as illustrated by the TCO estimate based on pilot performance during the optimal month (February 2020) in the *Best Observed* scenario (last column of the table).

[73] More detail about how electricity costs varied based on responsiveness to TOU rates is provided in the section "*How did the Performance Vary between Test Phases?*"

Table 67. Projected lifetime total cost of ownership per vehicle

Cost Component		Industry Average (Diesel)	Fleet Baseline (Diesel)	As Implemented (Electric)	Best Observed (Electric)
Assumptions: General: 10,000 miles, 17.5 years		7.4 miles/diesel gallon	5 miles/diesel gallon	2.96 kWh/mile	2.54 kWh/mile
Infrastructure Costs Paid By PG&E [a]		N/A	N/A	$40,000	
Vehicle Costs	Paid by Bay Area Air Quality Management District Grant	N/A	N/A	$280,000	
	Paid by PUSD [b]	$129,000	$185,000	$120,000	
Projected Fuel Costs [c,e]		$93,000	$79,000	$39,000	$14,000
Projected O&M Costs [d,e]		$154,000	$154,000	$116,000	$116,000
Total Cost of Ownership (TCO) to Fleet (under various scenarios)					
Actual Anticipated TCO		$376,000	$418,000	$275,000	$250,000
TCO without PRP Investments, with Vehicle Grant				$315,000	$290,000
TCO with PRP Investment, without Vehicle Grant				$555,000	$530,000
TCO without PRP or Vehicle Grant				$595,000	$570,000

[a] This includes the cost of EVSE and installation but not labor to stand up the charge management system.
[b] This is based on industry data from AFLEET (https://greet.es.anl.gov/afleet_tool), a New York State Office of General Services School Bus contract (https://online.ogs.ny.gov/purchase/spg/pdfdocs/4052423000Summary.pdf), and other documents provided by PUSD.
[c] Fleet baseline data provided was by PUSD and electric fuel costs are from PG&E bills. The diesel price is from the U.S. Energy Information Administration (https://www.eia.gov/dnav/pet/pet_pri_gnd_a_EPD2DXL0_pte_dpgal_a.htm).
[d] These costs include maintenance and EVSE networking, but not the cost of battery replacement, EVSE replacement, or credits from Low Carbon Fuel Standard participation for electric buses. Industry data is from the California Energy Commission (https://www.energy.ca.gov/sites/default/files/2020-04/Cost-Effectiveness_ada.pdf) and is used for the fleet baseline as well. Electric maintenance costs are based on estimates from a nearby fleet (based on conversation between Michelle Levinson of Cadmus and Raymond Manalo of Twin Rivers Unified School District on November 19, 2019).
[e] Assume 17.5-year lifetimes, as provided by PUSD (it is not known whether this is a reasonable estimate of performance for electric buses, which, as a novel technology, have not existed long enough to demonstrate such a lifetime). Industry fuel economy is from AFLEET via the California Energy Commission (https://www.energy.ca.gov/sites/default/files/2020-04/Cost-Effectiveness_ada.pdf). Fleet baseline data was provided by PUSD and electric fuel economy is based on actual and best observed performance.

Source: Evaluator Calculations

The TCO contains realistic assumptions about grant availability, but two major factors of uncertainty remain: (1) whether the fleet will succeed in utilizing its buses as heavily as its diesel baseline vehicles, and (2) the magnitude of Low Carbon Fuel Standard (LCFS) credit revenue the fleet could receive, which depends on future vehicle utilization, uncertain credit prices, and PUSD taking steps to monetize credits. The numbers above present a scenario in which high utilization is achieved, since the factors limiting observed utilization during the pilot period should eventually be resolved (e.g., COVID-19 pandemic, computer systems hacked, misalignment of original Lion with student seating needs).[74] While this assumption results in a more optimistic assessment of the TCO than can be strictly inferred from observed mileage achieved, our decision not to factor LCFS credits into the TCO provides a countervailing influence.

As noted, this TCO analysis underscores the importance of financial support for upfront procurement costs for the cost proposition of electric school buses to pencil out for fleets like PUSD. There are several funding programs aimed at shifting the school bus market and technology adoption trends, including $130 million in Volkswagen Mitigation Trust Funds for transit, school, and shuttle bus electrification, from which districts can receive up to $400,000 per electric bus. Also, the California Air Resources Board offers the Low Carbon Transportation Investments program and the Air Quality Improvement program, both of which support the deployment of advanced technology and clean transportation. In addition, there are local funding programs through regional air districts, such as what PUSD used for the vehicles in this PRP.

The infrastructure expenditures at PUSD that were covered by the PRP were a relatively small share of the TCO compared to the vehicle grants it received from the Bay Area Air Quality Management District. This may not be the case for other fleets because infrastructure costs for the PRP were surprisingly low due to the site's decision to procure low-cost, non-networked chargers, and the site's decision to oversize its infrastructure procurement relative to its bus acquisition, which likely introduced economies of scale that created additional savings. For fleets that select relatively higher-cost, networked chargers, financial support to reduce the upfront cost of electric school bus infrastructure and equipment would be even more central to making project costs pencil out.

What was the District's Overall Satisfaction with the PRP?

The electric buses have been quite popular among students, parents, and bus operators because of their quiet operations. The school board is very supportive and proud of the pilot because it aligns with the board's environmental values and furthers the educational mission. The project has met customer needs as initially scoped. PUSD staff were especially satisfied with the exceptionally low electric fuel costs that resulted from net metering credits. The evaluator team has drawn these insights from in-depth interviews and project meetings conducted with the project participants and implementors. The principle hurdle was the imperfect suitability of electric buses to serve as one-for-one replacements for diesel buses, primarily because of range limitations, rider capacity, and staffing constraints.

What is the Potential for Scale-Up in the Fleet?

The PUSD PRP has contributed to the acceleration of electrification within the site host's fleet. PUSD staff said their participation in this PRP fast-tracked the District's procurement schedule for subsequent vehicles. Because the PRP allowed them to install infrastructure that will accommodate the continued growth of PUSD's electric fleet, the upfront cost and complexity to deploy the next five electric buses

[74] See Interim Evaluation Report for additional details on challenges and operational disruptions.

has been greatly reduced. At the close of the project, PUSD expressed a continued interest in pursuing similar opportunities and in sharing lessons learned with other fleets.

Results Observed to Date: Societal Perspective

This section addresses whether the project successfully accomplished its objectives as outlined in the Decision, whether the project achieved immediate benefits that accrue to ratepayers and the general public, and whether the costs aligned with anticipated costs when the project was approved.

How, if At All, Did the PRP Change Electrification within the Fleet?

Across the fleet electrification PRPs in California, there are three main ways that the IOUs have aimed to change electrification within the participating fleets: (1) affecting vehicle procurement choices and timeline, (2) affecting infrastructure procurement choices and timeline, and (3) enhancing operational performance and capabilities, thereby advancing broader market readiness and desirability of electrification for other fleets in the future.

The PUSD PRP was primarily focused on the latter two, but it likely also had some effects on vehicle procurement and timeline decisions. Each of these topics is described sequentially below.

Vehicle Procurement Choices and Timeline

Although PUSD had already committed to purchase its first two electric buses, the PRP shaped the context in which PUSD made vehicle procurement decisions. Most importantly, the PRP reduced the upfront cost of future electric bus acquisition because the PRP funded the installation of infrastructure that could serve up to nine buses at a 1:1 ratio of bus to charger. This investment, in combination with grants secured from the local air district, brought upfront costs for electric buses in line with their conventional counterparts, making the fleet's purchase of its second set of electric school buses more likely (discussed in detail in the section "What were the Cost Impacts to the Fleet?"). PUSD staff confirmed that their participation in this PRP fast-tracked the District's procurement schedule for their third and fourth electric buses which have already been deployed.

Infrastructure Procurement Choices and Timeline

The PRP also affected the type and quantity of charging infrastructure installed at the site. The District was unlikely to have upgraded to higher-power Level 2 chargers (19.2kW) to serve these vehicles but for the PRP's funding and support. The lower-power chargers that the Lions were using prior to the PRP could not deliver energy to vehicle batteries as quickly as the Level 2 chargers installed through the PRP, so the vehicles would have needed to charge for much longer periods to meet their energy requirements. The PRP addressed the barriers posed by long charging times, increasing the fleet's operational flexibility and creating the opportunity for strategic charge management activities. Furthermore, it is unlikely that the District would have future-proofed their investment and achieved the economies of scale possible by installing all 9 chargers at once without the PRP investment.

Enhancing Operational Performance and Capabilities

One of the most important ways in which the PRP changed electrification at PUSD was by encouraging the District to implement a managed charging approach. Managed charging allowed PUSD to align its consumption with times that were low-cost, grid-favorable, and environmentally beneficial (e.g., low grid emissions factors).

A primary impact of the PRP on PUSD's approach to electrification was due to the pilot's integration of software, operational innovations, and the confirmation of corresponding relative cost savings. Because of the PRP, PUSD acquired a sophisticated charge management system for its low-cost, non-networked EVSE. This system enabled the fleet to demonstrate the value of charge management functionalities through its implementation of the various test phases. Energy costs during the uncontrolled phase were found to be higher than during the phase that tested the static charging schedule (discussed in detail in the section *"How did the Performance Vary between Test Phases?"*). Based on this evidence, the fleet has embraced scheduled charging as the standard charging protocol for its electric vehicles and is unlikely to have done so but for its participation in the PRP.

What were the Net Energy and Emissions Impacts (Relative to the No-PRP Scenario)?

In the Decision authorizing this project, the CPUC laid out anticipated benefits related to technology cost reductions, improved use of existing electric infrastructure, and a potentially accelerated adoption of clean energy technologies in the medium-duty and heavy-duty sectors. In addition, the CPUC highlighted reduced exposure to particulate matter as a key direct benefit expected from the project. Table 68 presents the PRP's petroleum reductions, avoided GHG emissions, and avoided emission of criteria pollutants.

Table 68. Annualized program fuel and emissions reductions

	Anticipated	As Implemented	Best Observed
Assumptions	4 concurrent buses 40,000 total miles 2.61 kWh/mile	1-3 buses concurrent 3,572 total miles 2.96 kWh/mile	2 concurrent buses 9,630 total miles 2.54 kWh/mile
Petroleum Reduction (gallons diesel)	8000	714	1926
Avoided GHG Emissions (tonnes CO2e)	83.6	6.3	20.1
Avoided SO2 (kilograms)	9.1	Negligible	2.2
Avoided NOx (kilograms)	199.4	17.5	48.2
Avoided CO (kilograms)	72.5	6.2	17.6
Avoided PM10 (kilograms)	4.6	Negligible	1.1
Avoided VOC (kilograms)	24.9	2.2	6.0

Source: Evaluator Calculations

Petroleum reductions are the estimated number of diesel gallons that would have been required to power an equivalent number of miles as were served by the electric fleet. GHG and criteria pollutant emissions for the baseline fleet are based upon the emission factors for low-sulfur diesel fuel provided by the California Air Resources Board in the CA-GREET3.0 Model, which is also used as the source for criteria pollutant emission factors for electricity.[75] Because GHG reductions were a primary focus of the PRPs and the carbon intensity of grid electricity varies markedly by season and time of day, the evaluation team used the hourly electricity carbon emission factors established for each quarter under the LCFS.[76] While LCFS values do a good job of capturing hourly emissions variation, because they represent average state-level grid emissions they may overstate project-related electricity emissions if the local grid is cleaner. These carbon intensities were applied to interval data from the EV charging meter to establish the emissions associated with charging the buses. In all cases, avoided emissions are calculated as the difference in emissions per mile between the electric fleet and baseline diesel vehicle fleet, scaled to the annual mileage anticipated or observed.

Calculations of the criteria pollutant impacts of the PRP suggest that some pollutants exhibited only minor reductions relative to the diesel baseline, primarily due to the fact that the buses were not driven enough miles to yield the level of diesel fuel displacement that could have been anticipated. It can be expected that after school operations resume and after more of the larger student capacity buses are put in use, the utilization will increase substantially. At the average efficiency of 2.96kWh/mile across the pilot duration, the percentage reduction of emissions relative to diesel on a per mile basis was substantial, ranging from 45 percent for PM10 to 87 percent for NOx, as shown in Table 69.

Table 69. Comparison of normalized emissions

	Fleet Baseline (Diesel)	**As Implemented** (Electric)	**Percentage Reduction**
GHG Emissions (kg/mile)	2.77	1.00	64%
SO2 Emissions (g/mile)	0.42	0.22	48%
NOx Emissions (g/mile)	5.62	0.72	87%
CO Emissions (g/mile)	2.34	0.60	74%
PM10 Emissions (g/mile)	0.22	0.12	45%
VOC Emissions (g/mile)	0.73	0.12	83%

Source: Evaluator Calculations

What were the Co-Benefits? And How Did these Impacts Accrue in Disadvantages Communities?

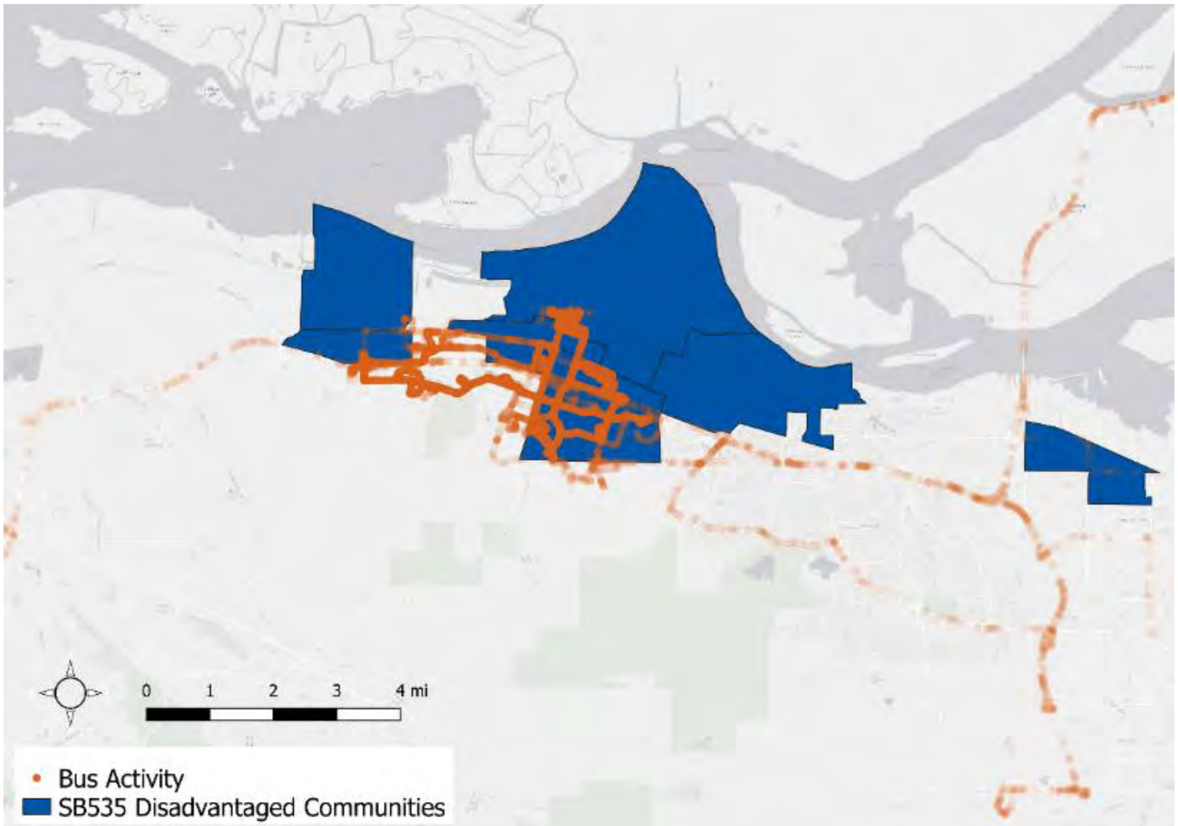
Stakeholders also identified non-energy benefits. District officials noted that the lower decibel of EV operations creates a more pleasant environment for both students and bus drivers because students on the bus are quieter when the bus itself is quieter.

[75] California Air Resources Board. "LCFS Life Cycle Analysis Models and Documentation." CA-GREET3.0 Model. https://ww2.arb.ca.gov/resources/documents/lcfs-life-cycle-analysis-models-and-documentation

[76] California Air Resources Board. Revised January 16, 2020. *Low Carbon Fuel Standard Annual Updates to Lookup Table Pathways; California Average Grid Electricity Used as a Transportation Fuel in California and Electricity Supplied under the Smart Charging or Smart Electrolysis Provision*. https://ww2.arb.ca.gov/sites/default/files/classic//fuels/lcfs/fuelpathways/comments/tier2/elec_update.pdf

Because 88.6% of bus activity took place within the boundaries of census tracts designated as DACs, both direct emission reductions and non-energy benefits were concentrated in these areas, as illustrated in Figure 218.

Figure 218. Electric bus location activity in disadvantaged communities



Notes: The orange dots indicate locations where the bus telemetry system reported bus activity. The dots are semi-transparent, so greater opacity indicates places with higher concentrations of bus activity. Blue coloring indicates the census tracts that are categorized as DACs.
Source: Telematics, California Office of Environmental Health Hazard Assessment

How did PG&E Project Costs Compare to Expectations?

In the CPUC's 2018 PRP decision, PG&E was approved for $2.21 million for this project, consisting of $510,000 in capital costs and $1.70 million in expenses. The total project expenditures through October 2020 show that the project remained on track to stay within the allocated $2.21 million budget.

There are several categories of costs (shown in Table 70):

- **Site assessment and design** includes the site assessment, electrical design, and estimation; no permitting costs were reported.
- **EVSE procurement** includes the acquisition of nine Clipper Creek CS-100 chargers and the Liberty Plugins Hydra charge management system, for which PUSD received a rebate; installation costs were not reported separately.

- **Make-ready infrastructure (utility-side)** includes to-the-meter costs for materials, construction labor, internal labor, inspection, and material burdens on cost.[77]
- **Make-ready infrastructure (customer-side)** includes behind-the-meter costs for charger installation, materials, construction labor, internal labor, and burdens on costs. No other construction costs were reported.
- **Project management** includes PG&E's activities for customer support, planning and direction of the implementation process, oversight for troubleshooting, budget tracking and processing of customer reimbursements, data review and analysis, management and planning of test phases, and coordination of stakeholders. This category also includes project management for the design and construction of PUSD's chargers.
- **Customer outreach (labor)** encompasses the labor related to recruiting a site host partner.
- **Outreach and education materials** includes project marketing and digital materials as well as $60,000 in funds associated with the Learning Center.
- **Other program costs** covered by PG&E include work conducted by Olivine and Liberty Plugins to enable integration of their systems, as well as additional costs for work conducted by Olivine to design and build real-time metering communications, a school bus–centric e-fleet website portal, and a variety of charge control optimization strategies. Olivine also integrated its systems with the on-board vehicle telematics systems, modeling, managing, and executing test phases; provided general project operations support; and prepared a final report and website to showcase the project.

Table 70. PUSD PRP costs as of October 2020

Cost Categories	Proposed	Actual
Site assessment and design	$100,000	$49,510
Permitting		$-
EVSE procurement—rebate paid	$152,300	$43,255
EVSE installation		$-
Make-ready infrastructure (utility side)	$151,200	$192,268
Make-ready infrastructure (customer side)	$106,000	$78,200
Other construction costs		$-
Project management	$750,000	$376,595
Customer outreach (labor)	$250,000	$11,516
Outreach and education materials	$100,000	$79,025
Other program costs	$600,000	$502,000
Total Costs	**$2,209,500**	**$1,332,369**

Source: PG&E

[77] Burdens indicate production costs required to produce the finished product.

The recorded costs to date show some deviations from forecasted costs across the cost categories detailed above, but not relative to the total approved levels for capital and non-capital costs. For example, the overage on utility-side make-ready costs relative to those proposed was because the contractors needed to tap a different transformer than initially planned, requiring some redesign and additional work.

Capital costs (including infrastructure, make-ready, and project management associated with the construction components of the PRP) are on track to remain within the approved ceiling of $510,000. PG&E's reported total capital spend was around $500,000, and no additional capital costs are anticipated. Non-capital costs are on track to remain within the approved ceiling of $1.7 million.[78]

Program savings on EVSE procurement are most likely due to the site host's decision to acquire relatively low-cost, non-networked chargers. PG&E also reported substantially lower costs in the customer recruitment category than the $250,000 originally budgeted, although some of these costs may have been attributed to the generic project management category.

Project Legacy and Learnings

This section addresses the knowledge generated by this project that could be more broadly applied to future projects. In particular, the design of this PRP prioritized lessons learned rather than immediate impacts because accruing lessons learned at this early stage is a critical precursor to market transformation and scalability. Several important lessons emerged both from the technological innovations and the testing conducted over the course of the project.

How did the Performance Vary between Test Phases?

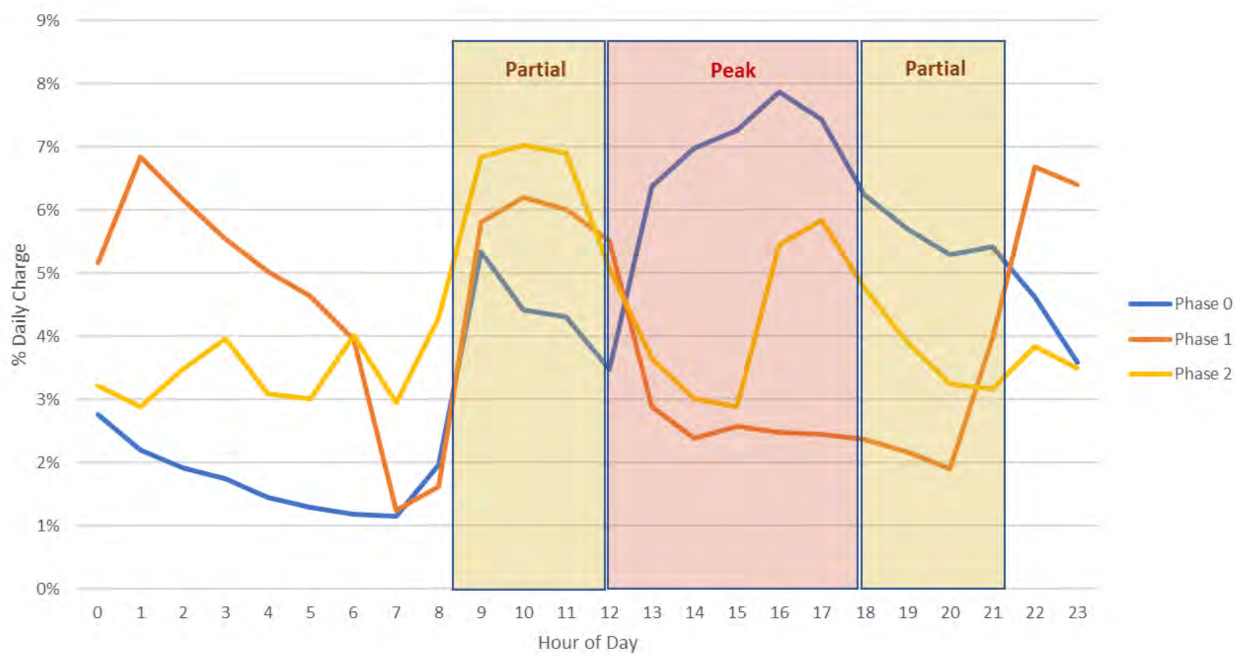
Performance varied significantly between the test phases in terms of the time of day of charging behavior, the average cost of electricity incurred, and the GHG emissions associated with electric bus energy. Figure 219 shows the share of total daily energy delivered during each hour in Phases 0, 1, and 2. During Phase 0 (in blue), buses began charging immediately upon being plugged in, with no application of any load management practices. During Phase 1 (in orange), on the other hand, the Olivine and Liberty Plugins charge management system was in place and charging activity was scheduled to avoid peak tariff windows. The low demand between 1PM and 8PM during Phase 1 aligns with a concerted effort to avoid the 12:00-6:00 PM peak window of the A-6 Summer tariff.[79] During Phase 2 (in yellow), charging activity was generally structured to follow the same static charging schedule as implemented in the Phase 1 schedule; however, charging activity in response to XSP events and the

[78] Non-capital costs include additional project management, charge management solution development, outreach and engagement plus the learning center, billing and technical support, charger incentives, load shift incentives, and the O&M of make-ready infrastructure.

[79] These average energy profiles, which represent only weekdays, do not dip to zero because they average the electric bus charging activity over all the days in the period. Notably, there were a number of operational reasons, such as bus capacity and staffing constraints, that resulted in unique usage patterns across days. Additionally, during Phase 1, to enable the charge management system for the Lions, the chargers each needed to supply a trickle charge of 1.3 kW to avoid electrical disconnection.

energy consumption of the Blue Bird bus delivered in October that was not configured to respond to charge management signals caused divergences relative to Phase 1.

Figure 219. Weekday load profiles: Pilot Phases 0, 1, and 2



Notes: Phase 2 data shows a deviation from the scheduled charging behavior in Phase 1 because it includes consumption due to participation in the XSP and the uncontrolled Blue Bird bus. While the schedule and utilization of individual buses varied considerably throughout the PRP, generally vehicles were on-route between 6am-9am and again between 3pm-6pm.

Source: Meter Data

As illustrated in Table 71, Phase 1 resulted in a substantial shift of charging away from on-peak hours, with only one-fifth of electricity consumption occurring during on-peak hours, whereas almost half of charging activity occurred during on-peak hours in Phase 0. Moreover, the shifted consumption activity was concentrated in off-peak hours rather than in partial peak hours. This shift in the timing of charging activity translated to reduced electric fuel costs in Phase 1 compared to Phase 0. Notably, these savings were realized even though Phase 0, which took place in April, was subject to the winter tariff schedule, while Phase 1, which took place in May, was subject to the pricier summer tariff schedule. While the electricity price during summer off-peak hours is only half a cent higher than the per kilowatt-hour price for the off-peak hours during the winter, the rate for summer on-peak hours is almost 2.5 times the highest hourly electricity price on the winter tariff. The effects of managed charging under the BEV rate are discussed in detail in the section “Innovation 3: Demonstrated the Alignment of the Commercial Business Electric Vehicle Rate with Cost Minimization and GHG Reductions.”

Table 71. Effects of managed charging protocol

	Phase 0	Phase 1	Phase 2
Share charging during on-peak hours	46%	21%	31%
Share charging during partial peak hours	32%	28%	35%
Share charging during off-peak hours	22%	52%	34%
Average electric fuel cost ($/kWh)	$0.21 [a]	$0.17 [a]	$0.02 [b]

[a] On-site renewables were not yet interconnected and did not generate NEM credits. This is responsible for the large cost differences between Phases 0/1 and Phase 2.

[b] Phase 2 costs do not include payments for participation in the XSP; preliminary data indicates a net benefit rather than cost when XSP payments are included.

Source: Meter Data, Utility Bills

Additionally, as shown in Table 71, compared to Phases 0 and 1, the charging activity during Phase 2 was more evenly spread across on-peak, partial peak, and off-peak hours. All the XSP events called during Phase 2 occurred between 8 AM and 1 PM, which are on-peak and partial peak hours according to the summer A-6 tariff. This means that when charging activity in Phase 2 deviated from the static charging schedule to respond to XSP events, it was likely to result in shifting charging activity away from off-peak consumption on those days. The trends are further diluted because the Blue Bird bus that was introduced during Phase 2 was not capable of delayed charging, yet its consumption is inherently included in the meter data summarized in Table 71. The average calculated fuel cost during Phase 2 was exceptionally low compared to the prior phases because the fleet benefited from application of NEM2A credits generated by the of solar that was interconnected on August 16, 2019.

Based on the theorized design of each test phase, it would be expected that, to the extent TOU prices were aligned with grid GHG emissions, the latter phases of the PRP would have lower GHG emissions on a per mile basis than would the earlier phases. In the case of Phase 0, no charge management system was in place, so there would be no means by which to target charging activity during times of low prices or low carbon intensity on the grid. In contrast, because the fleet employed a charge management system in Phase 1, to the extent that the low TOU periods were aligned with times of low grid electricity emissions, Phase 1 would be expected to demonstrate lower GHG emissions per mile than Phase 0. The GHG emissions values presented in Table 72 bear this out: the static charging schedule in Phase 1 resulted in observed per mile emissions that were 30% lower than they were during Phase 0.

Notably, Phases 0 and 1 both took place during the same quarter of the year and faced the same carbon intensity values for consumption during a given hour. Thus, the observed emission reduction can be attributed at least in part to the change in charging behavior between the Phases rather to seasonality of the grid emissions profile. Grid emissions do vary considerably by season, so adjusted emissions values were calculated that represent the annual averages for each hour of the day. Phase 2 took place during quarters 3 and 4, which have higher average GHG emissions than does quarter 2, when Phases 0 and 1 took place. However, when compared on the adjusted basis, Phase 2 emissions were comparable to Phase 1 emissions, and both were significantly lower than per mile emissions during Phase 0.

Table 72. Carbon intensity per mile across test phases

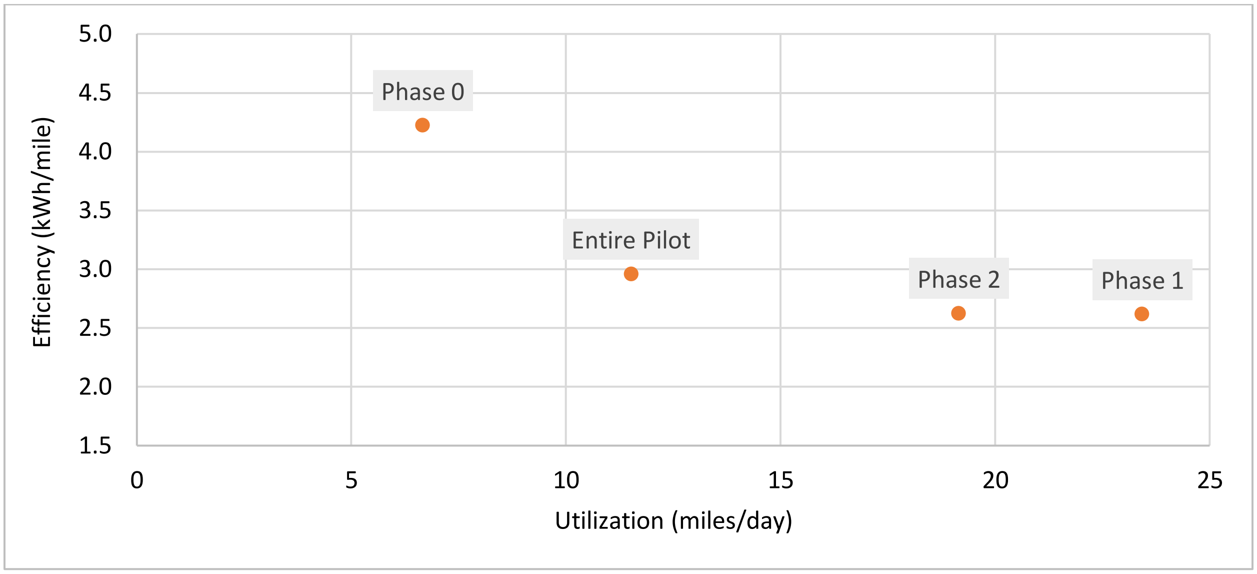
	Industry Average (Diesel)	Phase 0 (Electric)	Phase 1 (Electric)	Phase 2 (Electric)	Entire Pilot (Electric)
GHG Emissions (kg CO2e/mile)	1.54	0.97	0.68	0.87	0.86
Adjusted GHG Emissions (kg CO2e/mile) *Normalized to annual hourly averages*	1.54	1.26	0.77	0.76	0.86

Source: Evaluator Calculations

Participation in the XSP posed two potential benefits: revenue from providing grid services and the potential for additional GHG emission reductions due to the nature of XSP events. XSP events are called when grid managers expect the grid will have non-dispatchable supply available in excess of estimated demand. Because non-dispatchable supply to the CA grid is likely from low carbon sources such as solar and wind, if the school bus fleet were to respond to XSP events this would be expected to lower the fleet's GHG emissions compared to Phases 0 and 1, when the fleet was not participating in the XSP.

Although Phase 2 emissions were significantly lower than during the unmanaged scenario, Phase 2 did not bear out any additional reductions relative to Phase 1 emissions. One notable difference between Phases 1 and 2 was that partway through the Phase 2 test period an uncontrolled Blue Bird bus was added to the PUSD fleet. The introduction of the Blue Bird may have resulted in an increase in the share of energy drawn during higher-emission times of day, such as the late afternoon ramp-up, because the Blue Bird charging activity was not compliant with the default charging schedule. Secondly, the grid electricity emission factors used for this analysis—the hourly Low-Carbon Fuel Standard values per quarter—represent typical grid conditions. On the other hand, XSP events are atypical events called during renewable overgeneration events when the marginal emissions rate of the grid is zero. This may result in an overstatement of emissions during Phase 2 on account of the LCFS GHG emissions factor being assigned to the ~320 kWh consumed when the PUSD fleet was responding to XSP events, rather than a carbon intensity of 0 for those hours.

Figure 220. Correlation between utilization and bus efficiency



Source: Evaluator Calculations

Finally, analysis of the relationship between utilization and fleet electric efficiency presents an important insight. Not only does low utilization reduce the opportunity for operational savings relative to diesel buses (as discussed in the section “What were the Cost Impacts to the Fleet?”), but low utilization also translates to lower electric efficiency. When electric buses are not used regularly by the fleet, they still draw idle power for battery thermal management and other needs. The differences between the phases in these terms suggest that increased utilization is associated with improved efficiency up to a maximum real-world efficiency of about 2.5 kWh per mile.

What Innovations were Achieved?

As noted above, the deployment of electric buses poses new challenges for school districts, underscoring the value of the hands-on approach that PG&E and other partners took in implementing this PRP. The PRP allowed PG&E to test several hypotheses and to advance industry understanding of electrification opportunities for school buses, providing the foundation for three project innovations.

Innovation 1: Managed Charging with Low-Cost, Non-Networked Chargers

The PRP project team aimed to develop an approach that would enable sophisticated charge management of school buses with a low-cost, non-networked EVSE. However, available models of electric school buses have not been designed to accommodate delayed charging. For instance, neither the Lion nor Blue Bird buses supported a straightforward way to achieve managed charging because they both electrically disconnect after a period of time when a charge cable is plugged in, but no power is present. This interfered with the intended approach to have an automated system take care of energy management after the bus driver plugged in the vehicle.

The workaround solution for Lion buses was to employ a version of the Clipper Creek firmware called Maintenance Mode, which supplies a steady 1.3 kW trickle charge at all times when the bus is not scheduled to charge.[80] This adjustment meant there was marginally less capacity available on the battery with which to perform optimization or TOU arbitrage, but still enabled the Lion buses to serve as a managed load. Performance during Phase 1 confirmed that this managed charging solution for the Lion buses allowed the fleet to shift its charging activity toward lower-cost TOU bands. However, this solution did not work for the Blue Bird buses, and no solution had been developed for these buses before the end of the PRP.

Similarly, the selected Clipper Creek hardware does not permit electrical power throttling. This inability meant a workaround was needed for the site to engage in demand charge management. Olivine and project partners developed a round-robin charging solution modulating the duration of charging to achieve the same effect as power throttling. In future deployments this modified approach can be considered as an alternative to power throttling at the charger to achieve the benefits of peak demand management.

Software communication between Olivine and Liberty took more development effort than was initially anticipated, despite efforts during the procurement process to ensure compatibility between the two systems. The load management system needed to be able to manage charging port activity, so the procurement specified that the solution be compliant with the OpenADR 2.0b standard. However, many functionalities can be enabled under the OpenADR standard, and operators do not need to support all those functionalities to be deemed compliant. Olivine and Liberty were able to work through the issues and build a robust OpenADR-compliant interface and a capable charge management system.

More generally, Olivine and Liberty needed to collaborate to initiate the project and ensure that all infrastructure was effectively integrated. This effort can now be leveraged and repeated in future projects, as Liberty and Clipper Creek hardware can now be integrated in a quasi-turnkey way. In the future, PG&E could employ cooperative procurement or provide an approved vendor list to help school districts make informed procurement decisions, which would be a valuable resource for staff who may have limited expertise in EV charging.

Innovation 2: Used Dynamic Signaling to Optimize Buses for Grid Services, Renewables Integration, and GHG Reductions

The PRP project team also aspired to develop an approach that would enable charging activity to be responsive to dynamic signals. This allowed for deviations from the default charging schedule, which allowed PUSD to participate in XSP and to optimize the consumption of on-site renewables.

PRP Demonstrated Providing Grid Services through XSP

Phase 2 of the PRP demonstrated the feasibility of deploying electric school bus batteries as dispatchable loads. Between August 20 and November 26, Olivine signaled 57 battery load-up event hours across 29 events (i.e., charging at the full EVSE capacity during periods of excess wholesale supply)

[80] This is a 6 amp, 220 volt flow, about equivalent to 1.3 kW. This relatively low flow of power ensured that the Lion buses remained active as charging resources whenever the vehicles were plugged in, so they were available to receive signals from the energy management system to dynamically adjust power demand.

and the vehicles were able to increase charging demand relative to baseline consumption for 41 of those event hours. While the PRP effectively implemented the necessary communications and signals for dispatchable load, the magnitude of the load was lower than had been anticipated. The average incremental load during events was 5.15 kW and the fleet only achieved the incremental target of 8 kW or greater during 54% of these event hours. The limited scale of the fleet's battery load-up capacity was due in part to the limited use of Lions, which were the only buses for which controlled charging was accomplished. Low vehicle usage translated to less available battery capacity when XSP events were called.

Additionally, the rate of charge that electric school buses accept is relatively low, and therefore participation in the XSP necessitated an exception to the general pilot requirement of targeting 30 kW of load increase.[81] The Lion bus power conditioning hardware is configured by the manufacturer to accept only approximately 13 kW of power, even though the Clipper Creek chargers can provide 19 kW. Because of the specific characteristics of these technologies and the limitations in their combination, the two Lion buses could only draw a max total of around 26 kW. When calculating their XSP performance, this creates an upper bound to the amount of kW they could provide as dispatchable load because their power draw during the baseline period is not zero. The average baseline during event hours set based on activity on non-XSP days was just over 2 kW. If the state of charge of the bus batteries was low and they were fully deployed in response to an XSP event, they would achieve 24 kW of increase.

PRP Demonstrated Responding to Signals for Renewables Integration and GHG Reductions

During Phase 3 and Phase 4, Olivine used real-time data from the facility meter to identify instances when PUSD's on-site renewables were generating energy in excess of facility needs. The charge management system then would signal the Lion buses to begin charging. This arrangement was meant to result in coincident consumption that favored local, zero-emission renewables over general grid-sourced electricity. The PRP developed and demonstrated the capabilities and systems required to operate charging in this manner. These systems included a load management system (Liberty Plugins HYDRA), a smart energy monitoring device to relay data from the utility meter (Rainforest Automation[82]), a telemetry data connection (Geotab), and Olivine's custom E-Fleet charge management system to implement charge controls.

Although Phases 3 and 4 were successfully implemented, because of the compounded obstacles the PRP encountered in late 2019 through 2020 (refer back to "Timeline" for details), there is no pilot data on the emissions impacts of these phases. Thus, the PRP project team prepared a model that was used to conduct these test phases via virtual simulation.

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[81] Pacific Gas and Electric. Accessed 2019. "Business Energy Incentive Programs." https://www.pge.com/en_US/large-business/save-energy-and-money/energy-management-programs/energy-incentives.page

[82] Rainforest Automation. Last updated 2019. "Our Consumer Products." EAGLE-200. https://rainforestautomation.com/our-products/

Innovation 3: Demonstrated the Alignment of the Commercial Business Electric Vehicle Rate with Cost Minimization and GHG Reductions

As mentioned previously, PG&E created a virtual simulation tool to model the performance of four electric buses under test Phase 3 and Phase 4. These simulations prescribed fleet energy needs based on actual operational data from earlier phases. Bill impacts were assessed under the A-6 and the newer Commercial Business Electric Vehicle (BEV) rate. The PRP project team determined the BEV rate to be better suited than the A-6 rate to achieving the simultaneous goals of encouraging on-site renewables, minimizing GHGs, and reducing energy costs. As illustrated by the green Super Off cells in Table 73, the lowest cost TOU periods on the BEV rate are during midday hours. This encourages consumption during hours when the renewables penetration on the grid tends to be highest (indicated by green cells in the hourly emissions per quarter columns). On the other hand, the midday hours with low GHGs are among the highest cost TOU rate periods on the A-6 tariff (indicated by red cells in the A-6 column), creating a misalignment between the priorities of reducing costs and reducing GHG emissions.

Table 73. Alignment between tariff schedule and grid emissions intensity

Rate Structure			Hourly Emissions per Quarter (gCO2e/kWh)			
BEV rate	**A-6 (summer)**	**Hour**	**Q1**	**Q2**	**Q3**	**Q4**
Off-Peak	Off-Peak	12 a.m.	289	289	293	302
Off-Peak	Off-Peak	1 a.m.	289	289	289	295
Off-Peak	Off-Peak	2 a.m.	289	286	289	292
Off-Peak	Off-Peak	3 a.m.	289	290	288	291
Off-Peak	Off-Peak	4 a.m.	289	289	288	294
Off-Peak	Off-Peak	5 a.m.	295	303	289	321
Off-Peak	Off-Peak	6 a.m.	354	349	316	396
Off-Peak	Off-Peak	7 a.m.	377	244	304	387
Off-Peak	Partial	8 a.m.	277	8	293	318
Super Off	Partial	9 a.m.	194	6	204	300
Super Off	Partial	10 a.m.	191	9	212	200
Super Off	Partial	11 a.m.	187	167	233	212
Super Off	Peak	12 p.m.	98	177	262	217
Super Off	Peak	1 p.m.	98	183	300	306
Off-Peak	Peak	2 p.m.	187	195	325	311
Off-Peak	Peak	3 p.m.	192	211	382	337
Peak	Peak	4 p.m.	234	88	404	417
Peak	Peak	5 p.m.	385	106	433	500
Peak	Partial	6 p.m.	448	355	482	507
Peak	Partial	7 p.m.	436	501	516	485
Peak	Partial	8 p.m.	396	499	462	449
Peak	Partial	9 p.m.	332	404	390	398
Off-Peak	Off-Peak	10 p.m.	295	309	330	351
Off-Peak	Off-Peak	11 p.m.	289	292	301	312

Source: PG&E, CA 2020 Low Carbon Fuel Standard

Notably, modeling also suggested that the BEV rate does not integrate well with participation in the XSP. All XSP events called during Phase 2 occurred between 8 AM and 1 PM, exactly overlapping with the super-off-peak period of the BEV rate. Therefore, BEV rate customers that are actively managing their charging to minimize bills will regularly schedule as much consumption as they can during these hours. Meanwhile, participation in XSP requires setting a baseline level of consumption during non-event hours and increasing consumption substantially above that baseline during event hours. This means that it would be quite difficult for sites already optimizing for the BEV rate to deploy additional capacity on event days relative to their baseline. PG&E's Commercial BEV rate design is effective in motivating desired charging behavior and consumption patterns, while XSP participation is an alternative approach to encourage desired behaviors for fleets that do not adopt the BEV rate.

5.1.4 Conclusions

Accomplishments

At a high level, the project has had both successes and challenges. PG&E, Olivine, and PUSD worked well as a team to overcome many challenges during each stage, from planning to operating the buses. PG&E intentionally selected a project in a nascent market and planned to be closely involved to provide guidance. Nevertheless, the buses were underused relative to expectations due to several challenges typical to early-stage deployments of new products, as well as due to extraneous factors. Most of these challenges have been related to the buses; in other words, they do not reflect on the quality of the PRP effort, but they did limit the ability of the PRP project team to implement test phases to the extent and on the schedule originally anticipated. Although this PRP went beyond the near-term needs of most school districts, the innovations demonstrated are important proofs of concept to move the market forward in a statewide context, as it is expected that many more school districts will soon begin to increase their investments in both behind-the-meter renewables and electric buses.

The first innovation tested through this PRP was the feasibility of combining low-cost, non-networked EVSE and distributed energy resource technologies for dynamic charge management functions. When selecting system technologies, some customers may be drawn to the simplest, least-expensive options available. The PRP successfully demonstrated the feasibility of such a system. However, the experience has demonstrated that default electric school bus battery management systems are not currently designed to enable charge management.

The second innovation tested was to use electric school buses to facilitate the integration of intermittent renewable generation, both in the context of on-site solar and wind and in response to excess wholesale electricity supply during high renewable events on the grid. The PRP demonstrated the feasibility of using electric school buses for such purposes, as well as the complexity of establishing such a project and obtaining substantial participation from bus manufacturers. One complicating factor was that the on-site renewables were not within PG&E's purview for the PRP itself, and delays in the installation of some of these resources affected the ability of project implementers to maintain the protocol test schedule originally envisioned. Additionally, bus operational issues and driver staffing constraints reduced the District's ability to fully use the electric buses, which limited the amount of controllable load available to date.

Lessons Learned

- Contracting, construction, and implementing test protocols with schools may require planning for extra time to reflect their unique contracting processes and seasonal operational patterns.
- Fleet electrification projects do not occur in a vacuum and are subject to broader risks that site hosts face. For example, projects that implement networked systems or virtual charge management controls are exposed to cybersecurity threats. These internet-enabled capabilities are only as durable as the site host system is secure.
- School districts and other early fleet adopters may not be able to adjust operations to optimize the use of new electric buses. The suitability of selected electric buses to serve as a 1:1 replacement for existing fleet vehicles should be carefully considered during procurement (including passenger capacity and range), or expectations for usage (number of days in use and overall mileage) should be appropriately tempered.
- The electric school bus industry is experiencing growing pains, which affects equipment O&M. PRP activities brought to light new barriers and accelerated conversations between key industry actors to identify issues and search for solutions.
- When upfront cost support is available, electric school buses have strong potential to reduce fleet TCO relative to the fleet baseline due to the large fuel and O&M savings anticipated under normal operating patterns; lacking support in the form of grants and infrastructure, the cost of electric school buses relative to conventional vehicles does not pencil out.
- Managed charging with low-cost, non-networked chargers is feasible and can yield operational cost savings for the fleet compared to uncontrolled charging.
- PG&E was insightful in scheduling a significant block of time after commissioning during which project operators could iron out issues with project hardware and software integration. The challenge of identifying the cause of issues can be compounded when there are several distinct systems integrated in a single project.
- The use of dynamic signaling to optimize for grid services, renewables, and GHG reductions is feasible. These opportunities can be better realized with high, consistent utilization of the buses.
- PG&E's Commercial BEV rate design is effective in motivating desired charging behavior and consumption patterns but does not align well with XSP participation.

Potential for Scale-up

Several attributes of school bus electrification make it a promising target for scaling innovation: the alignment of times when school buses are available to charge at low-cost and during cleaner time periods for the grid, the availability of incentive money that funds bus replacements and infrastructure, and the eagerness of these districts to work as partners. Sharing the lessons learned and innovations demonstrated in this PRP has the potential to (1) streamline the process for future customer partners, (2) help school districts establish realistic expectations associated with their electrification strategies, and (3) increase the value and cost-effectiveness of deploying electric school buses.

One replicable aspect of the PRP is the charge management system that Olivine developed. For example, the E-Fleet User Interface web tool Olivine created can be used by other fleets. The interface displays daily energy exported to the grid by renewables, daily energy used to charge the vehicle fleet, the rate of charge for active buses, and calculations of avoided GHG emissions of vehicle activities relative to comparable diesel vehicles.

TCO analysis suggests that the innovations and lessons learned from this project are likely to pave the way for further deployment of electric school buses both at PUSD and throughout PG&E's territory. The PUSD pilot has demonstrated that electric school buses are feasible and can be cost-effective to the fleet when the right financial assistance is provided. Because school districts are extremely budget conscious, fleet managers who learn of these results can be expected to adopt electric buses at a faster pace than would have been achieved without PG&E's involvement in this PRP.

More generally, pilot projects like this one help the industry build key technology integrations. This project uncovered and resolved inevitable integration issues between buses, chargers, and charge controllers that can now be resolved more quickly in future applications. Such integrations require significant investments of time and expertise and will likely need to be revisited for different combinations of bus models, charger models, and control hardware and software. To the extent that industry players are observing this pilot and others like it, their awareness of the importance of working toward integrated solutions may have increased. The conversations between vehicle OEMs, charger OEMs, and program implementers (such as Olivine) contributed to fluency between key industry actors and led to key issues being discovered. As more of these technology integrations are implemented, the low-cost offerings should improve and become more turnkey.

To the extent that school districts are observing innovations that were put into action at PUSD, there is also the potential for increased demand for these solutions. PUSD has a strong culture of sharing its accomplishments, best practices, and lessons learned with fellow school districts. This PRP included the creation of a case study, webpage, and other informational material, which, when shared with other school districts, will enhance awareness of the viability and benefits of electric school buses.

5.2 Medium-/Heavy-Duty Customer Fleet Demonstration

5.2.1 Project Narrative

Overview, Objectives, and Barriers Being Addressed

Overview

This final evaluation report covers all Priority Review Project (PRP) stages completed: scoping and customer acquisition, project design and preparation, construction, commissioning, project operations, data collection and analysis, and lessons learned. This chapter summarizes the evaluation of the electric bus fleet demonstration in San Joaquin Regional Transit District between 2018 and 2020. The project is one of the PRPs as described in California Public Utilities Commission (CPUC) Decision 18-01-024.

For this PRP, PG&E sought a partner who operates a medium-duty and heavy-duty (MD/HD) fleet to assist in deploying electric vehicles (EVs) by leveraging the utility's resources and expertise. For PG&E to help the MD/HD fleet electrification market grow, it needs to support the early adopters and ensure they have positive experiences. By supporting early adopters, PG&E can not only develop innovations and best practices but also shape the narrative about the processes and benefits of deploying MD/HD EVs. PG&E aims to achieve a broad positive effect on the market by using this PRP to identify and showcase best practices in infrastructure and management of MD/HD fleet electrification.

A unique element of this project was PG&E's hands-on approach. They worked closely with all relevant stakeholders and collaborated extensively with the customer, vehicle and charger manufacturers, and other partners. This direct approach ensured PG&E could capture and develop lessons learned to inform long-term, widespread MD/HD transportation electrification, including the development of the Standard Review Project, the EV Fleet program.

With this collaborative approach, PG&E was responsible for designing and building the make-ready infrastructure to support the depot chargers of the new electrified fleet. The utility worked directly with the customer to find efficiencies in site planning and infrastructure sizing for the expected load. To manage charging costs on existing rates and to reduce peak demand use, PG&E worked with the customer and other third parties to incorporate technology solutions—primarily charge management software and energy storage.

Objectives

The primary goal of the project is to demonstrate if, with support from the utility, fleet managers can lower the total cost of ownership (TCO) for MD/HD electric fleets relative to fossil fuel alternatives. This demonstration will help inform other utilities, fleet operators, site hosts, and customers considering EV deployments. Specifically, the PRP will accomplish the following:

- Deploy utility-owned, make-ready infrastructure to serve expected growth in EV charging.
- Provide an incentive to deploy EV chargers.
- Provide technical assistance, including rate optimization and demand management technology, to minimize the operating costs of EVs.

- Produce a summary handbook of lessons learned to inform fleet and other MD/HD EV deployments.

PG&E also plans to use its non-electrification resources (such as energy efficiency, distributed generation, and demand response products and programs, along with rate analysis) to evaluate additional opportunities for energy management and customer bill savings. The most appropriate customer candidate for this project was a public transit agency, given the sector's maturity in commercially available electric buses, external funding sources for vehicles and charging infrastructure, and EV adoption goals. With California Air Resources Board (CARB) releasing its Innovative Clean Transit (ICT) regulation in December 2018, all public transit agencies are required to develop plans to procure electric buses and/or fuel cell buses and transition their existing fleets by 2040.[83] ICT requires transit agencies to substantially rethink their operations, particularly as these solutions and innovations affect their traditional finance models.

Barriers

Utility investment in MD/HD fleet electrification can address two key barriers: upfront electrical infrastructure costs and ongoing electrical charging costs. This demonstration aims to reduce these barriers and to provide a model for how utilities can support fleet electrification projects.

To maximize PG&E's success in future collaborations with transit agencies, those agencies must have confidence that they can achieve cost savings when operating an electric fleet. On the current rate structure most transit agencies use, demand charges have posed a challenge and ongoing operational costs have not always decreased following adoption of EVs. To this extent, PG&E has separately made a business EV (BEV) rate available, which will mitigate many challenges that transit agencies and other fleets face in managing their charging costs.[84]

The learning curve for planning and operating an electric fleet poses another barrier for transit agencies that PG&E can address. Most agencies do not know the best way to provide adequate charging infrastructure for electric buses. Additionally, they do not have experience with the new operational challenges associated with deploying electric buses, including understanding capabilities and limitations, and how to effectively integrate electric buses into their regular operations. Guidance from the utility for such implementation projects will prove crucial to advancing the MD/HD fleet electrification market.

Sites and Participants

Recruitment of Site Host

To recruit site hosts for the pilot in January 2018, PG&E created a list of over 50 transit agencies and contacted several to track electric bus interest and planned procurements. PG&E wanted to partner

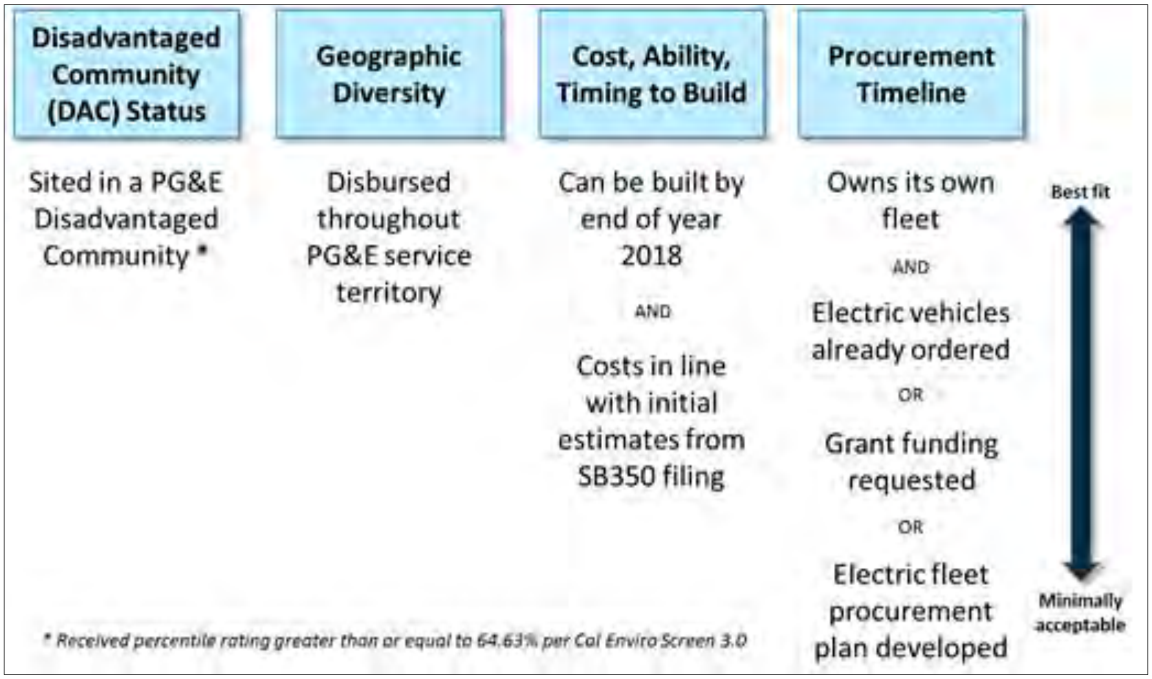
[83] CARB. Accessed 2019. "Innovative Clean Transit."https://ww2.arb.ca.gov/our-work/programs/innovative-clean-transit.

[84] CPUC. October 24, 2.19. Decision 19-10-055.
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M318/K552/318552527.PDF

with a transit agency that already used electric buses as this would likely result in a smoother design and construction process for charger installation to meet the January 2019 target completion timeframe.

PG&E then used the criteria outlined in Figure **221** to create a short list of potential transit agencies for the project. By early February 2018, PG&E had identified the San Joaquin Regional Transit District (RTD) as an ideal candidate for the pilot as it met all desired criteria; RTD had an existing fleet of 12 electric buses, had new buses on order, and had announced a goal to electrify 100% of its fleet operating within Stockton city limits by 2025.

Figure 221. Evaluation criteria for PRP participants[85]



Source: PG&E

Site Host

Prior to this project's start, RTD was already operating two generations of legacy electric buses. These included two 2013 Proterra prototypes and 10 2016 Proterra electric buses, both with 30-mile to 50-mile ranges, that RTD began operating in September 2017. Because of limited battery capacity and route requirements, these buses used on-route 500 kW overhead chargers to complete their routes; relying on overnight depot charging was not an option.

Prior to the PRP, RTD was experiencing high electric bus costs per mile resulting from demand charges and uncontrolled charging practices. RTD is currently a PG&E customer on the new BEV rate, but for the majority of this project they operated on the A-10 time-of-use (TOU) rate. The A-10 TOU rate includes a

[85] PG&E. January 31, 2019. *Interim Report of Pacific Gas and Electric Company (U 39 E) on Priority Review Projects Pursuant to Decision No. 18-01-024.* http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=285086006

demand charge (per kilowatt) and an energy charge (per kilowatt-hour).[86] PG&E's new BEV rate, which RTD implemented in July 2020, supports transportation electrification for commercial fleets and has helped manage costs for RTD.

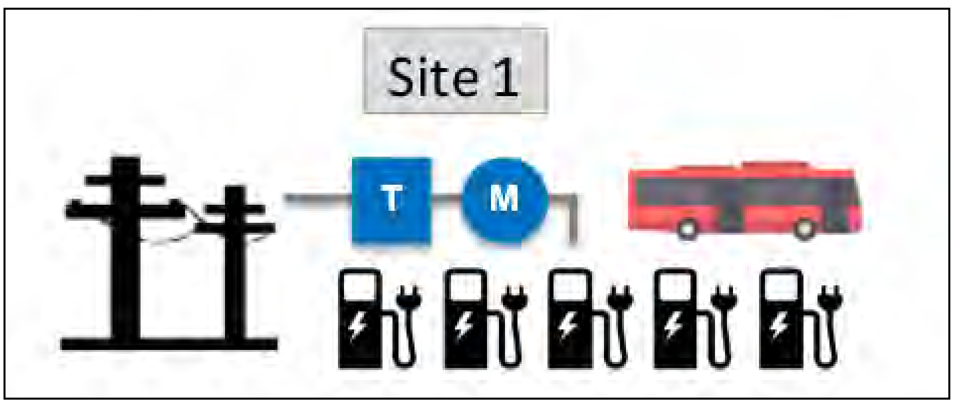
In early 2018, RTD began taking proactive measures to reduce future charging costs by procuring five new electric buses with longer nominal ranges (~250 miles) that could take advantage of overnight depot charging. RTD had not, however, yet developed a clear plan for how to charge and deploy these buses; discussions with PG&E through this PRP enabled RTD to pursue a demonstration targeting lower TCO.

RTD also has a goal to operate all routes within the City of Stockton exclusively with zero emission buses by 2025. As such, RTD seeks a better understanding of the requirements to scale up its electric fleet, as well as the level of collaboration needed with PG&E to upgrade its behind-the-meter and make-ready infrastructure to accommodate an increasingly electric fleet.

Sites

This PRP involved three sites at RTD. At Site 1, the Regional Transportation Center (RTC), five 60 kW depot chargers were installed to charge the five longer-range electric buses overnight. Figure 222 shows a diagram of Site 1's setup, which became operational in May 2019. A key question associated with this site is whether the TCO for a depot charger configuration is reduced relative to the baseline of diesel-hybrid buses on the same routes.

Figure 222. RTD Site 1 diagram



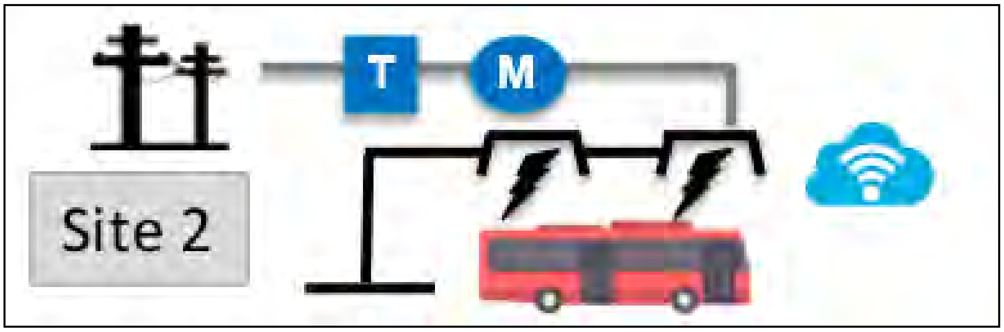
Note: T = Transformer and M = Utility Electric Meter
Source: PG&E

Site 2, the Downtown Transit Center (DTC), is the largest transit hub in Stockton and at the center of RTD's system. This is where RTD installed its original pantograph chargers (overhead fast chargers that automatically couple with an apparatus on the roof of the bus when the bus pulls into its parking space at the transit center). These two 500 kW Eaton overhead fast chargers serve electric buses operating on four short routes. Figure 223 illustrates Site 2's configuration. Although the chargers existed prior to the

[86] Full tariff details are provided here: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_A-10.pdf

PRP, PG&E deployed charge management software in October 2018 at this site to address high demand costs.[87] RTD is trying to determine whether managed charging will reduce electricity bills while still serving the operational needs for electric buses on these routes.

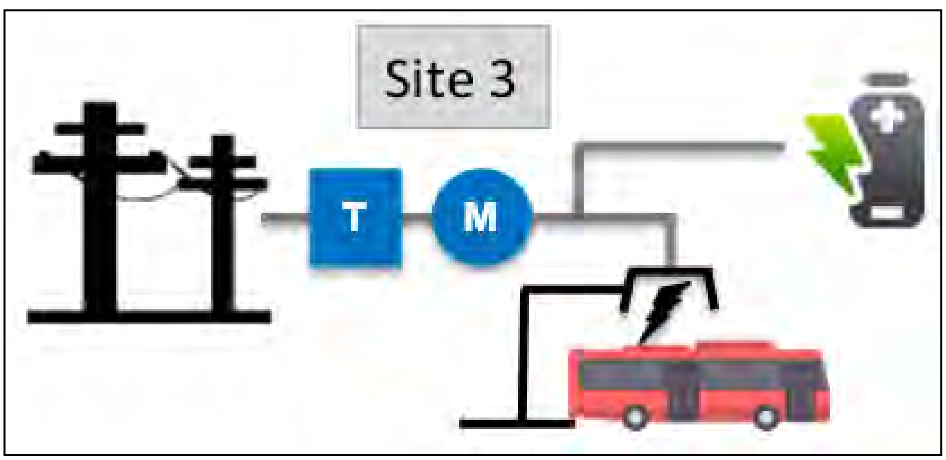
Figure 223. RTD Site 2 diagram



Note: T = Transformer and M = Utility Electric Meter
Source: PG&E

Site 3, Union Transfer Station (UTS), is where a new Siemens overhead fast charger was installed (paid for by RTD) and where this PG&E PRP plans to add a battery electric storage system (BESS). UTS is located at the intersection of two key RTD bus rapid transit routes, the Metro Express Airport and Martin Luther King Corridors, both of which now use electric buses. Figure 224 shows a diagram of Site 3. A key question here is the degree to which energy storage can reduce operational costs, particularly following the transition to the BEV rate.

Figure 224. RTD Site 3 diagram



Note: T = Transformer and M = Utility Electric Meter
Source: PG&E

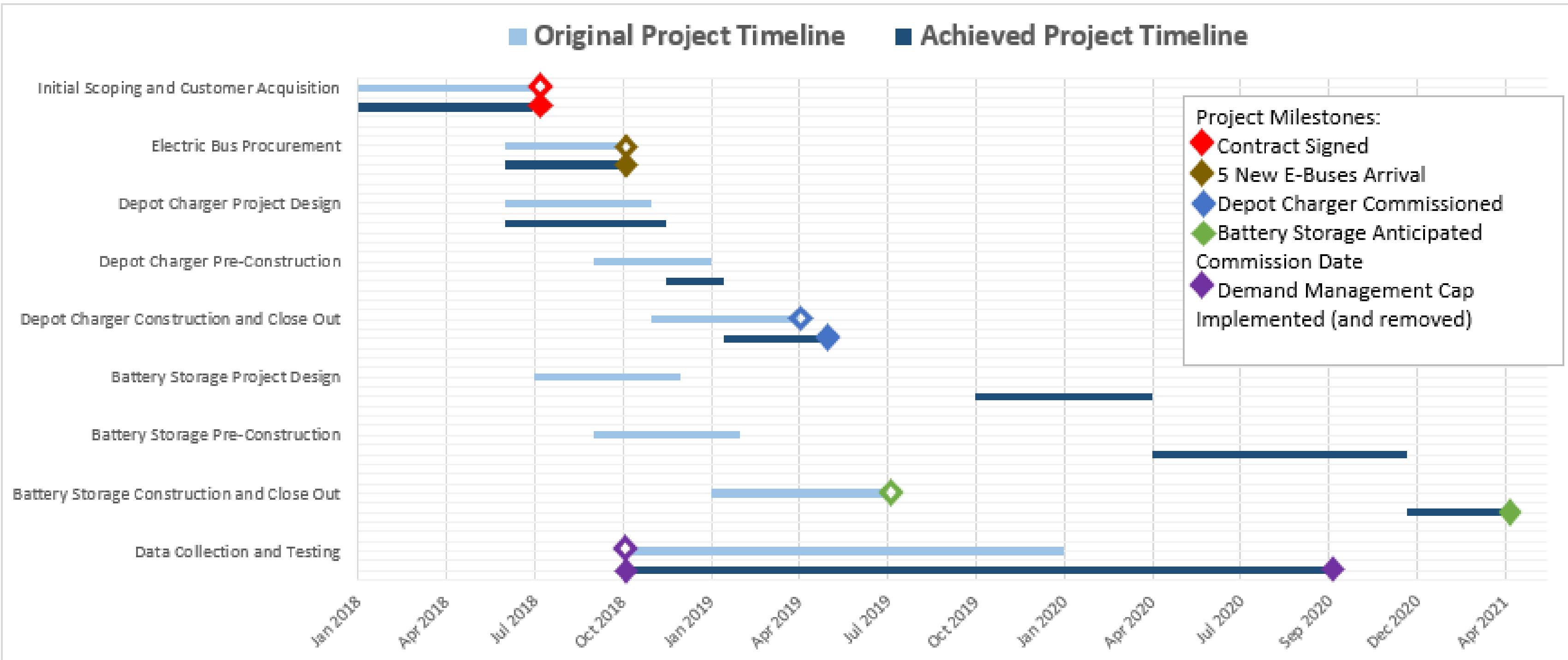
[87] In August 2020, RTD removed the charge management software following its transition to PG&E's BEV rate.

Timeline

Original Planned Timeline

Figure 225 illustrates the original timeline (pale blue) and the achieved timeline (medium blue) for the MD/HD PRP. This divergence reflects a variety of disruptions and challenges, many of which were unforeseeable on the part of PG&E or the site host.

Figure 225. PG&E Transit Fleet PRP comparative project timeline



Note: Open diamonds indicate original milestone date.

Source: PG&E

The original PRP plan had the depot chargers operational and the BESS integrated by January 2019 to collect a full year of operational use data, prior to the original timeline for the PRP's conclusion in December 2019. As CPUC approved a request to extend the final evaluation report to January 2021, PG&E was able to obtain more than 12 months of data for demand management and depot chargers. The BESS is anticipated to be integrated by March 2021 and therefore operational data are not available to include in this evaluation report.

What Went Well

A few factors also accelerated the project timeline, without which the delays would have been more substantial. First, the recruitment process aligned well with PG&E's goals, as RTD met all criteria that PG&E wanted in a partner. RTD had new electric buses on order, served DACs, had experience running electric buses, had a demonstrated need to implement better charge management protocols, and was keenly interested in learning and developing operational best practices to support its ultimate goal to electrify 100% of its fleet by 2025. Having buses on order enabled an early start to the design process, and prior electric bus experience addressed some common operational challenges in switching to this technology. Second, RTD could sole-source Proterra chargers, as it had already procured Proterra buses. If a sole-source procurement had not been possible, RTD would have needed to issue a solicitation, which could have added a month or more to the timeline. This efficiency could have saved even more time if RTD had intended to use Proterra chargers all along. Originally, RTD staff expressed interest in ChargePoint chargers because of their demand management capabilities, but ultimately selected Proterra equipment, which mitigates the complexity of resolving charging issues as a single company would be responsible for addressing these.

Explanation of Notable Timeline Alterations

At RTC

Depot chargers were delayed by about a month as a result of changes in the to-the-meter design. The construction duration was extended because of an increased scope of work. The project team planned to access a PG&E transformer located on a neighboring property. The team determined, however, that a new transformer, vault, and primary riser offered the best option to mitigate the need for easement. This resulted in a slight delay to the original schedule.

To mitigate further delays, behind-the-meter construction commenced while PG&E revised the to-the-meter design to accommodate the change in scope. With the changed scope, four out of five chargers were operational on March 21, 2019. The final charger, which required repair by the manufacturer, was activated on May 4, 2019.

At UTS

Several factors have contributed to a substantial delay in implementing the BESS. The full extent of delay is still unknown, as construction has yet to start as of November 2020.

First, RTD and PG&E needed time to identify the preferred location for the BESS. According to interviews with the RTD project manager, DTC was originally RTD's preferred location because of the large number of electric buses that charge there and the known need to manage demand charges. Concerns emerged, however, about space availability at DTC and the need to disrupt DTC services during the BESS installation (DTC is the busiest bus station in RTD's system). PG&E recommended that the BESS installation be shifted to UTS, a greenfield site under development for a new transit hub, with ample distribution system capacity and space for future expansion of batteries and solar. The addition of solar falls outside of this PRP's scope but could integrate well with BESS in the future. The grand opening of UTS did not occur until late February 2019, and some time was needed to operate the new station before planning the BESS installation.

Next, a number of factors slowed down planning and design of the BESS. Unlike the depot chargers, RTD was responsible for the design and installation of the BESS. Originally, RTD planned to solicit a design-build bid for the BESS installation, where contractors would design and build the system. After they submitted documentation to their procurement department in October 2019, leadership transition issues resulted in a delayed determination that the project was not of a high enough dollar amount to qualify for a design-build bid. This decision was made in February 2020. RTD took another two months to develop the designs with support from the vendor, ENGIE, before soliciting build bids.

