California Energy Commission

Alternative and Renewable Fuel and Vehicle Technology Program

FINAL PROJECT REPORT

Los Angeles Air Force Base Vehicle-to-Grid Demonstration

Logo of California Energy Commission

California Energy Commission

Edmund G. Brown Jr., Governor

October 2018 | CEC-500-2018-025

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Contract Number: 500-11-025

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ACKNOWLEDGEMENTS

The authors acknowledge Peter Klauer, Senior Advisor, Smart Grid Technology, California Independent Systems Operator for his insight and support throughout the project. The authors also acknowledge the exhaustive assistance and support provided by Nicholas Pileggi, fleet manager, Los Angeles Air Force Base.

PREFACE

Assembly Bill (AB) 118 (Nùñez, Chapter 750, Statutes of 2007), created the Alternative and Renewable Fuel and Vehicle Technology Program (ARFVTP). The statute authorizes the California Energy Commission (Energy Commission) to develop and deploy alternative and renewable fuels and advanced transportation technologies to help attain the state's climate change policies. AB 8 (Perea, Chapter 401, Statutes of 2013) re-authorizes the ARFVTP through January 1, 2024, and specifies that the Energy Commission allocate up to $20 million per year (or up to 20 percent of each fiscal year's funds) in funding for hydrogen station development until at least 100 stations are operational.

The ARFVTP has an annual budget of approximately $100 million and provides financial support for projects that:

- Reduce California's use and dependence on petroleum transportation fuels and increase the use of alternative and renewable fuels and advanced vehicle technologies.
- Produce sustainable alternative and renewable low-carbon fuels in California.
- Expand alternative fueling infrastructure and fueling stations.
- Improve the efficiency, performance and market viability of alternative light-, medium-, and heavy-duty vehicle technologies.
- Retrofit medium- and heavy-duty on-road and non-road vehicle fleets to alternative technologies or fuel use.
- Expand the alternative fueling infrastructure available to existing fleets, public transit, and transportation corridors.
- Establish workforce training programs and conduct public outreach on the benefits of alternative transportation fuels and vehicle technologies.

To be eligible for funding under the ARFVTP, a project must be consistent with the Energy Commission's ARFVTP Investment Plan, updated annually. The Energy Commission issued agreement 500-11-025 to demonstrate vehicle-to-grid ancillary services and demand response at Los Angeles Air Force Base. The recipient submitted an application and the agreement was executed as Contract 500-11-025 on September 7, 2012.

ABSTRACT

Electrification of non-tactical vehicle fleets represents a key efficiency and energy security objective for the United States Department of Defense. To achieve electrification, the department targeted vehicle-to-grid services as a way to decrease the overall cost of operating the vehicle fleet and achieve rough parity with traditional internal combustion engine vehicle fleets.

This report describes efforts to aggregate a fleet of bi-directional electric vehicles and charging stations to provide regulation up and regulation down in the California Independent System Operator ancillary services market. A 29-vehicle electric vehicle demonstration fleet, consisting of mixed purpose and duty vehicles such as sedans, pickups, vans, and medium-duty trucks, was deployed at the Los Angeles Air Force base. The fleet provided frequency regulation to the California Independent System Operator's wholesale electricity market to determine the capability of recouping some of the additional costs of procuring electric vehicles and their supporting infrastructure.

Lawrence Berkeley National Laboratory, with its partner Kisensum, LLC, developed the fleet scheduling, optimization, and control software to allow the vehicle fleet at the air force base to participate in the ancillary services markets. This report focuses on the control software and market interactions, the significant challenges faced and solutions devised to address them, and examines the potential of using the electric vehicle fleet as an energy storage resource for the base buildings, an application known as vehicle-to-building, in providing demand response and emergency backup power. The report discusses key findings related to providing frequency regulation to the California Independent System Operator market, electric vehicle fleet performance, compatibility of varying resource parameters of vehicle fleet aggregation, the need for automated methods for communicating hour-ahead energy bidding, challenges related to battery capacity and charge/discharge rates, and monthly settlement revenue.

Keywords: Vehicle-to-grid, vehicle-to-building, electric vehicle, electric vehicle service equipment, bi-directional, ancillary services, frequency regulation

Please use the following citation for this report:

Black, Douglas, Jason MacDonald, Nicholas DeForest, and Christoph Gehbauer. Lawrence Berkeley National Laboratory. 2017. *Los Angeles Air Force Base Vehicle-to-Grid Demonstration*. California Energy Commission. Publication Number: CEC-500-2018-025.

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Introduction

Electrification of non-tactical vehicle fleets represents a key efficiency and energy security objective for the United States Department of Defense. To achieve electrification, the department has targeted vehicle-to-grid services to help decrease the overall cost of operating a vehicle fleet and achieve rough cost parity with traditional internal combustion engine vehicle fleets, while evaluating how the technology supports or interferes with mission operations.

Vehicle-to-grid is the ability of plugged-in electric vehicles to charge and discharge their energy on command, in conjunction with bi-directional (moving electricity in either direction) charging stations. While it is a fairly simple concept in theory, vehicle-to-grid is complex in execution. The most challenging aspects include determining the optimal schedules to bid in the market for charging and discharging the vehicles, which must be available for their primary intended purpose as a fleet. Additionally, vehicle-to-grid becomes more challenging when a variety of fleet vehicle and charging infrastructure types are used, as was the case for this project.

It was important to show that vehicle-to-grid is technically and operationally feasible, and that its revenue could help defray the cost of converting vehicle fleets to zero-emission all-electric. The benefits include reduced pollution and dependence on petroleum, and the potential to provide additional services such as emergency backup power.

This report describes an attempt to aggregate an active fleet of bi-directional electric vehicles and charging stations to provide electricity grid services in the California Independent Systems Operator frequency regulation market.

Project Overview

Los Angeles Air Force Base replaced 42 internal combustion engine vehicles (sedans, pickups, vans, and medium-duty trucks) from its non-tactical general-purpose fleet with all-electric or plug-in hybrid electric vehicles. Twenty-nine of these electric vehicles were outfitted with bi-directional capability, meaning that they could be tapped as an energy resource when not being used for transportation.

The Los Angeles Air Force Base fleet provided frequency regulation, a service in which a resource consumes or discharges electricity on command to match electricity system demand to generation. This helps maintain a stable system frequency, supporting grid reliability. “Regulation up” and “regulation down,” respectively, refer to discharging or consuming electricity during frequency regulation.

Lawrence Berkeley National Laboratory, with its partner Kisensum, LLC, developed a fleet scheduling, optimization, and control software system to allow the vehicle fleet to participate in the California Independent System Operator’s ancillary services markets.

This project was attempting to participate in the California Independent System Operator's open electricity market with bi-directional charging and discharging of a vehicle fleet as an electricity supply source to earn revenue. The fleet successfully provided frequency regulation, a service procured in wholesale electricity markets. To a more limited extent, this project also explored using electric vehicles for vehicle-to-building applications, specifically "load shifting" for time-of-use electric utility cost management, as well as demand response and supporting critical base infrastructure in the event of an emergency.

The focus of this report is on the control software, market interactions, the significant challenges faced and solutions devised to address them. It also exams the potential to use the electric vehicle fleet as an energy storage resource for the base buildings, known as vehicle-to-building, to supply demand response and emergency backup power.

Project Process

The project team worked closely with Los Angeles Air Force Base site staff, the local utility Southern California Edison, the California Independent System Operator, the California Energy Commission, project subcontractors, and other stakeholders. Preparing for the demonstration included executing an interconnection agreement with Southern California Edison; procuring vehicles and other project equipment; conducting equipment safety and compatibility testing; developing fleet management, optimization, and control software; and successfully completing California Independent System Operator resource certification.

Once the fleet was successfully certified as a California Independent System Operator market resource, the team gathered the electric vehicle fleet travel requirements through an operations management system, developed schedules for optimal electric vehicle charging, and calculated the optimal schedule to submit to the system operator.

Kisensum's fleet operations management system, known as the On-Base Electric Vehicle Infrastructure, allowed base personnel to reserve and check out electric vehicles. This system collected information including planned trip departure and return times, vehicle preferences, and expected distance traveled. The system stored this information and provided an estimate of electric vehicle energy needs and when the vehicles would be available to charge.

Lawrence Berkeley National Laboratory's Distributed Energy Resources Customer Adoption Model delivered optimal scheduling for the fleet, taking into account the power and energy available from the plugged-in electric vehicle fleet for grid services while maintaining sufficient travel capability. The model is an optimization software program previously developed to minimize the cost of energy subject to physical and market constraints, such as retail tariffs and grid services. Originally this program applied to microgrids and distributed energy resources generally. For this project, the model was adapted to minimize the cost of fleet vehicle operations based on the physical, travel, and market constraints inherent to the system and the California

Independent System Operator's requirements. The cost of vehicle operations included the cost of electric vehicle charging under the base's retail tariff and the potential revenue that could be generated through frequency regulation market participation. The optimal schedules from the model were passed back to the On-Base Electric Vehicle Infrastructure to be bid through the scheduling coordinator's (Southern California Edison) bidding mechanism into California Independent System Operator markets.

Project Results

The demonstration successfully provided frequency regulation to the California Independent System Operator's market for a total of 255 megawatt hours of regulation up and 118 megawatt hours of regulation down for 20 months. Based on Lawrence Berkeley National Laboratory's implementation of the system operator's accuracy metric, the electric vehicle fleet generally performed well, exceeding the minimum required power performance.

While the California Independent System Operator is one of the most advanced markets for distributed energy resource integration, the variability of vehicle fleet aggregation adds complexity in providing the system operator's market systems with accurate resource inputs. Inputs such as state of charge can impact day-ahead market award eligibility or real-time resource optimization using the Regulation Energy Management model which controls state of charge based on a fixed energy capacity.

For continuous regulation provision over long periods, it is necessary to have a method for communicating hour-ahead energy bidding to maintain the stored energy in electric vehicle batteries. Because this was unavailable through the scheduling coordinator, the base reduced the hours in the market to create break periods during which the fleet energy storage could be recharged without impacting regulation performance.

Overall, the transportation mission of the vehicles was fundamental. Mobility predominated over grid services, which were only provided when the vehicles were plugged in and not needed for transportation.

Per vehicle, monthly settlement revenue (not including fees) from regulation up and regulation down was moderately encouraging given the available tariff structure. To be able to offer the full capacity to regulation markets, future electric vehicles and charging stations should have a ratio of useable battery storage to charge/discharge power of at least two (for example an electric vehicle using a station with 15 kilowatt charge/discharge power should have a battery with at least 30 kilowatt-hours of capacity).

The team observed overall battery capacity loss of 5 percent to 10 percent from May 2016 to August 2017, but could not determine if providing ancillary services affected degradation, since there was so little variation in the use of each individual electric vehicle in providing frequency regulation and travel that this impact was not measured.

The full Los Angeles Air Force Base electric vehicle fleet could have provided emergency backup power to the base's emergency operations center for approximately 80 hours if infrastructure changes were made. The infrastructure changes necessary include providing an exclusive physical connection from the electric vehicle chargers to the critical building, installing equipment to handle the different voltage levels between the electric vehicle charger distribution system and the critical building, and providing switching capabilities to disconnect non-critical buildings on the same circuit.

Revenue from using the electric vehicle fleet to participate in Southern California Edison's retail demand response bidding program could generate about $2,200 per summer season which may not be an economical investment for fleet owners. The electric vehicle fleet storage capacity, however, was too small to make participation in Southern California Edison's critical peak pricing demand response program a net gain for the base. Additionally, the base replaced most of the utility vehicles since there were challenges with vehicle performance including limited range of mileage, engine overheating (with one vendor), and one set of vendor vehicles that were ultimately not placed into service due to safety concerns. Federal funding has been discontinued for the demonstrations at the base and two other bases outside of California; however, the dozen vehicle-to-grid Leafs at the Los Angeles Air Force Base are still being used with funding from an Energy Commission grant.

Benefits to California

This project pushed the envelope by using electric vehicles to provide frequency regulation, and also required advancements in electric vehicle and charging station hardware technology development. This is important to a future in California where many electric vehicle fleets could provide services to the grid that will reduce ownership costs for the fleet owners and provide stability for the grid.

The project demonstrated participating in the frequency regulation market to better understand how the California Independent System Operator handles battery-based storage resources with varying capacity to bid into the ancillary services markets. The project identified and addressed challenges with controlling storage resources consisting of electric vehicles with a range of storage capacities, and charging stations with a range of charge and discharge power. Accompanying benefits include reduced pollution and reduced dependence on petroleum, and the potential to provide additional services such as emergency backup power.

The project was successfully demonstrated that vehicle-to-grid is technically and operationally feasible; however, revenue from the frequency regulation market may not be enough help defray the cost of converting vehicle fleets to zero-emission electric drive.

CHAPTER 1: Vehicle-to-Grid and Ancillary Services Market Participation

Overview

Electrification of non-tactical vehicle fleets represents a key efficiency and energy security objective for the U.S. Department of Defense (DoD). To achieve electrification, the DoD targeted vehicle-to-grid (V2G) services as a way to decrease the overall cost of operating the vehicle fleet to achieve some equality with traditional internal combustion vehicle fleets. A mixed-use 29-vehicle electric vehicle (EV) demonstration fleet was demonstrated at Los Angeles Air Force base (LAAFB). The LAAFB fleet provided a V2G service, frequency regulation, to the California Independent System Operator (California ISO) wholesale electricity market to attempt to recoup some of the additional costs of procuring EVs and their supporting infrastructure.

Lawrence Berkeley National Laboratory (LBNL), with its partner Kisensum, LLC, developed the fleet scheduling, optimization, and control software to enable the vehicle fleet at LAAFB to participate in California ISO's ancillary services markets. This project, used bi-directional charging and discharging of an operational vehicle fleet to provide financially-binding market participation for the most technologically demanding service that is procured in wholesale electricity markets. Further, a final project goal was to analyze the potential to use these EVs to support critical infrastructure on the base in the event of an emergency.

The vehicle fleet and charging infrastructure, jointly procured by the DoD, and by LBNL using California Energy Commission funds, consisted of sedans, vans, pickup trucks, box trucks, and a shuttle bus. The vehicles were a mix of plug-in hybrid electric vehicles and pure battery-electric vehicles capable of charging and discharging via AC level 2 and DC fast charging interfaces. The charging infrastructure was a mix of AC and DC charging, in which the AC level 2 charging/discharging was limited to ±15 kW and DC fast charging/discharging was either up to ±15 kW or up to ±50 kW.

The LAAFB fleet provided a specific electricity grid service, or ancillary service, to the wholesale electricity market to recoup some of the costs of the EVs and their supporting infrastructure. The ancillary service provided was frequency regulation, a continuous service in which a fast-responding electricity resource consumes and/or discharges electricity on command to maintain grid frequency as close as possible to 60 cycles per second, supporting grid reliability. For frequency regulation, charging or consuming electricity is called "regulation down" or "reg down," and discharging or generating electricity is called "regulation up" or "reg up." Command setpoints are provided by the California ISO. It is possible to bid for, and be awarded to provide, reg up and reg down

simultaneously. During a frequency regulation session, the command setpoints can change at 4-second intervals. Therefore, a frequency regulation resource must be able to adjust its power settings quickly and possess robust communications capabilities.

Each session of providing frequency regulation to the California ISO required several steps: 1) gathering the travel requirements of the vehicles through a fleet operations management system, 2) developing schedules for optimal EV charging and establishing regulation bid capacities (amounts of power and energy available from the plugged-in EV fleet while maintaining sufficient travel capability), 3) communicating those bids and the resulting awards and dispatches to/from the California ISO using open standard communications, and 4) during frequency regulation sessions, using an optimal hierarchical control framework to disaggregate electricity dispatches in real time to command individual EVs to charge or discharge.

Kisensum's fleet operations management system, On-Base Electric Vehicle Infrastructure (OB-EVI), allowed base personnel to reserve and check out EVs. OB-EVI collected information including planned trip departure and return times, vehicle preferences, and expected distance traveled. It stored this information along with actual trip information upon the vehicle's return to provide the system with an expectation of EV energy requirements and times the vehicles would be available to participate in grid services.

Optimization capability based on LBNL's Distributed Energy Resources Customer Adoption Model (DER-CAM) was extended to deliver optimal scheduling for the fleet. DER-CAM is a mixed integer linear programming optimization that minimizes the cost of vehicle operations subject to the physical, travel, and market constraints inherent to the system and the California ISO context. The cost of vehicle operations included the cost of EV charging under LAAFB's retail tariff, as well as the potential revenue that could be generated through frequency regulation market participation. The optimal schedules were passed back to OB-EVI to be bid through the scheduling coordinator's (Southern California Edison) bidding mechanism into California ISO markets. These schedules were also used by OB-EVI's implementation of the optimal control algorithms developed for disaggregation of dispatch signals to individual EVs. DER-CAM also collected other necessary input data, such as weather forecasts and historical market prices, for optimal scheduling.

Communications in the demonstration utilized open standards to the fullest extent possible. Open standards provide the benefit of wider adoption through complete and clear specifications of implementation, but may be slower to develop compared to proprietary standards that may be more lucrative to developers. Dispatch and resource telemetry were exchanged between the on-site resource control system and the scheduling coordinator Southern California Edison, the aggregated remote intelligent gateway (ARIG), and the California ISO via the Distributed Network Protocol 3 (DNP3) communications protocol. Communications between OB-EVI and electric vehicle

charging infrastructure used two standard data formats, Open Charge Point Protocol (OCPP) and the Smart Energy Protocol 2.0 (SEP2).[1]

Lastly, the real-time charging control algorithm disaggregated California ISO dispatch signals into individual charging and discharging commands for the EVs plugged in at the base. This algorithm attempted to minimize the norm of the deviation from optimal vehicular energy schedules predetermined by DER-CAM as the uncertain frequency regulation dispatches were received from the California ISO at four-second intervals.

This project was ambitious in its attempt to push the envelope of using EVs to provide grid services. Great leaps in EV and EVSE hardware technology development were needed. This report focuses on the control software, market interactions, significant challenges faced and solutions devised to address them, and an examination of the potential to use the EV fleet as an energy storage resource for the base buildings – an application known as vehicle-to-building (V2B) – in providing demand response (DR) and emergency backup power.

Structure of Report

Chapter 1 describes the overall objective of using EVs to participate in the California ISO ancillary services frequency regulation markets for "regulation up" and "regulation down."

Chapter 2 describes the efforts to examine the capacity and impact of the bi-directional EV fleet and their corresponding bi-directional EVSEs in providing DR capacity and emergency back-up power.

Appendix A provides a guide to V2G for ancillary services on California military bases.

Appendix B provides a table of data points shared between LAAFB and the scheduling coordinator Southern California Edison.

Additionally, this report's References section contains links to the DoD and SCE reports related to the demonstration. DoD's report, "Environmental Quality, Energy, and Power Technology–Task Order 012: Plug-In Electric Vehicle, Vehicle-to-Grid," gives an overview of V2G activities at four DoD sites in the continental United States. SCE's report, "Southern California Edison Company's Department of Defense Vehicle-To-Grid Final Report," was submitted to comply with the California Public Utilities Commission's Resolution E-4595 that approved a V2G pilot tariff.

Reserved-Based Ancillary Services

Ancillary services at the control level are basically standby reserve resources that system operators can call upon when conditions deviate from those they have planned or forecast (for example forced outages or small supply-demand balance fluctuations). For context, an imbalance caused by a large contingency event (such as a generator or

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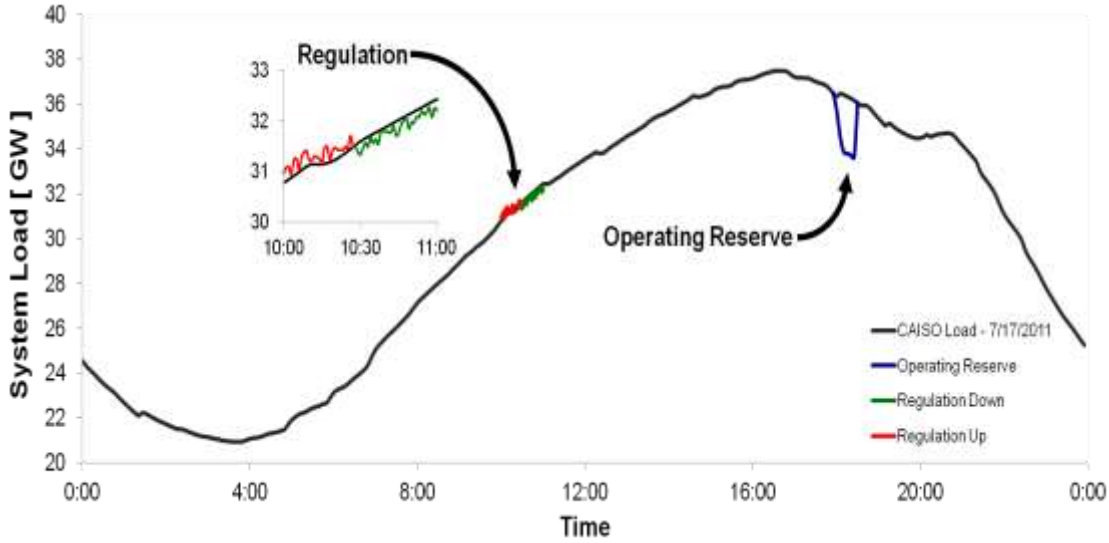
1 SEP2 was adopted by the Institute of Electrical and Electronics Engineers (IEEE) and is also known as IEEE 2030.5.

transmission outage) is shown in the upper right of Figure 1. Loss of a major resource, for example a power plant forced outage, creates a generation shortfall that must be rectified for the system to survive possible subsequent problems. Operating reserves consist of synchronous and non-synchronous capacity ready to be deployed within 10 minutes. Contingency events occur infrequently, and typically are between 10 and 30 minutes in duration.

The service shown on the left of Figure 1, frequency regulation, has a much smaller reserve capacity required at any given time compared to operating reserves, as is used primarily to handle small deviations in supply and demand between the 5-minute economic dispatches of the real-time energy market. Frequency regulation is a continuous service in which a fast-responding reserve resource responds to four-second dispatch signals from the ISO that fall within the capacity awarded to the resource in the day-ahead and real-time markets.