Finally, RTD underwent three rounds of bidding with contractors starting in April 2020. The first round came back with considerable variability in contractors' materials and labor cost estimates. The ongoing pandemic increased uncertainty in labor and material costs, and in processing times, causing additional delays. RTD revisited their drawings and added more details in an attempt to reduce the variability in responses. In the second round of bidding, one of the contractors identified a discrepancy in the design regarding a cost estimate. RTD corrected the mistake and issued a third set of drawings. The final round of bids came in September 2020, and RTD issued a notice to proceed in December 2020. RTD estimates a 60-day build period and 10-day commissioning period before the BESS is operational. When potential weather delays are taken into consideration, RTD expects the BESS to go live by the end of April 2021. They experienced delays in reviewing the bids and sending the notice to proceed due to significant staff and leadership changes. RTD purchased the battery from ENGIE in April 2020 and is storing it at a nearby warehouse.

Planned Activities and Test Phases

Currently, RTD operates three different models of Proterra electric buses (detailed in Table 74) that charge at the three sites described in the *Sites* section above. PG&E has concluded construction and implementation activities at Sites 1 and 2 and installing the BESS at Site 3 will complete all infrastructure installations for the PRP.

Table 74. Relevant electric bus specifications

Manufacturer	Proterra		
Model	BE35	Catalyst Fast Charge	Catalyst E2 Long-Range Buses
Vintage	2013	2016	2018
Quantity in RTD Fleet	2	10	5
Battery Size (kWh)	78	105	440
Nominal Range (miles)	49	62	251
Charging Protocol	DC Roof-Mounted Pantograph	DC Roof-Mounted Pantograph	DC SAE Combo and DC Roof-Mounted Pantograph (can be configured for both)

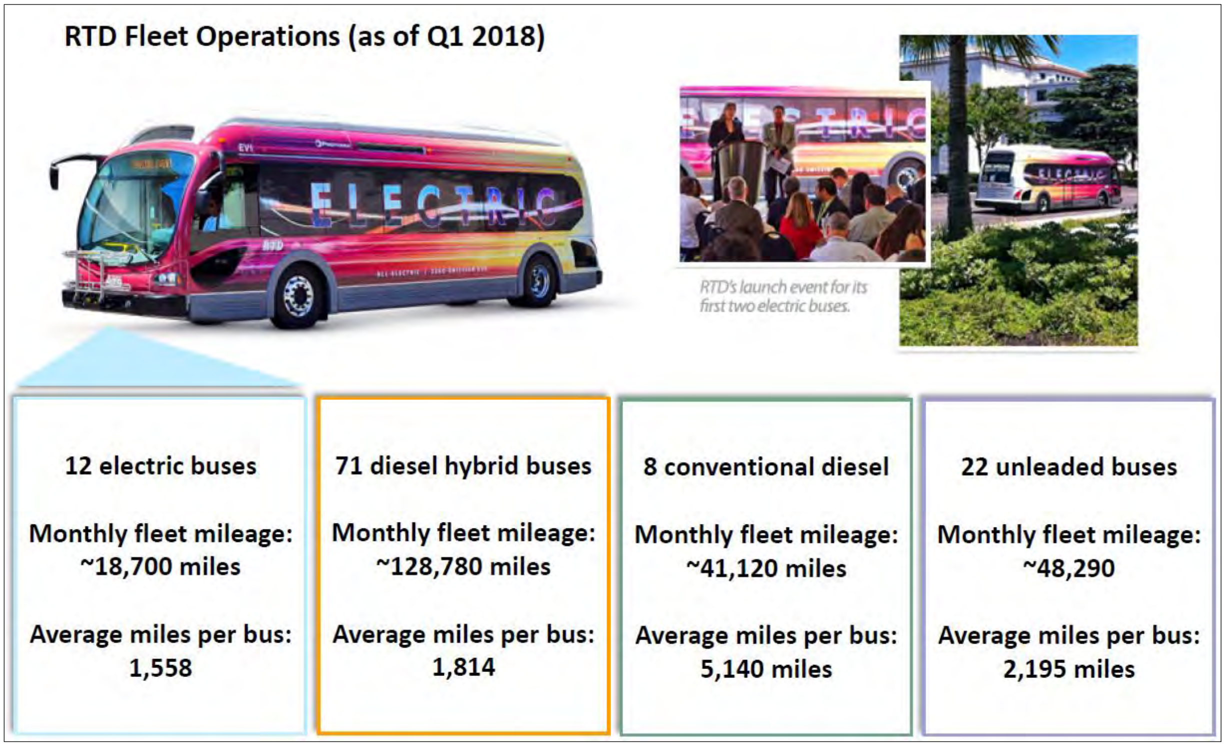
Source: PG&E

Toward the end of 2019, PG&E shifted its focus from PRP infrastructure to advising RTD and gathering insights by testing the cost and operational impacts of implementing different charging protocols. PG&E and the evaluation team collaborated with RTD to develop tests that would not adversely affect fleet operations and that aligned with RTD's informational needs. PG&E's objective for these tests was to better understand bus and charger system capabilities to apply lessons to future recruitment, planning, and implementation of transit electrification for other fleets across its service territory. For a discussion of the tests, refer to the section below that address these questions: *What were the cost impacts to the fleet?*

Operational Delays

Frequently, technical and maintenance issues have prevented the electric buses from being used as extensively as the fleet's diesel-hybrid and diesel buses. As shown in Figure 226, a typical diesel-hybrid bus accrues over 1,800 miles per month. As of Q1 2018, before RTD procured the new long-range buses, electric buses across the fleet averaged 1,558 miles per month. That average mileage dropped to 1,035 per electric bus throughout 2018 and rebounded to 1,348 per bus per month from January 2019 to October 2019.

Figure 226. Comparison of monthly mileage per bus, January 2018 to April 2018



Source: PG&E

The evaluation team's interviews with RTD staff revealed issues with the electric buses and charging infrastructure. For instance, the overhead chargers at DTC and UTS were down for multiple months in summer 2019. RTD also reported that the five new buses did not have sufficient range to operate all day on a single charge. The buses did not come close to their advertised nominal range, and RTD pulls them from service when they reach a 20% state of charge (SOC) so that they do not become stranded on route. These types of issues are not surprising given the relative early stage of electric bus deployment. The need to pull the new buses from their routes is reduced significantly when they take advantage of opportunity charging at UTS.

There were other issues with the chargers that did not affect operations but needed to be resolved. For instance, PG&E diagnosed a problem with the RTC overnight depot chargers because they went down regularly during midafternoon—an issue that did not affect current operations but still needed to be fixed. PG&E determined that the problem was a power-quality issue, rather than a problem with the chargers themselves, and took corrective action.

Additionally, PG&E continued to elevate the importance of addressing RTD's needs with Proterra, particularly in helping line up the buses early for the upgrade in Proterra's telematics system to obtain useful data more rapidly on fleet operations. PG&E has also advised RTD on rate structures, test designs, and collecting lessons learned, which will help it plan for the expansion of its electric fleet. RTD plans to continue working with PG&E as it expands the fleet through its new EV Fleet program.

Areas for Implementation Improvement

Partner Coordination

One area for improvement is to encourage partner agencies to coordinate with PG&E as early as possible, ideally prior to acquiring buses. This will enable PG&E to help the agencies understand their options and determine the best charging and bus configurations. By design, PG&E partnered in this project with an entity that already had made decisions about its electric bus procurement, so this was not possible. It is, however, a recommended best practice for future projects. For example, RTD was not aware that depot charging was even an option with the new electric buses and would have benefited from talking with PG&E earlier in the process. RTD was able to find the right configuration of chargers to suit its needs after working with PG&E.

Data Monitoring

Another challenge arose in obtaining and monitoring data when RTD first acquired the new long-range electric buses. The utility meter did not operate properly for the first six months, resulting in an electricity consumption data gap from January 18 to June 10, 2019. This prevented RTD from receiving valuable information about the amount of electricity buses consumed and how much it would have cost.

Another issue was that Proterra's data loggers were not able to keep up with the massive amounts of data on its servers (a result of their significant market growth). As a result, PG&E and RTD were not able to track real-time or historical data covering the period between early summer 2019 and late fall 2019. Proterra resolved these issues, and the improved access to data for the remainder of the PRP led to more comprehensive and informative lessons learned.

Project Planning and Design

Finally, RTD and PG&E may have shortened the delay to installing the BESS by making key design decisions about it earlier, including how to meet PG&E's interconnection application requirements such as operating requirements, single-line diagram requirements, and inverter certification. As described in *Explanation of Notable Timeline Alterations*, some delay was unavoidable because of the importance of PG&E aligning with RTD on key decisions (such as site selection) for this project component. Additionally, RTD may have avoided some delays had internal communication around the solicitation process been better; the BESS contractor solicitation was delayed six months because of a miscommunication regarding what RTD could solicit as a design-build bid.

5.2.2 Evaluation Objectives and Data Sources

Objectives and Research Questions

The objective of this PRP is to demonstrate lower TCO for MD/HDV electric fleets in comparison to fossil fuel alternatives and the value of utility assistance in achieving that goal. More specifically, this project is focused on better understanding charging protocols and demand management mechanisms to lower the fuel cost per mile of an electric fleet. By applying different charging protocols, this PRP aimed to better understand how to manage the rigid operational requirements of transit fleets with cost-effective fueling practices. The transit agency can then apply the lessons learned from this project to its future electrification plans and enable scale up within the fleet.

The evaluation team collected a range of data types to answer the PRP evaluation questions. For this PRP, in addition to the research questions that apply to every fleet electrification PRP, the evaluation sought to understand the challenges and innovations associated with implementing charge management, overnight charging, and coupling the BESS with an overhead fast charger. The evaluators investigated this by answering the following research questions:

- What were the operational impacts on the fleet and its staff?
- What were the cost impacts to the fleet?
- What was the fleets overall satisfaction?
- How, if at all, did the PRP change electrification within the fleet?
- What were the net energy and emissions impacts (relative to the no-PRP scenario)?
- How did these impacts accrue in disadvantage communities (DACs)?
- What were the co-benefits?
- How did PRP costs compare to expectations?
- What were the lessons learned on market readiness? What implications does this have for the role of the utility?
- What were the lessons learned on charging cost management?
- What were the lessons learned on measurement and tracking of bus performance in a complex fleet environment?

Of these research questions, the highest priority ones focused on managing the variability of fuel cost for the electric fleet and understanding the steps to rapidly scale up RTD's electric operations. At the onset of this project, RTD was experiencing high demand charges from its legacy buses and was interested in how to mitigate those costs with managed charging protocols that did not sacrifice the reliability of its operations. Their interest in active demand management protocols at their overhead chargers shifted after their transition to PG&E BEV rate and they saw a noticeable change in their electricity bill with this new rate structure. However, the evaluation team has still gleaned valuable lessons learned from testing different demand management strategies, regardless of whether RTD continues to implement them.

Data Sources

Data collection has included in-depth interviews with PG&E and the RTD staff to better understand the decision-making process and rationale behind the project. The evaluation team conducted the interviews following the completion of all possible testing to collect lessons learned on implementation, costs, and bus operations. The team also interviewed Proterra and ENGIE to collect lessons learned from vendors working with a transit agency and understand how their solutions are sized to fit the needs of an increasingly electric transit agency.

The evaluation team sent a survey to RTD's bus operators to collect data on their experience and satisfaction with the electric bus operations. RTD shared operational and cost data in the form of maintenance and fuel records, mileage records, and bus routes and assignments for both its electric fleet and the diesel-hybrid fleet operating on the same routes. The team also collected data from PG&E, including electricity bills, meter interval data, PG&E costs to implement the PRP, and equipment out-of-service dates. The team collected and shared data on the electric buses through Proterra's data portal, APEX. It was given access to RTD's account to independently extract and analyze operations of the electric fleet. This level of access allowed the evaluation team to better understand the operational range of the 2018 buses and how SOC is shown to drivers.

5.2.3 Evaluation Findings

This section is organized by the research questions articulated in the section above and grouped into three categories: (1) the results observed to date from a fleet perspective, (2) the results observed to date from a societal perspective, and (3) the project legacy.

Results Observed to Date: Fleet Perspective

This section address whether the project impacted the fleet's operations, demonstrated the TCO benefits of electric transit buses using depot chargers, and satisfied fleet and stakeholder needs

What were the operational impacts on the fleet and its staff?

RTD has carefully tracked the operational impacts of the electric buses and their chargers to enable more efficient scaling of its electric bus deployments. The District has dynamically modified its route assignments to learn about how it can increase the number of miles driven on the electric buses and manage charging costs. The electric buses and charging infrastructure have affected operations in three major ways:

- Ability to meet route needs for daily service
- Difference between expectations and actual charging capabilities
- Maintenance considerations and net changes in uptime relative to the diesel-hybrid buses that the electric buses replace

Ability to Meet Route Needs

Overall, RTD has adapted to enable operation of its electric bus fleet. To do so, the transit agency focused on two aspects of the PRP project: (1) the difference between nominal and real-world range of the buses and (2) the need for more careful management of state of charge when using the demand management cap at the DTC.

Nominal Versus Real-World Range

RTD has found the new Proterra Catalyst E2 buses do not achieve the ranges originally anticipated. As the agency transitions from a protocol where it previously used low-range buses with frequent-opportunity charging to a protocol that relies on overnight depot charging, fleet staff hopes to find that the larger batteries will enable them to serve longer routes without opportunity charging. In addition to expected impacts from extreme summer and winter temperatures, terrain, and passenger loads, RTD has found that the effective range in revenue service is limited by two other factors: (1) the manufacturer's recommendation not to deplete the battery below 20% SOC on a regular basis and (2) the nonrevenue service miles accrued driving the bus to the route from the depot (and the return trip). RTD has found that the trip from the depot to the route can deplete the SOC more than anticipated. Therefore, the District can use only 60% to 70% of the battery on productive revenue service miles after accounting for the 20% buffer and up to 10% loss before and after revenue service. Stockton is in a climate that experiences temperature extremes, including an average high above 90°F in July and August, which could explain why the effective range is lower than anticipated. The evaluation team found that on average, RTD was using 2.24 kWh per mile in July 2019 compared to 2.08 kWh per mile in May 2019. In future deployments of battery electric buses (BEBs) that rely primarily on depot charging, RTD now has more realistic expectations for range.

Adapting to the Demand Management Software at DTC

To achieve cost savings from implementing a demand cap at the DTC, RTD has carefully managed electric bus performance in coordination with the bus operators and the control center. As a part of demand management, not all buses can charge as a matter of standard operation. This means that every bus operator must confirm that the SOC is sufficient to complete the next lap on the route. When necessary, drivers call the control center for approval to continue operating without charging, and supervisors in the control center manage these routes much more closely. Prior to demand management, the operators simply pulled in and charged their buses without involving the control center or worrying about range.

Expectations for Charging Capabilities

RTD first learned of two limitations after it purchased buses and installed chargers. First, after some of the initial communications between RTD and Proterra, some RTD staff believed the 2016 short-range Catalyst FC buses would be able to use depot chargers installed as part of the PRP. However, the technologies were not compatible. This has not resulted in a major operational impact yet, but the lack of interoperability may affect future flexibility to respond to disruptions such as power outages at other sites.

Second, when RTD deployed its 2018 long-range Catalyst E2 buses (originally configured to use depot charging) on a route with an overhead fast charger, it learned that the rate at which the buses accepted an overhead fast charge was limited by the battery chemistry of the higher-capacity batteries on the Catalyst E2 model. In particular, when the SOC fell below 45% or rose above 67%, the rate of charging slowed substantially below the rated power of the selected charger. Interviewed RTD staff did not recall knowing about this prior to the purchase of the E2 buses in 2018 (a handout is available describing the issue).[88]

[88] For each of the issues described in this paragraph, we cannot verify what information and communications RTD received during procurement. However, regardless of how the mismatch in expectations arose, this experience points to the need for more Original Equipment Manufacturer (OEM) guidance, as well as careful review of specifications on the part of the purchaser.

Effects on Maintenance and Uptime

RTD observed that the percentage of days that electric buses were available for service was lower than that of the diesel-hybrid buses, but it could not quantify this observation. Anecdotally, RTD's maintenance superintendent reported 40% to 60% availability of the electric fleet, while the diesel-hybrid fleet operates at 75% to 85% availability. The superintendent claimed that the rate of availability has improved with each electric deployment. In addition, according to the superintendent the on-route chargers have frequently failed and required maintenance.

Electric buses and diesel-hybrid buses share many of the same maintenance needs related to the non-motive systems on the buses. Therefore, we only describe the *differences* in maintenance issues between these types of buses.

For electric buses and their chargers, the types of maintenance issues RTD has experienced can be grouped into three categories: (1) issues with the legacy overhead chargers (RTD did not report any issues with the overhead chargers installed in 2019 at UTS), (2) issues with the bus-charger interface (caused by both operators and the design itself), and (3) risk of electric vehicle supply equipment (EVSE) being out of service due to power outage or power quality issues.

Regarding the legacy overhead chargers, many of the issues were resolved (such as replacing pilot brushes and updating compressors used for pneumatic controls with a different make/model) and are not expected to be major problems moving forward. Regarding the bus-charger interface, training operators has helped, and the rapid SOC depletion issue identified was resolved.[89] With regard to the risk of power outages, thus far RTD has experienced minor issues,[90] but this is an important vulnerability to plan for, especially for other fleets that may be more at risk of public safety power shutoff impacts[91]. For more details on the issues experienced by RTD and their resolution, refer to Table 39 of the Interim Report.

For the diesel-hybrid buses operated by RTD, preliminary information indicates that issues arise approximately once per week and most frequently include issues with the following systems: (1) the dual power-inverter modules, (2) the hybrid energy storage systems, (3) the fuel system, (4) exhaust gas recirculation system, and (5) bus systems such as doors, fareboxes, HVAC, and radios. Neither the electric nor the conventionally fueled buses are maintenance free, and more information about the actual long-term maintenance of the electric buses will be needed to conduct robust comparisons.

Despite this list of challenges, RTD maintained its operations with a higher-than-usual spare ratio, which it created by delaying bus retirements. Due to these spares, RTD had available non-electric buses to use

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[89] The SOC depletes faster than RTD expected under certain conditions because bus batteries did not properly interface with chargers. Proterra recommended replacement of fans that cool the batteries (a $15,000 expense). This did not fix the problem, which RTD ultimately determined was related to balancing of the batteries.

[90] Outages in Stockton (due to fires) caused three grid areas to go offline and affected two overhead charge sites. RTD used spare buses to ensure service was not interrupted

[91] A public safety power shutoff occurs in response to severe weather. PG&E will turn off power to help prevent wildfire and keep communities safe. (https://www.pge.com/en_US/residential/outages/public-safety-power-shuttoff/learn-about-psps.page)

as replacements when issues arose with the electric buses or their chargers. As RTD scales its electric bus fleet, higher reliability will be required, which may come as the electric bus market matures.

What were the cost impacts to the fleet?

The PRP had a substantial positive impact on costs borne by RTD for two main reasons. First, the PRP addressed upfront costs of charging infrastructure, and second, the PRP positively impacted RTD's ability to manage ongoing fueling costs. Table 75 and Table 76 below show the differences in costs between owning and operating the diesel-hybrid buses and the five new Proterra E2 buses.

Summary of Costs Relative to Diesel Hybrids

Table 75 is intended to show the degree to which the PRP improved the cost profile of owning electric buses, from a TCO perspective. TCO is calculated under four different scenarios:

- *Industry Average* uses values representative of the average diesel-hybrid fleet in the U.S. for cost per mile and purchase costs.
- *Fleet Baseline* uses the values provided by RTD for their diesel-hybrid fleet for cost per mile and purchase costs.
- *Actual Performance + A10 Rate* takes the cost per mile and purchase costs realized throughout the data collection period for the 2018 BEBs.
- *Best Observed Performance + A10 Rate* uses the cost per mile for the month of highest utilization during the data collection period (May 2019).
- *Best Observed Performance + BEV Rate* uses a simulated cost per mile to estimate fuel costs if the 2018 BEBs operated in the month of highest utilization (May 2019) and were billed on the BEV rate.

While the value of the grants received for the buses themselves is significantly higher than the dollar value of the infrastructure provided by PG&E, PG&E's investment clearly results in a substantial improvement in the TCO relative to a no-PRP scenario. For future RTD procurements, or procurements by other fleets in which the fleet does not receive as much grant money, the PG&E infrastructure investment and efforts to contain the costs of charging the buses may make the difference between a project with a favorable TCO relative to diesel hybrid and one that does not.

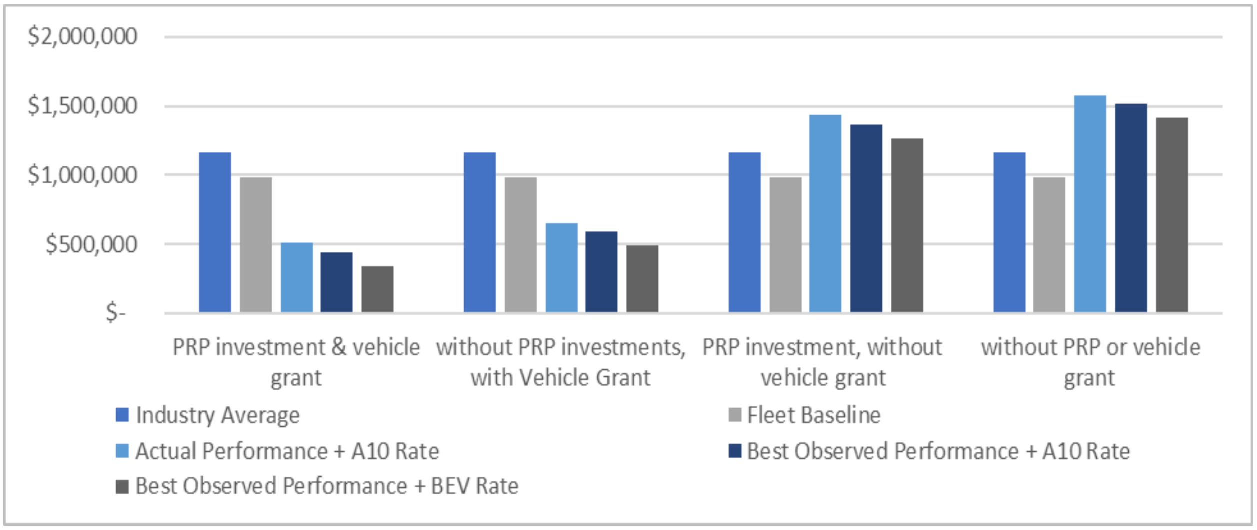
Table 75. Lifetime total cost of ownership per vehicle

<table>
<tr><th colspan="2" rowspan="2">Cost Component</th><th>Industry Average</th><th>Fleet Baseline</th><th>Actual Performance + A10 Rate</th><th>Best Observed Performance + A10 Rate</th><th>Best Observed Performance + BEV Rate</th></tr>
<tr><th>(Diesel-hybrid)</th><th>(Diesel-hybrid)</th><th>(Electric)</th><th>(Electric)</th><th>(Electric)</th></tr>
<tr><td rowspan="2">Infrastructure Costs</td><td>Paid by PG&E [a]</td><td>N/A</td><td>N/A</td><td colspan="3">$145,000</td></tr>
<tr><td>Paid by Fleet [b]</td><td>N/A</td><td>N/A</td><td colspan="3">$70,000</td></tr>
<tr><td rowspan="2">Vehicle Costs</td><td>Covered by Grants [c]</td><td>N/A</td><td>N/A</td><td colspan="3">$927,000</td></tr>
<tr><td>Paid by Fleet [d]</td><td>$715,000</td><td>$652,000</td><td colspan="3">$0</td></tr>
<tr><td colspan="2">Projected Fuel Costs [e, f, g]</td><td>$ 243,000</td><td>$155,000</td><td>$258,000</td><td>$192,000</td><td>$90,000</td></tr>
<tr><td colspan="2">Projected O&M Costs [h, f]</td><td>$204,000</td><td>$175,000</td><td>$180,000</td><td>$180,000</td><td>$180,000</td></tr>
<tr><th colspan="7">Total Cost of Ownership (TCO) to Fleet
(under various scenarios)</th></tr>
<tr><td colspan="2">TCO with PRP Investment and Vehicle Grant</td><td>$1,162,000</td><td>$982,000</td><td>$508,000</td><td>$442,000</td><td>$340,000</td></tr>
<tr><td colspan="2">TCO without PRP Investments, with Vehicle Grant</td><td>$1,162,000</td><td>$982,000</td><td>$653,000</td><td>$587,000</td><td>$485,000</td></tr>
<tr><td colspan="2">TCO with PRP Investment, without Vehicle Grant</td><td>$1,162,000</td><td>$982,000</td><td>$1,435,000</td><td>$1,369,000</td><td>$1,267,000</td></tr>
<tr><td colspan="2">TCO without PRP or Vehicle Grant</td><td>$1,162,000</td><td>$982,000</td><td>$1,580,000</td><td>$1,514,000</td><td>$1,412,000</td></tr>
<tr><td colspan="7">[a] Electric: includes the cost of the EVSE and installation.
[b] Electric: includes the cost to purchase another overhead charger at UTS, spread across five buses.
[c] Electric: RTD obtained funding from CARB (HVIP), FHWA's CMAQ program, CA State Greenhouse Gas (GHG) Reduction Fund, San Joaquin Council of Government's Measure K Local Sales Transportation Tax.
[d] IA: CARB estimates; FB: provided by RTD for their 2010 Gillig diesel-hybrid bus.
[e] IA: efficiency from CARB's estimates, diesel price is from the U.S. Energy Information Administration (https://www.eia.gov/dnav/pet/pet_pri_gnd_a_EPD2DXL0_pte_dpgal_a.htm), FB: efficiency, and diesel price provided by RTD, A: average $/mile calculated based on PG&E bills over the course of the project, O+A10: average $/mile calculated based on PG&E bills from May 2019, O+BEV: average $/mile calculated based on simulated PG&E bill on the BEV rate for May 2019.
[f] Calculation assumed buses travel 25,000 miles annually and have a lifetime of 12 years.
[g] Calculations do not assume a rate of increase in petroleum unit costs or electricity rates
[h] Includes annual maintenance on the vehicle, but not the cost of battery replacement, or EVSE replacement; IA: Maintenance cost per mile calculated based on CARB estimate, FB: provided by RTD; Electric: CARB estimate.</td></tr>
</table>

Source: Evaluator Calculations, PG&E, RTD

Figure 227 summarizes the results of the TCO analysis. When interpreting the results, there are a few assumptions to consider. Firstly, RTD's purchase costs for diesel-hybrid buses are lower than the industry average, making the argument for BEB deployment more challenging. Operationally, RTD is charging the electric buses at two stations, UTS and RTC, and incurring demand charges at each meter for a single set of buses, which is driving up their fuel costs. Nonetheless, fuel costs per mile decrease significantly as utilization increases. The difference in the fuel costs in the Actual Performance + A10 Rate scenario and the Best Observed Performance + A10 Rate scenario is due to a lower fuel cost per mile calculated during May 2019, the month of highest utilization, compared to the entire data collection period. The Best Observed Performance + BEV rate assumes the 2018 BEBs only charge at RTC and incur one subscription charge from the single meter. Lastly, these calculations do not include potential Low Carbon Fuel Standard (LCFS) credits that RTD may be able to take advantage of to further improve their long-term business case for electric buses.

Figure 227. Lifetime total cost of ownership



Source: Evaluator Calculations, PG&E, RTD

The *Efforts to Reduce Charging Costs* section below describes how RTD's costs per mile decreased as a result of the PRP. Not only has the costs per mile improved over time, RTD has switched the PG&E accounts for the fleet to the BEV rate. PG&E simulated RTD's electricity bills under the BEV rate, and their monthly savings are estimated to be $2,700 on average across all 3 meters. This should result in a much more favorable cost per mile, and the installation of the BESS at UTS may further improve fueling costs.

Table 76 shows that for most of the PRP, RTD did not achieve ongoing savings, either in fuel or maintenance. The cost per mile was higher than it was for diesel. In fact, this was a major motivating factor for PG&E to work with RTD on this PRP in the first place. PG&E knew that RTD had already experienced high costs, and the PRP could test several ways to decrease these costs and enable the fleet to accrue ongoing savings. Annualized program operational cost savings are calculated under 4 different scenarios:

- *As Anticipated* assumes the fleet travels the same annual miles as the diesel hybrid alternative, the electric fuel cost reaches cost parity with the average cost per mile of the diesel hybrid fleet.
- *As Implemented* annualizes the number of miles the fleet traveled and calculates the average electric cost per mile of the fleet during the data collection period
- *Best Observed + A10 Rate* annualizes the number of miles the fleet traveled and calculates the average electric cost per mile of the fleet during the month of highest utilization (May 2019) and under RTD's initial rate plan, A10.

- *Best Observed + BEV Rate* annualizes the number of miles the fleet traveled and calculates the average electric cost per mile of the fleet during the month of highest utilization (May 2019) and under RTD's current rate plan, the BEV rate.

Table 76. Annualized program operational cost savings

	As Anticipated	As Implemented	Best Observed + A10	Best Observed + BEV
Assumptions	5 buses 26,151 miles/ bus/year	5 buses 22,069 miles/ bus/year	5 buses 32,615 miles/ bus/year	5 buses 32,615 miles/ bus/ year
Fuel Savings [a]	$3,398.47	$(37,959.87)	$(20,222.88)	$35,223.15
Maintenance Savings [b]	$(7,432.07)	$(6,272.10)	$(9,269.34)	$(9,269.34)
Total	$(4,033.60)	$(44,231.97)	$(29,492.23)	$25,953.80

[a] All: baseline efficiency and cost of diesel from RTD's diesel hybrid fleet, A: annual miles from RTD's diesel hybrid fleet data, electric cost per mile assumed cost parity with average diesel-hybrid fleet cost per mile in 2019; I: annual miles and electric cost per mile assumes the average over the course of the data collection period; A10: annual miles and electric cost per mile calculated based on results from the month of highest utilization (May 2019), BEV: annual miles based on results from the month of highest utilization and cost per mile calculated from simulated bill on BEV rate

[b] Electric maintenance cost per mile based on a TCRP 2018 estimate; baseline maintenance cost per mile based on RTD's diesel hybrid fleet.

Source: Evaluator Calculations, PG&E, RTD

When interpreting the annualized operational costs, it is important to note how dependent these costs are on miles traveled. The fuel savings in the Best Observed scenario is greater because the fuel cost per mile improves with higher utilization as demand charges can be spread across more miles. The maintenance cost is higher in the Best Observed scenario than the Implemented scenario because the fleet will travel more in the Best Observed scenario, and savings are tied directly to miles traveled.

Additionally, RTD invested in a special projects manager to provide administrative and project management support, as well as core facilities and operational staff to install the depot chargers, implement demand management, and solicit the BESS contract. RTD also invested $5,000 per person to train its drivers, to improve driver experience and maximize operations. RTD has not quantified the value of this leveraged labor, but believes it is substantial.

Efforts to Reduce Charging Costs

The evaluation team also explored how fuel cost savings varied between how RTD charged its buses prior to PG&E's involvement and how it did so afterward. The PRP affects RTD's fueling costs in three main ways: (1) it modifies charging patterns at the RTC and the UTS (including battery storage at UTS); (2) it manages charging demand at DTC, and (3) it advises RTD on rate structures. Because the advice provided to RTD on rate structures was originally not scoped into the PRP activities, it is not included here, and instead described in Appendix A.

Modifying Charging Patterns at RTC and UTS

RTD wanted to determine optimal charging protocols for the long-range buses that allows them to meet the operational needs of their routes and reduce the cost per mile to below the diesel-hybrid alternative. RTD, with PG&E, designed tests to determine if the buses should charge only at the depot chargers or at a combination of depot chargers and opportunity charging at UTS. The evaluation team originally planned to test winter 2019 and summer 2020 to understand seasonal variations in the bus's performances. However, the team could only complete tests for winter 2019 due to disruptions from the COVID-19 pandemic.

Table 77 summarizes the results of the tests RTD conducted over three months. In November and January, RTD operated the long-range buses using a combination of depot (RTC) and opportunity charging (UTS) and in December, they charged only at the depot chargers. The test was conducted using both charging protocols twice to capture performance under mild winter weather in November, and extreme winter weather in January. RTD also operated a diesel-hybrid fleet on the same route and used this as a representative baseline for comparison. In all three months, the cost per mile was higher for the electric buses relative to diesel hybrid. In the depot-only scenario, the cost per mile was lower but electric buses were not able to complete their routes. During the testing period, an electric bus was replaced 48 times by a diesel-hybrid bus.

Table 77. Charging test results

	Test 1 Depot + XFC 10/31/19–11/26/19		Test 2 Depot Only 12/3/19-12/29/19		Test 3 Depot + XFC 1/2/2020–1/28/2020	
	Electric	Diesel Hybrid	Electric	Diesel Hybrid	Electric	Diesel Hybrid
Total Miles Traveled	6,116	3,141	4,429	4,838	5,709	3,592
Total Gallons		696.3		1078.3		774.41
Total kWh at RTC	5,652		10,501		5,973	
Total kWh at UTS	9,502				10,626	
Cost Per Unit of Fuel	$0.51	$2.93	$0.39	$2.34	$0.54	$2.34
Cost Per Mile	$1.27	$0.65	$0.92	$0.52	$1.56	$0.50
Cost Per Mile Comparison	*1.95x as expensive as diesel*		*1.77x as expensive as diesel*		*3.12x as expensive as diesel*	
Number of Bus Exchanges [a]	2		48		4	
[a] Buses were exchanged because SOC was too low						

Source: Evaluator Calculations, PG&E, RTD

Due to a lack of sufficient data and reduced operational schedules, RTD was not able to repeat this test during the summer months. However, based on the performance of the depot-only charging month, it was clear that summer charging would need to be a combination of depot and opportunity charging. As such, comparing the cost per mile of the two protocols is not needed.

RTD plans a final attempt to modify charging patterns once the BESS comes online. This test will determine the extent the BESS can reduce charging costs at the UTS and if the additional savings make the BESS economical for this application. It is anticipated that savings will be low because RTD switched to a more favorable rate (as described below). This is because the primary value of the BESS is to reduce demand charges, which are not a substantial part of the new rate. A relatively low number of charging sessions would happen during on-peak TOU time periods, even without the BESS, because E2 batteries are large enough to operate for most of the on-peak period, particularly if they are opportunity charging at off-peak period times during the day. Aside from the BESS' potential to reduce charging costs, these deployments are still nascent and are an opportunity for PG&E to learn alongside RTD and continue to improve their understanding of transportation electrification and cost reduction options. Learning how a BESS integrates with a transit system will also help PG&E apply this solution toward resiliency and islanding efforts in future projects.

RTD Charging Sites

PG&E's BEV rate was approved in October 2019 and opened for enrollment in May 2020, two years after the start of this project. This rate is designed specifically for business customers with on-site and separately metered EV charging. It includes a customizable monthly subscription charge instead of traditional demand charges, which are variable and depend on the highest demand meter reading each month. Customers set their subscription rate based on their highest expected demand. The rate includes a TOU energy charge as well. It was designed to make fuel costs for EV charging more predictable and reduce the variability in monthly bills. RTD switched to the new rate in July 2020 and set their subscription rate to 300 kW of demand.

Table 78 summarizes the savings RTD experienced in its first month on the new rate. It is important to note that while operations in June and July 2020 were comparable to each other, they were significantly reduced relative to RTD's regular operations. Therefore, the scale of the savings recorded at DTC and UTS may not be consistent in the future, but the potential for savings is evident and would significantly change the cost per mile for the long-range electric buses if these tests were repeated using the BEV rate.

Table 78. Savings from BEV rate

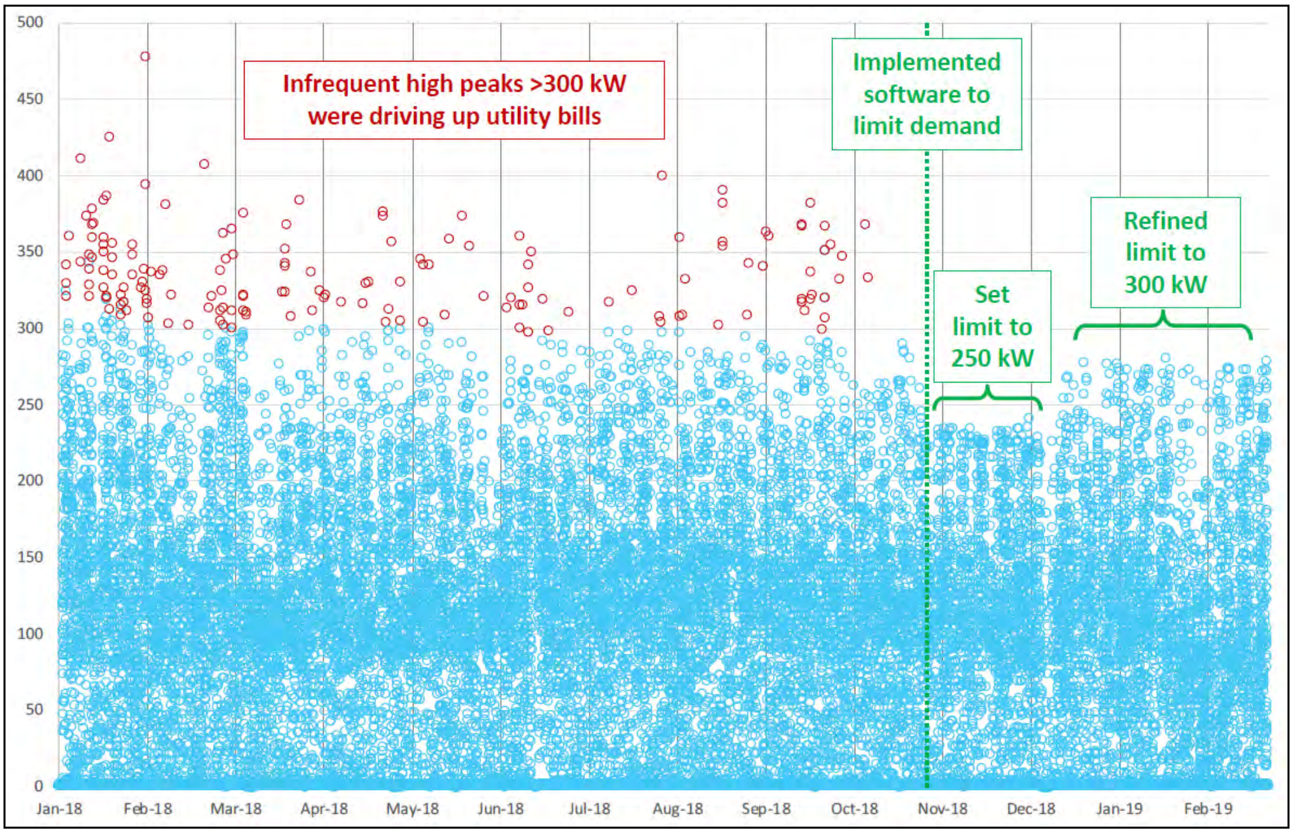
Site	Billing Details	June Bill A10 rate	July Bill BEV rate	Savings
RTC	5 Depot Chargers No TOU Charges	$3,181	$1,001	$2,181
DTC	2 Overhead Chargers Demand Management Software in Place	$8,334	$1,707	$6,627
UTS	2 Overhead Chargers No Demand Management Software	$9,437	$3,423	$6,014
Fleet cost per mile [a]		$2.31	$0.68	$1.63
[a] Miles traveled in June 2020: 9,062, miles traveled in July 2020: 8,974				

Source: Evaluator Calculations, PG&E, RTD

Managing Charging Demand at DTC

PG&E noted that, prior to this PRP, RTD routinely incurred higher costs per mile for its buses charged via the extreme fast chargers at DTC. As noted in the *Project Narrative* section, PG&E worked with RTD and Proterra to develop a software solution to address this challenge by capping demand. This intervention was effective in reducing costs per mile for those buses, *provided that the fleet also maintained a high level of charger utilization*. Figure 228 and Figure 229 show the effectiveness of demand management in the first few months and subsequent six months, respectively.

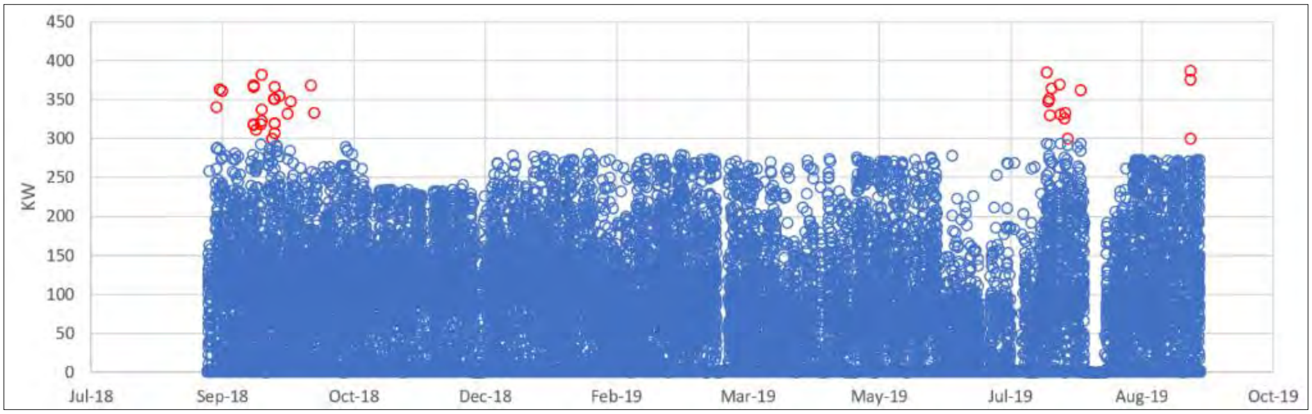
Figure 228. PG&E Transit Fleet PRP daily demand at DTC by 15-minute interval



Source: PG&E

Datapoints highlighted in red are time intervals in which demand exceeded 300 kW. One month after RTD implemented the demand limiting software, it determined that the initial threshold of 250 kW was too restrictive and affected the ability to adequately charge buses for their duties, so it increased the threshold to 300 kW.

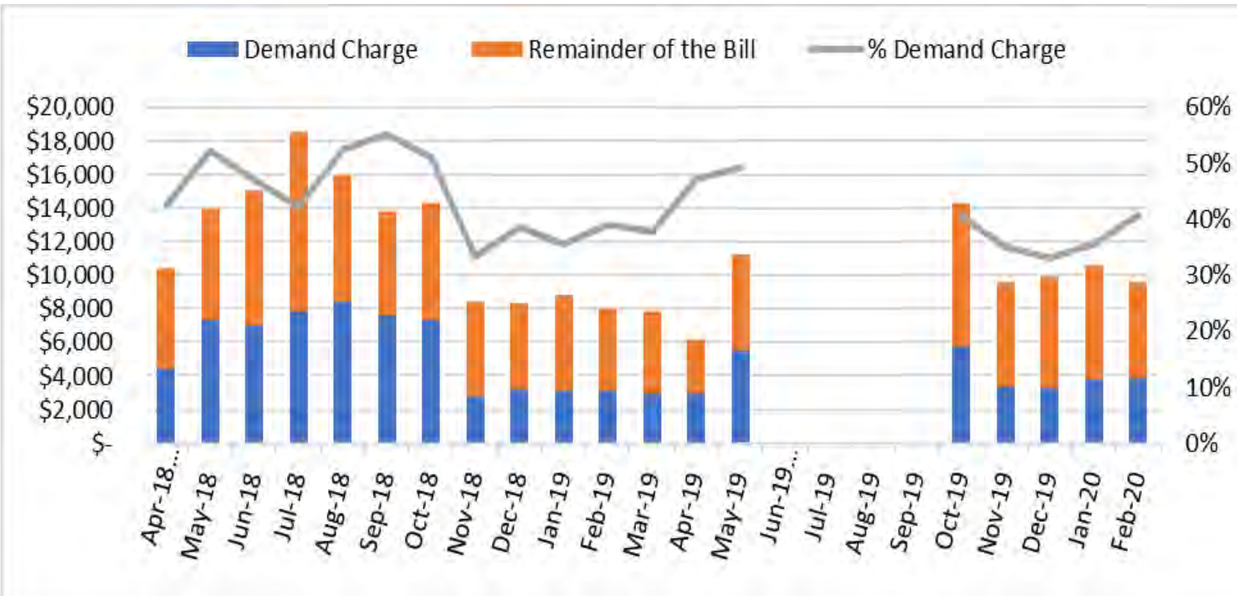
Figure 229. PG&E Transit Fleet PRP demand plot from September 2018–August 2019



Note: Datapoints highlighted in red are time intervals in which demand exceeded 300 kW.
Source: PG&E meter data

As shown in Figure 229, RTD successfully stayed under its demand management cap from October 2018 to June 2019. It appears it overrode the demand management cap at DTC in July and September 2019 for operational reasons, resulting in higher costs for those months. Despite the limitations associated with managing bus charging patterns while attempting to maintain maximum utilization of these resources, demand charge savings are clearly documented through RTD's electric bills. Figure 230 summarizes electricity bills at DTC from April 2018 to February 2020. From April 2018 until the demand management software was operational in October 2018, RTD paid on average 49% of their bill in demand charges. While actively using the demand management software, the agency paid 39% of its bill on average in demand charges. June and July 2019 are excluded from this dataset because the overhead chargers at both DTC and UTS were not operational for more than a month at a time and their electricity bill is not representative of typical operations. August and September 2019 are also excluded from this dataset because, as seen in Figure 229, because RTD exceeded its demand cap on a few instances during those months. Figure 230 depicts significant variability not only in the magnitude of the electricity bill at DTC, but also in the share of the demand charge. It is important to note that there was a learning curve to implementing the demand management software, and that RTD had to occasionally override it to keep buses on their operational schedule.

Figure 230. Demand charges at DTC



Source: RTD

The demand management software provided by Proterra was a custom solution created for RTD's needs that both parties were able to learn from. RTD needed a solution that would not impede the flexibility of their operations. Proterra learned that demand management for chargers was going to be a common need among fleet operators. And while Proterra will not be implementing this exact same solution for other customers, the company iterated its demand management protocols for other customers and aims to continue to provide a service to meet demand management needs.

When RTD switched to the BEV rate and immediately realized significant savings at both DTC and UTS, it decided to informally test removing the demand management software from DTC in August and September 2020 and evaluate the impact to its bill. Given how drivers had been experiencing delays due to the demand cap restricting the number of buses that can charge in a 15-minute interval, RTD was interested to see if the software was the only reason for delays. While the agency was running 85% operations at this time and could not directly compare savings to the previous year's bill, the savings on the BEV rate were apparent. Additionally, RTD monitored the meter at DTC and only recorded demand reaching 270 kW in a few cases, but never exceeding 300 kW, the level it had subscribed to on the BEV rate.

What was the fleet's overall satisfaction?

The evaluation team attempted to understand satisfaction of several stakeholder groups by conducting interviews and fielding surveys. These include RTD management, bus dispatchers, and vehicle operators. No feedback was obtained from passengers, although RTD management provided insights about customer feedback.

RTD management staff cares primarily about their ability to maintain operations and manage fuel costs. Staff said the performance of the electric buses has improved with every deployment. An interview with bus dispatcher confirms the same sentiment, both dispatchers and bus drivers prefer the newer models of BEBs compared to their first 2012 deployment. RTD has been pleased with PG&E's support in installing their charging infrastructure and helping them to understand the options available to them, such as the BEV rate. There have been some challenges, as noted in *What were the operational impacts on the fleet and its staff?* Vehicle operators have provided feedback to RTD management. At the start of this project, some operators would try to avoid being assigned to the electric buses, as they did not like the auto-docking process at the overhead chargers. It slows the bus down and takes control out of the driver's hands. As operators became more familiar with the electric buses, and they began to drive the newer buses, their opinion shifted. And while the electric buses require the drivers to be more aware of their SOC and communicate with the bus dispatchers more than with the diesel-hybrid fleet, they are more open to driving the 2018 BEBs that are less dependent on overhead charging. The bus dispatchers also had a significant learning curve to overcome. If the bus is not docking, they need to be able to determine if the fault is coming from the bus or the charger, or if the driver can make their next route without the opportunity charge and instruct the driver to either drive around the block and try and dock again, or to wait for a different charger to open. Some passengers have also expressed nervousness regarding timed transfers, and if the first attempt to dock fails, the bus has to go around the block and try again. This also cuts into the driver's scheduled break.

Ultimately, one of RTD's most important objectives from this PRP was to learn how to scale their deployment of electric buses. In interviews with the management team, the evaluators learned that a significant participation motivator was to understand what it would take to upgrade behind-the-meter infrastructure and make-ready infrastructure to accommodate electrification of their fleet. Interviewees wanted to learn about working with PG&E and the timelines involved, particularly the amount of lead time needed for PG&E to help with the make-ready investments.

In the context of RTD's commitment to electrify 100% of its intracity fleet by 2025, RTD management values the lessons learned from the project and staff are very satisfied with the support that PG&E has provided throughout the project. They note that the implementation process went as smoothly as one would expect for this sort of infrastructure project.

Results Observed to Date: Societal Perspective

This section addresses whether the project successfully accomplished its objectives as outlined in the Decision, whether the project achieved immediate benefits that accrue to ratepayers and the general public, and whether the costs aligned with anticipated costs when the project was approved.

How, if at all, did the PRP change electrification within the fleet?

Across the fleet electrification PRPs in California, there are three main ways that the investor-owned utilities have aimed to change electrification within the participating fleets: (1) affecting vehicle procurement choices and timeline, (2) affecting infrastructure procurement choices and timeline, and (3) enhancing operational performance and capabilities, thereby advancing broader market readiness and desirability of electrification for other fleets in the future.

The RTD PRP was primarily focused on the latter two, but it likely also had some effects on vehicle procurement and timeline decisions. Each of these topics is described sequentially below.

Vehicle Procurement Choices and Timeline

Although RTD had already planned to procure its five new Proterra buses prior to the PRP, the PRP shaped the context in which RTD will make future vehicle procurement decisions. RTD announced it will continue expansion of its electric fleet and will buy nine long-range electric buses from Gillig and seven more depot chargers from ChargePoint. During an interview, RTD explained it decided to use Gillig this time around because it worked with Gillig in the past and has a good working relationship with them. When RTD started using electric buses, Proterra was at the forefront of the market and one of the only options. But now, with more options available, RTD is interested to see how electric buses from a traditional bus manufacturer performs.

RTD had also established a goal of 100% electrification of their Stockton Metro Area fleet by 2025 prior to the start of this PRP. This goal was amended in May 2020 to 100% zero-emission buses of the same fleet by 2025 to include the possibility of fuel cell electric buses (FCEB) in their fleet. While the technology and range of electric buses continues to improve, RTD is aware of the difficulty of electrifying some of its longer routes and noted in an interview that fuel cell technology might be a solution. The agency has not planned to procure fuel cell buses or designed charging protocols to accommodate them. The adjustment in goals gives RTD the option to evaluate those solutions after continuing the monitor the progress of electric bus operations. The experience RTD gained during the PRP helped the agency understand the need of being flexible in how it approaches its electrification goals. RTD is also at a point in the electric deployments where it has gained a solid understanding of which routes and blocks are conducive to BEBs. And alternatively, which routes they might need to redesign, or consider FCEBs to operate. RTD's strategic planning has to take these future goals into account. Additionally, CARB's ICT regulation, which requires transit agencies to develop plans to procure zero-emission buses by 2029, will likely force a rapid procurement schedule.

Infrastructure Procurement Choices and Timeline

The PRP also gave RTD its first experience with depot charging, and PG&E's efforts helped RTD to install and ensure adequate electrification infrastructure to support five 60 kW depot chargers. The depot chargers were commissions on a reasonable timeline with minimal delays with PG&E's support. This experience has also led RTD to procure seven more depot chargers to support its upcoming BEB deployment from Gillig. RTD opted for a lower charger to bus ratio in this round, 7 to 9 instead of 1 to 1, because the PRP demonstrated that operations do not require every bus to fully recharge every night after operations.

RTD would also not have been able to procure a BESS without the PRP. PG&E not only supported the procurement financially, but also advised in the site selection and planning leading up the bid solicitation RTD issued. PG&E will continue to support RTD throughout the installation process and monitor the results from the BESS following the completion of the PRP.

Enhancing Operational Performance and Capabilities

One of the most important ways in which the PRP advanced electrification at RTD was by helping the agency develop knowledge and capabilities that inform the way it deploys buses and manages charging—specifically, adopting a load profile aligned with lower costs and lower emissions times on the grid. Prior to the PRP, RTD struggled to manage cost per mile of the fleet and availability of its legacy fleet when only using the overhead extreme fast chargers. During the interview, RTD staff expressed frustration with the overhead charger system for a number of reasons: drivers knocking the paddles on the charger out of alignment if they turn too soon after disengaging, drivers losing their break time at DTC layovers because of delays when trying to dock, and in-house labor needing to frequently change the brushes.

With the test phases, RTD learned it could manage the costs of the legacy buses but at a cost. The demand management protocol put in place at DTC affected operations but reduced the fleet's cost per mile. Then, with testing, RTD also learned it could serve the majority of its energy needs for the new buses overnight and take advantage of opportunity charging at UTS to meet the daily route needs. Charging at UTS and DTC can be aligned with TOU periods and lower the average cost per mile to fuel the fleet. RTD is also positioned to do well under the BEV rate. The larger battery capacity of the 2018 BEBs enables the fleet to use predominantly overnight charging and opportunity charging during solar-aligned periods. During the peak and super-peak TOU periods, these buses can float and rely on their longer ranges.

What were the net energy and emissions impacts (relative to the no-PRP scenario)?

In the Decision authorizing this project, the CPUC highlighted this PRP's potential to support improved public health and achieve GHG reduction goals. In particular, this PRP is expected to reduce contributions to nitrous oxide (NOx) and particulate matter pollution since heavy duty vehicles are the largest source of NOx and produce more particulate matter pollution than all of California's power plants combined.[92]

While not the primary focus of this PRP, PG&E also engaged with RTD to help them manage their legacy electric buses. The evaluation team estimated that the legacy electric bus fleet avoids 505 tonnes of CO_2 annually.[93]

Table 79 summarizes the PRP's petroleum reductions, avoided GHG emissions, and avoided emission of criteria pollutants. The calculations presented here focus exclusively on the impacts of the five new buses for which the PRP provided charging infrastructure. These are calculated in comparison to the performance characteristics of RTD's diesel-hybrid bus fleet. Each column is calculated under different assumptions:

- *As Anticipated* uses the same annual mileage as one of the diesel-hybrid buses that operate on the same route as the long-range electric buses. Emissions reductions per mile are calculated using the average kilowatt-hour per mile as the implemented PRP given the lack of specific forecast provided as the beginning of the pilot. This column should be seen as if the electric

[92] Greenlining Institute testimony noted in final decision

[93] GHG calculation based on the fleet average efficiency of 2.19 kWh/mile, annualized emissions from the data collection period (May 2019 – February 2020), and meter data from the overhead chargers used by the legacy fleet.

buses were successfully able to meet the same operational demands of their diesel-hybrid counterparts.

- *As Implemented* uses energy consumed and miles traveled during the months of standard operations that data were collected for (May 2019 to February 2020) and annualizes the results. This column captures the benefits given how the fleet has operated over the course of the PRP, which includes operational hurdles RTD faced in learning how to best to deploy and charge their electric fleet.
- *Best Observed* annualizes the mileage and energy consumed of the month with the highest utilization. May 2019 had the most miles traveled across the fleet during regular operations. This column presents benefits as if the entire project operated under similar conditions.

Table 79. Net energy and emission impacts

	As Anticipated	As Implemented	Best Observed
Assumptions	5 buses 26,151 miles/bus/year	5 buses 22,069 miles/bus/year	5 buses 32,615 miles/bus/year
Petroleum Reduction (gallons diesel)	27,901	23,546	34,798
Avoided GHG Emissions (tonnes CO2e)	290	245	362
Avoided SO2 (kilograms)	38	32	47
Avoided NOx (kilograms)	686	579	855
Avoided CO (kilograms)	312	263	389
Avoided PM10 (kilograms)	23	20	29
Avoided VOC (kilograms)	101	85	125
DAC Impact (% miles within DAC)	100%	100%	100%

Source: Evaluator Calculations

Petroleum reductions are the estimated number of diesel gallons that would have been required to power an equivalent number of miles by the electric fleet. GHG and criteria pollutant emissions for the baseline fleet are based on emission factors for hybrid electric vehicle low sulfur diesel provided by CARB in the CA GREET 3.0 Model, which is also used as the source for criteria pollutant emission factors for electricity.[94]

The evaluation used the hourly electricity carbon emission factors established for each quarter under the Low Carbon Fuel Standard.[95] These carbon intensities were applied to interval data from the meters at RTC (where the depot chargers are connected) and at UTS (where the long-range buses take advantage of opportunity charging). The long-range buses are not the only buses that use UTS, therefore

[94] CARB. January 4, 2019. "LCFS Life Cycle Analysis Models and Documentation." CA GREET 3.0 documentation. https://ww2.arb.ca.gov/resources/documents/lcfs-life-cycle-analysis-models-and-documentation

[95] CARB. Revised January 16, 2020. *Low Carbon Fuel Standard Annual Updates to Lookup Table Pathways; California Average Grid Electricity Used as a Transportation Fuel in California and Electricity Supplied under the Smart Charging or Smart Electrolysis Provision*. https://ww2.arb.ca.gov/sites/default/files/classic//fuels/lcfs/fuelpathways/comments/tier2/elec_update.pdf

a proportionate share of the electricity metered, and associated emissions, was assigned to the long-range buses based on the headways of each route. In all cases, avoided emissions are calculated as the difference in emissions per mile between the electric fleet and baseline diesel-hybrid fleet and scaled to the annual mileage estimate.

Calculations of emissions and petroleum reductions associated with each scenario align with what might be expected from such a project. The principal driver of differences in energy and emissions savings between scenarios is the assumed number of miles the buses travel. Additionally, the annualized GHG savings in the *Best Observed* scenario may overstate actual achievable reductions because they are extrapolated from May, which is during the quarter of the year when grid emissions are lowest. While it is necessary to include changes to annual miles in the benefits analysis for a project testing new technology, it is also helpful to see how the implemented strategy compares to the baseline if operations were the same. Table 80 removes the distance variable and compares emission rates on a per mile basis. These comparisons show per mile reductions ranging from 10% for VOCs to 91% of NOx.

Table 80. Comparison of normalized emissions

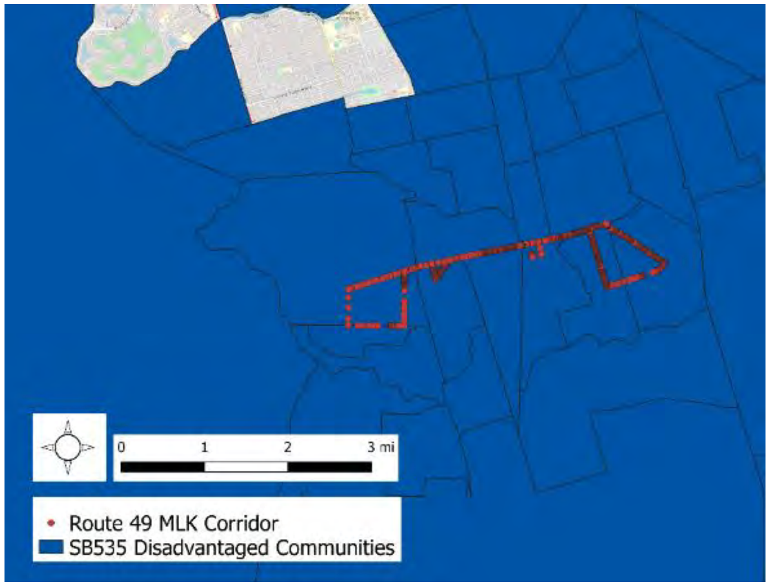
	Fleet Baseline (Diesel-Hybrid)	As Implemented (Electric)	Percentage Reduction
GHG emissions (kg/mile)	2.96	0.74	75%
SO2 Emissions (g/mile)	0.45	0.16	64%
NOx Emissions (g/mile)	5.77	0.53	91%
CO Emissions (g/mile)	2.82	0.44	84%
PM10 Emissions (g/mile)	0.27	0.18	34%
VOC Emissions (g/mile)	0.86	0.77	10%

Source: Evaluator Calculations

How did these impacts accrue in disadvantaged communities?

Energy and emission benefits were accrued entirely in DACs. Figure 231 shows that 100% of the bus route that the new long-range buses operate on, the red marks, is in a DAC, the shaded blue area. One of the grants used to purchase the buses stipulated the buses have to operate along routes that serve census tracts designated as DACs and therefore RTD operates them on Route 49. This was one of the key reasons that PG&E decided to partner with RTD at the onset of the project.

Figure 231. Bus route in DACs



Source: RTD

What were the co-benefits?

Stakeholders at RTD identified non-energy benefits from operating the BEBs. In response to a survey aimed at gathering the bus driver's perspective, some drivers reported that the electric buses make much less noise than their alternative. Noise reduction is an expected co-benefit, but we did not attempt to quantify it any further.

How did PG&E project costs compare to expectations?

PG&E was approved for $3,355,000 initially to complete this project, with $1.73 million allocated to capital costs and $1.63 million to expenses. The total project expenditure through October 2020 shows that the project remained on track to stay within the allocated budget.

Upfront project costs were incurred for each of the three sites in the PRP. As the work at Site 3 is not complete, final budget estimates for the BESS are not available. From conversations with PG&E and RTD, the evaluation team knows that the bid estimates to install the system were significantly higher than expected. The following cost categorization applies to Table 81:

- **Site Assessment and Design** includes design and estimating for the depot chargers at RTC and the BESS at UTS.
- **EVSE Procurement (rebate)** includes procurement of the five 60 kW depot chargers (Proterra PCS), a five-year warranty, and sales tax. The chargers were originally procured by RTD, who was then fully reimbursed by PG&E.
- **Make-ready infrastructure (utility)** includes the following utility-side costs: materials, construction labor, internal labor, inspection, and burdens on cost.
- **Make-ready infrastructure (customer)** includes the following customer-side costs: charger installation, materials, construction labor, internal labor, and burdens on costs.

- **Project management** includes PG&E's activities for customer support, planning and direction of the implement process, oversight for troubleshooting, budget tracking and processing of customer reimbursements, data review and analysis, management and planning of test phases, and coordination of stakeholders.
- **Customer outreach (labor)** is the labor related to recruiting a site host partner.
- **Outreach and education materials** includes project marketing and digital materials.

Table 81. PG&E Transit Fleet PRP costs as of October 2020

Cost Categories	Proposed	Actual
Site Assessment and Design	N/A	$61,270
EVSE Procurement (Rebate)	$285,280	$285,280
Make-Ready Infrastructure (Utility Side)	$370,000	$242,092
Make-Ready Infrastructure (Customer Side)	$210,000	$145,619
Project Management	$250,000	$275,777
Customer Outreach (Labor)	$100,000	$11,516
Outreach and Education Materials	$100,000	N/A
Total	**$1,315,280**	**$1,021,554**
Remaining Budget Available	**$2,039,720**	**$2,333,446**

Source: PG&E

PG&E still plans to create outreach and education materials based on this project, but as of October 2020, had not spent the budget allocated to this category. The final cost of the BESS component of this PRP is forecasted to be $650,000, which is well below the remaining budget available shown in Table 81. The project is on track to stay within the proposed $3,355,000 estimated budget approved by CPUC.

In addition to costs covered or reimbursed by PG&E, other project partners have provided valuable in-kind contributions. For instance, Proterra developed the demand management software that RTD implemented at the DTC at no cost to RTD or the PRP. ENGIE collaborated with RTD to develop the battery designs to include in its build bid.

Project Legacy and Learnings

This section addresses the knowledge generated by this project that could be more broadly applied to future projects. In particular, the design of this PRP prioritized lessons learned rather than immediate impacts. Several important lessons emerged both from the technological innovations and the testing conducted over the course of the project.

What were the lessons learned on market readiness? What implications does this have for the role of the utility?

This PRP illustrated that agencies benefit from utility involvement in transit electrification projects to support resolution of integration challenges and to supplement the technical knowledge of fleet managers. In terms of market readiness, even buses with high battery capacity are not a perfect one-for-one replacement for conventional vehicles in terms of daily mileage capabilities and in terms of reliability.

Despite being identified as a beachhead sector for transportation electrification by CARB,[96] transit agencies can benefit from hands-on assistance from utilities to deploy projects. Customers procuring their first round of electric buses in 2020 stand to benefit from standardization and progress made by industry. However, for agencies that were among the first purchasers of electric buses, like RTD, factors such as lower reliability of early generations of charging equipment, limited interoperability of systems designed for different model years of buses and chargers, and a low degree of interest from original equipment manufacturers (OEMs) in developing solutions that are backwards compatible with earlier models can make it challenging for fleets to fully optimize usage of their electric buses. While many of the challenges faced by RTD were eventually solved, having the utility as an ally pushing for more detailed information and solutions may have resulted in faster resolution of problems and a better overall experience. For instance, when the original data loggers needed replacement with a second generation of telematics devices, Proterra understood how important data access was for PG&E and prioritized RTD's buses to be among the first in the country to receive the upgrade.

Even buses with some of the highest battery capacities available still face limitations in being perceived by agencies as a perfect one-for-one replacement for conventional vehicles. For instance, due to the mismatch between the nominal range and the actual range achieved under normal operations, 440kWh buses were not able to complete a full day's service on RTD's Route 49 without opportunity charging. When RTD avoided opportunity charging for a month, the agency needed to deploy spare buses on 48 occasions, on a route that is served by three buses a day, to complete the remainder of the day's service when the SOC dipped too low, even during times of relatively mild weather. Using both depot and opportunity charging may not be financially viable for many other fleets without the right grants since it requires additional upfront investment and may lead to higher costs per mile relative to depot-only charging.

Additionally, buses are vulnerable to charger unreliability and RTD found that its electric buses experienced more downtime than its diesel hybrids, including more than a month of consecutive limitations on bus usage due to all overhead chargers being out of commission at one point in Summer 2019. Transit agencies that intend to retire diesel buses one-for-one when they purchase electric buses will need quick resolutions to their maintenance problems, or they must maintain adequate redundancy in buses and charging infrastructure. RTD has been fortunate in having sufficient non-electric spare buses to operate without major interruptions, despite the reliability issues with some buses and chargers.

As an impartial third party that assists numerous fleet partners with electrification, PG&E can fill an important niche by educating its fleet partners not just about the process of obtaining chargers and make-ready infrastructure, but also about opportunities and limitations associated with certain strategic decisions on charging approaches, such as the pros and cons of working with each OEM, the appropriate ratio of chargers to buses, the desirability of opportunity charging versus depot charging, the most appropriate rate to enroll in, how other distributed energy resources could be factored into a fleet

[96] California Air Resources Board, "Proposed Fiscal Year 2017-18 Funding Plan for Clean Transportation Incentives," November 9, 2017, https://ww2.arb.ca.gov/sites/default/files/classic//msprog/aqip/fundplan/proposed_1718_funding_plan_final.pdf.

electrification strategy, and other topics on which PG&E has gained expertise through its growing portfolio of electrification projects (for instance through the EV Fleet program). Even if PG&E is not able to directly recommend one set of products over another, the utility can take actions such as developing qualified products lists (as they have done with the EV Charge Network qualified list), maintaining a database of products used in each project, and assisting fleets in connecting with other fleets that have used those products in the past, to learn from each other.

Finally, for fleets like RTD that need customized solutions, whether due to having multiple generations of electric buses already in the fleet or due to unique operational constraints, more hands-on support from the utility can be beneficial. This is because bus and charger OEMs are busy scaling up to meet new product demand and are focused on the next round of standardized and turnkey solutions for customers. In interviews with Proterra and ENGIE, both product manufacturers articulated that RTD was more hands-on and involved in the project planning and design than their other customers, with a more unique set of needs due to their operation of several different types of buses and chargers at several locations. PG&E's involvement may have given RTD leverage to ask for more from their vendors, particularly given that the results of the PRP would be evaluated and published for all to see.

What were the lessons learned on charging cost management?

Through this PRP, PG&E demonstrated there are multiple options available to transit agencies to manage their charging costs. By partnering with their utility, agencies can determine which solution best suits their operational constraints.

PG&E developed several approaches for managing charging costs, both by modifying operations and by offering a more suitable tariff. These included implementing a software solution to limit demand, designing a BESS that would provide RTD with more control over when the buses drew grid electricity, and offering the BEV rate. Demonstrating that the fueling cost of the electric buses could be on par with or lower than diesel was a critical objective, but it also became clear that once costs reach an acceptable level for a fleet, the agency's desire to obtain operational simplicity and lower probabilities of interruption may trump additional cost savings. In RTD's case, the BEV rate was sufficient to bring charging costs down to an acceptable level.[97] However, the BEV rate was not available until late in the project (May 2020), and therefore, PG&E proceeded early on to develop the solutions necessary to help RTD modify its charging profile.

The first intervention, the software system installed at DTC, was shown to be highly effective at controlling costs by capping average demand in any 15-minute window at 300 kW. However, the protocol was not advanced enough to enable RTD to override it in real time or to prioritize buses with low SOC when they arrive at the charger. Therefore, the system produced extra anxiety for drivers and made the dispatchers' jobs more complicated, as they needed to advise drivers whether to complete the next loop if they missed receiving a charge. In the final interview with the evaluators, RTD emphasized the imperative of eliminating as many risks as possible to maximize the chance of successful and reliable

[97] As shown in the *Efforts to Reduce Charging Costs* section, the BEV rate preliminarily demonstrated significant cost savings for RTD, but it remains untested during regular (post-COVID) operations.

charging on every charging cycle—and this includes the risk that the software would prevent a necessary charging session. Further evidence that software demand caps on opportunity charging are not likely to be widely desired by fleets came from an interview with Proterra. Specifically, Proterra indicated there was not sufficient customer demand for management solutions for opportunity charging. As such, the company decided to discontinue support for such software (and not to offer support in designing the software to optimize the BESS site), in favor of putting its efforts into charging management of overnight depot chargers. This solution that is less complex or likely to cause operational challenges than capping demand at opportunity chargers.

The second intervention, the BESS, is not yet complete as of the publication of this report. While originally scoped to support peak shaving at UTS, the BESS also has the potential to entirely eliminate charging from the peak TOU periods of the day for RTD's Route 49. However, the same conclusions that apply to the demand management cap at DTC apply to the BESS—RTD has determined that the charging costs under the BEV rate are already sufficiently low that they are unlikely to obtain cost savings from the BESS of the scale that it would warrant their own substantial financial investment in the BESS. Because the installation is entirely funded by the PRP, RTD is still interested in deploying the BESS both to gain experience that may be relevant to its longer-term zero-emission fleet goals and to help PG&E gather lessons on how BESS can contribute to cost management for transit and other applications. While the savings to RTD are not anticipated to be high, due to the savings already obtained with the BEV rate, there could be other agencies that would benefit from such a solution. Though it is unlikely that a BESS will be a cost-effective approach for most agencies, unless other benefits can be captured (such as developing an islandable system that is resilient to short-term power outages, which is not a feature of the BESS currently planned for RTD's site). However, if an agency has no choice but to charge during the peak hours of the day, or if an agency is ineligible for the BEV rate (such as a fleet in a location outside PG&E's service territory), a BESS may provide the only workable solution for cost management—and in such cases, agencies may benefit from finding grants or funding opportunities that offset the large upfront investment required for such an approach.

Ultimately, this PRP shows that multiple solutions for cost management are available or technically feasible, with tradeoffs associated with cost of implementation and operational impacts. In many cases, the simplest workable solution may be preferred by the fleet partner. In PG&E's territory, for the majority of fleets, this is likely to be simply subscribing to the BEV rate.

What were the lessons learned on measurement and tracking of bus performance in a complex fleet environment?

This PRP highlighted the difficulty of capturing precise data across multiple meters, charging protocols, and bus generations. This can lead to higher cost per mile calculations for the fleet, a key metric many agencies use to evaluate their electric fleet operations.

With RTD, PG&E was able to gather a better understanding of how to manage a deployment of buses that operate on a variety of routes with a complex charging protocol. When there are multiple generations of electric buses charging at both overhead chargers and depot chargers, it is difficult to measure and evaluate the cost per mile of each bus. With multiple meters, charging protocols, and generations of buses, it becomes difficult to accurately attribute the energy used on a meter to a specific bus that was serving a certain route and evaluate its performance and efficiency. One the same note, assigning operational costs to buses gets complicated when the buses charge across multiple meters and more than one bill is generated.

RTD determines cost per mile by evaluating the mileage of the entire electric fleet relative to its electricity bills at the three charging sites. This method likely overstates cost per mile, as the older generation of buses have lower efficiencies than the latest fleet procurements. Because of this overstatement, if RTD, or other fleets utilizing a similar approach to estimate costs, should exercise caution if basing future procurement decisions on these costs.

Access to data from Proterra's APEX portal was critical for RTD to manage its fleet as it captures bus telematics and can differentiate between on-route charging and depot charging. Unfortunately, the data on this portal were inconsistent and often included faults and error codes, making it unreliable in the early days of this project. RTD actively worked with Proterra to develop this data portal and provided feedback on which metrics were the most useful for them to track. RTD's management focuses on capturing the energy delivered to the bus and monitoring for changes in bus efficiencies. And, when RTD removed their demand management software, they used the APEX portal to regularly monitor the demand at DTC. Access to data will be an important lesson for PG&E to communicate to transit fleets as they begin their procurement planning. Particularly as charging and energy systems become more complex and incorporate BESS, renewable generation, and multiple charging options that serve buses of several different vintages. With these intricate systems, it will become increasingly difficult to allocate costs to individual buses and assess their efficiencies.

5.2.4 Conclusions

Accomplishments

As a result of this PRP, additional knowledge and technical capacity is being built that will enable better management of electric buses and related assets at RTD. Management of electricity costs is challenging, particularly given the limited flexibility transit agencies have in their routes and operations, especially in cases where many buses share charging across several sites, as at RTD. Shifting from managing diesel expenses (long-term contracts can be locked in) to electricity (prices can fluctuate over the course of a day, and a single anomaly can result in substantially higher costs) requires careful planning and sophisticated management. At the onset of this project, demand dictated a high percentage of the monthly electric bill and the cost per mile could be very high if buses were not heavily utilized. RTD demonstrated how high utilization can lower cost per mile and the savings potential of the BEV rate.

The second principal accomplishment of this PRP was to test a new and innovative demand management system aimed at reducing their electricity costs. Prior to the PRP, RTD incurred high demand charges so this project implemented demand management software. This step successfully capped demand and reduced total electricity expenditures. RTD's switch to the BEV rate reduced RTD's cost even further. This is important for PG&E because a transit agency's change in rate is an easier solution to implement than relying on a product manufacturer to create custom demand management software. And if operational cost savings are not realized, more transit agencies may begin to reevaluate their compliance pathways for the CARB ICT and consider a different balance between battery electric buses and alternatives such as fuel cell buses. This PRP also installed the most reliable charging ports in RTD's system, the five depot chargers. RTD gained valuable experience managing buses that primarily charge at the depot overnight.

The test phases of this project enabled RTD to understand the capabilities and limitations of its buses and chargers, so it will have more knowledge and flexibility to deploy buses in the future while managing on-time performance, demand charges, and peak TOU periods. This knowledge has already proven useful, as RTD has been monitoring its demand peaks at DTC after removing the demand management software to determine if it can optimize its operations even further and make electrification even more cost-effective.

Lessons Learned

- The process of deploying energy storage in relatively new applications like transit transfer stations may be more complex and time consuming than expected because local contractors and customers like transit agencies may still have uncertainty about what is required for the install, cost of components, and cost of labor. This issue may or may not be resolved if a turnkey solution is procured from product manufacturers.
- Early partnership and regular coordinated discussions between the utility, transit agencies, and relevant vendors will provide opportunities for transfer of knowledge and best practices. The utility brings unique insights and can support agencies with expertise developed through implementing programs and projects throughout the territory.
- Direct access to vehicle manufacturer's online portal with electric bus and charger operational data expedited the data collection process and analysis. It provided transparency into RTD's operations and enabled the evaluation team to react quickly to operational changes.
- The complexity of managing the charging protocol of multiple generations of buses with a mix of overhead fast charging and depot charging warrants extensive guidance from the bus manufacturer and requires sophisticated management from the transit agency.

Potential for Scale-Up in the Fleet and Beyond

CARB's ICT regulation will require a dramatic shift to incorporate more zero emission buses in the next 20 years. The onset of this regulation phases in quickly relative to the timescale of bus procurement decisions. Therefore, the lessons on how to integrate electric buses into fleets at scale are of critical importance. Learnings on both operations and cost-effectiveness to the fleet are necessary to enable scale up. If the cost concerns that fleets like RTD have cannot be addressed, the motivation and ability of fleets across the state to adopt electric buses ahead of the ICT mandate timeline will be limited. Yet, if more early adopters continue to buy electric buses and innovate in their operational approaches, the transit industry will be better equipped to successfully transition to an increasingly electric fleet in the future. Despite several electric buses already deployed across the state, each agency will likely have its own set of challenges and opportunities.

RTD's experience is particularly interesting because of how financially challenging the operations were at the onset of the PRP. They learned an incredible amount over the course of this project. To manage operations, the agency learned how to track performance across three generations of electric bus procurements that charged at multiple locations. With support from PG&E and their product manufacturers, RTD was able to develop a plan to reduce its upfront and ongoing costs and transition from an electric fleet only using overhead charging to incorporating depot charging into refueling protocols. RTD also monitored new offerings from bus manufacturers that open up more possibilities for future procurements, as evidence by its planned procurement from Gillig. From experience with this

PRP, RTD would like to explore FCEBs as part of a dual solution but have more to learn before moving forward.

Transit buses present good opportunities for electrification because of their high utilization rates, fixed routes, and return-to-base at night operations. Nonetheless, many barriers persist, including upfront cost premiums, costly infrastructure, time-consuming processes for procurement and permitting, range limitations for the most energy-demanding routes, resilience concerns in areas prone to power shutoffs, and HVAC requirements in extreme weather conditions. This PRP advanced the state of knowledge on how to address many of these challenges and helped RTD have a more positive experience with its electric bus deployment. This will be an important contribution to enabling scale up not just at RTD but broadly across California.

5.3 Idle Reduction Technology

5.3.1 Project Narrative

Overview, Objectives, and Barriers Being Addressed

In its January 11, 2018 order (D.18-01-024), the CPUC approved $1.72 million for PG&E to pursue an Idle Reduction Technology Project among its priority review project (PRP) efforts.[98] A May 2018 advice letter (Advice 5279-E) further detailed PG&E's intention to focus on the electric standby transport refrigeration unit (eTRU) market.[99] This final report summarizes evaluation activities.

An eTRU is a hybrid model with electrically driven refrigeration components that can be powered by an onboard diesel generator or through electric power, if plugged into a charging port. The objectives of the eTRU PRP are to (1) demonstrate a lower total cost of ownership (TCO) for the technology through minimizing fuel and infrastructure costs, (2) develop lessons learned to share with other distribution facilities supporting PG&E's EV Fleet program, and (3) reduce emissions of harmful pollutants from diesel engines.

The PRP was designed to address several barriers that may be limiting the uptake and full implementation of eTRU technology. The 2018 advice letter cited findings from the California Air Resources Board (CARB) that "limited fueling infrastructure exists and fueling infrastructure costs are significant." These, along with research from the Electric Power Research Institute (EPRI), formed the basis for PG&E's selection of two key barriers to address with the project:

- High up-front capital costs of infrastructure and capital constraints on the part of fleet owners and facility owners
- Lack of awareness and misconceptions about the technology's return on investment

Transport refrigeration is a good candidate for electrification because eTRU technology is broadly available. Additionally, shifting from diesel to electric energy is expected to generate valuable fuel cost savings and create air quality improvements at distribution centers, which are likely to be in or near disadvantaged communities (DAC). The success of this PRP will pave a pathway for refrigerated distribution centers to comply with anticipated eTRU regulations from CARB and for broader deployment of the technology across the state.

[98] Public Utilities Commission of the State of California. January 11, 2018. "Decision on the Transportation Electrification Priority Review Projects." Decision 18-01-024. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M204/K670/204670548.PDF

[99] Public Utilities Commission of the State of California. May 24, 2018. Advice Letter 5279-E. https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_5279-E.pdf

Site and Participants

Initial Scoping and Customer Acquisition

The PRP scope covered a variety of potential site host types, including truck stops as well as small, medium, and large warehouse and distribution facilities. PG&E collaborated with CARB to generate a list of eTRU fleet owners that could be approached to host the project. A few key factors drove the final decision to partner with the Albertsons Distribution Center in Tracy, California:

- ***Internal capacity*****:** Albertsons was able to dedicate sufficient institutional resources to meet the data collection, project management, and scoping requirements of PRP participation.
- ***Capital flexibility*****:** As a larger company, Albertsons has more flexibility to absorb shifts between capital and operating budgets relative to small- or medium-sized businesses.
- ***Rebate option:*** Albertsons is a transmission-level customer that had enough capacity available on its existing service infrastructure to pursue the project completely on the customer side of the meter, which allowed PG&E to test out a rebate approach for make-ready infrastructure. This is an option that is available in PG&E's EV Fleet program, as part of its SRPs.
- ***Aligned incentives*****:** Unlike truck stops and smaller distribution centers, which often serve fleets that are not owned by the same owner as the facility, the vehicles served at the Albertsons distribution center are not owned by third-party operators. Therefore, the savings on fuel costs over the lifetime of the project are captured by the same entity that paid for the upfront capital expenditures. Albertsons' operations encompass all aspects of the project value chain, ensuring aligned incentives that encourage utilization of the infrastructure.
- ***Streamlined implementation*****:** As the single owner and operator for both the facility and fleet, Albertsons presented a simplified project. There was no need to arrange a payment mechanism for electricity supplied to eTRUs or coordinate with multiple stakeholders representing separately owned fleets that might utilize the infrastructure.

Site Host

The site host in this PRP, Albertsons, is a large grocery company that operates a seven day per week and 24 hour per day food distribution service center in Tracy, California. Located in a DAC, the 2.2 million square foot facility has 313 loading dock doors and more than 400 staging spaces where loaded trailers wait until their delivery time. Albertsons is a sophisticated electricity consumer because the distribution center requires significant energy to regulate the facility temperature. There are two, 1 MW wind turbines at this site to help support this electrical demand.

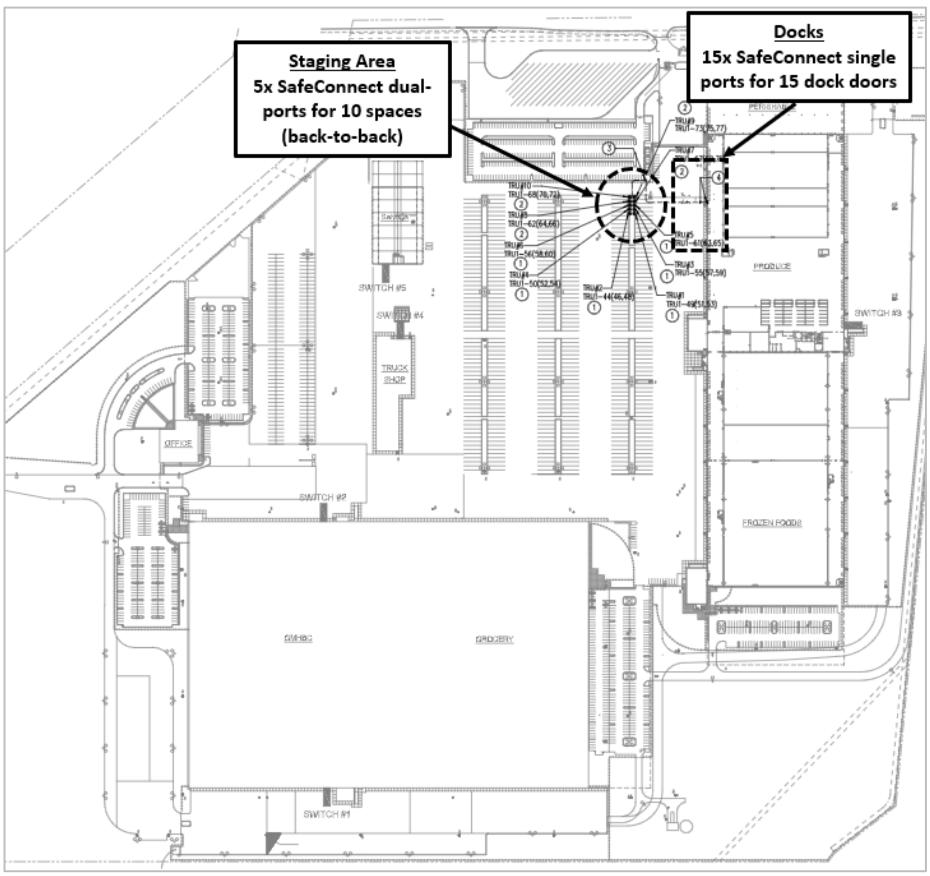
Albertsons is a Direct Access customer subscribed to a unique electricity rate. In fact, Albertsons' electricity consumption at the Tracy facility is so significant that facility staff expect the load impacts of the 25 eTRU SafeConnect connection ports at the docks and staging areas to be imperceptible relative to total facility consumption.[100]

As a company operating within a very competitive industry with narrow margins, Albertsons' approach to the PRP was different from that of public-sector fleets in other PG&E PRPs. Albertsons was supportive of helping to advance transportation electrification technology for this application but also needs to protect its business interests. For instance, while Albertsons was collaborative in sharing information, staff requested review and approval before disclosing operational data or inviting others for site tours.

Albertsons also had the capacity to manage the engineering and construction process entirely internally. Albertsons managed the project, paid for expenses as they arose, and received reimbursements from PG&E on a milestone completion basis.

Figure 232 shows an overall schematic of the Albertson's Tracy facility.

Figure 232. PRP site facility layout



Source: PG&E

[100] According to specifications, the SafeConnect ports selected for the PRP are each capable of delivering up to approximately 20 kW, although, on average, an eTRU does not consume the full amount of power available.

Existing Fleet Operations

Albertsons operates approximately 790 active trailers, the majority of which are equipped with refrigeration units. According to the active trailer database provided by Albertsons in September 2020, only about 20 trailers are dry (non-refrigerated).

During the day, the distribution center receives product from supplier trailers through outer-facing loading docks. During the afternoon and throughout the night, product is selected and loaded onto Albertsons' trailers at the inner-facing docks. Once loaded, the trailers are moved by yard hostlers to staging areas. Starting in the early morning through mid-day, loaded trailers leave the facility for delivery routes. Transport refrigeration unit (TRU) compressors mainly operate at high speed during the pre-cooling cycle prior to loading, as the trailers are warm from returning from deliveries (units are turned off after all product is unloaded at their delivery locations). Pre-cooling may occur at either docks or staging areas, depending on space availability. In the staging areas when loaded with product before deliveries, the TRU compressor cycles on and off to maintain the trailer temperature setpoint.

Table 82 summarizes the overall TRU inventory by engine year. Half the trailers are less than 10 years old and most of the remaining trailers are between 10 and 15 years old. Only a few of Albertsons' trailers are over 15 years old. This age distribution is in line with expected TRU lifespan, which varies between 10 and 20 years based on operating hours (higher operating hours result in reduced lifespan).

Table 82. PRP site host TRU inventory by engine year as of September 2020

Engine Year	Quantity	Percentage of Total Fleet
2002 to 2005	34	4%
2006 to 2010	341	44%
2011 to 2015	141	18%
2016 to 2020	251	33%
Total	**767**	**100%**

Note: This table includes both diesel-only TRUs and eTRUs.
Source: PRP Site Host

Of the active trailers, 280 are equipped with eTRUs. Table 83 summarizes the eTRU fleet by engine year and Table 84 summarizes the eTRU fleet by eTRU make and model. A majority of the eTRU fleet (89%) have Carrier Vector model eTRUs. Prior to this PRP, none of the eTRUs were plugged into the grid while docked or in the staging areas.

Table 83. PRP site host eTRU inventory by engine year as of September 2020

Engine Year	Quantity	Percentage of eTRU Fleet
2010	2	1%
2011	5	2%
2012	22	8%
2014	39	14%
2015	38	14%
2016	68	24%
2017	52	19%
2018	3	1%
2019	50	18%
2020	1	0%
Total	**280**	**100%**

Source: PRP Site Host

Table 84. PRP site host eTRU inventory by make and model as of September 2020

Make	Model	Quantity	Percentage of eTRU Inventory
Carrier	Reefer	2	1%
Carrier	Vector	233	83%
Carrier	Vector-860	1	<1%
Carrier	Vector-850	15	5%
Carrier	Galaxy-R8	2	1%
Thermo King	Spectrum	27	10%
Total		**280**	**100%**

Source: PRP Site Host

Implementers and Additional Vendors

This PRP required fewer third parties to serve as implementers and vendors compared to PG&E's other PRPs because the focus is on how to successfully install and operate the infrastructure. Furthermore, PG&E did not need to invest substantial effort in guiding Albertsons through the design and construction process. This was primarily because Albertsons is a transmission-level service customer and had sufficient power available on the company's existing service. Albertsons decided to power its eTRU infrastructure using the internal switchgear and electrical system rather than pulling a new service from PG&E. This eliminated the need to coordinate with PG&E for to-the-meter construction, but prevented the installation of a separate, utility-grade meter to monitor the eTRU electricity consumption and demand.

Two external project vendors supported the construction and equipment needs. Albertsons engaged Hansen Rice, a contractor with extensive experience working with the company at that site. The contractor did not have eTRU experience, but Albertsons and Hansen Rice did not deem this as a major hurdle. Albertsons also worked with SafeConnect Systems[101] to provide the connection ports and receptacles (Figure 233). At the time of project initiation, SafeConnect was the most mature vendor offering this type of product and Albertsons deemed their six-pin plug as satisfactory from a safety standpoint.

Figure 233. SafeConnect Systems eTRU receptacle (left) and wall-mounted port (right)

Source: SafeConnect

Another unique aspect of this PRP is that the site host owns and maintains the infrastructure. This meant that Albertsons could conduct internal coordination to deploy the project. However, PG&E faced the risk that, if the project were not a priority for the site host, implementation could be delayed because PG&E would not have control over the schedule. The utility mitigated this risk by structuring the incentive to Albertsons in milestones, releasing incentive payments after the completion of critical steps throughout the project, such as charger procurement, finalization of design and engineering, and close of construction.

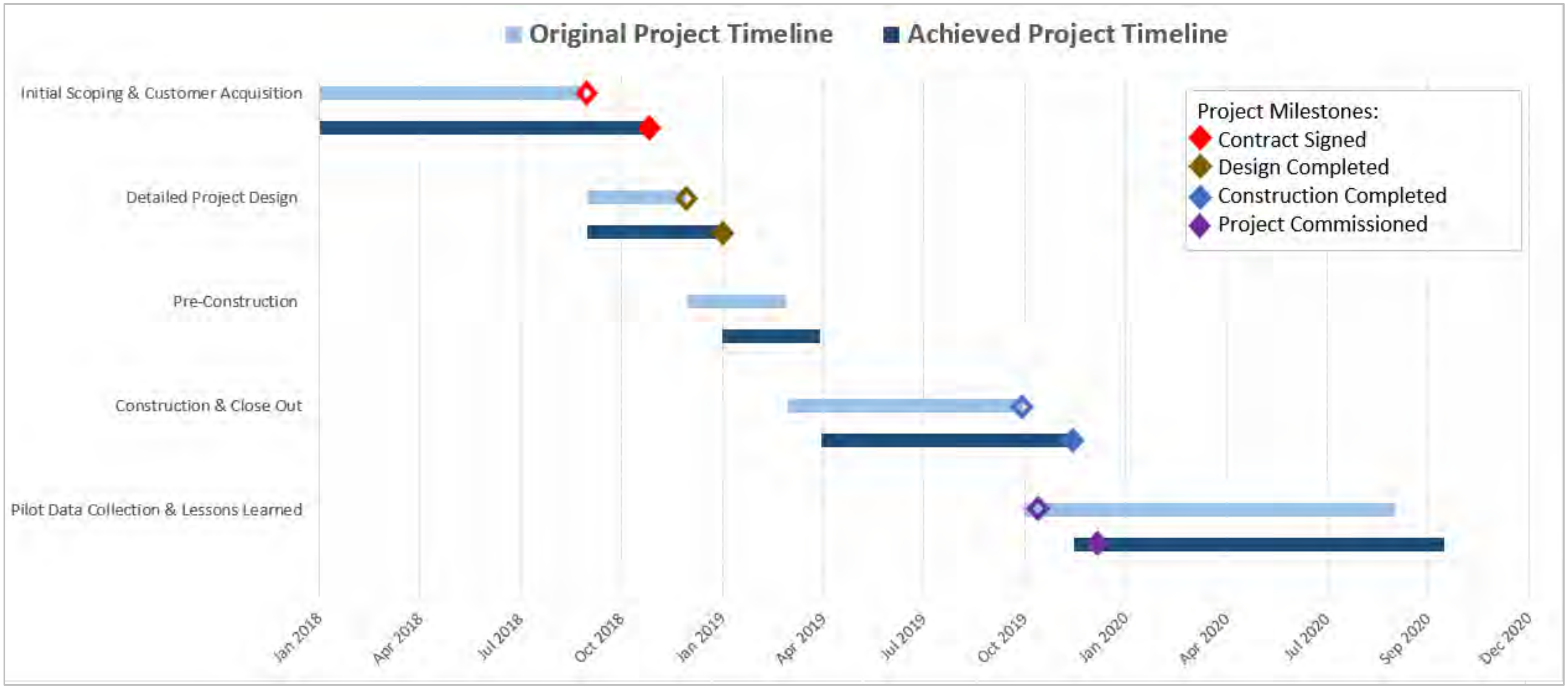
PG&E did not actively manage the design and construction of this project and had less influence on the onsite data collection methodology. However, PG&E's engineering and construction teams were involved in reviewing the project design and inspecting the installed equipment prior to the release of incentive payments. The utility was able to leverage these steps to gain insight into the design and installation of eTRU plugs without actively managing the project. Ultimately, this PRP required relatively little coordination with additional partners and vendors.

[101] For more details, see the SafeConnect Systems website (https://www.safeconnectsystems.com/six-pins-for-safety/).

Timeline

Figure 234 illustrates the original timeline (pale blue fill) and the achieved timeline (medium blue fill) for the eTRU PRP. This divergence reflects a variety of disruptions and challenges, many of which were unforeseeable on the part of PG&E or Albertsons. The activities shown in Figure 234 are detailed in text below.

Figure 234. PG&E Idle Reduction PRP timeline



Note: Open diamonds indicate original milestone date.
Source: PG&E

The permitting process with the local authority having jurisdiction (AHJ) took a month longer than expected. The AHJ was unfamiliar with this technology, which prompted additional back-and-forth between county staff and Albertsons. While permitting delays are typically out of the hands of both utilities and site hosts, it may be effective for utilities and state agencies such as CARB to work with AHJs to inform them of eTRU technology to help streamline the permitting process for future eTRU projects. This could be strategically focused on AHJs where food distribution centers are located to streamline permitting processes more effectively.

Construction included procurement and installation of 25 SafeConnect eTRU ports, which involved:

- Replacing switchgear and running wiring and conduit to 15 docks
- Running wiring and conduit across the parking facility to the staging area for five additional SafeConnect dual-port units (which required 300 feet of trenching)
- Installing protective mounting systems for the units in the staging area
- Installing two Eaton Power Xpert Multi-Point submeters to monitor power use from each port individually (one for the dock ports and one for the staging ports)
- System commissioning

Albertsons experienced a few minor timeline setbacks during construction. The project was delayed nearly two months because of an issue with existing electrical switchgear. The switchgear was rated with sufficient electrical capacity to serve the additional load; however, the switchgear safety interlock was found to be non-operational and the part necessary to replace it was no longer available. This caused a two-month delay as the legacy part was fabricated. Had Albertsons' staff tested the legacy equipment at the start of the implementation process, the issue may have been detected earlier.

Albertsons estimated that, if the company were to do the project again, the timeline of the construction process would be closer to four months rather than the seven to eight months it took for this project.

The 25 ports were electrified and ready for operational use in early November 2019. The busiest loading docks were selected for electrification, which enables Albertsons to maximize the amount of time that eTRUs can be plugged in. The docks that were electrified are on the loading (outbound) side.

In parallel with the decision to build the infrastructure, Albertsons retrofitted approximately 270 of its newest eTRU trailers with a SafeConnect port compatible plug at the rear of the trailer. Rather than retrofit the remaining older trailers, Albertsons has decided to specify that any newly procured trailer be compatible with the charging ports every time an older trailer is retired.

To maximize the data collection period and meet the reporting timeline, the evaluation team collected the final set of data in October 2020.

5.3.2 Evaluation Methodology

Objectives and Research Questions

PG&E used this PRP to learn more about eTRU operations and how to implement supporting electrical infrastructure. PG&E expects refrigerated trailers to be a key market segment for transportation electrification, so staff hope to determine the extent of customer demand and to understand how customers are using the technology. Since cost-effectiveness is expected to be a major driver of demand, the project focused on reducing TCO. While PG&E originally considered investigating whether eTRUs can be leveraged as grid assets, this aspect is not currently addressed by the project. Furthermore, Albertsons staff are primarily interested in protecting their cold products, schedules, and logistics and said they are not interested in demand management at this time if there is any chance that such actions could interfere with business priorities. Demand management solutions that would not affect logistics would likely require expensive additions to the project (such as energy storage) or temporarily switching to diesel when needed (which would be contrary to the PRP goals).

Participating in the PRP allowed Albertsons to learn about eTRU technology and its impacts on facility operations. One of Albertsons' primary goals was to learn how to use this technology while protecting the 'cold chain' that is the cornerstone of its business. Albertsons wanted to understand how fueling and maintenance costs differ when running eTRUs on electricity versus diesel. Likewise, Albertsons monitored and addressed potential impacts on employee productivity and safety, as well as reception of the project by key staff—fueling staff, yard hostler drivers, and distribution drivers. Finally, recognizing that there will likely be future CARB requirements to run eTRUs on electricity, Albertsons was motivated to understand how to scale eTRU technology in the future.

For this PRP, in addition to the research questions that apply to every fleet electrification PRP, the evaluation team used to several questions to understand how projects driven entirely by the site host differ from those in which the utility has a more active management role:

- **Source: Evaluator Calculations**
- **Results Observed to Date: Fleet Perspective**
  - What were the operational impacts on the fleet and its staff to accommodate electrification?
  - What were the cost impacts to Albertsons?
  - What is the potential for scale-up in the fleet?
- **Source: Evaluator Calculations**
- **Results Observed to Date: Societal Perspective**
  - How, if at all, did the PRP change electrification within the fleet?
  - What were the net energy and emissions impacts (relative to the no-PRP scenario)? How did these impacts accrue in DACs?
  - What were the co-benefits? How did these impacts accrue in DACs?
- **Project Legacy and Learnings**
  - What innovations were achieved?
  - How could PRP implementation be improved?
  - How did PG&E project costs compare to expectations?

Data Sources and Collection Challenges

The evaluation team conducted in-depth interviews with PG&E staff to better understand the decision-making process and reasoning behind this project. During the first interview, we collected lessons learned on the implementation process, discussed data collection, and confirmed the partner outreach and selection approach. Following commissioning of the electrical connections, the evaluation team interviewed Albertsons' staff (including management personnel who oversee engineering, transportation, and distribution center operations) during a site visit, then afterward by phone. These conversations captured an understanding of the project barriers, expected savings from idle reduction, lessons learned from planning and construction, seasonality of eTRU deliveries and activities, and how best to gather feedback from staff affected by the PRP (such as fueling staff, hostler drivers, distribution drivers, and maintenance staff). The evaluation team also interviewed a representative from SafeConnect to discuss the eTRU port market, details on the six-pin technology, typical customer operations, expected economies of scale with market growth, and lessons learned from the Albertsons project. The evaluation team interviewed each of these entities again at the end of the project.

The evaluation team fielded a survey with Albertsons' trailer drivers, yard hostler operators, and maintenance staff during August and September 2020, after the eTRU electrical ports had been operating for almost a year. The survey aimed to understand users' comfort with the connection ports, the level of training provided by Albertsons, required changes in operations due to the electric connection ports, and any non-energy benefits experienced by the staff. The findings in this report draw substantially upon the interviews and survey.

The evaluation team also assessed quantitative data to estimate project impacts and analyze eTRU usage patterns and costs. These included 15-minute power metered data for each SafeConnect port from November 8, 2019 through October 8, 2020, maintenance reports, eTRU refrigeration system energy management data (supply and return temperatures, compressor run hours, start cycles, and engine mode), PG&E's costs to implement the PRP, electrical schematics showing port locations, and equipment specifications.

The evaluation team conducted market research of comparable fleets, electric connection ports, and TRU standard practice throughout the duration of the PRP. As CARB is one of the leading regulatory and data collection resources in this industry, the evaluation team hosted a conference call with representatives from CARB's Transportation Systems Planning Branch in May 2020. During this call, we discussed the existing market, upcoming regulation changes, and expected challenges. The evaluation team also interviewed representatives of ESL; another eTRU connection port vendor based out of California. Resources discussing the state of eTRU technology, analyses of TRU fuel consumption and emissions, and other relevant references provided a baseline and context for the primary data collected as part of the evaluation.

The evaluation team navigated several data collection challenges throughout the PRP, detailed in Table 85.

Table 85. Data collection challenges and resolutions

Item	Issue	Result/Resolution
eTRU refrigeration system energy management data	Data was provided in PDF format with inconsistent intervals and summary parameters could not be easily extracted	The evaluation team worked with Albertsons staff to add summary parameters (including engine run hours, electric standby hours, and compressor run hours) to the data export.
eTRU port metered data	Could not access data remotely and onsite IT staff could not access due to security network	Albertsons brought a data management vendor onsite to install an interface to make it easier to download the Eaton submeter data remotely. Data management vendor experienced issues so Albertsons' engineering project manager visited the site to manually download data from the Eaton meter.
eTRU port metered data	Data must be exported from Eaton interface in weekly increments to collect 15-minute granularity	Albertsons' engineering project manager exported over 100 individual metered data files (one per week per meter). Albertsons' is pursuing a software reporting interface for the Eaton meters, but it has not yet been implemented.
eTRU port metered data	Eaton submeter maximum true power higher than expected	The evaluation team discussed this issue with the Albertsons team and SafeConnect representative. Albertsons has not experienced any breakers tripping and SafeConnect confirmed that the ports should not be able to accept more than 30 amps. While we were unable to troubleshoot the issue without being onsite to collect secondary data, the teams agreed that the high metered power demand is likely a meter data quality issue.
eTRU port metered data	Lack of back-up data source	Without a back-up data collection source, the evaluation team could not verify or troubleshoot the Eaton submeter data. The COVID-19 pandemic limited site access for the evaluation team and the data management vendor. The site's electrical safety procedures also prohibit live electrical monitoring.

Source: Evaluator, PG&E, PRP Site Host

5.3.3 Evaluation Findings

This section is organized around the priority evaluation questions articulated above, grouped into three main categories: (1) the impact from the fleet perspective, (2) the immediate impact from a societal perspective, and (3) the project legacy.

High-Level Quantitative Summary

Table 86 presents a summary of annualized program benefits as calculated in comparison to the performance characteristics typical of the industry and of Albertsons' eTRU fleet. Each column represents different assumptions:

1. ***Anticipated*** uses equivalent average annual utilization rates for the baseline diesel fleet and Albertsons' eTRU fleet. An average annual use rate of 18.7% (equivalent to 1,636 annual utilization hours) is based on EPRI and CARB study results for comparable TRU fleets (see Table A-60 in Appendix A for details). An average diesel TRU generator fuel consumption rate during operation of 0.85 gallons per hour and the eTRU port average demand during plug-in operation of 9.0 kW are based on EPRI's 2015 eTRU market and technology assessment report.[102] *Anticipated* is not a project target, rather what would have been expected based on average eTRU utilization from similar fleets.
2. ***Implemented*** uses the same diesel TRU fuel consumption rate and eTRU average demand as described in *Anticipated* but incorporates an actual average port use rate of 11.9% (equivalent to 1,039 annual utilization hours) based on results from the PRP data collection period.
3. ***Best Observed*** uses the same diesel TRU fuel consumption rate and eTRU average demand as described in *Anticipated* but incorporates an actual port use rate of 18.5% (equivalent to 1,621 annual utilization hours) during September 2020, the month of highest utilization during the PRP data collection period.

The fuel cost savings are presented using two electric utility rates: (1) a low average rate of $0.05 per kilowatt-hour, which may represent the average cost for direct-access, high-energy consumers, and (2) $0.16 per kilowatt-hour, the 2019 weighted average statewide electricity rate calculated by the California Energy Commission based on the number and location of eTRU candidate facilities.[103]

Other assumptions underlying this table are described in more depth in the *What were the Net Energy and Emissions Impacts (Relative to the No-PRP Scenario)? What were the Cost Impacts to the Fleet?,* and *Potential for Scale-Up Across the State* sections.

[102] Electric Power Research Institute. December 22, 2015. *Market and Technology Assessment of Electric Transport Refrigeration Units*. https://www.epri.com/research/products/000000003002006036

[103] California Air Resources Board. August 20, 2020. *Preliminary Cost Document for the Transport Refrigeration Unit Regulation*. https://ww2.arb.ca.gov/sites/default/files/2020-08/Preliminary%20TRU%20Cost%20Doc%2008202020.pdf

Table 86. Annualized program benefits

	Anticipated	Implemented	Best Observed
Assumptions	25 ports, 18.7% utilization (1,636 hours/year)	25 ports, 11.9% utilization (1,039 hours/year)	25 ports, 18.5% utilization (1,621 hours/year), (September 2020)
Petroleum Reduction (diesel gallons)	34,769	22,089	34,448
Avoided Greenhouse Gas (GHG) Emissions (tonnes CO_2)	374	246	383
Avoided SO_2 (kilograms) [a]	N/A	N/A	N/A
Avoided NOx (kilograms)	3,364	2,143	3,341
Avoided CO (kilograms)	846	542	845
Avoided PM10 (kilograms)	335	214	333
Avoided VOC (kilograms)	694	442	689
Impact to Disadvantaged Communities (percent utilization within DAC)	100%	100%	100%
Annual Electric Utility Grid Impact (MWh)	368	210	328
Operation and Maintenance Cost Savings – Equipment ($) [b]	$38,593	$23,675	$38,215
Operation and Maintenance Cost Savings – Staff ($) [c]	-$59,040	-$59,040	-$59,040
Fuel Cost Savings ($) ($0.05/kWh electricity rate)	$117,993	$76,141	$118,743
Fuel Cost Savings ($) ($0.16/kWh electricity rate)	$77,497	$53,010	$82,670
Other Co-Benefits		Reduced ambient noise	Reduced ambient noise

[a] SO_2 diesel TRU emissions were not measured in NREL's study of diesel TRU emissions.[104] See *What were the Net Energy and Emissions Impacts (Relative to the No-PRP Scenario)?* for details.
[b] Equipment operation and maintenance costs do not include fuel cost savings.
[c] Staff operation and maintenance costs are higher with eTRU plug-in operation due to the need for an extra staff member for every shift.

Source: Evaluator Calculations

Results Observed to Date: Fleet Perspective

This section addresses whether the project affected the fleet's ability to perform its core functions, satisfied fleet and stakeholder needs, and demonstrated the technological readiness and TCO benefits of plugging-in eTRUs at docks and staging areas.

[104] National Renewable Energy Laboratory. May 2010. Emissions of Transport Refrigeration Units with CARB Diesel, Gas-to-Liquid Diesel, and Emissions Control Devices. https://www.nrel.gov/docs/fy10osti/46598.pdf

What were the Operational Impacts on the Fleet and Staff?

The evaluation team investigated the operational impacts on the fleet and Albertsons' staff through in-depth interviews, regular project status calls with management, and the driver survey. Generally, Albertsons staff reported satisfaction with the eTRU ports and minimal changes to operations. In the driver survey, 86% (n=25) said operational procedures had not changed significantly with plug-in operation.

The most noteworthy operational change for the facility has been the physical plug-in/plug-out process and manually switching the eTRUs from diesel to electric. With diesel-only operation, yard hostler operators could do their work without having to leave the yard hostler cab. With plug-in operation, staff need to climb down from the cab, walk to the back of the trailer, plug in the SafeConnect port, and manually switch the eTRU from the diesel generator to electric shore power. This makes the job much more physical, as yard hostler cabs are high off the ground and the trailers are 40 feet to 53 feet long. During the in-depth interview, Albertsons management staff said they had to add a staff member to each shift to account for this change. Each shift has between five and seven staff members, so electrification required up to a 20% increase in staffing.

Drivers and yard hostler operators who participated in the survey expressed that it would simplify their job if the eTRUs automatically switched from diesel to electric when plugged in. During project status discussions in September and October 2020, Albertsons staff said they are pursuing a software update for the eTRUs to automatically switch to electric shore power when connected; according to a SafeConnect representative, most new eTRUs will come with this built in.

Albertsons management staff reported that the eTRU ports have been reliable since installation. As of October 2020, almost one-year after installation, no port repairs had been required. Of the drivers and yard hostler operators who participated in the survey, 70% (n=21) had never encountered a problem with the ports and only two had experienced issues *often* (more than 50% of the time).

Since trailers are placed at docks based on food distribution logistics, dock ports are used less often than staging area ports. The loading process cannot always be adjusted to ensure that compatible eTRU trailers, which account for approximately 35% of the overall TRU fleet, are placed at the electrified docks. The 9% average dock utilization recorded during the PRP data collection period is 40% less than the staging area port utilization (see Table 87). Albertsons staff are working to adjust the process to increase dock electrification utilization, as operationally feasible.

The selection of staging area locations in the yard for loaded trailers is more easily adjusted for compatible eTRUs. Albertsons' operations management implemented a new procedure and instructed yard hostler operators to park compatible trailers, which have a large sticker on them indicating compatibility, at an available electrified space to maximize electric usage. Management maintained a tracking log for the staging area ports, recording when eTRUs were plugged in and the associated trailer number, and staff maintaining the log drove out to ensure the eTRUs were plugged in. The amount of time a loaded trailer is parked in a staging area can also be significantly longer than the time parked at a loading dock. These factors are apparent in the average staging area port utilization of 16%.

Table 87 summarizes the individual dock and staging area port average utilization rates, average electric demand during utilization, and projected annual electric energy consumption (assuming the utilization rate is consistent year-round, across operations that are 24 hours per day, seven days per week), based on the Eaton submeter data provided for the PRP data collection period.

Table 87. PRP site host eTRU port utilization rate, electric demand, and annual energy use

Location	Port ID [a]	Utilization Rate	Average Electric Demand (kW)	Projected Annual Electric Energy Consumption (kWh)
Docks	1	14%	7.0	8,462
	2	6%	11.2	5,951
	3	14%	6.8	8,468
	4	8%	6.8	4,736
	5	7%	11.2	6,474
	6 [b]	0%	0.0	0
	7	14%	6.8	8,165
	8	5%	9.1	3,984
	9	14%	6.9	8,553
	10	8%	4.4	3,102
	11	9%	11.6	9,548
	12	8%	11.8	7,978
	13	14%	6.6	7,881
	14	6%	10.8	5,251
	15	14%	6.3	7,611
	Dock Average	**9%**	**7.8**	**6,411**
Staging Area	16	19%	3.8	6,316
	17	20%	9.3	16,169
	18	25%	11.5	25,260
	19	19%	9.2	15,083
	20	19%	3.7	6,223
	21 [c]	2%	10.5	2,168
	22 [c]	2%	8.7	1,303
	23	21%	11.0	20,290
	24	29%	9.2	23,308
	25 [c]	1%	8.2	582
	Staging Area Average	**16%**	**8.5**	**11,670**
Total		**11.9%**	**8.1**	**210,282**

[a] The evaluation team anonymized Albertsons' port IDs.

[b] This port was not used during the PRP data collection period. According to Albertsons staff, the dock is difficult to access for loading because the electrical cabinet for the eTRU ports was installed too close to the door.

[c] According to Albertsons' operations manager, staging ports 21, 22, and 25 are used less due to their locations in the yard. The yard hostler operators typically leave the end spots open and fill in every other parking spot, then fill in the gaps.

Source: PRP Site Host Meter Data

Operators are constantly rotating trailers from docks to staging areas and vice versa and likely interact with the ports daily. Drivers have less experience, since trailers are exchanged in a general pool and it is not common for a driver to get the same trailer that goes to the same destination every day. Per the staff survey results for drivers and yard spotters:

- 20% use the ports daily (n=6),
- 13% use the ports a few times per week (n=4),
- 23% use the ports a few times per month (n=7), and
- 43% have used the ports a couple of times since they were installed (n=13).

However, almost half the survey respondents (48%, n=14) rated themselves as *comfortable* or *very comfortable* using the ports and only eight (28%) rated themselves as *uncomfortable* or *very uncomfortable* using the ports.

SafeConnect provided training materials to Albertsons, including a demonstration kit for physical interaction. Over 40% of participants (n=19) said they received adequate training to use the ports and 23% (n=7) said they received encouragement from Albertsons staff to use the ports instead of idling the diesel generators.

Due to varying experience, tight operation schedules, and mix of diesel TRUs and eTRUs onsite, it is critical to provide safety features for eTRU ports (such as SafeConnect' safety control circuit) and clear signage for drivers to protect against electrical arcs from accidental drive-offs. As Albertsons installs more ports and more staff become comfortable with plugging-in the eTRUs, some of these operational challenges will equalize. However, electrical safety procedures will always be important.

What were the Cost Impacts to the Fleet?

Since Albertsons is a direct-access, high-energy consumer and the 25 installed ports have a minor impact on the facility's overall energy use, the evaluation team did not collect site-wide electric utility bill data. However, as Albertsons increases the number of ports at the site, they will need to estimate the impact on their existing electrical infrastructure and overall energy cost.

The evaluation team calculated the average annual energy consumption per eTRU port in this PRP using the data presented in Table 87. Table 88 compares the expected annual electric utility bill cost increase for eTRU port operation under two electric utility rates.

Table 88. Projected annual utility bill cost comparison for eTRU port operation

Number of Ports	Annual Electric Energy Consumption (kWh)	Average Utility Rate ($/kWh) [a]	
		$0.05 [b]	$0.16 [c]
Per Port	8,411 [d]	$421	$1,346
Total (25 Ports)	210,282	$10,514	$33,645

[a] This represents the weighted average annual rate, including demand costs.
[b] This low average utility rate of $0.05 per kilowatt-hour may represent a direct-access, high-energy consumer.
[c] This is the 2019 electricity cost from a California Energy Commission staff email to CARB staff dated February 26, 2020. CARB staff calculated a weighted statewide electricity rate based on the number and location of estimated facilities (California Air Resources Board. August 20, 2020. *Preliminary Cost Document for the Transport Refrigeration Unit Regulation*. https://ww2.arb.ca.gov/sites/default/files/2020-08/Preliminary%20TRU%20Cost%20Doc%2008202020.pdf).
[d] This is the average annual electric energy consumption calculated from Table 87.

Source: PRP Site Host Meter Data

The evaluation team calculated the PRP operational fuel cost savings for Albertsons using the average diesel TRU fuel consumption of 0.85 gallons per hour[105] and diesel fuel cost of $3.92 per gallon[106] for the two electric utility rate scenarios.

The evaluation team calculated the baseline diesel TRU and eTRU equipment maintenance costs using rates provided in CARB's *Preliminary Cost Document for the Transport Refrigeration Unit Regulation*.[107] The maintenance cost for eTRUs that run on electricity during idling is lower due to the reduced operating hours of the diesel engine.

Table 89. Maintenance cost estimates

Equipment	Maintenance Cost	Unit
eTRU Plug	$92.50	$/port/year
Diesel TRU	$1.50	$/hour of operation
eTRU	$0.50	$/hour of operation

Source: PRP Site Host Meter Data

Based on feedback from Albertsons management, the evaluation team also estimated the cost to employ an additional staff member per shift. At an hourly rate of $19.68 (the hourly wage for a yard hostler operator in California on Indeed.com), the annual cost to employ an additional yard hostler operator to assist with plug-in operation is approximately $60,000, including overhead and benefits. Including an additional staff member per shift results in a maintenance and operations cost penalty with

[105] Electric Power Research Institute. December 22, 2015. *Market and Technology Assessment of Electric Transport Refrigeration Units*. https://www.epri.com/research/products/000000003002006036

[106] U.S. Energy Information Administration. California average diesel fuel cost per gallon in 2019. https://www.eia.gov/dnav/pet/pet_pri_gnd_dcus_sca_a.htm

[107] California Air Resources Board. August 20, 2020. *Preliminary Cost Document for the Transport Refrigeration Unit Regulation*. https://ww2.arb.ca.gov/sites/default/files/2020-08/Preliminary%20TRU%20Cost%20Doc%2008202020.pdf

the eTRUs, but this additional cost is likely to scale down as more staff are trained, more of the facility's parking spots are electrified, and automated switch-over technology is in place.

Overall, Albertsons attained cost savings from its participation in the PRP relative to a no-PRP scenario. The program benefits presented in Table 90 suggest the potential for saving almost $62,000 per year (or approximately $2,474 per port) if utilization is similar to that modeled in the *Best Observed* scenario under a $0.16 per kilowatt-hour utility rate.

Table 90. Annualized program operational cost savings

	Anticipated	Implemented	Best Observed [a]
Assumptions	25 ports, 18.7% utilization (1,636 hours/year)	25 ports, 11.9% utilization (1,039 hours/year)	25 ports, 18.5% utilization (1,621 hours/year)
Fuel Cost Savings ($) ($0.05/kWh electricity rate)	$117,993	$76,141	$118,743
Fuel Cost Savings ($) ($0.16/kWh electricity rate)	$77,497	$53,010	$82,670
Operation and Maintenance Savings – Equipment ($)	$38,593	$23,675	$38,215
Operation and Maintenance Savings – Staff ($)	-$59,040	-$59,040	-$59,040
Total Savings ($) ($0.05/kWh electricity rate)	**$97,545**	**$40,776**	**$97,918**
Total Savings ($) ($0.16/kWh electricity rate)	**$57,049**	**$17,645**	**$61,845**

[a] The highest utilization period was observed in September 2020.

Source: Evaluator Calculations

The TCO analysis detailed in Table 91 presents a wholistic picture of the cost profiles of different TRU operational scenarios from the perspective of Albertsons' fleet. The analysis uses industry standard data and assumes diesel TRU, eTRU, and connection port lifespans of 15 years. As implemented, the TCO per eTRU port including PRP investments is almost $11,000 less than a diesel TRU equivalent over the equipment lifetime. These calculations do not include potential Low Carbon Fuel Standard (LCFS) credits that Albertsons may be able to take advantage of to further improve their long-term business case for eTRUs.

Table 91. Lifetime total cost of ownership per port

Cost Component	Diesel			Electric	
	Industry Average (As Anticipated)	As Implemented	Best Observed	As Implemented	Best Observed
Infrastructure Costs Paid By PG&E [a]	N/A	N/A	N/A	$19,245	
Infrastructure Costs Paid by Albertsons [b]	N/A	N/A	N/A	$0	
Projected Fuel Costs	$81,840	$51,993	$81,084	$20,187	$31,482
Projected O&M Costs	$36,815	$23,388	$36,474	$44,608	$48,970
Total Cost of Ownership to Fleet (under various scenarios)					
Actual Anticipated TCO	$118,654	$75,381	$117,558	$64,795	$80,452
TCO without PRP Investments				$84,040	$99,697

[a] Estimated cost per port including equipment and installation.

[b] Albertsons' paid for the SafeConnect trailer eTRU retrofit kits in conjunction with this PRP. According to the SafeConnect representative, Albertsons' cost per kit is approximately $285 with approximately one hour of installation labor per unit. At $100 per hour, the total cost to retrofit 270 trailers is approximately $103,950.

Source: Evaluator Calculations

What is the Potential for Scale-Up in the Fleet?

A major question is whether PG&E's efforts caused or have the potential to advance the electrification of equipment in this application by addressing critical barriers. To address this question, it is important to assess the baseline of industry uptake and innovations developed through the project that have the potential to be broadly applied.

The broader context of the PRP is that eTRU deployment is quite prevalent, but it is rare that the units are being plugged in to run on electricity. According to Albertsons staff, even salespeople who represent the leading eTRU manufacturers were uncertain about the necessary specifications of charging ports to plug in these units. CARB is currently working a 2021 regulatory proposal to transfer truck TRUs to zero-emission, impose a stricter diesel emission standard for newly manufactured TRUs in other TRU categories, require the use of lower global warming potential refrigerant, and will include facility reporting requirements.[108] CARB is planning to assess zero-emission options for trailer TRUs and other TRU categories as part of an additional rulemaking in 2023 or 2024. These various regulatory programs are aimed at shifting the refrigerated transportation market and technology adoption trends. The Albertsons PRP is representative of a situation—one likely to be increasingly common in the future—in which warehouses and distribution centers must meet a requirement to electrify but have little experience managing the process, including procurement, installation, and operation of the

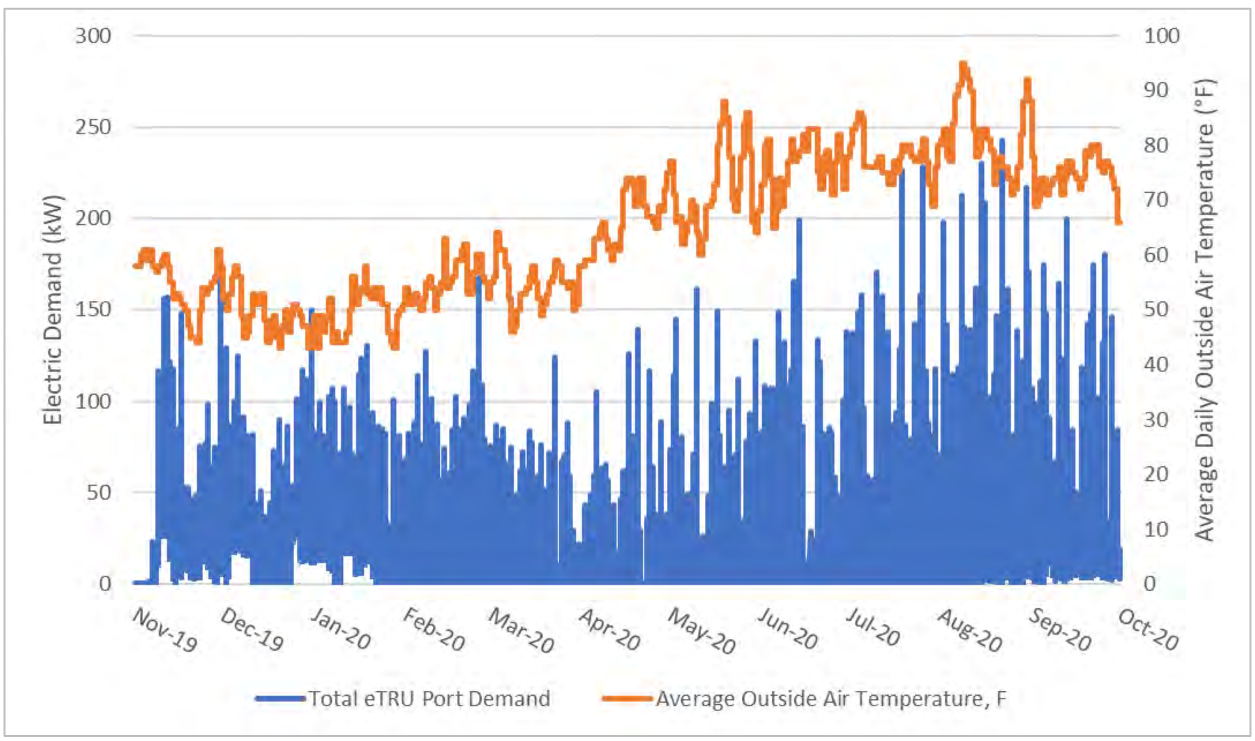
[108] California Air Resources Board. Accessed December 2020. "Current Activities." https://ww2.arb.ca.gov/our-work/programs/transport-refrigeration-unit/new-transport-refrigeration-unit-regulation

infrastructure. The value of this project is that it provides lessons about the pathway to scale deployment of eTRUs in PG&E's territory faster and more effectively than facilities would achieve without PG&E's involvement.

During the in-depth interview, Albertsons staff said the PRP had accelerated the installation of ports and plug-in operation, but that their overall electrification goals have not changed. They plan to continue electrifying their TRU fleet as units are retired and are planning to electrify the entire fleet by the time CARB regulations take full effect (potentially by 2030 depending on regulation timelines). Albertsons has already participated in PG&E's EV Fleet program and is discussing a new fleet of eTRUs to serve individual stores with their PG&E account manager. While Albertsons' existing electrical infrastructure was able to support the increased load from the 25 eTRU ports, Albertsons will need to consider the increased load from electrifying approximately 700 spaces (docks and staging areas) over the next 10 years.

Albertsons staff provided data from the Eaton submeters in 15-minute intervals from early November 2019 through the beginning of October 2020. Figure 235 summarizes total eTRU port demand for the data collection period compared to average daily outside air temperature. Higher port demand appears to be correlated to high outside air temperatures when refrigeration loads are highest, and compressors are operating at high speeds for longer periods of time.

Figure 235. PRP site host total eTRU port demand [a]

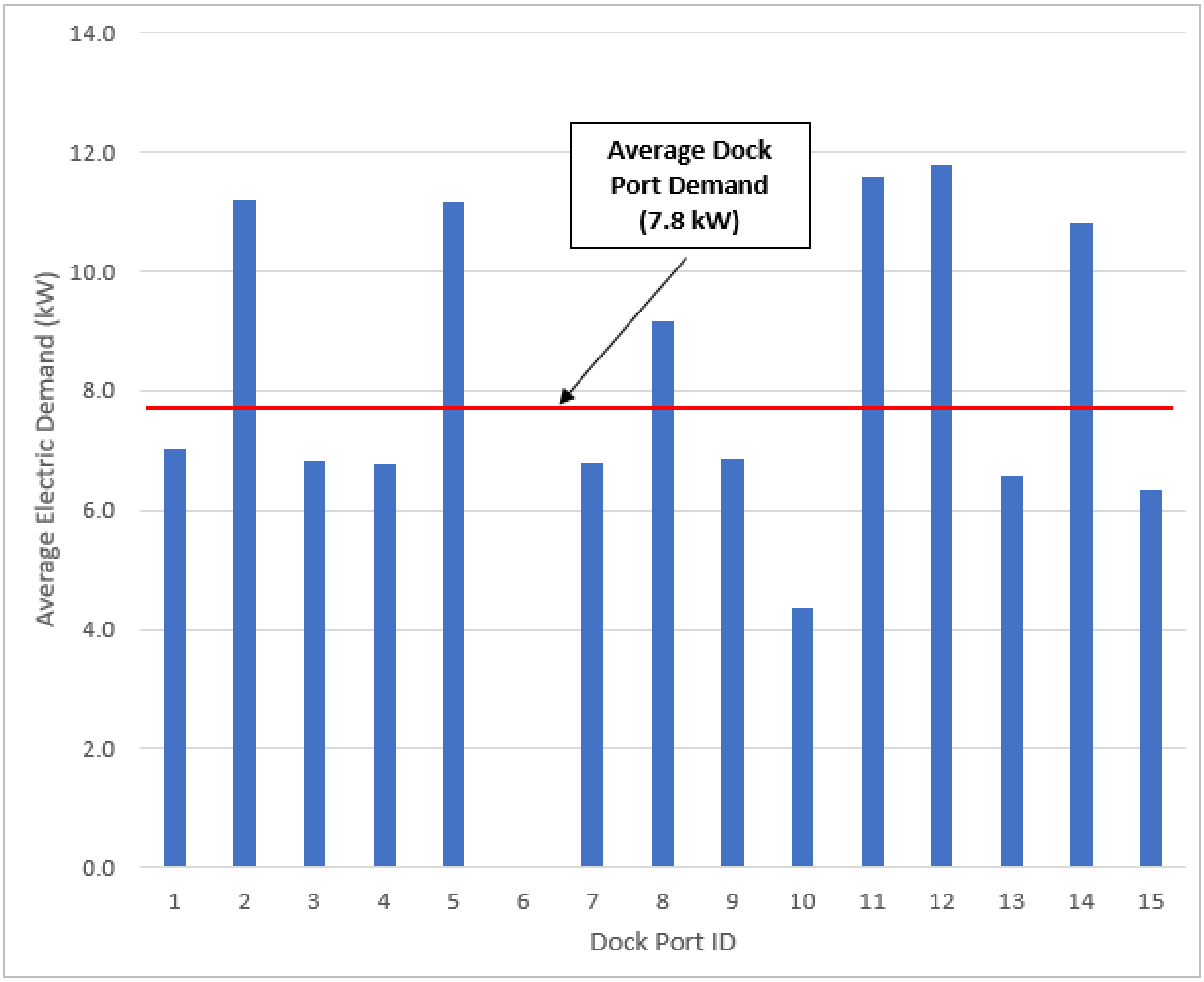


[a] As detailed in Table 85, the maximum metered port demand was higher than expected for 30-amp breakers and the evaluation team did not have a secondary data source (such as spot-checked power or a submeter) to compare the metered demand to. Additional data will be required to comfirm the peak port demand, but the average metered demand is in line with EPRI's 2015 eTRU market and technology assessment report.

Source: PRP Site Host Meter Data

Figure 236 and Figure 237 show the average electric demand for each dock and staging area port, respectively, over the data collection period. As shown and discussed below Table 87, port 6 has not been used to its location. Other ports with low average electric demand may be used less than others due to inconvenient locations and yard parking procedures.

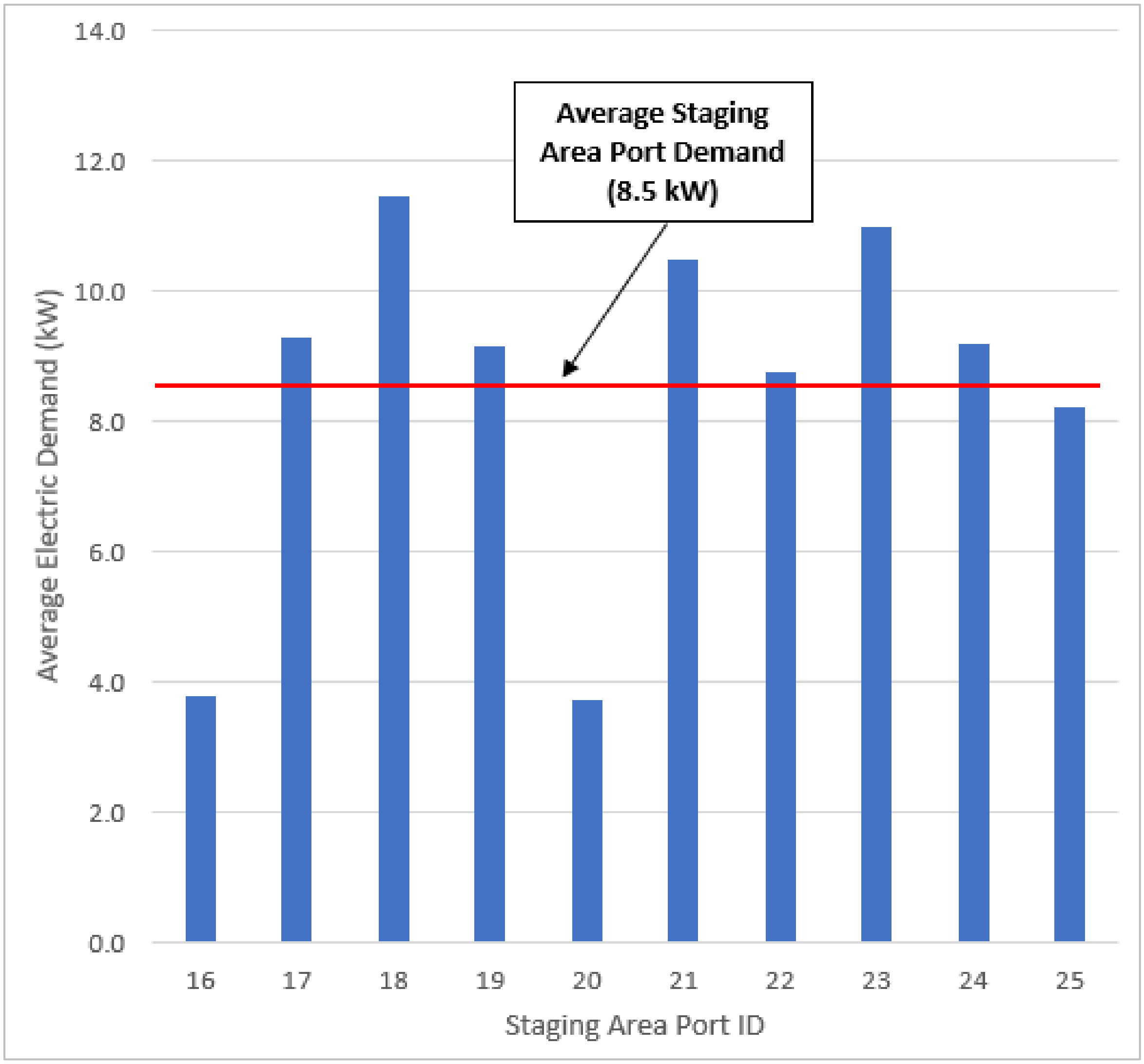
Figure 236. PRP site host dock port average electric demand [a]



[a] As detailed in Table 85, the maximum metered port demand was higher than expected for 30-amp breakers and the evaluation team did not have a secondary data source (such as spot-checked power or a submeter) to compare the metered demand to. Additional data will be required to comfirm the peak port demand, but the average metered demand is in line with EPRI's 2015 eTRU market and technology assessment report.

Source: PRP Site Host Meter Data

Figure 237. PRP site host staging area port average electric demand [a]

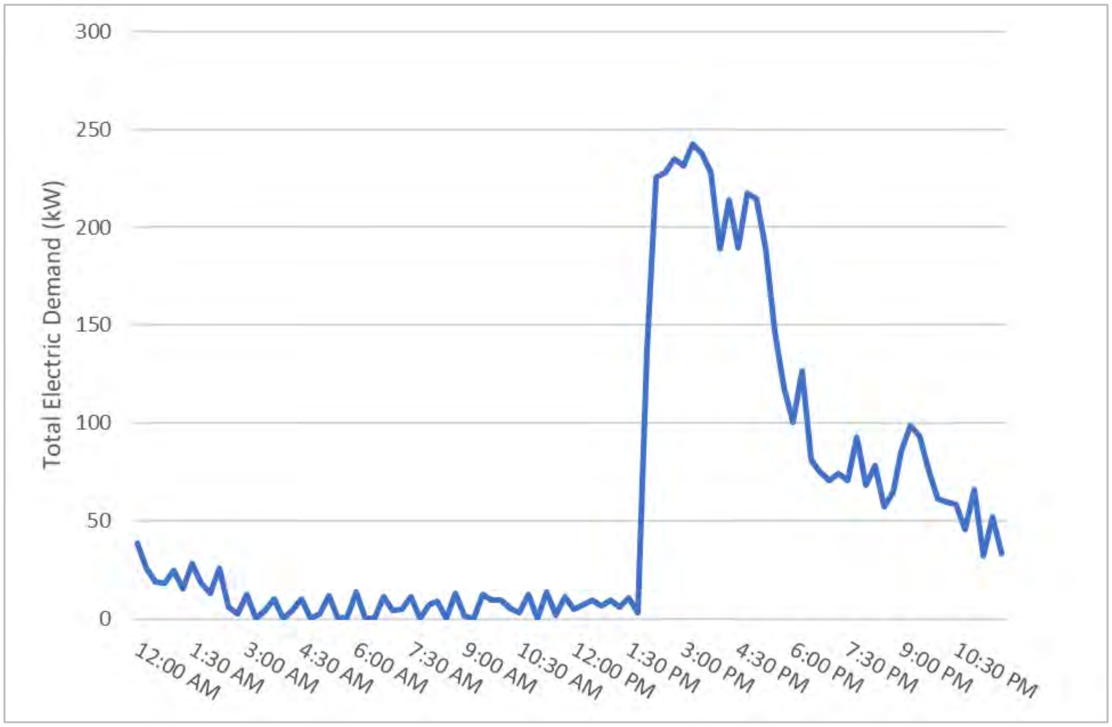


[a] As detailed in Table 85, the maximum metered port demand was higher than expected for 30-amp breakers and the evaluation team did not have a secondary data source (such as spot-checked power or a submeter) to compare the metered demand to. Additional data will be required to comfirm the peak port demand, but the average metered demand is in line with EPRI's 2015 eTRU market and technology assessment report.

Source: PRP Site Host Meter Data

Figure 238 shows the total eTRU port electric demand for the peak day during the data collection period (August 29, 2020), when the total port demand reached 243 kW.

Figure 238. Total eTRU port demand on peak day – August 29, 2020



Source: PRP Site Host Meter Data

Albertsons' facility operations are dictated by their outbound delivery schedule and management does not want to restrict port use. However, the facility may need to consider staggered dock loading periods (when refrigeration compressors are operating at high speeds to rapidly pre-cool warm trailers) to mitigate triggering electrical infrastructure upgrades as they scale-up the number of ports onsite.

Table 92 summarizes the projected annual electric energy use and peak demand if approximately 700 parking spaces are electrified. Albertsons' operations manager estimated that approximately 40% of the parking spaces are used for refrigerated loads daily. If site operation schedules and average port demand and utilization rates are comparable to the Best Observed scenario, the facility could see an annual electric energy increase of almost 4,000 MWh and a peak electric demand of over 2,800 kW.

Table 92. Projected annual electric energy use and peak demand impacts for scaled-up eTRU plug-in operation

Scenario	Quantity of Electrified Ports	Ratio of Ports in Use	Annual Electric Energy Use (kWh)	Peak Electric Demand (kW)
Implemented	25	96% [a]	210,282	243
Best Observed	25	96% [a]	327,937	243
100% Electrified	700	40%	3,825,935	2,832

[a] One of the dock ports was not used during the data collection period.

Source: Evaluator Calculations

Results Observed to Date: Societal Perspective

This section addresses whether the project successfully accomplished its objectives as outlined in the Decision, whether the project achieved immediate benefits that accrue to ratepayers and the general public, and whether the costs aligned with anticipated costs when the project was approved.

How, if At All, Did the PRP Change Electrification within the Fleet?

Across the fleet electrification PRPs in California, there are three main ways that utilities have aimed to change electrification within the participating fleets: (1) affecting vehicle procurement choices (in this PRP, 'vehicle' refers to the eTRU) and timeline, (2) affecting infrastructure procurement choices and timeline, and (3) enhancing operational performance and capabilities, thereby advancing broader market readiness and desirability of electrification for other fleets in the future.

The eTRU PRP was primarily focused on the latter two, but it likely also had some effects on eTRU timeline decisions. Each of these topics is described sequentially below.

eTRU Procurement Choices and Timeline

Although Albertsons' existing refrigerated trailer fleet included almost 300 eTRUs prior to this PRP, none of them were operated with electric shore power. From discussions with Albertsons' staff in October 2020, all new trailers will come equipped with port-compatible receptacles at the rear and eTRUs that can automatically switch from the diesel generator to electric shore power when plugged in and.

Albertsons staff also said they have started piloting all-electric eTRUs at one of their southern California facilities. An all-electric eTRU is powered solely by onboard batteries, which can be charged on-route with roof-mounted solar panels or a wheel axle regenerator. At the yard, all-electric eTRUs are plugged in to recharge the batteries. Depending on results of the all-electric eTRU pilot, Albertsons will consider using them at other facilities.

Infrastructure Procurement Choices and Timeline

This PRP accelerated eTRU port installation at the Tracy facility. It is expected that PG&E's investment in this PRP also encouraged the retrofit of almost 300 eTRU trailers with receptacles compatible with the ports, which likely resulted in increased port utilization and helped future-proof many of the existing trailers.

Based on the positive results of this project, Albertsons has started expanding electrification plans at the Tracy facility through PG&E's EV Fleet program and other California-based facilities. They have also started using shore power at distribution facilities in Alaska and Arizona, along with over 40 grocery stores.

Enhancing Operational Performance and Capabilities

Since Albertsons is primarily interested in protecting their cold products, adhering to schedules, and simplifying logistics, they were not interested in managed charging or peak demand management at this time. Demand management that does not impact logistics will likely require expensive additions (such as battery energy storage) or temporarily switching to diesel when needed.

However, findings from this PRP have helped inform operational adjustments that may increase port utilization and assist with planning for future port installations:

- Albertsons can prioritize staging area ports installations, as staging area ports are used more than dock ports.
- Albertsons can retrofit existing eTRUs and specify that new eTRUs must come with compatible receptacles and automatically switch from diesel to electric shore power when plugged in.
- Albertsons can provide additional training for drivers and yard hostler operators to ensure staff are comfortable with using the ports and understand the energy and environmental benefits.

What Were the Net Energy and Emissions Impacts (Relative to the No-PRP Scenario)?

In the Decision authorizing this project, the CPUC laid out anticipated benefits related to technology cost reductions and a potentially accelerated adoption of clean energy technologies in the medium- and heavy-duty sectors. In addition, the CPUC highlighted reduced exposure to particulate matter as a key direct benefit expected from the project.

Table 93 presents the PRP's petroleum reductions, avoided GHG emissions, and avoided emission of criteria pollutants. While all energy and emissions impacts presented in Table 93 were realized at the Tracy facility, which is in a DAC, the retrofitted trailers can be used at any grocery store with compatible ports, providing additional benefits to other DACs and some non-disadvantaged communities during deliveries.