Bi-directional PEVs are well suited to provide either type of reserve-based ancillary service. The shallow charge/discharge cycles and higher price offered for frequency regulation, however, make it a more appealing service in the present markets.

Figure 1: Example California Independent System Operator System Load With Notional Examples of Regulation and Operating Reserve



Source: Lawrence Berkeley National Laboratory

California Independent System Operator Ancillary Services Market Participation

California ISO has separate competitive markets for trading energy and each of its ancillary services (AS). These markets operate at three different timescales: day-ahead (DA), hour-ahead (HA), and real-time. The ancillary services (AS) markets are voluntary bid-in markets in which all successful bids are paid the market clearing price (MCP) of

the highest accepted bid for the award period. The DA Market is where 100 percent of the forecasted AS needs are procured. Bidding for the DA Market closes at 10AM on the day prior to the operating day, and awards are for full hour-long time steps. The HA Market closes its bidding 75 minutes before the operating hour, and makes awards in 15-minute intervals. The Real-Time Market uses the HA bid, and dispatches every 15 minutes for AS. Fifteen-minute awards are given 7.5 minutes in advance, and aim to meet shortfalls in AS capacity in real-time. The majority of AS capacity is awarded in the DA Market and its prices are higher on average, which makes offering the best possible DA bids a critically important analytic challenge.

Vehicle-to-Grid Control System for Ancillary Services

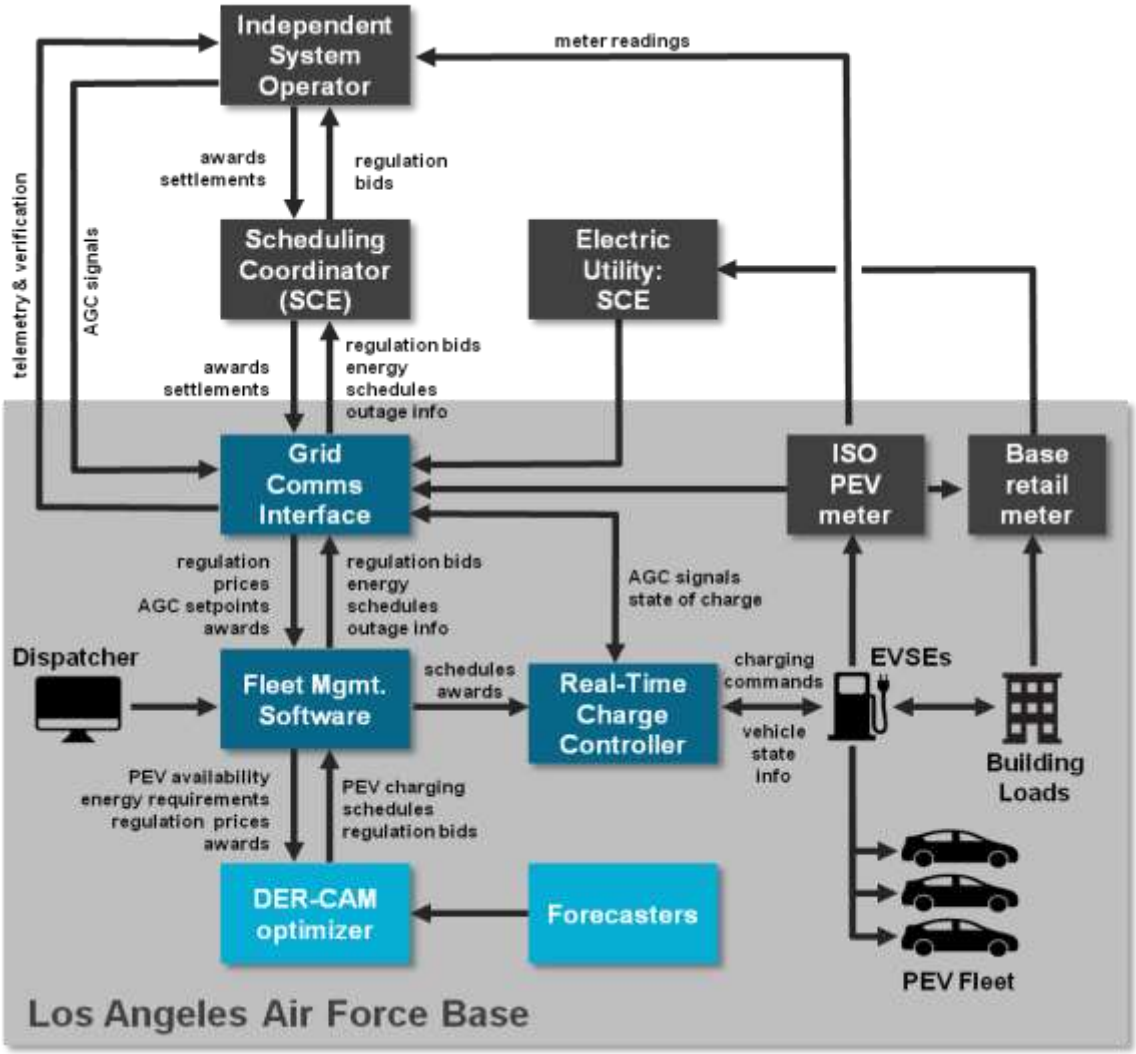
Figure 2 shows the overall approach for aggregating the fleet of bi-directional EVs and EVSEs at the LAAFB to provide frequency regulation in the California ISO ancillary services market. The EVSEs were all behind a single dedicated California ISO meter (Schneider Electric Model S8600) with redundant paths of communication to California ISO. The California ISO meter was behind LAAFB's single Southern California Edison (SCE) retail meter.

At a high level, the controller communicated with the EVSEs to determine which EVs were connected and their battery state of charge (SOC). The controller also collected EV reservation trip data through the fleet management system (FMS), provided DA Market bid schedules generated by the DER-CAM optimizer to the scheduling coordinator (SC), which was SCE, and to the California ISO through the grid communications interface, and received DA Market awards from California ISO via the SC. During market participation, the controller received the automatic generation control (AGC) dispatch setpoints from California ISO via the SC at up to four-second intervals, disaggregated each AGC setpoint into individual se points for each active EVSE/EV, and provided operating telemetry data to California ISO via the SC. The components of the control system are described in detail.

Grid Communications Interface

Communications between California ISO and the SC were made by a California ISO-approved AT&T ANIRA VPN router connected to the California ISO's private communication network known as the Energy Communication Network (ECN). LBNL created its own translator to communicate with California ISO and the SC using the DNP3 communications protocol. The full set of data points shared between the LAAFB resource and the SC are provided in Appendix B.

Figure 2: Los Angeles Air Force Base Vehicle-to-Grid for Ancillary Services System Overview



Source: Lawrence Berkeley National Laboratory

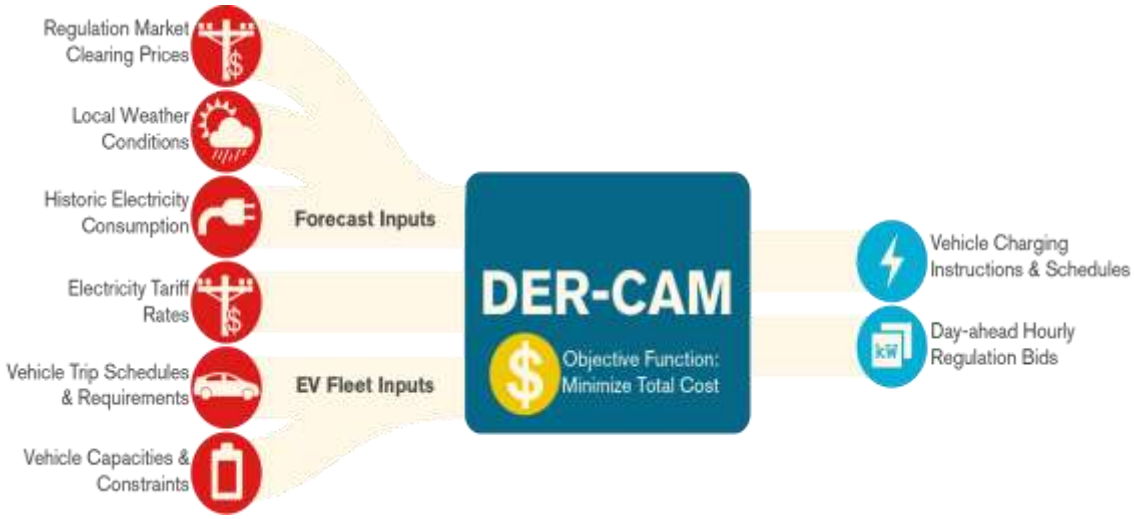
Fleet Management System

The fleet management system (FMS) was designed to support LAAFB transportation scheduling by providing an automated solution to dispatch personnel for them to administer reservations and input requests to drive EVs on or off the base. This component generates daily vehicle utilization schedules that are provided as an input to the DER-CAM optimization function (described below). This schedule optimizes the use of EV batteries when the cars are not in use. The FMS displays battery state information that can be used by dispatch personnel to select vehicles for trips. This system provides a web interface that can be used by dispatchers and by Unit Vehicle Control Officers (VCOs) to schedule and manage the dispatching of cars.

Distributed Energy Resources Customer Adoption Model Optimizer Overview

Operations DER-CAM is a tool designed to inform decision making regarding the scheduling and use of distributed energy resources (DER). Whereas Investment & Planning DER-CAM was written to generate the optimal combination of DER from historic data for a given building site or microgrid, Operations DER-CAM is intended to provide detailed operations scheduling of pre-existing DER equipment based on forecasted data, to minimize either cost, carbon, or some multi-objective combination of the two (Figure 3). Operations DER-CAM was initially developed as a complementary tool to Investment & Planning DER-CAM. DER operation decisions are based on techno-economic criteria and ensure that both thermal and electric building loads are satisfied. Operations DER-CAM solves the system analytically as a mixed integer linear program and is capable of running in 1-hour, 15-minute and 5-minute time steps.

Figure 3: DER-CAM Operations Inputs and Outputs



Source: Lawrence Berkeley National Laboratory

The major inputs to Operations DER-CAM as adapted for the LAAFB V2G application are the following:

1. Forecasted or historic load profiles for the given building site.
2. Detailed definition of electricity and natural gas tariffs and rate structures.
3. Detailed description of installed DER and their respective technical constraints. These constraints include capacities, charging/discharging rates and efficiencies.
4. Forecasted weather data for forecasting day-ahead facility demand.
5. Forecasted or historic market clearing prices for ancillary services in wholesale markets.
6. Forecasted fleet plug-in and plug-out times and mobility-driven energy consumption.

The major outputs from Operations DER-CAM are the following:

1. Time-resolved operations schedules for all installed DER.
2. Operations costs for the investigated time horizon.
3. Savings relative to a base-case operations scenario.
4. Hourly ancillary services capacity bid quantities.

Operations DER-CAM is currently capable of considering the following DER technologies: photovoltaics, stationary electric storage, flow batteries, electric vehicles, solar thermal collection, high- and low-temperature hot water storage, chilled water storage, absorption cooling and refrigeration, fuel cells, combustions engines, and combined heat and power (CHP).

Operations DER-CAM can also assess the economic and operational impact of programs including demand response, and tariffs with critical peak-day pricing schemes. Later sections provide more details on the optimization formulation.

Real-Time Charge Control Overview

The LAAFB control system coordinates the execution of two optimization functions: the day- or hour-ahead DER-CAM optimization and the real-time optimization based on meter readings, EVSE telemetry and the AGC signal. The control system communicates with the EVSEs. The optimization performed by DER-CAM is based on inputs that include the fleet utilization schedule for the next day or hour. The output of DER-CAM's optimization is a "charging trajectory" for each vehicle in the fleet. This trajectory reflects the energy capacity (target state of charge) requirements of each vehicle, based on the trips the vehicle is expected to take that day.

Charging trajectories are one of the primary inputs to the real-time optimization function along with meter telemetry and the AGC signal while performing regulation services. The real-time control optimization uses the formula described by Juul et al., 2015. Applying this formula is discussed in detail in the Real-Time Charge Control Formulation section.

Bids and Awards in California Independent System Operator Ancillary Services Market

Day-ahead bids were submitted in a spreadsheet format (shown on the left side of Figure 4) created by the scheduling coordinator, SCE, that was sent as an attachment in daily e-mails to SCE. Bids had to be submitted by 8AM to SCE so that they could meet the California ISO bid submission deadline of 10AM.

Day-ahead awards (example shown on the right side of Figure 4) were sent as e-mail attachments from the SC to the LAAFB V2G control team. The award spreadsheet differed from the bid spreadsheet only in that it had a single energy column, rather than one for each energy generation (discharging) and energy load (charging).

Figure 4: Example Bid Submission and Award Spreadsheets

Hour Ending	Energy (Generation)	Energy (Load)	RegUp	RegDown	Initial SOC
100	0.0	0.0	0.0	0.0	0.2
200	0.0	0.0	0.0	0.0	
300	0.0	0.0	0.0	0.0	
400	0.0	0.0	0.0	0.0	
500	0.0	0.0	0.0	0.0	
600	0.0	0.0	0.0	0.0	
700	0.0	0.0	0.0	0.0	
800	0.0	0.0	0.0	0.0	
900	0.0	0.0	0.0	0.0	
1000	0.0	0.0	0.0	0.0	
1100	0.0	0.0	0.0	0.0	
1200	0.0	0.0	0.0	0.0	
1300	0.0	0.0	0.0	0.0	
1400	0.0	0.0	0.0	0.0	
1500	0.0	0.0	0.0	0.0	
1600	0.0	0.0	0.0	0.0	
1700	0.01	0.0	0.10	0.10	
1800	0.01	0.0	0.10	0.10	
1900	0.10	0.0	0.10	0.10	
2000	0.01	0.0	0.10	0.10	
2100	0.01	0.0	0.10	0.10	
2200	0.10	0.0	0.10	0.10	
2300	0.01	0.0	0.10	0.10	
2400	0.01	0.0	0.10	0.10	

Hour Ending	Energy Award	RegUp Award	RegDown Award
100	0.000	0.000	0.000
200	0.000	0.000	0.000
300	0.000	0.000	0.000
400	0.000	0.000	0.000
500	0.000	0.000	0.000
600	0.000	0.000	0.000
700	0.000	0.000	0.000
800	0.000	0.000	0.000
900	0.000	0.000	0.000
1000	0.000	0.000	0.000
1100	0.000	0.000	0.000
1200	0.000	0.000	0.000
1300	0.000	0.000	0.000
1400	0.000	0.000	0.000
1500	0.000	0.000	0.000
1600	0.000	0.000	0.000
1700	0.010	0.100	0.100
1800	0.010	0.100	0.100
1900	0.010	0.100	0.100
2000	0.010	0.100	0.100
2100	0.010	0.100	0.100
2200	0.010	0.100	0.100
2300	0.010	0.100	0.100
2400	0.010	0.100	0.100

Source: Lawrence Berkeley National Laboratory

Model Optimization of Charge Scheduling and Market Bids

Distributed Energy Resources Customer Adoption Model Electric Vehicle Charging and Regulation Module Formula

The optimization formula minimizes the cost of operation for an EV fleet, subject to constraints that account for the dynamics of energy storage in the vehicles, physical infrastructure constraints, and market participation constraints (DeForest et al., 2017). The decision variables are the charge/discharge power of each vehicle for each interval in the optimization horizon ($P_i(k)$), the regulation up and down capacity that the fleet may provide for each hour ($R_U(h)$, $R_D(h)$), as well as how the expected impact of regulation is distributed among the connected EVs ($P_i^{reg}[k]$). This leaves the optimization of the form:

$$\min_{(P_i(k),P_i^{reg}(k)\in\mathbb{R}^n;R_D(h),R_U(h)\in\mathbb{R}^+)\forall k,h\in T} \text{Objective Function}$$

Subject to:

EV Physical Constraints

Market Constraints

Energy Storage Dynamics

In this application of the model, the horizon of the optimization is 48 hours. Within this horizon, only the first 24 hours are used to generate an actionable bidding plan. The second 24 hours are used only to ensure that the terminal conditions of variables in the actionable horizon (such as vehicle states-of-charge) are positioned to satisfy future requirements. The timestep resolution (Δt) is five minutes, and the regulation bid interval (Δt_h) is 1 hour. Parameters and decision variables indexed by k are defined on a granularity of Δt, whereas those indexed by h are defined by the lower-granularity Δt_h. The timescales of EV scheduling vis-à-vis ancillary service markets requires this multi-scale time indexing.

Optimization Objective

Optimization minimizes the total cost of charging an electric vehicle fleet while maximizing revenue obtained from participation in the wholesale electricity frequency regulation market, as shown in equation 1a. Energy is procured under a retail tariff that includes both a cost for energy, C_e, and a demand charge, C_d defined in Equations 1b and 1c, respectively. For frequency regulation, revenue from capacity payments, R_{reg} is included for expected frequency regulation awards in the wholesale market.

This results in an objective function of the form:

$$J = \mathcal{C}_e + \mathcal{C}_d + \mathcal{C}_{SOC} - \mathcal{R}_{reg} \tag{1a}$$

where:

$$\mathcal{C}_e = \sum_{k=0}^{T} P_{flt}(k) * c_e(k) * \Delta t \tag{1b}$$

$$\mathcal{C}_d = \sum_{j=1}^{m} \max\left(\{E_{flt}(\mathcal{K}) + E_{base}(\mathcal{K});\ \text{for all } \mathcal{K} \in I_j\}, E_{max,mo}(I_j)\right) * c_{I_j}/\Delta t_{\mathcal{K}} \tag{1c}$$

$$\mathcal{C}_{SOC} = \sum_{i=1}^{n}\sum_{k=0}^{T} c_{SOC} * \Delta t * \left(1 - \frac{E_i(k)}{\mathcal{B}_i}\right) \tag{1d}$$

$$\mathcal{R}_{reg} = \sum_{H} \left(R_D(h) * c_D(h) + R_U(h) * c_U(h)\right) \tag{1e}$$

$$E_{flt}(\mathcal{K}) = \sum_{k} P_{flt}(k) * \Delta t;\ \text{for all } k \in \mathcal{K} \tag{1f}$$

In this formula, $P_{flt}(k)$ is the power consumed by the fleet of electric vehicles for interval k, $p_e(k)$ is the price of energy in that interval, Δt is the time step between intervals, $E_{flt}(K)$ is the total energy consumed in the time intervals contained in set K as shown in Equation 1f. For example, each interval k may be five minutes long, but demand charges are calculated as energy consumption more than 15 minutes, so each set K will contain three intervals of the optimization. $E_{base}(K)$ is the forecast base demand for all uncontrolled, non-EV loads. I_i are the m separate demand charge intervals in the retail tariff, these typically span hours. $E_{max,mo}$ is the previously set, or forecast, monthly maximum demand. R_{reg} is the sum over all hours of regulation capacity bids ($R_U(h)$, $R_D(h)$) multiplied by the hourly prices ($c_U(h)$, $c_D(h)$) for up and down, respectively (Equation 1e).

This also includes a SOC penalty cost C_{SOC}, which incentivizes the model to charge vehicles above the minimum SOC required for trips (Equation 1d). The total SOC penalty cost is the sum over all intervals and EVs of the empty usable energy capacity of each EV multiplied by a user defined SOC penalty value c_{SOC}. Additional details on the application of the SOC penalty are provided below.

Electric Vehicle Constraints and Dynamics

Electric vehicles are constrained in their energy storage capacity and their power capacity.

$$b_i^{av}(k)P_i^{min} \leq P_i(k) + P_i^{reg}(k) \leq b_i^{av}(k)P_i^{max} \quad (2)$$

$$\mathcal{B}_i \times SOC_i^{min} \leq E_i(k) \leq \mathcal{B}_i \times SOC_i^{max} \quad (3)$$

In equation $P_i(k)$, the power delivered to/from EV i, is constrained.

$P_i(k)$ is defined as the power on the meter side of the EV inverter, and is positive when the EV is charging.

$b_i^{av}(k)$ is a binary input parameter indicating whether EV i is connected to its EVSE.

P_i^{min} and P_i^{max} are the minimum and maximum power capacity of the ith EVSE/EV pair as measured at the electricity grid interconnection.

Equation 3 constrains the energy stored in EV i during interval k, $E_i(k)$.

B_i is the rated battery capacity of EV i.

SOC_i^{min} and SOC_i^{max} are the minimum and maximum allowable energy state of charges for the battery during operation.

The previous equations constrained the absolute ranges in which the state variables of each EV can operate, but the dynamics of those state variables, particularly for energy storage, must be added to the constraints:

$$E_i(k) = E_i(k-1) + \left(b_i^{ch}(k) \times \eta_i^{ch} P_i(k) + \left(1 - b_i^{ch}(k)\right)\frac{1}{\eta_i^{dis}} P_i(k) + P_i^{tr}(k) - P_i^{reg}\right)\Delta t \quad (4)$$

where:

$$b_i^{ch}(k) = \begin{cases} 1 & \text{if } P_i \geq 0 \\ 0 & \text{otherwise} \end{cases}$$

Equation 4 is a compact form of a set of linear equations that introduces a binary variable, $b^{ch}(k)$, that is dependent on the charging/discharging decision variable for each vehicle. This effectively allows the system to differentiate between charging and discharging efficiency, while also ensuring that individual EVs cannot charge and discharge within the same time step k. Charging and discharging efficiencies are modeled as fixed input parameters: η_i^{ch} and η_i^{dis}.

Equation 4 also introduces two new power terms: $P_i^{tr}(k)$ is an input parameter that represents the average power consumed during interval k of a vehicle that is on a trip, and P_i^{reg} is the expectation of average power provided during an interval in which the vehicle provides frequency regulation. Because P_i^{reg} is defined as power provided from the fleet, it is given a negative sign in Equation 4 to indicate discharging. This value will be further defined when the requirements of frequency regulation are described. Including $P_i^{tr}(k)$ in this constraint ensures that the EVs are always charged in a manner that satisfies their mobility energy requirements.

California Regulation Market Constraints

To ensure that the capacity available from the fleet for frequency regulation is properly bounded, it must be constrained by the vehicles that are expected to be connected during any hour, h.

$$P_{flt}(k) = \sum_{i=1}^{n} P_i(k) \tag{5}$$

$$R_U^h \leq R_U(k), \forall k \in h \tag{6}$$

$$R_D^h \leq R_D(k), \forall k \in h \tag{7}$$

$$R_U(k) \leq \sum_{i=1}^{n} (P_i^{min} \times b_i^{av}(k)) + P_{flt}(k) \tag{8}$$

$$R_D(k) \leq \sum_{i=1}^{n} (P_i^{max} \times b_i^{av}(k)) - P_{flt}(k) \tag{9}$$

Equations 6 and 7 ensures that the up/down regulation capacity (R_U^h or R_D^h) offered for hour h, is the minimum available regulation capacity ($R_U(k)$ or $R_D(k)$) for all intervals in the hour. Further, equations 8 and 9 limits capacity to the sum of power capacity (P_i^{min}, P_i^{max}) of vehicles that are connected in an interval, as indicated by availability parameter $b_i^{av}(k)$. These constraints are appropriate for any market context; however, there are also constraints that are specific to the California ISO context:

$$R_D(k) \leq \sum_{i=1}^{n} \left((SOC_i^{max} \times \mathcal{B}_i - E_i(k)) \times b_i^{av} \right) / \Delta t_h - P_{flt}(k) \tag{10}$$

$$R_U(k) \leq \sum_{i=1}^{n} \left((E_i(k) - SOC_i^{min} \times \mathcal{B}_i) \times b_i^{av} \right) / \Delta t_h + P_{flt}(k) \tag{11}$$

$$R_U^h \geq R_U^{min} \text{ or } R_U^h = 0 \tag{12}$$

$$R_D^h \geq R_D^{min} \text{ or } R_D^h = 0 \tag{13}$$

In the California wholesale market, a resource must maintain enough energy capacity to provide the intended frequency regulation at full dispatch for the entire hour of an award. This is represented in equations 10 and 11, which use the available energy capacity for charging and discharging to constrain hourly regulation capacity. The bid

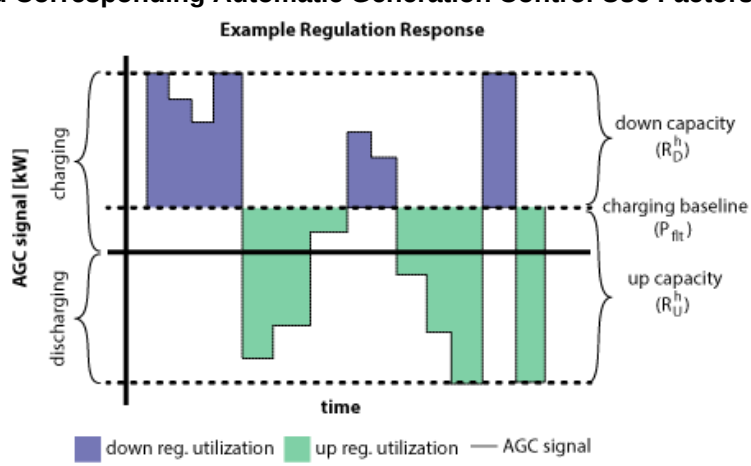
time interval Δt_h in this case is one hour. Further, every ISO has a minimum reserve quantity that a resource may bid, represented by R_U^{min} and R_D^{min}. For the California ISO, that quantity is 0.1 MW-h for ancillary service reserves.

Equation 5 defines the fleet charging level, which determines the baseline around which the resource provides regulation. As such, the scheduled charging baseline must be considered in determining available regulation capacities (for example. Equations 8-11) and acts effectively as a capacity offset. For instance, scheduled charging $P_{flt}(k)$ can be shed to increase up regulation capacity, whereas the same scheduled charging diminishes the available capacity to absorb energy via down regulation.

$$f_U(h) * R_{U,bid}(h) - f_D(h) * R_{D,bid}(h) = \frac{1}{\Delta t_h} \sum_{i=1}^{n} P_i^{reg}(k), \forall k \in h \qquad (14)$$

Finally, the model takes into account the expected impact of participating in regulation to ensure the EV SOCs are not depleted, and that the resource maintains sufficient capacity when providing regulation for multiple continuous hours. To do this, the model requires hourly AGC use factors for up $f_U(h)$ and down $f_D(h)$ regulation, which estimate how much the resource will be exercised in each direction during each hour of reserve provision. Figure 5 is provided as an illustrative representation of these AGC factors for better understanding. It shows a generic AGC signal over an hour of reserve provision in both up and down regulation (R_U^h, R_D^h) that includes non-zero scheduled charging for the fleet (P_{flt}). In this example, the dimensionless AGC factors are calculated as the ratio of the shaded AGC dispatch energy over the total possible energy that could have been dispatched throughout the reserve provision period (R_U^h or R_D^h multiplied by the one-hour period).

Figure 5: Visualization of the Relationship Between Actual Automatic Generation Control Signal and Corresponding Automatic Generation Control Use Factors (fU(h), fD(h))



Source: Lawrence Berkeley National Laboratory

To incorporate the AGC use factors in the model, the factor values are applied to their corresponding bids to estimate a net energy flow to or from the resource in each hour.

For instance, in an hour where $f_U(h)$ =0.25 and $R_{U,bid}$ (h)=100 kW, a net discharge of 25 kWh would be estimated for the hour. This net impact is then distributed among the fleet in the form power flows to or from individual EVs P_i^{reg} (k), which are linked to each EVs energy balance in Equation 4.

Real-time Charge Control Formula

The real-time charge controller implemented the optimization algorithm described by Juul et al. in Python using the open source libraries NumPy & cvxpy. NumPy is a widely used scientific computing package for Python and cvxpy is a library for modeling and solving convex optimization problems.

Objective Function

Juul et al. describe an objective function comprised of two cost components to be minimized: the sum of squared errors between actual and planned EV battery energy trajectories (as directed here by DER-CAM generated schedules) and the signal error (sum of vehicle power commands vs. AGC setpoint). Both of these cost terms involve "weights" that are not precisely specified. There is a coefficient matrix for the sum of squares, W, and a weight, M, on the signal error term that is described as "an arbitrarily large number."

In the initial implementation, LBNL chose W as the identity matrix multiplied by a scalar weight factor, *a*. When the system was providing AGC, called signal follow mode, the weight on the squared error term, *a*, equaled 1 and on the signal error, M, equaled 1000. This weighting ensured that the system prioritized meeting the instantaneous power commanded by California ISO's AGC over differences from the optimal SOC trajectories for individual vehicles. When the system was not providing frequency regulation, termed trajectory follow mode, those weightings were reversed so that the system prioritized returning to an optimized SOC over following the commanded power (nominally zero). Improvements to this weighting scheme to handle the varying sized EVs in the fleet are described in the Control Challenges Addressed section.

Feedback Control

The convex optimization problem described in Juul, et al. lacked specific areas of feedback in the system. While the optimization compared the reference SOC to actual SOC, it did not include the overall fleet EV meter to compare the AGC power command. This became an issue if a vehicle failed to respond to a charging command as expected or if there were other loads such as uncontrollable vehicles connected to charging equipment behind the California ISO meter. To mitigate this, a simple feedback control loop was placed around the real-time charging optimization to adjust the AGC reference based on the system's response error at the meter. A Proportional Integral Differential (PID) controller was implemented for this purpose.

Proportional Integral Differential Control

Once the real-time charge controller has determined each battery's optimal setpoint and sent that command to its inverter, a PID Control function ensures that the total power delivered by the fleet's batteries matches the frequency-regulation setpoint as closely as possible. This is an essential feedback loop that makes continual adjustments to battery setpoints, aligning the sum of actual power produced/consumed (as measured by one or more site meters) with the frequency regulation setpoint. PID Control enables the Kisensum controller to follow a setpoint with a high degree of accuracy while managing a fleet of batteries that may each have different latencies and response characteristics.

The PID control implementation is the standard form (Astrom and Murray, 2008) with one notable exception described below:

$$u(t) = k_p e(t) + k_i \int_0^t e(\tau)\, d\tau + k_d \frac{de}{dt}$$

In code, e(t) is the difference between the desired setpoint and current meter reading. The integral term is the accumulated sum of errors across calls capped by a maximum value. The derivative term is calculated as e(t1) - e(t0). Each of these terms is multiplied by a constant that has been tuned empirically based on results at LAAFB (Table 1).

Table 1: Proportional Integral Differential Constants and Internal Correction Values

Constant	New Setpoint	Internal Correction
K_p (proportional)	0.9	0.6
K_i (integral)	0	0.03
K_d (derivative)	0.1	0.1

Source: Lawrence Berkeley National Laboratory

The absolute value of the maximum accumulated integral error is 1000 which means that the maximum integral adjustment is +/- 0.03*1000 = +/- 30.

Changing constant values between iterations of the PID controller is non-standard but was introduced because it achieved a better balance between responsiveness to new setpoints and oscillations due to overshooting that could occur when the proportional term was held constant near 0.9. Experiments were done with larger values of K_i but LBNL never found a value that seemed satisfactory. It is quite possible that these constants would have to be adjusted with a different mix of vehicles.

Finally, the maximum update frequency is 12 times per minute or once every five seconds. Intervals less than five seconds can result in oscillations because some of the non-PPS charge stations take 4-5 seconds to register any kind of response to a new

setpoint. The PPS stations respond more quickly and a system with all PPS stations could probably reduce this interval to 3-4 seconds.

Bi-directional Vehicle-to-Grid Electric Vehicles and Electric Vehicle Supply Equipment at Los Angeles Air Force Base

Nissan LEAFs Procured by Lawrence Berkeley National Laboratory with California Energy Commission Funding

LBNL procured 13 previously owned model year 2012 Nissan LEAFs (Table 2).

Table 2: Nissan LEAF Mileage at Purchase

#	October 2013 Odometer (miles)	September 2017 Odometer (miles)
1	7389	12247
2	5940	12160
3	7140	13066
4	4945	10968
5	6601	12617
6	4576	7702
7*	6029	15133
8	3282	8344
9	4011	13631
10	4226	7827
11	5790	9408
12	9069	11648
13	4326	11799

Vehicle 7 was in an accident and was no longer operating after Feb 26, 2016.

Source: Lawrence Berkeley National Laboratory

Nissan LEAFs sold in the U.S. have a software block to prevent bi-directional (i.e. battery discharging) capability. Enabling bi-directional capability in the LEAFs purchased with Energy Commission funds for the LAAFB V2G demonstration only required a software upgrade, which was performed by a Nissan technician in the field (this option is not currently available to the public). The software change consisted of upgrades to three systems: 1) lithium battery controller; 2) on-board charger; and 3) vehicle control module. The technicians who visited the Base used re-programming tools to make the upgrades. The process took about one hour per vehicle.

In addition to the changes made to the LEAFs, an additional piece of hardware was needed to enable bi-directional flow - the CHAdeMO connector, which connects the charging station and the vehicle to allow direct charge and discharge of the batteries in the EVs. This demonstration used the CHAdeMO standard version 0.9, which was

developed by Nissan and Nichicon, an electrical hardware vendor, to provide a bi-directional connector for the Japanese market.

Once the software upgrade to enable bi-directionality was completed, some issues surfaced that led to delays and limited details shared about the upgrade.

The main delay was that Southern California Edison (SCE) required that the LEAFs and associated charging stations be tested by SCE technicians for safety and performance. This process took months as the bi-directional capability didn't appear to be working initially. However, the problem turned out to be a technical issue with the charging stations.

Additionally, LBNL learned that with the software upgrade to the EVs, Nissan no longer considered the vehicles standard production models and voided the standard warranty. Under this Energy Commission agreement, LBNL purchased an extended warranty for the vehicles with some exceptions. Any issues related to the software change or discharge operation were no longer covered under the extended warranty. The software upgrades did not affect the drivability, on-road performance, or electrical safety of the LEAFs.

In the early stages of the project when charging stations were being commissioned, and the LEAFs were not being fully used as fleet vehicles, LBNL discovered that when the LEAFs were connected to their charging stations and not driven for at least 1-2 weeks, the 12-volt accessory batteries would be drained to the point of inoperability. LBNL devised a protocol to maintain the charge of the 12-volt batteries that was performed every 1-2 weeks by LAAFB fleet operations staff. The process consisted of disconnecting the charging connector, pressing the Start button, turning off all accessories and leaving for 30 minutes before switching off and re-connecting to the charging station.

Charging station faults, on several occasions, led to deep discharges of the LEAF drivetrain battery. In one early case, the discharge was so deep that the battery in LEAF 12B80023 could not be recovered and had to be replaced with a new battery.

On Feb 26, 2016, a truck turned in front of a LAAFB service member driving LEAF 12B80017, resulting in a vehicle collision and minor injuries to the service member. The insurance company adjuster declared the vehicle was totaled and a financial settlement, negotiated by legal staff from both LBNL and the Energy Commission, was mutually agreed upon. The total number of Energy Commission-owned Nissan LEAFs was reduced to 12. Concurrent Technologies Corporation (CTC) re-located a bi-directionally enabled LEAF from their facility, where it was being used for charging station development and testing, to the LAAFB to maintain a total of 13 LEAFs in the V2G fleet.

Other Bi-directional Electric Vehicles Procured by the Department of Defense

Military facilities often require a mix of fleet vehicles beyond standard sedans like the Nissan LEAF, and the LAAFB is no exception. Cargo and passenger vans, medium-duty trucks, and a shuttle bus were needed in addition to the sedans, to meet mission

requirements. The vehicle makes, models, and types along with the number of each and the individual rated battery capacity of each are shown in Table 3. The total aggregate rated battery capacity was intended to be 859 kWh.

Table 3: Fleet Electric Vehicles at Los Angeles Air Force Base

Quantity	Vehicle Make and Model	Battery Capacity (kWh)
13	Nissan LEAF	24
1	Phoenix Motor Cars Shuttle Bus	100
4	EVI Stake and Box Trucks	54
11	VIA Van	21

Source: Lawrence Berkeley National Laboratory

Electric Vehicle Service Equipment Procured by the Department of Defense

The electric vehicle service equipment (EVSE), more commonly known as charging stations, at the LAAFB are shown in Table 4. The Princeton Power Systems (PPS) and the Coritech VGI-50-DC EVSEs are equipped with AC-to-DC inverters that provide DC power to their respective vehicles. The Coritech VGI-15-AC provided AC power to its corresponding EVs (an inverter on-board the EV converted from AC to DC power). The PPS EVSEs connected to the EV with the CHAdeMO standard connector and communicated via the Open Charge Point Protocol (OCCP). Both of the Coritech EVSEs communicated via the Smart Energy Protocol 2.0 (SEP2).

Table 4: Electric Vehicle Service Equipment at Los Angeles Air Force Base

Quantity	Manufacturer and Model	Vehicle Served	Capacity / Type	Comm. / Connector
13	Princeton Power Systems GTIB-208-30	Nissan LEAFs	±15 kW / DC	OCPP / CHAdeMO
5	Coritech VGI-50-DC	EVI and Phoenix	±50 kW / DC	SEP2 / J1772
11	Coritech VGI-15-AC	VIA	±15 kW / AC	SEP2 / J1772

Source: Lawrence Berkeley National Laboratory

Aggregate Ancillary Services Resource Capacity

The amount of storage capacity available to provide grid services is not simply the sum of the rated battery capacities. Li-Ion batteries in general, and those used in the vehicles in this study, should not be discharged completely to zero because of the potential for irrevocable damage to the batteries. To be safe in this study, batteries were not dispatched below approximately 20 percent of their rated capacities.

Battery charge rates also slow as battery state of charge (SOC) nears full capacity. For the Nissan LEAF, LBNL observed an approximately 50 percent decrease in charge rate at approximately 85 percent of full SOC. LBNL assumed the usable capacity of each vehicle battery in this study to be approximately 70 percent of its rated capacity.

How usable capacity is defined also depends on the market bidding strategy. Symmetric bidding of up and down regulation means that the usable capacity for each is further reduced by 50 percent. For example, the Nissan LEAFs have a rated battery capacity of 24 kWh, the "safe" linear capacity is 70 percent of that, 16.8 kWh, and the usable capacity for symmetric regulation up and regulation down bidding is 8.4 kWh for each.

Results

The team successfully overcame technical and market-based challenges to aggregating a fleet of heterogeneous bi-directional PEVs and EVSEs to provide regulation ancillary services in actual market participation.

The important outcomes of this project are those related to:

- Participation in the frequency regulation markets of California ISO for 18+ months, providing a total of 255 MW-h of regulation up and 118 MW-h of regulation down[2].
- Identified and addressed challenges of controlling a diverse mix of EVs and EVSEs to rapidly and accurately follow the ISO AGC.
- Demonstrated the use of two open standards, the OCPP and SEP 2.0 protocols, to successfully share critical data and setpoints between a centralized control system and EVSEs and EVs.

Aggregate Vehicle Battery Capacity Available for Ancillary Services Market Participation

The DoD intended to have a fleet of 29 bi-directional EVs and EVSEs, including the Energy Commission-procured Nissan LEAFs, at LAAFB with an aggregate rated energy capacity of 994 kWh, and aggregate rated discharge and charge capacity of +/- 685 kW. The actual number of EVs/EVSEs available as transport and for California ISO AS regulation market participation (Figure 6) was much lower. EV availability was low overall except for the LEAFs, and their availability was often limited by EVSE faults that were the consequences of using first generation hardware. These hardware issues existed even when EVs/EVSEs were available, with sometimes intermittent charging and discharging operation or erroneous battery capacity reported as available despite a vehicle's inability to respond to dispatch commands.

This inconsistent capacity had negative consequences for overall participation. The uncontrollable capacity would indistinguishable from controllable capacity to the system and be included in the total capacity reported to California ISO in telemetry, resulting in an inability to follow AGC setpoints. This had the effect of forcing the team

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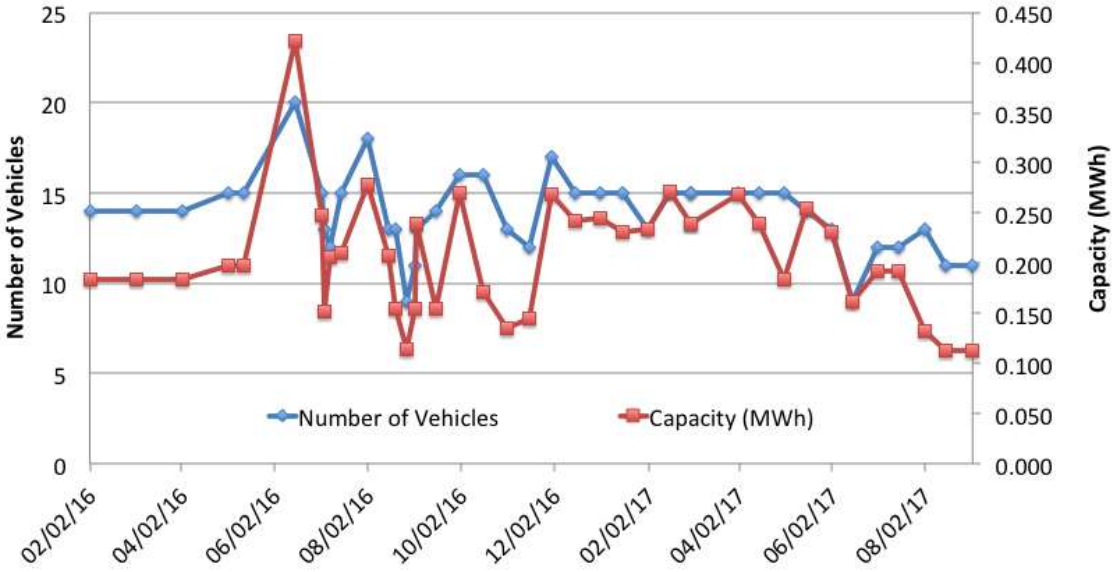
2 The units of capacity for ancillary services are MW held in reserve for one hour, denoted here as MW-h. The units are sometimes reported as MWh, however that could be confused as a quantity of energy rather than reserve capacity, and so is not used here.

to bid conservatively, near the minimum capacity offer threshold, to avoid over-committing the fleet's capacity and improve the system's performance.

Figure 6: Number of Vehicles Indicating As Available and Usable Capacity



Source: Lawrence Berkeley National Laboratory

Operations

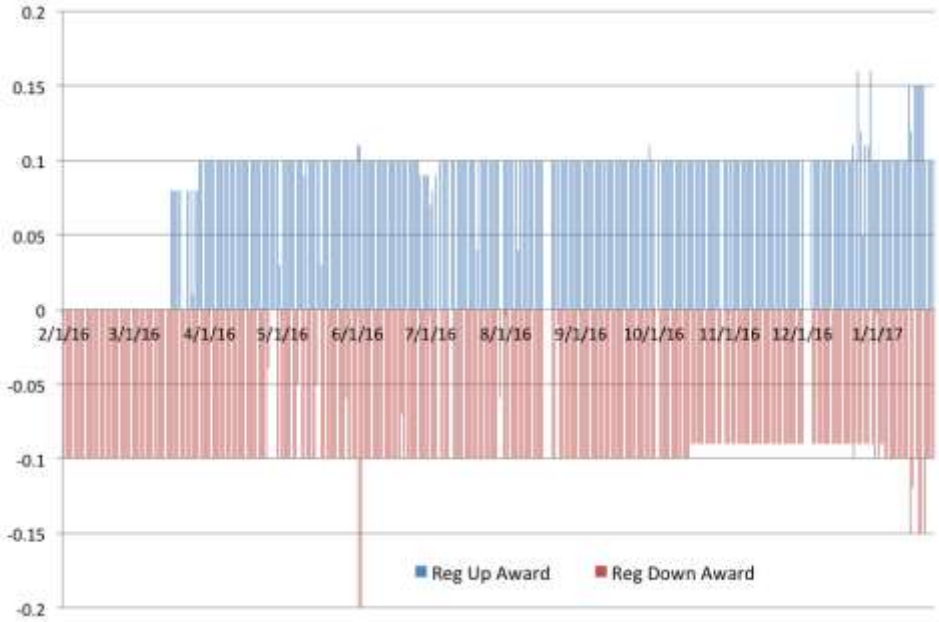
Submitting Bids and Receiving Awards

Goal of submitting bids each day was met for the most part over the course of the study. Regulation up and regulation down awards were almost always equal to the bids that were placed. From January 30, 2016 to September 30, 2017, the LAAFB V2G resource provided a total of 255 MW-h of regulation up and 118 MW-h of regulation down.