Table 93. Annualized program fuel and emissions reductions

	Anticipated	Implemented	Best Observed
Assumptions	25 ports, 18.7% average utilization	25 ports, 11.9% average utilization	25 ports, 18.5% average utilization
Petroleum Reduction (gallons diesel)	34,769	22,089	34,448
Avoided GHG Emissions (tonnes CO_2e)	374	246	383
Avoided NOx (kilograms)	3,364	2,143	3,341
Avoided CO (kilograms)	846	542	845
Avoided PM10 (kilograms)	335	214	333
Avoided VOC (kilograms)	694	442	689

Source: Evaluator Calculations

Petroleum reductions are the estimated number of diesel gallons that would have been required to power diesel TRUs for equivalent hours as the eTRUs powered by electric ports. GHG and criteria pollutant emissions for the baseline TRU fleet are based upon the average measured emission factors for a Thermo King diesel trailer TRU provided in the National Renewable Energy Laboratory's *Emissions of Transport Refrigeration Units with CARB Diesel, Gas-to-Liquid Diesel, and Emissions Control Devices* conference paper.[109] Emission factors (grams per hour) were measured over eight test runs, using two diesel fuel types, low and high engine speeds, and two exhaust configurations.

CARB's CA-GREET3.0 Model was also used as the source for criteria pollutant emission factors for electricity.[110] Because GHG reductions were a primary focus of the PRPs and the carbon intensity of grid electricity varies markedly by season and time of day, the evaluation team used the hourly electricity carbon emission factors established for each quarter under the LCFS.[111] These carbon intensities were applied to interval metered data from the port meters to establish the emissions associated with powering the eTRUs. In all cases, avoided emissions are calculated as the difference in emissions per hour between the eTRUs and baseline diesel-powered TRU fleet, scaled to the annual utilization observed during the PRP data collection period (Table 94).

Table 94. Comparison of normalized emissions

	TRU Baseline (Diesel)	Implemented (Electric)	Percentage Reduction
GHG Emissions (kg/hour)	12.3	2.8	77%
NOx Emissions (g/hour)	84.4	1.97	98%
CO Emissions (g/hour)	22.5	1.64	93%
PM10 Emissions (g/hour)	8.6	0.34	96%
VOC Emissions (g/hour)	17.3	0.33	98%

Source: Evaluator Calculations

What Were the Co-Benefits? How Did These Impacts Accrue in Disadvantages Communities?

When electricity instead of a diesel generator is used to power an eTRU, there are co-benefits such as reduced noise and diesel fumes.

Albertsons management staff, yard hostler operators, and trailer drivers reported co-benefits from electric operation of the TRUs at the docks and staging areas. In the driver and yard hostler operator survey (n=31), 48% of respondents (n=15) said there is less noise around those docks and staging areas since the diesel generators are not running. Cleaner air in the yard was the second highest reported co-benefit, by 29% of respondents (n=9). More reliable refrigerated trailer and product temperatures were reported by 13% of respondents (n=4), and one respondent reported feeling safer in the area. Of the 31 survey participants, nine did not report any co-benefits (29%).

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[109] National Renewable Energy Laboratory. May 2010. *Emissions of Transport Refrigeration Units with CARB Diesel, Gas-to-Liquid Diesel, and Emissions Control Devices*. https://www.nrel.gov/docs/fy10osti/46598.pdf

[110] California Air Resources Board. Last updated 2020. "LCFS Life Cycle Analysis Models and Documentation." CA-GREET3.0 Model. https://ww2.arb.ca.gov/resources/documents/lcfs-life-cycle-analysis-models-and-documentation

[111] California Air Resources Board. Revised January 16, 2020. *Low Carbon Fuel Standard Annual Updates to Lookup Table Pathways; California Average Grid Electricity Used as a Transportation Fuel in California and Electricity Supplied under the Smart Charging or Smart Electrolysis Provision*. https://ww2.arb.ca.gov/sites/default/files/classic//fuels/lcfs/fuelpathways/comments/tier2/elec_update.pdf

All the co-benefits described above are accruing in the DAC, where the Tracy facility is located. However, as stated above, trailers with eTRU port-compatible plugs can be used at any grocery store with compatible ports, providing these co-benefits to a wide range of areas during deliveries.

Project Legacy and Learnings

This section addresses the knowledge generated by this project that could be more broadly applied to future projects. PG&E designed this PRP to prioritize accruing lessons learned, which is a critical precursor to market transformation and scalability, rather than prioritizing immediate impacts. Several important lessons emerged both from the technological innovations and the testing conducted over the course of the project.

What Innovations Were Achieved?

During the project planning, design, and construction, Albertsons and PG&E reviewed available technologies and developed solutions that may provide useful lessons for future eTRU projects.

- Albertsons mitigated the risk that drivers would pull vehicles away from ports without properly disconnecting chargers.[112] Albertsons' staff researched available options, finding that SafeConnect's products haves safeguards to mitigate this pull-away risk. SafeConnect's six-pin connection has a tension release mechanism, which automatically releases the receptacle from the port.
- Since there is no standard for eTRU connectors, the eTRUs needed to be retrofitted with SafeConnect trailer kits. Albertsons chose to retrofit approximately 270 trailers, placing a SafeConnect receptacle at the rear on the driver's side (such that when the vehicle is at the dock, the receptacle is close to the port).
- At the staging area location, Albertsons designed a protective mounting system comprising 4-inch thick steel posts that are driven deep into the ground on all four sides of the equipment (see Figure 239). This helps to shield the SafeConnect ports from unintended impacts.

[112] Driving away while connected to an energized 6 kW to 18 kW charger could create an arc, which poses a significant safety risk and could damage equipment.

Figure 239**. SafeConnect ports in use at staging area, with protective mounting system**

Source: PRP Site Host

How Could PRP Implementation Be Improved?

The evaluation team collected feedback from Albertsons, PG&E, and project vendors on aspects of PRP implementation that could be improved for future eTRU projects.

- ***Installation***
  - According to the SafeConnect representative, the installed port protective posts in the staging areas do not provide enough space around the ports and do not fully protect them. SafeConnect recommends adding more space around the ports for future installations.
  - One of the ports was installed at a dock that is inaccessible from the inside (dock 6 in Table 87), resulting in no use during the PRP data collection period. This dock is inaccessible because the electrical cabinet for the eTRU ports was installed too close to the loading door. The placement of electrical infrastructure and additional eTRU ports should be carefully considered to maximize use.
- ***Data Collection***
  - Collecting granular power metered data for every eTRU port was the most challenging aspect of this PRP. Metering every port was also more expensive and time consuming than expected by Albertsons staff. Albertsons explored multiple data collection methods and has not yet found an economical solution for metering every port. Staff is unsure of how they will handle data collection for more ports installed through the EV Fleet program.

    - While some Albertsons staff are unsure of the value of monitoring individual port electric demand, operations management expressed that individual use data is helpful to determine yard staff compliance with procedures and for optimizing operations.
    - PG&E did not actively manage the design and construction, so they had less influence on the onsite data collection methodology. For future large-scale projects, PG&E could consider requesting a combination of eTRU session data, temporary third-party monitoring equipment, and utility check meters (where possible) to reduce the risk of data loss.
    - The data exported from the Eaton power meter shows higher peak electric demand than the SafeConnect ports are designed to support. However, Albertsons has not reported any electrical issues such as tripped breakers. Since the evaluation team was not onsite during meter installation and COVID-19 prevented a return visit, we cannot diagnose the reason for the high reported demand, but it is likely a data quality issue.
    - The eTRU data collection from OEM platforms was also problematic and the data did not export in a manipulatable format. Albertsons provided this feedback to their Carrier and Thermo King representatives. Albertsons also recommended that eTRU OEMs include generator run time and shore power operation in the eTRU reports.
  - ***Education and Training***
    - Most yard hostler operators are comfortable with the eTRU ports, but drivers have limited exposure. Albertsons is planning to provide additional training and encouragement to use the ports instead of running the diesel generators, especially as they scale-up electrification onsite.

During the final PG&E interview, staff indicated that the utility would discuss incorporating educational aspects around eTRU utilization into the EV Fleet program. PG&E will also work with vendors such as SafeConnect and eTRU OEMs to develop trainings, recommendations, and improve the data collection processes.

How Did PG&E Project Costs Compare to Expectations?

In the CPUC's 2018 PRP Decision, PG&E was approved $1.72 million for this PRP, consisting of $870,000 in capitalized costs and $850,000 in expenses. The total project expenditures through October 2020 show that the project remained well within the allocated $1.72 million budget. No additional costs are anticipated.

There are several reporting categories for actual costs, but a similar breakdown was not available for the proposed costs (shown in Table 95):

- **Site assessment and design** includes the site assessment, electrical design, and estimation; no permitting costs were reported.
- **EVSE procurement** includes the acquisition of 10 SafeConnect 480-volt standard docking stations and 15 SafeConnect 480-volt remote single docking stations; shipping and handling; and burdens on cost; all for which Albertsons received a rebate.
- **EVSE installation** includes installation materials and labor for installing the 25 SafeConnect ports.

- **Make-ready infrastructure (customer-side)** includes behind-the-meter costs for switchgear materials and burden on costs. No other construction costs were reported.
- **Project management** includes PG&E's activities for customer support, planning and direction of the implementation process, oversight for troubleshooting, budget tracking and processing of customer reimbursements, data review and analysis, and coordination of stakeholders.
- **Customer outreach (labor)** encompasses PG&E's labor related to recruiting a site host partner.

Table 95. PRP site host eTRU PRP costs as of October 2020

Cost Categories	Proposed	Actual [a]
Site assessment and design	N/A	$12,619
EVSE procurement	N/A	$80,370
EVSE installation	N/A	$334,154
Make-ready infrastructure (customer side)	N/A	$53,983
PG&E Rebate Paid	N/A	**$481,125**
PG&E project management	N/A	$107,034
Customer outreach (labor)	N/A	$11,516
Total PG&E PRP Cost	**$1,719,400**	**$599,675**

[a] Actual project costs do not include the SafeConnect eTRU retrofit kits, for which Albertsons' paid.

Source: PG&E

Albertsons' owns and maintains the infrastructure and conducted internal coordination to deploy this project, resulting in cost savings for PG&E. While the PRP came in 65% less than the proposed total cost, the data collection process could have been improved if additional budget had been put into submetering planning and implementation.

5.3.4 Conclusions

Accomplishments

Albertsons was interested in participating in the project to gather learnings that would help it comply with the forthcoming CARB regulations. Anticipating needs for future regulatory compliance, rather than securing an economic payback, was the principal driver for Albertsons' experimentation with this technology; it is likely this will be the primary motivation for future program participants as well.

The PRP motivated Albertsons to move forward and install and test the electrical connections in collaboration with PG&E, an action company management intended to complete but had not prioritized. The lessons learned through the course of the PRP will help Albertsons and similar fleets prepare for CARB's eTRU zero-emission regulations. During the final in-depth interview, Albertsons staff expressed that they are now confident they can meet the upcoming regulations as currently proposed.

PG&E is developing a handbook to document the process and share lessons learned with other fleets. Considering likely future requirements in California to run eTRUs on electricity and the limited availability of eTRU electrification case studies, this handbook could be very valuable, particularly for operations like Albertsons. Additional considerations will need to be explored to determine how these lessons can be extrapolated to other types of eTRU site hosts, such as medium and small customers, customers that do not own the trailers that operate at their sites, and customers with a lower level of energy management knowledge and attention. Nonetheless, this project provides important lessons that can be applied to future eTRU efforts.

Lessons Learned

- Private-sector facilities and fleets may be sophisticated electricity consumers. This makes them valuable partners that can implement projects quickly, but they also pose challenges associated with collecting operational data (since some operational data may be considered proprietary) and compiling lessons learned that can apply to other site hosts (since operations may be unique and challenging to compare across sites). Utilities should work with private-sector facilities early-on in the project design process to define critical data points and agree on a method for collecting project data.
- Legacy equipment (such as existing electrical infrastructure) may not be in sufficient condition to be relied upon for new electrification infrastructure; this equipment should be analyzed, and its condition tested for electrical safety, equipment compatibility, and capacity. Additionally, projects can benefit from strategic sequencing of required phases or activities to reduce delays overall.
- While permitting delays are typically out of the hands of both utilities and site hosts, utilities and state agencies such as CARB should work with AHJs and inform them of eTRU technology to streamline the permitting process for future eTRU projects. The Governor's Office of Business and Economic Development (GO-Biz) has had success streamlining the permitting process for passenger vehicles. Utilities should contact GO-Biz to discuss lessons learned from their efforts.
- Project implementers should be made aware in advance that there is not a standard for eTRU connectors and receptacles, and that retrofitting trailer and truck receptacles may be necessary. Utilities should support the establishment of a standard, industry-wide eTRU connector to simplify future deployments. Likewise, design guidelines and installation best practices are needed and should be shared broadly.
- Albertsons invested approximately $100,000 to retrofit their existing refrigerated trailer receptacles to accept the SafeConnect plus outside of this project's funding. For customer-owned and operated projects, the utility should continue to consider ways to ease the customer's upfront outlay of funds, such as making reimbursements payable upon the achievement of milestones rather than at project conclusion or including required equipment retrofits (such as Albertsons' trailer receptable retrofits) in the project cost.
- Data collection for each eTRU port is logistically challenging and expensive. Utilities, eTRU OEMs, and connection port vendors could consider investing in ways to automate and simplify the data collection process for other eTRU projects:
    - eTRU and connection port OEMs should discuss required data collection capabilities and formats with customers and vet compatibility between the customer's existing

equipment (both eTRUs and electrical infrastructure) and any new hardware or software during contracting and project design.

- While likely not feasible for individual ports, utilities could recommend that their customers install or provide funding for utility check meters or non-utility monitoring equipment for ports without dedicated utility meters.

- The eTRU ports installed at loading docks were used less than the staging areas due to short loading durations and logistical challenges of ensuring a trailer with a compatible eTRU receptable is parked at a dock with a port. Other eTRU fleets could face similar challenges and could increase utilization by installing compatible plugs on all eTRU trailers or by electrifying all loading docks, if economically feasible.
- Albertsons' yard hostler operators who responded to the survey are comfortable with eTRU port operation, but truck drivers have limited exposure to eTRU technology. Distribution warehouses and utilities could consider incorporating additional education and training on the benefits of eTRU ports to increase staff comfort and utilization.

Potential for Scale-Up Across the State

There is significant potential for eTRU plug-in operation across the state, as California is a major food producer and distributor. However, utilities and customers will need to be prepared for the increased electrical infrastructure and financial challenges.

Multiple California utilities have started offering incentive programs aimed at encouraging eTRU plug-in operation, including PG&E's EV Fleet program. To date, customer interest in eTRU technology is low and most customers are waiting to take next steps when CARB's regulations are finalized. Most of the utility incentive participants have been distribution warehouses but interest from grocery stores is increasing, especially those that use diesel fueled TRUs for temporary cold product storage (typically around the holidays). These facilities are not accustomed to monitoring fuel levels or generator maintenance. With electric plug-in operation, the staff does not need to worry about refueling the generators and potentially losing product.

This section summarizes the evaluation team's market research activities to determine the scale-up potential and associated challenges.

Market Potential

To determine the market potential for eTRU plug-in operation, the evaluation team researched current industry standard practice and diesel TRU operation in the State of California. In addition to resources and presentations available on CARB's website,[113] the CARB team provided a detailed breakdown of the total TRU population operating in California by vehicle type and by in-state versus out-of-state operation, as shown in Table 96. This data is based on CARB's projections of cargo and throughput.

[113] California Air Resources Board. Last updated 2020. "Transport Refrigeration Unit." https://ww2.arb.ca.gov/our-work/programs/transport-refrigeration-unit

According to this data, approximately 60,000 TRUs operate daily in California. According to this data, trailer TRUs account for approximately 75% of the TRUs operating in California.

Table 96. TRU populations and activity within California

Vehicle Type	Registration	2019 Population	Average Activity In-State by Vehicle Miles Traveled [a]	Population Operating In-State per Day
Truck	In-State	7,173	100%	7,173
	Out-of-State	264	12.4%	33
Trailer	In-State	34,051	78.1%	26,594
	Out-of-State	134,681	12.4%	16,700
Generator Set	In-State	4,206	78.1%	3,285
	Out-of-State	16,723	12.4%	2,074
Rail	All	9,234	18.9%	1,745
Total		**206,332**	**27.9%**	**57,604**

[a] The average activity in-state by vehicle type does not sum to 100%; these values are the percentage of the 2019 population that operates in the state of California on a given day. In-state activity is estimated using the International Registration Program's tracking data of vehicle miles traveled for interstate trucks entering California. (For details, see California Air Resources Board. October 2019. *Draft 2019 Update to Emissions Inventory for Transport Refrigeration Units*. p. 23. https://ww3.arb.ca.gov/cc/cold-storage/documents/hra_emissioninventory2019.pdf)

Source: Details provided via email to the evaluation team by CARB's Freight Operations Section of the Freight Transportation Branch, May 8, 2020.

The EPRI report cites an average TRU fuel consumption rate of 0.85 gallons of diesel per hour. Based on the fuel consumption rate used in the EPRI report, CARB's estimated number of trailer TRUs operating in California per day, and average TRU iding hours per year, the evaluation team estimated that over 64 million gallons of diesel are consumed annually in California alone by idling trailer and truck TRUs. Table 97 summarizes these annual diesel fuel consumption estimates for the average daily trailer and truck TRU population operating in California. The calculations assume the same diesel fuel consumption for trailers and trucks.

Table 97. Estimated annual TRU diesel fuel consumption during idling by vehicle type

Vehicle Type	Average Population Operating In-State per Day	TRU Diesel Fuel Consumption (gal/hr)	Idling Hours Per Year	Idling TRU Diesel Fuel Consumption Per Year (gallons)
Truck	7,206	0.85	666	4,081,767
Trailer	43,294		1,636 [a]	60,212,044
Total	**50,500**	-	-	**64,293,811**

Notes: These estimated fuel consumption calculations assume that none of the operating trucks and trailers are plugged in during idling, but the evaluation team acknowledges that a minor portion of the population is plugged in (see Table 96).
a The trailer idling hours per year are based on Table A-60 (Appendix A).

Source: Evaluator Calculations

CARB's air emissions regulations for TRUs in California will continue to tighten and, based on the current TRU population shown in Table 96, there are significant opportunities for TRU electrification. Table 98 summarizes the estimated number of eTRUs currently in California, based on percentage capable estimates provided by CARB. Based on this data, there are almost 25,000 eTRUs currently operating in California.

Table 98. Estimated number of plug-in capable TRUs in California

Vehicle Type	Registration	2019 Population	Plug-In Capable (Percentage of Total) [a]	Total Plug-in Capable
Truck	In-State	7,173	60%	4,304
Trailer	In-State	34,051	16%	5,448
	Out-of-State	134,681	11%	14,815
Total		**175,905**	**14%**	**24,567**

[a] Source: Plug-in capable percentage is based on information provided by CARB via email to the evaluation team on May 21, 2020.

However, many of the plug-in capable TRUs that are already on the market are not operating on electricity to take advantage of emissions and fuel cost savings. Trucks are more likely than trailers to be equipped with plug-in capable eTRUs and are more commonly plugged in because otherwise truck eTRUs can only operate when the truck engine is running, which is highly inefficient.

eTRU Connection Port Vendors

Switching to plug-in operation requires a safe shore power connection point to prevent electrical arc flashes, as well as training for drivers and loading dock operators to avoid accidental drive-offs. There are two main eTRU connection port vendors in the California market: ESL Power and SafeConnect. The evaluation team interviewed representatives from both vendors to understand their technology, the size of their current market, and their thoughts on future market potential.

SafeConnect, which provided the 25 connection ports for this PRP, has been operating and deploying six-pin connection ports for eTRUs since 2014. They have ports deployed in over 30 states across the U.S. and Canada. The SafeConnect trailer/truck kit converts existing plugs from four-pin to six-pin and takes about 45 minutes to install for each TRU. The six-pin connection has a tension release mechanism, which releases the receptacle from the port (in case of a drive-off).

SafeConnect has one major competitor in Southern California: ESL Power.[114] ESL started developing eTRU connection ports approximately four years ago while working with an existing large national box store customer, who was branching into the food delivery market. ESL developed a standard four-pin reefer outlet for this customer (without a safety release) and supplied approximately 200 units to this account.

Between the two vendors, there were approximately 850 ports installed in California as of July 2020, mainly at distribution warehouses. These ports account for less than 4% of the total plug-in capable eTRUs in California. Since multiple eTRUs will share the same connection port (as this is not a one-to-one

[114] For more details, see the ESL Power website (https://eslpwr.com/etruconnect/).

ratio), this supports the finding that most of the existing eTRUs are not plugged in when stationary and are still running off diesel generators.

Additional details on these eTRU vendors are provided in Appendix A.

Scale-up Challenges and Opportunities

Electric utilities and operators of refrigerated distribution warehouses, grocery stores, and other industries that use TRUs will soon need to consider the equipment, operations, and grid impacts of transitioning to eTRUs:

- ***Electric grid peak demand impacts:*** Electric utilities will need to work closely with their customers to mitigate the increased grid peak demand from large scale eTRU plug-in operation. It is likely that other distribution warehouses follow similar operational procedures as Albertsons, with peak eTRU utilization coincident with the grid's afternoon peak demand period, but additional research will be necessary to confirm.
- ***Customer-side infrastructure:*** Refrigerated warehouse facility and grocery store operators with plug-in capable eTRUs must also consider the electric load requirements associated with plug-in operation. Depending on the number of trailers plugged in simultaneously, distribution warehouses need to consider the added electric demand and determine whether their facilities have the utility service capacity to meet the added load. Albertsons did not have to address this challenge for this PRP because their current infrastructure can support the added load, but most customers will not have that capability.
- ***Utility tariffs:*** eTRU plug-in operation may trigger a change in utility rate for some smaller customers. But if separately metered, eTRU ports may be eligible for PG&E's business electric vehicle (BEV) rate. The BEV rate may result in cost savings for some customers who mainly use the ports during off-peak periods or who can manage charging to meet expected monthly demand.
- ***Opportunities for distributed energy resource integration:*** Plug-in operation may not trigger new tariffs for most large customers, but it will likely have a substantial demand impact, which could potentially be offset by battery storage and onsite renewable energy generation. PG&E has had some discussions with customers about considering battery storage systems, but the high up-front cost has been a barrier. More customers are interested in pursuing on-site solar energy systems.
- ***Equipment installation:*** During the in-depth interview with SafeConnect representatives, they expressed concern over not having enough licensed electricians in California to perform the work needed to electrify all docks and staging areas to meet CARB's regulations.

5.4 Home Charger Information Resource

5.4.1 Project Narrative

Overview, Objectives, and Barriers Being Addressed

Pacific Gas and Electric Company (PG&E) initially proposed the Home Charger Information Resource (HCIR) program to develop a web-based tool that would help customers research their options on the level of electric vehicle (EV) charging that best matched their driving patterns, help these customers understand the process to install EV charging, and connect them with a list of local certified electrical contractors who could safely install residential EV charging equipment. This web-based tool was intended to complement the new EV Savings Calculator provided by PG&E. To promote the tool, PG&E also planned to conduct outreach to customers who had recently purchased an EV.

PG&E staff intended for the web-based tool and outreach to help customers overcome informational barriers to EV adoption by simplifying the process of understanding home EV charging needs, educating prospective EV purchasers about available charging options, and connecting EV owners with local charging station installers. PG&E also planned to provide information to help customers understand whether Level 1 charging exclusively during off-peak times could meet their typical daily mileage needs, and to help customers understand how the decision between Level 1 and Level 2 charging could impact their ongoing costs for overnight charging under the current PG&E time of use (TOU) periods.

However, while reviewing the initial program design, PG&E found multiple existing home charger installer tools available in the marketplace (Angie's List, Home Advisor, Porch, and Amazon) that fulfilled most of the functions originally proposed for PG&E's tool. Therefore, understanding the CPUC's intent not to duplicate existing tools, PG&E submitted an Advice Letter[115] outlining a modified program objective to focus on exposing residential customers to these existing market resources and presenting comprehensive information about home chargers and the installation process in an easy to digest format.

During 2020 PG&E staff enhanced the EV charging information that was previously provided on their website, while expanding the webpage from English only to include Spanish and Chinese. These pages include information to help customers understand their available charging options, what to look for when purchasing a Level 2 charging station, provide an installation checklist with guiding questions to ask their electrician in Spanish, Chinese, and English (Figure 240), connect customers to home services vendors to find local EV charging station installers, and discuss factors to consider for installing in a multifamily dwelling.

[115] Pacific Gas and Electric. August 16, 2019. Advice Letter 5621-E. https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_5621-E.pdf

Figure 240. EV charger installation checklist

Source: PG&E

Additional items to expand customer knowledge and support their decision making include allowing them to browse EV models and compare the average total cost of ownership (TCO) to similar internal combustion vehicles using PG&E's EV Savings Calculator, as well as a list of EV incentives and tax credits, an EV rate comparison tool to help customers determine the best residential electric rate based on their charging habits (that considers the car model, average yearly miles driven, time to charge, current rate, and recommended rate), location of a map for public charging, comparison of Level 2 home chargers available through PG&E's online marketplace, which links to Amazon, where customers can buy their preferred charger, and frequent questions and answers.

Lastly, PG&E staff are creating an educational animated video to support the enhanced EV charging webpage. The educational video will help customers understand whether a Level 1 or Level 2 charging station best fits their charging needs, how to install a residential charger, how chargers receive power, and how much power they need to fully charge their EV. In the future, staff hope to continue to reach even more customers and to continue translating the webpage into additional languages to foster greater engagement and provide education on the home charger installation process, especially in disadvantaged communities (DAC).

In February 2020 PG&E collected feedback from 230 customers to gather insights to inform the website design and customer materials. Although staff were unable to conduct outreach as hoped in 2020 (due to COVID-19 pandemic), PG&E did run two targeted LinkedIn campaigns. The first campaign targeted low adoption and DAC territories and the second targeted higher adoption and DAC adjacent territories. These campaigns ran from July 7th to September 1, 2020, and together collected 374,813 impressions and received 774 clicks. Overall, the marketing campaign was a success and generated sizeable impressions and good click activity. LinkedIn affords the opportunity to do some targeting and enabled PG&E staff to produce a quick message test with two audiences to help understand the message that resonates best. The results of the campaign allow staff to take lessons learned and apply them to future customer outreach efforts. In addition to conducting specific EV outreach through the website and LinkedIn, staff also promoted the webpage through the PG&E e-newsletter.

Participation

Although PG&E updated their website as planned in 2020, they were unable to conduct outreach activities due to COVID-19 pandemic. Therefore, the customer engagement process and participation are not evaluated in this report; however, PG&E was able to report on customer website engagement, as shown in Table 99.

Table 99. PG&E Customer Website Engagement

Category	Unique Engagements
EV Home Charger webpage	94,155 Unique Visits
Charger Installer Tab	636 Unique clicks
Angie's List link	195 Unique clicks
Amazon link	45 Unique clicks
Home Advisor link	47 Unique clicks
Porch link	58 Unique clicks

Source: PG&E

Timeline and Status

The CPUC approved the HCIR program in January 2018 as part of Decision 18-01-024. As directed in Ordering Paragraph 29 of D. 18-01-024, PG&E filed the Tier 2 Advice Letter 5316-E in June to outline how it will spend the authorized budget, which the CPUC approved in August 2018. PG&E completed additional program scoping, as requested by the CPUC, between April and July 2019. PG&E filed Advice Letter 5621-E in August to propose changes in the scope of the HCIR program, which the CPUC approved in September 2019. Staff conducted customer insight research in February 2020, completed the website in April 2020, and finished the translation pages in July 2020; however, due to COVID-19 pandemic, staff were unable to conduct in-person outreach as planned in 2020.

5.4.2 Evaluation Methodology

Selected Methods and Rationale

The evaluation team initially sought to address the common evaluation questions that apply to all priority review projects (PRPs) and those specific to the Education and Outreach PRPs. To evaluate this PRP, the team (1) reviewed program information and (2) interviewed PG&E staff.

As part of revising the program, per the August 2019 Advice Letter, PG&E staff also conducted secondary research to determine if the content intended for the new website was already offered elsewhere. For this research, PG&E considered 15 community choice aggregators (CCAs) and utilities and focused on four key components:

- Did the content connect readers directly to electric vehicle supply equipment (EVSE) installers?
- Did the content provide targeted information on home charger installation?
- Was the content offered in multiple languages?
- Was the content easy to understand?

Using this research, PG&E found that although there is well-developed content related to the availability of home charging, no CCA or utility provided a comprehensive source of the content. Therefore, PG&E sought to develop a comprehensive and evolving customer-oriented EV charging resource through this PRP, including steps to installing a home charging station, EVSE specifications, how to engage with PG&E and electricians, and additional resources.

Data Sources

Working closely with PG&E, the evaluation team modified the evaluation approach to reflect the changes to the program design and launch timing. The team reviewed all program-related materials.

In November 2019 the team interviewed key PG&E staff to gain insight on the HCIR program progress to date, and in September 2020 the team interviewed key PG&E staff again and reviewed conducted customer insight research and LinkedIn campaign summary findings. The evaluation team covered several topics during staff interviews:

- Initial program design (and changes)
- Electrification barriers the HCIR program will address, and how these barriers will be addressed

- Availability of analytics
- Customer insights
- Areas of successes, challenges, and lessons learned from the program (including the possibility of scaling)

5.4.3 Evaluation Findings

Staff Feedback

The evaluation findings for the HCIR program are based on the PG&E staff interviews and review of PG&E's customer insight data, LinkedIn campaign, and initial data tracking intent provided by PG&E.

PG&E staff reported a collaborative and positive atmosphere in pursuing the modified HCIR program. For example, during early interviews staff noted the possibility of collaborating with the Low-Income and General Marketing teams within PG&E to take advantage of existing outreach activities in combination with translating the webpage into Spanish and Chinese.

Staff maintained a customer focus throughout developing the HCIR program. Through the customer research to examine the upcoming webpage and customer outreach materials, conducted in February 2020, staff identified several key insights:

- Overall, customers viewed the tested webpage and material information as clear and easy to read.
- Customers found a design that used graphics and linear layouts as being the most appealing.
- Customers responded to information presented in a tabular format, finding it more engaging and easier to read.
- Customers wanted more detail, such as comparison data and understanding the relationship between amperage, voltage and watts of charging stations.

PG&E staff used these insights and added more visuals and graphics, organized the information in a more intuitive and engaging manner, and added additional details and quick links for references. In addition, PG&E staff indicated they will continue to collect customer feedback as they develop education and outreach materials. As customers' understandings of EVs develop, staff will work to identify new gaps and ensure the information offered is useful and accessible (through multiple channels). Staff said the webpage, which was completed in July 2020 (including translations into Spanish and Chinese), directs customers to market resources and promotes tools such as PG&E's EV Savings Calculator and a checklist that includes common questions to ask an electrician. Other key information outlines how to select the right rate plan and what level charger best suits a customer's needs.

Ultimately, staff said the goal of the HCIR program is to empower customers by giving them the knowledge and confidence to transition to an EV and engage with technical professionals for help with the charger installation process, acting as a resource hub when customers begin their EV journey.

Currently, PG&E staff are working with their internal Marketing team and resource vendors to confirm what data is available to track, which may include several options:

- Unique visitors to the landing page
- Unique visitors with a preferred language who view the landing page
- Bounce rate of visitors to the landing page
- Unique click rates of visitors to external party sites
- Feedback on the webpage survey (regarding website helpfulness)
- Click-through rate of customers who received an email promotion
- Campaign ID tracker to identify specific customers within a targeted campaign
- Number of visitors who move from the PG&E website to the Porch site and possible leads to installation jobs
- Number of visitors who move from the PG&E website to Home Advisor or Angie's List (and the location of submitted project requests)

When reflecting on the HCIR program development, staff said the most difficult aspect has been driving customers to install a charger. While staff said they have done a good job of providing education materials and resources, they noted that a gap remains between being informed and taking action. As staff note, each customer is on their own EV journey and PG&E is trying to support them in this journey. Staff also acknowledged the impact of COVID-19 pandemic, both on the outreach efforts of the HCIR program and on the customer EV journey overall. For example, PG&E staff reported that they had begun to collaborate internally to leverage their resources and expand outreach to DAC customers; however, due to COVID pandemic no direct outreach was possible. Therefore, staff redirected efforts to online outreach such as the LinkedIn campaign which targeted DAC and non-DAC residential customers within the service territory.

Despite these challenges, staff were pleased to see that the website and customer-facing materials are helping to fill the information gap and educate customers. Furthermore, staff confirmed that they plan to continue efforts to further translate the webpage (such as into Russian, Vietnamese, Tagalog, and Korean) and to develop an educational outreach video explaining how to choose between a Level 1 and Level 2 charger, how to install a residential charging station, and how chargers receive power and the difference between amps, volts, and watts. Finally, staff reported that a key lesson has been to be realistic about customer engagement, noting that the most important factor is to keep the customers moving along on their EV journey.

Costs

The approved PRP had an anticipated total cost of $185,295. The PRP costs as of October 2020 totaled $146,392 as shown in Table 100, based on data available to PG&E. The program is still ongoing and PG&E plans to use up the remaining budget in 2021.

Table 100. PG&E HCIR PRP costs as of October 2020

Cost Category	Actual PG&E Costs	Budgeted PG&E Costs
Project Management	$99,369	$87,500
Website Update	$12,259	$32,795
DAC Marketing	$20,475	$45,000
Marketing	$11,962	$20,000
Total Costs	$146,392	$185,295*
		*$203,825 with 10% contingency

Source: PG&E

5.4.4 Conclusions

Though the HCIR program underwent a significant design change, which delayed its launch, PG&E staff experienced successes and can apply lessons learned as the program moves forward.

Successes and Lessons Learned

The ability to adapt in a rapidly changing market, while truly reflecting customer needs, is essential for any innovative customer-oriented program. PG&E responded to a rapidly changing market and made changes to the initial program concept by investigating current market offerings. The proposed modifications maintained the objective to provide suitable information to customers in three languages (English, Spanish, and Chinese) to ensure that DACs are engaged, and staff are considering other languages to expand this outreach. Staff developed the HCIR program and collected customer input on the website and outreach materials to ensure that it provides information and resources needed by customers. At this stage in development, the HCIR program provides customers with resources to identify EV charger installers and questions to ask electricians, and comprehensive information about EVs and charging options.

Next Steps

PG&E staff are considering additional language translations to expand outreach to DACs and will continue targeted advertising campaigns. Once data availability is confirmed, staff will regularly track metrics to identify the most effective outreach strategies, as well as possible charger installations identified as a result of information provided on the webpage. Finally, staff look forward to conducting outreach, when possible, following COVID-19 pandemic and are currently exploring what this future outreach will look like.

6. Three Small Investor-Owned Utilities Priority Review Projects

In June 2017, PacifiCorp, BVES, and Liberty filed an application with the CPUC proposing seven PRPs to promote transportation electrification. The CPUC approved the proposed programs in September 2018 as part of Decision 18-09-0341. That decision included a requirement to use the same third-party evaluator selected by the three large utilities in support of their transportation electrification projects. The smaller utilities launched these PRPs well after the large utilities' PRP start dates; therefore, their PRPs are still ongoing.

6.1 PacifiCorp Outreach and Education and Demonstration and Development Programs

6.1.1 Project Narrative

Overview, Objectives, and Barriers Being Addressed

In 2019, PacifiCorp launched two transportation electrification programs as part of an effort to meet California's electrification and greenhouse gas reduction goals as outlined in Senate Bill 350. The two programs are Outreach and Education and Demonstration and Development. PacifiCorp serves approximately 45,000 customers in rural communities in Northern California. The rural and dispersed nature of PacifiCorp's service area presents unique challenges to the adoption of electric transportation.

PacifiCorp designed the Outreach and Education program to engage with residential and commercial customers and inform them about electric vehicles (EVs). Forth Mobility (Forth) supports the marketing component of this program, which seeks to address customers' perceived barriers to operating and owning an EV by providing information on home charging, gas savings, emissions reductions, and available federal tax credits. As part of this effort, PacifiCorp and Forth brought EVs to community events and allowed customers to test drive the car. PacifiCorp also conducted online and traditional mail marketing to encourage residential customers to purchase an EV and commercial customers to install EV charging stations on their properties. The marketing materials also encourage commercial customers to apply for grant funding available through the Demonstration and Development program.

The Outreach and Education program also provides a feasibility assessment for commercial customers' parking lots, which are conducted by C2 Group (C2). These assessments involve a desk review and an on-site review of the property. Customers receive an assessment report at the end of their participation. With the onset of COVID-19 pandemic, C2 adjusted its approach to offer virtual assessments.

The Demonstration and Development program allows commercial customers to apply for grant funding to cover some or all of the upfront costs for installing an EV charging station. Applications are accepted quarterly, and PacifiCorp holds an event halfway through the grant submittal period to answer any questions applicants may have before submitting their applications.[116] Additionally, Nexant supports the Demonstration and Development program by scoring qualifying applications and recommending which applicants should or should not receive grant funding.

Together, the two programs seek to address awareness and informational barriers regarding EV ownership for residential customers and charging station installations for commercial customers in PacifiCorp's territory. Specifically, the Outreach and Education program aims to increase awareness of the federal and state tax credits for EV ownership and raise more awareness of the technical aspects of fuel savings and home charging. The Demonstration and Development program addresses limited financial resources for commercial customers to make an investment in EV chargers on their properties.

Participation

The next section describes the recruitment process and breaks down participation to date.[117]

Outreach and Education

The Outreach and Education program has three modes of customer engagement and participation: a targeted mailing campaign, community events, and a technical assessment.

PacifiCorp sent emails and traditional mailers to residential and commercial customers to promote EV ownership for residential customers and to encourage commercial customers to apply for grant funding and complete a technical assessment. Communications materials promoted online tools and resources including WattPlan, an EV cost calculator tool. To-date over 1,298 customer calculation reports have been generated.[118]

PacifiCorp and Forth also attended a classic car event to promote EVs and brought two EVs for customers to test drive or ride along in with staff. One car was a luxury EV from BMW and the other was a Nissan Leaf (used to demonstrate the affordability of EVs). They also attended a farmer's market to promote EV awareness and inform visitors about operation and ownership. Due to COVID-19, PacifiCorp and Forth suspended all in-person events, which unfortunately had provided customers with the most tangible experience with EVs, and pivoted outreach to directing customers to online resources such as the cost calculator.

PacifiCorp reported receiving four commercial customer requests for a technical assessment through the Outreach and Education program. One customer completed an assessment, but the other three customers did not proceed past the initial request. One of these customers backed out saying their company was no longer interested in pursuing EV charging stations, and the other customer lived outside the service territory. PacifiCorp staff reflected that the degree that COVID-19 impacted

[116] Although the application period is formally on a quarterly calendar, PacifiCorp reported it would receive applications at any point given the low uptake in the program.

[117] Due to the nature of the Outreach and Education program, participation results are limited to technical assistance offering.

[118] Due to data limitations this numbers represents the service territory of all three PacifiCorp west coast states.

participation was unclear, citing a lack of awareness in the community as the critical barrier to engagement.

Demonstration and Development

In November 2019 PacifiCorp hosted an EV workshop aimed at driving interest in technical assistance in the Demonstration and Development grants. PacifiCorp staff brought fleet electric vehicles and information to promote EV awareness and inform visitors about operation and ownership.

PacifiCorp reported that the Demonstration and Development program received three applications in the second quarter of 2019, two applications in the fourth quarter of 2019, and no applications in 2020 for EV charging station funding. Only one application moved forward to the scoring round and was approved. This applicant received approximately $71,000 in funding. The other applications did not meet the technical feasibility requirements. PacifiCorp encouraged applicants who were turned down to ask program staff for feedback on how to improve their applications and reapply during the next quarter. PacifiCorp also reported that the barrier of the upfront cost commitment, prior to receiving the incentive funding, may have been just too much of a hurdle for customers during COVID-19.

Timeline and Status

In June 2017, PacifiCorp filed an application to the California Public Utilities Commission (CPUC) proposing two programs to promote transportation electrification. PacifiCorp designed the Outreach and Education program to promote awareness of EV ownership options and address barriers to ownership, while it designed the Demonstration and Development program to provide competitive grant funds to commercial applicants for the purpose of installing EV charging stations on their properties. The CPUC approved the two programs in September 2018 as part of Decision 18-09-034.[119] In April 2019, PacifiCorp began sending education emails to residential and commercial customers through the Outreach and Education program. In May 2019, PacifiCorp launched the Technical Assistance program with the support of the C2 and in September started attending community outreach events with the support of Forth. Applications for the Demonstration and Development program started coming in during the second quarter of 2019. Staff were unable to conduct planned on-site and in-person events in 2020 as they were suspended due to the COVID-19 pandemic.

6.1.2 Evaluation Methodology

Selected Methods and Rationale

Based on discussions with PacifiCorp in August 2019, the evaluation team developed and submitted an evaluation plan for review. In addition to the common research questions that apply to all Priority Review Projects (PRPs), and those specific to the Education and Outreach PRPs, the evaluation team

[119] Decision on the Priority Review and Standard Review Transportation Electrification Projects. *California Public Utilities Commission.* September 27, 2018. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M231/K030/231030113.PDF

sought to assess how, if at all, PacifiCorp's education and outreach PRPs changed customer awareness and purchasing behavior.

The evaluation team employed the following data collection tasks:

- Information and data review
- Stakeholder in-depth interviews with PacifiCorp and the implementers (Forth and C2 for the Outreach and Education program; Nexant for the Demonstration and Development program)
- A residential general population online survey[120]

Data Sources

Working closely with PacifiCorp, the evaluation team modified the evaluation approach based on actual participation, assessing customer engagement from the fourth quarter of 2019 through the third quarter of 2020. Based on the evaluation plan and these discussions, the evaluation team ultimately relied on the data sources outlined below.

Information and Data Review

For this data collection task, the evaluation team requested the following program information from PacifiCorp regarding the two programs:

- Marketing efforts (e.g., marketing plans and materials)
- Program design process
- Program rules and operations manual

In addition, the evaluation team requested PacifiCorp provide the following data:

Grant recipient application documents and all related data: The team reviewed the initial steps in the grant application process to identify possible bottlenecks in the scale-up, the number of applicants at each stage, common barriers to completing the application stage, and why some applicants were turned away. The team also reviewed the criteria for successful applicants and the range of application types (applicant, size of grant, etc.).

Outreach and education data: The team analyzed data to determine what types of education materials and outreach PacifiCorp can use in direct communications (e.g., paid advertisements), self-service resources and tools (e.g., web portals), technical assistance (e.g., providing qualified consultants to perform site feasibility assessments), and community events (e.g., ride-and-drive events).

[120] Due to low participation and timing of grant approval, the evaluation team did not conduct a grant recipient interview.

In-Depth Interviews

The evaluation team used in-depth interviews to gain insight into the success of PacifiCorp's programs and the potential for scale-up. The team conducted one interview with PacifiCorp staff in early November 2019 and two interviews with implementation staff from C2, Forth, and Nexant. The team conducted a final interview with PacifiCorp staff in October 2020. The interviews covered both programs as appropriate and covered the following topics:

- The electrification barriers addressed by the programs, what the programs did to address these barriers, and the success in overcoming these barriers
- How the programs were developed and marketed
- Participant feedback
- Stakeholder experience, including satisfaction
- Areas of success, challenges, and lessons learned
- Potential of scaling up programs
- The application process for the Demonstration and Development program (the amount of time and resources needed to review all the required grant documents for each application and the staffing required to scale up, as well as how to streamline the process)

Residential Online Survey

The evaluation team developed an online residential survey for PacifiCorp's California customers to inform future decisions regarding outreach, education, and investment to spur the adoption of electric EVs and electric vehicle supply equipment (EVSE) in the territory.

The survey lasted approximately 15 minutes and included questions to explore customer awareness, interest, motivation, and perceived barriers of EVs and EVSE. The survey additionally asked about the influence of existing PacifiCorp marketing and outreach related to EVs and EVSE as well as general demographic information such as housing type, number of vehicles, and average miles driven per week.

PacifiCorp provided the evaluation team with a dataset containing all active residential customer accounts in California. The team developed a sample from the full dataset with a goal of obtaining at least 70 completes to achieve 90% confidence at ±10% precision. In total, 73 customers completed the survey by February 10, 2020. Table 101 shows the number of customers in the original dataset, the number in the sample, and the number who completed the survey.

Table 101. Sample dataset and total responses

Step	Number Included
Dataset from PacifiCorp	17,146
Random sample selected	1,000
Total completes	**73**

Source: Evaluator Survey

The team entered survey respondents (who provided their contact information) into a drawing to win one of two $100 Amazon.com gift cards.

6.1.3 Evaluation Findings

This section presents the evaluation findings for both programs.

Implementation Process

PacifiCorp works with implementation contractors to successfully deploy the Outreach and Education and Demonstration and Development programs. Table 102 breaks out the role of each implementation contractor for each program.

Table 102. Implementation contractor roles and associated programs and tasks

Implementer	Program	Subtask
Forth Mobility	Outreach and Education	Mass media outreach, ride-and-drives
C2 Group	Outreach and Education	Technical assessment
Nexant	Demonstration and Development	Grant application review and scoring

Source: Evaluator

Outreach and Ride-and-Drives

When PacifiCorp launched the Outreach and Education program in April 2019, it worked with Forth to engage customers through ride-and-drives, mass media outreach, and online resources. PacifiCorp first sent targeted emails to residential and commercial customers and then attended community events and hosted workshops to address awareness and barriers to EV operation and ownership. Late in 2019 and into 2020, PacifiCorp ramped up the outreach campaign with additional social media advertisement buys and a targeted email campaign to customers with email addresses. PacifiCorp included EV information in its newsletter and sent it via traditional mail to reach customers who may not have access to email.

Forth partnered with car dealerships and municipalities to expand the reach of the Outreach and Education program in 2019 and early 2020 (pre COVID-19). For example, car dealerships provided credibility by lending their name to the program and encouraged customers to attend ride-and-drive events by providing test cars. Forth reported that customer interest in ride-and-drives increased if the route included a stop at a nearby charging station to demonstrate how to charge an EV. Forth also reported that stopping at a charging station helped customers understand the ease of charging, as well as where charging stations are located throughout the community. Each driving route was scheduled to last about 10 to 15 minutes, including the charging simulation.

Forth reported higher customer interest in the luxury BMW EV over the Nissan Leaf, despite the Leaf being the more economical and affordable option. Forth logged six test ride-and-drives with the Nissan Leaf and 30 with the BMW. The ride-and-drives used vehicles either owned by the implementer or by a local dealership. Forth owns the Nissan Leaf, and a dealership in Oregon loaned the BMW to Forth to use for ride-and-drive events in California. Forth reported difficulty in growing relationships with dealerships in California, specifically in PacifiCorp’s rural territory.

Technical Assessments

In the second quarter of 2019, one commercial customer completed a technical assessment conducted by C2. The assessment included a customer interview, site walk of the property, and desk review. The interviews and assessments are designed to accommodate customers with varying levels of knowledge about EV charging stations, with education and information provided as needed. For example, assessments with novice customers were designed to provide basic information such as explaining the different types of EV charging stations available, helping the customer understand the costs, and discussing immediate needs of the site. On the other hand, assessments with more knowledgeable customers were designed to focus less on education and instead on broader site aspects such as transformer set up and construction. C2 reported each site assessment involved explaining the benefits and costs of specific types of charging stations and assessing the site's immediate needs. In 2020, due to COVID-19, C2 shifted to offering virtual assessments.

After completing the initial interview, on-site walk through or virtual assessment, and the technical desk review, C2 planned to provide a report to the customer. The assessment report included recommendations for equipment, options for site design, requirements under the Americans with Disabilities Act, and transformer information. The total process—from application submittal to receiving a report—took about six weeks.

Although there were five application cycles (the second through fourth quarters in 2019 and the first and second quarters in 2020) at the time of the final interview for the Demonstration and Development program, Nexant had only received three applications, of which one was approved. This applicant received approximately $71,000 in funding. Of the remaining applications, one was turned down due to insufficient information provided with the application. PacifiCorp encouraged the customer to reach out for feedback and to reapply during the next grant application cycle.

Funding Workshops

As part of the Demonstration and Development program, PacifiCorp held workshops during the grant application cycle to answer questions and spur awareness of the grant opportunity; however, they suspended these workshops due to COVID-19. In addition, PacifiCorp encouraged customers to contact them directly with any questions about the grant or application.

Stakeholder and Ad Hoc Customer Feedback

PacifiCorp reported that, overall, both programs were running smoothly despite limited staff resources and the limitations on outreach imposed by COVID-19. Staff also shared a few changes that they made to make the application process easier for customers interested in the Demonstration and Development program. Specifically, although the application grant cycle in the Demonstration and Development program is technically only open for 30 days, PacifiCorp encouraged customers to send in applications at any time; however, this flexibility did not increase application submissions.

PacifiCorp continued to extend the reach of both programs to increase diversity in participation, focusing on helping the customer move along the journey from awareness to action (i.e., purchasing an EV). However, staff reflected that this journey is not a fast one, and given the impact of COVID-19, it may have become even slower as customers face economic hardship. Despite these challenges, staff were proud of the comprehensive information on the program website and continue targeted email campaigns in an attempt to better educate the customer about the technical aspects of EVs and charging stations.

Overall, despite the challenge to spur rural transportation electrification, PacifiCorp has received positive customer feedback on the Outreach and Education program, particularly about the EV cost calculator tool that calculates petroleum savings for customers interested in purchasing an EV.[121] Forth reported the largest barrier to EV ownership is that most customers are not in the market for a new car. On this point, PacifiCorp also noted customers may want to further delay large purchases due to current economic struggles. As such, PacifiCorp's focus will remain on education and the benefits of EV ownership, so that when customers are ready to purchase a new vehicle, they are aware of their choices and associated benefits. PacifiCorp also reported positive feedback on their ability to answer customers' questions at community events and workshops (pre-COVID-19) and on the phone. In addition, C2 reported positive feedback from the participant that completed the technical assessment.

Both Forth and C2 reported they have geographic limitations within PacifiCorp's California territory since neither have staff located in northern California.

Residential Customer Survey Feedback

This section presents findings from the PacifiCorp general population survey by topic area:

- General EV and EVSE awareness, interest, and motivation
- PacifiCorp's Outreach and Education awareness and experience
- Respondent demographics

General EV and EVSE Awareness, Interest, and Motivation

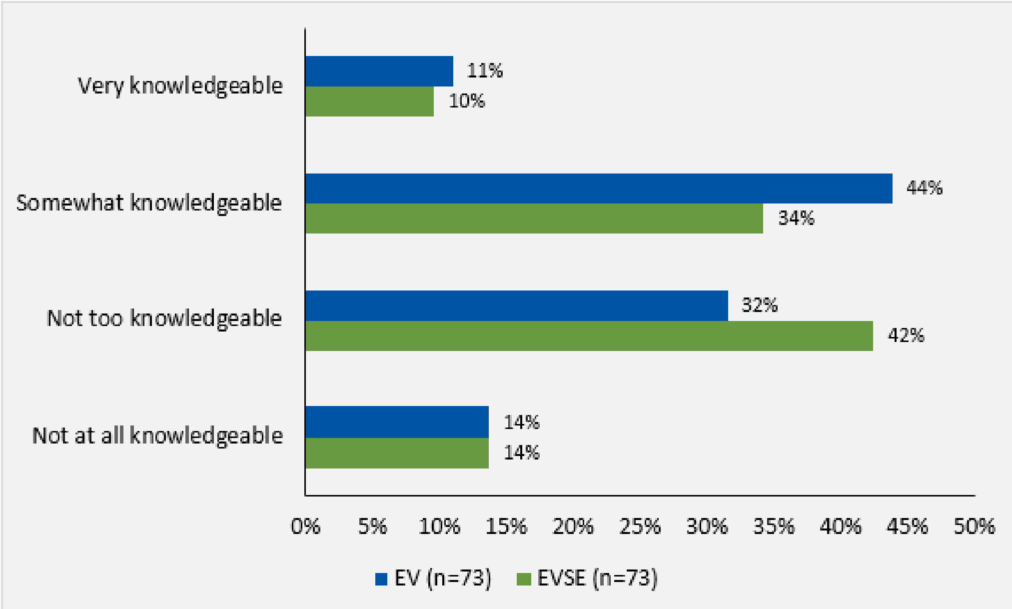
This section provides detailed findings of respondents' awareness, ownership, and motivations for purchasing an EV; charging habits (for current EV drivers) and interest in and barriers to EVs and EVSE (non-EV drivers); and overall perceptions of EVs (non-EV users).

Awareness of EV and EVSE

Survey respondents (n=73) rated how knowledgeable they are about EV and EVSE. Overall, respondents indicated they are more aware of EVs than of EVSE. As shown in Figure 241, 55% of respondents rated themselves as *somewhat knowledgeable* or *very knowledgeable* about EVs and 44% rated themselves the same for EVSE. This leaves 56% of respondents who rated themselves as either *not too knowledgeable* or *not at all knowledgeable* about EVSE and 45% who reported the same for EVs. Four of the eight respondents who rated themselves as *very knowledge* about EVs either own or lease an EV.

[121] https://pacificpower.wattplan.com/ev/

Figure 241. Respondents' reported knowledge of EVs and EVSE



Source: PacifiCorp Residential General Population Survey Q1 and Q2. "How knowledgeable are you regarding electric vehicles (plug-in or full battery, aka non-hybrid)?" and "How knowledgeable are you regarding electric vehicle charging options?"

EV Owners and Lessees

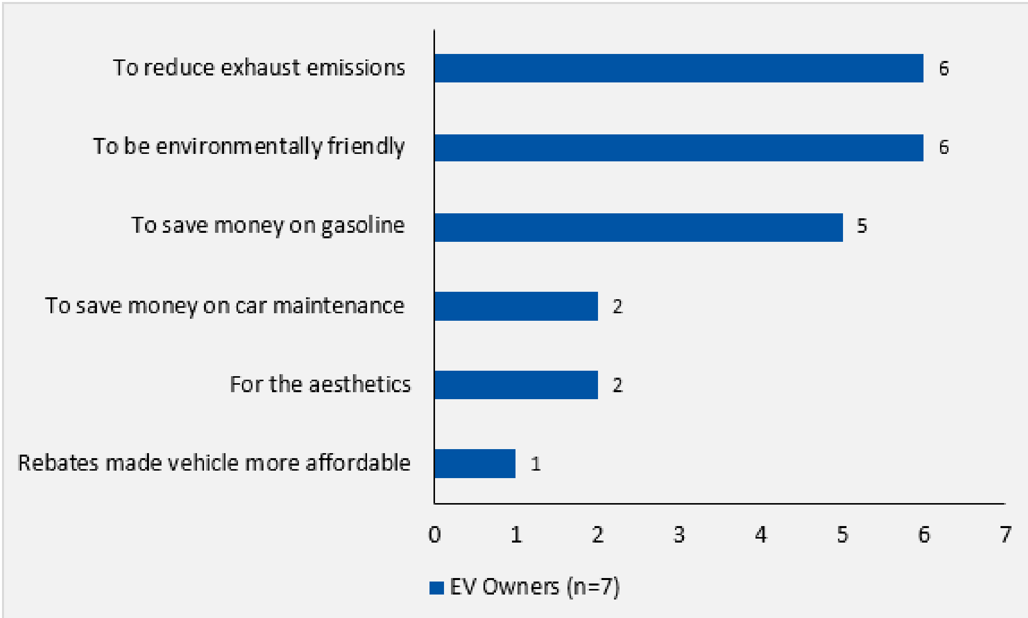
All respondents (n=73) reported if they own or lease an EV: six own and one leases. The one lessee planned to purchase or continue leasing an EV once the current lease expires.

All but one of the seven EV drivers had their vehicles before PacifiCorp launched the Education and Outreach program. All but one of the EV drivers had their vehicles for over one year (two of whom have owned their EV for over five years). The respondent who purchased an EV within the last year found EV information from basic internet searches and from a car manufacturer website and said they were not influenced by the Education and Outreach program.

Motivations for EV Use

Respondents who own or lease an EV were asked about their motivations to drive an EV. As shown in Figure 242, nearly all of these respondents (six of seven) said they were motivated to get an EV to reduce exhaust emissions and to be environmentally friendly. Five EV drivers said they got an EV to save money on gasoline. Other responses included saving money on car maintenance and for the aesthetics of an EV. One respondent reported being motivated by the rebates, which made the EV more affordable.

Figure 242. Motivations to purchase or lease an EV



Source: PacifiCorp Residential General Population Survey Q5. "What motivated you to purchase or lease an electric vehicle?" (Multiple responses allowed)

Charging and Driving Habits

Most EV drivers (six of seven) use a home charging station for their vehicle, while the remaining respondent uses a public Level 2 charging station. Of the six respondents who charge at home, five use a Level 1 charging station, and one uses a Level 2 charging station.

EV drivers also reported how many miles they drive per week (on average) and how many hours they charge their EVs. As shown in Table 103, respondents who use a Level 1 or Level 2 home charger drive their vehicles an average of 170 miles per week and charge their vehicles for an average of 35 hours per week (with a range of 100 to 250 miles driven per week and 10 to 90 hours of charging per week).

Table 103. EV Charging Preferences

Charging Location	Respondents	Average Miles Driven Per Week	Average Hours Charged per Week
Residential home	**6**	**170**	**35**
Level 1 charging station	5	140	38
Level 2 charging station	1	200	20
Public lot	**1**	**200**	**20**
Level 2 charging station	1	200	20

Source: PacifiCorp Residential General Population Survey Q38, Q40, Q41, and Q42. "What is the average number of miles driven in your electric vehicle per week?" (n=7), "Do you charge your electric vehicle at your home?" (n=7), "Which type of charger do you typically use to charge in public?" (n=7), and "How often, in hours, do you charge per week?" (n=7)

Vehicle Purchase Preferences and Barriers

Non-EV drivers reported whether they plan to purchase or lease a vehicle within the next 12 months. While 17% (n=11) said they plan to get a new vehicle within 12 months, only two of the 11 said they are planning to purchase (one) or lease (one) an EV.[122] Both respondents said their motivations for getting an EV were saving money on gasoline and environmental, with one respondent specifically citing exhaust emission reduction.

Four of the nine respondents who plan to purchase or lease a vehicle within the next 12 months but are not considering an EV reported several concerns with EVs (multiple responses allowed):

- Lack of information or do not know enough about EVs (four responses)
- EVSEs are too complex to install (one respondent)
- Not enough charging stations available (one respondent)
- EVs are too expensive (one respondent)
- EVs do not have enough driving range (one respondent)

EV and EVSE Perceptions

Respondents who do not own or lease an EV and are not planning to purchase or lease an EV within the next 12 months answered a series of questions about their EV and EVSE perceptions. These respondents were given 10 statements about EVs or EVSE covering four topic areas (barriers, benefits, interest, and overall PacifiCorp support) and rated whether they *strongly agree*, *somewhat agree*, *somewhat disagree*, or *strongly disagree* with each statement.

Perceived Barriers

Overall, this subset of respondents converged on several perceived barriers related to EVs and EVSE:

60% said EVs have low driving ranges

67% said EVs take too long to charge between trips

76% said EVs are out of their price range

Other perceived barriers were not as universally agreed upon, including cost and vehicle options: 46% of respondents said EVs and EVSE cost too much in upkeep, while 54% disagreed. In addition, 50% said that an EV model that meets their driving needs is not yet available for purchase, but 35% *somewhat disagreed* and 15% *strongly disagreed*. Figure 243 shows response trends for perceived barriers.

[122] Five of the 11 respondents did not provide an answer on if they were planning to purchase an EV or a non-electric car as their next vehicle purchase.

Figure 243. Respondent perceived barriers

EV and EVSE Question	Strongly Agree	Somewhat Agree	Somewhat Disagree	Strongly Disagree
An electric vehicle is out of my price range. (n=34)	47%	29%	15%	9%
Electric vehicles have low driving ranges. (n=33)	30%	30%	37%	3%
Electric vehicles take too long to charge between trips. (n=24)	25%	42%	25%	8%
Electric vehicles cost too much to upkeep. (n=22)	14%	32%	36%	18%
An Electric vehicle model that would meet my needs (size) is not yet available. (n=34)	29%	21%	35%	15%

Source: PacifiCorp Residential General Population Survey Q28. "For each of the next statements, please let us know if you *strongly disagree, somewhat disagree, somewhat agree*, or *strongly agree."*

Perceived Benefit

Most respondents (88%) view EVs as more environmentally friendly than conventional non-EVs. In addition, most (86%) also said that adding more public charging stations would increase EV adoption in the PacifiCorp's service territory. Figure 244 shows response trends for perceived benefits.

Figure 244. Respondent perceived benefits

EV and EVSE Question	Strongly Agree	Somewhat Agree	Somewhat Disagree	Strongly Disagree
Electric vehicles are more environmentally friendly than non-electric vehicles. (n=40)	43%	45%	8%	5%
Public charging stations would increase electric vehicle adoption in Pacific Power's territory. (n=37)	43%	43%	0%	14%

Source: PacifiCorp Residential General Population Survey Q28. "For each of the next statements, please let us know if you *strongly disagree, somewhat disagree, somewhat agree*, or *strongly agree*."

Interest in EVs and EVSE information

Other questions gauged interest in personal EV ownership and EVSE information. As shown in Figure 245, respondents reported more mixed results in these two categories. While 41% of respondents said they are interested in purchasing an EV but need more information first, 59% disagreed with that same statement. This is only slightly different from 48% of respondents who agreed with the statement, "I have no interest in purchasing an electric vehicle," while 52% disagreed.

Figure 245. Respondent interest in EVs

EV and EVSE Question	Strongly Agree	Somewhat Agree	Somewhat Disagree	Strongly Disagree
I'm interested in purchasing an electric vehicle, but need more information first. (n=41)	19%	22%	27%	32%
I have no interest in purchasing an electric vehicle. (n=44)	32%	16%	25%	27%

Source: PacifiCorp Residential General Population Survey Q28 "For each of the next statements, please let us know if you *strongly disagree, somewhat disagree, somewhat agree*, or *strongly agree*."

PacifiCorp Support

Finally, respondents provided feedback on PacifiCorp's role in promoting EVs and EVSE. As shown in Figure 246, respondents look to PacifiCorp for leadership, with 83% saying they *somewhat agree* (24%) or *strongly agree* (59%) that PacifiCorp should do more to educate their customers about EVs and EVSE.

Figure 246. Respondent interest PacifiCorp support

EV and EVSE Question	Strongly Agree	Somewhat Agree	Somewhat Disagree	Strongly Disagree
Pacific Power should do more to educate their customers about electric vehicles. (n=41)	24%	59%	7%	10%

Source: PacifiCorp Residential General Population Survey Q28. "For each of the next statements, please let us know if you *strongly disagree, somewhat disagree, somewhat agree*, or *strongly agree*."

PacifiCorp Outreach and Education Awareness and Experience

This section describes respondents' awareness of PacifiCorp's Education and Outreach program, as well as their preferences for EV and EVSE communications.

Education and Outreach Initiative Awareness

All survey respondents reported whether they had seen any EV or EVSE advertisement or educational information from PacifiCorp. Those who had seen advertising were then asked to describe what types of materials they had seen and what affect those materials had on their perceptions of EVs and EVSE.

The survey was designed to ask additional questions of respondents who had participated in a ride-and-drive event, where customers are allowed to test drive (or test ride) an EV; however, none had participated in a ride-and-drive event. The survey did ask additional questions of one respondent who had visited the online self-service webtool (known to PacifiCorp customers as the WattPlan Calculator), where PacifiCorp shows the cost, energy, and environmental savings associated with several dozen various EV makes and models available in the PacifiCorp service territory.[123] This respondent indicated having no issues with using the self-service webtool and rated themselves as *somewhat satisfied* with the tool.

Overall, 5% of all respondents (four total) said they were familiar with PacifiCorp specific advertisements or education information related to EVs and EVSE (multiple responses allowed):

- Facebook advertisement (two respondents)
- PacifiCorp email (two respondents)
- PacifiCorp website (one respondent)
- PacifiCorp bill insert (one respondent)

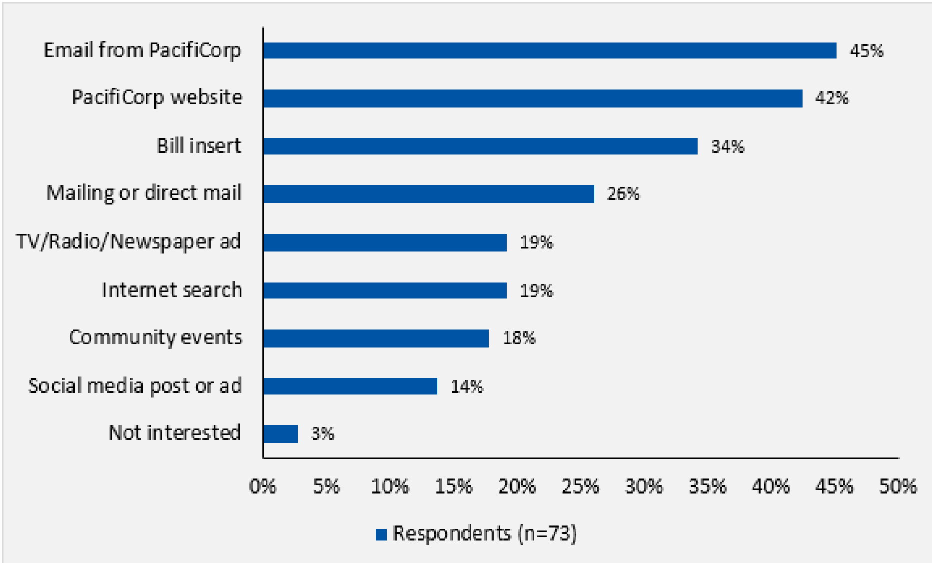
The survey asked these four respondents if the materials increased their likelihood to consider an EV as their next vehicle purchase. Two respondents answered this question, with one saying they are *more likely* to consider an EV than before they saw the education materials and the other saying they *are just as likely* as before. The respondent who is *more likely* to consider an EV said they saw materials on Facebook, the PacifiCorp website, emails from PacifiCorp, and a PacifiCorp bill insert, and that those materials helped them understand affordability, travel range, charging options, incentives, and environmental benefits associated with EVs.

Outreach and Communication Preferences

All respondents indicated their media preferences for future communications from PacifiCorp and topics of interest related to EVs and EVSE. As shown in Figure 247, customers prefer receiving information from multiple sources, with 82% selecting more than one response. Respondents most often selected a PacifiCorp email (45%), followed by the PacifiCorp website (42%) and a utility bill insert (34%).

[123] Clean Power Research. Last updated 2020. “Is an Electric Vehicle Right for Me?” https://pacificpower.wattplan.com/ev/

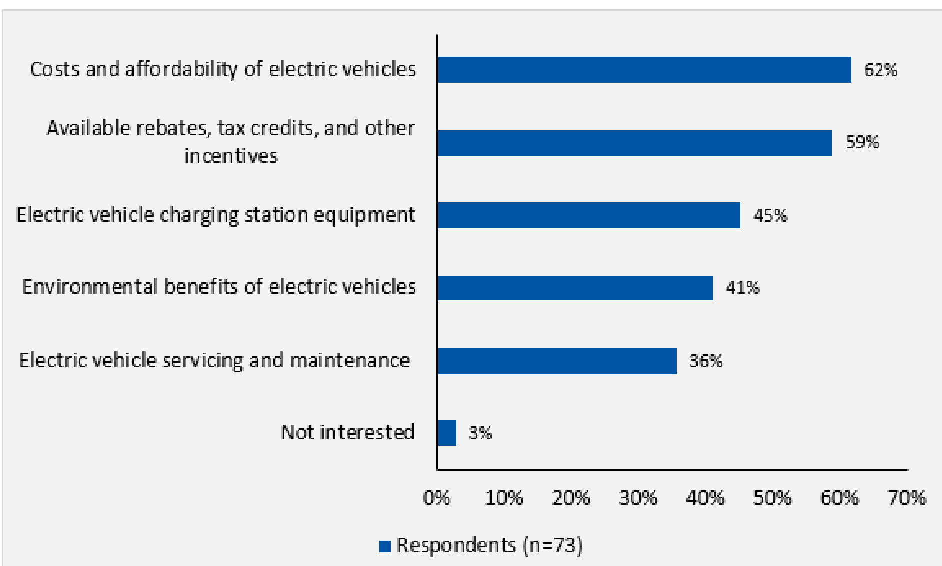
Figure 247. Preferred method of EV and EVSE communication



Source: PacifiCorp Residential General Population Survey Q29. "What are the best ways for PacifiCorp to keep you informed about electric vehicles and electric vehicle charging equipment?" (Up to three responses allowed)

The survey asked about what types of messaging respondents would be interested in hearing about from PacifiCorp regarding EVs and EVSE. As shown in Figure 248, respondents most commonly cited the costs and affordability of EVs (62%), as well as information on rebates, tax credits, and other incentives available for EVs and EVSE (59%). In addition, 62% of respondents said they would be interested in a ride-and-drive event in their area.

Figure 248. Preferred EV and EVSE content from PacifiCorp



Source: PacifiCorp Residential General Population Survey Q27. "Which of the following would be beneficial for PacifiCorp to focus on when communicating information regarding electric vehicles?" (Multiple responses allowed)

Respondent Demographics

This section presents the respondent demographics including dwelling type, income, age, number of cars owned, and average number of miles driven per car per week.

Dwelling

A majority of respondents (81%) live in a single-family home, while 10% live in a mobile home or manufactured home and 9% live in an apartment, condo, townhouse, or duplex. Table 104 shows the breakout of reported dwelling type and number of years respondents have lived in their home. Nearly one-third of respondents have lived in their home between 11 and 20 years and one-fourth have lived in their home five years or less.

Table 104. Dwelling type and number of years lived in dwelling

Dwelling Type and Number of Years Lived in Dwelling	Respondents
Detached single-family home	**56**
0 to 5 years	13
6 to 10 years	9
11 to 20 years	19
21 to 30 years	5
31 to 50 years	10
Mobile home or manufactured home	**7**
0 to 5 years	3
6 to 10 years	1
11 to 20 years	2
21 to 30 years	0
31 to 50 years	1
Townhouse or duplex	**3**
0 to 5 years	0
6 to 10 years	2
11 to 20 years	1
Apartment or condo	**3**
0 to 5 years	0
6 to 10 years	2
11 to 20 years	1

Source: PacifiCorp Residential General Population Survey Q31 and Q33. “Which of the following best describes the type of residence you live in?” (n=69) and “How many years have you lived at this residence?” (n=69)

Age and Income

Table 105 shows the breakout of age and income for respondents, revealing that 74% of respondents are 55 or older and 60% make less than $75,000 per year.

Table 105. Respondent age and income

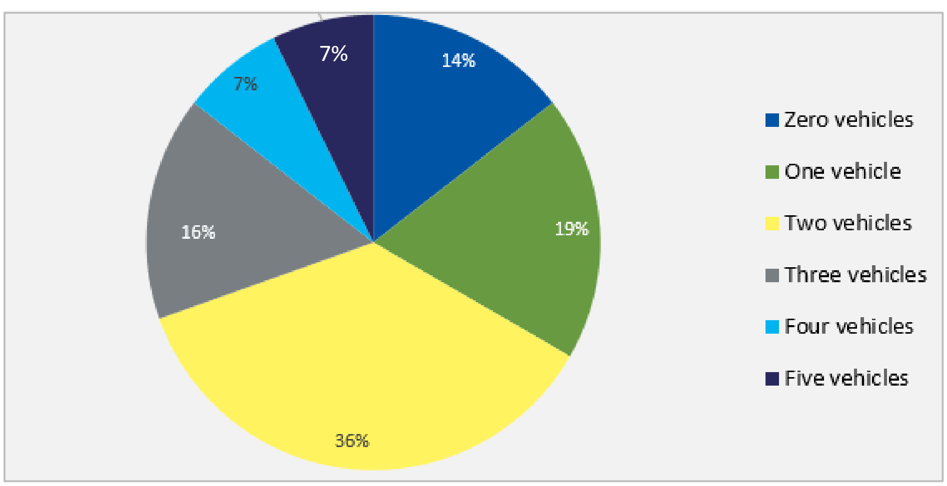
Income	25 to 34	35 to 44	45 to 54	55 to 64	65 or over	Total
More than $200,000	0	0	0	0	3	3
$100,000 up to $199,999	1	3	2	2	4	12
$75,000 up to $99,999	1	2	0	3	3	9
$50,000 up to $74,999	0	2	1	3	6	12
$25,000 to $49,999	2	0	1	3	9	15
Less than $24,999	1	0	0	5	3	9
Prefer not to answer	1	1	0	2	5	9
Total	6	8	4	18	33	

Source: PacifiCorp Residential General Population Survey Q35 and Q36. "Which of the following range best describes your age?" (n=69) and "Which of the following range best describes your total annual household income?" (n=69)

Number of Household Vehicles and Average Driving

Respondents reported how many non-electric vehicles are in their household and the average miles driven per vehicle per week. As shown in Figure 249, 19% of respondents have one vehicle, 36% have two vehicles, and 16% have three vehicles, while 14% of respondents do not have a vehicle at all.

Figure 249. Distribution of number of vehicles owned per respondent

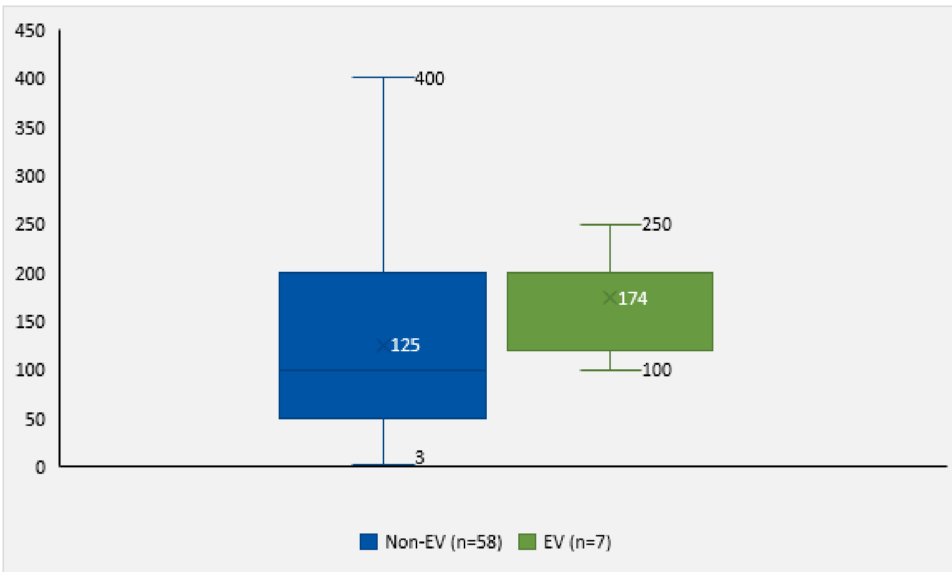


Source: PacifiCorp Residential General Population Survey Q37.2. "How many non-electric vehicles do you have in your household?" (n=69)

Respondents without an EV drive their primary vehicle 125 miles a week on average, with a range of three to 500 miles. Respondents drive fewer miles in their second vehicle, averaging 68 miles per week with a range of 0 to 500 miles. Respondents drive their third vehicle an average of 26 miles per week, while they drive their fourth and fifth vehicles only six and five miles per week on average, respectively.

Respondents with an EV drive 174 miles per week on average, well above the average total miles driven by respondents without an EVs. Only 25% of non-EV owners (n=17) drive their primary vehicle more than EV owners drive on average. The highest reported weekly driving from a non-EV respondent was 400 miles, which is substantially higher than what was reported for weekly EV respondent driving (250 miles). Figure 250 shows the breakdown of number of miles driven by the priority of the vehicle in the household.

Figure 250. Average miles driven per week



Source: PacifiCorp Residential General Population Survey Q38 and Q39. "What is the average number of miles driven in your electric vehicle per week?" (n=7) and "Approximately what is the average number of miles driven in your non-electric vehicle per week?" (n=58)

Costs

Per the Decision, the approved budget for the Outreach and Education Program was $170,000 and $270,000 for the Demonstration and Development Program. These were all considered expenses and not capital costs.

Table 106. Outreach and education

Cost Category	Actual Costs	Budgeted Costs
Customer Communications	$7,426	$20,000
Self-Service Resources	$7,398	$10,000
Community Events	$25,633	$50,000
Technical Assistance	$10,119	$40,000
Program Administration	$942	$20,000
Total Costs	$59,252	$140,000

Source: PacifiCorp

Table 107. Demonstration and development

Cost Category	Actual Costs	Budgeted Costs
Program Management	$9,723	N/A
Program Administration	$1,153	$60,000
Grant Application Evaluation	$3,662	$10,000
Grant Funding	$0	$200,000
Total Costs	$14,538	$270,000

Source: PacifiCorp

6.1.4 Conclusions

Though COVID-19 impacted the two programs, limiting outreach and possibly increasing the barrier to participation in the Demonstration and Development program, PacifiCorp was able to identify successes and lessons learned as the programs move forward.

Successes and Lessons Learned

Although the two programs began to address awareness and informational barriers regarding EV ownership for residential customers and on a more limited basis charging station installations for commercial customers, continued efforts will be required to mitigate customer concerns and increase awareness. PacifiCorp designed the Outreach and Education program to engage and inform residential and commercial customers about EVs. Starting in April 2019, PacifiCorp began its outreach to customers by offering ride-and-drives, conducting mass media outreach, building online resources, sending targeted email campaigns, and making social media advertisement buys. For the Demonstration and Development program, PacifiCorp engaged interested customers through workshops where they answered questions and sought to generate interest in the offering. Despite the outreach efforts and in-person workshops, very few customers submitted the Demonstration and Development applications and only one was approved. Staff reflected that the upfront cost of installing the infrastructure in advance of receiving a rebate may be a hindrance to the application process. The upfront cost barrier may have been exasperated with the onset of COVID-19, which required PacifiCorp to limit its outreach efforts to online and discontinue the in-person workshops. Despite these challenges, staff see a path ahead to continue to provide education to customers to increase awareness and knowledge of EVs and EVSE with 56% of residential survey respondents rating themselves as either *not too knowledgeable* or *not at all knowledgeable* about EVSE and 46% who reported the same for EVs.

Developing complementary programs leverages limited resources. With limited internal resources, developing complementary programs allows staff to expand customer awareness, reduce perceived barriers, promote technical knowledge through on-site and virtual assessments, and provide financial support to commercial customers who want to install charging infrastructure.

The Outreach and Education program is an opportunity for residential customers to learn about EVs and for commercial customers to learn about grant funding for charging stations. The technical assessment in the Outreach and Education program also completes the feasibility assessments that are required for the Demonstration and Development program. The Demonstration and Development program then provides financial support to commercial customers interested in installing charging infrastructure.

Programs must be designed to meet customers where they are on their journey. PacifiCorp recognizes that the rural California customers are not as far along in their EV journey as customers in other areas of the state. This sentiment was also reflected from survey respondents, who look to PacifiCorp for leadership, with 83% saying they *somewhat agree* (24%) or *strongly agree* (59%) that PacifiCorp should do more to educate their customers about EVs and EVSE. With this in mind, PacifiCorp refocused education and outreach efforts on building awareness and providing education on the benefits of EVs. While the ride-and-drive events provided an excellent opportunity for customers to experience EVs first-hand, COVID-19 pandemic curtailed any opportunity to provide customers with any in-person experiences. Understanding that customers may not be ready to make the jump to EVs, PacifiCorp continues to focus on providing them with factual and useful information, ensuring PacifiCorp remains a trusted information source.

When considering the Demonstration and Development program, PacifiCorp recognizes that the upfront cost investment required by participants remains a barrier as the program incentive is not provided until after the installation. In addition, customers must identify and select an EVSE vendor and have it installed. Staff reported that there are a limited number of vendors in the area, and this may further impact customer interest in the program. Despite these challenges, PacifiCorp was pleased with the one project that is moving ahead.

Next Steps

PacifiCorp is considering more fully integrating the two programs, and possibly offering a standardized incentive as part of the Demonstration and Development program. In the meantime, they will continue to conduct virtual technical assessments with the support of C2 and inform their customers about EV ownership and charging station installations.

6.2 Liberty Priority Review Projects

6.2.1 Project Narrative

Overview, Objectives, and Barriers Being Addressed

In September 2018, Liberty was approved to launch four transportation electrification programs as part of an effort to meet California's electrification and greenhouse gas reduction goals as outlined in Senate Bill 350. The four programs are 1) Direct Current Fast Charger (DCFC) Project, 2) Residential Charger Installation Rebate, 3) Small Business Charger Installation Rebate, and 4) Customer Online Resource Project. Liberty serves more than 48,000 customers in the Lake Tahoe basin. This area is a tourist destination known for ski resorts and summer outdoor adventures. Its mountainous location and winter season present unique challenges to the adoption of electric transportation. Not only does the winter affect the driving conditions, but it also affects construction in the Tahoe basin, as there is a no-dig moratorium from October until May.

Liberty designed their priority review projects (PRPs) to engage with residential and commercial customers, inform them about electric vehicles (EVs), and provide incentives for installation of EV charging stations.

DCFC Project ($4M approved budget)

Participating site hosts will provide make-ready infrastructure for the installation of electric vehicle supply equipment (EVSE). Site hosts will receive a rebate that covers up to 50 percent of the base cost of the EVSE, as set through a request for proposal (RFP) process, if they choose to own the EVSE. Site hosts that opt out of EVSE ownership will pay a participation payment to Liberty equal to 50 percent of the base cost of the EVSE. Liberty's ownership of EVSE is limited to 35 percent of the charging ports within the scope of the DCFC project. Based on the estimated cost of make-ready infrastructure, Liberty anticipates construction of up to nine project sites, with rebate funding available to support several EVSE per project site.

Liberty will establish base costs for EVSE through an RFP process in which responders will be asked to provide price quotations, following prescriptive requirements for qualifying equipment. Because some site hosts may want to install higher-capacity EVSE chargers, Liberty will solicit pricing and set base costs on three different power tiers (i.e., 50 kW, 100 kW and 150 kW). This tiered pricing is needed to avoid skewing the market by driving all participants to the lowest-capacity EVSE just to meet program requirements. Liberty will utilize the lowest price quotation from the RFP for each power tier to set the maximum rebate (for site-owned EVSE) and participation payment (for Liberty-owned EVSE).

Residential Charger Installation Rebate Program ($1.6M approved budget)

This program is designed to incentivize EV adoption by offsetting the costs of installing EVSE at a residence for daily charging. The first 1,000 qualifying residential customers will receive rebates of up to $1,500. To receive a rebate for permitting, installation, equipment, and service upgrades, the following criteria must be met:

- Provide proof of purchase or lease of EV on or after June 30, 2017,
- Install a networked charging station that meets Nationally Recognized Testing Laboratory (NRTL) standards,
- Own or lease the residential site and be the Liberty customer of record associated with the premises where the networked charging station is installed,
- Provide copies of all permits required by the relevant authority having jurisdiction and a receipt from a licensed electrical contractor for installing the networked charging station,
- Provide Liberty access to the property to confirm that the work was performed, and the networked charging station is operational,
- Participate in the program for 10 years, including maintaining the networked charging station in working order and contracting with a qualified EV charging network service provider to provide transactional data to Liberty, and
- Agree to take service on an eligible time-of-use (TOU)-EV rate.

Small Business Charger Installation Rebate Program ($0.3M approved budget)

This program is similar in design to the Residential Program. The exceptions are (1) owning or leasing an EV is not required, and (2) public access to charging stations must be provided. A rebate of up to $2,500 will be provided to the first 100 qualifying small commercial customers.

Customer Online Resource Project ($0.24M approved budget)

This project will develop information to educate and inform customers about the environmental, economic, and societal benefits of driving an EV. Liberty's website will be expanded to offer EV-specific information regarding incentives and programs available to Liberty customers, as well as charger locations and charging requirements in the Liberty service territory. The PRP is designed to increase awareness and reduce barriers to EV adoption.

Participation

Only the DCFC project has opened its application website; Residential and Small Business Rebate programs have prepared the application website but not yet made it available to the public. Seven applications have been received for the DCFC project, and one site, the City of Portola, has been selected, but the agreement had not been signed yet at the end of 2020.

Liberty selected firms to support these PRPs. Porter Novelli conducted a survey to gain insights on EV and charging station perceptions of Liberty's residential and commercial customers. CLEAResult developed the online application intake and management portal. Liberty also contracted with Clean Power Research to develop an EV savings tool.

Timeline and Status

In June 2017, Liberty filed an application with the California Public Utilities Commission (CPUC) proposing four programs to promote transportation electrification. The CPUC approved the four programs in September 2018 as part of Decision 18-09-034.[124] In July 2019, Liberty filed Tier 2 Advice Letter No. 114-E-A with an amended plan to conduct a request for proposal and calculate EVSE base cost for the DCFC project, which will be used to calculate the rebate and participation amounts for all PRPs installing infrastructure. The original Advice Letter No. 114-E was protested by the Public Advocates Office for not providing rebates based on the lowest-cost EVSE bid. In August 2019, the pre-application site for the DCFC project was launched. In September 2019, Liberty submitted a Tier 3 Advice Letter to propose using its small commercial customer rate (A-1 rate class), with no demand charges, as a temporary rate for DCFC infrastructure installed under the PRP; this proposal was approved. In May 2020, a residential and commercial customer survey was conducted. In October 2020, the base cost for the DCFC program rebate was established. Liberty staff were unable to conduct planned in-person meetings and site visits in 2020, as these were suspended because of the COVID-19 pandemic. According to Liberty projections:

- The 5 to 9 (sub)projects selected in the DCFC project will complete construction by Q3 2024.
- The application activity in the small business rebate program will peak in the middle of 2022, and the final projects (of the 100-project target) will be completed in Q2 of 2023.
- The application activity in the residential rebate program will peak in early 2023, and the final projects (of the 1,000-project target) will be completed in Q4 of 2023.
- The online customer resource will be offered throughout the term of residential and small business rebate programs.

6.2.2 Evaluation Methodology

Selected Methods and Rationale

Based on discussions with Liberty in August 2019, the evaluation team developed and submitted an evaluation plan for review. In addition to the common research questions that apply to all PRPs, those specific to the Public Access Stations and Incentives were applied.

The evaluation team employed the following data collection tasks:

- Information and data review
- Stakeholder in-depth interviews (IDIs) with Liberty and CLEAResult

Since no chargers were installed under any of the three charging-infrastructure-related PRPs, no utility construction costs, customer participation costs, utility meter data, EV service provider charging session data, or customer monthly billing statements were available for evaluation of the program. No IDIs were conducted with participating sites for the DCFC project or residential and commercial customers for the same reason. An EV driver survey was planned for the DCFC project, and questions were developed, but as there were no active sites in 2020, the survey was not conducted.

[124] Decision on the Priority Review and Standard Review Transportation Electrification Projects. *California Public Utilities Commission.* September 27, 2018. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M231/K030/231030113.PDF

Data Sources

Working closely with Liberty, the evaluation team modified the evaluation approach based on actual participation, assessing customer engagement in August 2019 through the third quarter of 2020. Based on the evaluation plan and discussions with Liberty, the evaluation team ultimately relied on the data sources outlined below.

Information and Data Review

For this data collection task, the evaluation team requested the following program information from Liberty regarding the four programs:

- Marketing efforts (e.g., marketing plans and materials)
- Program design process
- Program rules
- CPUC advice letters
- Quarterly PRP activity summaries
- PRP expenditures

In addition, the evaluation team requested Liberty provide the residential and commercial customer survey results.

In-Depth Interviews

The evaluation team used IDIs to gain insight into the success of Liberty's programs and the potential for scale-up. The team conducted an initial interview with Liberty staff in August 2019 and a final interview in December 2020. The interviews covered all four PRPs as appropriate and a variety of topics related to the evaluation objectives.

Residential and Commercial Customer Survey

Liberty commissioned a customer survey to support their EV education and outreach efforts. The survey was conducted by Liberty's vendor, Porter Novelli, in May 2020 to gain insights on EV and charging station perceptions of Liberty's residential and commercial customers. The survey also sought to understand customers' motivations and barriers for purchasing or leasing EVs and installing charging stations at their homes or companies. Additionally, the survey intended to learn about customers' information needs related to EVs and charging station installation, along with their preferred sources for this information. The survey methodology sought participants via email using Liberty's customer lists, and qualitative data were analyzed to identify emergent themes and insights.

6.2.3 Evaluation Findings

This section presents the evaluation findings for all four programs.

Implementation Process

Liberty progresses steadily toward full public availability of charger rebates for the DCFC project and the small business and residential rebate programs. Most of the program materials required for launch of these programs have been completed. Liberty contracted with CLEAResult, who developed an online application intake and management portal, PowerClerk, which will be used for the three infrastructure PRPs. This portal simplifies customer applications and provides detailed project reporting. CLEAResult worked closely with Liberty and the third-party evaluator to ensure the relevant data fields for CPUC reporting and evaluation would be captured as part of the customer applications and participation agreements.

The Participant Program Handbook for residential and small business programs was in final internal review at the end of 2020. This resource will inform customers, installers, and equipment providers about program requirements. For residential and small business programs, Liberty will offer a list of licensed electrical contractors on its website to help customers find installers. Liberty is communicating program status updates to electrical contractors in the region, including those companies that are actively participating in the Liberty Solar Incentive Program. Liberty will be offering cooperative marketing opportunities to listed contractors, including online presentations and print-ready, Liberty-branded material that contractors may co-brand to provide to prospective customers.

Additional PRP-specific details are provided in the section below.

DCFC Project

The **required materials** for the DCFC program have been developed, including the online application intake and management portal, which is open for applications. The standardized participation agreement is finalized and has been shared with prospective participants. The application scoring process has been developed to grade and compare prospective sites based on their benefits to the program goals. Graded categories include location, access and siting, equipment and service provider, pricing, viability, feasibility, and small business benefits.

As part of the **project design,** participants must agree to maintain a 10-year operation and maintenance warranty and network subscription service for the DCFCs. Liberty included these costs in the base charger cost estimate, which increased the incentive amount. Program participants need to provide annual usage reporting to Liberty, including applicable parameters from the CPUC SB 350 Data collection template. Liberty may own and operate chargers if a property owner desires to have charging on site but prefers not to own and operate the equipment (this cannot apply to more than 35% of the total sites). In this case, the property owner must pay a participation fee equal to the amount that would have been available as an incentive (50 percent of the applicable base charger cost estimate). Liberty will track participation from small businesses and benefits to small businesses, including priority scoring of sites that may benefit businesses around the completed fast chargers.

As part of **project outreach**, Liberty engaged regional electrical contractors and West Coast EV charging developers to generate project interest. Liberty also coordinates with Tahoe Regional Planning Agency transportation planners and with NV Energy and Nevada Governor's Office of Energy project leads on the best charger locations, according to known traffic patterns.

Residential Charger Installation Rebate Program

The required materials for the program have been developed, including the online application intake and management portal and the Participant Program Handbook. The **marketing strategy** for the program was being finalized at the end of 2020 and will be ready for deployment when the program is opened. Most initial marketing efforts will be online because of the COVID-19 pandemic; however, the materials have been designed to be easily adapted to print in anticipation of increasing direct customer interaction when in-person restrictions are lifted.

As part of the **project design**, Liberty is negotiating directly with selected EV service providers to access residential customer data to overcome the challenge of customer liability for high and ongoing network service fees to facilitate data-gathering. Participants must consent to data-sharing with Liberty, and the EV service provider will provide access to the provider's proprietary data-reporting tool(s). Liberty is seeking low- to no-cost solutions from EV service providers who wish to make their equipment eligible and available to participating customers.

Small Business Charger Installation Rebate Program

The required materials for the program have been developed, including the online application intake and management portal and the Participant Program Handbook. As part of the program design, the participants must agree to provide annual usage reporting to Liberty, including applicable parameters from the CPUC SB 350 data collection template.

Customer Online Resource Project

Liberty contracted with Clean Power Research in 2019 to provide a customized version of their EV savings tool, WattPlan. This tool is on a dedicated, Liberty-branded website (*https://libertyutilities.wattplan.com/ev/*) and provides Liberty customers with a personalized estimate of prospective savings for operating an EV. The tool uses current vehicle and gasoline prices—combined with actual Liberty electric rates, including the EV charging TOU rate—to provide estimates.

Liberty marketing and outreach efforts will encourage customers to utilize WattPlan, where, along with information about current vehicle rebates, customers will find details on the residential and small business charger rebate programs.

Stakeholder Feedback

Liberty reported that they have encountered several challenges while implementing the PRPs. The project manager for all four PRPs left in March 2020, and Liberty was unable to find a replacement for eight months because of COVID-19 pandemic-related hiring challenges. DCFC project challenges include staff- and budget-constrained customers, especially for public agencies. There was also a limited initial response to the RFP to set the DCFC base cost. Residential rebate program challenges include data-sharing and network service requirements for 10 years. The customer costs to maintain network subscription and internet connection would likely exceed the value of the rebate. Small business customers are focused on COVID-19 pandemic-related issues outside of this program, and outreach is significantly hampered without in-person meetings and site visits.

Residential and Commercial Customer Survey Feedback

Liberty's vendor, Porter Novelli, surveyed 23 residential customers through four 60-minute virtual focus groups and eight commercial customers through 30-minute, one-on-one interviews. Here are their takeaways from the survey:[125]

- Residential customers showed interest in EVs and in charging station installations at their homes.
- Interested customers did not see any issues with charging station installation but thought having a charging station at home was a prerequisite for EV ownership.
  - EV owners without charging stations are not opposed to installation; many would have to update their homes' electrical systems, which is an expensive undertaking, but these customers would be motivated by a program that would reduce these costs.
  - Residents would benefit from knowing what vehicle options exist that are suitable for Tahoe-Truckee's unique environment and lifestyle, as they currently perceive limited options.
  - A minority of residents perceived EVs to be too much effort and impractical; for this group, simplifying EV ownership and charging is essential.
- Differences emerged between primary and non-primary residents.
  - Non-primary residents perceive a need to keep their gas vehicles; they would use EVs in their day-to-day travel near their residences but plan to use gas cars to travel to and within Tahoe-Truckee.
  - Non-primary residents who rent their homes in Tahoe-Truckee had mixed interest in installing charging stations at these homes; some viewed having charging as a perk for their guests, while others were concerned about their renters' electricity usage.
- Commercial customers are interested in installing charging stations, but they need more information before making decisions.
  - Though they perceive several benefits related to having charging stations on the premises, installation needs to make financial sense absent of any customer demand.
  - Both residential and commercial customers want more information related to EVs and charging station installation, and they trust Liberty to provide this information.
  - Residential and commercial customers want more information about the costs and logistics of installation and maintenance, and programs available to reduce their costs.

A key takeaway for Liberty was that four-wheel/all-wheel drive is critical for an EV, as during the winter months, residents must navigate through snow and wet conditions. Important factors in vehicle

[125] Electric vehicle and charging station perceptions: Liberty residential & commercial customers, Peter Novelli, May 26, 2020

selection include cargo space and towing capabilities for recreational equipment, as well as getting up and down the mountains in the region.

Costs

Table 108 presents the CPUC Decision-approved PRP budgets, the rebate portion of the approved budgets, and current expenditures through December 2020. The DCFC project includes capital costs of $2,195,085. Through December 2020, Liberty recorded $90,459 in capital expenditures and $138,730 in administrative expenditures across the four PRPs.

Table 108. Approved budgets and incurred costs for Liberty PRPs

Cost Category	Decision Approved	Rebate Funding	Incurred Cost
DCFC Project	$4,000,000	$1,800,000	$116,230
Residential Rebate Program	$1,600,000	$1,500,000	$23,672
Small Business Rebate Program	$300,000	$250,000	$16,929
Customer Online Resource Project	$240,480	$240,480	$26,650

The majority of Liberty's expenses to date include staff labor for outreach and vendor costs for development of the online application management portal that applied to all projects. The capital costs are for the current active DCFC project, inclusive of Liberty- and vendor-related capital expenses. No rebates have been issued for DCFC, residential, or commercial programs. As described in the timeline section, Liberty expects to continue all PRPs well into 2023, with the DCFC project closing out in 2024. Therefore, it is expected that significant additional expenses will be incurred, potentially up to the approved budget limits, depending on customer interest.

6.2.4 Conclusions

Liberty is progressing toward full public availability of charger rebates for the DCFC project and the small business and residential rebate programs. Seven applications have been submitted to the DCFC program, and one site, owned by the City of Portola, has been selected for participation. Final requirements for the opening of the small business and residential programs continue, and Liberty intends to offer these programs starting in early 2021. The customer online resource has been open for over one year in support of the DCFC project.

Though COVID-19 affected all four programs, limiting outreach and possibly increasing the barrier to participation in the DCPC project, Liberty was able to identify successes and lessons learned as the programs move forward.

Successes and Lessons Learned

While Liberty's PRPs are not yet fully deployed, **Liberty has successfully coordinated marketing and outreach efforts across the PRPs and with local ongoing efforts**. Liberty will encourage customers to utilize WattPlan, developed under the Customer Online Resource, where, along with information about current vehicle rebates, customers will find details on the residential and small business charger rebate programs. Liberty is communicating residential and small business rebate program status updates to electrical contractors in the region, including companies actively participating in the Liberty Solar Incentive Program. In support of the DCFC project, Liberty engaged regional electrical contractors and West Coast EV charging developers to generate interest. Liberty also coordinates with transportation planners at Tahoe Regional Planning Agency and with NV Energy and the Nevada Governor's Office of Energy on best charger locations.

Staffing has proven to be a challenge, as Liberty lost the PRP project manager and was unable to find a replacement for eight months because of COVID-19 pandemic-related hiring challenges. The utility ultimately hired the vendor's project manager for the utility's PRP online application portal, which allowed them to gain ground quickly owing to his familiarity with the programs. There are also competing interests within Liberty for limited staffing resources (management, design, and construction teams), as there are several ongoing EVSE installation programs (e.g., Schools and Parks/Beaches under Assembly Bill 1802/1083).

Liberty developed an online application intake and management portal that will be used for all three infrastructure PRPs. This portal simplifies customer applications and provides detailed project reporting. Based on discussions with the third-party evaluator, Liberty included the relevant information fields in the customer application and ensured the participant and EV service provider agreements included provisions requiring data collection, which will be used to complete PRP reporting requirements. Through third-party evaluator engagement, **Liberty was able to leverage relevant materials and learnings from other DCFC PRPs** (SCE and SDG&E) and PG&E's standard review project. For example, because the limited initial response to the RFP made it difficult to set the base charge cost for DCFC, Liberty is leveraging the large utilities EVSE approved product list. Since a full evaluation of Liberty PRPs was not possible in time for this report, Liberty engaged with the CPUC Energy Division and the third-party evaluator to prepare for self-reporting upon PRP completion.

Ten-year data sharing and network service requirements for the residential rebate program presented a significant challenge. The customer costs to maintain network subscription and internet connection would likely exceed the value of the rebate. To address this issue, Liberty is negotiating directly with selected EV service providers to access residential customer data to overcome the challenge of customer liability for ongoing network service fees to facilitate data-gathering. Participants must consent to data-sharing with Liberty, and the EV service provider will provide access to their proprietary data reporting tool(s). Liberty is seeking low- to no-cost solutions from EV service providers who wish to make their equipment eligible and available to participating customers.

The COVID-19 pandemic has prevented in-person meetings and site visits, which has hampered outreach to small business customers. In response, most initial Liberty marketing efforts will be online, but the materials have been designed to be easily adapted to print in anticipation of increasing direct customer interaction when possible. Liberty will be offering cooperative marketing opportunities to listed contractors, including online presentations and print-ready, Liberty-branded materials that contractors may co-brand to provide to prospective customers.

Developing complementary programs leverages limited resources. With limited internal resources, launching all four related PRPs simultaneously allows staff to expand customer awareness, reduce perceived barriers, promote technical knowledge, and provide rebates to residential and small business customers who want to install charging infrastructure. The Customer Online Resource provides an opportunity for residential customers to learn about EVs and for commercial customers to learn about rebates for charging stations. The residential and small business rebate programs then provide financial support to residential and commercial customers interested in installing charging infrastructure.

Programs must be designed to meet customers where they are on their journeys. Liberty recognizes that their customers are not as far along in their EV journey as customers in other areas of the state. Lack of available vehicle choices with four or all-wheel drive capability, larger batteries to overcome temperature losses, and towing capability are significant factors. Survey respondents are looking to Liberty for leadership in providing EV information resources and letting customers know how or when these barriers are addressed. Understanding that customers may not be ready to make the jump to EVs, Liberty continues to focus on providing factual and useful information, ensuring Liberty remains a trusted information source.

Next Steps

Liberty is planning to open the online application portal for the small business and residential rebate programs in early 2021. Depending on customer interest, Liberty anticipates that both rebate programs will be completed by the end of 2023. The first DCFC installations should be complete in 2021, with the project anticipated to install final chargers within 2024. The third-party evaluator helped set up Liberty for self-reporting to meet the PRP reporting and evaluation requirements.

6.3 Bear Valley Electric Service Destination Make Ready Pilot

6.3.1 Project Narrative

Overview, Objectives, and Barriers Being Addressed

In June 2017, Bear Valley Electric Service (BVES), along with PacifiCorp and Liberty, filed an application with the California Public Utilities Commission (CPUC) proposing priority review projects (PRPs) to promote transportation electrification (TE). The CPUC approved the proposed programs in September 2018 as part of Decision 18-09-034. Under the Decision, BVES was approved to launch a TE PRP as part of an effort to meet California's electrification and greenhouse gas (GHG) reduction goals as outlined in Senate Bill 350. Under the Destination Make-Ready PRP, BVES was approved to spend $607,500 to install, own, and operate the make-ready infrastructure that supports up to 50 Level 2 (L2) charging stations at destination centers in its service territory. The decision included a non-binding target of at least 20% participating small businesses sites. All participants are required to maintain operational charging stations for at least 10 years. This program is applicable to commercial customers and works in conjunction with electric vehicle (EV) time-of-use (TOU) tariffs. This commercial program would also provide rebates for up to 50 L2 charging stations.

BVES serves about 23,000 customers in the Big Bear Valley. This area is a tourist destination known for ski resorts and summer outdoor adventures. This resort community has a mix of 20,000 full-time and part-time residents. BVES also serves approximately 2,500 commercial, industrial, and public authority customers, including Bear Mountain and Snow Summit ski resorts. Its mountainous location and winter driving conditions present unique challenges to the adoption of electric transportation.

More visitors to the Big Bear Lake region and local residents are starting to drive EVs as four-wheel drive options become available (although they are still very limited). This PRP addresses the lack of charging stations, which is an EV adoption barrier. Through this PRP, BVES is helping businesses interested in deploying EV charging stations by offering to install the needed electrical infrastructure at no charge. Commercial customers need only to purchase the charging equipment, and BVES will pay for the site preparation and installation.

Participation

BVES has contracted with the Center for Sustainable Energy (CSE) to coordinate program outreach and implementation. Outreach is performed by BVES's customer service team, with the assistance of regulatory affairs staff regarding the applicable tariffs. Since program launch, 7 entities have expressed interest. Four of those are in the application process and BVES has conducted three site visits. No applicants have completed all the required paperwork. BVES has also engaged the City of Big Bear and identified two sites for EV charging installations but has not yet received a completed application from the City.

BVES is working with electrical contractors to advise them of installation best practices, working with EV service providers on commissioning process, and assisting interested customers with the application process. BVES is planning additional information mailers targeted to commercial properties because COVID-19 pandemic restrictions are preventing any in-person workshops, marketing, education and outreach events, speaking events, and direct customer engagement.

Timeline and Status

In June 2017, BVES filed an application to the CPUC proposing one PRP to promote TE. The CPUC approved the PRP in September 2018 as part of Decision 18-09-034.[126] BVES issued a request for proposals (RFP) in April 2019 to coordinate program outreach and implementation, then selected and contracted with CSE in July 2019. BVES also conducted an EV survey in July 2019 and created a list of licensed C-10 electricians. The program was launched on December 11, 2019, by holding community outreach and contractor meetings for electricians and commercial customers.

BVES staff were unable to conduct many in-person meetings and site visits in 2020 because of the COVID-19 pandemic. The program is anticipated to run through December 2021 or until funds are exhausted. BVES expects the first commercial EV charging site to be commissioned in early 2021 and the last one by the end of 2022.

6.3.2 Evaluation Methodology

Selected Methods and Rationale

Based on discussions with BVES in August 2019, the evaluation team developed and submitted an evaluation plan for review. In addition to the common research questions that apply to all PRPs, those specific to the Public Access Stations were applied.

The evaluation team employed the following data collection tasks:

- Information and data review
- Stakeholder in-depth interviews (IDIs) with BVES and CSE

Since no chargers were installed under the PRP by November 2020, no utility construction costs, customer participation costs, utility meter data, EV service provider charging session data, or customer monthly billing statements were available for evaluating the program. No IDIs were conducted with participating sites for the same reason.

Data Sources

Based on actual participation in the program, the evaluation team modified the evaluation approach and ultimately relied on the data sources outlined below.

Information and Data Review

The evaluation team requested the following program information from BVES:

- Marketing efforts (e.g., marketing plans and materials)

[126] Decision on the Priority Review and Standard Review Transportation Electrification Projects. *California Public Utilities Commission.* September 27, 2018.
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M231/K030/231030113.PDF

- Program design process
- Program rules
- CPUC advice letters
- Quarterly PRP activity summaries
- PRP expenditures

In addition, the evaluation team requested BVES provide the customer EV survey results.

In-Depth Interviews

The evaluation team used IDIs to gain insight into the success of BVES's program and the potential for scale-up. The team conducted an initial interview with BVES in August 2019 and a final interview in October 2020. The interviews covered a variety of topics related to the evaluation objectives.

6.3.3 Evaluation Findings

This section presents the evaluation findings for the program.

Implementation Process

BVES contracted with CSE to coordinate program outreach and implementation. CSE is responsible for administering the application phase only. Approved applications are submitted to BVES for final contract execution, followed by electrical contractor design and site work. Outreach is performed by BVES's customer service team, with the assistance of regulatory affairs staff regarding the applicable tariffs.

BVES has completed the following required program documentation: application, license agreement, terms and conditions, website landing page (Figure 251), interest form (Figure 252), and program handbook. The Bear Ready Commercial Program Handbook (Program Handbook shown in the bottom right of Figure 252) details eligibility and program requirements, while also providing the necessary definitions, explanations, and processes associated with the program requirements for commercial properties.[127]

BVES conducted an EV survey and created a list of licensed C-10 electricians. The BVES Destination Make-Ready PRP was named Bear Ready Commercial program and launched on December 11, 2019, by holding community outreach and contractor meetings for electricians and commercial customers.

[127] Bear Valley Electric Service, Inc, website, Efficiency & Environment https://www.bvesinc.com/media/managed/bearreadydocuments/BVES_Bear_Ready_Commerical_Program_Handbook.pdf accessed October 2020

Figure 251. Bear Ready commercial flyer

BEAR READY

Is Your Business Ready for Electric Vehicle Charging?

Introducing a Bear Valley Electric Service program to help you attract visitors and customers who drive electric cars.

Increasingly, visitors to the Big Bear Lake region and local residents are driving electric vehicles – even four-wheel drive electric cars and SUVs. However, the valley has a shortage of electric vehicle charging stations. That's why Bear Valley Electric Service is helping businesses prepare to support EV charging through a program to install the needed electrical infrastructure at no charge. All you have to do is purchase the charging equipment, and BVES will pay for the site preparation and installation – an up to $50,000 savings.

Through Bear Ready Commercial, BVES will install and maintain the electrical infrastructure to support 50 Level 2 chargers at commercial locations throughout the valley. Be a leader in meeting the growing need for EV charging.

Here's How It Works

1. Request an application and apply.
2. Agree to the procedures and terms and conditions of the Bear Ready program.
3. Install an eligible charger through an approved contractor.
4. Add your business as a charging point on PlugShare, Google Maps and other online sites.

Eligibility Requirements

- Must be a Bear Valley Electric Service commercial customer with a peak energy demand of less than 500 kW.
  - Businesses below a 20-kilowatt peak load are eligible to apply for 1-5 Level 2 connectors
  - Businesses exceeding a 20-kilowatt peak load are eligible to apply for 3-5 Level 2 connectors
- Be the property owner or an individual authorized by the property owner to apply on their behalf.
- Be a Bear Valley Electric Service commercial customer.
- Be a resort, hotel, motel, restaurant, recreation facility, grocery store or commercial retail establishment.
- Have off-street, point of power connection-accessible parking serving the main use of your business.

Get Started

To take advantage of the Bear Ready Commercial program, visit our website.

BVES-BR-CSE-102019

BEAR VALLEY ELECTRIC SERVICE

Source: BVES

Figure 252. Bear Ready interest form

BEAR READY

Take Charge of Your Business with Bear Ready

Request an application for Bear Valley Electric Service's free electric vehicle (EV) charging infrastructure installation program

First Name:	Last Name:	
Phone Number:	Email:	
Business Name:		
Business Address:		
City:	State:	ZIP:
Number of EV-ready parking spaces requested ☐ 1 ☐ 2 ☐ 3 ☐ 4 ☐ 5		

Once you receive an application, Bear Ready staff will schedule a site assessment and send a proposal.

If you are unable to return this form in person, please return it by mail or email.

Mail
Center for Sustainable Energy
Attn: Bear Ready Commercial
3980 Sherman Street, Suite 170
San Diego, CA 92110

Email
Scan this document and send to
BearReady@energycenter.org

BEAR VALLEY ELECTRIC SERVICE

Source: BVES

Program eligibility requirements include the following:[128]

- Must be a BVES commercial customer with a peak energy demand of less than 500 kilowatts (kW).
    - Businesses below a 20-kW peak load are eligible to apply for one to five L2 connectors.
    - Businesses exceeding a 20-kW peak load are eligible to apply for three to five L2 connectors.
- Be the property owner or an individual authorized by the property owner to apply on their behalf.
- Be a resort, hotel, motel, restaurant, recreation facility, grocery store, or commercial retail establishment.
- Have off-street, point of power connection-accessible parking serving the main use of your business. The off-street parking must be reasonably accessible from a point of power connection, and parking spaces available for Bear Ready must be clustered together.
- Be available to move forward in the Bear Ready program within a reasonable timeframe.

According to the BVES website, the program participation process includes the following steps.

1. Participant emails their contact information to CSE with the number of chargers (up to five) the interested party is ready to install. CSE will review the property and parking availability to determine preliminary eligibility. Once selected, CSE will send out a Bear Ready Commercial application form to complete.
2. Participant submits a preliminary service request to BVES.
3. Participant submits the application form, along with a marked aerial image of the preferred parking for the EV charger locations.
4. BVES staff will schedule a full site assessment.
5. BVES will provide eligible applicants with a proposed Bear Ready EV charging solution based on the full application and on the site assessment.
6. Participant completes the Bear Ready License Agreement and purchases an L2 EV charger that has the capability to be networked, provides full charging session data, and allows for TOU pricing.
7. BVES will install everything up to the mounting apparatus and EV charger, which can be installed by one of the contractors from the BVES Big Bear approved list.
8. Participant posts EV charging station information to the PlugShare, Google maps, and Alternative Fuels Data Center station locator tools.

BVES also developed commercial equipment charging requirements, which are shown at the top of Figure 253. Figure 254 shows a few recommended charging stations, which range in price from $1,200 to $5,000 for a single-port and from $5,400 to $7,200 for a dual-port charger. The owner of each funded

[128] Bear Valley Electric Service, Inc, website, Efficiency & Environment https://www.bvesinc.com/efficiency-&-environment/electric-vehicle-charging-pilot/bear-ready-commercial, accessed October 2020

site will be responsible for paying the monthly network subscription charges to meet the 24-month EV charging data collection requirement. The costs range from zero when the charging station is connected to a home Wi-Fi network to $42 per month for a dual-port charging station.

Figure 253. Bear Ready commercial charging equipment requirements

BEAR READY

Charging Equipment Requirements

Bear Ready participants need to select an Electric Vehicle Supply Equipment (EVSE) that meets or exceeds these requirements:

1. Be VGI capable.
2. Use VGI communication protocols, such as Open Charge Point Protocol (OCPP), OpenADR 2.0b, and/or IEEE 2030.5 or greater.
3. Offer an electric utility dashboard to view real-time EVSE production and produce (hourly/daily/weekly/monthly) reports.
4. Have a mobile website or application that can communicate with the user (participant's customer) and signal price changes and availability status.
5. Ability to set prices by TOU plus a set percentage.
6. Be able to mount outside and be weatherproof.
7. Offer a minimum two-year warranty.

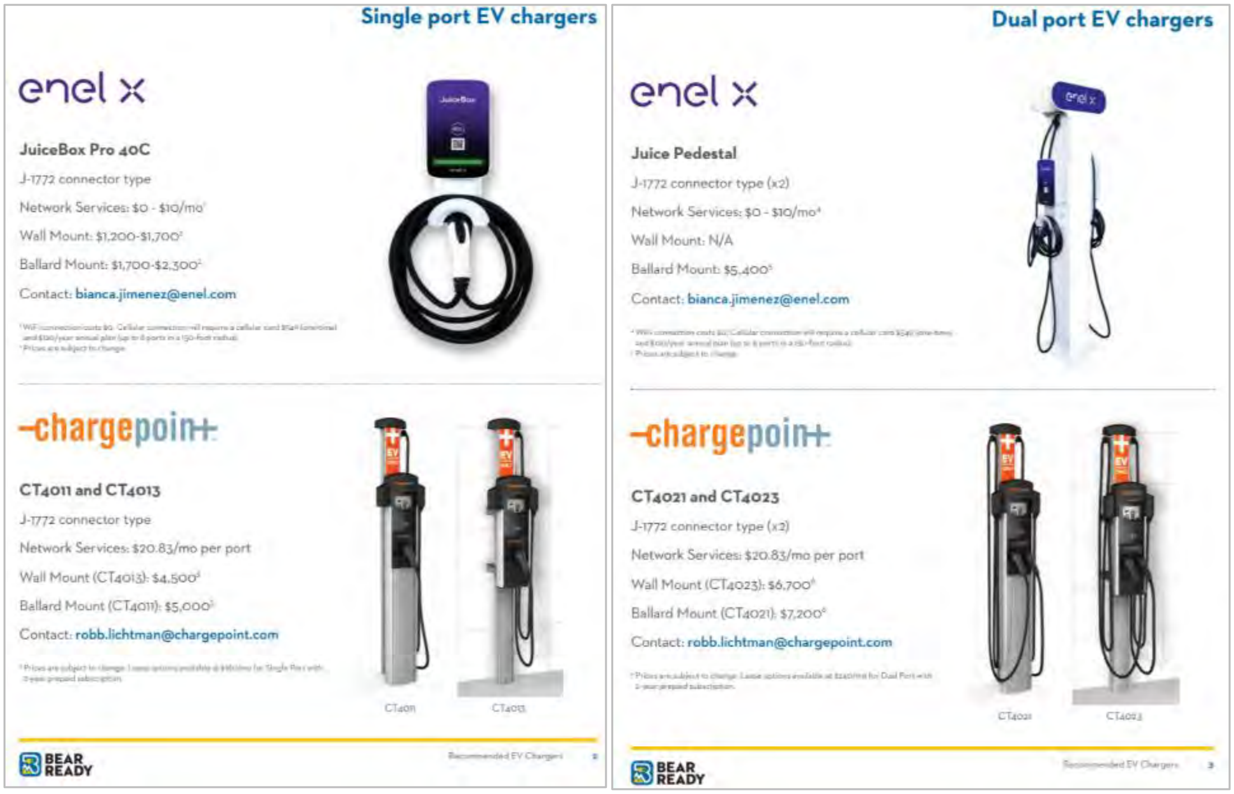
The EVSE needs to be selected, but not necessarily purchased, prior to the Bear Ready electrical contractor initial design. The placement of the electric runs is dependent to the type of EVSE selected. Once selected, participants will not have the option to change to a different EVSE. All electric runs will be 208/240V x 40A, allowing the EVSE to output 7.2 or 7.7 kWh.

A few recommended EV chargers have been provided on the following pages. While these chargers are recommended, any EVSE that meets the **Bear Ready** requirements can be utilized.

BEAR VALLEY ELECTRIC SERVICE

Source: BVES

Figure 254. Bear Ready commercial charging equipment options in the Program Handbook



Source: BVES

BVES will provide the substructure to the site where the owner is installing the charger. Based on the available PRP budget, BVES expects to support up to six commercial charging sites. For program participants, BEVS offers two unique rate structures: TOU-EV-2 (small commercial accounts with max monthly demand of 20 kW) and TOU-EV-3 (large commercial accounts with max monthly demand above 20 kW but below 500 kW), with super-off-peak rates during the day.

Table 109. BVES TOU-EV-2 and TOU-EV-3 rates

		TOU-EV-2 and TOU EV-3 Energy Charge ($/kWh)	TOU EV-3 Demand Charge ($/kW)
Summer	On-Peak	$0.18149	$9.00
	Off-Peak	$0.13612	
	Super Off-Peak	$0.09074	
Winter	On-Peak	$0.31446	$9.00
	Off-Peak	$0.12704	
	Super Off-Peak	$0.09074	

Source: BVES

Costs

Table 110 presents the CPUC Decision-approved PRP budget and current expenditures through December 2020. The PRP approved budget of $607,500 consisted of $471,950 in capital costs and $135,550 in expenses. Through December 2020, BVES recorded an estimated $75,000 in expenditures.

Table 110. Approved budgets for BVES PRP

	Decision Approved	Incurred Cost
Destination Make-Ready Program	$607,500	$75,000

Source: BVES

BVES expenses to date include utility labor for outreach and vendor costs for development of the program materials. No capital costs have been incurred as of November 2020. As described in the timeline section, BVES expects to continue the PRP well into 2021, with a likely close out in 2022. Therefore, it is expected that significant additional expenses will be incurred, potentially up to the approved budget limit, depending on commercial customer interest.

6.3.4 Conclusions

BVES has successfully developed all required program materials. The program opened for applications in December 2019 by holding community outreach and contractor meetings for electricians and commercial customers. The COVID-19 pandemic restrictions prevented any in-person workshops, marketing, education and outreach events, speaking events, and direct customer engagement in 2020. The customers that BVES engaged about the program expressed concerns about limited EVs in the region (as there is a lack of four- or all-wheel drive capabilities), loss of parking with installation of EV chargers, and customer participation costs. The pandemic has likely increased the cost barrier to EV adoption, as many commercial customers, especially small businesses, are dealing with COVID 19’s impact and likely do not consider installing EV charging as a financial priority. As a result, no customer agreements have been signed as of December 2020.

Given these challenges, BVES is planning to send additional information mailers targeted to commercial properties and continuing to target small businesses to meet the 20% goal for participation in the program. Anticipating some relief from the pandemic restrictions, BVES should be on track to install the first commercial EV charging site in 2021 and to complete the last installations by the end of 2022.

Next Steps

The Bear Ready Commercial program will continue to be open for interested customers until the funding is exhausted. Marketing and outreach will continue in 2021 and will be adjusted to the pandemic environment. Depending on customer interest, BVES anticipates installing up to six charging sites, with the last one to be completed by the end of 2022. The third-party evaluator will help set up BVES for self-reporting to meet the PRP reporting and evaluation requirements.

Appendix A. Additional PRP Information and Detailed Benefit Calculations

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1. Vehicle Emission Determinations

In each PRP, both electric and baseline pollutant emissions are derived from annual fuel use. The annual fuel use is determined based on a representative project period of operation and then converted to an annualized figure. This is determined by establishing the number of days of data and dividing the determined fuel use by those days and then multiplying by 365 for an annualized figure in kWh or gallons/yr. Some select projects had metrics determined based on hours per year depending on the available statistics where hours per year were determined in a similar methodology.

1.1 Baseline Emissions

Baseline emissions for on-road vehicles were determined using California GREET 3.0[129] for specific fuels by determining a well-to-wheels emission factor in grams/mmbtu of fuel input and then using displaced fuel use as determined by the project and lower heating value energy content available within that fuel on a per unit energy (btu) basis most often measured in btu/gallon to achieve a grams/gallon basis and ultimately a grams per year determination.

In the case of off-road vehicles, emissions tend to be slightly higher than on-road vehicles on a per unit basis and a different mechanism was necessary due to a lack of emissions aftertreatments. The California OFFROAD2017-ORION[130] was used in many cases to determine standard emission factors on a per hour of operation basis and multiplied by the annual hours of operation determined in the individual project analysis. In each PRP, the specific emissions basis used is described in the individual appendix.

1.2 Utility Emissions

Utility emissions were determined using a combination of the hourly/quarterly emission carbon intensities determined through the 2020 Low Carbon Fuel Standard (LCFS)[131] and for criteria pollutants using California GREET 3.0, also distributed through the LCFS program. Table A-1 shows the criterial pollutant emissions factors and greenhouse gas emissions factors are shown in Figure A-1. For criterial pollutants, 2020 and 2030 emissions factors from GREET were averaged based on an assumed 10-year electric vehicle charging infrastructure life to arrive at an annual average number that was used in calculations. To differentiate between fleets that are able to avoid charging during on-peak time and ones that do not, a more granular approach for calculating greenhouse gas emissions was used. Figure A-1 shows times of low carbon intensities in green and high intensities in red. It can be seen that lowest emissions occur between 8 AM and noon. Note ultra-low intensities in quarter 2 between 8 AM and 10 AM and highest emissions in general during on-peak hours between 4 PM and 9 PM.

[129] California Air Resources Board, "CA-GREET3.0 Model and Tier 1 Simplified Carbon Intensity Calculators," accessed 2020, https://ww2.arb.ca.gov/resources/documents/lcfs-life-cycle-analysis-models-and-documentation.

[130] California Air Resources Board, "OFFROAD2017-ORION," accessed June 15, 2020, https://www.arb.ca.gov/orion/.

[131] California Air Resources Board, "California Average Grid Electricity Used as a transportation fuel in California," January 16, 2020, https://ww2.arb.ca.gov/sites/default/files/classic//fuels/lcfs/fuelpathways/comments/tier2/elec_update.pdf.

Table A-1. Electricity Emissions Factors determined by California GREET 3.0

Year	SO_x (g/kWh)	NO_x (g/kWh)	CO (g/kWh)	PM (g/kWh)	VOC (g/kWh)
2020	0.107	0.283	0.191	0.047	0.043
2030	0.042	0.204	0.213	0.036	0.039
Average	0.075	0.244	0.202	0.042	0.041

Source: California GREET 3.0

While LCFS greenhouse gas emissions were determined for each hour of specific operation, few projects achieved a full year of fully developed operation. In these cases, the hourly factor used was based on an average emission for all four quarters of the year for the specific hour prior to scaling to the entire year providing a more appropriate factor for annual emissions.

Figure A-1. Utility Greenhouse Gas Emissions

	Hourly Emissions per Quarter (gCO2/kWh)			
Hour	**Q1**	**Q2**	**Q3**	**Q4**
12 a.m.	289	289	293	302
1 a.m.	289	289	289	295
2 a.m.	289	286	289	292
3 a.m.	289	290	288	291
4 a.m.	289	289	288	294
5 a.m.	295	303	289	321
6 a.m.	354	349	316	396
7 a.m.	377	244	304	387
8 a.m.	277	8	293	318
9 a.m.	194	6	204	300
10 a.m.	191	9	212	200
11 a.m.	187	167	233	212
12 p.m.	98	177	262	217
1 p.m.	98	183	300	306
2 p.m.	187	195	325	311
3 p.m.	192	211	382	337
4 p.m.	234	88	404	417
5 p.m.	385	106	433	500
6 p.m.	448	355	482	507
7 p.m.	436	501	516	485
8 p.m.	396	499	462	449
9 p.m.	332	404	390	398
10 p.m.	295	309	330	351
11 p.m.	289	292	301	312

Source: CARB LCFS

2. DAC Methodology

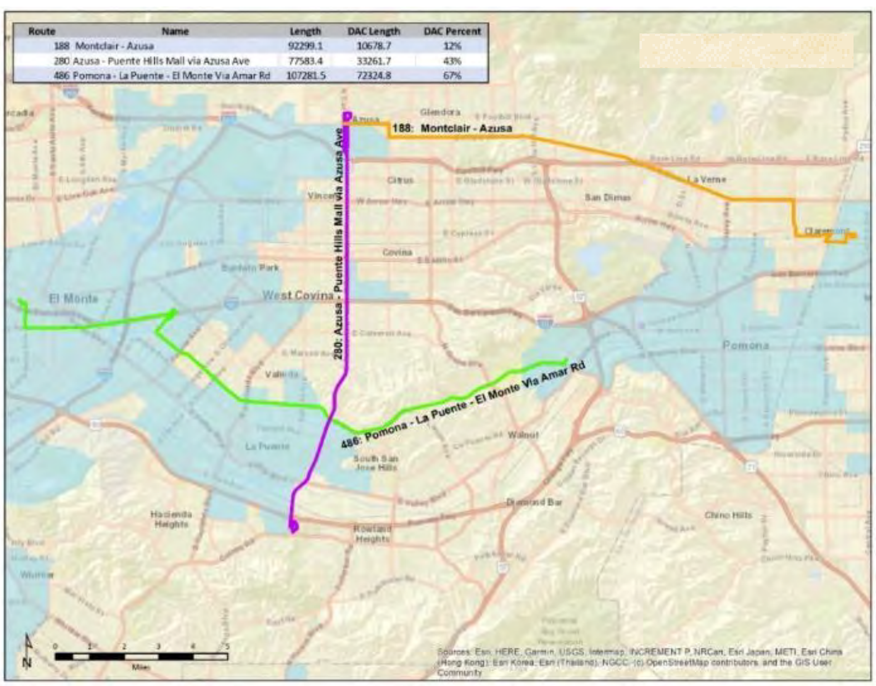
The methodology for attributing benefits to economically disadvantaged communities (DAC) follows the location of the vehicle to the best of the assessment teams' abilities. DAC criteria were determined using CaliforniaEnviroScreen 3.0. In general, there are three categories for the types of projects evaluated in the PRP program as follows:

1. **Fixed location** projects, where the vehicles stay within the property of concern. Examples of these types of project are the Port pilots and Airport ground support equipment.
2. **Known route** projects, where a vehicle operates on a known route continuously. Examples of these types of project are transit buses or school buses. Another example is in the case where GPS data are available on the location of the vehicle.
3. **Stochastic route** projects, where the vehicle is travelling an estimated number of miles within certain zones, but the specific route cannot be known. Examples of these types of projects are package delivery and commuter vehicle programs where little information is available about drivers or routes.

Fixed location projects are more binary in nature and the determination is simply completely within or completely outside of a known DAC. All fixed location projects are attributed either 100% of the benefits or 0% of the benefits to a DAC depending on the location of the property to within or outside of a DAC.

Known route projects are attributed benefits based on plotting the route of the vehicle superimposed onto a DAC map and determining the percentage of miles within and outside of a DAC. This percentage is then applied to the annual figures for mileage, emissions, etc. An example of this methodology is shown in Figure A-2.

Figure A-2. Known Route DAC Determination



Route	Name	Length	DAC Length	DAC Percent
188	Montclair - Azusa	92299.1	10678.7	12%
280	Azusa - Puente Hills Mall via Azusa Ave	77583.4	33261.7	43%
486	Pomona - La Puente - El Monte Via Amar Rd	107281.5	72324.8	67%

Source: Esri ArcGIS and Foothill Transit

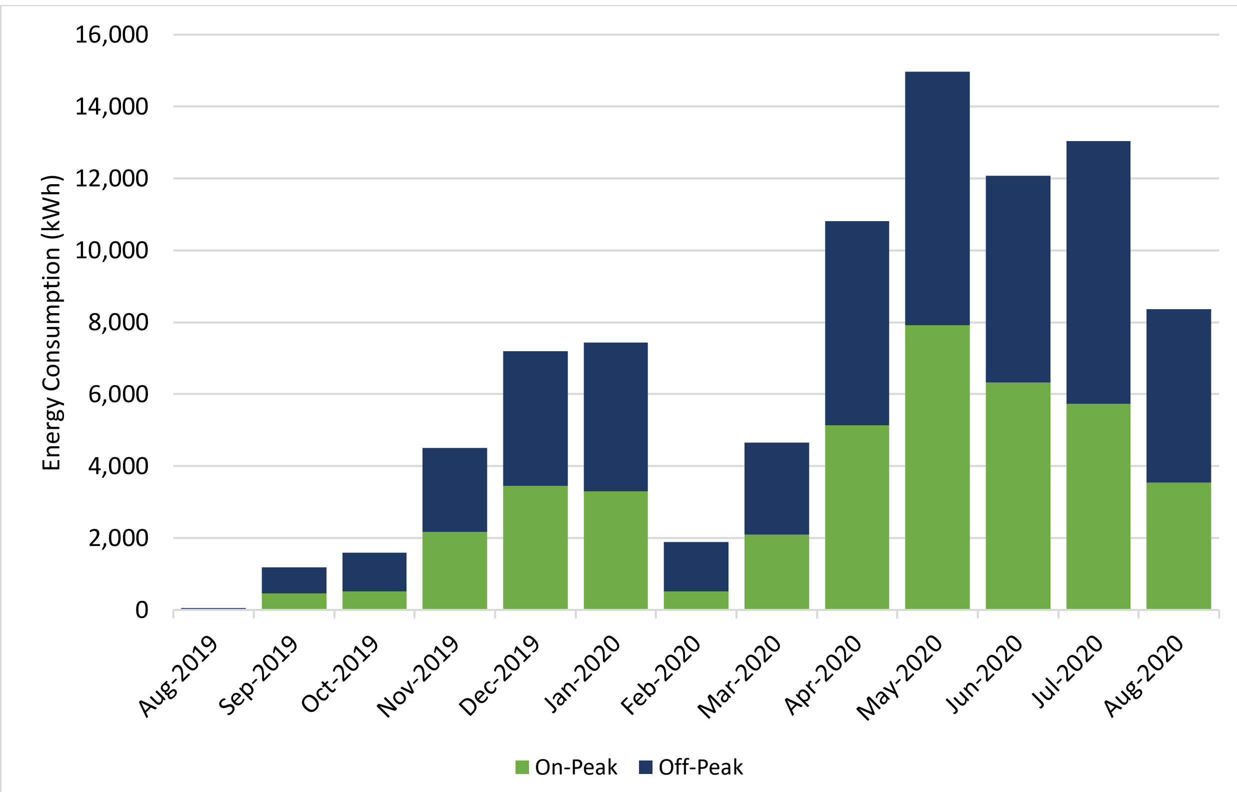
Stochastic route projects are attributed benefits based on an established centroid of activity, with determined radii of activity by % activity. In some of these projects, available data are station locations and operator home zip codes, while others we may be able to geofence a service territory along with an approximate attribution of effort within those zones. In this case, the DAC attribution is made by determining a DAC attribution as a percentage of the zone and weighting overall benefits to the DAC by the percentage of the zone multiplied by the % activity within that zone. The sum of the activities within all zones must equal 100%.

3. SDG&E Electric Fleet Delivery Calculations

The summary results of the fleet delivery program compare the actual use of installed electric charging infrastructure and operation of 15 EVs at one site to a baseline fleet. The baseline fuel used was gasoline from commercial fueling stations. Based on EV OEM provided telematics data used for meeting the CARB HVIP reporting requirements, 35% of the miles driven by the EVs were within economically disadvantaged communities (DACs) based on CalEnviroScreen 3.0 using the statewide determination.

This analysis used utility meter 15-minute interval data, charging session summaries, vehicle onboard telematics trip summaries, and fleet operator interviews. Utility meter data for the PRP charging infrastructure was available from July 29, 2019, through August 30, 2020. Figure A-3 shows the variable energy usage during this period as vehicle deployment and commissioning occurred. During this period, the telematics reported electric efficiency was 0.84 kWh per mile.

Figure A-3. Fleet Delivery electric energy use by month



Source: SDG&E Meter Data

There was a gradual increase in electrical consumption as vehicles were delivered and commissioned between September and November of 2019. Therefore, the evaluated period of performance is from November 2019 through August 2020. There is high on-peak charging (weekdays between 4:00 PM and 9:00 PM) in all months.

Annualized Emissions and Fuel Use

Emission factors presented in Table A-2 were determined on a per-mmBtu basis from the California GREET 3.0 model.[132] These well-to-wheels gasoline emission factors assume a *US Average Mix* for fuel production of gasoline in 2020 and use the *Light Duty Truck 2* methodology. GHG emissions include CO_2 combined with a weighted CO_{2e} value of 298 and 25 for N_2O and CH_4, respectively. An industry average baseline fuel economy of 13 mpg for delivery vehicles was used.

Table A-2. Gasoline baseline emissions factors determined by California GREET 3.0

GHG (g/mmBtu)	SO_X (g/mmBtu)	NO_X (g/mmBtu)	CO (g/mmBtu)	PM_{10} (g/mmBtu)	VOC (g/mmBtu)
99,590	23.583	104.98	1,114.2	7.8976	68.414

Source: CARB, California GREET 3.0

Extrapolating the electricity consumption from November 2019 to August 2020 to an annual basis yields 102,339 kWh per year, with 48,387 kWh (47%) occurring during on-peak hours between 4:00 PM and 9 PM. Based on the EV efficiency of 0.84 kWh per mile, the electricity consumption would result in 121,832 annual miles. Using the estimated average baseline fuel economy, the total annual mileage would have required 9,372 gallons of gasoline per year, which was saved. Annual emissions and emission reductions are presented in Table A-3. If renewable electricity is used to fuel electric delivery trucks there would be no electric emissions, resulting in 100% reduction of GHG and criteria pollutant emissions. Amazon is on a path to powering their operations with 100% renewable energy by 2025 as part of their goal to reach net zero carbon by 2040. In 2019, Amazon reached 42% renewable energy across their business.[133]

Table A-3. Fleet Delivery operation annual emissions

	GHG (MT/yr)	SO_X (kg/yr)	NO_X (kg/yr)	CO (kg/yr)	PM (kg/yr)	VOC (kg/yr)
Gasoline	106	25	112	1,191	8	28
Electric	36	8	25	21	4	4
Net Reduction	**71**	**18**	**87**	**1,171**	**4**	**24**
% Reduction	**67%**	**70%**	**78%**	**98%**	**49%**	**85%**

Source: Evaluator Calculations

[132] Argonne National Laboratory. (2019, January 4). *CA-GREET3.0 Model and Tier 1 Simplified Carbon Intensity Calculators*. (California Air Resources Board) Retrieved November 15, 2020, from https://www.arb.ca.gov/fuels/lcfs/ca-greet/ca-greet30-corrected.xlsm?_ga=2.33513724.376401253.1608679427-2142270589.1595360336

[133] Environment, Sustainable Operations, Renewable Energy. (Amazon) Retrieved November 30, 2020, from https://sustainability.aboutamazon.com/environment/sustainable-operations/renewable-energy?energyType=true

Best Observed Scenario

The above benefits are based on operations for the established pilot period, which likely includes variations due to this technology's initial adoption in the fleet or other factors (i.e., 2 months of very limited use in March and April). The best observed scenario takes a high utilization period within the pilot and extrapolates that over an entire year to evaluate the projected annualized emissions. The best observed operations for the fleet delivery program were in May 2020, when the highest monthly mileage was observed. The fleet would accumulate 216,712 annual miles if this rate were applied across the whole year (14,500 miles per vehicle per year). Under this scenario, the fleet would consume 182,038 kWh annually, with 92,243 kWh (53%) on-peak. Table A-4 shows the annual benefits if this level of utilization were experienced across an entire year, which would save 16,670 gallons of gasoline per year.

Table A-4. Fleet Delivery best observed operation annual emissions

	GHG (MT/yr)	SO_X (kg/yr)	NO_X (kg/yr)	CO (kg/yr)	PM (kg/yr)	VOC (kg/yr)
Gasoline	189	45	200	2,119	15	49
Electric	65	14	44	37	8	7
Net Reduction	**124**	**31**	**155**	**2,083**	**7**	**42**
% Reduction	**66%**	**70%**	**78%**	**98%**	**49%**	**85%**

Source: Evaluator Calculations

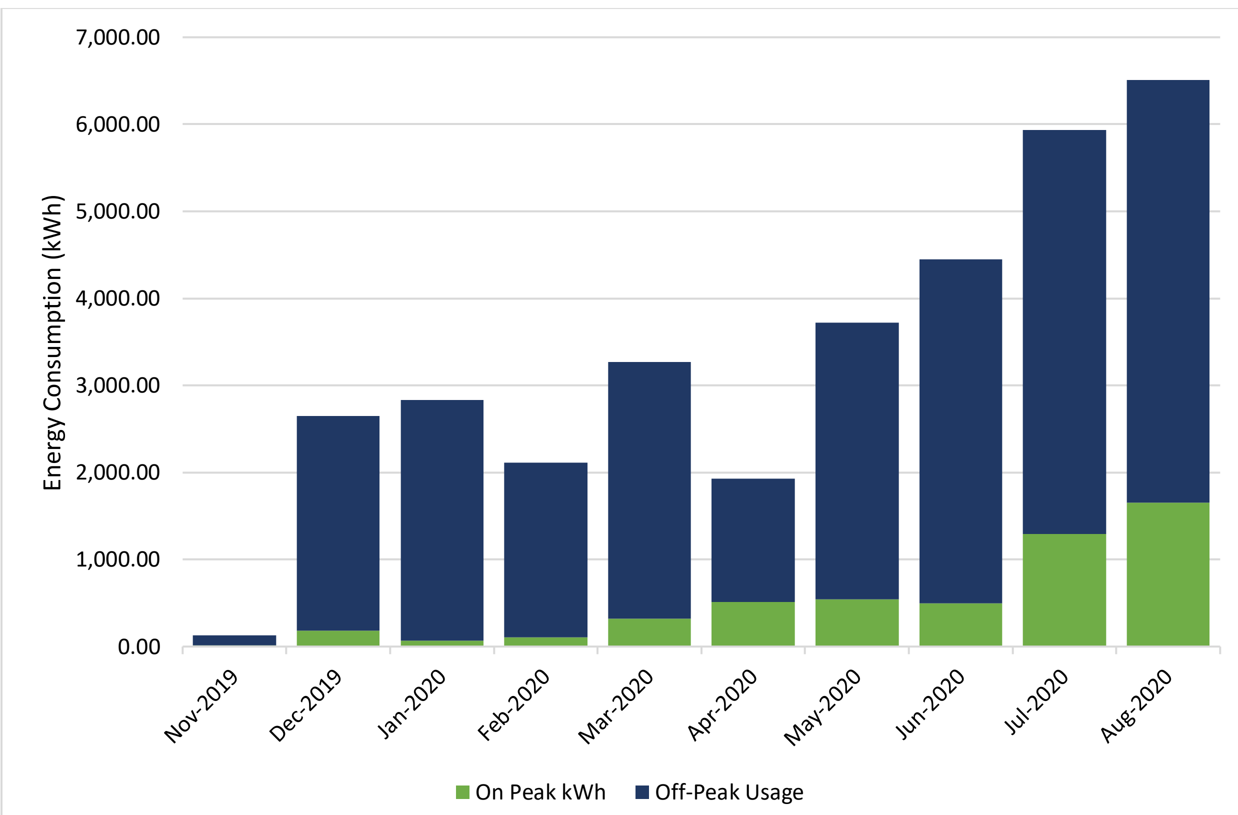
4. SDG&E Green Shuttles Calculations

The Green Shuttle Electrification PRP contains several fleet pilots; however, only San Diego Airport Parking Company (SDAP) was in full operation at the end of 2020. SDAP service is a fixed-route operation that is not within a DAC, according to CalEnviroScreen 3.0 using the statewide or SDG&E territory determination. Therefore, none of the economic and emission benefits are attributed to DACs.

Fifteen-minute utility demand data are available for the DCFC stations installed through this pilot, but the electric shuttle buses also had access to existing L2 charging. Two new shuttle buses were acquired from GreenPower to use the DCFC stations, while a bus conversion from Maxwell Vehicles was able to utilize only the L2 charging during the data collection period. To the extent possible, the three data streams (utility meters, vehicle operational information, and EVSE charging sessions) are compiled to present an accurate picture of each project and the net benefits. In this pilot, fifteen-minute interval utility meter data was available from November 13, 2019, to August 30, 2020, as was one-hour data from the itemized billing statements, providing 42 weeks of data for evaluation.

To determine the impacts of this PRP, estimates for both the electric use per mile and fuel use per mile for an equivalent internal combustion engine shuttle were determined. For the electric shuttle buses, both driver logs, and electric charging session data were available.

Figure A-4. SDAP Green Shuttle monthly DCFC energy consumption



Source: SDG&E Meter Data

Electric energy consumption was calculated from a summation of energy use during fifteen-minute utility meter periods (see Figure A-4). The pilot demonstration period from December 2019 to August 2020 is used to calculate performance. Once the chargers were activated on November 27, 2019, the first shuttle showed consistent consumption until May, at which point the second shuttle noticeably increased demand through August 2020 when this data collection period ended.

Baseline shuttle buses used renewable diesel. Fuel logs from baseline shuttle bus operations included fuel amounts and odometer readings. However, an analysis of the logs shows inconsistencies that indicate some fueling events were likely missing, because some periods showed unrealistically high fuel economy ranging up to 166 MPG. Observing known fueling periods and eliminating outliers provides an average fuel economy of 18.4 MPG across the three baseline vehicles for which 2019 data was available.