Each hourly award from January 30, 2016, when consistent bidding and awarding with California ISO was established, to Jan 24, 2017, the last day of regulation down certification (see California ISO Decertification of Regulation Down section below), are shown in Figure 7. Due to limited resource capacity, bids were nearly all 0.1 MW (reg up) and -0.1 MW (reg down) in each hour, with some exceptions toward end when operation of a subset of the EVs/EVSEs was more consistent.

DER-CAM optimized schedules were implemented when the availability of EVs and EVSEs stabilized at the beginning of 2017. Before that, inconsistent resource performance required fairly static minimum bids of 0.1 MW and -0.1 MW to reduce market settlement risk.

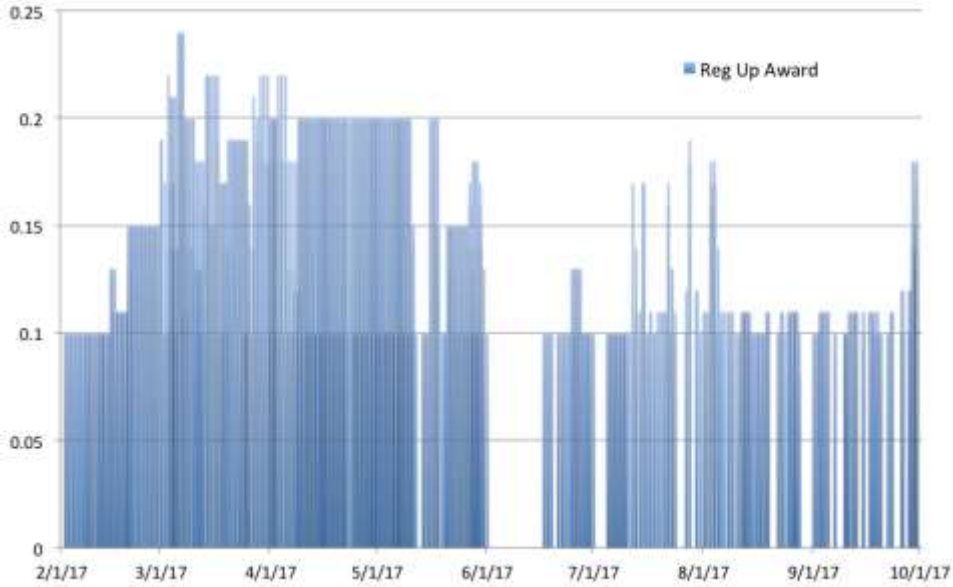
Figure 7: All Hourly Awards (megawatts) from 1/30/16 to 1/24/17



Source: Lawrence Berkeley National Laboratory

When bidding was regulation up only, the bid magnitudes increased in March-May 2017, as shown in Figure 8. From early June through September, bid magnitudes were reduced mostly due to lower hardware availability. Hardware availability was so constrained in early June that no bids could be made in that period.

Figure 8: All Hourly Awards (megawatts) from 1/25/17 to 9/30/17

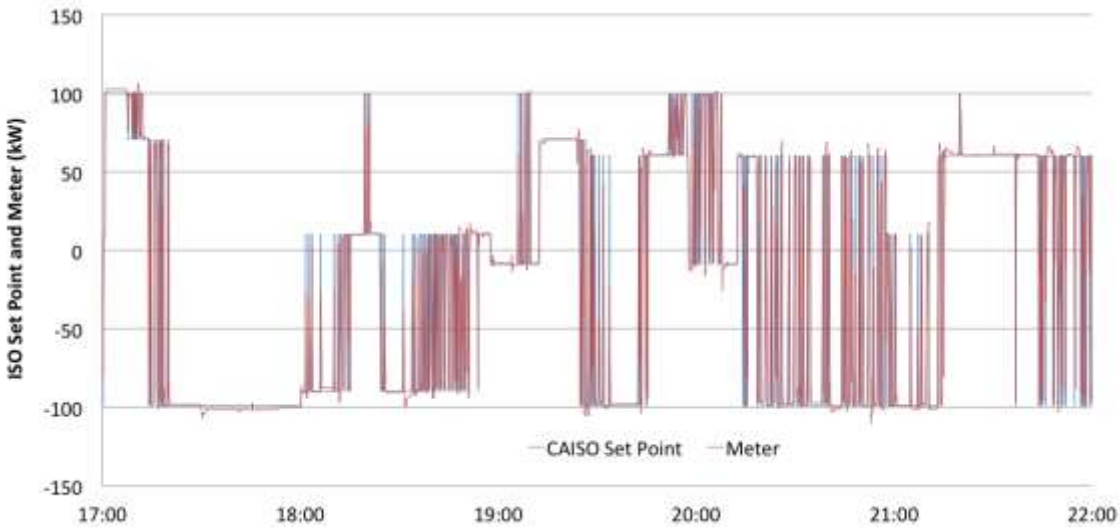


Source: Lawrence Berkeley National Laboratory

Following Automatic Generation Control Dispatch

An example of several hours of the LAAFB V2G battery resource following the AGC setpoint dispatched by California ISO at 4-second intervals is shown in Figure 9.

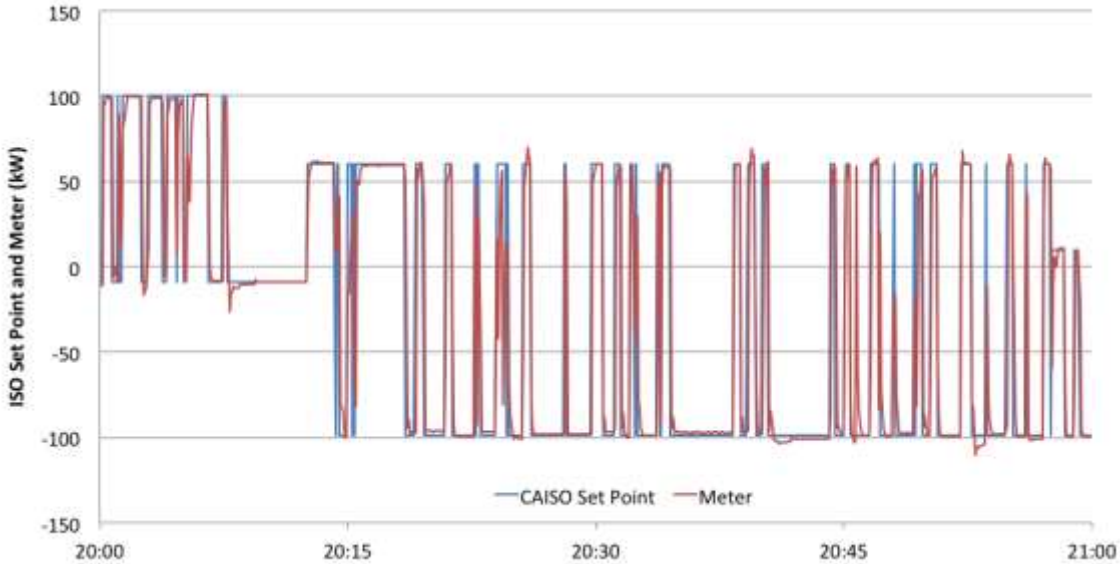
Figure 9: California ISO Automatic Generation Control Dispatch Setpoint (Blue) and Resource Meter (Red) Over Five Hours with ±15 kilowatt Electric Vehicle Service Equipment/Electric Vehicles Only



Source: Lawrence Berkeley National Laboratory

Zooming into a single hour illustrates the quick response time and accurate tracking (Figure 10) of the aggregate EV meter relative to the setpoint dispatched by California ISO. Figures 9 and 10 show a period when only ±15 kW EVSEs were active.

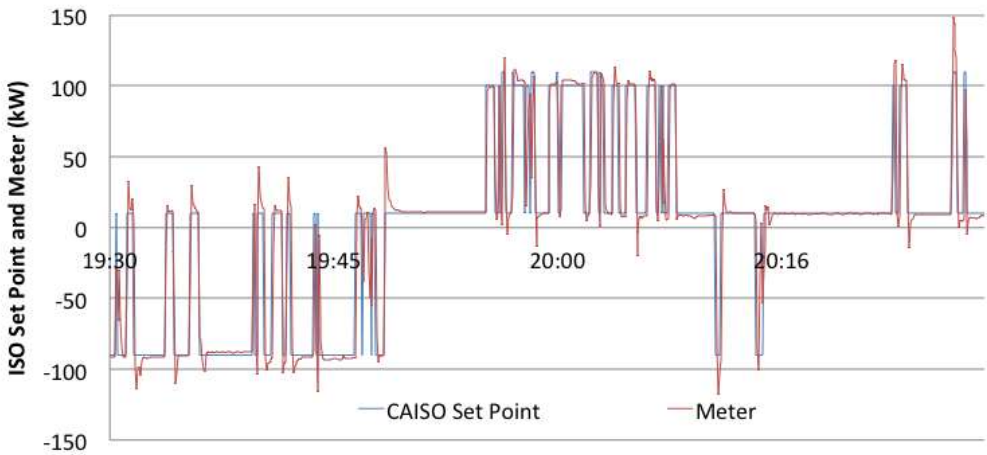
Figure 10: California Independent System Operator Automatic Generator Control Dispatch Setpoint (Blue) and Resource Meter (Red) Over One Hour with ±15 kW Electric Vehicle Service Equipment/Electric Vehicles Only



Source: Lawrence Berkeley National Laboratory

Figure 11 shows a period when both ±15 kW EVSEs and a ±50 kW EVSE was active. There is greater overshoot of the meter value relative to the target California ISO setpoint. This resulted due to the longer time that it takes for the ±50 kW EVSE to reach its higher setpoint. The real-time charge controller compensates for that lag time by setting individual setpoints that overshoot the target California ISO setpoint. The benefit of this overshoot is that it leads to overall lower error between the aggregate meter value and the California ISO setpoint, when compared at 4-second intervals.

Figure 11: California Independent System Operator Automatic Generator Control Dispatch Setpoint (Blue) and Resource Meter (Red) Over One Hour with ±15 kilowatt and ±50 kilowatt Electric Vehicle Service Equipment/Electric Vehicles



Source: Lawrence Berkeley National Laboratory

California Independent System Operator Decertification of Regulation Down

A letter from California ISO to SCE dated Oct 14, 2016 stated that the LAAFB V2G resource, resource ID ELNIDS_2_DODEV, had received accuracy scores for regulation down that were less than the allowable threshold of 25 percent for the months of July (23.6 percent) and August (11.4 percent) 2016. The low accuracy scores were partly due to hardware and control system faults, but primarily due to a problem with null accuracy values stemming from the need to use operating limits. Accuracy scores for August 2016 were nearly all null values for regulation down (only three 15-min accuracy scores were reported). According to the California ISO Business Requirements Specification: Pay for Performance Regulation document, a null value will result when the "net regulation" – the absolute value of the difference between the AGC setpoint and the Dispatch Operating Point – is less than 0.1 MW. For example, the base bid and was awarded -0.01 MW energy and -0.10 MW regulation (down). The AGC signal should have been -0.11 to get -0.10 regulation down relative to the -0.01 MW energy, but the project team had erroneously hard-coded the operating limit to -0.10 MW. With an AGC of -0.10 MW and a Dispatch Operating Point of -0.01 MW, the net regulation down was -0.09 MW, which led to null values for these time periods because the absolute value was less than 0.10 MW. The resource was following AGC and providing regulation down, albeit 0.01 MW lower than the awarded value.

The primary reason for setting an operating limit was due to a defect within the ISO Outage Management System (OMS), which prevented limits from being established. The effect of that defect caused a condition where the AGC setpoints being received were not limited to award values, but instead went to the maximum certified values for regulation up and down (or to limits set in the OMS. Ultimately it was the project team's responsibility for incorrectly setting the operating limit (-0.10 MW instead of -0.11 MW), but limits would not have had to be set dynamically if AGC setpoints were constrained to award values rather than to the resource certified maximums or to the limits set in the OMS, which cannot be dynamically adjusted in a manner suitable for the varying capacity of an aggregated EV resource. Although the ISO OMS defect was corrected in June 2016, it was a contributing factor to overall performance accuracy.

Also, the root cause here, outage limits incorrectly set by the operator, could have been easily corrected before accruing too much performance error in July and August if there was more timely performance feedback. If performance reports were available in timeframes shorter than quarterly, it could greatly increase a resource's ability to correct operation problems.

There, of course, was the option to repeat the certification test procedure with California ISO to maintain status as a regulation down resource, but several of the EVs and EVSEs that were operational in the original October 2015 certification test were no longer reliably operational in October 2016. On January 24, 2017 the base was no longer able to bid or receive awards to provide regulation down. After that date, the base alternated between bidding regulation up only for one to two hours and recharging the vehicle fleet back to full capacity out of market, multiple times in weekday evenings, and throughout the day and evening on weekends (when resource capacity and performance allowed).

Accuracy Performance

Monthly Regulation Accuracy

Based on the description outlined in California ISO Business Requirements Specification: Pay for Performance Regulation, the project team sought to implement an internal calculation of monthly regulation accuracy metrics to assess the performance of the resource using observed signal and response data. In the following sections the full methodology, based on the team's interpretation of the California ISO description is provided. The methodology is then applied to the collected AGC signal and response data collected during the operational phase of the project to assess the historic performance of the EV fleet resource.

Accuracy Methodology

In the accuracy formulation (Equation 15), the weighted monthly accuracy (A_d) in each direction (d) is the sum of all un-weighted period accuracy values ($a_{p,d}$) with an applied period mileage weight ($w_{p,d}$), for each 15 minute period (p). The resulting sum is

normalized by the sum of all period mileage weights to ensure A_d is between 0 and 1. Each period mileage weight (Equation 16) is sum of absolute changes in the AGC dispatch signal (D_t), recorded in 1-second intervals within the period. Mileage weights are calculated separately for up and down regulation. So mileage only accrues in a given direction when the signal is in the corresponding domain (i.e. charging or discharging).

The accuracy of each period is given in Equation 17. Here the deviation is defined as the absolute difference between the dispatch signal (D_t) and the metered response 4 seconds later (M_{t+4}). The signal magnitude is defined by the difference between the dispatch signal and the energy baseline (E_t), which is determined by the energy award for each hour. The deviation and signal magnitude are each summed for each 1-second interval observation (t) within the given period (p). The period error is the deviation sum over the signal magnitude sum, while the period accuracy is one minus the error. It is possible, for example. in instances of large or sustained deviations, that the raw period accuracy can be below 0. In these instances, the period accuracy is replaced with 0.

The documentation of the California ISO accuracy metric suggests there is a minimum signal magnitude (100 kW) for observations to be included in the accuracy metric. The effects of this may be disproportionate on a small resource such as that present at LAAFB. To investigate this, accuracy metrics are calculated with and without this 100 kW threshold applied.

$$A_d = \frac{\sum_p (w_{p,d} * a_{p,d})}{\sum_p w_{p,d}} \qquad (15)$$

$$w_{p,d} = |D_t - D_{t-1}| \qquad (16)$$

$$a_{p,d} = max\left(1 - \frac{\sum_t |D_t - M_{t+4}|}{\sum_t |D_t - E_t|}, 0\right) \qquad (17)$$

where:

A_d : monthly accuracy in direction d

$a_{p,d}$: unweighted accuracy for period p in direction d

$w_{p,d}$: mileage weight of period p in direction d

D_t : dispatch signal at timestep t

M_{t+4} : meter response at timestep t + 4 seconds

E_t : energy purchase baseline at time t

d : regulation direction up or down

t : one second interval timestep

p : 15 minute interval starting at 00:00 of each hour

Observed Fleet Accuracy

Table 5 provides the calculated resource accuracy for each month the fleet has participated in regulation. Due to low reported accuracy scores in late 2016, the resource could not participate in down regulation after January 2017. It also appears that with the 100 kW minimum signal threshold applied, there were no down regulation observations accrued in August 2016, so no down accuracy score could be reported (as discussed above, California ISO reported a total of three 15-min accuracy scores for August 2016).

Based on LBNL's implementation of the accuracy metric, it appears that the EV fleet generally performs well, exceeding the minimum required performance of 0.25 in all months, with accuracy scores ranging from 0.66-0.91 for up, and 0.54-0.90 for down, when all observations are included. When the minimum threshold is applied, up accuracy appears to increase slightly. Down accuracy does not exhibit as clear a trend, though in some months, the application of this limit causes accuracy to fall substantially (July, August and November, 2016). These low-score months contributed to the decertification of the resource in down regulation, indicating that the minimum signal magnitude constraint creates challenges for small regulation resources that bid near the minimum bidding threshold.

Table 5: Monthly Accuracy Metrics Calculated From Observed Signal and Response Data

		DOWN ACCURACY		UP ACCURACY	
Year	Month	Signal > 0 kW	Signal > 100 kW	Signal > 0 kW	Signal > 100 kW
2016	May	0.768	0.920	0.790	0.912
	June	0.770	0.891	0.790	0.871
	July	0.741	0.372	0.661	0.656
	August	0.855	-	0.664	0.836
	September	0.803	0.710	0.714	0.871
	October	0.843	0.967	0.771	0.918
	November	0.862	0.415	0.770	0.916
	December	0.868	0.811	0.730	0.887
2017	January	0.838	0.816	0.750	0.889
	February	0.753	-	0.885	0.888
	March	0.541	-	0.848	0.850
	April	0.901	-	0.852	0.853
	May	0.606	-	0.844	0.846
	June	0.836	-	0.872	0.873
	July	0.563	-	0.889	0.893
	August	0.529	-	0.919	0.920
	September	0.881	-	0.919	0.920

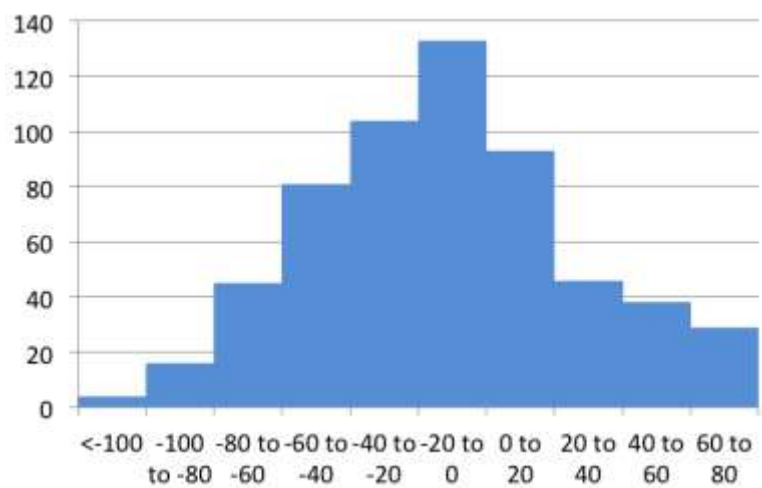
Source: Lawrence Berkeley National Laboratory

Variation of Automatic Generation Control Use

AGC use is defined as the percentage of energy dispatched during regulation relative to the maximum dispatch at the awarded capacity over a given period. To optimize bids and resource management, a good forecast of AGC use is required. The base often placed and was awarded symmetric bids of -100 kW (regulation down) and +100 kW (regulation up). In these cases, AGC utilization can be looked at slightly differently, as the average of the AGC dispatch setpoint, with an average value of zero indicating equal dispatch of regulation up and regulation down. Figure 12 shows the hourly average AGC setpoint in kW when regulation up and regulation down bids and awards were symmetric. Values on the far left correspond to nearly all regulation down in an hour and values on the far right correspond to nearly all regulation up. A value of zero indicates an even distribution of AGC dispatch for regulation up and regulation down. The majority of hourly AGC use tends toward zero skewed somewhat to regulation down. The variation in hourly AGC use leads to lower bidding since more battery storage capacity has to be kept in reserve in case there are consecutive hours with net AGC that is not neutral.

Daily AGC use shows a similar pattern, and while the tendency towards zero or slightly to regulation down is good in that it is more likely that AGC dispatch intended to leave the battery resource at an SOC near or above where it started. There was significant variation, which presents a challenge for optimizing bids for the Day-ahead market.

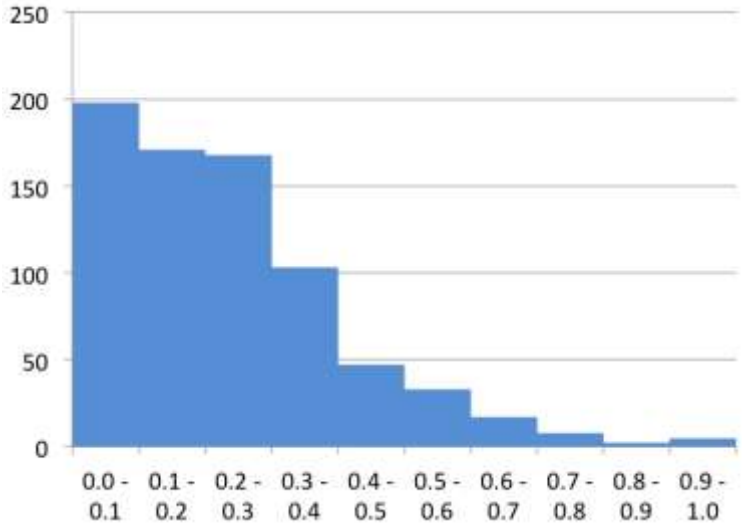
Figure 12: Hourly Automatic Generation Control Use With Symmetrical Reg Up and Reg Down Awards



Source: Lawrence Berkeley National Laboratory

One opportunity bidding only regulation up provided was to get a measure of the magnitude and variation of AGC dispatch in a single direction. Figure 13 shows the ratio of the hourly average AGC dispatch to the hourly regulation up award value. Usage is somewhat low, with three quarters of all use below 0.4 or less but, this may be specific to this resource.

Figure 13: Hourly AGC Use When Only Reg-Up is Bid and Awarded



Source: Lawrence Berkeley National Laboratory

Environmental Impact

The LAAFB replaced internal combustion engine (ICE) gasoline vehicles with the 13 Nissan LEAFs purchased by the Energy Commission for this study. The LEAFs travelled a total of 73,000 miles during the study. To calculate CO_2 emissions, assume the LEAF efficiency is 3.4 kWh/mile and that electricity generation feeding LAAFB on average produces 0.62 kg CO_2 per kWh. Also assume that the gasoline vehicles had average fuel economy of 20 mpg and that each gallon consumed releases 20 lbs of CO_2. During the study, CO_2 emissions were reduced by 36 tons or 83 percent relative to what they would have been from a gasoline powered fleet making the same trips.

The project earned credits in the California Air Resources Board Low Carbon Fuel Standard (LCFS) program, which is designed to encourage the use of cleaner low-carbon fuels in California and reduce greenhouse gas (GHG) emissions. The EVs in this project replaced ICE vehicles. LCFS credits were based on the difference between overall GHG emissions from the vehicle miles travelled by the EVs compared to making those same trips in gasoline ICE vehicles. From the start of the project to the second quarter of 2017, the LCFS credits totaled 21 worth $1827.

Enhancements to Distributed Energy Resources Customer Adoption Model Electric Vehicle Charging and Regulation

This section details the features, enhancements, and modifications made to DER-CAM day-ahead EV regulation model, as outlined above, to enable the automated execution, optimization, and delivery of daily, day-ahead EV charging schedules and regulation bids plans.

The day-ahead model consists of the core DER-CAM optimization model, as well as the surrounding support code, which collects and preprocesses input data from various

sources, defines constraints and prepares data for the optimization, post-processes and validates optimization results, and prepares and delivers outputs to LBL operators, systems on the base, and the scheduling coordinator for submission to California ISO.

The structure of these model components largely conform to the designs and specifications developed early in the LAAFB project. However, as testing and operation proceeded, additional features and modifications were identified and used. These changes broadly fit in to the following categories:

- **Automated deployment**: These features relate to the automated operation of the day-ahead model, and include the development and deployment of APIs to external data sources, and data exchange with on-base systems.
- **Data management**: These features relate to the management and storage of data used and generated by the day-ahead optimization model.
- **Input data**: These features relate to the structure, content, and format of input data used to populate, tune, and execute the daily optimization.
- **Optimization constraints**: These features relate to the definitions and implementation of system constraints within the optimization model
- **Output data**: These features relate to the content, structure, and formatting of the output data produced by the day-ahead model, and include additional post-optimization analysis and metrics.

A detailed description of modifications and enhancements by category are provided below.

Automated Deployment

Input/Output API: The API between the day-ahead DER-CAM model and the on-base EV management system were deployed and finalized. These APIs allowed for the automated collection of input data to initiate an optimization, as well as the automated return of day-ahead and re-optimization output data.

Email Alerts: Automated email alerts to report critical errors and track model performance have been added to both the day-ahead and re-optimization models. The features, has been critical to identifying and correcting performance problems throughout the testing and operational phase of the project.

Run Summary Email: Code was deployed to generate an email containing a summary of model results, including optimization status and runtime, EV fleet information, bid and charging plans as part of day-ahead run. The summary email proved highly useful for the project team to track the status and performance of the fleet, and quickly diagnose bugs across all system components.

Results Data Visualization: Functions to generate summary graphics were added to the day-ahead model. These graphics provided additional guidance for debugging the model

and understanding the model dynamics more generally. Results visualizations code be provided along with run summary emails or generated as needed by users.

Bid Submission Generator: Functions to generate formatted bid files were deployed. Once vetted, these functions allowed the system to submit daily bid plans without human intervention. Bid files were generated to the specifications of the scheduling coordinator (SCE), yet were developed to be flexible re file formatting.

Data Management

Day-ahead Databases: Databases to log all model inputs, outputs, run performance and status of all automated runs, both testing and live, have been deployed. These databases allow the team to retain all information relevant to the testing and operation of the system, and performance extensive analysis of system dynamics and performance.

Offline Analysis Features: Features have been added that allow users to perform offline analysis with user-selected data. Test analysis data is retained but differentiated from live data when stored. The offline analysis test-bed allows the team to quickly replicate the inputs of constraints of the current live system, and test and deploy changes without impacting the rest of the system.

Rerun Analysis Features: As an expansion of the above, offline analysis, a re-run feature was developed and deployed. The feature allows for previous live runs to be quickly re-run, with the option to alter inputs parameters. This allows the project team to quickly assess the impact of new changes on the model under representative test conditions.

California ISO Price Database: A database of historic California ISO hourly regulation prices was created and populated using an existing California ISO API. The presence of a local price database allows the project team to develop an internal, adaptive regulation price forecast.

Regulation Award Processing: An automated system to find and process incoming award files from the scheduling coordinated was deployed. The process allowed the system to collect this critical dataset without human intervention.

Regulation Award Transfer: An automated system to share the collected award dataset was also deployed. The system allowed the award dataset to be shared with other system components, e.g. the on-base EV management system and real-time AGC control system.

Site Weather Database: A database of historic weather conditions for LAAF was created and populated with data collected using existing weather data APIs. The script ensured that most up to date weather data was used to power the adaptive load forecaster.

Input Data

Historic Load Data Input: Because an API to the base's historic load data could not be deployed, a system to upload historic load data was created. The system required minimal human intervention and was used to populate the historic load database, which in turn drove the internal load forecaster.

Maximum Demand Level Forecaster: In addition to a forecaster for the base's load profile, a forecaster to predict maximum monthly demand levels was deployed. The support forecaster helped improve the system's demand management functionality.

State-of-Charge Penalty Tuning: The baseline SOC penalty, which had been tuned initially to test conditions, was further tuned to eliminate a problematic behavior of discharging large-capacity EVs overnight. While the model reserved adequate time to charge the EVs before their morning trips, occasional overnight EV testing would result in the battery not being fully charged, but charged sufficiently for its scheduled route. Having critical vehicles (especially the shuttle bus) not charged to capacity created anxiety among base personnel, and therefore the testing behavior was reduced.

Optimization Constraints

Forced SOC Constraints: Model constraints were added to force EVs to have user-defined SOCs at user-defined times. The constraint was employed for testing, diagnostics, and cell balancing of individual vehicles. Such testing often requires vehicles to be charged to full or discharged to empty. Incorporating this behavior into the model allows the rest of the fleet to be operated in a complementary way, to minimize cost or stay in the regulation market while EV testing is conducted.

Hourly Regulation Participation: Additional flexibility was added into the model to allow hourly participation in up or down regulation to be selectively enabled or disabled. The flexibility allowed for partial participation in ancillary services if there were selected times when participation was expected to be problematic.

Regulation SOC Reporting: An initial SOC report was added as part of the regulation bid submission file. Constraints were added to the model such that an adequate initial SOC was provided, which ensure the day's regulation bids would be feasible (based on the fleet's California ISO resource definition), and thus awarded each day.

Regulation Energy Bid Constraints: Initial participation in the market indicated that the fleet resource had less flexibility to self-schedule energy in hours when it was also participating in regulation. To incorporate this real-world condition, a constraint was added to the optimization to allow for a user-defined energy bid amount in regulation hours. Under this constraint, rather than allowing the optimization to select the optimal energy bid, the model is instead forced to select the constrained energy bid amount.

Reduction of Energy Bid Gaming: When unconstrained, the model would occasional inflate hourly energy bids in order to increase the effective capacity it could bid into regulation. The model was especially susceptible to this in hours with unusually high regulation prices. To prevent such gaming from occurring, penalties were added to the model to reduce the amount of "gamed" energy that could be used in forming a regulation bid.

Hourly SOC Penalty Constraint: An hourly resolved SOC penalty input was deployed in the day-ahead model to increase the flexibility of this constraint. The objective of the

SOC penalty is to incentivize the model to charge vehicles more than in necessary to meet the given mobility requirements. In so doing, the model creates a SOC cushion that mitigates the risk of depletion from unexpectedly high regulation discharging or from trips that exceed their scheduled energy requirements. Testing was conducted to develop a base-line SOC penalty profile, which was also used with the other model inputs.

Output Data

Infeasible EV Error Handling: Under basic conditions, if an infeasible EV trip is provided as an input (such as if the energy required for the trip exceeds the total capacity of the assigned vehicle) the whole optimization will be infeasible and no solution will be produced. Within the optimization mode, internal EV infeasibility tracking was deployed. When infeasible EV inputs are provided, this tracking allows the model to identify the problematic schedule and return this information to the EV management system for correction.

Projected Initial SOC Reporting: A new output: projected initial SOC was added to output dataset of day-ahead model. The new output is an important component of consecutive day-ahead runs, as it links the EV SOCs between days. For instance, the ending SOC of EVs in today's optimization provides the best prediction of the starting SOC of the same EVs for tomorrow's optimization. Thus, this dataset must be reported and stored to ensure that EV SOC trajectories remain consistent across runs.

Delayed SOC Depletion: The project team deployed a methodology to delay reporting of trip-related SOC depletion due to vehicle trips. The optimization tracks the SOC trajectories of all EVs in the fleet. When charging, these SOCs increase, when discharging for V2G or regulation, the SOCs fall. The SOCs also fall when the EV is being used for a trip. The raw EV SOC profiles include all these changes. However, the modified SOC trajectory reports a flat SOC when an EV is on a trip. When the EV returns from the trip, the reported SOC drops instantaneously to what is expected to be upon its return. Modifying SOC trajectories in this way helps prevent V2G discharging if the departure time for an EV trip is delayed.

Additional Result Metrics: Additional results and metrics were added, including total reported fleet capacity, hourly fleet average SOC, market energy participation, and in-market hours. These additional results and metrics help the project team understand better the fleet, participation, and model performance at a glance.

Optimization Status Reporting: Outputs to track optimization status and report critical problems back to on-base EV management system were also added. By tracking the optimization status, bugs can more quickly be addressed, and automated error handling can also be deployed.

California Independent System Operator Ancillary Services Market Challenges Addressed

Integrating an electric vehicle fleet into California ISO markets and operations is challenging on a number of levels. The markets were appropriately designed with large, static resources in mind and the characteristics of small V2G resource aggregations do not fit the market framework well at this time. The majority of the challenges come from the dynamic nature of an EV aggregation's physical characteristics as vehicles plug in and unplug to provide their primary service, mobility. There are also contractual challenges associated with forced representation, idiosyncrasies of the market, and challenges specific to small resources attempting to provide services. While these challenges were observed, they were not wholly the fault of the market and ISO operations. Some of these challenges may be mitigated in the future locally with improved resource performance and increasing capacity offers above the minimum bid quantity that California ISO's market rules allow. In this section, the LAAFB team highlights these challenges and describes how they were addressed in the demonstration.

The dynamic nature of the EV aggregation's physical characteristics creates a number of significant challenges for market inclusion:

- The most basic challenge is that its physical characteristics (ramp rate, battery capacity, power capacity, etc.) change throughout the day, proportional to the number of electric vehicles connected to their system at any given moment. These types of parameters are generally thought of as static for a typical generating resource, and are thus a part of the resource data file. This file can't be changed on a regular basis, and under typical procedure takes two weeks to update once California ISO has been notified of a change. The other way to indicate a change in these parameters to California ISO would be through their outage management system, a manual process. However, distinguishing between a normal daily change and an equipment failure that is causing an outage is not feasible in the system, and thus is not an appropriate method to indicate the quickly changing parameters of a resource. In the end, only telemetry in real-time is able to provide the California ISO with a real sense of the changing resource parameters and the resource data template will represent maximum capacity conditions with conservative ramp rates, but the fact that this information is not available to the market optimizations and the telemetry may disagree with other market systems may cause challenges in resource settlement and could result in a significant amount of rescinded payments to the resource.
- EV aggregations are modeled as Limited Energy Storage Resources (LESRs) in the California ISO markets. One very favorable aspect of the LESR designation for V2G applications could be the option to be a Regulation Energy Management resource, because this requires less energy storage and ensures that while providing regulation, the battery state of charge is maintained near 50 percent. However, because of the changing size of the aggregated battery and its reliance

on managing to 50 percent of the energy storage as recorded in the master file, V2G aggregations are inappropriate for the REM designation, and must manage their SOC through interaction with real-time energy market while providing regulation services.

- To clear LESRs in the California ISO day-ahead markets, the market algorithm attempts to calculate the resource's aggregate state of charge at each hour based solely on the energy awards of that hour. Again, the dynamic nature of electric vehicles, such as their consumption of electricity during driving, prevents the DA market algorithm from accurately predicting the SOC, and may provide erroneous dispatch results. Further, the market does not include any impact of providing frequency regulation on the calculated SOC, even in instances where the frequency regulation offer is asymmetric and would always result in either an energy loss or gain to the battery over time. As discussed in the AGC Use results, this assumption is often false, particularly if a resource is only providing a single direction of regulation resource. This further complicates the ability of the market to accurately predict the state of charge of the resource throughout the day. California ISO did adapt their market to support the resource providing an initial SOC state for each day with their bid to help them get closer to a realistic prediction of SOC. However, to be able to provide a truly accurate picture, the resource must provide information on all energy subtractions and additions to the aggregated battery as the vehicles plug in and out throughout the day, which would be another 24 data points at minimum. This seems cumbersome for California ISO to manage if V2G resources ever reach scale. In fact, the initial SOC provided with the bids for the LAAFB was calculated such that all energy and capacity offers would be feasible throughout the 24-hour day-ahead award period, and did not represent any true estimation of state of charge. A better solution for the California ISO would be to ignore the SOCs of its LESRs altogether in the DA market algorithm, and rely on telemetry to indicate if a resource misrepresented its availability, in a way that their DA capacity payment should be rescinded and any real-time cost be allocated to their non-performance.

Other bidding idiosyncrasies make for mild challenges to V2G market integration:

- The requirement discussed earlier that a resource must bid a non-zero energy quantity to be available for frequency regulation can have implications for continuous regulation offers. This requirement made sense before the LESR model was created and all resources had positive power values only, but now that a resource can offer both positive and negative capacity, it would be beneficial to allow the resource to have a zero energy baseline, which may improve state of charge management of a resource over continuous hours of frequency regulation provision.
- For an LESR, the scheduling coordinator must be the load serving entity for the resource as well. This requirement makes sense from the California ISO's

perspective for settlement purposes, but not all LSE's are equipped to provide scheduling coordinator services, nor do they have a method of monetizing the service due to their regulated status. This makes it a challenge for them to justify investments to do so. Opening up the scheduling coordinator role to third parties and aggregators could benefit the ability for V2G resources to transact in wholesale markets and may reduce costs overtime due to competition.

Finally, there are some operational challenges that manifest for V2G resources, these more than the other challenges identified could be addressed from the California ISO operations and improved EV performance:

- While it is uncommon to be able to obtain state of charge measurements reported by an EV, the vehicle manufacturers supported this functionality for the demonstration. However, the measure of SOC in a vehicle is often sensed by measuring the voltage of the battery pack, which can vary widely depending on the direction of power flow. This means that there might be sudden changes in the reported energy stored in the battery if the system went from charging to discharging, and this may cause confusion for the system operator and the California ISO's Automatic Generation Control (AGC) system. This is further complicated by step changes in the reported SOC and power available when a vehicle disconnects or reconnects from the system. Stability analysis of the impact on AGC of rapidly-changing SOC, and other telemetry data, if EV fleet participation achieves a significant market share would be useful to ensure reliable electricity system operation with V2G resources.
- The local optimization algorithm will often withhold some capacity available in a single hour in order to ensure that that capacity can be properly deployed in subsequent hours when it expects more value, or if the fleet might run the risk of being unable to provide mobility services in the future. Thus, an Ancillary Service bid may be less than the total connected capacity. This becomes a challenge in operation when the resource reports through telemetry its actual connected capacity (which is greater than its AS award) and finds that the AGC system will attempt to dispatch that additional capacity. After being over-dispatched like this on multiple occasions, the LAAFB telemetry system started reporting its power capacity limits as the minimum of connected capacity and the awarded capacity to prevent the system from dispatching power greater than what was intended during the frequency regulation award. This approach solved the problem of over-dispatch, but the project team understands is not ideal from a California ISO perspective.
- Controlling the maximum power limits in this fashion resulted in some hours in which the system accidentally reports an incorrect lower limit and was given no-pay penalties for the period. This occurred due to an error in the expected baseline energy purchase for the resources, which meant that the internal calculation of regulating range was off by 10kW, meaning that the power limits

result in lower regulation capacity than awarded. While this could be avoided if AGC limited dispatch to the award value, it is ultimately a failing of the on-base infrastructure that resulted in these poor performing periods.

- As discussed, the LAAFB was de-certified to provide regulation down ancillary services because of monthly performance scores that were lower than the minimum performance threshold. However, these scores were severely impacted by the filtering performed in California ISO's calculation of performance. While California ISO allows for a 100kW minimum regulation offer in markets, to qualify for the performance score, the resource must be dispatched to at least 100kW according to their Business Practice Manuals. California ISO will often dispatch regulation below its offered capacity, but those periods do not count toward performance. This filtering of the intervals that make up the performance score should be scaled to the resource or offer size to better capture the quality of service being offered. However, it should be noted that while their minimum bid value is 100kW, the minimum resource size certified for the market is 500kW. If the LAAFB system was able to offer something closer to its certified capacity, as the market intends, the decertification would likely never have occurred.

The last challenge interfacing with the market is the interface to the scheduling coordinator. Southern California Edison (SCE) graciously agreed to perform scheduling coordinator duties for the demonstration, however they typically do not offer this service and did not have all the mechanisms in place to allow for optimal interaction with the market. Resource bids were dictated to SCE through email. These bids would then have to be manually entered by an operator at SCE into California ISO's systems. This manual entry process was too cumbersome to allow us to actively participate in the hour-ahead market, as that kind of volume of bidding could not be done manually. As a non-REM resource, to provide continuous service, the fleet would need to adjust its energy position in the wholesale market throughout the day. Without an automated way to upload bids, the base was forced to enter the market only for short periods at a time, and then go off of ISO control to recharge the batteries. For SCE to invest in infrastructure to provide these type of services (and according to California ISO rules they have to be the SC for LESR resources), they require an economic incentive enacted by regulators to do so. Until this happens, participation of any vehicle to grid resource of comparable size will be too limited to make up the transaction costs incurred for participation.

For nearly the first year of market participation, energy load bids had to be made in an hour before, on the same day as, the first regulation up bid so the California ISO optimization would "add" that load to the battery, which the California ISO optimization otherwise would have assumed was at zero SOC. The amount of the energy load bid had to exceed the first regulation up bid. After that, regulation down bids, or at least the amount the optimization awarded, would get counted toward SOC, less the assumed efficiency loss, to cover the subsequent hour's regulation up bids. The primary problem with needing to make the energy load purchase was that the fleet would have to drain

the batteries in the hour(s) before the energy load award so that the fleet would be at the desired initial SOC for providing regulation up or down—~50 percent.

The initial SOC field became available November 20, 2016, and after that the pre-regulation energy bid was no longer necessary. The base still entered small, -0.01 MW, energy load bids to cover the energy requirements of the charging stations and to minimally charge the EV batteries when neither regulation up or down was called for by the California ISO AGC dispatch. This was the intended approach. In practice, the California ISO AGC dispatch was rarely, if ever, -0.01 MW (load), but rather 0.01 MW (generation). This may be because the California ISO treats the fleet resource like a traditional resource, which would tend toward a state of small generation when not requesting regulation up or down.

LBNL had planned to re-run its optimization at least hourly during the day to make changes in the hour-ahead energy market to mitigate impacts related to unscheduled vehicle trips, or scheduled trips not being taken. While LBNL was able to run the re-optimization software, the base was not able to submit the energy bids in the hour-ahead market because the scheduling coordinator does so manually. It was not feasible to expect to manually enter varying bids in the hour-ahead market multiple times per day, so the base's bids during business hours were very limited. LBNL was able to work around the scheduling coordinator's process of manually submitting day-ahead bids by creating its own automated methods for submitting, receiving, and parsing bids and awards.

Charge Control Challenges Addressed

For frequency regulation, California ISO requires resources that respond rapidly and accurately to desired setpoints. Specifically, resources must meet the setpoint specified by the automatic generation control (AGC) within four seconds. Kisensum's OB-EVI charge control module specified power setpoints for each available EVSE/EV so that the aggregate load (reg down) or generation (reg up) would match the AGC setpoint. Control challenges that were addressed include disproportionate dispatch of EV batteries of different sizes and oscillation between charging and discharging to maintain a setpoint.

Disproportionate Dispatch of Different Size Batteries

The EV rated battery capacities fell into three categories: ~25 kWh, 50 kWh, and 100 kWh and the EVSE ratings fell into two categories: ±15 kW and ±50 kW. The large spread in capacity and charge/discharge rate presented a challenge for setting proportional individual dispatch setpoints. A 5 kWh error from target represents 25 percent of capacity for a Nissan LEAF and only 6 percent for a Phoenix Bus with a usable battery capacity of 80 kWh. Larger capacity vehicles were proportionally favored by the optimization algorithm, which often left Nissan LEAFs further from their target in percentage terms. In practice, the larger capacity batteries would be discharged faster, and, sometimes, to their minimum allowable SOCs. At which point, the ~50 kW of

regulation up that the larger battery/EVSE was providing would be lost and the remaining vehicles could rarely make up the difference resulting in poor accuracy performance.

To mitigate the disproportionate utilization of smaller resources, W was tuned in production, based on the reciprocal of capacity of the vehicle battery. The W resulting in the most even distribution of charge/discharge setpoints was a matrix in which the diagonal was the reciprocal of the vehicle capacity in kWh to the power 1.5.