Annualized Emissions and Fuel Use

Calculated on an annual basis, the operations from December 2019 to August 2020 represent 44,535 kWh of DCFC energy used, with 6,900 kWh (16%) occurring during the on-peak hours between 4:00 PM and 9:00 PM. Mileage equates to 27,835 miles per year per vehicle (55,669 miles total), based on the electricity usage and EV's fuel economy. Based on the estimated baseline fuel economy, this operation would have required 3,025 gallons of renewable diesel fuel annually. A factor of 1.155 GGE per gallon of renewable diesel[134] is used to convert the renewable diesel usage to a gasoline gallon equivalent (GGE), providing a baseline of 3,494 GGE of renewable diesel annually—the amount saved by switching to an EV.

Propel Fuels provides this fleet's renewable diesel, and specific emissions for this fuel are unavailable. Emission factors for vehicles using renewable diesel were determined on a million Btu basis from the California GREET 3.0 model[129] for pyrolysis-based renewable diesel fuel emissions in 2020, using a *US mix* and *Light Duty trucks 2* simulation as a reasonable approximation. The resulting factors are presented in Table A-5.

Table A-5. Renewable diesel baseline emissions factors, as determined using California GREET 3.0

CO_2 (g/mmBtu)	SO_X (g/mmBtu)	NO_X (g/mmBtu)	CO (g/mmBtu)	PM_{10} (g/mmBtu)	VOC (g/mmBtu)
31,069	87.09	311.22	95.50	20.31	25.77

Source: California GREET 3.0

Annual emissions and emission reductions were calculated using the determined annual energy consumption and baseline fuel use, combined with the energy factor of 128,488 Btu per diesel gallon equivalent of renewable diesel. The results are presented in Table A-6.

[134] U.S. Department of Energy, "Fuel Conversion Factors to Gasoline Gallon Equivalents," accessed October 21, 2020, https://epact.energy.gov/fuel-conversion-factors.

Table A-6. Green Shuttle PRP operation annual emissions

	GHG (kg/yr)	SO_X (kg/yr)	NO_X (kg/yr)	CO (kg/yr)	PM (kg/yr)	VOC (kg/yr)
Renewable Diesel	12,078	34	121	37	8	10
Electric	12,809	3	11	9	2	2
Net Reduction	**-731**	**31**	**110**	**28**	**6**	**8**
% Reduction	**-6%**	**90%**	**91%**	**76%**	**76%**	**82%**

Source: Evaluator Calculations

Best Observed Scenario

The above benefits are based on operations for the established pilot period, which likely includes variations due to the initial adoption of this technology in the fleet or other factors. The best observed scenario takes a high utilization period within the pilot and extrapolates that over an entire year to evaluate the projected annualized emissions. July 2020 had the highest monthly mileage; using July data for calculations results in 96,380 total miles, or 48,190 annual miles per vehicle. Two diesel-powered shuttle buses driving this many miles would have consumed 5,238 gallons of renewable diesel (6,050 GGE) per year; two EVs driving the same total distance would require 77,104 kWh per year. The calculated benefits of using EVs are shown in Table A-7. If another two electric shuttle buses share the DCFC stations (both SDAP and Aladdin believe so based on this pilot), these benefits could double for the existing infrastructure investment.

Table A-7. Best observed Green Shuttle PRP operation annual emissions (July 2020)

	GHG (kg/yr)	SO_X (kg/yr)	NO_X (kg/yr)	CO (kg/yr)	PM (kg/yr)	VOC (kg/yr)
Renewable Diesel	20,910	59	209	64	14	17
Electric	23,891	6	19	16	3	3
Net Reduction	**-2,981**	**53**	**191**	**49**	**10**	**14**
% Reduction	**-14%**	**90%**	**91%**	**76%**	**76%**	**82%**

Source: Evaluator Calculations

The carbon intensity of renewable diesel according to California GREET 3.0 alters the calculations to show a slight increase in CO_2 emissions based on July 2020 operations. Operations in January 2020 had lower mileage per vehicle, which would equate to only 23,015 miles per year per vehicle (46,030 total), but the on-peak electrical use was much lower, which results in a favorable CO_2 emissions reduction. Using January as the best observed case for carbon reduction still yields an annual petroleum reduction of 2,889 GGE, or 2,502 gallons of renewable diesel.

Table A-8. Alternative best observed Green Shuttle PRP operation annual emissions (January 2020)

	GHG (kg/yr)	SO_X (kg/yr)	NO_X (kg/yr)	CO (kg/yr)	PM (kg/yr)	VOC (kg/yr)
Renewable Diesel	9,987	28	100	31	7	8
Electric	9,091	3	9	7	2	2
Net Reduction	**896**	**25**	**91**	**23**	**5**	**7**
% Reduction	**9%**	**90%**	**91%**	**76%**	**76%**	**82%**

Source: Evaluator Calculations

To allow for comparison of emissions benefits against a conventional low-sulfur diesel fuel, Table A-9 presents the emissions and reductions that would be expected for the highest mileage month (July 2020). These numbers would be applicable to shuttle bus fleets who operate on conventional diesel fuel and would be considering a switch to electric vehicles.

Table A-9. Best observed Green Shuttle PRP operation annual emissions (July 2020) vs. diesel

	GHG (kg/yr)	SO_X (kg/yr)	NO_X (kg/yr)	CO (kg/yr)	PM (kg/yr)	VOC (kg/yr)
Diesel	67,789	10	138	57	5	18
Electric	23,891	6	19	16	3	3
Net Reduction	**43,898**	**5**	**119**	**42**	**2**	**15**
% Reduction	**65%**	**44%**	**86%**	**73%**	**41%**	**82%**

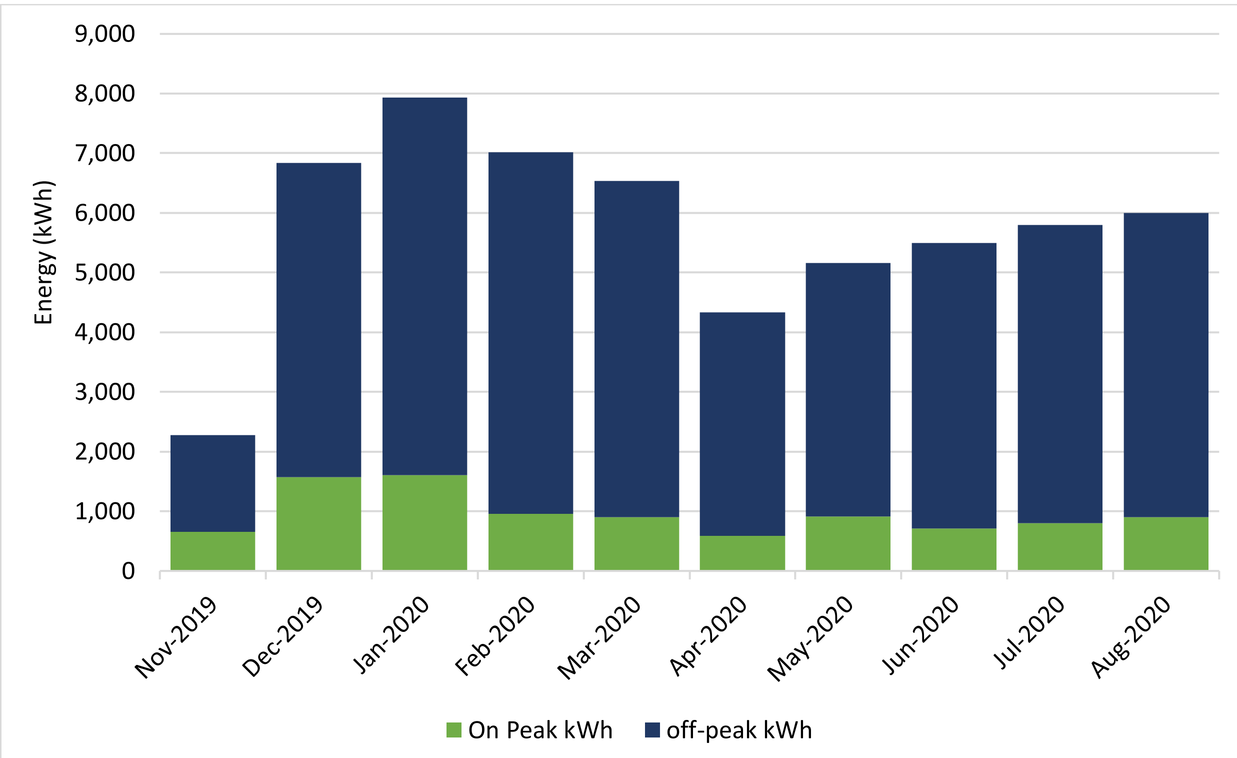
Source: Evaluator Calculations

5. SDG&E Airport Ground Support Equipment Calculations

In Phase 1, the Airport GSE PRP installed 8 chargers with 16 total ports with smart charging infrastructure from Webasto. Existing electric GSE was upfitted with battery management hardware to interface with updated vehicle chargers. Neither the airport not the surrounding area is within a disadvantaged community (DAC), according to CalEnviroScreen 3.0 using the statewide or SDG&E territory determination. Therefore, none of the economic and emission benefits should be attributed to DACs.

This analysis used 15-minute electrical use data from the utility meter from November 2019 to August 2020. The results are shown in Figure A-5.

Figure A-5. Metered electric use for SDG&E GSE



Source: SDG&E Meter Data

Data from the charging stations were also available for the same period. The chargers provide limited vehicle information from charging sessions, such as a vehicle identification, energy consumption, and charging duration and time stamps. Data from charging sessions indicate that, between November 2019 and August 2020, 31 vehicles used the stations; 19 of those vehicles were baggage tugs, and 12 were belt loaders. From November 2019 to August 2020, baggage tugs accounted for 71% of the electric energy consumed, and belt loaders used 29%. The analysis used this same ratio to establish baseline emissions factors, integrating U.S. Environmental Protection Agency (EPA) emission factors[135] for gasoline GSE and California GREET[129] ratios, as shown in Table A-10.

Table A-10. GSE mix baseline emission factors

	GHG (g/hr)	SO_X* (g/hr)	NO_X (g/hr)	CO (g/hr)	PM_{10} (g/hr)	VOC* (g/hr)
Baggage Tug	43,583	14.3	226.6	18,678	2.2	35.2
Belt Loader	23,773	7.8	123.6	10,188	1.2	19.2
Blended Rate	37,798	12.4	196.5	16,199	1.9	30.5
*** SO_X and VOC are inferred based on California GREET ratios and EPA factors for NO_x and PM, respectively.**						

Source: EPA and California GREET

Annualized emissions and fuel use

The period of performance used to calculate PRP benefits is from December 2019 to August 2020. The annualized electric use was 73,693 kWh per year, with 12,164 kWh per year (16.5%) occurring during the on-peak hours between 4 PM and 9 PM. Using a baggage tugs' average energy use of 7.5 kWh for an hour, the annual energy consumed equates to 9,826 hours of operations. Conventional gasoline baggage tugs consuming 1.5 gallons per hour results in petroleum consumption of 14,739 gallons of gasoline per year, which this PRP saves through electrification. Annual emissions and emission reductions, based on the determined hours and energy consumption, are presented in Table A-11.

Table A-11. GSE annualized emissions

	GHG (MT/yr)	SO_X (kg/yr)	NO_X (kg/yr)	CO (kg/yr)	PM (kg/yr)	VOC (kg/yr)
Gasoline	371	122	1,931	159,156	19	300
Electric	13	6	18	15	3	3
Net Reduction	**358**	**116**	**1,913**	**159,151**	**16**	**297**
% Reduction	**97%**	**95%**	**99%**	**100%**	**83%**	**99%**

Source: Evaluator Calculations

Best Observed Scenario

The best observed scenario takes a high utilization period within the pilot and extrapolates that over an entire year to evaluate the projected annualized emissions. The best observed period was in January 2020, shortly before the COVID-19 pandemic shuttered a majority of airline traffic. That monthly use yields a rate of 95,951 kWh per year, with 18,518 kWh (19.2%) of the electricity consumed on-peak.

[135] U.S. Environmental Protection Agency, Office of Mobile Sources, "Technical Support for Development of Airport Ground Support Equipment Emission Reductions," Washington, DC, 1999.

Table A-12 shows the annual benefits if this level of utilization were experienced across an entire year (12,879 hours of eGSE use), which would save 19,318 gallons of gasoline per year.

Table A-12. Best observed operation annual emissions

	GHG (MT/yr)	SO_X (kg/yr)	NO_X (kg/yr)	CO (kg/yr)	PM (kg/yr)	VOC (kg/yr)
Gasoline	487	160	2,531	208,624	24	393
Electric	17	7	24	20	4	4
Net Reduction	**470**	**152**	**2,507**	**208,605**	**20**	**389**
% Reduction	**97%**	**95%**	**99%**	**100%**	**83%**	**99%**

Source: Evaluator Calculations

6. SDG&E Port Electrification Calculations

6.1 Metro Cruise

The Port Electrification PRP contains two distinct sites, Metro Cruise operates forklifts in limited weekly duty cycles for the Cruise Ship Terminal entirely within the Port property.

Fifteen-minute utility demand data is available for this site, but data from vehicles and charging stations is limited. To the extent possible, the three data streams (utility meters, vehicle operational information, and charging station sessions) are compiled to present an accurate picture of each project and the net benefits. When one of these data sets is unavailable, assumptions must be made about the operations. In cases where two of these data sets are unavailable, the net benefits calculation requires significant assumptions.

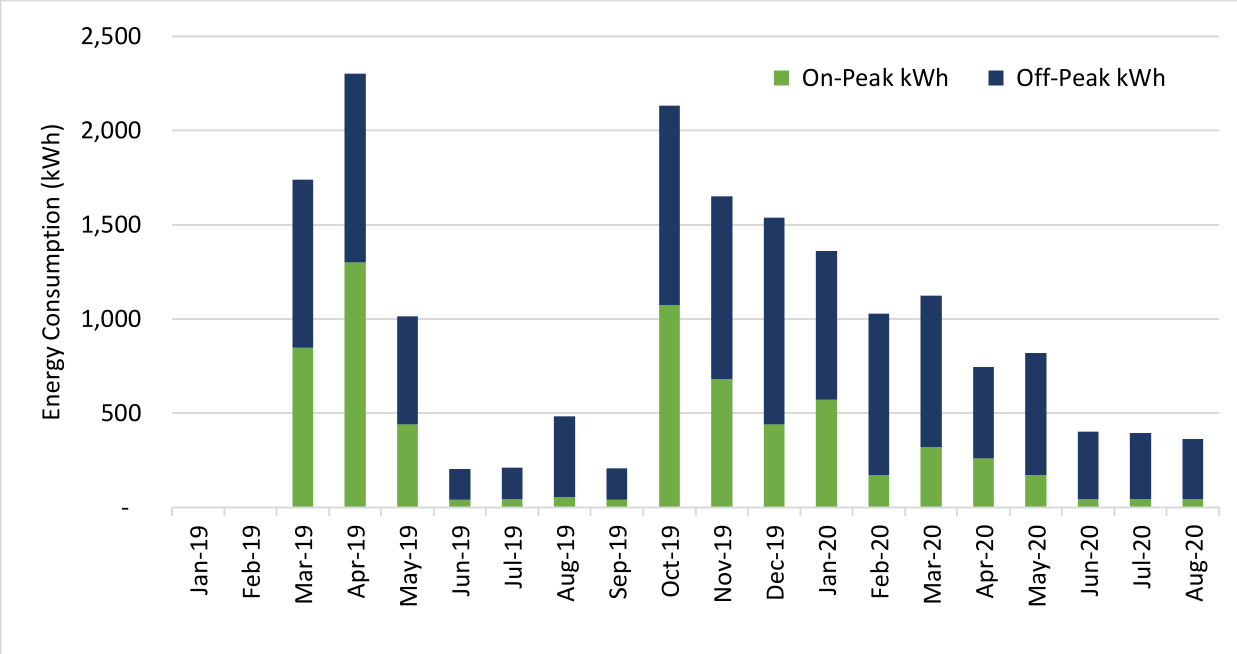
The Cruise Ship Terminal at the San Diego Port is not in a statewide defined DAC according to CalEnviroScreen 3.0 but is in an SDG&E DAC (applying the same statewide DAC definition to only SDG&E territory).

Cruise Ship Terminal Operations

In the forklift pilot, utility data was made available in fifteen-minute intervals from January 16, 2019 to August 30, 2020, providing 85 weeks of data to evaluate. In addition to the utility meter data, the forklift chargers provided session data from March 4, 2019 until August 7, 2020, resulting in 74 weeks of overlapping data with the meter data. Each vehicle was fitted with a battery management identification unit that communicates with the charging station, which provided data about individual forklift usage. Unfortunately, individual forklift hour meter data were unavailable, therefore hours of use per day and energy consumption are assumed based on observation of other available data and several key assumptions.

Total energy use was determined from a summation of kWh during fifteen-minute periods provided from the utility meter. Monthly utility meter data summaries are shown in Figure A-6. March to May of 2019 shows significantly higher usage than March to May of 2020. This is due to the impact of the COVID-19 pandemic on the cruise ship industry from March 2020 onward. As a result, pilot performance will focus on the period between March 2019 and February 2020 as a more typical one-year period of performance. During this period, there were 13,877 kWh of energy used, with 5,714 of those kWh occurring during the on-peak hours between 4 and 9 PM.

Figure A-6. Metered electric use for Cruise Ship Terminal



Source: SDG&E Meter Data

To determine working days, we assumed forklifts would be plugged in on or right after days when they were used. The charger data show nine forklifts being used during the 74-week period, although utilization ranges from 109 days of use for most used forklift to only 22 days for the least used one. As forklift operational data was not available, an assumption of eight hours of operation per working day per forklift was used. Some forklifts underwent multiple charging sessions per working day. Workdays typically occurred on Fridays and Saturdays with Thursday and Sunday seeing slightly lower usage. Using 8-hours of operation per workday, a summary of use for each forklift is shown in Table A-13.

Table A-13. Forklift operational summary

Forklift	Capacity (kWh)	Earliest Session	Latest Session	Working Days	Total Use (hours)	Total Sessions	Total Energy (kWh)	Daily Use (kWh/day)	Efficiency (kWh/hr)
No. 9	32	12/5/2019	7/21/2020	22	176	71	566	25.7	3.2
No. 4	32	3/5/2019	7/21/2020	65	520	110	1983	30.5	3.8
No. 3	16	3/4/2019	7/22/2020	86	688	241	1797	20.9	2.6
No. 5	16	3/5/2019	8/7/2020	98	784	172	2050	20.9	2.6
No. 6	16	3/5/2019	8/7/2020	91	728	440	1907	21.0	2.6
No. 1	16	3/4/2019	7/22/2020	94	752	533	1835	19.5	2.4
No. 7	16	3/5/2019	7/22/2020	102	816	266	2205	21.6	2.7
No. 8	16	3/5/2019	8/7/2020	109	872	187	2451	22.5	2.8
No. 2	32	3/4/2019	7/21/2020	73	584	171	2168	29.7	3.7

Source: EVSP Charging Session Data

Based on the estimated hours of use, which varied from 872 hours for the highest utilized forklift down to 176 hours for the lowest, efficiencies (dividing the total use in hours by the total energy in kWh) ranged from 3.7 kWh per hour for larger forklifts to 2.2 kWh per hour for a smaller forklift while operating. These figures are within the typical range of use for forklifts in this size range.[136]

The operational hours are then used to determine baseline fuel consumption and emissions. In this pilot, the electric forklifts were already in the fleet for several years; therefore, no actual fuel and emissions benefits resulted. However, within the industry, most forklifts use propane for similar operations and that was used to calculate typical benefits that a project like this would result in. Standard industry propane fuel tanks on forklifts are eight gallons and can generally serve an 8-hour shift,[137] providing an average consumption of one gallon of propane per hour of operation.

Annualized Emissions and Fuel Use

The data in Table A-13 represents the entire monitoring period, but all annualized statistics will be using the data collection period from March 2019 to February 2020. Annual equivalent usage for this project is 13,877 kWh with 5,266 kWh (38%) consumed on-peak time period. Baseline fuel consumption for an equivalent forklift use was calculated to be 1,080 gallons of propane. Converting the propane usage to a gasoline gallon equivalent (GGE) by a factor of 0.758 GGE per gallon of propane[134] results in 819 GGE of propane for the baseline per year which is saved due to switching over to an EV.

Emission factors for forklifts were determined on an hourly basis from the CARB OFFROAD2017 (ORION) emissions inventory[130] and are presented in Table A-14.

Table A-14. Propane forklift baseline emissions factors determined by CARB ORION 2017

GHG (g/hr)	SO_x (g/hr)	NO_x (g/hr)	CO (g/hr)	PM (g/hr)	VOC (g/hr)
6,720	Negligible	23.37	86.96	0.60	Negligible

Source: CARB ORION 2017

Using the actual annual kWh and calculated baseline fuel use, annual emissions and emission reductions presented in Table A-15 were calculated.

[136] S. Munton, "Electric Forklifts vs LP Forklifts," Warehouse IQ, January 2, 2011, https://www.warehouseiq.com/electric-forklifts-vs-lp-forklifts-reduce-operating-costs/.

[137] Toyota Material Handling of Northern California, "How Long Can a forklift run on one tank of propane?," 2020, https://www.tmhnc.com/blog/how-long-can-a-forklift-run-on-one-tank-of-propane-lpg.

Table A-15. Forklift operation annual emissions

	GHG (kg/yr)	SO_x (kg/yr)	NO_x (kg/yr)	CO (kg/yr)	PM (kg/yr)	VOC (kg/yr)
Propane	7,258	-	25.24	93.91	0.65	-
Electric	3,065	1.04	3.38	2.80	0.58	0.57
Net Reduction	**4,193**	**-1.04**	**21.86**	**91.11**	**0.07**	**-0.57**
% Reduction	**58%**	**-**	**87%**	**97%**	**11%**	**-**

Source: Evaluator Calculations

Best Observed Scenario

The above benefits are based on operations for the established pilot period, which likely includes variations due to the initial adoption of new chargers in the fleet or other factors. The best observed scenario takes a high utilization period within the pilot and extrapolates that over an entire year to evaluate the projected annualized emissions. The best observed operation for this pilot was in October 2019 which was a particularly productive month for the Cruise Ship operation, with an estimated 168 hours of operation across all forklifts. This would require 27,726 kWh of electricity per year for 9 forklifts. The same hours of operation would require 2,184 gallons of propane or 1,655 GGE.

Table A-16. Best observed cruise ship operation annual emissions

	GHG (kg/yr)	SO_x (kg/yr)	NO_x (kg/yr)	CO (kg/yr)	PM (kg/yr)	VOC (kg/yr)
Propane	14,676	-	51.04	189.91	1.31	-
Electric	6,858	2.07	6.75	5.60	1.15	1.13
Net Reduction	**7,819**	**-2.07**	**44.29**	**184.31**	**0.16**	**-1.13**
% Reduction	**53%**	**-**	**87%**	**97%**	**12%**	**-**

Source: Evaluator Calculations

6.2 Pasha

The Port Electrification PRP contains two distinct sites, Pasha operates heavy-duty trucks moving freight both inside of the Port as well as taking freight from the Port property to remote sites both North and South of the Port.

Fifteen-minute utility demand data is available for the charging site; however, data from the vehicles is limited to periodic odometer readings and charging stations are not networked resulting in no charging session data from the chargers. To the extent possible, the utility meter data and vehicle odometer readings were compiled to portray the vehicle usage and calculate net benefits. Due to lack of charging session and vehicle operational data, the net benefits calculation required significant assumptions.

Pasha terminal operations within the San Diego Port along with their route back and forth to Otay Mesa where they transport cargo is in a statewide defined DAC according to CalEnviroScreen 3.0. Therefore, 100 percent of the economic and emission benefits are attributed to disadvantaged communities.

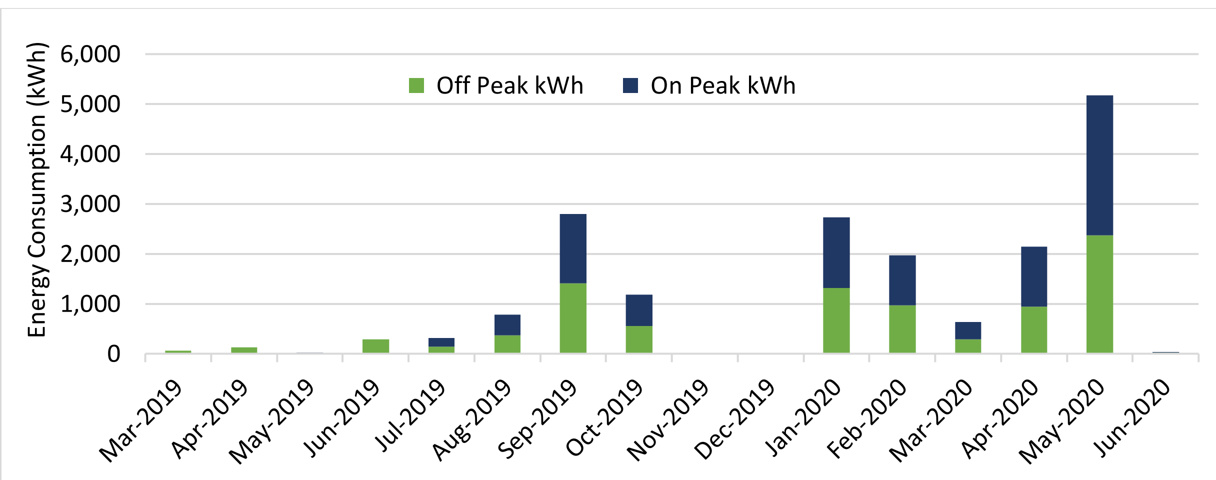
HD Freight Operations

In this pilot, utility data for the chargers was available in 15-minute intervals from February 16, 2019 to June 29, 2020, providing 70 weeks of data to evaluate. The only additional data were periodic odometer readings from electric trucks and onboard telematics data from a baseline diesel truck. There were three vehicles in this pilot, two Drayage trucks, ETRK-100 and ETRK-200 as well as one yard-tractor, BYT-P. The yard tractor was used in very limited capacity due to charging and battery issues and was soon determined to be unsuited for roll-on roll-off ship use. One of the two drayage trucks, ETRK-100 had a smaller battery pack that resulted in an unsuitable driving range of less than 80 miles per charge and was used in limited capacity until a larger battery drayage truck, ETRK-200 was put in service in September 2020. ETRK-200 was regularly used from October 8, 2019 to June 3, 2020.

ETRK-200 efficiency (kWh per mile) was calculated from monthly odometer readings and utility meter data. Baseline diesel truck fuel economy was calculated from on-board datalogger data that was collected for the same drayage shuttle route from the Port to Otay Mesa and back. Using a period of consistent use of the ETRK-200 between 2/7/2020 and 5/1/2020 and the total electricity consumed by the utility meter for the chargers, 2.87 kWh per mile was the resulting electric truck efficiency.

Once ETRK-200 entered service, it was exclusively used for transport of cargo between the Port and Pasha's storage facility in Otay Mesa. For the conventional diesel baseline truck (2014 Peterbilt Model 388), an occurrence of the representative duty-cycle for the ETRK-200 was found among the logged data for October 4, 2018. That included some movement around the port and two trips to Otay Mesa for a total daily distance of 119.8 miles. The baseline fuel economy was assumed to be 5.4 MPG based on existing literature for similarly loaded vehicles and given the observed low speed operations observed at both the port and depot ends of each trip.[138]

Figure A-7. HD freight port operation monthly energy consumption



Source: SDG&E Meter Data

[138] E. A. Coralie Cooper, "Reducing heavy-duty long-haul combination truck fuel consumption and CO_2 emissions," International Council on Clean Transportation, Washington, DC, 2009.

The overall electric energy consumption is a summation of energy use during fifteen-minute utility meter periods shown per month in Figure A-7. Energy consumption increased significantly in September 2019 with the arrival of the ETRK-200. The use tailed off due to vehicle issues and operations on longer routes beyond the electric truck range which led to no use in November and December 2019. Utilization became more consistent from January to April 2020 with a large spike of usage in May 2020 for a short-term hauling contract that was ideally suited for the ETRK-200 (short daily transports). Based on the observed usage, the period from September 2019 to May 2020 is used for the pilot's primary performance results.

Annualized Emissions and Fuel Use

Extrapolating the ETRK-200's performance during the pilot to an annual scale, the one vehicle uses 22,167 kWh per year of energy, with 11,693 kWh (53%) occurring during the on-peak hours between 4 and 9 PM. This equates to a baseline annual utilization of 7,724 miles based on the electric usage and observed electric truck fuel economy. This translates to 1,430 gallons of diesel fuel consumed annually based on the estimated baseline fuel economy. The diesel usage is converted to GGE by its respective conversion factor of 1.155 GGE per gallon of diesel.[134] This results in 1,652 GGE of diesel reduced. Diesel fuel emission factors for drayage trucks are presented in Table A-17 on a per million Btu basis from the California GREET 3.0 model.[129]

Table A-17. Diesel baseline emissions factors determined by California GREET 3.0

GHG (g/mmBtu)	SO_x (g/mmBtu)	NO_x (g/mmBtu)	CO (g/mmBtu)	PM_{10} (g/mmBtu)	VOC (g/mmBtu)
100,723	15.39	204.60	85.20	8.13	26.54

Source: California GREET 3.0

Annual emissions and emission reductions are presented in Table A-18 using the determined annual kWh and baseline fuel use combined with the energy factor of 128,488 Btu per gallon of diesel fuel.

Table A-18. HD freight port operation annual emissions

	GHG (kg/yr)	SO_x (kg/yr)	NO_x (kg/yr)	CO (kg/yr)	PM (kg/yr)	VOC (kg/yr)
Diesel	18,510	2.83	37.60	15.66	1.49	4.88
Electric	7,446	1.65	5.40	4.48	0.92	0.91
Net Reduction	**11,064**	**1.18**	**32.2**	**11.18**	**0.57**	**3.97**
% Reduction	**60%**	**42%**	**86%**	**71%**	**38%**	**81%**

Source: Evaluator Calculations

Best Observed Scenario

The above benefits are based on operations for the entire pilot period, which includes variations due to the initial adoption of this technology in the fleet or other factors. The best observed scenario takes a high utilization period within the pilot and extrapolates that over an entire year to evaluate the projected annualized emissions at its highest potential. The best observed operations for this pilot were in May of 2020 which would result in 18,731 annual miles, requiring 3,469 gallons of diesel for the baseline truck and 53,758 kWh for the electric truck. This annual performance results in the benefits shown in Table A-19.

Table A-19. Best observed HD freight port operation annual emissions

	GHG (kg/yr)	SO_x (kg/yr)	NO_x (kg/yr)	CO (kg/yr)	PM (kg/yr)	VOC (kg/yr)
Diesel	44,891	6.86	91.19	37.97	3.62	11.83
Electric	18,348	4.01	13.10	10.86	2.24	2.20
Net Reduction	**26,543**	**2.85**	**78.09**	**27.11**	**1.39**	**9.63**
% Reduction	**59%**	**42%**	**86%**	**71%**	**38%**	**81%**

Source: Evaluator Calculations

7. SDG&E Electrify Local Highways

DAC Impact

The Electrify Local Highways PRP includes four separate public charging station locations. Two of these, Chula Vista and National City are in a DAC according to CalEnviroScreen 3.0 using the SDG&E territory determination. EV drivers using these sites have unknown travel patterns before and after they charge at these locations; however, at least half of these trips are likely to or from their home. The charging session data provided the driver ZIP code and the top 15 of them are listed in Table A-20, which represent 47% of the total charging sessions recorded through the end of October 2020. Also listed in Table A-20 are the percentages of DAC households within the ZIP code. An estimation of the percentage of ZIP code area covered by DAC census tracts was used to compensate for the difference in geography used to collect the charging session (driver ZIP Code) and CalEnviroScreen 3.0 (census tract) data. Overlaying the two spatial datasets in GIS allowed for this to be done visually, as shown in the % DAC column in the table below. Weighting this DAC percentage by the portion of sessions within the top 15 driver ZIP codes, 46% of the top 15 driver ZIP codes were determined to be DACs based on SDG&E territory determination.

Table A-20. Top 20 driver ZIP codes using Electrify Local Highways sites

Driver Zip Code	Sessions	% Sessions	% DAC	% DAC * Portion of top 20
91911	204	12%	80%	20%
92054	129	8%	40%	6%
91906	72	4%	100%	9%
91901	55	3%	0%	0%
92008	55	3%	5%	0%
92056	53	3%	15%	1%
92154	45	3%	90%	5%
92139	41	2%	30%	1%
92083	30	2%	5%	0%
91950	27	2%	95%	3%
91913	25	1%	0%	0%
92019	25	1%	0%	0%
92116	25	1%	10%	0%
92065	21	1%	0%	0%
92115	21	1%	15%	0%
Totals	**828**	**47%**		**46%**

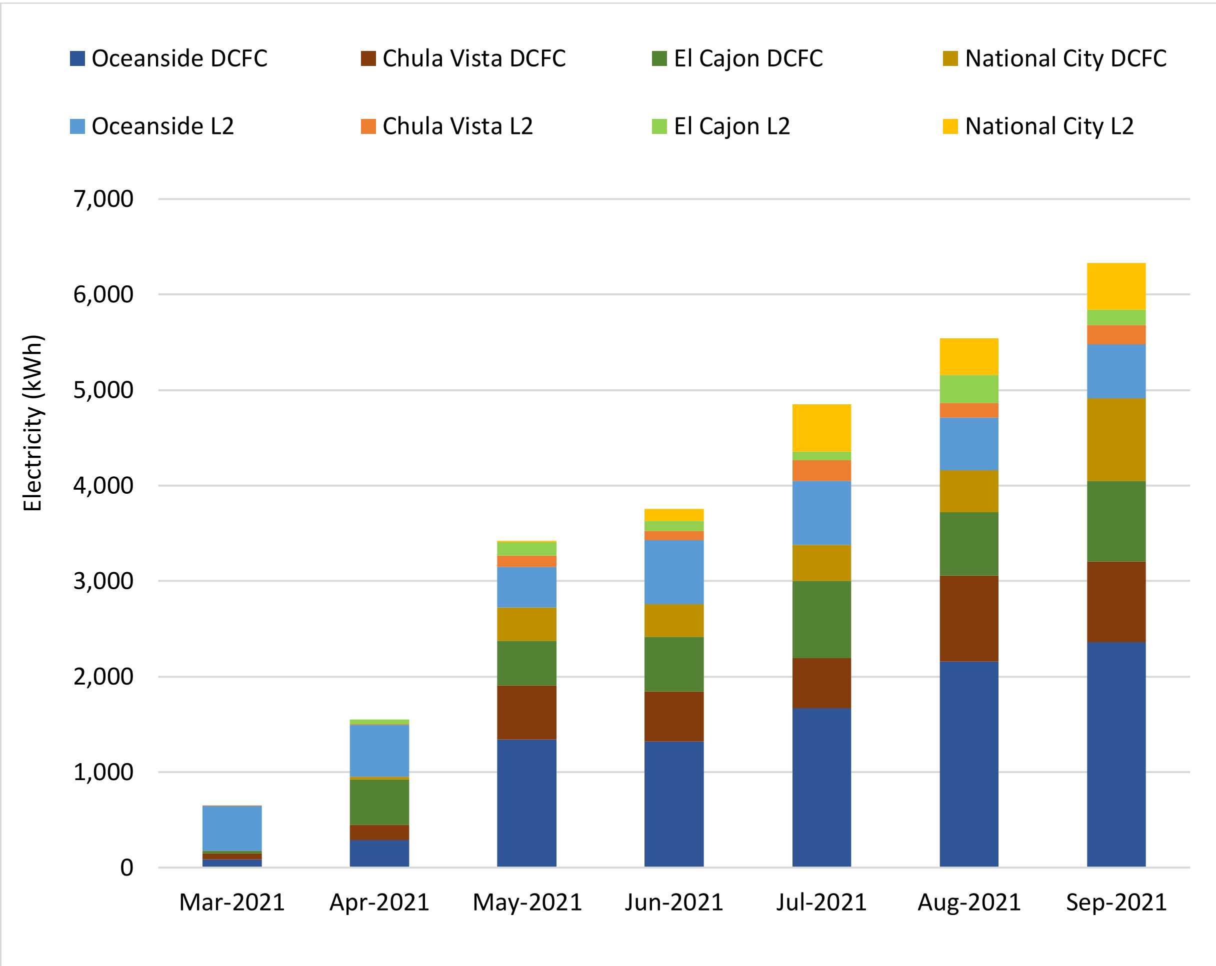
Source: California Energy Commission

Given that half of the charging station locations are in a DAC and half of the drivers using these stations live or regularly travel in a DAC near their home, 50% of the emission benefits can be attributed to disadvantaged communities. The other two charging station locations are adjacent to a DAC and EV drivers living in or near a DAC also regularly drive in areas adjacent to a DAC, so an additional 25% of this PRPs benefits are estimated to occur adjacent to a DAC.

Annualized Emissions and Fuel Use

Fifteen-minute utility interval data is available for the two separate meters at each site (one for all L2 EVSE and the other for the two DCFC stations).

Figure A-8. Electrify Local Highways monthly energy dispensed by site and charger type



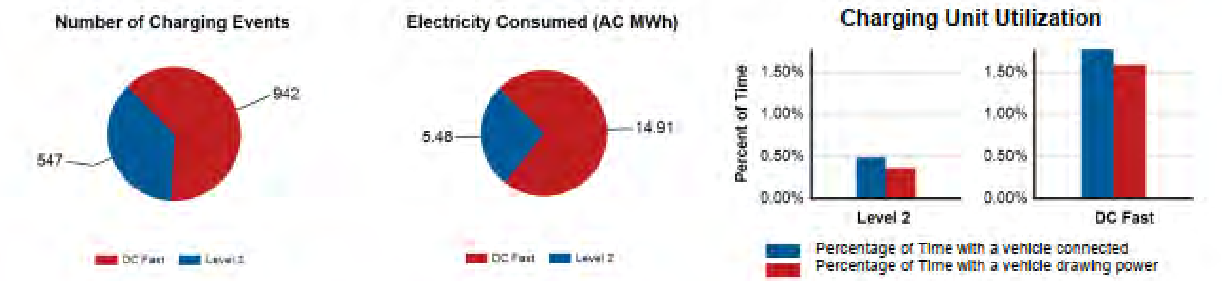
Source: SDG&E Meter Data

Electric energy consumption was determined from a summation of energy use during fifteen-minute utility meter intervals as shown in Figure A-8. The chargers were activated in March 2020 for initial testing and opened to the public in April. However, consistent use of the chargers did not occur until May. Therefore, the pilot demonstration period from May 2020 to September 2020 is used to calculate performance. Figure A-9 through Figure A-18 provide usage profiles and port statistics for all Electrify Local Highway sites combined and by individual location.

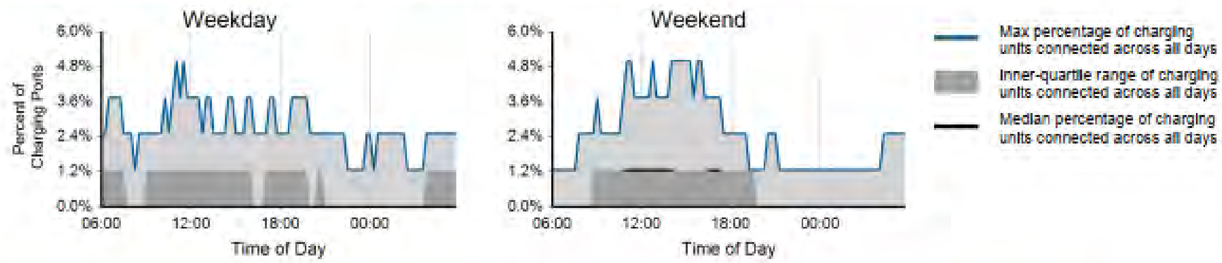
Figure A-9. Electrify Local Highways – all sites usage profile

Report period: May through September 2020

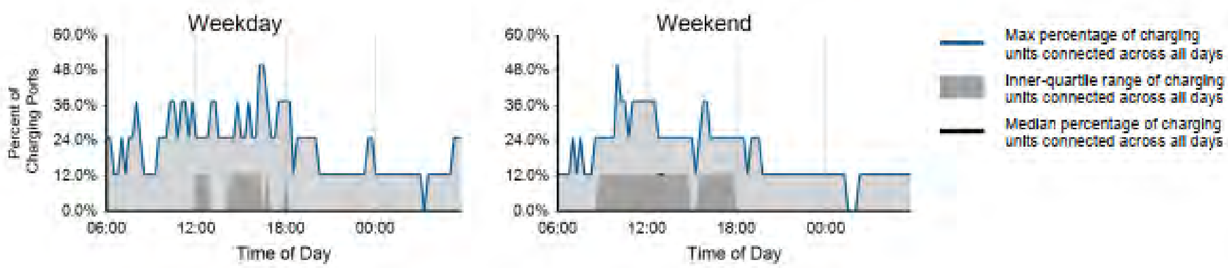
EVSE Usage	Level 2	DC Fast	Total
Number of charging ports[1]	80	8	88
Number of charging events[2]	547	942	1,489
Electricity consumed (AC MWh)	5.48	14.91	20.39
Percent of time with a vehicle connected	0.48%	1.77%	0.60%
Percent of time with a vehicle drawing power	0.36%	1.58%	0.47%



Charging Availability: Range of Percentage of **Level 2** Ports with a Vehicle Connected versus Time of Day[3]



Charging Availability: Range of Percentage of **DC Fast** Ports with a Vehicle Connected versus Time of Day[3]



[1] Includes all EVSE ports available during the reporting period and have reported data to INL.

[2] A charging event is defined as the period when a vehicle is connected to a charging unit, during which power is transferred.

[3] Weekends start at 6:00am on Saturday and end 6:00am Monday local time.

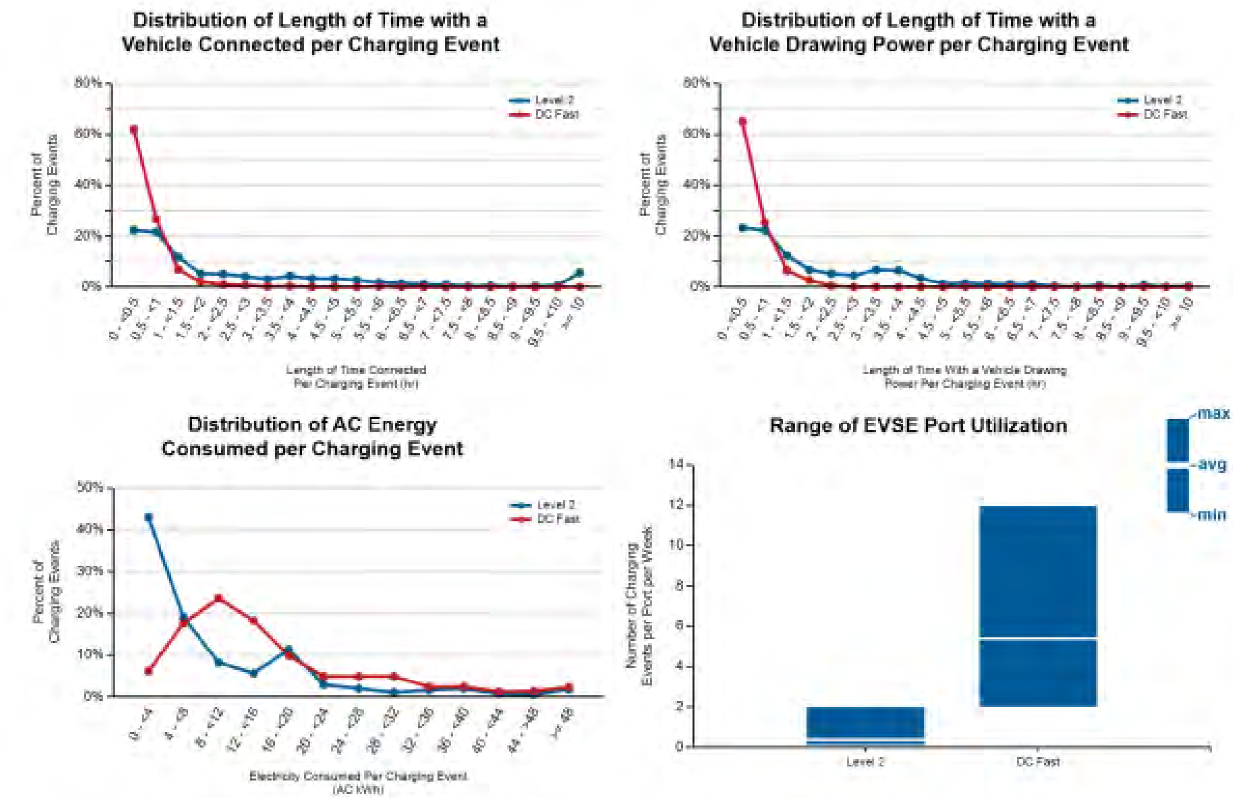
Source: EVSP Charging Session Data

Figure A-10. Electrify Local Highways – all sites port statistics

Report period: May through September 2020

EVSE Usage - By EVSE Level

	Level 2	DC Fast
Number of charging ports[1]	80	8
Number of charging events[2]	547	942
Charging energy consumed (AC MWh)	5.5	14.9
Average percent of time with a vehicle connected per charging port	0.48%	1.77%
Average percent of time with a vehicle drawing power per charging port	0.36%	1.58%
Average number of charging events started per charging port per week	0.31	5.39
Average electricity consumed per charging port per week (AC KWh)	3.13	85.29
Average length of time with vehicle connected per charging event (hr)	2.56	0.55
Average length of time with vehicle drawing power per charging event (hr)	1.91	0.49
Average electricity consumed per charging event (AC kWh)	10.01	15.83



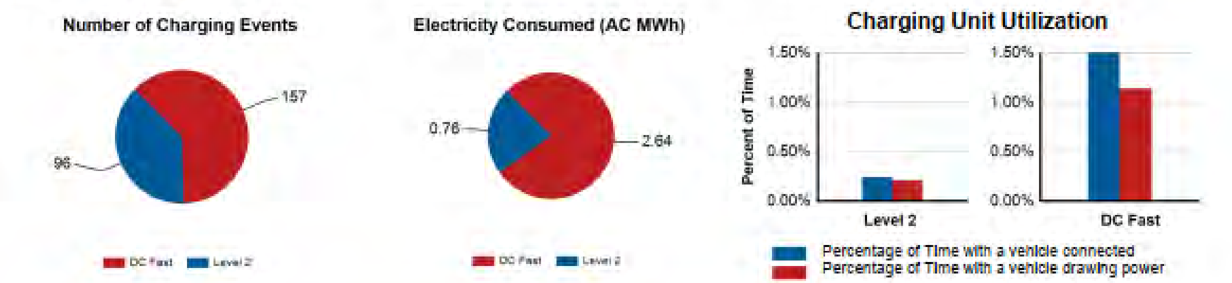
[1] Includes all EVSE ports available during the reporting period and have reported data to INL.
[2] A charging event is defined as the period when a vehicle is connected to a charging unit, during which power is transferred.

Source: EVSP Charging Session Data

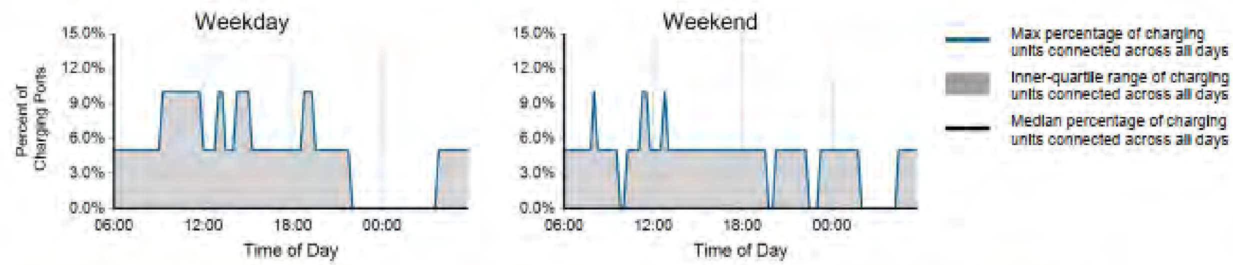
Figure A-11. Electrify Local Highways – Chula Vista usage profile

Report period: May through September 2020

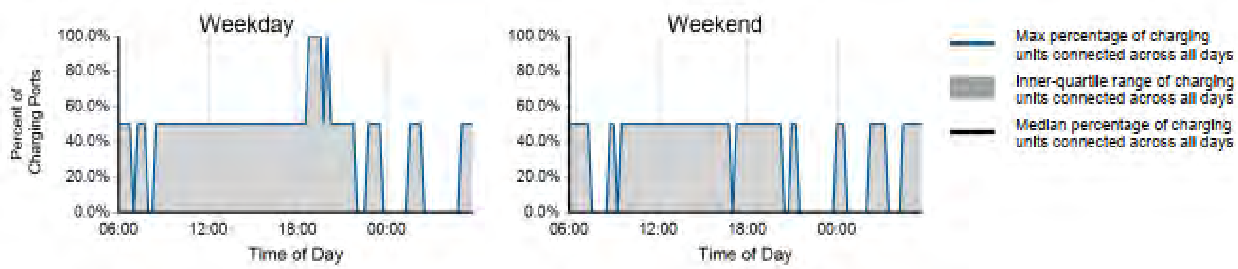
EVSE Usage	Level 2	DC Fast	Total
Number of charging ports[1]	20	2	22
Number of charging events[2]	96	157	253
Electricity consumed (AC MWh)	0.76	2.64	3.40
Percent of time with a vehicle connected	0.24%	1.51%	0.36%
Percent of time with a vehicle drawing power	0.21%	1.14%	0.29%



Charging Availability: Range of Percentage of **Level 2** Ports with a Vehicle Connected versus Time of Day[3]



Charging Availability: Range of Percentage of **DC Fast** Ports with a Vehicle Connected versus Time of Day[3]



[1] Includes all EVSE ports available during the reporting period and have reported data to INL.

[2] A charging event is defined as the period when a vehicle is connected to a charging unit, during which power is transferred.

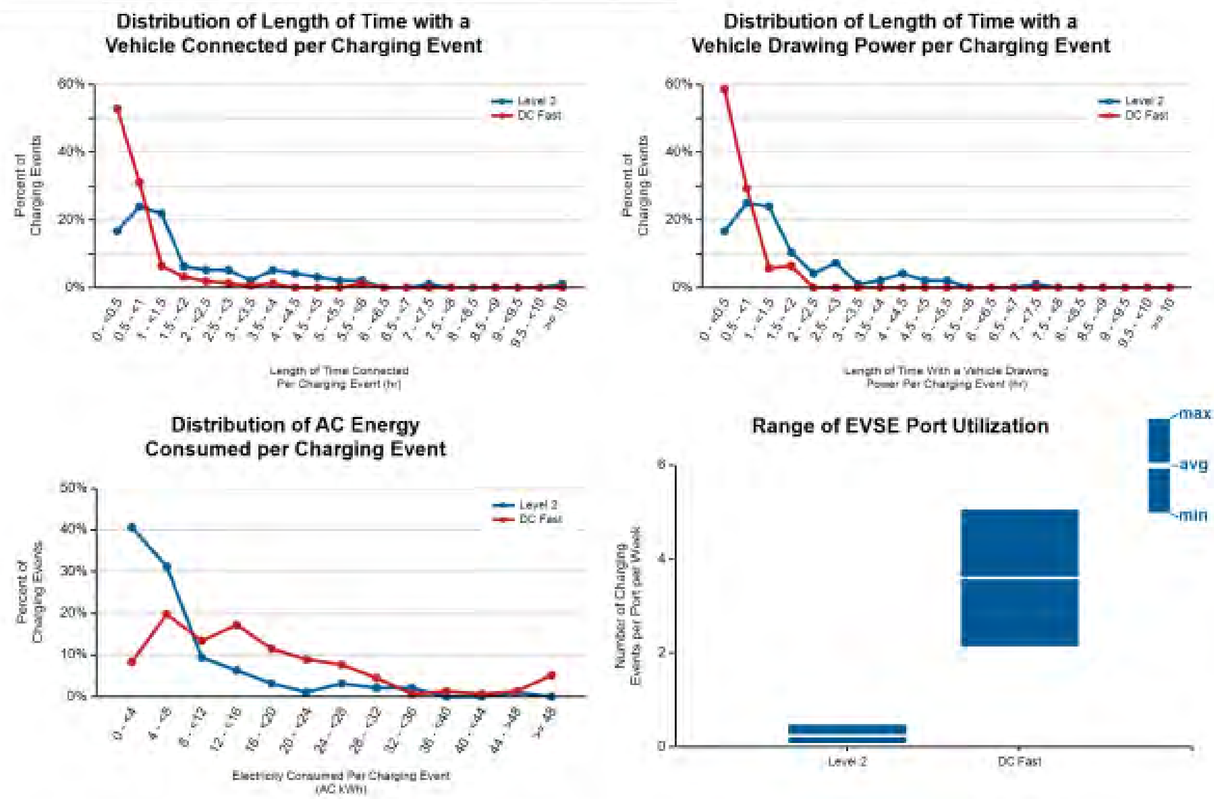
[3] Weekends start at 6:00am on Saturday and end 6:00am Monday local time.

Source: EVSP Charging Session Data

Figure A-12. Electrify Local Highways – Chula Vista port statistics

Report period: May through September 2020

EVSE Usage - By EVSE Level	Level 2	DC Fast
Number of charging ports[1]	20	2
Number of charging events[2]	96	157
Charging energy consumed (AC MWh)	0.8	2.6
Average percent of time with a vehicle connected per charging port	0.24%	1.51%
Average percent of time with a vehicle drawing power per charging port	0.21%	1.14%
Average number of charging events started per charging port per week	0.22	3.59
Average electricity consumed per charging port per week (AC KWh)	1.75	60.30
Average length of time with vehicle connected per charging event (hr)	1.84	0.71
Average length of time with vehicle drawing power per charging event (hr)	1.58	0.53
Average electricity consumed per charging event (AC kWh)	7.97	16.79



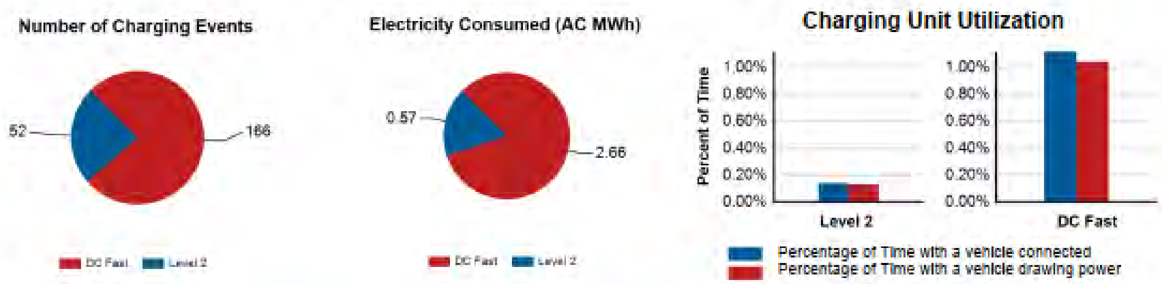
[1] Includes all EVSE ports available during the reporting period and have reported data to INL.
[2] A charging event is defined as the period when a vehicle is connected to a charging unit, during which power is transferred.

Source: EVSP Charging Session Data

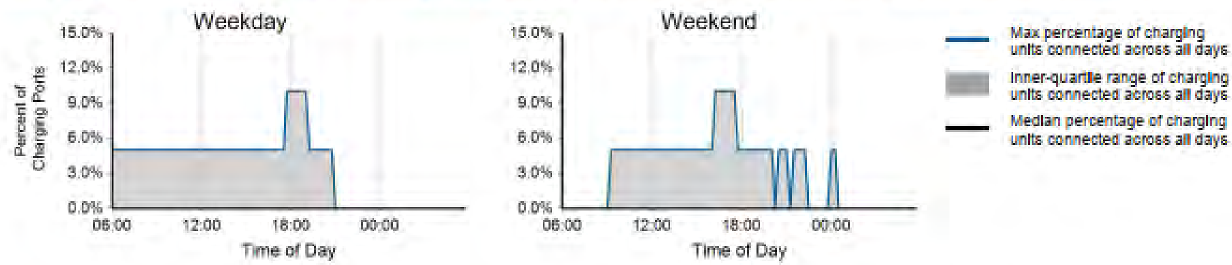
Figure A-13. Electrify Local Highways – El Cajon usage profile

Report period: May through September 2020

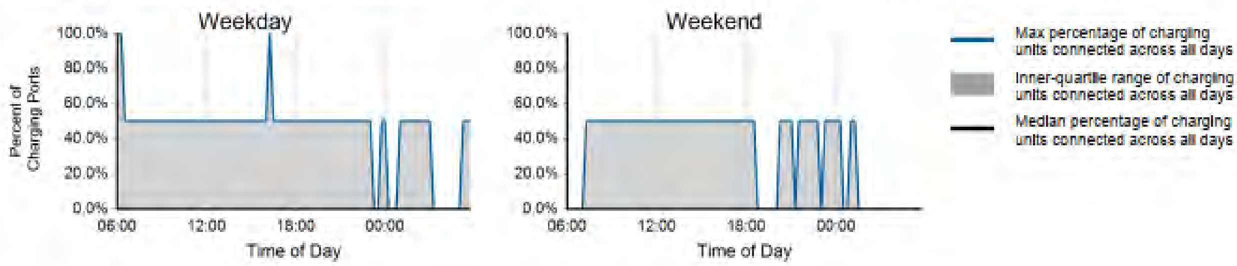
EVSE Usage	Level 2	DC Fast	Total
Number of charging ports[1]	20	2	22
Number of charging events[2]	52	166	218
Electricity consumed (AC MWh)	0.57	2.66	3.23
Percent of time with a vehicle connected	0.14%	1.12%	0.23%
Percent of time with a vehicle drawing power	0.13%	1.04%	0.22%



Charging Availability: Range of Percentage of **Level 2** Ports with a Vehicle Connected versus Time of Day[3]



Charging Availability: Range of Percentage of **DC Fast** Ports with a Vehicle Connected versus Time of Day[3]



[1] Includes all EVSE ports available during the reporting period and have reported data to INL.

[2] A charging event is defined as the period when a vehicle is connected to a charging unit, during which power is transferred.

[3] Weekends start at 6:00am on Saturday and end 6:00am Monday local time.

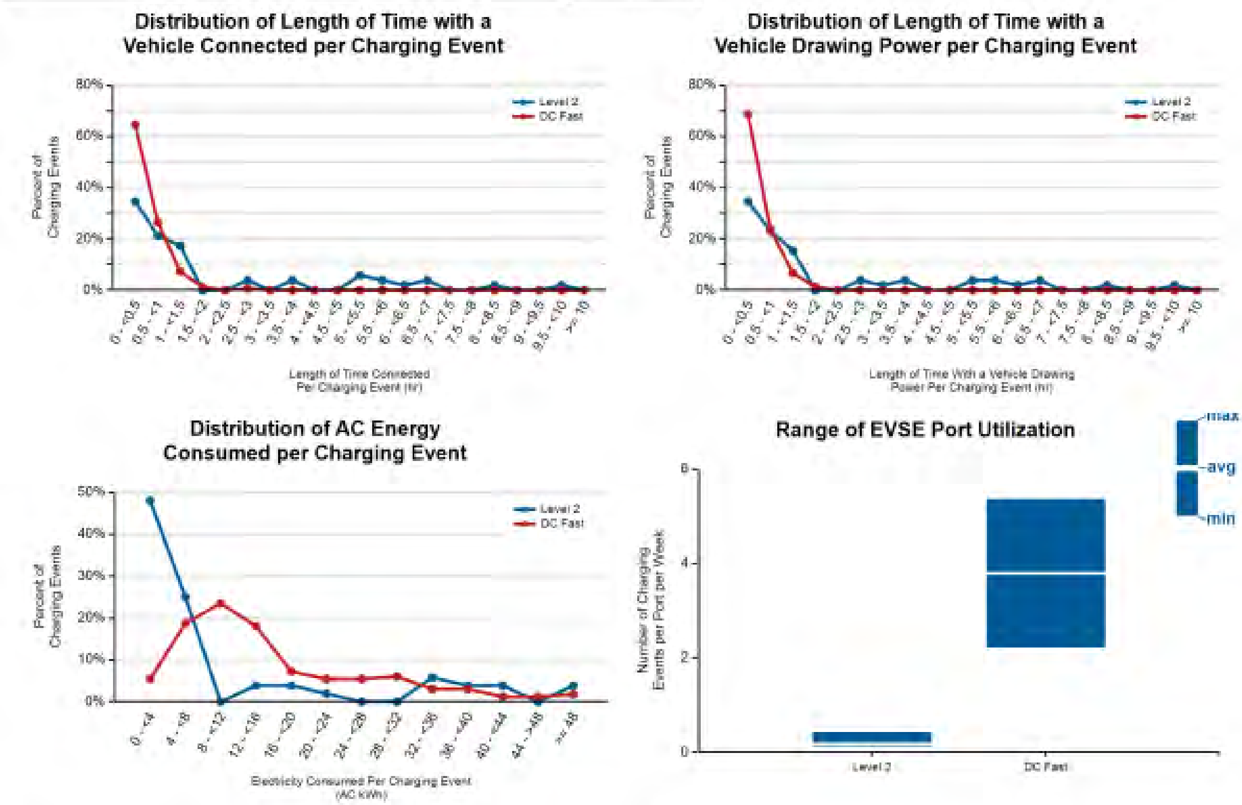
Source: EVSP Charging Session Data

Figure A-14. Electrify Local Highways – El Cajon port statistics

Report period: May through September 2020

EVSE Usage - By EVSE Level

	Level 2	DC Fast
Number of charging ports[1]	20	2
Number of charging events[2]	52	166
Charging energy consumed (AC MWh)	0.6	2.7
Average percent of time with a vehicle connected per charging port	0.14%	1.12%
Average percent of time with a vehicle drawing power per charging port	0.13%	1.04%
Average number of charging events started per charging port per week	0.12	3.80
Average electricity consumed per charging port per week (AC kWh)	1.31	60.76
Average length of time with vehicle connected per charging event (hr)	1.92	0.50
Average length of time with vehicle drawing power per charging event (hr)	1.88	0.46
Average electricity consumed per charging event (AC kWh)	11.03	16.00



[1] Includes all EVSE ports available during the reporting period and have reported data to INL.

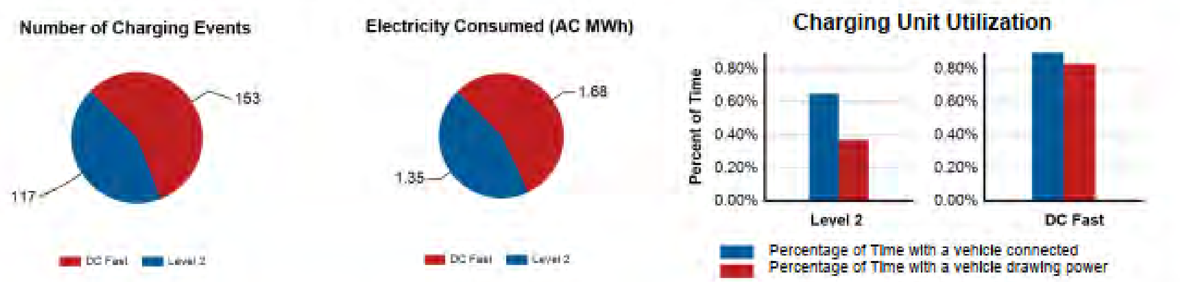
[2] A charging event is defined as the period when a vehicle is connected to a charging unit, during which power is transferred.

Source: EVSP Charging Session Data

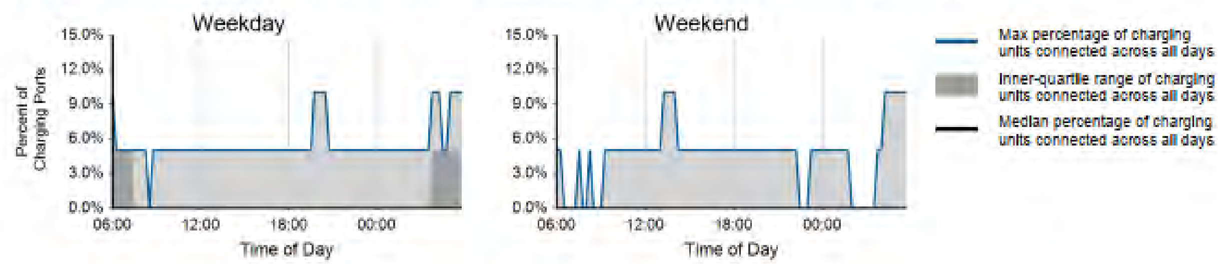
Figure A-15. Electrify Local Highways – National City usage profile

Report period: May through September 2020

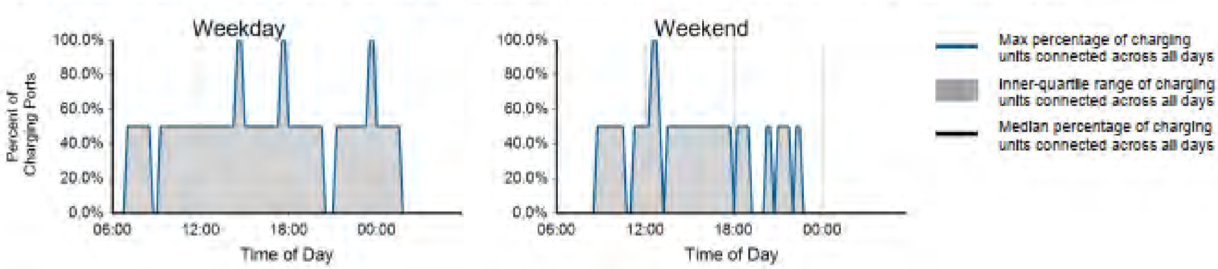
EVSE Usage	Level 2	DC Fast	Total
Number of charging ports[1]	20	2	22
Number of charging events[2]	117	153	270
Electricity consumed (AC MWh)	1.35	1.68	3.03
Percent of time with a vehicle connected	0.65%	0.90%	0.87%
Percent of time with a vehicle drawing power	0.37%	0.83%	0.41%



Charging Availability: Range of Percentage of **Level 2** Ports with a Vehicle Connected versus Time of Day[3]



Charging Availability: Range of Percentage of **DC Fast** Ports with a Vehicle Connected versus Time of Day[3]



[1] Includes all EVSE ports available during the reporting period and have reported data to INL.

[2] A charging event is defined as the period when a vehicle is connected to a charging unit, during which power is transferred.

[3] Weekends start at 6:00am on Saturday and end 6:00am Monday local time.

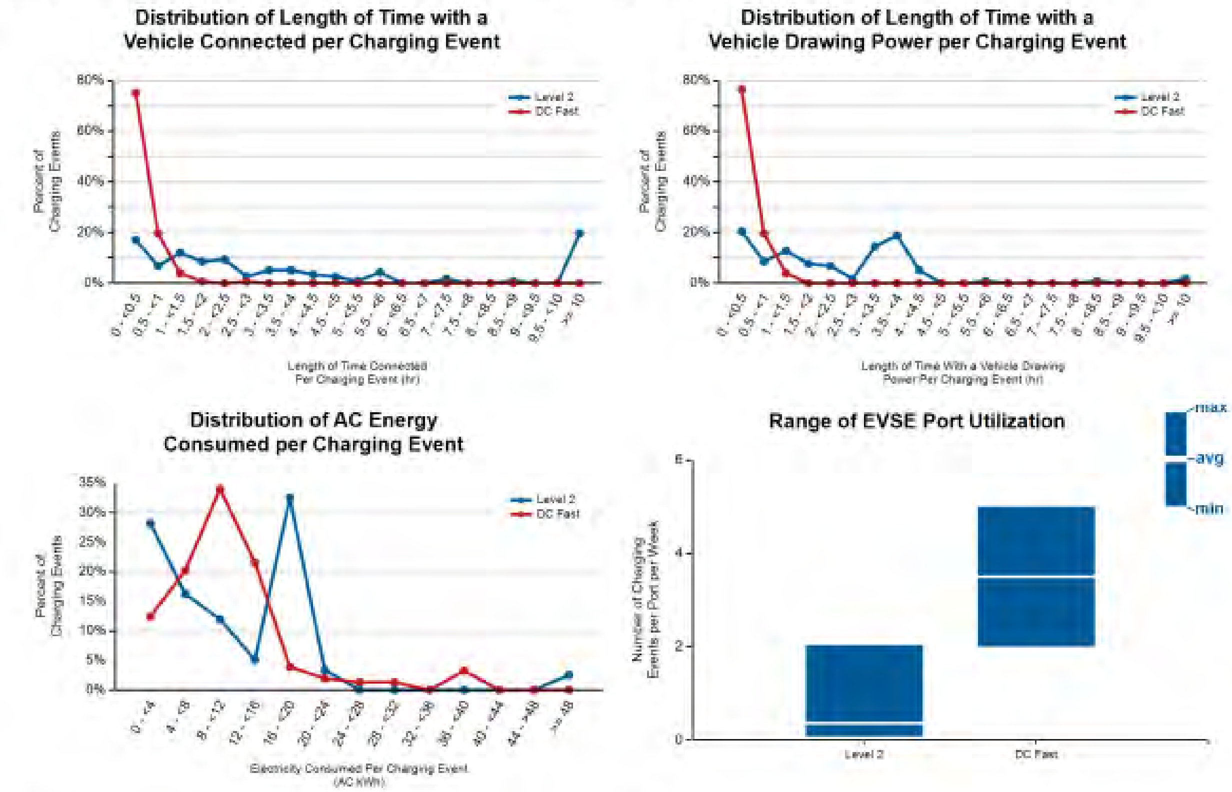
Source: EVSP Charging Session Data

Figure A-16. Electrify Local Highways – National City port statistics

Report period: May through September 2020

EVSE Usage - By EVSE Level

	Level 2	DC Fast
Number of charging ports[1]	20	2
Number of charging events[2]	117	153
Charging energy consumed (AC MWh)	1.3	1.7
Average percent of time with a vehicle connected per charging port	0.65%	0.90%
Average percent of time with a vehicle drawing power per charging port	0.37%	0.83%
Average number of charging events started per charging port per week	0.27	3.50
Average electricity consumed per charging port per week (AC kWh)	3.09	38.35
Average length of time with vehicle connected per charging event (hr)	4.05	0.43
Average length of time with vehicle drawing power per charging event (hr)	2.30	0.40
Average electricity consumed per charging event (AC kWh)	11.53	10.96



[1] Includes all EVSE ports available during the reporting period and have reported data to INL.