Dispatch Oscillation

Oscillations between charging and discharging during regulation prompted another change to the objective function. Since the trajectory errors are squared and the large signal error weight during regulation ensures that trajectory errors will always be traded for reduction in signal error, the optimization would frequently charge some EVs and discharge others simultaneously to reach a setpoint. Furthermore, vehicles near their target SOC would oscillate between charging and discharging. This oscillation was undesirable not only for its potential impact on battery life but also due to frequent setpoint changes that caused unwanted perturbations during signal following.

To minimize setpoint changes and reduce the oscillations, an absolute power term was added to the objective function from Juul et al. This term represents the sum of the absolute power of all individual setpoints and encourages a result in which all stations are moving energy in the same direction. The weight for the absolute power term was arbitrarily set at 1 and results were satisfactory.

Frequency Regulation Revenue Potential in California Independent System Operator

Frequency regulation has been identified by many to be a high value Vehicle-to-Grid (V2G) opportunity. Initial revenue estimates have been as much as $100/month/vehicle (Marnay et al., 2013). These estimates rely on a number of assumptions relating to the power resource from a vehicle, their availability, and their interactions with the wholesale market and automatic generation control systems. With hindsight from the demonstration's market participation in California, the project team re-evaluated the results of the initial estimate of opportunities.

The first revenue analysis presented in Marnay, et al. was an estimate based both on historical price data in the California ISO day-ahead frequency regulation market and expectations of the fleet composition that would be purchased for the LAAFB Demonstration. Using an average combined frequency regulation up and down price of $16/MW-h (the historical average in California from April 2009 to March 2012) and assuming 41 vehicles capable of charging and discharging at 15kW to provide frequency regulation, the monthly value of providing frequency regulation from 5PM to 8AM the next morning was approximately $101/month/vehicle. If this amount could be captured, it would represent a significant opportunity to offset nearly a third of the cost of leasing a vehicle. However, the reality of the LAAFB demonstration hardware and its interactions with the market challenges some of the assumptions made in that analysis.

First, the project team recalculated the potential regulation revenue using the actual market clearing prices while the base provided frequency regulation services, from January 2016 through July 2017. Table 6 shows relevant monthly revenue statistics. Performing the same analysis as in Marnay et al., 2013, yields a considerably higher average monthly revenue for the generic 15kW charge/discharge capable EV, implying higher prices for day-ahead frequency regulation over the period of performance.

Table 6: Simple Vehicle-to-Grid Revenue Analysis Using California Independent System Operator Reg Prices for January 2016-July 2017

	Average	Median	Minimum	Maximum
Fleet Capacity [kW]	615	615	615	615
Reg_Dn Revenue [$/month]	$1,610	$1,436	$816	$4,062
Reg_Up Revenue [$/month]	$3,488	$3,406	$2,016	$5,390
Total Revenue [$/month]	$5,097	$5,027	$2,832	$8,571
Generic Vehicle Revenue [$/veh/month]	$124	$123	$69	$209

Source: Lawrence Berkeley National Laboratory

This generic fleet can be replaced with the LAAFB vehicle fleet that existed around the time of resource certification (Table 7) and the same analysis can be performed.

Table 7: Los Angeles Air Force Base Electric Vehicle Fleet Parameters

Vehicle	EVSE Manufacturer and Model	Qty	Rated Charge Power [kW]	Rated Battery Capacity [kWh]
Nissan LEAF	Princeton Power Systems GTIB-208-30	13	15	24
Phoenix Motor Cars Shuttle Bus	Coritech VGI-50-DC	1	50	100
EVI Stake and Box Trucks	Coritech VGI-50-DC	4	50	54
VIA Van	Coritech VGI-15-AC	11	15	21
Fleet Totals		29	610	859

Source: Lawrence Berkeley National Laboratory

The slight change in overall rated charging capacity (from 615kW to 610kW) would have a proportional change on fleet revenue from frequency regulation in the simple analysis case, resulting in an average of $5,056/month for the fleet. A failure of this analysis is that there is only a single parameter constraining the frequency regulation capacity offered by a vehicle, their charging/discharging power rating. The energy storage in the battery of a V2G resource will impact a frequency regulation capacity offer, even when the frequency regulation signal is assumed to be zero mean during the offer period. California ISO requires that any Limited Energy Storage Resource (LESR) that operates in

all markets must have enough energy stored (or empty storage headroom) to provide the regulating reserve capacity offered for a full hour, or the entire period of any single offer. To provide symmetrical up and down frequency regulation capacity a resource requires battery capacity equal to the sum of their max charge and discharge rates multiplied by an hour.

The battery storage limitation has a relatively significant impact on the overall fleet's capacity offer. Examining the vehicles used at LAAFB, the Nissan Leafs have a battery capacity that allows for at most a symmetric regulation offer of 12 kW in each hour, while the EVI box trucks can offer no more than 27kW-h at their rated battery capacity, and the VIA Vans can offer only 10.5 kW. The impacts this has on the revenue analysis are shown in Table 8.

Table 8: Los Angeles Air Force Base Electric Vehicle Fleet Monthly Revenue Considering Limited Storage Capacities

	Average	Median	Minimum	Maximum
Fleet Capacity [kW]	424	424	424	424
Reg_Dn Revenue [$]	$1,110	$990	$563	$2,801
Reg_Up Revenue [$]	$2,404	$2,348	$1,390	$3,716
Total Revenue [$]	$3,514	$3,466	$1,953	$5,909
Nissan Leaf Vehicle Revenue [$/veh]	$99	$98	$55	$167
Phoenix Bus Vehicle Revenue [$/veh]	$414	$409	$230	$697
EVI Truck Vehicle Revenue [$/veh]	$224	$221	$124	$376
VIA Van Vehicle Revenue [$/veh]	$83	$82	$46	$139

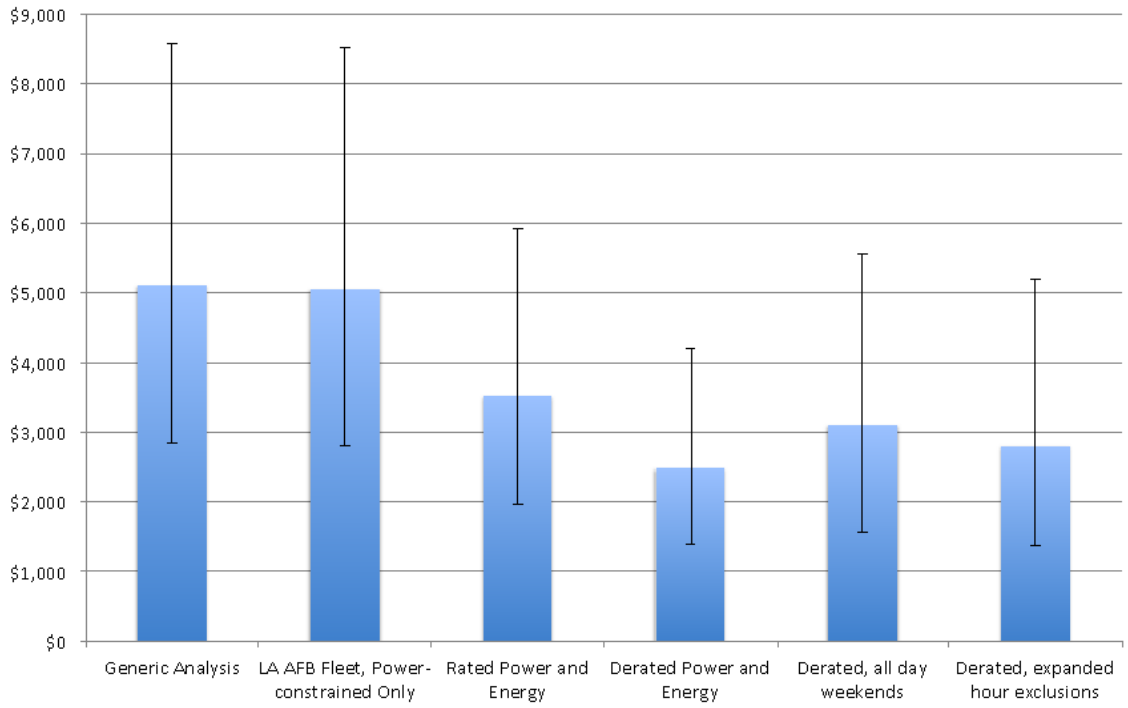
Source: Lawrence Berkeley National Laboratory

According to California ISO market rules, to offer regulation up and down simultaneously, a battery must have enough capacity to offer any single service for the whole hour. Thus the optimal state of charge for a battery to maximize both offers will be at about 50 percent, leaving the ability to store energy for regulation down and the ability to discharge for regulation up. Table 8 identifies the impacts that limited storage can have on individual vehicle's ability to earn revenue in the California ISO regulation markets. The Nissan LEAF and the Via Vans have the same power capacity, but the larger LEAF batteries allow them to capture a little more revenue. The same is true of the Phoenix Bus and the EVI Trucks, in which the much smaller battery of the EVI trucks make their revenue potential nearly half of what the Phoenix buses could achieve. However, even this significantly reduced revenue opportunity does not fully capture the full physical limitations that impact a V2G resource's ability to capture revenue in California ISO regulation markets.

The rated power and energy capacity of electric vehicles rarely represents the actual values observable from actuating Vehicle-to-Grid Resources. Vehicle manufacturers operate electric vehicles within a subset of their energy capacity to minimize battery degradation. Their charge control will also throttle charging power at high states of charge for the same purpose. This yields a useable state of charge range under which the vehicle responds to charge and discharge commands. In the LAAFB demonstration, the project team typically found operating a vehicle between 20 percent and 90 percent state of charge was an appropriate useable range. This results in an overall fleet capacity of around 301 kW available for symmetric regulation offers, and a 29 percent drop in average monthly revenue from the fleet.

There is one way that the original analysis was a bit conservative: its treatment of availability on weekends. By adding the excluded 18 hours from the weekend, the monthly revenue increases by 24 percent, an indication that those daytime hours on the weekends have considerable value. However, the exclusion of only the hours between 8AM to 5PM on the weekdays is unrealistic for operation at the base. Communications to the scheduling coordinator for real-time market opportunities were not possible, and a time to charge outside the market is required to ensure that battery states of charge are adequate to provide mobility at the start of the work day, or in a position to provide the regulation service at the end of the work day. Expanding the exclusion hours for market participation to 7AM to 6PM to account for this adjustment period at either end of the work day. Removing these 10 hours per week from the revenue potential calculation has the effect of removing approximately half of the gains from adding back the weekend hours. Figure 14 displays the effect of each of the adjustments to the baseline revenue potential analysis described above. The blue bar represents the average monthly revenue potential the LAAFB fleet could obtain, and the error bars indicate the maximum and minimum monthly revenue potentials observed in the California ISO price data.

Figure 14: Los Angeles Air Force Base Monthly Revenue Potential With Adjusted Assumptions



Error bars represent max and min monthly fleet revenue using prices for the period of performance.

Source: Lawrence Berkeley National Laboratory

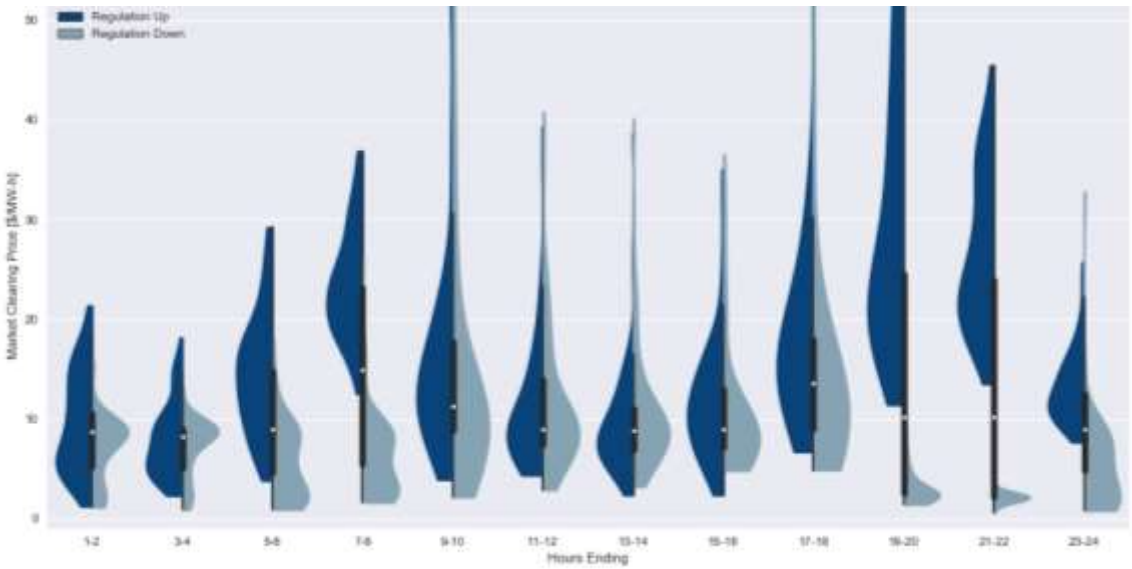
The revenue potential analysis highlights the importance of sizing the useable capacity of the battery relative to the charging and discharging power of the resource. A resource with a useable battery capacity equal to twice the charging/discharging power of the Electric Vehicle Supply Equipment (EVSE) will be able to maximize its total symmetric capacity offer into the California ISO frequency regulation market. The analysis assumes that symmetric frequency regulation is offered to the system operator to minimize the amount of battery SOC that is consumed while providing service, ensuring delivery for consecutive hours. However, there are times when it may be more lucrative to offer a larger percentage of one service over another because of the difference in price. This option is not considered in this simple analysis, because of the impact on continuous service delivery. But with an optimization approach like the one employed in the demonstration, additional revenue is possible if the prices can be adequately forecast.

Forecasting California Independent System Operator Market Clearing Prices:

The ability to capture value for a V2G implementation is highly dependent on the quality of the forecast of market clearing prices that is used in determining optimal regulation offers because these V2G resources operated in the market as essentially self-scheduled price takers. This becomes challenging when there are high price events that drive the average up, but may be hard to predict. Figure 15 shows the prices for

frequency regulation up and down for a month during the demonstration. The image shows all prices within the 99th percentile for that month, and there are a few hours in which there are outlier high prices well off the y-axes shown in the graph. This indicates the importance of accurate forecasting to capture those few high value hours.

Figure 15: Regulation Market Clearing Prices in California Independent System Operator South Region in April 2017



Source: Lawrence Berkeley National Laboratory

The focus of the project, however, was not on forecasting Ancillary Services prices and as such, the team opted for an easily implemented forecasting method: Persistence Forecasting. In this context, employing persistence forecasting for Day Ahead market clearing prices meant that tomorrow's 24-hour time series of forecasted prices was equal to the most recent historical prices available to us from a similar day-type. The project team considered two day-types: Weekdays and Weekends. The price forecasted for each hour on any given Tuesday would be the actual day-ahead market clearing prices reported in California ISO's OASIS database for the same hours on Monday. A Saturday would look to the preceding Sunday, and a Monday to the most recent Friday prices. This seems to be a relatively inexact method of forecasting prices, which is shown in the root-mean-squared error (RMSE) for each hour over the course of market participation. Table 9 shows the RMSE generated for each hour of both the regulation up and regulation down market clearing prices from March 2016 through July 2017.

Table 9: Root-Mean-Squared Error for Persistence Forecasts

Hour Ending	Regulation Up MCP RMSE			Regulation Down MCP RMSE		
	All Up	Weekday Up	Weekend Up	All Down	Weekday Down	Weekend Down
1	7.90	8.63	5.66	8.13	9.16	4.64
2	7.93	7.85	8.11	8.17	8.12	8.27

Hour Ending	Regulation Up MCP RMSE			Regulation Down MCP RMSE		
	All Up	Weekday Up	Weekend Up	All Down	Weekday Down	Weekend Down
3	5.10	3.49	7.86	5.56	3.94	8.39
4	6.84	5.98	8.61	7.35	6.60	8.98
5	5.24	4.80	6.22	5.15	5.05	5.40
6	5.57	4.19	8.05	5.76	3.92	8.84
7	6.69	4.54	10.27	6.33	2.58	11.14
8	7.91	4.82	12.70	7.75	3.21	13.60
9	8.61	4.75	14.27	10.62	4.87	18.35
10	10.84	9.46	13.71	12.93	10.95	16.89
11	10.70	9.59	13.07	13.96	13.66	14.68
12	31.61	6.32	58.38	11.73	9.36	16.22
13	10.00	7.44	14.56	11.71	8.52	17.29
14	7.28	6.54	8.87	9.31	7.17	13.25
15	7.35	5.79	10.27	10.07	8.30	13.52
16	10.13	9.42	11.72	8.67	5.70	13.49
17	13.68	14.66	10.87	8.83	8.18	10.29
18	14.44	15.63	10.89	7.55	5.71	10.89
19	18.21	20.77	8.97	3.35	2.67	4.65
20	29.81	34.73	9.53	2.15	2.03	2.41
21	10.80	11.98	6.98	1.87	1.85	1.91
22	4.41	4.24	4.79	2.06	1.99	2.22
23	3.87	3.06	5.40	3.48	2.54	5.14
24	4.78	4.55	5.32	4.95	4.81	5.30

Source: Lawrence Berkeley National Laboratory

RMSE tends to inflate the importance of outliers in a data set. Another way to gauge the quality of the forecast is how well the persistence forecast predicts the timing of the peak hour each day. In the case of regulation up, a persistence forecast predicts the hour with the highest price 48.8 percent of the time during the performance period of the demonstration. For regulation down, persistence is a much worse indicator, only capturing the peak pricing hour 21.1 percent of the time.

Costs of Providing Regulation Services

Some of the revenue potential for the project has been discussed, but what about the costs that will eat into that revenue potential? There are two types of costs that should be considered: One-time capital investments and monthly costs associated with transacting in the marketplace.

The one time capital costs include the marginal cost of bi-directional EVs and charging stations, any other site electrical upgrades, distribution interconnection studies (if

required), as well as the California ISO certified metering infrastructure. While the LAAFB Demonstration can quantify these costs for their specific implementation, they are not extensible to future V2G applications because of their use of prototype hardware, save for the costs of meter installation and certification.

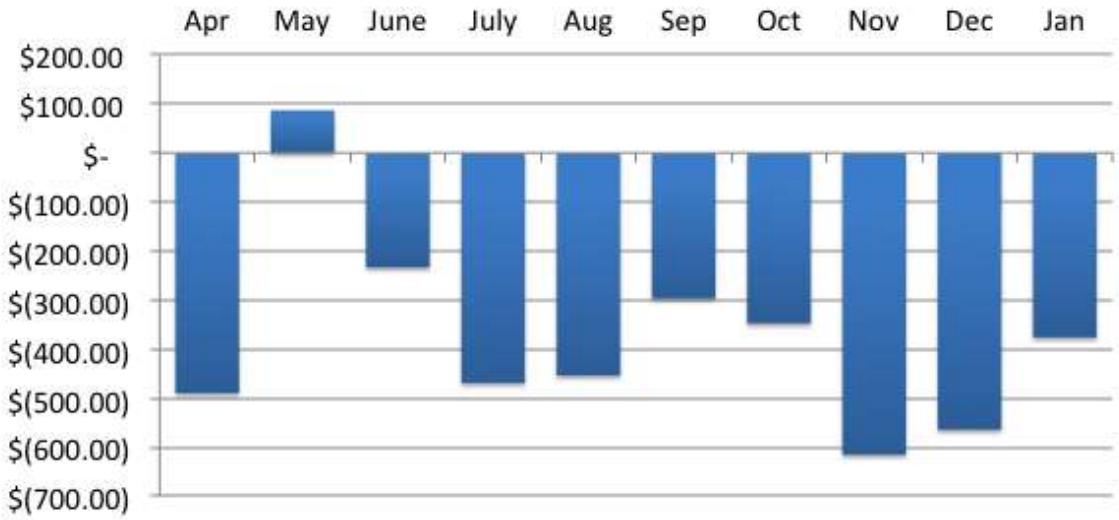
The transaction costs for an aggregation of resources in California ISO market can be considerable for small resources. First, the California ISO charges $1,000/month for the Scheduling Coordinator ID. This is by far the largest charge, but does not scale with the size of the aggregation, so it suggests that larger aggregations are always preferable from a cost perspective. California ISO has other monthly transaction costs including a charge for the amount of bidding performed, as well as flexible capacity obligation charges, and other similar monthly charges. These typically add up to less than $50/month. Additionally, the scheduling coordinator and distribution utility has significant monthly costs to provide scheduling coordinator services, including a $118.46/month manual billing fee and a $216.50 meter data feed fee. Finally, a monthly fee of about $100 is paid to AT&T for access to the California ISO's ECN.

Yes, But How Much Did It Make?

This is the question most often asked, and the project team was not able to answer it fully, however here is what they did find. The California ISO settlement is the sum of more than 30 different charge codes, with about a dozen making-up the bulk of the net settlement. Actual monthly California ISO settlements, shown in Figure 16, were only positive in one month, May 2016. After fees from the scheduling coordinator were applied, that month was also in the red.

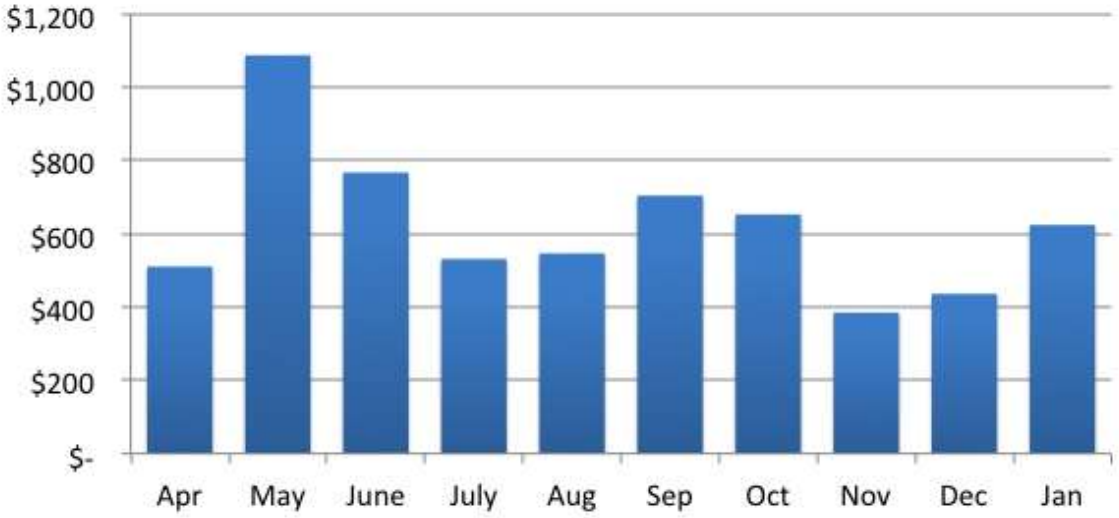
Fees have an obviously negative impact on the net settlement, but represent costs incurred by the market facilitators, California ISO and the SC. In the future or in other applications, these fees may change or be scaled to resource size either by the facilitators or by division of the fees among aggregations of resources. Estimates of revenue from V2G providing AS regulation in other work, and in preliminary analysis for this study, do not include these fees. Figure 17 shows the monthly net settlement, not including fees, for April 2016-January 2017. While the base was in the market in January-March 2016, that period was primarily spent working with California ISO and the SC to investigate why awards were not being made or being dispatched incorrectly, which prevented the resource from participating to any meaningful extent over that period. January 2017 was the last month before decertification for regulation down as described in the Decertification section. Without fees, settlements were net positive, and reasonably good considering that the bids were typically only 0.1 MW regulation up and -0.1 MW regulation down each hour for an average of about 5 hours per night.

Figure 16: Monthly California Independent System Operator Settlement with Reg Up and Reg Down



Source: Lawrence Berkeley National Laboratory

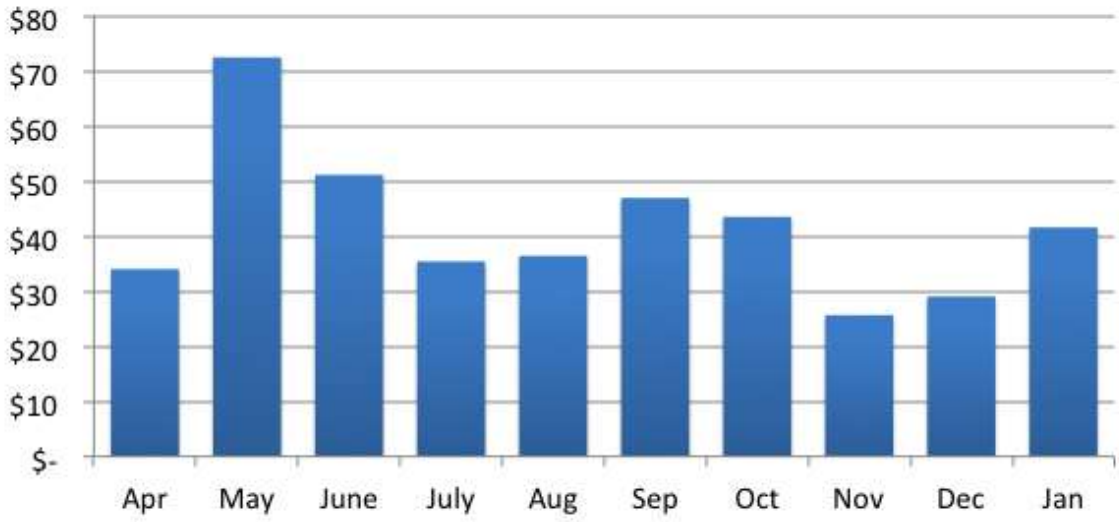
Figure 17: Monthly Net Settlement Not Including Fees with Both Reg Up and Reg Down



Source: Lawrence Berkeley National Laboratory

Also, on a per vehicle basis, settlement revenue was encouraging. Figure 18 shows the net settlement per vehicle where up to 15 EVs/EVSEs (12 of the sedans or vans and 3 of the larger capacity vehicles) participated in market operations over that period. Again, even with the limited bid magnitudes, participation hours, and numbers of active EVs and EVSEs, the revenue ranged from $25 to $72 per vehicle per month, with an average of $41 per vehicle per month (when market participation fees were not included).

Figure 18: Per Vehicle Monthly Net Settlement Not Including Fees with Reg Up and Reg Down



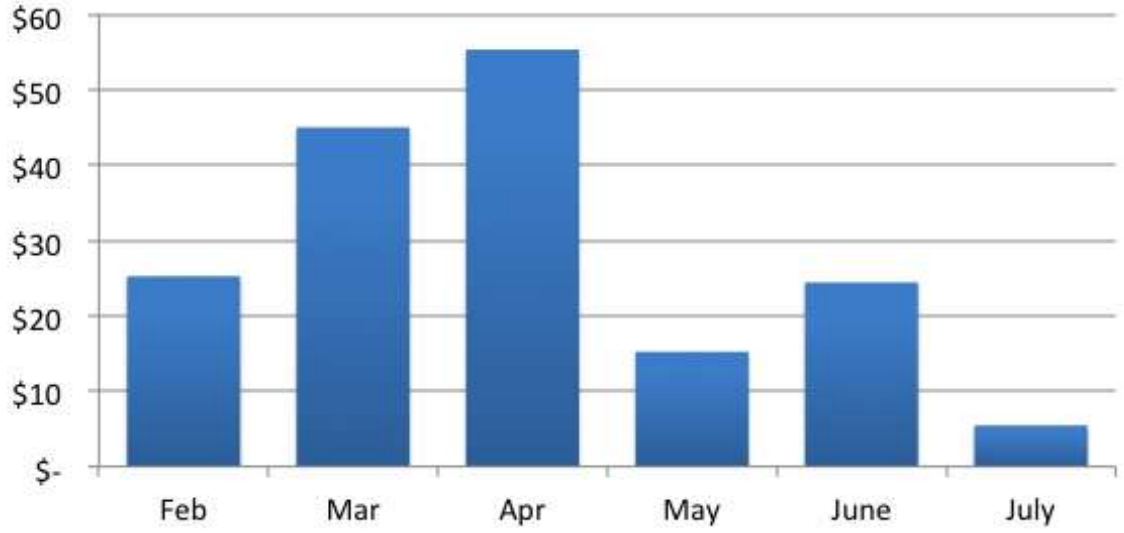
Source: Lawrence Berkeley National Laboratory

Due to the decertification for regulation down that went into effect on January 24, 2017, the base was only able to bid regulation up from then on. Despite the limited service available, just bidding nearer to the low end of the range between 0.1 MW to 0.24 MW regulation up for 3-12 hours per day (about five hours average), monthly per vehicle revenue ranged from $5 to $55 when fees were ignored, as shown in Figure 19. Settlement data for July 2017 was the most recent available at the time of the writing of this report. The root cause of the wide range of monthly revenue earned was not clear, as it was difficult to disentangle the impact of varying prices, performance penalties, and real-time awarded capacity.

Battery Degradation

This section focuses on quantifying battery degradation when providing frequency regulation. It is assumed that V2G services can cause additional battery degradation, but it is difficult to quantifiably isolate this impact from other factors such as driving, temperature, and aging effects. Understanding the loss in capacity that may come from V2G is a critical part of determining the complete economic costs, specifically earlier battery replacement, that may offset grid service market revenues.

Figure 19: Per Vehicle Monthly Net Settlement Not Including Fees with Both Reg Up Only



Source: Lawrence Berkeley National Laboratory

Data Collection

The dispatch controller regulated each EV/EVSE individually based on defined discharge characteristics, actual state of charge and California ISO AGC regulation signal. The AGC regulation signal was updated as rapidly as every four seconds and the V2G control system stored data at 1-second intervals. Along with the AGC, power data from a meter (Schneider Electric model S8600) in front of the aggregated fleet of EVs/EVSEs and individual EVSE meter (Accuenergy model AXM-IO1-1) data was acquired every second and stored in a database. Scripts processed the data to filter not-a-number (NaN) or other invalid readings. For quick analytics, a data visualization tool was implemented to interactively plot multiple data fields simultaneously for the aggregated fleet and individual EVs/EVSEs. The data was generally very consistent, but occasionally the last minutes of the day were missing (such as dataset ending at 23:57:38). This data loss is a small amount of the total data collected. In addition to the measured data, LBNL also received self-reported data from the vehicles, for example mileage, driving parameter, consumed energy and SOC for each trip. This data was collected by an external fleet management system which used the vehicles' on-board diagnosis (OBD). An acquisition board plugged into the OBD connector to record data continuously and transfer it to a server. The data was then available through a webpage, either visualized or as a CSV file download.

Methodology

A multi-dimensional linear regression, with independent variables representative for driving and regulation, was proposed to build up a statistics based battery degradation model to assess degradation due to providing ancillary services. The model was based on the battery capacity loss over a defined period, the battery degradation, as dependent variable. All input data was normalized to a range from -1 to 0, and 0 to 1,

for negative and positive values accordingly. This step was necessary to account for the different magnitudes in the input data. The scaled data was fed into a multi-dimensional linear regression model which can be described as:

$$y = \beta_0 * 1 + \beta_1 * x_1 + \beta_2 * x_2 + \ldots + \beta_n * x_n$$

And y was the dependent variable, battery degradation, which was predicted by the sum of regression coefficient β_n multiplied by independent variable x_n. The model minimized the distance of the resulting dependent variable to a linear function, by varying the regression coefficients. The reported coefficients were then used to generate a ratio of contribution towards driving, β_1, and regulation, β_2. This effectively split the offset coefficient β_0, in the ratio of $\beta_1 : \beta_2$. Depending on the number of independent variables, additional contributors β_n could be added to β_1 or β_2. The offset coefficient β_0 could be forced to 0 which would allow for direct determination of the ratio between $\beta_1 : \beta_2$, but was likely to decrease the fit of the model. Once determined, the ratio was used to assess the measured battery degradation to contributions of driving and regulation. Further, the contributions were related to cost of operation for each service as an economic analysis.

The independent variables for this study (Table 10) rely on measurements conducted at LAAFB and/or the fleet management system. To represent the impact of driving and regulation, two different models were chosen.

Table 10: Energy Models for Battery Degradation Assessment

	Independent Variable for Regulation	**Independent Variable for Driving**
Energy model	Regulation charging [kWh]	Driving discharging [kWh]
Mileage model	Regulation mileage [MW]	Diving mileage [mi]

Source: Lawrence Berkeley National Laboratory

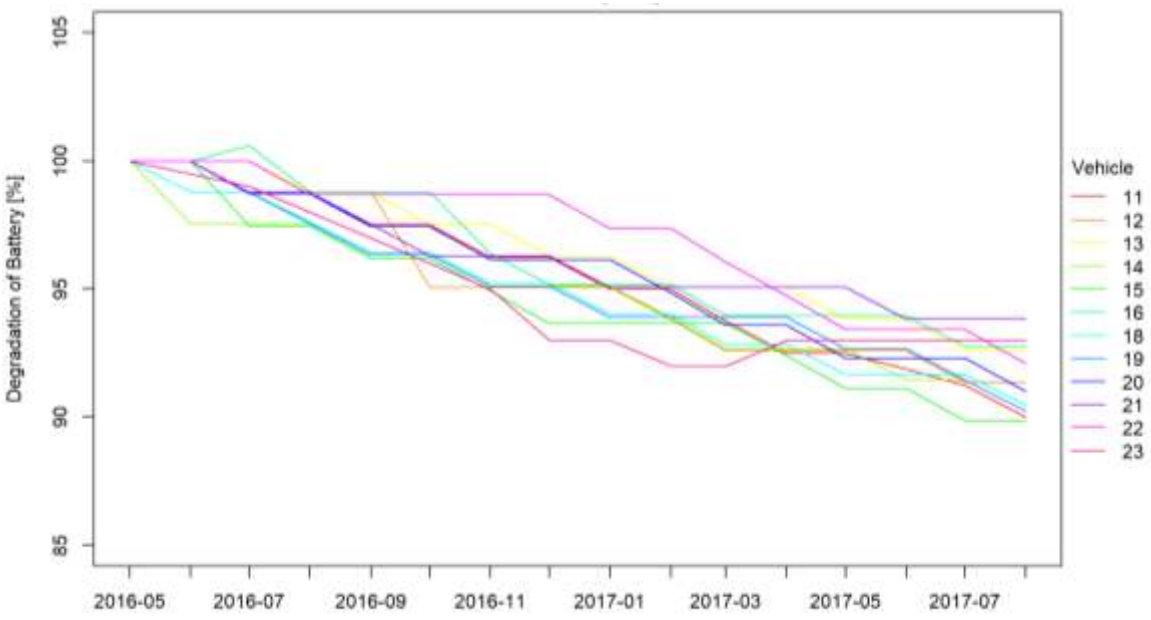
The two different models were used for cross-validation to increase confidence in the final result. The specific independent variables were selected by their common availability from EVs. Depending on model significance, additional variables to account for degradation not related to driving, nor regulation could be added. One example would be additional aging due to level of state of charge (SOC) while parked. A further overview of the input variables is given in Model Inputs.

An economic study was conducted to compare a baseline scenario of driving only to one with regulation only, and finally combined driving and regulation. A battery replacement is assumed to be necessary at a capacity drop below 60 percent with a replacement cost of $6,000. To analyze the data, the open source statistical environment R was used. This analysis was performed for the 12 Energy Commission-owned Nissan LEAFs (the project started with 13, but that an accident resulted in a loss of one of the vehicles).

Model Inputs

Each model implemented here, used the battery degradation as dependent variable and model specific independent variables. The battery degradation was determined by the delta in monthly battery capacity, which was based on the self-reported battery capacity and acquired at LAAFB in a 1-second interval. Initial analysis of SOC measurements from the LEAFs showed high noise ratios, which were significantly improved by a filter algorithm. The individual daily capacity readings were filtered for periods of discharge only, and the daily median of the remaining readings was reported. The battery degradation for the whole period was determined by the difference in monthly median of daily capacity readings, for the first and last month of analysis. The LEAFs' reported battery capacity in 200 Wh increments, which resulted in an uncertainty of ±283 Wh on the degradation measurement. With additional metering, external battery capacity tests could replace and/or validate the self-reported battery capacities and resulting degradation. Figure 20 illustrates the monthly degradation for each vehicle, normalized to capacity reported in May 2016.

Figure 20: Nissan LEAF Battery Degradation from May 2016 to July 2017

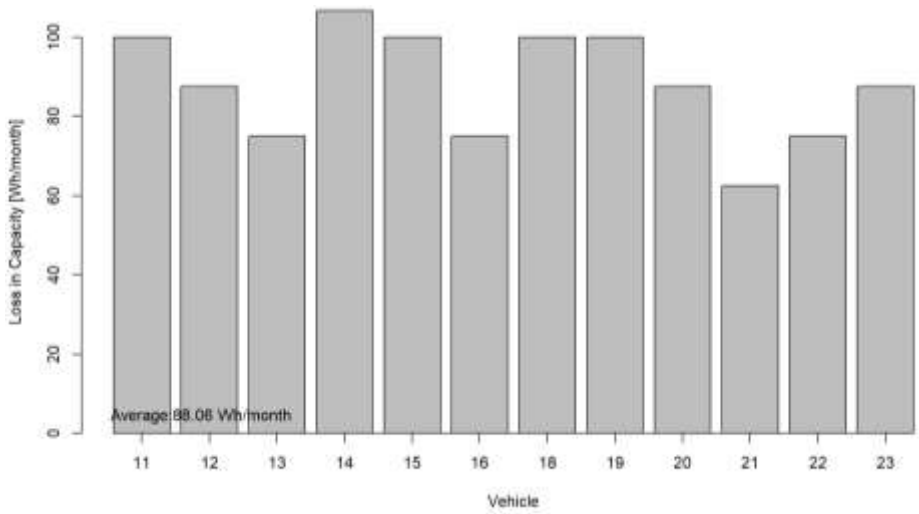


Source: Lawrence Berkeley National Laboratory

The monthly available battery capacity for all 12 vehicles shows some variation, but from May 2016 to August 2017, it can be better estimated. One exception was vehicle 23, in pink, where capacity drops to 18.4 kWh in February and March 2017 but then recovers back to 18.6 kWh in April 2017. Overall battery capacity degradation ranges from 5-10 percent over the period. Monthly degradation profiles vary based on vehicle utilization, but typically all profiles showed capacity degradation. Figure 21 shows the average monthly battery degradation in Wh/month for each vehicle.

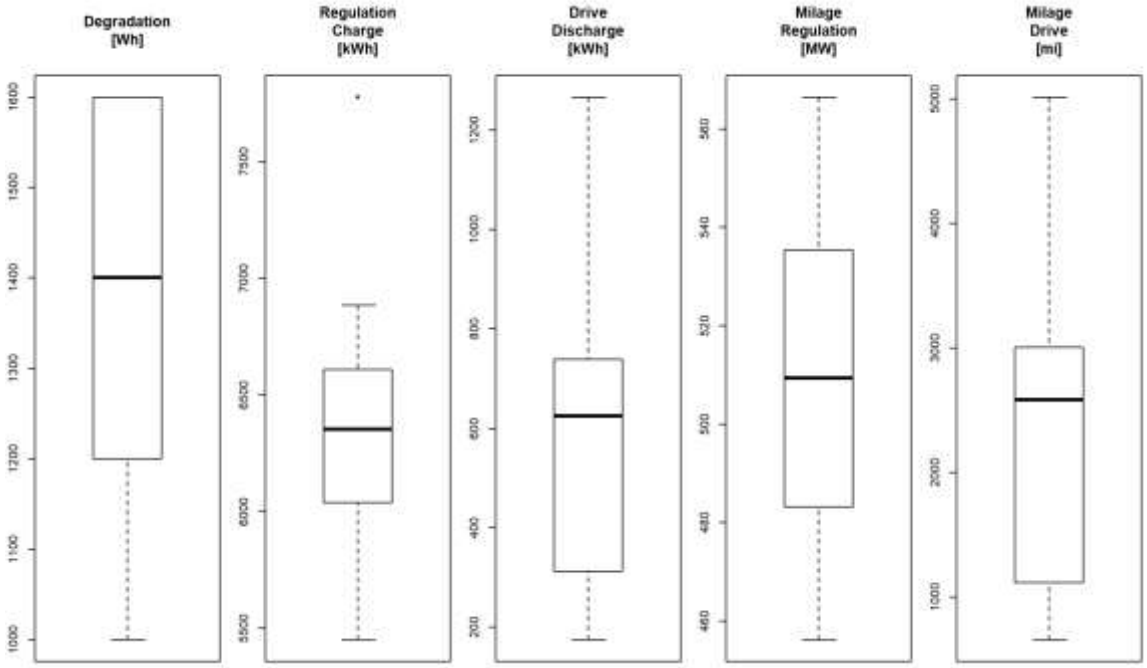
It can be seen that the monthly degradation was similar for most vehicles, which was attributable to the real-time charge controller's objective to disaggregate the AGC setpoint evenly across all active EVs/EVSEs. For battery degradation estimation, this was counterproductive, as high variations in data are desired for accurate statistics based models. To further analyze the variability of the input data, box plots of the observed degradation and the main factors assumed to drive that degradation, for example. regulation and driving, are shown in Figure 22.

Figure 21: Average Monthly Battery Degradation



Source: Lawrence Berkeley National Laboratory

Figure 22: Degradation Model Input Distributions



Source: Lawrence Berkeley National Laboratory

The first parameter of interest is the absolute battery degradation over the whole period. A median of 1,400 Wh was reported with a variability of ±200 Wh. As noted in the previous section, the uncertainty associated with the degradation was ±283 Wh. Therefore, the measure of degradation shows no significant variability between vehicles, especially as the associated uncertainty is higher than the variability. A much wider spectrum of multiples of the uncertainty would be required for significant multi-regression modeling. Regulation charging is the externally metered power consumption at the charging station. Across the 12 EVs, this externally metered power consumption attributed to regulation charging had a median of 6,300 kWh with a standard deviation of ±260 kWh. This measurement also included the EVSE's power consumption and conversion efficiency, as well as the LEAF's standby losses. Regulation charging and driving discharge were nested with the assumption that all vehicles were exclusively charged at the LAAFB. For decomposition, drive discharging energy was subtracted from regulation charging. Hereby battery conversion losses are not considered and a simplified round-trip efficiency of 1 was assumed. The resulting variability of 4 percent was critically low as overall measurement accuracy might be less than that. Drive discharge had a median of 625 kWh with a standard deviation of 313 kWh. The resulting variability was 50 percent and therefore closer to being suitable for regression, but higher variability is desired. Regulation mileage was the aggregated absolute change in power level over each time step. It was a calculated indicator of battery use. The driving mileage was the self-reported total mileage driven within the analyzed period. The last two measures are somewhat correlated to the energy inputs and therefore show similar variability.

Discussion

The study found that the input data show insufficient variability for the multi-regression model in the input dataset. One example was the battery degradation, which show a variability between the vehicles of 200 Wh, but with an associated uncertainty of at least ±283 Wh. This is attributable to the real-time charge controller's objective to disaggregate the AGC setpoint evenly across all active EVs/EVSEs, which was counterproductive to a study attempting to determine impacts of specific uses, e.g. regulation vs. driving, on battery degradation. Another problem is the determination of uncertainty on the input data itself, with self-reported battery capacity as example. It is currently purely based on the reporting resolution of the Nissan LEAFs, but might be higher when internal measurement uncertainty is included. The external power measurements could allow the determination of battery capacity to validate and/or replace the self-reported capacities.

Other inputs which are used as independent variables, such as the energy charged in regulation mode, also showed a very low variability of 4 percent. In addition, measurement uncertainty may be higher than the measured variation. Another simplification being made is the battery charge and discharge efficiency of 1 and the assumption that all trip energy was charged at LAAFB. The main issue here is the energy

model which utilizes regulation charging, but driving discharging. These different measures require a separation of the total energy charged, which includes charging for driving, and for regulation. One solution would be the replacement of regulation charging with regulation discharging energy, but in this case the battery charge and discharge efficiency would be omitted. Another consideration is the consistency of data. While vehicles were intensively used for regulation, with an average energy use of 15 kWh per day, they were fairly lightly driven, with an average of six miles per day, or energy use of 1.4 kWh per day.