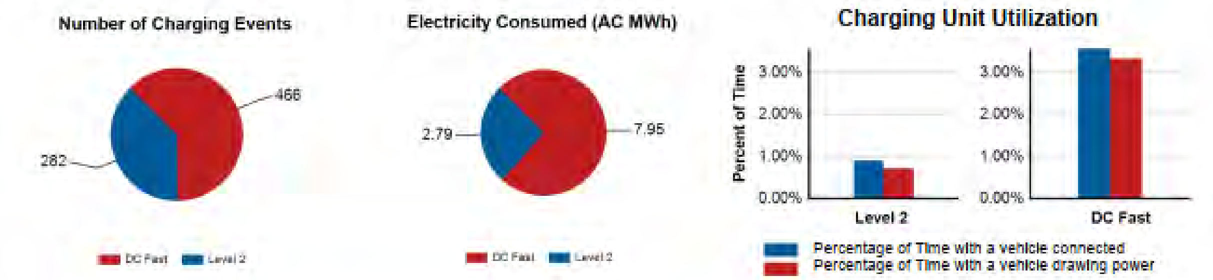
[2] A charging event is defined as the period when a vehicle is connected to a charging unit, during which power is transferred.

Source: EVSP Charging Session Data

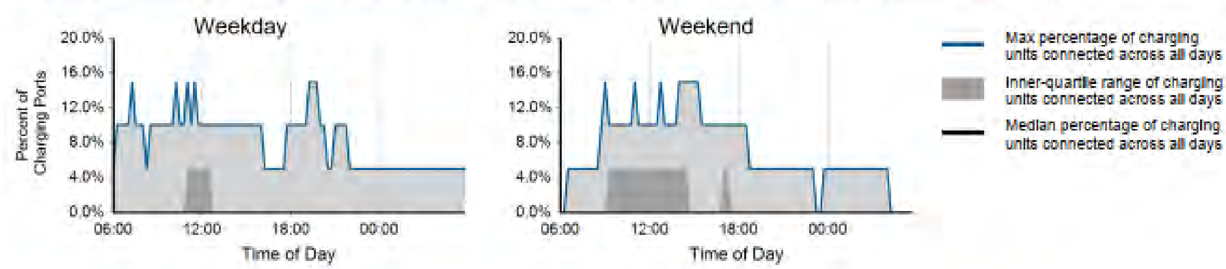
Figure A-17. Electrify Local Highways – Oceanside usage profile

Report period: May through September 2020

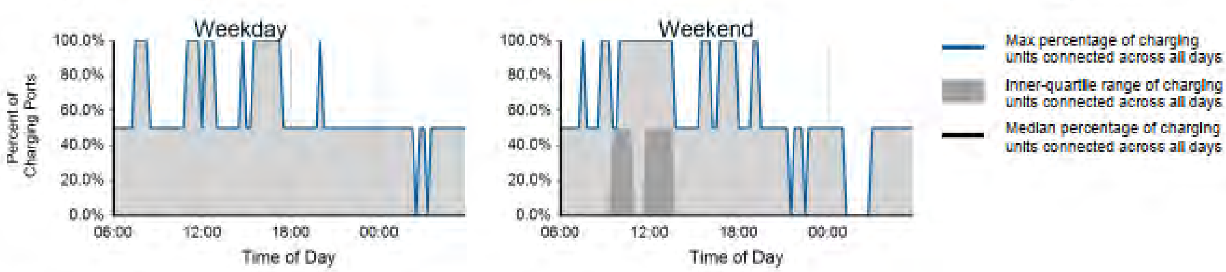
EVSE Usage	Level 2	DC Fast	Total
Number of charging ports[1]	20	2	22
Number of charging events[2]	282	466	748
Electricity consumed (AC MWh)	2.79	7.95	10.74
Percent of time with a vehicle connected	0.89%	3.56%	1.13%
Percent of time with a vehicle drawing power	0.71%	3.32%	0.95%



Charging Availability: Range of Percentage of **Level 2** Ports with a Vehicle Connected versus Time of Day[3]



Charging Availability: Range of Percentage of **DC Fast** Ports with a Vehicle Connected versus Time of Day[3]



[1] Includes all EVSE ports available during the reporting period and have reported data to INL.

[2] A charging event is defined as the period when a vehicle is connected to a charging unit, during which power is transferred.

[3] Weekends start at 6:00am on Saturday and end 6:00am Monday local time.

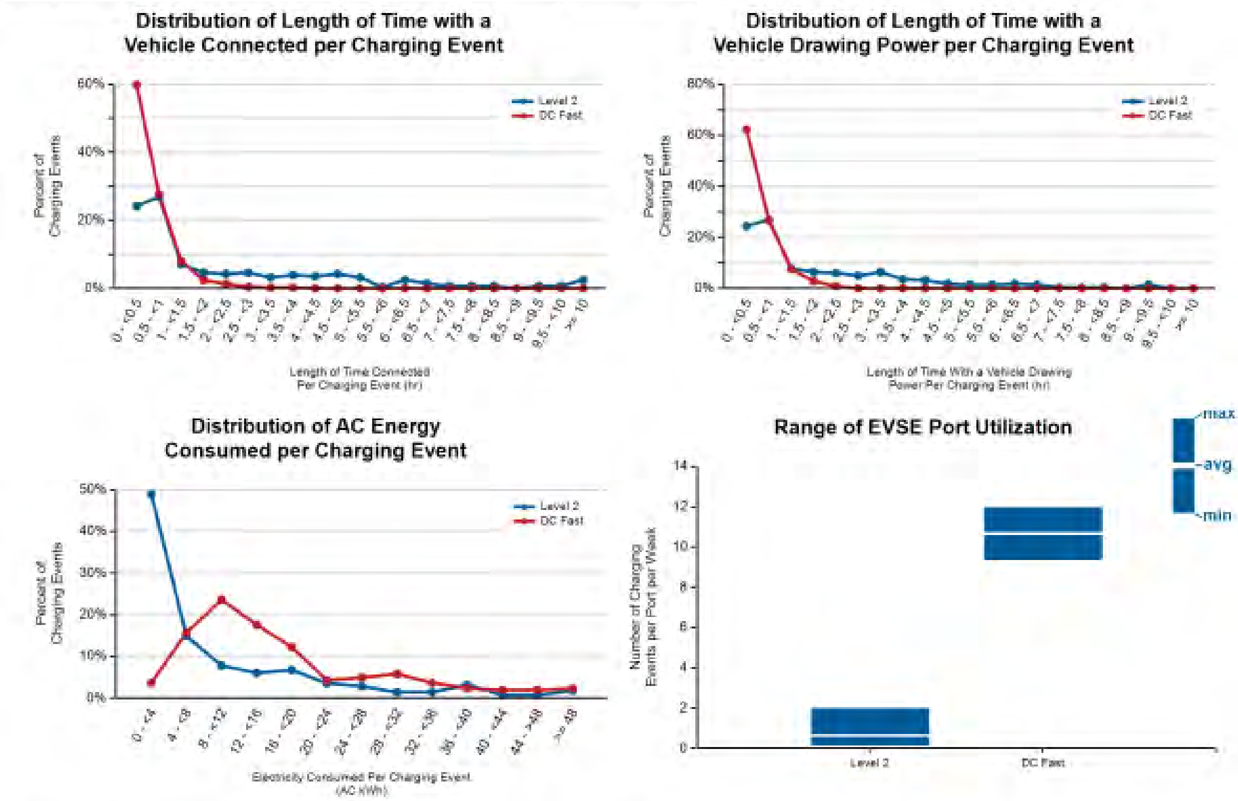
Source: EVSP Charging Session Data

Figure A-18. Electrify Local Highways – Oceanside port statistics

Report period: May through September 2020

EVSE Usage - By EVSE Level

	Level 2	DC Fast
Number of charging ports[1]	20	2
Number of charging events[2]	282	466
Charging energy consumed (AC MWh)	2.8	7.9
Average percent of time with a vehicle connected per charging port	0.89%	3.56%
Average percent of time with a vehicle drawing power per charging port	0.71%	3.32%
Average number of charging events started per charging port per week	0.65	10.66
Average electricity consumed per charging port per week (AC KWh)	6.38	181.75
Average length of time with vehicle connected per charging event (hr)	2.31	0.56
Average length of time with vehicle drawing power per charging event (hr)	1.86	0.52
Average electricity consumed per charging event (AC kWh)	9.90	17.05



[1] Includes all EVSE ports available during the reporting period and have reported data to INL.

[2] A charging event is defined as the period when a vehicle is connected to a charging unit, during which power is transferred.

Source: EVSP Charging Session Data

Annualized Emissions and Fuel Use

Extrapolating the PRP demonstration period from May 2020 to September 2020 on an annual basis, the public charging stations would have dispensed 48,940 kWh of electricity. The corresponding utility supplied electricity annual total (accounting for standby load and charger efficiency) is 56,780 kWh with 14,000 kWh (25%) occurring during the on-peak hours between 4 PM and 9 PM. An analysis of EVs registered in the San Diego County was conducted to determine the average efficiency. The 30 most popular EV are listed in Table A-21 along with their current registration numbers and efficiency rating.

Table A-21. EV numbers and efficiency in San Diego County

Make	Model	Number of Vehicles	kWh/100 mi	Efficiency (miles/kWh)
Tesla	Model 3	9,171	24	4.17
Tesla	Model S	5,041	29	3.45
Chevrolet	Volt	4,152	31	3.23
Nissan	LEAF	2,928	30	3.33
Toyota	Prius Prime	2,650	25	4.00
Chevrolet	Bolt EV	2,083	29	3.45
Tesla	Model X	1,980	35	2.86
Ford	Fusion Energi	1,918	33	3.03
Toyota	Prius Plug-in Hybrid	1,362	25	4.00
Ford	C-MAX Energi	1,284	33	3.03
Honda	Clarity Plug-In Hybrid	1,118	31	3.23
BMW	i3 REx	1,092	32	3.13
FIAT	500e	1,008	30	3.33
Volkswagen	e-Golf	663	30	3.33
BMW	5 Series	581	47	2.13
Chrysler	Pacifica Hybrid	540	41	2.44
BMW	i3	486	30	3.33
Audi	A3 Sportback e-tron	414	44	2.27
Kia	Niro Plug-In Hybrid	405	32	3.13
BMW	3 Series	330	45	2.22
Smart	Fortwo Electric Drive	325	31	3.23
Ford	Focus	301	31	3.23
BMW	X5	297	63	1.59
Hyundai	Ioniq Plug-in Hybrid	288	28	3.57
Chevrolet	Spark EV	272	28	3.57
Hyundai	Kona EV	257	27	3.70
Hyundai	Sonata Plug-in Hybrid	213	34	2.94
Kia	Soul EV	213	31	3.23
Mitsubishi	Outlander PHEV	202	45	2.22
Mercedes-Benz	GLC	194	49	2.04

Source: California Energy Commission

Based on this EV mix with an average efficiency of 3.46 miles per kWh and annual electricity dispensed, 169,300 electric miles are driven. Based on an estimated baseline fuel economy of 24.9 MPG,[139] internal combustion engine vehicles would consume 6,800 gallons of gasoline, which would be saved if driving an EV. Emission factors for light-duty gasoline vehicles on an mmBtu basis from the California GREET 3.0 model[129] are presented in Table A-22.

Table A-22. Light-duty gasoline baseline emissions factors from California GREET 3.0

GHG (g/mmBtu)	SO_x (g/mmBtu)	NO_x (g/mmBtu)	CO (g/mmBtu)	PM_{10} (g/mmBtu)	VOC (g/mmBtu)
100,170	22.35	81.25	720.81	9.40	90.33

Source: California GREET 3.0

Using the calculated annual kWh and baseline fuel use combined with the energy factor of 114,102 Btu per gallon of gasoline, the resulting annual emissions and emission reductions are presented in Table A-23.

Table A-23. Electrify Local Highway charging station annual emissions

	GHG (kg/yr)	SO_x (kg/yr)	NO_x (kg/yr)	CO (kg/yr)	PM (kg/yr)	VOC (kg/yr)
Gasoline	77,700	17	63	559	7.3	70
Electric	12,500	4	14	11	2.5	2
Net Reduction	**65,200**	**13**	**49**	**548**	**4.8**	**68**
% Reduction	**84%**	**75%**	**77%**	**98%**	**66%**	**97%**

Source: Evaluator Calculations

Best Observed Scenario

The above benefits are based on operations for the established pilot period, which likely includes variations due to the initial adoption of EVs in the market and COVID-19 pandemic significantly limiting commuting. The best observed scenario takes a high utilization period within the pilot and extrapolates that over an entire year to evaluate the projected annualized emissions. Because several factors limited the use of these charging station during the demonstration period, even taking the best observed week for this entire set of charging stations would likely underestimate the potential future use of these installations. Therefore, the analysis will look at the busiest week for an individual location for each type of charging (DCFCs and L2 EVSE).

[139] Internal combustion engine vehicle efficiency same as used in the Electric Vehicle-Grid Integration Pilot Program ("Power Your Drive") Ninth Semi-Annual Report of San Diego Gas & Electric Company (https://www.sdge.com/sites/default/files/regulatory/R.18-12-006%20Ninth%20Oct%202020%20PYD%20Final%20Report%2010%2014%202020.pdf), October 14, 2020.

For DCFCs, the busiest week occurred at Oceanside during the week of September 6 – 12, 2020. This week saw the highest utilization, as judged by four different metrics: the number of charging events performed, the number of distinct users, the percent of time with vehicles connected to the chargers, and total energy consumed by vehicles. Table A-24 provides metrics describing the use of the Oceanside DCFCs during the busiest week. The percent of time with a vehicle connected calculation assumes availability of DCFCs 7 days-a-week and 24 hours-a-day. This was the actual availability of these vehicles, but in some charging station installations certain periods of the day may be excluded if it is unreasonable to assume vehicle charging could occur then (e.g., such as 10 PM to 6 AM at an unlit public lot not near any housing). Nine of the 39 charging events at this location during this week were performed between 10 PM and 6 AM, indicating that there is demand for late-night charging and that it is prudent to consider around-the-clock utilization. Metrics for percent of time with a vehicle connected were also calculated for the busiest day for the week (which occurred during the weekend) for additional comparisons. The DCFCs at this site experienced their peak single-day utilization during this week on Saturday, September 12, 2020. Eight users conducted nine charging events, averaging 32 minutes and 18 kWh per charge. The longest charging event lasted 1.5 hours. Charger utilization over this 24-hour period was 10%. This suggests that the pair of DCFCs has the capacity to handle up to 10 times as much charging.

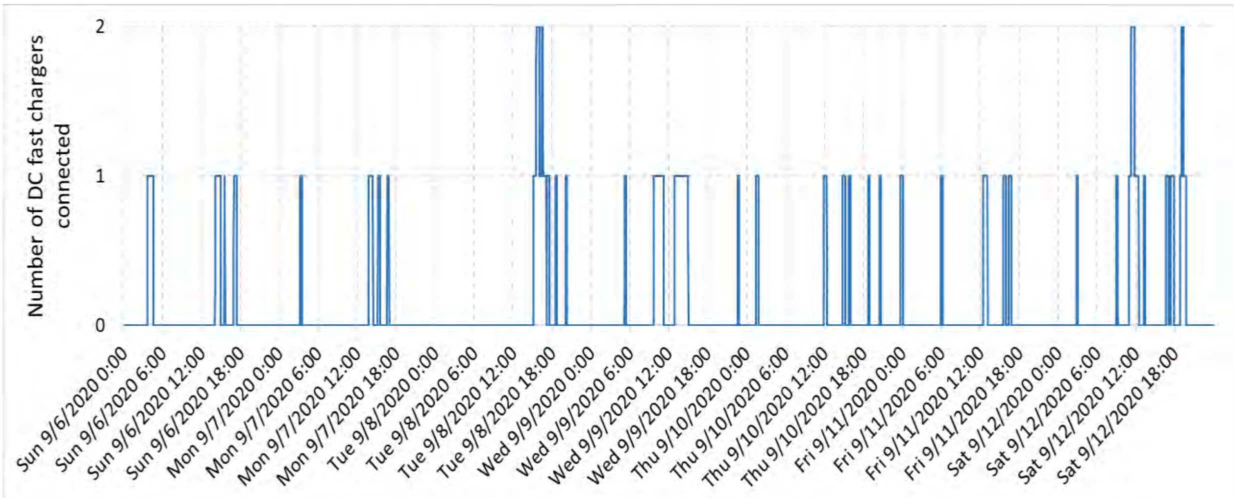
Table A-24. DCFC use at Oceanside, September 6–12, 2020

Charging Station Metric	Weekdays	Weekend	Full Week
Number of charging events	26	13	39
Number of charging events per day (min/avg/max)	4 / 5.2 / 7	4 / 6.5 / 9	4 / 5.6 / 9
Number of distinct users	17	10	24
Percent of time with a vehicle connected (busiest day)	6%	8% (10%)	6%
Percent of time with vehicles connected to both DCFC simultaneously (busiest day)	1.8%	0.7% (4%)	1%
Energy consumed by vehicles (AC kWh)	462.6	225.0	687.6
Energy consumed per day (AC kWh)	92.5	112.5	98.2

Source: EVSP Charging Session Data

Charger utilization is visualized in Figure A-19 by plotting the number of DCFCs in use relative to time.

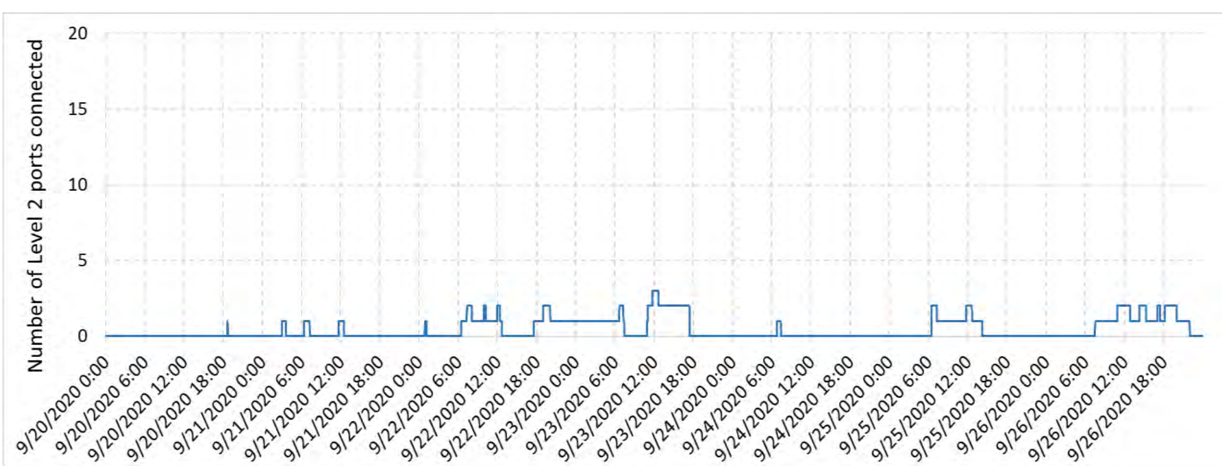
Figure A-19. Time of day when and how many DCFCs were connected to vehicles at Oceanside, September 6–12, 2020



Source: EVSP Charging Session Data

For L2 EVSE, the Oceanside site during the week of September 20 – 26, 2020 saw the highest use, in terms of the number of charging events performed (29), the number of distinct users (17), and percent of time with a vehicle connected (2%). Utilization during this week was still quite low, relative to the number of EVSE installed. The site never had more than three of its 20 L2 ports connected to vehicles at the same time, as shown in Figure A-20. If the site were to have been built with three L2 ports and experienced the same use, its three ports would have been connected to vehicles 14% of the time, assuming 7 days-a-week and 24 hours-a-day operation. Utilization would have been 20% if only the time between 6 AM and 10 PM was considered. While there was much less L2 EVSE use overnight, two of the 29 charging events occurred between midnight and 4 AM, so it may not be prudent to ignore the late-night period when considering utilization. Had only three L2 EVSE been at this location, they would have all been in use only one hour during this week (0.6% of the time).

Figure A-20. Time of day when and how many L2 EVSE were connected to vehicles at Oceanside, September 20–26, 2020



Source: EVSP Charging Session Data

Since these locations are park-and-ride lots primarily serving commuters (which are expected to park their EV all workday on a L2 EVSE), the impact of COVID-19 pandemic is greater on L2 EVSE utilization. Even the busiest week of L2 EVSE use at Oceanside from September 20-26, 2020 likely underestimates the potential. Therefore, this use will be scaled by dividing by the highest number of chargers in use at any one time (3 chargers for 1 hour during this week) and then multiplying by the total number of installed L2 EVSE (20). Based on this calculation, the 168 kWh of electricity dispensed during this week at Oceanside would be scaled up to 1,120 kWh per week across 193 charging events.

Multiplying the L2 potential use at Oceanside by the four locations results in 773 events per week dispensing 4,480 kWh. Multiplying the best DCFC use at Oceanside by the four locations results in 156 events per week dispensing 2,750 kWh of electricity. Combining these totals 929 events per week dispensing 7,220 kWh of electricity. This is slightly higher than the estimated utilization in the testimony at 120 events per day. Across an entire year, this utilization results in 375 MWh of electricity dispensed (393 MWh of supplied electricity with 20% on-peak) supporting 1,300,000 electric miles which would have required 52,200 gallons of gasoline, resulting in benefits presented in Table A-25.

Table A-25. Best observed Electrify Local Highways annual emissions

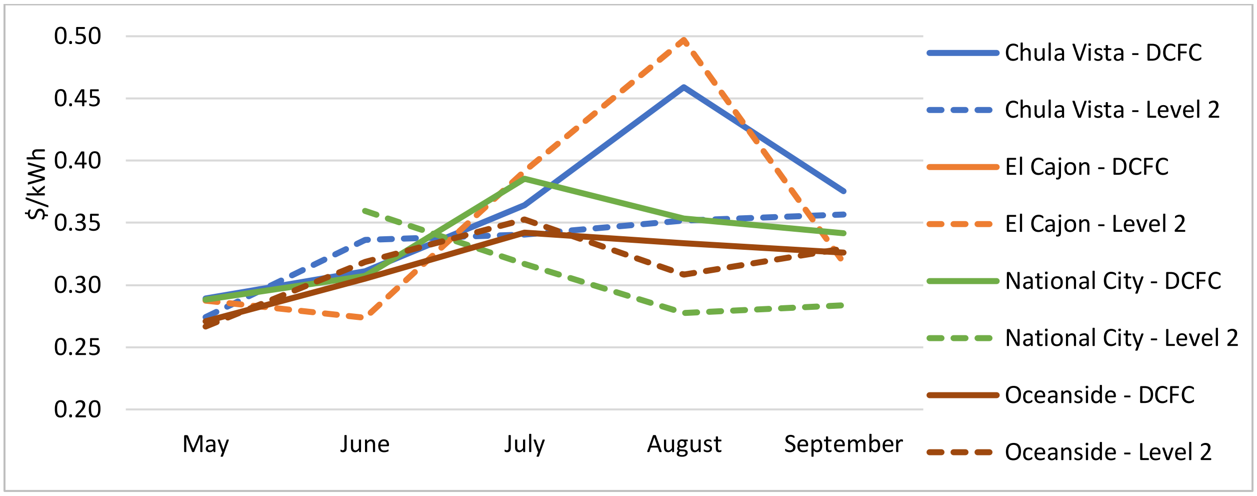
	GHG (kg/yr)	SO_x (kg/yr)	NO_x (kg/yr)	CO (kg/yr)	PM (kg/yr)	VOC (kg/yr)
Gasoline	596,000	133	484	4,290	56	538
Electric	78,000	29	96	79	16	16
Net Reduction	**518,000**	**104**	**388**	**4,212**	**40**	**522**
% Reduction	**87%**	**78%**	**80%**	**98%**	**71%**	**97%**

Source: Evaluator Calculations

Operational Cost Savings

Operational cost savings may be provided to the host site of the charging stations (if the stations generate revenue) and EV drivers that for displacing gasoline with electricity. The charging station host, in this case ChargePoint, has set pricing to reflect the expected costs of electricity. As shown in Figure A-21, the average cost of electricity at these sites was $0.33 per kWh between May 2020 and September 2020 and $0.33 per kWh in September 2020.

Figure A-21. Average monthly electricity cost per site for Electrify Local Highways PRP



Source: SDG&E Monthly Billing

Charging station revenue is recorded for each charging session and can be totaled for a set period before being scaled up to an annual basis. EV drivers realize operational cost savings when their cost per mile on electricity is less than the cost per mile to drive on gasoline. The average cost of gasoline on the West Coast in July 2020 was $3.00 per gallon.[14] Therefore, the EV driver's operational cost savings can be calculated as follows:

Driver Savings = Equivalent Gasoline Saved (gallons) X Average Gasoline Cost ($/gallon) – Charging Station Revenue

Table A-26. Summary of operational cost savings results

	PRP Implementation Period		Projected based on Best Observed Period	
	May – September 2020	Annualized	One Site for Week in September 2020	Annualized
Electricity Dispensed	20,390	48,940 kWh	1,805 kWh (688 DCFC + 1,117 L2)	375,500 kWh
Electricity Supplied	24,290	58,300 kWh	1,884 kWh	391,800 kWh
Gasoline Gallons Saved	2,830 gallons	6,800 gallons	250 gallons	52,200 gallons
EVSE Revenue	$7,511 ($5,550 from DCFCs + $1,961 from L2)	$18,030	$600 ($290 from DCFCs + $310 from L2)	$124,800
Host Electricity Costs	$8,016	$19,200	$620	$130,400
Driver Fuel Costs Saved	$8,490	$20,400	$750	$156,600
Driver Savings	$980	$2,370	$150	$31,800

Source: SDG&E Meter and Billing Data and EVSP Charging Session Data

User Feedback

Table A-27. User comments from experience at Oceanside

Date	Comment
Apr 6, 2020	DCFCs say available, but upon trying to activate they say card read error session limit exceeded. They are not on the ChargePoint app and cannot be remote started by ChargePoint. Wasting my time on L2 charger to get enough juice to go somewhere else.
May 5, 2020	Good deal. $0.31/kWh
May 7, 2020	Charged up, great to have these ChargePoint Fast chargers
May 21, 2020	Completely deserted at 3:40 PM on a Thursday.
May 26, 2020	Amazing charger
Jun 6, 2020	I love this location!
Jul 11, 2020	Lunch break charge while it's $0.20/kWh on weekends until 2pm!
Jul 12, 2020	Fast charger is ridiculously expensive in peak times
Jul 25, 2020	$3.21 to get 20 miles. Expensive
Aug 9, 2020	Seems like ChargePoint app either has a bug or they got rid of weekend super-off-peak until 2pm. Charging here on a Sunday at 9 AM and being charged $0.35/kWh. Supposed to be $0.20/kWh until 2pm.
Aug 29, 2020	[Vehicle] plugged in at DCFC at 100% no one inside. Screen says it's been here for 2:30 hours. Not good etiquette
Sep 19, 2020	Nice new chargers right at end of 78
Oct 25, 2020	Had to call to get the charge started. Charging at about 30 kW. Kind of slow for $0.50 a kW.

Source: PlugShare

Table A-28. User comments from experience at Chula Vista

Date	Comment
May 21, 2020	Awesome spot!
May 27, 2020	Love this spot. Thanks for charging by kWh and not minute!
Jun 24, 2020	Love it!!
Jun 28, 2020	Charged up, but plan on coming during off-peak times or it's expensive.
Jul 26, 2020	Across street from Greg Roger's Park. Plenty of chargers but they are Time of Use.

Source: PlugShare

Table A-29. User comments from experience at El Cajon

Date	Comment
Jun 5, 2020	Worked great. Rates vary by time of day, so 4-9 PM is pricey.
Jul 12, 2020	Works! 41kW. Thanks!
Sep 13, 2020	Excellent location
Oct 21, 2020	Much better than [a nearby charging location]. Use this one instead.

Source: PlugShare

Table A-30. User comments from experience at National City

Date	Comment
Aug 16, 2020	Getting some of that cheap fast charge. Weekend $0.20/kWh off-peak until 2 PM.
Nov 21, 2020	Super-off-peak pricing weekend before 2pm.

Source: PlugShare

8. SDG&E Dealership Incentives Additional Information

Market Lift

This section provides details on the evaluation team's calculation approach, results, and limitations of the PlugStar market lift analysis.

Calculation Approach

The team used a difference-in-differences approach for determining the market lift. If PlugStar dealerships had a higher increase in plug-in vehicle sales than non-PlugStar dealerships, the difference in the increases is defined as a positive market lift. Similarly, if PlugStar dealerships had a lower decrease in plug-in vehicle sales than non-PlugStar dealerships, they would be shown to have a positive market lift, even though plug-in vehicle sales decreased between the baseline and program period.

Because plug-in vehicle models became available or unavailable at different times relative to the baseline period and program period, the difference in differences approach is critically important to avoid the impact of new plug-in vehicle models biasing the results. This enables the evaluation team to control for changes in the broader new vehicle market that would otherwise lead to an increase and decrease in sales, provided that these changes in the market could be assumed to affect both PlugStar and non-PlugStar dealers in a similar manner. For instance, the arrival of the Tesla Model 3 in the market in late 2018 likely had the effect of decreasing sales of competing plug-in vehicle models, both relatively soon before its release (as buyers may have chosen to wait for the Model 3) and after the release since buyers would have had one more vehicle model to choose from. While Model 3 is the most obvious example since it was the top selling plug-in vehicle in 2019, each of the original equipment manufacturers (OEMs) selling vehicles in California was at a slightly different stage of its models' lifecycles, and these changes could also have had effects on the sales trends for plug-in vehicles at all the dealerships, whether they were PlugStar or not.

This complexity confounded the evaluation team's ability to develop definitive conclusions on market lift since in order to have a robust finding for overall market lift, the ratio of dealerships representing each OEM would have needed to be closely proportional to that OEM's share of the overall plug-in vehicle market. Since participation was open to all dealerships that applied to recruit as many dealers as possible, this feature was not built into program design. The obvious solution to this challenge would be to calculate a separate market lift figure for every type of dealership (e.g., comparing Chevrolet dealerships in San Diego that participated to those that did not, and repeating for all the other OEMs). This approach is also limited because the sample size becomes smaller and some OEMs had no participating dealers in San Diego, or no dealers that were not participating.

In response to these limitations, the evaluation team attempted to find *directional and anecdotal* evidence of a market lift using both methods, the top-down lift across all OEMs, and the lift for individual OEMs that represent a large percentage of the plug-in vehicle market.

Market Lift Results

In both major markets, the percentage of sales for which salespeople submitted incentive claims to PIA was relatively low (20% of sales in San Diego and 38% in the Sacramento area).[140]

The 15 participating PlugStar dealers were responsible for 27.5% of plug-in vehicle sales in the baseline period within San Diego County. While the 15 dealers sell vehicles for a wide variety of OEMs, sales of plug-in vehicles from these 15 dealers during the baseline period were heavily skewed to the top two OEMs by sales volume: Chevrolet and BMW (58% and 24% of plug-in sales, respectively, for a total of 82% of the plug-in vehicles sold by these PlugStar dealers).

With this context in mind, the analysis shows that plug-in vehicle sales decreased in San Diego when the analysis is confined to the following subset of sales:

1) Plug-in vehicle sales only, which includes full BEV and PHEV, but not other hybrids
2) Non-fleet purchases (PlugStar is targeted toward general consumers, not commercial or public fleets)
3) New vehicle purchases only (PlugStar only applies to new vehicles)
4) Non-Tesla vehicle sales (Tesla does not use the traditional dealership franchise approach to selling vehicles, and was not part of the PlugStar program)

Not only did overall plug-in sales decrease, but they decreased for participating and non-participating dealers alike (Table A-31). Sales were down at non-participating dealers as well, likely due to the rise of the Tesla Model 3 as a highly popular substitute vehicle for other plug-ins during the program period.

The results of the market lift are inconclusive as the evaluation team cannot conclude that confounding factors did not cause the difference between participating and non-participating dealerships. Taken at face value, the comparison in Table A-31 shows a *negative* market lift (-8.5%) for the SDG&E-sponsored PlugStar program in San Diego County. As will be discussed later, Sacramento area participating dealers had a positive market lift, and the evaluation team cannot robustly conclude how much of the difference is due to natural variability, confounding factors such as the mix of OEMs represented by PlugStar dealers and the vintages of their plug-in offerings, or differences in program design.

[140] Reasons that salespeople may have opted not to file for their incentive payment include: (1) inability to receive it because customer did not enroll on the TOU rate (San Diego area only), and (2) not being trained through the PlugStar program (in both San Diego and Sacramento area, the incentive was only half as valuable if the salesperson did not go through training). The latter effect may have been slightly more significant in San Diego since as noted above a lower number of salespeople per dealership in San Diego opted for training and a lower percentage of sales were completed by trained salespeople. These two effects together can explain the substantially lower percent of sales for which the salesperson claimed the incentive in San Diego relative to Sacramento.

Table A-31. Sales during baseline and program periods – San Diego County

<table>
<tr><th></th><th>Market Lift Period</th><th>Plug-in Sales</th><th>Net Change</th><th>Market Lift</th></tr>
<tr><td rowspan="2">Non-participating dealers</td><td>Baseline</td><td>5,427</td><td rowspan="2">-6.8%</td><td rowspan="4">-8.5%</td></tr>
<tr><td>Program</td><td>5,058</td></tr>
<tr><td rowspan="2">Participating dealers</td><td>Baseline</td><td>2,059</td><td rowspan="2">-15.3%</td></tr>
<tr><td>Program</td><td>1,744</td></tr>
</table>

Source: PIA

Two factors that may have obscured the market lift of the SDG&E-sponsored PlugStar program include:

1) The participating dealership numbers are heavily representative of Chevrolet and BMW, both of which had significant appeal during the baseline period and had been available for multiple years by the time the program period began in August 2018.[141] This may explain the particularly sharp decrease in sales at PlugStar dealers. While Chevrolet plus BMW represented 82% of baseline period plug-in sales at PlugStar dealers, they only represented 18% of plug-in vehicle sales at non-participating dealers, so these dealers were not hit as hard by the overall market decline for those makes and models.
2) The EV-TOU rate enrollment requirement likely had a dampening effect on the San Diego program, as described above in the sections "**Timeline and Status**" and "**Incentive Claims Awarded**."

Next, the evaluation team attempted to find evidence of market lift for dealerships representing specific OEMs, looking only at the top four OEMs by plug-in sales volume that had both participating and non-participating dealerships within the county. Table A-32 shows that no positive market lift was detected for any of these four OEMs, with all but Toyota registering negative market lift findings of double digits.

[141] Chevrolet Bolt became available in October 2016 and was the first competitor to Tesla to offer 200+ mile range. Chevrolet Volt had also peaked in popularity by 2016. BMW i3 was available prior to the baseline period, but the newest model years had increased range. National sales data show that these models declined in popularity after the baseline period as more OEMs offered competing models. https://afdc.energy.gov/data/10567

Table A-32. Sales during baseline and program periods – San Diego County, by OEM, top four OEMs by plug-in sales volume

OEM	PlugStar Participation	Market Lift Period	Plug-in Sales	Net Change	Market Lift
Chevrolet	Non-participating dealers	Baseline	627	-22%	-20%
		Program	490		
	Participating dealers	Baseline	1,185	-42%	
		Program	687		
Toyota	Non-participating dealers	Baseline	776	53%	-3%
		Program	1,191		
	Participating dealers	Baseline	63	51%	
		Program	95		
BMW	Non-participating dealers	Baseline	363	-17%	-16%
		Program	300		
	Participating dealers	Baseline	500	-33%	
		Program	333		
Honda	Non-participating dealers	Baseline	32	>1,500%	>-1,000% [a]
		Program	525		
	Participating dealers	Baseline	41	>500%	
		Program	257		

[a] The small number of Honda plug-in sales during the baseline period followed by rapid growth in the program period cause the market lift calculation to be sensitive to stochastic variation and appears to be a high magnitude.

Source: PIA

Comparison with Comparable Program in the Sacramento Area

As noted above, the Sacramento area provides a useful comparison to the San Diego program due to the program design difference that enabled all salespeople to claim incentives for selling plug-in vehicles regardless of whether the customer ultimately adopted an EV-TOU rate.

In the three Sacramento counties that had participating PlugStar dealers (Sacramento, Yolo, and Placer), the PlugStar dealers already accounted for 44% of plug-in sales during the baseline period, a significantly higher market share than the San Diego PlugStar dealers. We found an overall market lift of 10.9%, with plug-in sales increasing by over 20% at PlugStar dealers versus 9.6% at non-PlugStar dealers (Table A-33). As described above, these differences with the San Diego program could be due to natural variability, the OEM mix, and program design.

Table A-33. Sales during baseline and program periods – Sacramento area counties with PlugStar participating dealers

	Market Lift Period	Plug-in Sales	Net Change	Market Lift
Non-participating dealers	Baseline	1,797	9.6%	10.9%
	Program	1,969		
Participating dealers	Baseline	1,415	20.4%	
	Program	1,704		

Source: PIA

Discussion

As described above, the evaluation team failed to find a positive market lift for PlugStar in San Diego County. In addition to the points made above regarding the mix of OEMs represented in the program and the challenges of the EV-TOU requirement, other factors may be responsible for the lack of lift. For example, dealerships that participated are likely to have been the types of dealerships that had already been successful at selling plug-in vehicles in the baseline period. Their customers may have been more likely to buy plug-in vehicles early, and as a result they may have gotten more supply from their OEMs early on, facilitating higher early sales. Therefore, as Tesla Model 3 siphoned off demand from many other plug-in vehicle makes and models, these dealerships had farther to fall. This speculation is bolstered by the fact that preliminary exploration of the data shows that for the most part across the larger OEMs by plug-in sales volume the market lift tended to correlate with the overall growth for that make of plug-in vehicle. For instance, in both San Diego and the Sacramento area, Chevrolet plug-in sales fell, and this correlated with a negative lift for PlugStar in both markets. On the other hand, Toyota plug-in sales grew substantially in these markets between the baseline period and the program period, and Toyota was the least negative market lift for the San Diego area and a positive lift for dealers in the Sacramento area programs.

Furthermore, statements of the participating dealerships about why they participated in the program appear to indicate that the managers of the dealerships were excited to participate in PlugStar. Many of the dealerships have goals of being leaders in plug-in vehicle sales and have had past success. In short, the evaluation team believes that self-selection bias may have inflated baseline period plug-in sales, further obscuring market lift.

The difference-in-differences approach with a comparison to a similar program in northern California enabled the evaluation team to view results that controlled for economic conditions, overall vehicle sales, entrance of new competitors, and other broad trends in plug-in vehicle adoption, since both participating and non-participating dealers are subject to the same trends. Unfortunately, however, the unique makeup of the participating dealerships makes it difficult to fully control for availability and substitution of plug-in vehicle makes and models. The Sacramento area results show that PlugStar can produce a sizable market lift, even if it could not be observed in San Diego.

9. SCE Port of Long Beach Yard Tractor Program

The SCE Port of Long Beach pilot integrated 7 electric yard tractors into an existing fleet of over 700, including 570 diesel-fueled yard tractors ranging from 250 HP down to 135 HP, 134 gasoline yard tractors at 335 HP, and 2 propane yard tractors at 173 HP.[41]

The port operates these yard tractors entirely within the property, which is directly adjacent to an economically disadvantaged community (DAC) according to CalEnviroScreen 3.0. As a result of this determination, all the estimated benefits are attributable to the DAC.

Baseline Performance

Baseline performance was calculated from a similar yard tractor (ITS recorded the engine electronic controller unit [ECU] diagnostic readout monthly. The baseline truck was a Kalmar yard tractor with a Cummins 173 HP diesel engine. According to ITS reported data, the baseline truck consumed 1,572 gallons of diesel fuel between August 14, 2020, and December 1, 2020, and operated for 582 hours for an average consumption rate of 2.7 gallons of diesel consumed per hour of operation. According to port operation inventories, yard tractors were used for as many as 4,338 hours per year, with an average of 1,738, so the baseline unit's annual average of 1,995 hours was higher than average.

For almost 30% of the time, the baseline truck operated at 30% of peak torque and 1,250 RPM. The second-highest operational use point (12% of the time) was at 10% of peak torque also around 1,250 RPM, followed by peak torque at 1,825 RPM for 7% of the time. The engine ECU readout also reported cumulative idle time at 180 hours (31%), which corresponded to idle fuel consumption of 147 gallons (9% of the total fuel consumption). The frequent idling of the baseline truck should boost the benefits gained by converting to an electric model, as EVs have near-zero energy consumption at idle.

Emission factors were developed using the California GREET 3.0 model on a mmBtu basis and are presented in Table A-34. The emission factors have been adjusted for fuel correction and exhaust control factors.

Table A-34. Diesel baseline emissions factors determined using California GREET 3.0

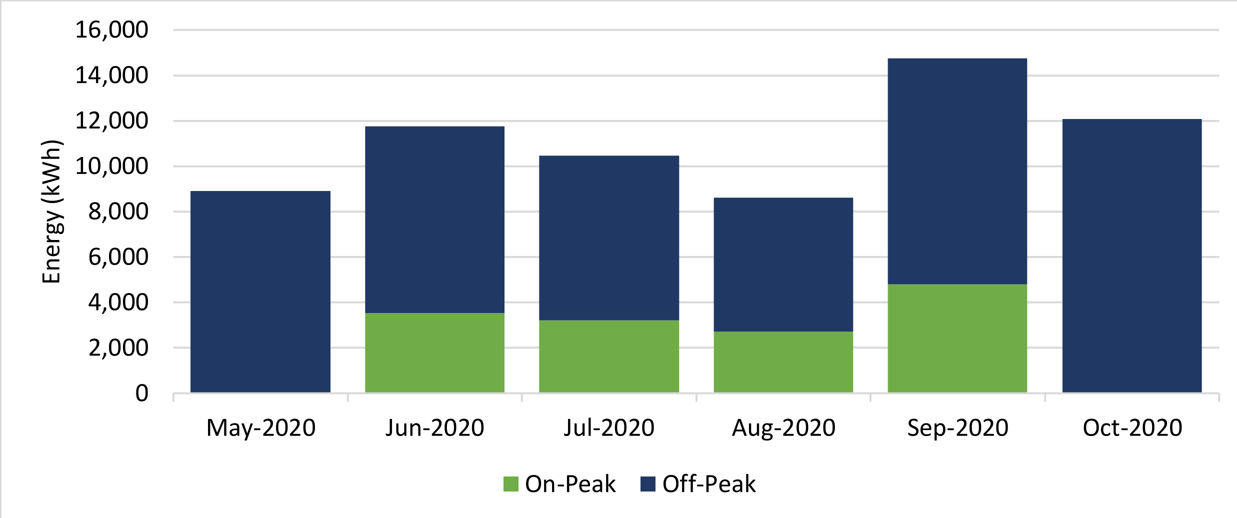
GHG (g/mmBtu)	SO_X (g/mmBtu)	NO_X (g/mmBtu)	CO (g/mmBtu)	PM_{10} (g/mmBtu)	VOC (g/mmBtu)
100,723	15.39	204.60	85.20	8.13	26.53

Source: California GREET 3.0

Electric Use

Utility meters captured 15-minute interval electricity use from electric tractors from mid-May 2020 to the end of October 2020, as shown in Figure A-22. The data collection period in support of 3rd party evaluation ended in August 2020 for most PRPs; however, due to EV deployment delays and resulting limited operational data set, two more months of in-service operating data were collected. These two additional months provided both highest monthly and weekly usage which were used for benefit calculations.

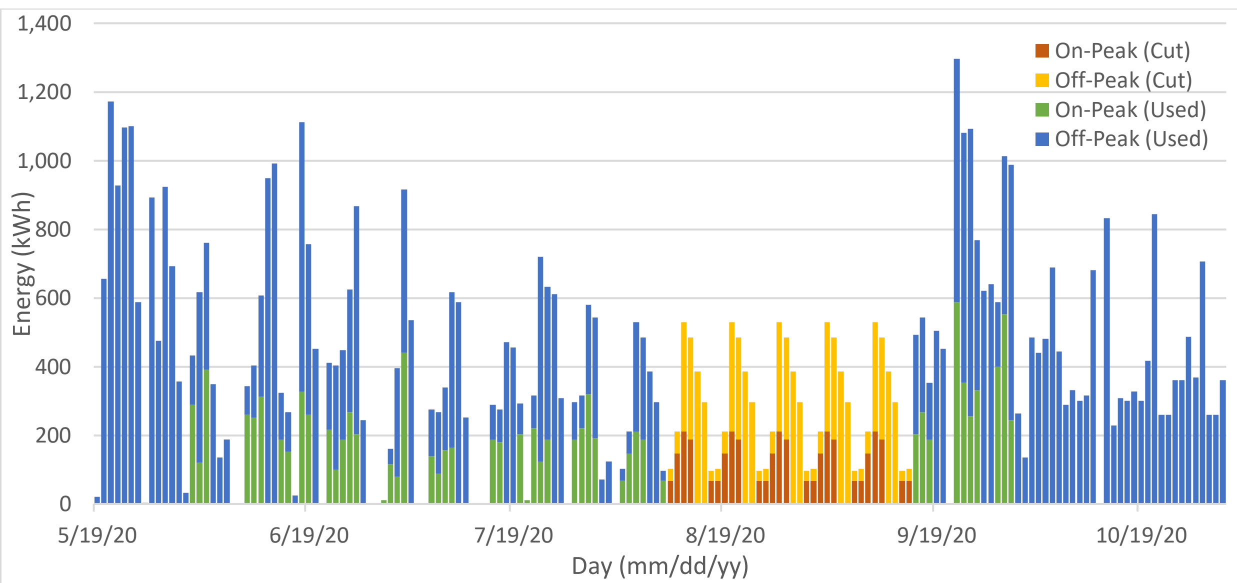
Figure A-22. Electric utility meter data for Port of Long Beach yard tractors



Source: SCE Meter Data

Closer inspection of the utility metering data revealed an anomaly in the data—there were 36 days of identical weekly energy consumption pattern where each day of the week is different but matches exactly the same day of the previous week (see Figure A-23). While not confirmed by the utility, a hypothesis is that the individual 15-minute interval data was not transmitted or recorded but the overall meter kWh count continued. To fill in the data gap, the daily energy consumption pattern for the week before or after the data loss was likely used. As a result, the annualized energy use calculation excludes the repeated data shown in yellow and red in Figure A-23.

Figure A-23. Daily electric meter use for yard tractors



Source: SCE Meter Data

The resulting evaluation period was 129 days; a total of 55,928 kWh was consumed, for an average of 433 kWh per day. This level of use would result in 158 MWh annually. The annualized on-peak electricity use would be 16,520 kWh, or 10% of the consumption using the SCE on-peak hours (weekdays 4:00-9:00 PM during summer months). While 7 vehicles were deployed for the pilot, they were phased in and not all of them were used consistently throughout the evaluation. Based on data logs for vehicle use, 4 to 5 vehicles were consistently used in each given month. Using a conservative estimate of 5 vehicles in use, the daily energy use per vehicle is 87 kWh, with an annual use of 31,600 kWh.

Data from electric yard tractors' telematics showed DC electric consumption of 25.1 kWh per hour of operation (including idling) during the entire monitoring period. Using the evaluation period annual rate of electricity consumption and the hourly electric consumption yields 6,300 hours of use per year.

Annualized Emissions and Fuel Use

Based on the estimated electric yard tractor use (6,300 hours) and a baseline energy consumption rate of 2.7 diesel gallon equivalent (DGE) per hour, the electric yard tractors would displace 17,040 gallons of diesel fuel annually. The resulting annual emissions and reductions are presented in Table A-35.

Table A-35. Port yard tractor expected operation annual emissions

	GHG (MT/yr)	SO_X (kg/yr)	NO_X (kg/yr)	CO (kg/yr)	PM (kg/yr)	VOC (kg/yr)
Diesel	221	34	448	187	18	58
Electric	43	12	39	32	7	6
Net Reduction	**177**	**22**	**409**	**155**	**11**	**52**
% Reduction	**80%**	**65%**	**91%**	**83%**	**63%**	**89%**

Source: Evaluator Calculations

Best Observed Scenario

A limited timeframe of data was available due to EV deployment delays, and the number of available EVs varied. Therefore, the evaluation is focused on the best observed period, which was determined to be a single week of use from September 22 to 28, 2020. During this week, five of the seven trucks were used, according to the data loggers. Annualized fuel use extrapolated from this period is 317 MWh, with 34 MWh (11%) of that usage during on-peak hours. This best observed operation represents an estimated 12,700 hours of use per year, with an equivalent diesel fuel consumption of 34,200 gallons. The resulting emissions are presented in Table A-36.

Table A-36. Port yard tractor best observed operation annual emissions

	GHG (MT/yr)	SO_X (kg/yr)	NO_X (kg/yr)	CO (kg/yr)	PM (kg/yr)	VOC (kg/yr)
Diesel	442	68	898	374	36	116
Electric	86	24	77	64	13	13
Net Reduction	**356**	**44**	**821**	**310**	**22**	**103**
% Reduction	**81%**	**65%**	**91%**	**83%**	**63%**	**89%**

Source: Evaluator Calculations

10. SCE Electric Transit Bus Make-Ready Calculations

The SCE Transit Electrification PRP contains three transit fleets, each of which is evaluated individually, then combined for the total benefits as presented in the body of this report. For these projects, all the three data streams (utility meters, vehicle operational information, and charging station sessions) were available and are compiled to present an accurate picture of each project and the net benefits.

The baseline fuel for all three fleets is CNG. Emission factors presented in Table A-37 were determined on a per mmBtu basis from the California GREET 3.0 model.[129] These well-to-wheels CNG emission factors assume a *US Average Mix* for fuel production in 2020 and use the *Light Duty Truck 2* methodology.

Table A-37. CNG baseline emissions factors determined by California GREET 3.0

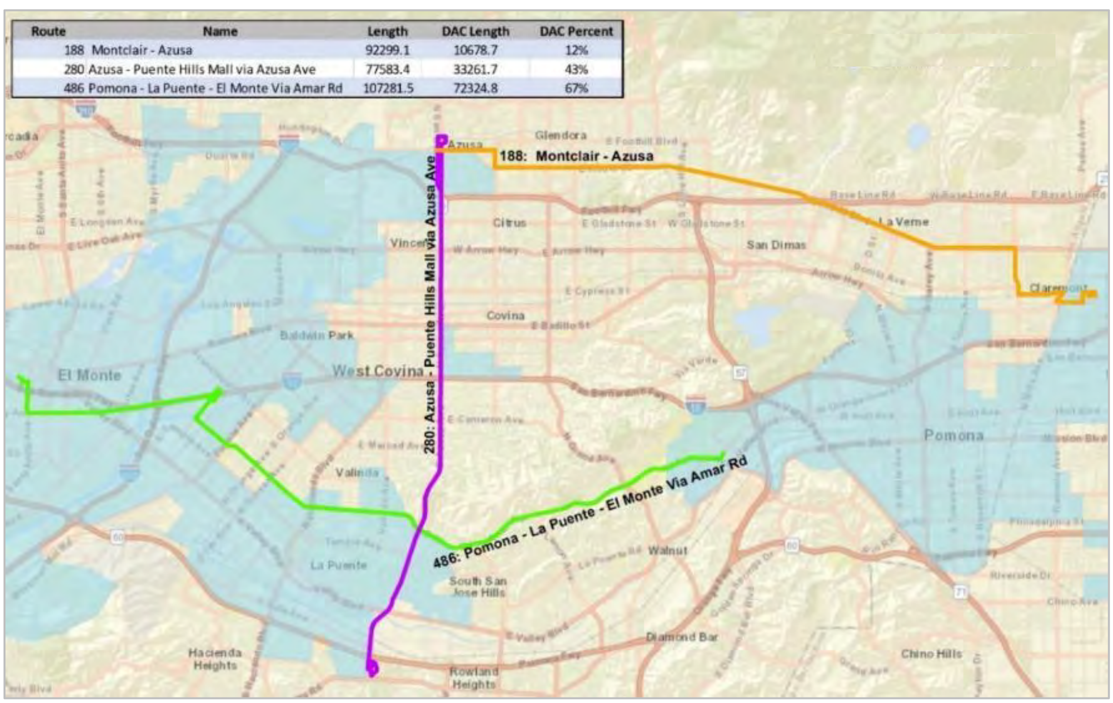
GHG (g/mmBtu)	SO_x (g/mmBtu)	NO_x (g/mmBtu)	CO (g/mmBtu)	PM_{10} (g/mmBtu)	VOC (g/mmBtu)
83,361	17.30	118.95	1,171.21	5.84	45.54

Source: California GREET 3.0

10.1 Foothill Transit (Fleet 3)

Fleet 3 operates on fixed routes that are partially within a DAC according to CalEnviroScreen 3.0. DAC designations were overlaid on each route to determine its percentage in a DAC as shown in Figure A-24. The electric buses supported by the PRP charging infrastructure operate almost exclusively on Route 280 which is 43% in a DAC.

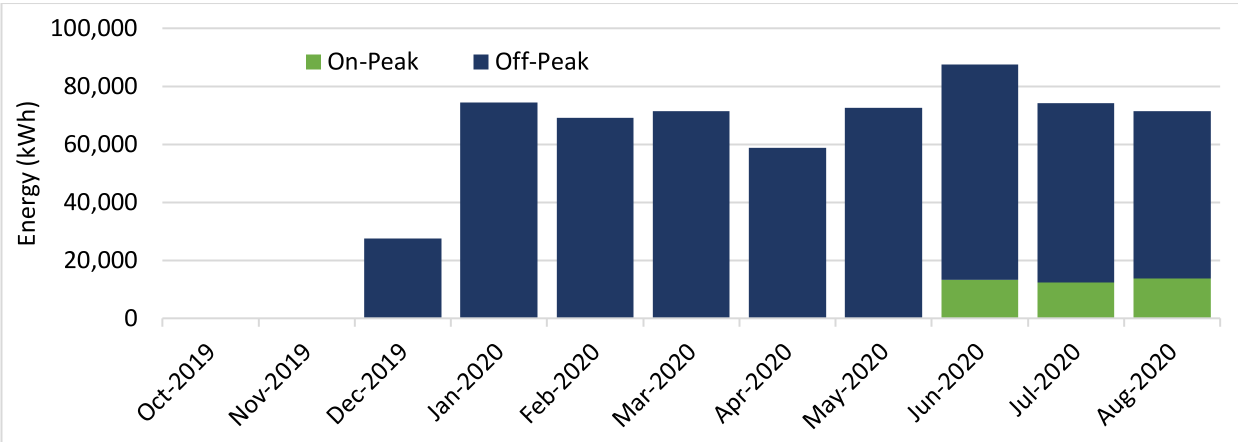
Figure A-24. Fleet 3 key routes and DAC proportions



Source: Esri ArcGIS and Fleet 3

Evaluation team member NREL has historically worked closely with Foothill Transit to evaluate new technology approaches and leveraged that relationship to lead the analysis of these 14 electric buses and several baseline buses. SCE provided utility data for Fleet 3 from October 20, 2019 to August 30, 2020 for the analysis.

Figure A-25. Fleet 3 monthly energy consumption



Source: SCE Meter Data

While some negligible monthly utility meter data for the charging infrastructure showed up as early as October 2019, buses did not begin operation until December and showed less than average utilization. Therefore, January 2020 to August 2020 was selected as the evaluation period.

The average fuel economy numbers for the baseline CNG buses and the electric buses were based on vehicle odometer readings and fuel consumption. The resulting fuel economy for the baseline buses was 3.88 miles per DGE of CNG and for the electric buses it was 1.85 kWh per mile.

Annualized Emissions and Fuel Use

Determined on an annual scale, usage from January 2020 to August 2020 results in 860,256 kWh per year (61,447 kWh per bus each year) with 42,630 kWh (5.0%) consumed during on-peak hours between 4 and 9 PM on summer month weekdays. This equates to 33,199 miles per year per bus (464,789 miles total) at 1.85 kWh per mile. This same annual mileage would have required 119,668 DGE (138,216 GGE) of CNG for the baseline buses, which is saved. Annual emissions and emission reductions are presented in Table A-38 using the determined annual kWh and baseline fuel use.

Table A-38. Fleet 3 operation annual emissions

	GHG (MT/yr)	SO_x (kg/yr)	NO_x (kg/yr)	CO (kg/yr)	PM (kg/yr)	VOC (kg/yr)
CNG	1,282	266	1,829	18,017	90	700
Electric	284	65	210	174	36	35
Net Reduction	**998**	**202**	**1,619**	**17,844**	**54**	**665**
% Reduction	**78%**	**76%**	**89%**	**99%**	**60%**	**95%**

Source: Evaluator Calculations

Best Observed Scenario

The above benefits are based on operations for the established pilot period, which likely includes variations due to the initial adoption of this technology in the fleet or other factors. The best observed scenario takes a high utilization period within the pilot and extrapolates that over an entire year to evaluate the projected annualized emissions. The best observed operations for the Foothill Transit was in June 2020 when the highest monthly mileage was observed. The fleet would accumulate 615,270 annual miles if this rate were applied across the whole year (43,948 miles per bus). Table A-39 shows the annual benefits if this level of utilization was experienced across an entire year which would save 182,965 GGE of CNG per year.

Table A-39. Fleet 3 best observed operation annual emissions

	GHG (MT/yr)	SO_x (kg/yr)	NO_x (kg/yr)	CO (kg/yr)	PM (kg/yr)	VOC (kg/yr)
CNG	1,697	352	2,421	23,851	119	927
Electric	385	85	278	230	48	47
Net Reduction	**1,311**	**267**	**2,143**	**23,621**	**71**	**880**
% Reduction	**77%**	**76%**	**89%**	**99%**	**60%**	**95%**

Source: Evaluator Calculations

10.2 Porterville Transit (Fleet 2)

Fleet 2 operates on fixed routes that are partially within a DAC according to CalEnviroScreen 3.0. DAC designations were overlaid on each route to determine its percentage in a DAC and all routes were combined to determine that 57% of the overall portion of electric operations occurred in a DAC as shown in Table A-40.

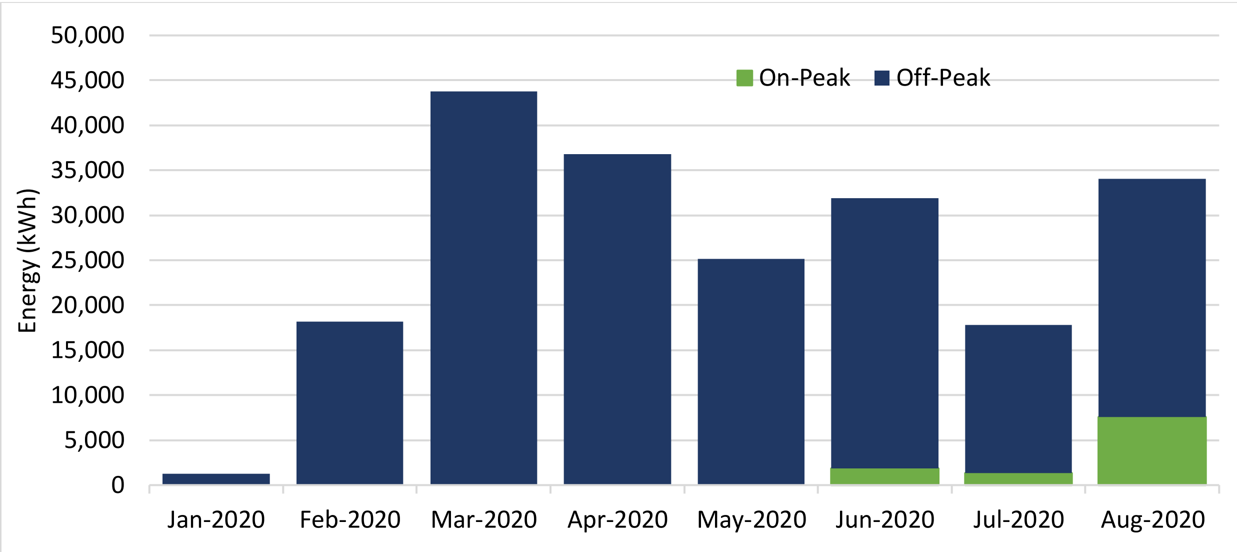
Table A-40. Fleet 2 DAC calculations by route

Route	Name	Total Length (ft)	DAC Length (ft)	DAC Percent
1	Olive–Morton	63,137	13,379	21%
2	Henderson–Westfield	52,681	16,802	32%
3	Plano–E Springfield Dr	47,161	43,495	92%
4	Developmental Center–Porterville College	50,077	32,467	65%
5	Morton–Henderson	47,101	8,847	19%
6	Family Healthcare Network–Eastridge Mall	44,487	37,980	85%
7	Porterville Adult School	58,088	16,148	28%
8	Northeast Porterville	54,078	43,547	81%
9	Tule River Reservation	55,163	49,088	89%
All				57%

Source: Porterville Transit and Evaluator Calculations

Fleet 2 provided vehicle logs for the electric buses in 2020 and 13 baseline CNG buses in 2019. Utility data for the new PRP charging infrastructure used by the electric buses was available from January 1, 2020, to August 30, 2020.

Figure A-26. Fleet 2 electric energy use by month



Source: SCE Meter Data

Charging infrastructure use began in January 2020 with an increase through March 2020, when the COVID-19 pandemic likely slowed operations. The electric energy consumption for January to August 2020 was determined by totaling energy use during utility meter fifteen-minute demand periods. The charging infrastructure dispensed 260,281 kWh of electricity in this time period to support 123,455 miles of use by the electric buses which resulted in an average efficiency of 2.11 kWh per mile.

Fuel logs for individual CNG buses were provided from January to December 2019. Monthly fuel economy was consistently between 3.91 and 4.86 miles per diesel gallon equivalent (mpdge) for 11 of the 12 months in 2019 with the exception of November 2019, where an anomalous data point of 1.88 mpdge appeared and was removed from the analysis as an outlier. The average baseline fuel economy for the remaining 11 months was 4.17 mpdge for CNG. It should be noted that the baseline buses are 35-foot buses versus the electric buses, which are 40-foot buses. This difference can explain the higher baseline fuel economy versus the other two transit agencies.

Annualized emissions and fuel use

The selected evaluation period used is from March 2020 to August 2020, which excludes the first two months of much lower use during start-up operations for these electric buses. Extrapolating this usage to an annual basis would equate to 378,984 kWh per year, with 9,861 (2.6%) of those kWh occurring during the on-peak hours between 4 and 9 PM on weekdays during the summer months. Based on the calculated electric bus efficiency, this would result in annual mileage of 17,961 per bus (179,613 miles total). Using the estimated average baseline fuel economy, this annual mileage would require 43,073 DGE of CNG per year, which is saved. Annual emissions and emission reductions are presented in Table A-41 using the determined annual kWh and baseline fuel use.

Table A-41. Fleet 2 operation annual emissions

	GHG (kg/yr)	SO_x (kg/yr)	NO_x (kg/yr)	CO (kg/yr)	PM (kg/yr)	VOC (kg/yr)
CNG	461,347	96	658	6,485	32	252
Electric	135,084	28	92	77	16	16
Net Reduction	**326,263**	**67**	**566**	**6,409**	**16**	**236**
% Reduction	**71%**	**70%**	**86%**	**99%**	**51%**	**94%**

Source: Evaluator Calculations

Best Observed Scenario

The above benefits are based on operations for the established pilot period, which likely includes variations due to the initial adoption of this technology in the fleet or other factors. The best observed scenario takes a high utilization period within the pilot and extrapolates that over an entire year to evaluate the projected annualized emissions. The best observed operations for Fleet 2 was in March 2020 when the highest monthly mileage was observed. The fleet would accumulate 269,562 annual miles if this rate were applied across the whole year (26,956 miles per bus). Table A-42 shows the annual benefits if this level of utilization was experienced across an entire year, which would save 64,643 DGE of CNG per year.

Table A-42. Fleet 2 best observed operation annual emissions

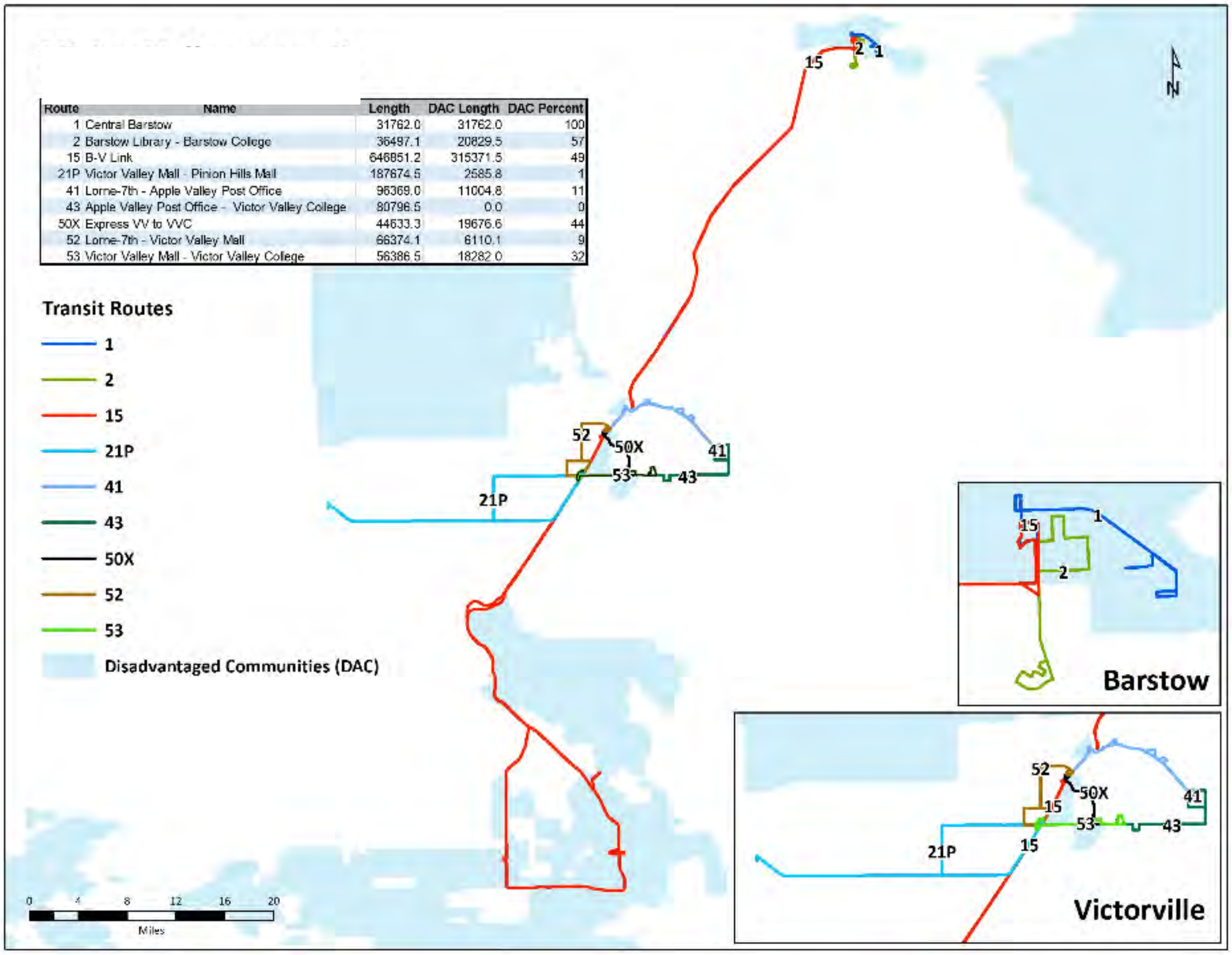
	GHG (kg/yr)	SO_x (kg/yr)	NO_x (kg/yr)	CO (kg/yr)	PM (kg/yr)	VOC (kg/yr)
CNG	692,386	144	988	9,733	48	378
Electric	182,212	43	139	115	24	23
Net Reduction	**510,174**	**101**	**849**	**9,618**	**25**	**355**
% Reduction	**74%**	**70%**	**86%**	**99%**	**51%**	**94%**

Source: Evaluator Calculations

10.3 Victor Valley Transit (Fleet 1)

Fleet 1 operates on fixed routes that are partially within a DAC according to CalEnviroScreen 3.0. DAC designations were overlaid with each route to determine its percentage in a DAC as shown in Figure A-27. Based on this, the percentage of DAC operations for each route was calculated as shown in Table A-43, which also includes bus mileage per route from telematics data over a period of several initial months. An average of 22% of Fleet 1 electric bus operations occur in a DAC based on a mileage weighted percentage.

Figure A-27. Fleet 1 Key Routes and DAC Proportions



Source: Esri ArcGIS and Fleet 1

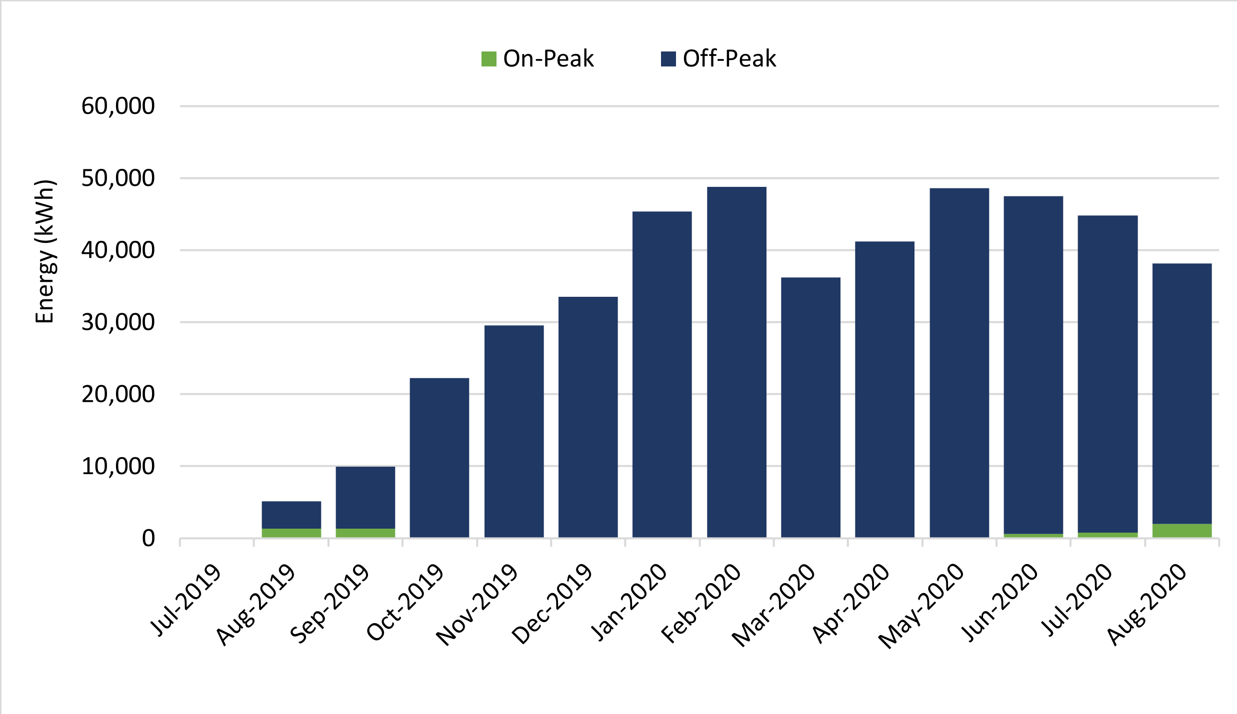
Table A-43. Fleet 1 DAC Calculations by Route

	VVT-301	VVT-302	VVT-303	VVT-304	VVT-305	VVT-306	VVT-307
% DAC from route data	22%	22%	21%	21%	23%	25%	18%
Miles from vehicle telematics	23,042	16,929	19,260	22,738	18,516	23,201	21,767

Source: Evaluator Calculations and Fleet Telematics

This analysis used utility meter 15-minute interval data, charging sessions summaries, vehicle onboard telematics trip summaries, and daily driver logs for the seven electric buses in Fleet 1. Utility meter data for the new PRP charging infrastructure used by the electric buses was available from August 24, 2019, to August 31, 2020.

Figure A-28. Fleet 1 electric energy use by month



Source: SCE Meter Data

There was a gradual increase in electrical consumption at the charging stations from July 2019 to February 2020 as additional electric buses were delivered and entered service. The selected evaluation period is from January 2020 to August 2020, which excludes the initial ramp-up period. The electric energy consumption for this period was determined by totaling energy use during utility meter fifteen-minute demand periods. Records of vehicle utilization and electricity consumption were used to determine an average electric fuel economy of 1.99 kWh per mile. Baseline vehicle fuel economy was determined to be 3.71 miles per diesel gallon equivalent of CNG based on logs available from 2019.

Annualized Emissions and Fuel Use

Extrapolating this electricity consumption from January 2020 to August 2020 to an annual basis would equate to 521,169 kWh per year, with 3,024 (1%) of those kWh occurring during the on-peak hours between 4 and 9 PM on weekdays during the summer months. Based on the calculated electric bus efficiency, this would result in 37,338 annual miles per bus (261,369 miles total). Using the estimated average baseline fuel economy, this annual mileage would require 70,450 DGE or 81,369 GGE of CNG per year, which is now saved. Annual emissions and emission reductions are presented in Table A-44 using the determined annual kWh and corresponding calculated baseline fuel use.

Table A-44. Fleet 1 operation annual emissions

	GHG (MT/yr)	SO_x (kg/yr)	NO_x (kg/yr)	CO (kg/yr)	PM (kg/yr)	VOC (kg/yr)
CNG	755	157	1,077	10,607	53	412
Electric	166	39	127	105	22	21
Net Reduction	**589**	**118**	**950**	**10,502**	**31**	**391**
% Reduction	**78%**	**75%**	**88%**	**99%**	**59%**	**95%**

Source: Evaluator Calculations

Best Observed Scenario

The above benefits are based on operations for the established pilot period, which likely includes variations due to the initial adoption of this technology in the fleet or other factors. The best observed scenario takes a high utilization period within the pilot and extrapolates that over an entire year to evaluate the projected annualized emissions. The best observed operations for Fleet 1 was in February 2020 when the highest monthly mileage was observed. The fleet would accumulate 318,360 annual miles if this rate were applied across the whole year (45,480 miles per bus). Table A-45 shows the annual benefits if this level of utilization was experienced across an entire year, which would save 99,112 GGE of CNG per year.

Table A-45. Fleet 1 best observed operation annual emissions

	GHG (MT/yr)	SO_x (kg/yr)	NO_x (kg/yr)	CO (kg/yr)	PM (kg/yr)	VOC (kg/yr)
CNG	919	191	1,312	12,920	64	502
Electric	206	48	155	128	27	26
Net Reduction	**713**	**143**	**1,157**	**12,792**	**38**	**476**
% Reduction	**78%**	**75%**	**88%**	**99%**	**59%**	**95%**

Source: Evaluator Calculations

11. SCE Urban DC Fast Charging Clusters

DAC Impact

The SCE Urban DCFC Clusters PRP includes five separate public charging station locations. Two of these, Corona Sun Square and 7-Eleven are in a DAC according to CalEnviroScreen 3.0, while the two AAA locations are directly adjacent to a DAC. EV drivers using these sites have unknown travel patterns before and after they charge at these locations. Based on the average energy dispensed per charging event and average efficiency for electric vehicles in this region, the average driving distance for users of each site were determined. Using this to create a radius around the charging station location, a percentage of DAC within this area was calculated (an example is shown in Figure A-29). This was done for the four sites that recorded regular charging activity (excluding the AAA Upland site) with results shown on Table A-46 determining that 15% of the emission benefits can be attributed to DACs.

Figure A-29. Example DAC Calculation Approach Shown here for 7-Eleven Pomona

Source: Esri ArcGIS

Table A-46. DAC calculation results

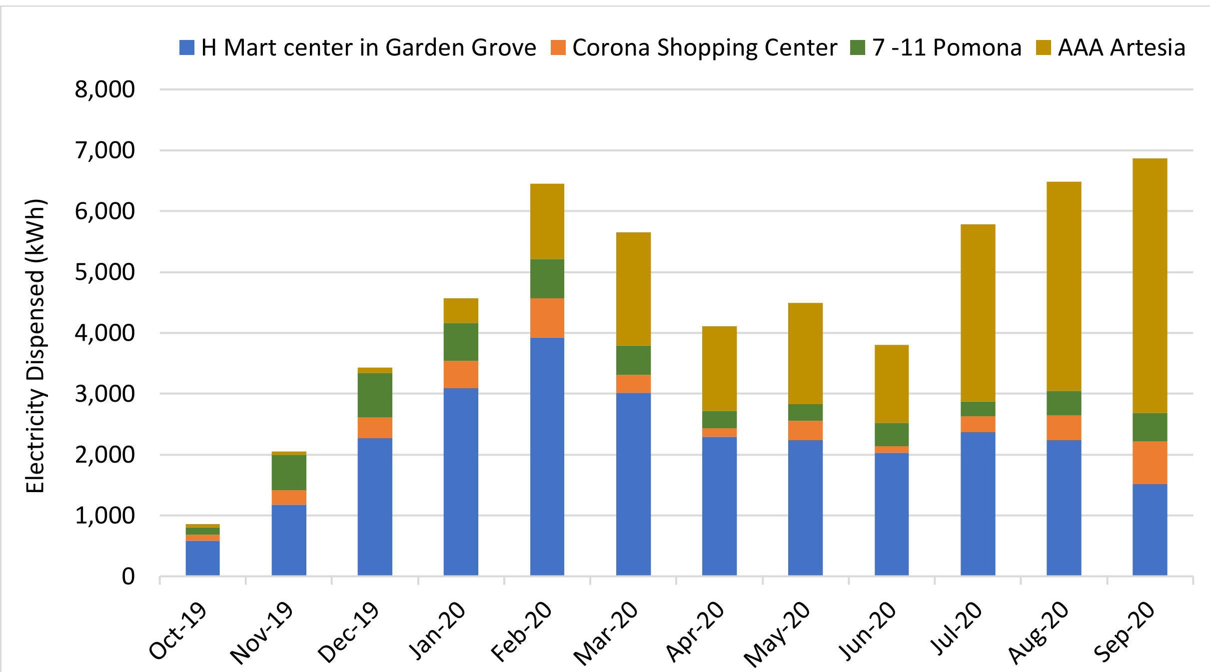
PRP Site	Percent of PRP Charging Activity	Average Electric Driving Distance from Charge Events	DAC Percentage within this Area
Corona Sun Square	7%	33 miles	21%
H Mart center in Garden Grove	49%	45 miles	14%
AAA Artesia	34%	46 miles	12%
7-Eleven Pomona	10%	28 miles	25%
		Weighted Average	**15%**

Source: Evaluator Calculations

Annualized Emissions and Fuel Use

The utility meter 15-minute data was available from a dedicated EV meter at each site. Charging session data was also shared by SCE from ChargePoint.

Figure A-30. Urban DCFC Clusters monthly energy dispensed by site

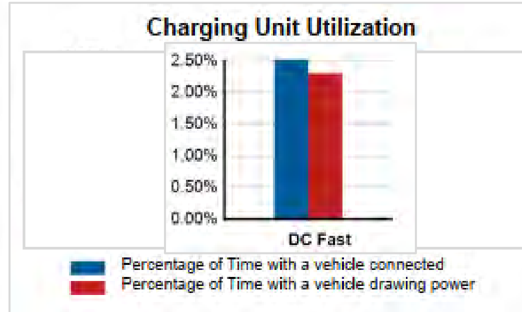


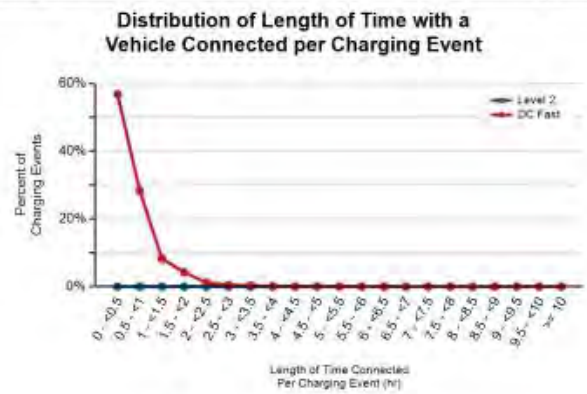
Source: SCE Meter Data

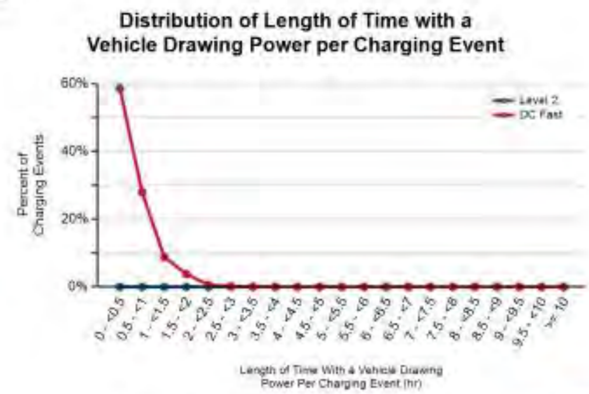
Electric energy consumption was determined from a summation of energy use during 15-minute utility meter periods shown in Figure A-30. The chargers were activated in September 2019 for initial testing and opened to the public in October. However, there was a steady increase in use through February 2020 as EV drivers discovered these new chargers. While the COVID-19 pandemic likely caused a decline in use from March through June 2020, the period from February to September 2020 is used to calculate performance. Figure A-31 through Figure A-35 provide usage profiles and port statistics for the four sites combined and by individual location during this time period.

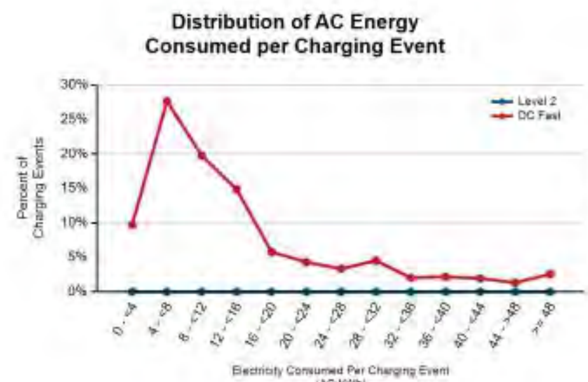
Figure A-31. Urban DCFC – all four sites usage profile and port statistics

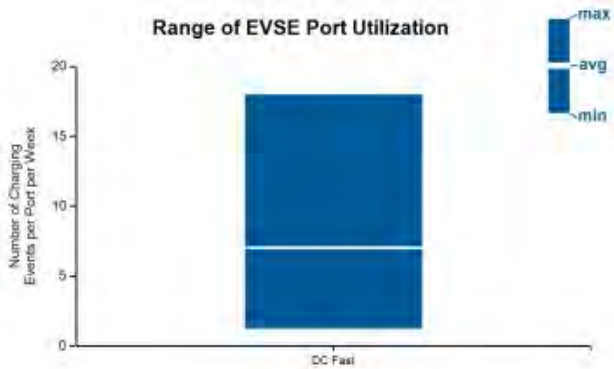
EVSE Usage - By EVSE Level	DC F
Number of charging ports[1]	12
Number of charging events[2]	2,933
Charging energy consumed (AC MWh)	42.7
Average percent of time with a vehicle connected per charging port	2.52%
Average percent of time with a vehicle drawing power per charging port	2.30%
Average number of charging events started per charging port per week	7.04
Average electricity consumed per charging port per week (AC KWh)	102.39
Average length of time with vehicle connected per charging event (hr)	0.60
Average length of time with vehicle drawing power per charging event (hr)	0.55
Average electricity consumed per charging event (AC kWh)	14.54



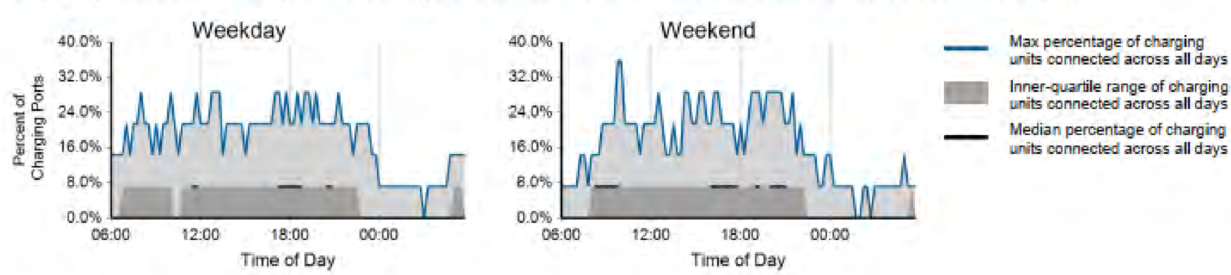








Charging Availability: Range of Percentage of DC Fast Ports with a Vehicle Connected versus Time of Day[3]



[1] Includes all EVSE ports available during the reporting period and have reported data to INL.

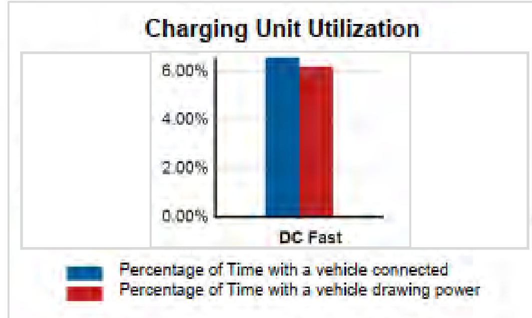
[2] A charging event is defined as the period when a vehicle is connected to a charging unit, during which power is transferred.

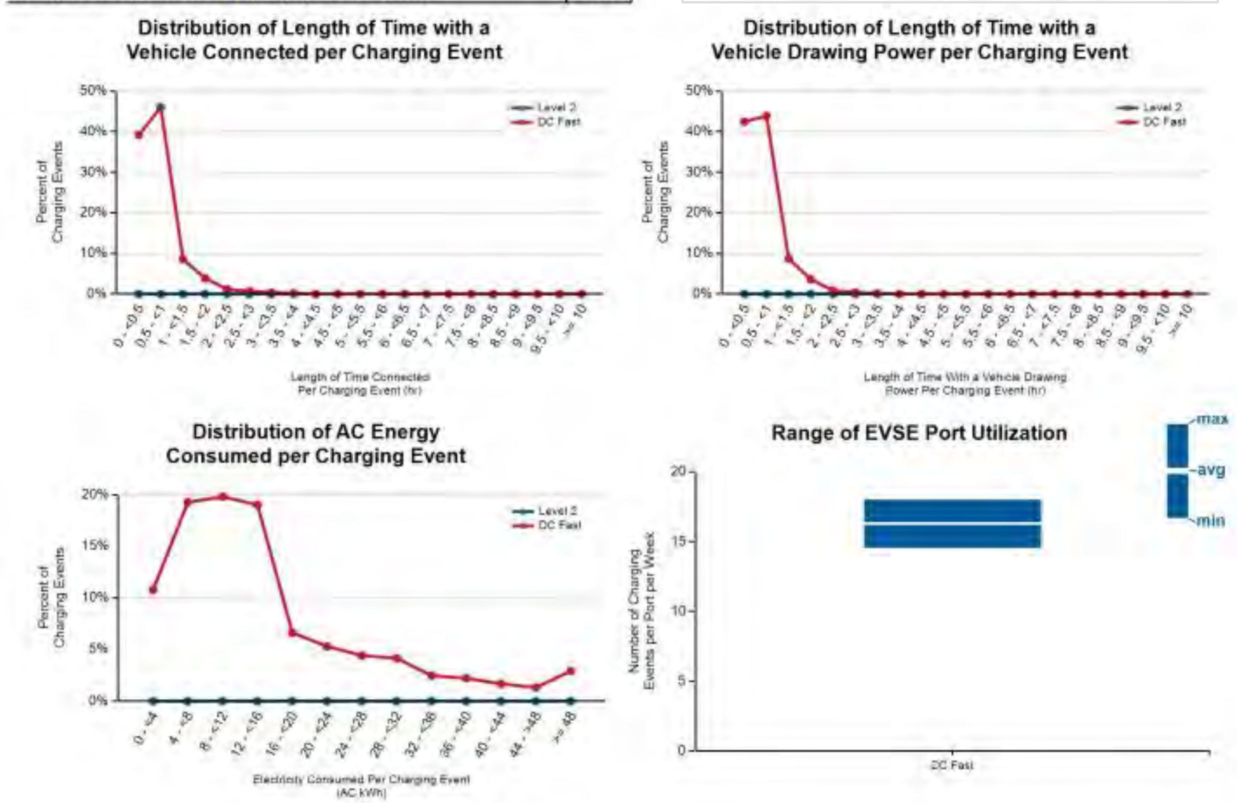
[3] Weekends start at 6:00am on Saturday and end 6:00am Monday local time.

Source: EVSP Charging Session Data

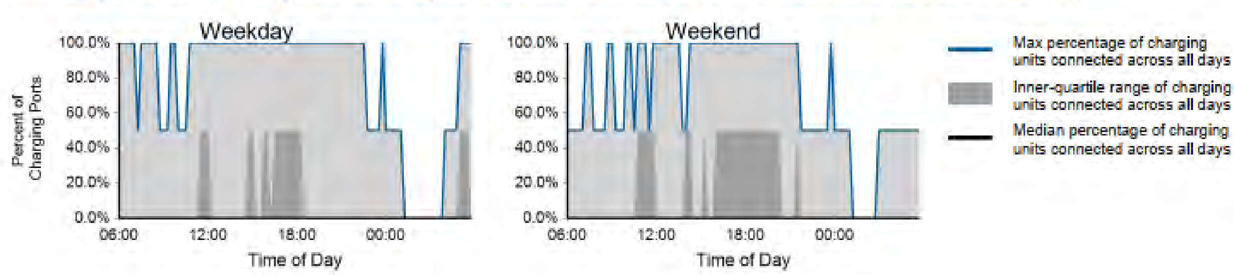
Figure A-32. Urban DCFC – AAA Artesia usage profile and port statistics

EVSE Usage - By EVSE Level	DC F
Number of charging ports[1]	2
Number of charging events[2]	1,131
Charging energy consumed (AC MWh)	17.6
Average percent of time with a vehicle connected per charging port	6.58%
Average percent of time with a vehicle drawing power per charging port	6.20%
Average number of charging events started per charging port per week	16.29
Average electricity consumed per charging port per week (AC KWh)	252.80
Average length of time with vehicle connected per charging event (hr)	0.68
Average length of time with vehicle drawing power per charging event (hr)	0.64
Average electricity consumed per charging event (AC kWh)	15.52





Charging Availability: Range of Percentage of DC Fast Ports with a Vehicle Connected versus Time of Day[3]



[1] Includes all EVSE ports available during the reporting period and have reported data to INL.

[2] A charging event is defined as the period when a vehicle is connected to a charging unit, during which power is transferred.

[3] Weekends start at 6:00am on Saturday and end 6:00am Monday local time.

Source: EVSP Charging Session Data

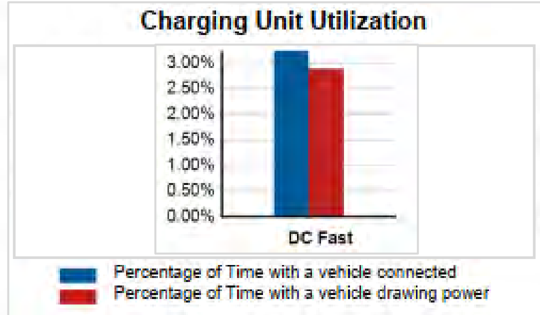
Figure A-33. Urban DCFC – Corona Sun Square usage profile and port statistics

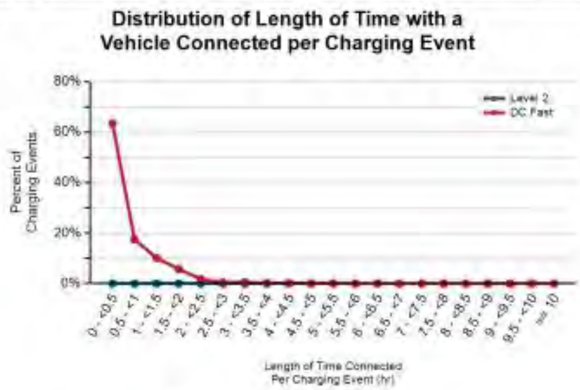
Data has been removed for confidentiality reasons.

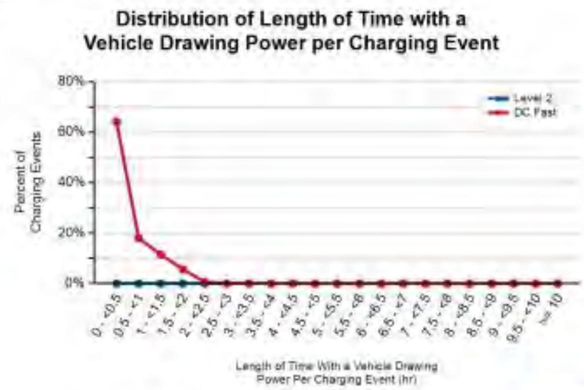
Source: EVSP Charging Session Data

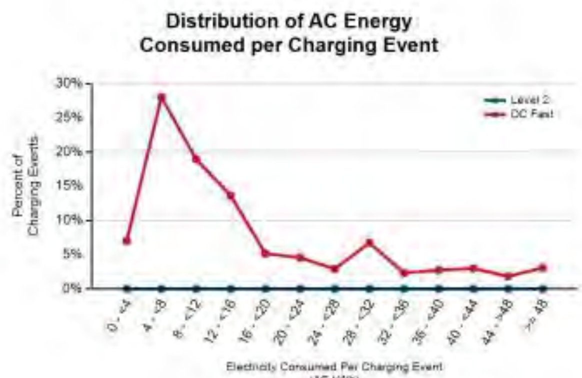
Figure A-34. Urban DCFC – H Mart center in Garden Grove usage profile and port statistics

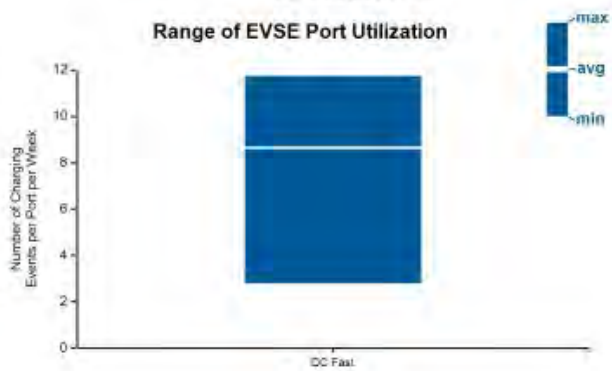
EVSE Usage - By EVSE Level	DC
Number of charging ports[1]	4
Number of charging events[2]	1,202
Charging energy consumed (AC MWh)	19.2
Average percent of time with a vehicle connected per charging port	3.24%
Average percent of time with a vehicle drawing power per charging port	2.88%
Average number of charging events started per charging port per week	8.66
Average electricity consumed per charging port per week (AC KWh)	138.00
Average length of time with vehicle connected per charging event (hr)	0.63
Average length of time with vehicle drawing power per charging event (hr)	0.56
Average electricity consumed per charging event (AC kWh)	15.94

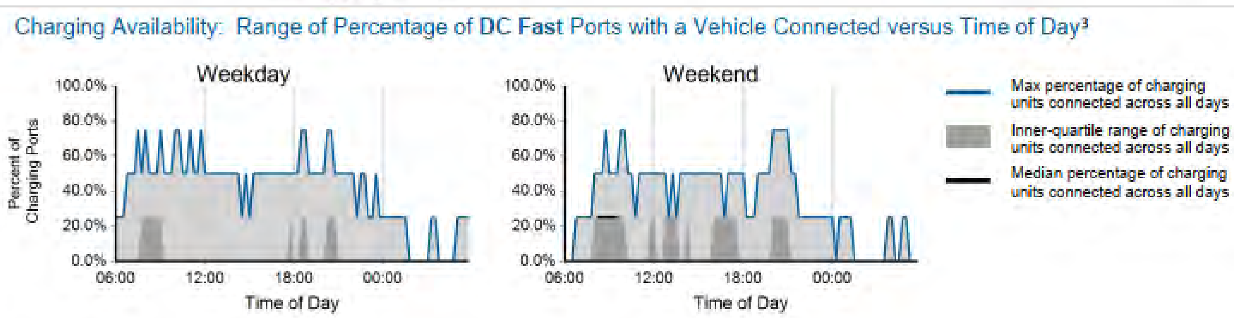












[1] Includes all EVSE ports available during the reporting period and have reported data to INL.

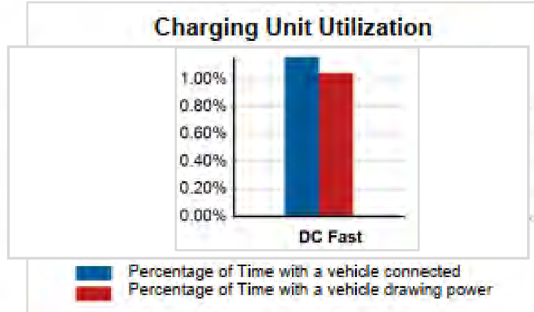
[2] A charging event is defined as the period when a vehicle is connected to a charging unit, during which power is transferred.

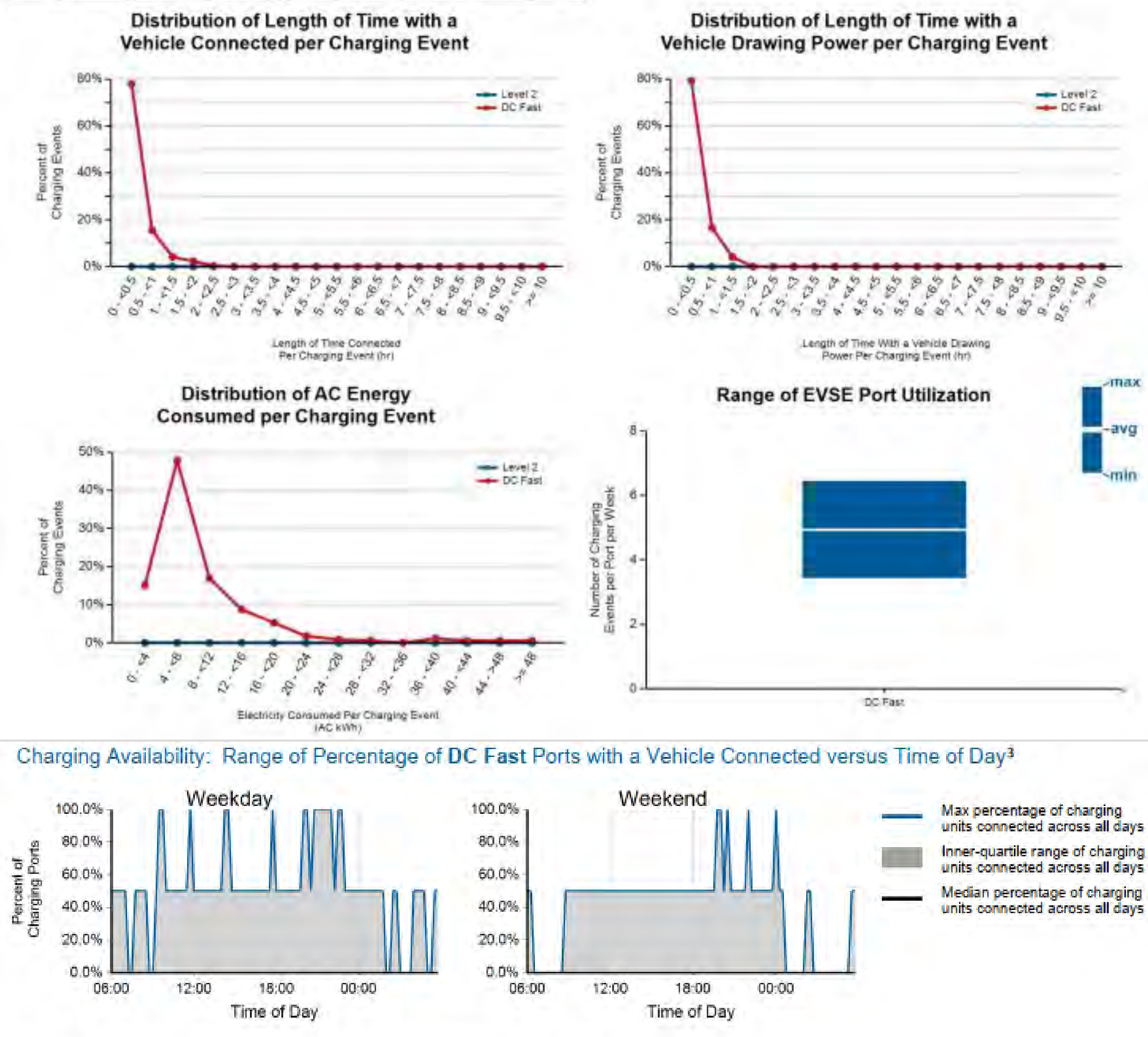
[3] Weekends start at 6:00am on Saturday and end 6:00am Monday local time.

Source: EVSP Charging Session Data

Figure A-35. Urban DCFC – 7-Eleven Pomona usage profile and port statistics

EVSE Usage - By EVSE Level	DC F
Number of charging ports[1]	2
Number of charging events[2]	343
Charging energy consumed (AC MWh)	3.1
Average percent of time with a vehicle connected per charging port	1.16%
Average percent of time with a vehicle drawing power per charging port	1.04%
Average number of charging events started per charging port per week	4.94
Average electricity consumed per charging port per week (AC KWh)	44.97
Average length of time with vehicle connected per charging event (hr)	0.39
Average length of time with vehicle drawing power per charging event (hr)	0.35
Average electricity consumed per charging event (AC kWh)	9.10





[1] Includes all EVSE ports available during the reporting period and have reported data to INL.

[2] A charging event is defined as the period when a vehicle is connected to a charging unit, during which power is transferred.

[3] Weekends start at 6:00am on Saturday and end 6:00am Monday local time.

Source: EVSP Charging Session Data

Annualized Emissions and Fuel Use

Extrapolating the PRP demonstration period from February 2020 to September 2020 on an annual basis, the twelve DCFCs (does not include AAA Upland due to no charging) would have dispensed 65,400 kWh of electricity. The corresponding utility supplied electricity annual total (accounting for standby load and charger efficiency) is 87,700 kWh with 8,500 kWh (10%) occurring during weekday on-peak hours between 4 and 9 PM from June to September. An analysis of EVs registered in the Greater Los Angeles area was conducted to determine the average efficiency. The most popular plug-in vehicles are listed in Table A-47 with their current registration numbers and efficiency.

Table A-47. EV registrations and efficiency in greater Los Angeles

Make	Model	Number of Vehicles	kWh/100 mi	Efficiency (miles/kWh)
Tesla	Model 3	43,259	24	4.17
Chevrolet	Volt	26,796	31	3.23
Tesla	Model S	24,705	29	3.45
Toyota	Prius Prime	17,116	25	4.00
Ford	Fusion Energi	12,902	33	3.03
Tesla	Model X	12,343	35	2.86
Toyota	Prius Plug-in Hybrid	11,700	31	3.23
Chevrolet	Bolt EV	10,071	29	3.45
Nissan	LEAF	8,314	30	3.33
Honda	Clarity Plug-In Hybrid	7,847	31	3.23
BMW	5 Series	6,787	47	2.13
BMW	i3 REx	6,753	32	3.13
Ford	C-MAX Energi	6,034	33	3.03
FIAT	500e	5,822	30	3.33
Toyota	Mirai	3,401	67	1.49
Audi	A3 Sportback e-tron	2,918	44	2.27
BMW	i3	2,800	30	3.33
Volkswagen	e-Golf	2,778	30	3.33
BMW	3 Series	2,612	45	2.22
BMW	X5	2,177	63	1.59
Mercedes- Benz	GLC	2,177	49	2.04
Chrysler	Pacifica Hybrid	1,945	41	2.44
Hyundai	Ioniq Plug-in Hybrid	1,312	28	3.57
Kia	Niro Plug-In Hybrid	1,312	32	3.13
Honda	Clarity Electric	1,230	31	3.23
Hyundai	Sonata Plug-in Hybrid	1,005	34	2.94
Kia	Soul EV	1,000	31	3.23
Mercedes- Benz	C-Class	989	56	1.79
BMW	i8	985	49	2.04
Hyundai	Ioniq Electric	974	25	4.00
Chevrolet	Spark EV	955	28	3.57

Source: California Energy Commission

Based on these EVs, an average efficiency of 3.34 miles per kWh and annual electricity dispensed, 219,000 electric miles were driven. Based on an estimated baseline fuel economy of 24.9 MPG[142], internal combustion engine vehicles would consume 8,800 gallons of gasoline, which would be saved if driving an EV. Emission factors for light-duty gasoline vehicles on an mmBtu basis from the California GREET 3.0 model[129] are presented in Table A-48.

Table A-48. Light-duty gasoline baseline emissions factors determined by California GREET 3.0

CO_2 (g/mmBtu)	SO_x (g/mmBtu)	NO_x (g/mmBtu)	CO (g/mmBtu)	PM_{10} (g/mmBtu)	VOC (g/mmBtu)
100,170	22.35	81.25	720.81	9.40	90.33

Source: California GREET 3.0

Using the determined annual kWh and baseline fuel use combined with the energy factor of 114,102 Btu per gallon of gasoline, the resulting annual emissions and emission reductions are presented in Table A-49.

Table A-49. Urban DCFC Clusters charging station annual emissions

	GHG (kg/yr)	SO_x (kg/yr)	NO_x (kg/yr)	CO (kg/yr)	PM (kg/yr)	VOC (kg/yr)
Gasoline	100,300	22	81	722	9.4	90
Electric	20,165	7	21	18	3.7	4
Net Reduction	**80,152**	**16**	**60**	**704**	**5.7**	**87**
% Reduction	**80%**	**71%**	**74%**	**98%**	**61%**	**96%**

Source: Evaluator Calculations

Best Observed Scenario

The above benefits are based on operations for the established pilot period, which likely includes variations due to the initial adoption of EVs in the market or other factors (COVID-19 limiting travel). The best observed scenario takes a high utilization period within the pilot and extrapolates that over an entire year to evaluate the projected annualized emissions.

Of the five PRP sites, the busiest week occurred at AAA Artesia during the week of September 6–12, 2020. This week saw the highest utilization per DCFC, as judged by four different metrics: the number of charging events performed, the number of distinct users, the percent of time with vehicles connected to the chargers, and total energy consumed by vehicles. Table A-50 shows the metrics for AAA Artesia DCFCs during the busiest week. The percent of time with a vehicle connected calculation assumes

142 Internal combustion engine vehicle efficiency same as used in the Electric Vehicle-Grid Integration Pilot Program ("Power Your Drive") Ninth Semi-Annual Report of San Diego Gas & Electric Company (https://www.sdge.com/sites/default/files/regulatory/R.18-12-006%20Ninth%20Oct%202020%20PYD%20Final%20Report%2010%2014%202020.pdf), October 14, 2020.

availability of DCFCs 7 days-a-week and 24 hours-a-day. This was the actual availability of these vehicles, but in some charging station installations certain periods of the day may be excluded if it is unreasonable to assume vehicle charging could occur then (e.g., such as 10 pm to 6 am at an unlit public lot not near any housing). Only six of the 63 charging events at this location during this week were performed between 10 pm and 6 am, which indicates there is some demand for late-night or early morning charging, therefore, around-the-clock utilization was considered.

Metrics for percent of time with a vehicle connected were also calculated for the busiest day for the week (which occurred during the weekend) for additional comparisons. The DCFCs at AAA Artesia experienced their peak single-day utilization during this week on Sunday, September 6, 2020. Twelve users conducted 14 charging events, averaging 55 minutes and 23 kWh per charge. The longest charging event was 3.4 hours. Utilization over this 24-hour period was 28%. This suggests that the pair of DCFCs has the capacity to handle about 3 times as much charging.

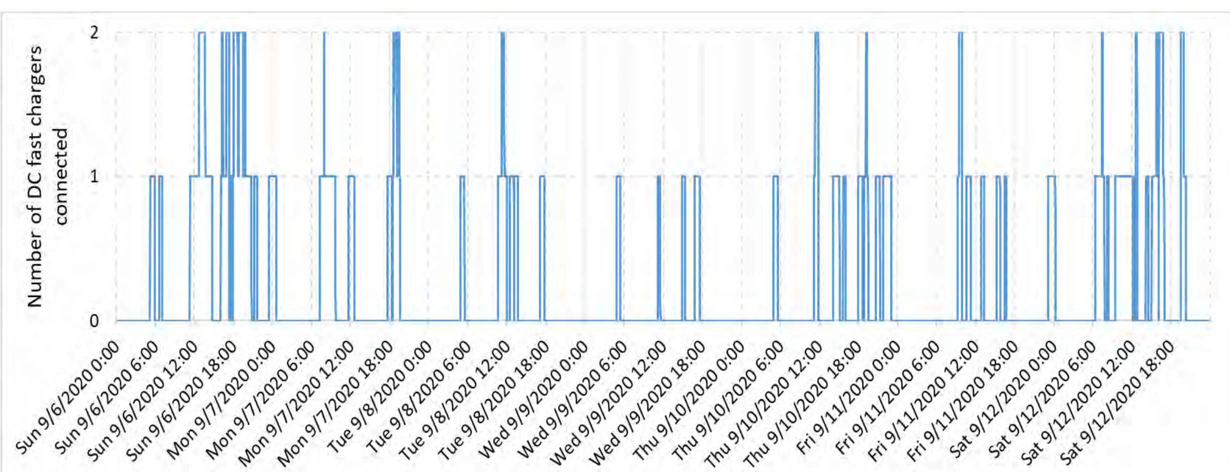
Table A-50. DCFC use at AAA Artesia, September 6–12, 2020

Charging Station Metric	Weekdays	Weekend	Full Week
Number of charging events	35	28	63
Number of charging events per day (min/avg/max)	4 / 7 / 10	13 / 14 / 15	9
Number of distinct users	21	20	28
Percent of time with a vehicle connected (busiest day)	10%	24% (28%)	14%
Percent of time with vehicles connected to both DCFCs simultaneously (busiest day)	2%	10% (14%)	4%
Energy consumed by vehicles (AC kWh)	595	657	1,252
Energy consumed per day (AC kWh)	119	328	179

Source: EVSP Charging Session Data

Figure A-36 shows the site utilization by the number of chargers in use during each hours of the week.

Figure A-36. Time of day when and number of DCFCs in use at AAA Artesia, September 6–12, 2020



Source: EVSP Charging Session Data

Multiplying the highest DCFC use at AAA Artesia by seven (14 total DCFCs installed divided by the two installed at AAA Artesia) results in 441 events per week dispensing 8,760 kWh. Across an entire year, this would be equivalent to 456 MWh of electricity dispensed (466 MWh of supplied electricity with 7% on-peak) supporting 1,520,000 electric miles which would have consumed 61,100 gallons of gasoline, resulting in the benefits presented in Table A-51.

Table A-51. Best observed Urban DCFC Clusters annual emissions

	GHG (kg/yr)	SO_x (kg/yr)	NO_x (kg/yr)	CO (kg/yr)	PM (kg/yr)	VOC (kg/yr)
Gasoline	698,700	156	567	5,028	66	630
Electric	107,033	35	114	94	20	19
Net Reduction	**591,656**	**121**	**453**	**4,934**	**46**	**611**
% Reduction	**85%**	**78%**	**80%**	**98%**	**70%**	**97%**

Source: Evaluator Calculations

Operational Cost Savings

Operational cost savings may be provided to the host site of the charging stations (if the stations generate revenue) and EV drivers that replace gasoline miles with electric miles. Charging station revenue is recorded for each charging session and can be totaled for a set period before being scaled up to an annual basis. EV drivers realize operational cost savings when their cost per mile of electricity are less than the cost per mile to drive on gasoline. The average cost of gasoline on the West Coast in July 2020 was $3.00 per gallon.[14] Therefore, the EV driver's operational cost savings can be calculated as follows:

Driver Savings = Equivalent Gasoline Saved (gallons) X Average Gasoline Cost ($/gallon)– Charging Station Revenue

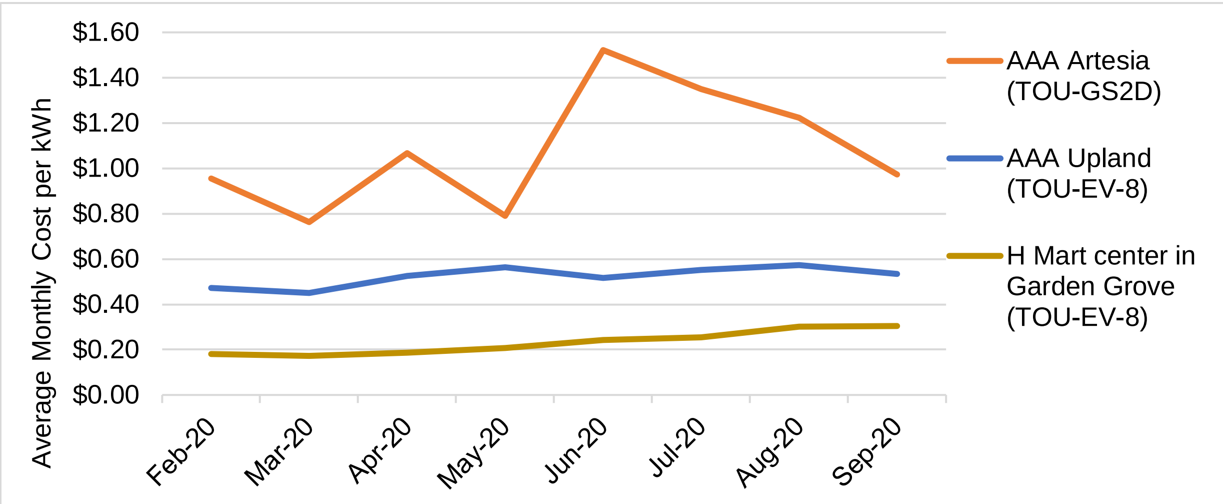
Table A-52. Summary of operational cost savings results for all sites

	PRP Implementation Period		Projected based on Best Observed Period	
	Feb – Sept 2020	Annualized	One Site for Week in September 2020	Annualized
Electricity Dispensed	43,600 kWh	65,400 kWh	1,250 kWh	456,000 kWh
Gasoline Gallons Saved	5,850 gallons	8,800 gallons	168 gallons	61,100 gallons
EVSE Revenue	$8,500	$12,750	$0 (AAA Artesia does not charge a fee)	$89,000 (scaled from PRP period)
Driver Fuel Costs Saved	$17,550	$26,300	$500	$183,000
Driver Savings	$9,050	$13,550	$500	$95,000

Source: SCE Meter Data, EVSE Charging Session Data, and Evaluator Calculations

As shown in Figure A-37, the average monthly cost of electricity at these sites varied widely from a low of $0.18 per kWh to $1.50 per kWh. Evaluator pricing analysis unveiled that AAA Artesia was on an incorrect rate (TOU-GS2D) and SCE rebilled them after switching to TOU-EV-8 resulting in a significant refund as their electricity costs per kWh were more than double compared to other sites. The resulting range of electricity cost per kWh for this PRP was $0.18 to $0.60 depending on time of use.

Figure A-37. Average monthly electricity costs per kWh



Source: SCE Meter Data and Rates

Cost savings are skewed towards the driver benefiting because the AAA Artesia DCFCs are free to use. The charging station hosts set their own pricing which is described in the Implementation Process section of Evaluation Findings.

Table A-53. Summary of operational cost savings results by individual site

	Garden Grove 2/1/20-4/9/20 ($0.25/kWh)	Garden Grove 4/9/20-9/30/20 ($0.30/kWh)	7-Eleven 2/1/20-9/30/20 ($0.41-$0.55/kWh + $0.10-$0.15/min)
Electricity Dispensed	7,600 kWh	12,000 kWh	3,180 kWh
Electricity Supplied	8,600 kWh	17,000 kWh	5,620 kWh
Gasoline Gallons Saved	1,000 gallons	1,600 gallons	400 gallons
EVSE Revenue	$1,900	$3,600	$2,000
Host Electricity Costs	$1,500	$4,200	N/A
Driver Fuel Costs Saved	$3,060	$4,800	$1,300
Driver Savings	$1,170	$1,200	-$700

Source: SCE Meter Data and Rates, EVSE Charging Session Data, and Evaluator Calculations

User Comments

Table A-54. User comments from experience at AAA Artesia

Date	Comment
Sep 4, 2020	Thank you, AAA, for the free quick charging.
Sep 5, 2020	Thx 4 FREE charging AAA!
Sep 24, 2020	Nice location across the street from Cerritos mall.
Oct 4, 2020	Only fast charger that's free that I know of.
Oct 10, 2020	Both were open and very accessible! Enter directly right off of Gridley Road, not 187th Street!
Oct 20, 2020	Thanks to AAA and ChargePoint.
Oct 26, 2020	Using the DCFC I am halfway done, there is another spot open though.
Nov 14, 2020	Thanks for another quick free session.
Nov 15, 2020	I could not get the unit EVSE 2 to charge very fast (maybe 21 kW), but EVSE 1 is going fine, though I will be shocked if it goes over 50 kW even with the 62.5 kW labels they have.
Nov 16, 2020	Left charger only going 28 kW.
Nov 22, 2020	The charging speed is now half of what it used to be.
Nov 27, 2020	First time using the fast charger here and I'm really happy. Didn't realize it was even here and I'm proud to be a AAA member)
Nov 28, 2020	Anyone know why these stations are now so slow?
Nov 28, 2020	I tried both chargers and the max they charge is between 20 to 27 kW.

Source: PlugShare

Table A-55. User comments from experience at Corona Sun Square

Date	Comment
Dec 31, 2019	This charger was excellent, if only a bit pricey. If you can find cheaper one (shouldn't be hard) go there instead.

Source: PlugShare

Table A-56. User comments from experience at H Mart center in Garden Grove

Date	Comment
Oct 28, 2019	All 4 chargers are down, I've contacted ChargePoint and they are going to send a technician to figure it out sometime this week.
Nov 15, 2019	Successfully charging now. However, customers of shopping center in non-electric vehicles parking in the event spaces.
Dec 15, 2019	4 DCFC chargers but 0 level 2!
Dec 22, 2019	Awesome. Cheap! 2 ICE cars parked!
Feb 22, 2020	Rav4 with aftermarket CHAdeMO cannot initiate the charge and there is no button to press to start the charge. Wish they could add a button on the touch screen interface to initiate charge.
Feb 27, 2020	Working and all spots available.
Oct 26, 2020	CHAdeMO is working

Source: PlugShare

Table A-57. User comments from experience at 7-Eleven Pomona

Date	Comment
Oct 24, 2019	Just opened site in great location! Charging at 7-11 is awesome.
Nov 5, 2019	Expensive comparing with others. I paid $6.90 for 15 kWh in 28.5 mins.
Nov 16, 2019	Great site.
Nov 21, 2019	Nice, new chargers.
Nov 27, 2019	Nice new chargers. Able to pull 47.5 kW peak (~120 A). Couldn't verify whether these are actually 156 A chargers. Maybe my battery was too cold? Ambient was 58 deg F.
Nov 27, 2019	Definitely 50 kW+ chargers. Kia Soul EV peaked at 55 kW (140 A @394 V).
May 20, 2020	2nd ChargePoint DC fast charge unit that did not charge my car today. The EVgo worked down the street. I don't know if it was an account balance issue but maybe...a Nissan Leaf was charging next to me.
Jun 17, 2020	Pricey yet worked with the ChargePoint app by it reading the account on my phone.

Source: PlugShare

12. PG&E Transit Fleet PRP Rate Structures

PG&E simulated RTD's expected electricity bills on the BEV rate prior to their switch to the BEV rate. Table A-58 and Table A-59 summarize the energy and demand charges for the A-10 TOU and the BEV rates used in the rate analysis.

Table A-58. PG&E A10 TOU rate

		Energy Charge ($/kWh)	Demand Charge ($/kW)
Summer	Peak	$0.2343	$ 20.46
	Partial Peak	$0.1791	
	Off-Peak	$0.1511	
Winter	Partial Peak	$0.1497	$ 11.94
	Off-Peak	$0.1327	

Source: PG&E

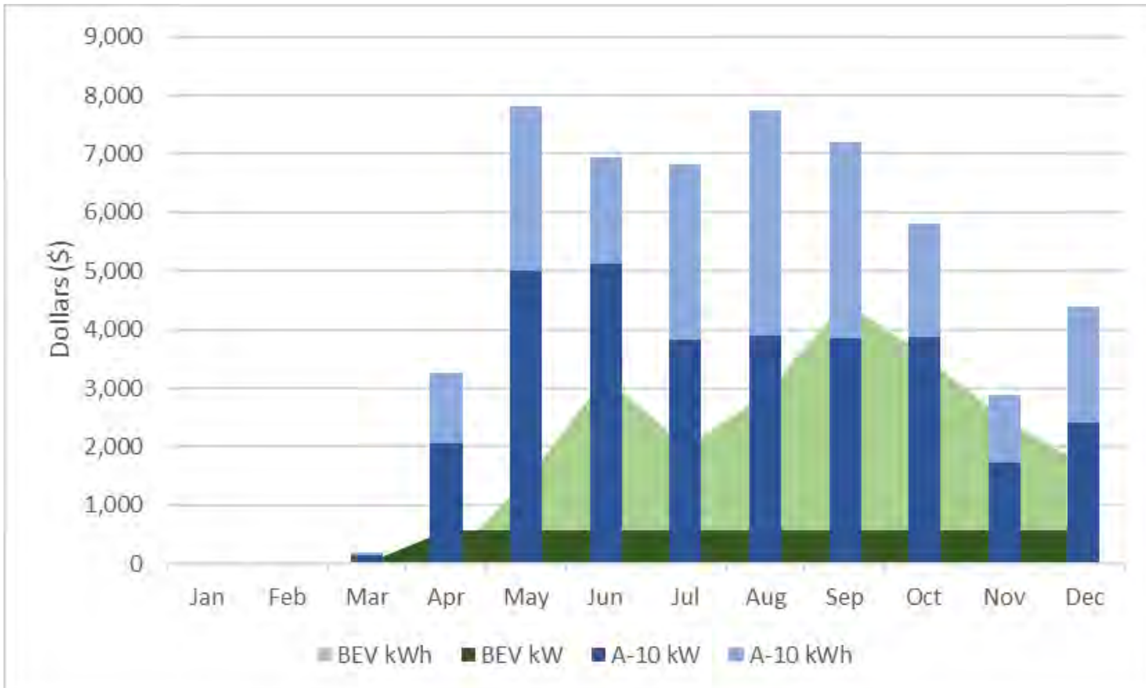
Table A-59. PG&E BEV rate

	Energy Charge ($/kWh)	Subscription Charge ($/50 kW)
Peak	$0.33	$95.56
Off-Peak	$0.12	
Super-Off-Peak	$0.10	

Source: PG&E

Related analysis follows and provides a comparison of RTD's actual costs with its theoretical costs on the new rate at each location. Figure A-38 illustrates the potential savings RTD can realize at RTC and the depot chargers. The blue bars are RTD's actual bills at RTC during 2019 and the dark blue bars represent the demand charges incurred. The green lines represent the simulated bill on the BEV rate). The dark green represents the energy charge, and the light green the customizable subscription rate that is based on demand. The simulation highlights how the bulk of the bill is not dependent on the energy charge, and the demand component is no longer variable each month.

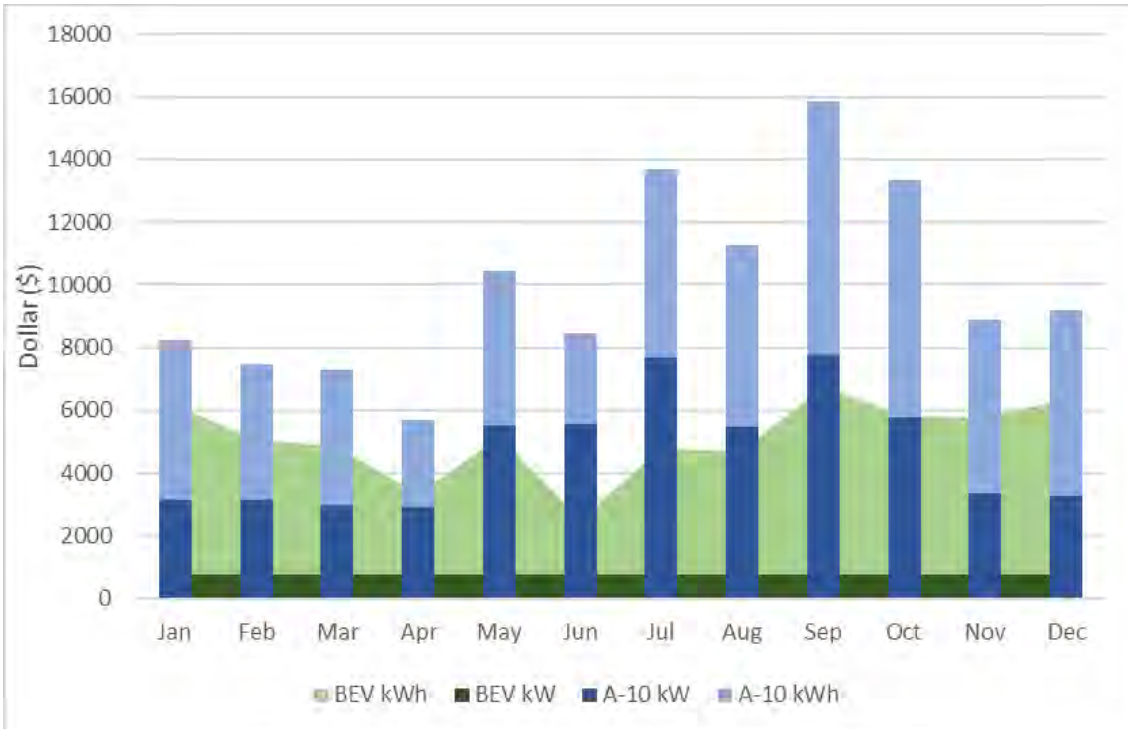
Figure A-38. RTC depot overnight charging cost rate comparison (2019)



Source: Evaluator Calculations, PG&E, RTD

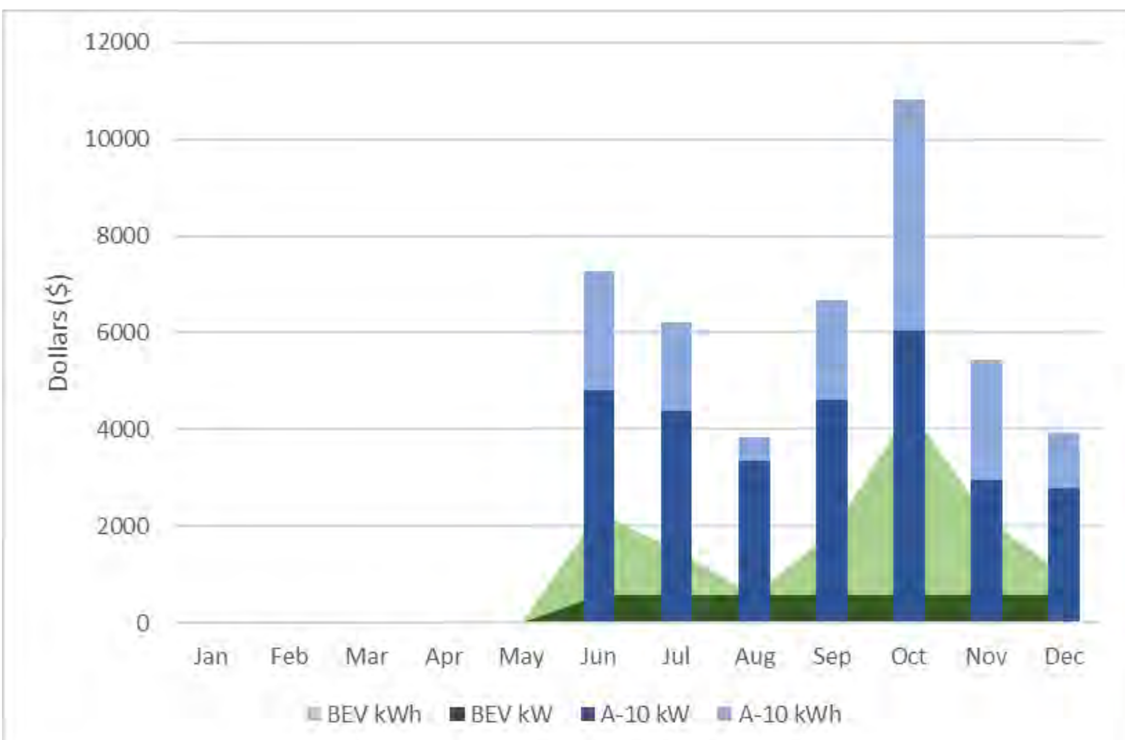
Figure A-39 and Figure A-40 show the potential savings at the DTC and UTS extreme fast charger locations. At DTC, the savings potential is clear, as the bill on the BEV rate rarely goes above $6,000 in a month while RTD's bills often exceed $10,000 a month. Bill data were limited at UTS as it was only operational starting June 2019 and experienced faults throughout that summer. However, savings can be expected to look similar to those at DTC.

Figure A-39. DTC opportunity charging cost rate comparison (2019)



Source: Evaluator Calculations, PG&E, RTD

Figure A-40. UTS opportunity charging cost rate comparison (2019)



Source: Evaluator Calculations, PG&E, RTD

13. PG&E Idle Reduction Technology Calculations

TRU Operating Hours

TRU operating hours vary by vehicle and facility type and are highly site specific. Table A-60 summarizes the trailer TRU idling operation data reported in EPRI's 2015 *Market and Technology Assessment of Electric Transport Refrigeration Units* and CARB's *Draft 2019 Update to Emissions Inventory for Transport Refrigeration Units* reports. From these reports, the weighted average annual trailer TRU idling opertation is 1,636 hours.

Table A-60. Trailer TRU idling hours per year

Source	Facility Type	Sample Size	Average Idling Hours per Day	Facility Operations Days per Week	Average Idling Hours per Year [a]
EPRI Case Study 1	Grocery Distribution Center	5	7.25	6 [b]	2,268
EPRI Case Study 2		120	10.80	7	3,379
EPRI Case Study 3	Food Service Distribution Center	38	4.10	5	1,283
EPRI Case Study 4		12	3.7	6 [b]	1,158
EPRI Case Study 5	Less-than-Truckload Carrier	120	5.0	5	1,564
CARB Draft Emissions Report	Various	811	N/A	N/A	1,409
Total or Average		**1,106**			**1,636**

[a] Assumes 50 weeks of operation per year.
[b] Not reported. Assumes six days of operation per week.

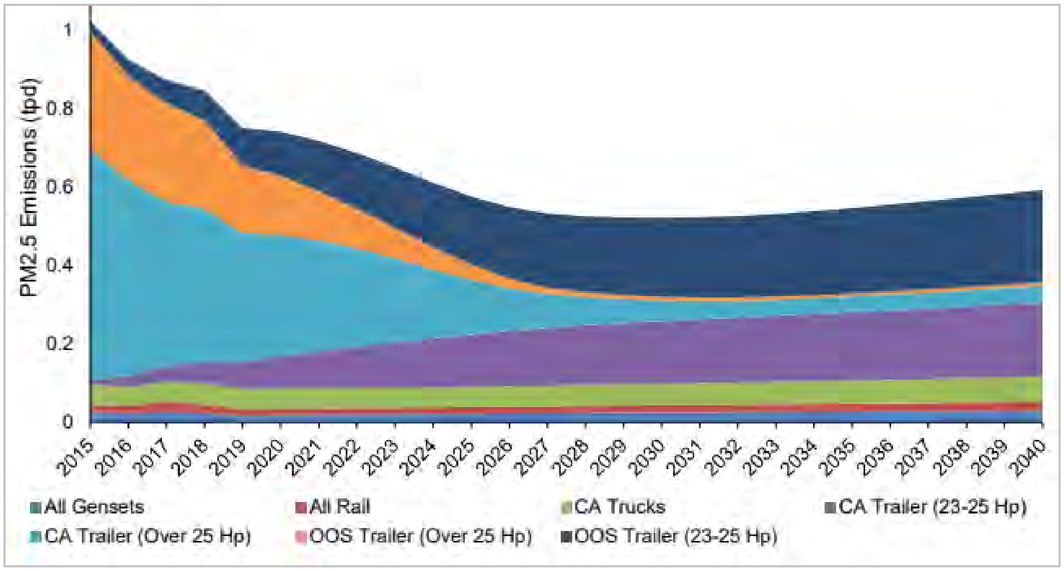
Source: Evaluator Calculations

The EPRI report case studies focused on trailer TRUs and did not present operating data for truck TRUs. Refrigerated trucks are typically used for shorter, local deliveries and are loaded during the evening and then idle or plug in overnight to maintain temperature setpoints. The CARB report cites a 2011 facility survey that included 459 trucks with an average total activity of 1,360 hours per year, where 49% of those hours were idling (666 hours).

TRU Emissions

In addition to incurring diesel fuel expenses, diesel-powered TRUs release harmful pollutants while idling. CARB's *Draft 2019 Update to Emissions Inventory for Transport Refrigeration Units* estimates criteria pollutant and emissions from existing diesel-powered TRU engines. Figure A-41 shows CARB's forecasted findings for diesel TRU particulate matter emissions under 2.5 microns in diameter (PM2.5) by vehicle category from 2015 to 2040. PM2.5 emissions are of high concern because this size of particle can easily pass through the nose and lungs. According to the report, without significant regulatory changes, the 23 horsepower (hp) to 25 hp trailer TRUs will dominate TRU PM2.5 emissions by 2030. The 23 hp to 25 hp trailer TRU models recently came onto the market as a smaller engine option and have grown in popularity, but the particulate matter emissions standards for these units are 15 times higher than for trailers with greater than 25 hp TRUs.

Figure A-41. Statewide PM2.5 from TRUs under existing airborne toxic control measure



Source: CARB's *Draft 2019 Update to Emissions Inventory for Transport Refrigeration Units* (Figure 2, p. 7).
https://ww3.arb.ca.gov/cc/cold-storage/documents/hra_emissioninventory2019.pdf

CARB is working on an update to the draft emissions report that will include diesel parts per million, greenhouse gas, and criteria pollutant reductions from transitioning to plug-in TRUs in compliance with the upcoming and pending regulation changes. This emissions inventory will be based on weighted emissions for fleets, estimated idling time, and number of facilities expected to be captured in the regulation.

eTRU Connection Port Vendors

Switching to plug-in operation requires a safe shore power connection point to prevent electrical arc flashes, as well as training for drivers and loading dock operators to avoid accidental drive-offs. There are two main eTRU connection port vendors in the California market: ESL Power and SafeConnect. The evaluation team interviewed representatives from both vendors to understand their technology, the size of their current market, and their thoughts on future market potential.

SafeConnect, which provided the 25 connection ports for this PRP, has been operating and deploying six-pin connection ports for eTRUs since 2014. They have ports deployed in over 30 states across the U.S. and Canada. The SafeConnect trailer/truck kit converts existing plugs from four-pin to six-pin and takes about 45 minutes to install for each TRU. SafeConnect's products are UL-listed and an EPA Smartway verified technology. The six-pin connection has a tension release mechanism, which releases the receptacle from the port (in case of a drive-off). SafeConnect is on Southern California Edison's (SCE) approved vendor list for their Charge Ready Transport program.

Most of SafeConnect's trailer and vehicle-side retrofit products are installed on Carrier and Thermo King 30-foot to 50-foot trailer TRUs. SafeConnect has not yet installed any connection ports at interstate truck stops but received inquiries and expect the market to pick up soon. The SafeConnect representative expressed concern that COVID-19 is having a huge impact on food distributors nationwide, especially those serving restaurant clients.

To date, a majority of SafeConnect's customers have been distribution warehouses such as Albertsons, but interest from grocery stores and food banks is increasing. According to SafeConnect, the interest has more to do with cost reductions and energy efficiency than CARB regulations. For example, McDonalds has installed ports at many of their facilities initially to support a sustainability initiative aimed at customers but also found significant cost savings from switching to plug-in operation.

While SafeConnect can currently ship product same day, they expect 2023 through 2027 to be challenging to keep up with demand and are expecting to produce over 100,000 units during that time period, as trucks and trailers based out of state will also need the retrofit kits to comply with in-state regulations. Most of the components used in SafeConnect's products are readily available on the market, but some parts are specifically milled, as each trailer OEM requires slightly customized parts. SafeConnect performs the design and coordinates product assembly. They have also started working with Carrier, Thermo King, and several eTRU OEMs to include SafeConnect trailer/truck kits as part of new trailer specifications to simplify the process for customers.

SafeConnect has one major competitor in Southern California: ESL Power.[143] ESL started developing eTRU connection ports approximately four years ago while working with an existing large national box store customer, who was branching into the food delivery market. ESL developed a standard four-pin reefer outlet for this customer (without a safety release) and supplied approximately 200 units to this account.

ESL launched its eTRUconnect safety connection port one year ago. The eTRUconnect is a standard, four-pin connector for 480-volt, 30 ampere applications. It uses a safety-actuated pin-and-sleeve system and cannot be energized until the connector and inlet are mated. A connection detection device (IEC60309 and UL-listed) is embedded in the safety-interlocked female connector installed at the end of the cable. As a four-pin connector, it does not require a retrofit kit unless the customer wants to move the connection port to the back of the truck (which is recommended for safety to reduce the length of the power cord connection). ESL's eTRUconnect is on Southern California Edison's approved vendor list for their Charge Ready Transport program and Southern California Edison is providing incentives for installations.

ESL currently has an eTRUconnect new construction project underway in California at a large cold storage facility. The facility is not operating yet, but every dock and some of the staging areas are electrified with approximately 200 connection ports. ESL's representative expects the connector port market to continue to expand into long-haul trucks and trailers.

According to the representative, many ESL customers load their trucks and trailers in the afternoon and evening and keep the eTRUs plugged in overnight, then deliver the product the next morning, similar to Albertsons. ESL's customers include maintenance cost reductions in their return-on-investment calculations since maintenance time and costs are high for their diesel generators, which can sit loaded in staging areas for hours before delivery.

[143] For more details, see the ESL Power website (https://eslpwr.com/etruconnect/).

Appendix B. Acronyms and Abbreviations

A	Ampere(s)
ADA	Americans with Disabilities Act of 1990
AFUDC	Allowance for Funds Used During Construction
AHJ	Authority Having Jurisdiction
BEV	Battery Electric Vehicle
BTU	British Thermal Unit
BVES	Bear Valley Electric Service, Inc.
BYD	BYD Motors Inc.
CARB	California Air Resources Board
CEC	California Energy Commission
CNG	Compressed Natural Gas
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
CPUC	California Public Utilities Commission
CRHIRP	Charge Ready Home Installation Rebate Program
CSE	Center for Sustainable Energy
CSV	Comma-Separated Values (computer spreadsheet-type file)
CVRP	Clean Vehicle Rebate Project
DAC	Disadvantaged Community
DC	Direct Current
DCFC	Direct Current Fast Charger
DGE	Diesel Gallon Equivalent
DR	Demand Response
DTC	Downtown Transit Center
eGSE	Electric Ground Support Equipment
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute, Inc.
eRTG	Electrified Rubber Tired Gantry
eTRU	Electric Transport Refrigeration Unit
EV	Electric Vehicle
EVSE	Electric Vehicle Supply Equipment
FCM	Flex Charge Manager

g	Gram(s)
GGE	Gallons of Gasoline Equivalent
GHG	Greenhouse Gas
GREET	Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (model)
GSE	Ground Support Equipment
HD	Heavy-Duty
HDEV	Heavy-Duty Electric Vehicle
HOA	Homeowners' Association
HOV	High-Occupancy Vehicle
HP	Horsepower
HVAC	Heating, Ventilation, and Air Conditioning
HVIP	Hybrid and Zero-Emission Truck and Bus Voucher Incentive Project
IDI	In-Depth Interview
IT	Information Technology
ITS	International Transportation Service
kg	Kilogram(s)
kV	Kilovolt(s)
kVA	Kilovolt-Ampere(s)
kW	Kilowatt(s)
kWh	Kilowatt-Hour
L2	Level 2
LBCT	Long Beach Container Terminal
LCFS	Low-Carbon Fuel Standard
MBE	Minority-Owned Business Enterprise
MD	Medium-Duty
MHD	Medium- and Heavy-Duty
mmBTU	Million British Thermal Units
MPG	Miles per Gallon
MPGe	Miles per Gallon Gasoline Equivalent
MT	Metric Ton(s)
MUD	Multi-Unit Dwelling
MW	Megawatt(s)
MWh	Megawatt-Hour
NEMA	National Electrical Manufacturers Association
NOx	Nitrous Oxide(s)
NREL	National Renewable Energy Laboratory

NRLT	Nationally Recognized Testing Laboratory
O&M	Operations and Maintenance
PAC	Program Advisory Council
PG&E	Pacific Gas and Electric
PM	Particulate Matter
PME	Pad-Mounted Equipment
POLB	Port of Long Beach
PRP	Priority Review Project
PV	Photovoltaic
PVC	Polyvinyl Chloride
Q	Quarter
ROG	Reactive Organic Gas(es)
RPM	Rotations per Minute
RTC	Regional Transportation Center
RTD	Regional Transit District
RTG	Rubber Tire Gantry
SCCR	Short Circuit Current Rating
SCE	Southern California Edison
SDAP	San Diego Airport Parking
SDIA	San Diego International Airport
SDG&E	San Diego Gas and Electric Company
SO_X	Sulfur Oxide
SRP	Standard Review Project
SSA	Stevedoring Services of America
TOU	Time of Use
TRU	Transport Refrigeration Unit
UPS	United Parcel Service
UTS	Union Transfer Station
V	Volt(s)
VOC	Volatile Organic Compounds
WBE	Woman-Owned Business Enterprise
ZEB	Zero-Emission Bus
ZEV	Zero-Emission Vehicle