A new Energy Commission EPIC project led by LBNL, will focus further on studying battery degradation, among other project goals. A major advantage of the future project in studying battery impacts is that the study will start with new batteries installed in the 12 Nissan LEAFs. This will allow for a much more controlled study of the various factors related to degradation. In addition, EVs will be separated into focus- and control groups to increase the variability of regulation (or other grid services) and driving. The fleet management system will be utilized to control total travel of EVs by preferential assignment rules. Variation in regulation energy for each EV will be increased by configuring the real-time charge controller to dispatch regulation according to different rules established for different groups of EVs. EVs will be placed into groups of no, low, and high regulation for the duration of the study. A control group without either driving or regulation would be hard to justify. As an alternative, this type of battery degradation, called battery calendar aging, can be modeled and subtracted from measured degradation levels. This would effectively transform the pure statistics based model to a hybrid one, which allows for more flexibility in data inputs, but increased uncertainty in the outcome.

Based on the findings with the currently available dataset, no statistically significant degradation model was developed. This work will serve as a framework for the next stage of the project with a much more controlled study of battery degradation starting with new EV batteries.

Final Observations and Recommendations

In this demonstration, the project team was “building the airplane as it was flying.” It would have been much better to have had the resource functional and had time to test communications and controls for at least a few months before adding the complexity of live market participation. Time to test the hardware with the software and then to test individually with the SC and California ISO before commencing operations or even certifying would have reduced the overall lost time for integration in the first months.

Regular feedback on the quality of performance would yield better results. The LAAFB demonstration for all its success in market participation still suffered from technical challenges in implementing communications and control. The resource was even de-certified to provide regulation down because of a small error. Unfortunately, the only feedback was a letter two months after the poor performance score period that triggered the decertification. A daily, or even weekly, calculation of preliminary performance data

that was sent as feedback to the SCs would go a long way to helping new resources identify any issues in their systems and maximize performance for California ISO.

Finally, before entry into the market, it would be beneficial to new resources, and to California ISO, to better understand how the resource will perform in market operations. A simulation environment for testing day ahead and real-time market interactions, structuring bidding and receiving awards, receiving dispatch signals from a simulated AGC system, and to send telemetry data that allows it to provide a simulated settlement would give useful guidance to the resource and useful resource performance data for California ISO. With these kind of interactions in a risk-free environment, new potential resources could also evaluate their opportunities and enter the California ISO market operations without as much disruption into the market.

CHAPTER 2: Vehicle-to-Building for Demand Response and Emergency Backup Power

In a vehicle-to-building (V2B) approach, EV batteries are used as energy storage that, when discharged, lower a building's net demand, otherwise known as demand management or demand response (DR). Being behind the same meter as the buildings, and all of the electric loads on the base, the EV fleet was effectively providing V2B anytime the vehicles were discharging. The focus here was to examine the capability and impact of the bi-directional EV fleet and their corresponding bi-directional EVSEs in providing demand response capability and emergency backup power.

Site Description

LAAFB, shown in Figure 23, is 0.25 miles x 0.4 miles and houses 10 major buildings including three large office buildings (in the center) and two large retail buildings (on the right). Other facilities include a childcare center, recreational facility, medical clinic, warehouse/maintenance facilities, a gas station, and a parking garage. The base currently has 700 kW of photovoltaic (PV) panels in separate installations on carports and on the rooftops.

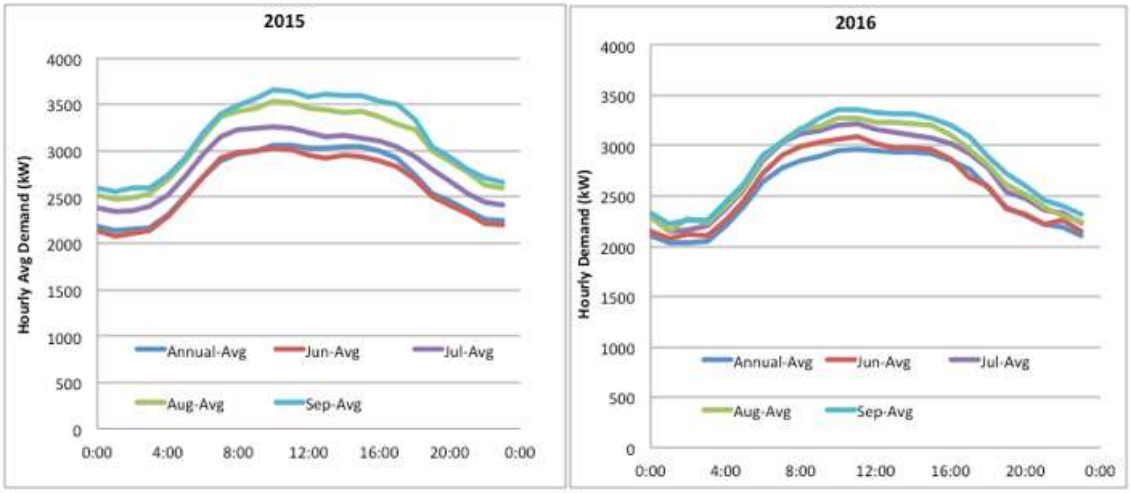
Figure 23: Aerial View of Los Angeles Air Force Base

Source: Lawrence Berkeley National Laboratory

Whole-Base Demand

The net electricity demand/consumption (building loads minus PV generation) at the site is measured by a single SCE meter. Average hourly net demand for weekdays in 2015 and 2016 summer months (June, July, August, and September) are shown in Figure 24. The average annual load was similar in shape and magnitude for 2015 and 2016. Load shapes for June and July are similar year-to-year, as well, while those for August and September were higher in 2015 possibly due to higher outdoor temperatures and higher cooling loads. The base nighttime loads ranged from ~2.0 to ~2.5 MW in 2015, and in 2016 was similar but more consistent at ~2.2 MW. The daytime load shape is rather flat reaching about 80 percent of peak load by 6 AM with a plateau starting at ~10 AM and ending at ~4 PM. PV meter data was not available to further break down the net electricity demand data. The rather flat load presents a significant challenge to peak demand reduction either with energy storage or load shedding (such as increasing thermostat set-points).

Figure 24: Whole-base Demand for Summer Months in 2015 and 2016



Source: Lawrence Berkeley National Laboratory

Bi-directional Electric Vehicles for Vehicle-to-Building

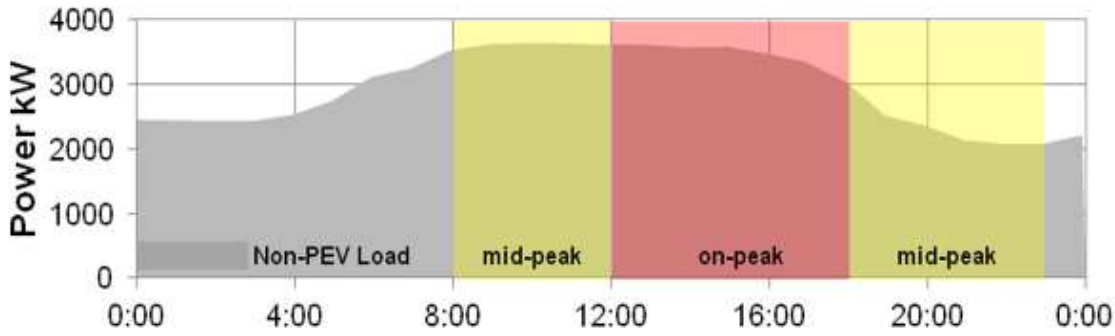
Standard uni-directional charging has very limited capabilities of providing building load support and/or DR. Charging can be curtailed to create a pseudo “to-building” net load, but charging duration and magnitude is limited by depth of discharge (total travel) before connecting to EVSE. Vehicle-to-building where vehicle battery is supporting building loads, or providing DR, can only be accomplished with bi-directional capability.

Bi-directional V2B offers different potential economic benefits including time-of-use (TOU) demand management, retail DR, and emergency backup power (EBP).

Time of Use Demand Management

Time-of-use (TOU) refers to electricity tariffs that have different energy consumption rates and demand charges for different times of day (Figure 25) to encourage use at times of greater supply/lower demand and discourage use during times of lower supply/greater demand.

Figure 25: Summer Net Load of Base



Source: Lawrence Berkeley National Laboratory

A challenge with using EV battery storage for load shifting in a typical government or commercial fleet application is that the EVs are most likely being used for transport and are not connected to host EVSEs during on-peak demand periods, as they are currently defined (for example 12 PM-6PM for Southern California Edison [SCE]). With increasing PV generation, and the growth of the "duck" curve, the peak period will likely be more associated with late afternoon and evening hours when fleet EVs are more likely to be available to provide load shifting resources.

The technologies developed and demonstrated in this project could lead to significant benefits to California IOU electricity ratepayers, particularly as peak load shifting and energy cost reductions; helping to deliver reliability at a lower cost. EV batteries can provide energy storage for load shifting, but are limited in their capacity and availability unless the EVs and EVSEs are bi-directional, which is why this project is focusing on true bi-directional technologies. With bi-directionality, the full range of the EV batteries' capacity is available whenever the EV is connected to the host EVSE. With one direction flow, only EV battery capacity equal to that consumed during travel before connecting to the EVSE is available. Table 11 shows the total number of each type of vehicle, the battery capacity (kWh) of each, the max discharge rate (kW) of each, and the individual and aggregate discharge rate that each vehicle could maintain over two-hour and six-hour periods. During both time periods, each vehicle type is limited by its battery capacity rather than its discharge rate. If each vehicle is connected (not on a trip) and fully charged at the start of the period, a total of nearly 350 kW can be shed for two hours and 116 kW for six hours.

Table 11: Load Shifting Capacity of Los Angeles Air Force Base Electric Vehicle Fleet

Vehicle	Number	Individual Rated kWh	Max Individual Discharge Rate (kW)	Individual 2-h Discharge Rate (kW)	Individual 6-h Discharge Rate (kW)	Aggregate 2-h Discharge Rate (kW)	Aggregate 6-h Discharge Rate (kW)
LEAF	13	24	15	8.4	2.8	109.2	36.4
Phoenix	1	100	40	35	11.7	35	11.7
VIA	11	24	14	8.4	2.8	92.4	30.8
EVI	4	50	40	17.5	5.8	70	23.3
Total						306.6	102.2

Source: Lawrence Berkeley National Laboratory

The LAAFB is on the SCE TOU-8 tariff, which in 2016 had summer (June 1 to October 1) demand charges of $16.92/kW on-peak (12-6p) and $17.58/kW for monthly (anytime). To conservatively quantify cost savings that take into account vehicle use during the peak period 12 PM-6 PM, assume that 8 of the 13 LEAFs, the Phoenix bus (returns from shuttle route at 11:30a), 7 of the 11 VIA vans, and two of the four EVI trucks are connected and fully charged. The total demand shed for six hours with this vehicle fleet make-up would be 65 kW. The entire base load shape shows that any demand shifted from on-peak to off-peak periods would not set a new monthly demand, therefore, the monthly demand cost savings would be 65 kW x ($16.92 + $17.58) = $2,243. There are no peak or mid-peak period demand charges in the winter, but assuming there is a sufficient winter diurnal peak in which 65 kW over a 6-hour period would decrease the monthly peak demand by 65 kW, the monthly winter cost savings would be 65 kW x $17.58 = $1,143. The annual demand cost savings would be $18,114.

Building 229 and the Emergency Operations Center

Since the focus of this study was on V2G and its potential to provide V2B and emergency backup power, the building related part of this study focused on the building closest to the EVSE infrastructure, building 229, that also contained the base's emergency response center (Figure 26).

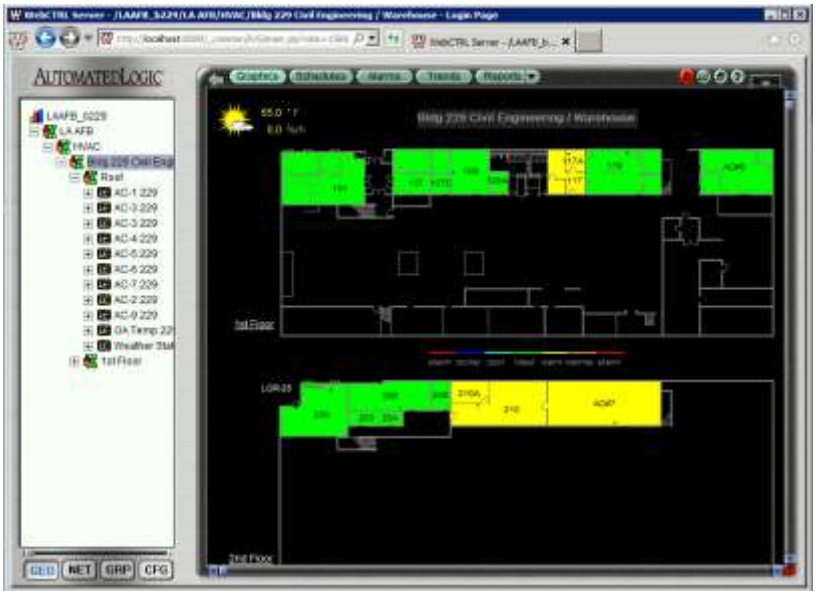
Energy Management Control System Upgrade to Remotely Control Building Loads

The intention here was to link the energy management control system (EMCS) of one or more buildings with the V2G control system. Building 229 was selected to be the focus of this effort. Because of cybersecurity concerns, the EMCS for building 229 was separated from the rest of the base network so that it could be connected to the V2G control system. The Automated Logic Control EMCS (Figure 27) was separated from the base network and installed on the V2G server with remote access and control of building schedule and operating setpoints enabled.

Figure 26: Building 229 and the Electric Vehicle Parking Lot

Source: Lawrence Berkeley National Laboratory

Figure 27: Energy Management Control System Interface for Building 229



Source: Lawrence Berkeley National Laboratory

Demand Response Assessment for Building 229

Using the Demand Response Quick Assessment Tool (DRQAT), LBNL found that a shed average of 6 kW from 12 PM-6 PM could be achieved with a setback of all building thermostats of 4°F. This represents roughly 5-10 percent of the observed building demand during peak of 12 PM-6 PM and would provide modest additional DR capability.

Using Electric Vehicles as Emergency Power Supply for a Critical Building

This section focuses on the feasibility of using EVs as emergency backup power, also known as emergency power supply (EPS) for a critical building. First, this section will look at the capacity of the bi-directional EVs/EVSEs to provide EPS to the EOC.

The emergency operations center serves as a common area for tracking and dispatching critical facility infrastructure and resources. Table 12 shows the critical loads, peak demands, and average loads. The "Emergency Use" value is an estimate of the fraction of the number of devices and/or the fraction of time the active devices would be operating during an emergency. The primary energy demand in the center is for laptops connected to the base network and large monitors for common viewing. A printer and shredder make up the other primary plug loads. The non-plug loads make up the bulk of the energy required to support the center and consist of lights and a roof-top-unit providing heating, ventilation, and air conditioning (HVAC).

Table 12: Emergency Operations Center Loads

Load	Qty	Peak Demand (kW)	Peak Total Demand (kW)	Emergency Use	Average Demand (kW)
HVAC (AC-1)	1	10	10	0.3	3
Ceiling lights	20	0.1	2	0.6	1.2
Laptops	15	0.05	0.75	0.5	0.38
Printer	1	0.3	0.3	0.2	0.06
Shredder	1	0.2	0.2	0.1	0.02
Large TV/Monitor	2	0.1	0.2	0.8	0.16
Medium TV/Monitor	2	0.06	0.12	0.8	0.1
Small Monitor	8	0.03	0.24	0.6	0.14
Plug loads other than EOC	—	1	1	0.2	0.2
Total			14.8		5.3

Source: Lawrence Berkeley National Laboratory

To maximize the duration that any backup power supply could support the EOC, all loads other than those serving the EOC should be shut down. The building 229 EMCS can be used to shut off the RTUs serving all rooms other than the EOC, but lights and plug loads would have to be manually shut down. Lights in rooms outside of the EOC would be fairly easy to shut off manually in the event of an emergency, but plug loads may not be, so an estimate of those are included in the loads that would have to be supported by the EV batteries, or any other EPS.

The full EV resource has a capacity of 859 kWh. Assuming 70 percent of that is available as useful capacity and, during an emergency 70 percent of the vehicles would be connected to EVSEs at the base and not out on trips, the EV fleet could provide EPS for

~80 hours. If only the Energy Commission-purchased Nissan LEAFs were used, and the same assumptions of usable capacity and number connected are made, they alone could support the EOC for a little over 24 hours. Using the EVs for emergency power requires that some or all of their storage capacity be held in reserve to be ready for use at any time. This would come at a cost of using that reserve capacity for other purposes. In providing AS regulation, the cost would be in reduced market revenue roughly proportional to the fraction of storage capacity held in reserve.

Making the Vehicle-to-Building Connection for Emergency Power Supply.

EVs providing EPS would require exclusive physical connection of their electric vehicle service equipment (EVSE) to the critical building. The different voltage levels in the distribution system for the EVSEs and the critical building prevent a direct connection. Further, buildings on the same circuit as the critical building would have to be disconnected from the critical building to ensure powering that building only.

The required separation is described for two options: (a) Disconnecting non-critical buildings on the same circuit by installing a new transformer, further referred to as "hardware separation", and (b) installing a power switch to cut off non-critical buildings from the busbar serving critical and non-critical buildings in case of electricity failure, referred to as "software separation."

Emergency Power–Hardware Load Separation Option

A hardware load separation (HLS) would be reliable because the EVSE line and the critical building line would be physically disconnected from other loads. In this configuration, the building voltage busbar serving the non-critical buildings would be separated. A new line from the main medium voltage busbar would be connected to a new transformer and fuse connected to the critical building. During an electricity outage on the grid, a power switch on the main medium voltage busbar would disconnect non-critical circuits and the distribution grid from the emergency power grid. The new sub-grid would consist of the EVSEs as the EPS of the critical building. A second EPS generator (EPS2), e.g. a fixed storage battery or diesel generator, which does not currently exist on the site and is not included in the cost estimations below, could be installed on the building voltage busbar connected to the critical building and locally support the emergency power grid during switching operation.

This HLS design requires a new transformer sized for the critical building load. The rewiring is mainly necessary for the new transformer and to connect to the existing distribution line. The distribution to the non-critical buildings would remain unchanged, except for one cut of the distribution line at the branch to the critical building. The new transformer would connect to the distribution side of the primary switch.

Emergency Power–Software Load Separation Option

Unlike the HLS option, the software load separation (SLS) does not require an additional transformer. Instead, a second power switch would be attached to the building voltage busbar of the new transformer connected to the critical building. In the case of a grid failure, the grid power switch on the medium voltage line between feeds to the critical and non-critical buildings and a second power switch on the building voltage busbar between the critical and non-critical buildings would open immediately to (a) disconnect buildings the non-critical buildings from the critical building at the building voltage busbar, and (b) to disconnect the lines in the created emergency power grid from the distribution gird. The EPS from the EVSEs would start powering the critical building immediately.

The new circuit breaker on the building voltage busbar is relatively compact and could be attached to the existing switch gear on the secondary side of the transformer connected to the critical building. The required rewiring would be limited to a new transmission line to the branch of the critical building from the secondary distribution system. The logic operation is more critical, since the switch is required to open immediately after power outage and before the EVSEs can feed-in the emergency power grid. A second EPS generator (EPS2), such as a fixed storage battery or diesel generator, which does not currently exist on the site and is not included in the cost estimations below, installed on the building voltage busbar connected to the critical building and locally support the emergency power grid during switching operation.

Cost Evaluation

Table 13 shows required equipment and materials for each load separation configuration. For each, estimated costs are shown separately, split by planning and installation, material, and safety margin. Bids from electrical contractors would be necessary to get more specific cost figures.

The planning and installation cost for the SLS is higher due to the logic implementation of a second power switch with is required to open simultaneously to the grid power switch. Also, the two power switches for the SLS are high power equipment and, therefore, are more expensive than the hardware load separation (HLS) with a single smaller switch. On the other hand, the HLS would need an additional transformer and its integration into the distribution system. The expected re-wiring of both separation types is similar with about the same length of cable needed. Including tax and safety margin of 30 percent, the totals are $110K for the HLS and $125K for the SLS.

Table 13: Cost Estimates for Hardware Load Separation and Software Load Separation Options for Using Electric Vehicle Service Equipment as an Emergency Power Supply for a Critical Building at Los Angeles Air Force Base

	Hardware Load Separation (HLS)	Software Load Separation (SLS)
Planning & Installation	$50,000	$60,000
Transformer	$10,000	—
Power switch	$7,500	$20,000
Power cable and equipment	$7,500	$7,500
Tax and safety margin*	$35,000	$37,500
Total	**$110,000**	**$125,000**

***110% sales tax; 30% safety margin**

Source: Lawrence Berkeley National Laboratory

This report does not include any costs or cost comparisons related to the EVs and EVSEs. Also, eventual accelerated aging of the EV batteries by providing EPS is not investigated.

Anti-Islanding Protection

The actual IEEE Standard 1547-2003 for interconnecting distributed resources with electric power systems requires distributed generation (DG) to detect instability in the attached distribution grid. During electricity failure of the distribution grid, the DG is required to immediately shut down generation. The state of a disconnected power grid is called islanding. The anti-islanding protection is intended to prevent (a) damage to electric equipment, since frequency and voltage output of DG are often not controlled effectively, and (b) safety hazards to utility workers and customers in case of maintenance or other forced grid shutdowns. This switching operation must be completed within 160 ms (10 cycles), triggered either by local mains monitoring units with allocated all-pole switching devices, or supervisory control and data acquisition (SCADA) system. Since 1999, the standard for anti-islanding protection in the United States has been UL 1741, harmonized with IEEE 1547.

The bi-directional EVSEs are DG and would, by default, immediately shut down generation in case of electricity failure. This issue was not further addressed within this work, but could be addressed in future charging stations. Another way to enable persistent generation would be to emulate a gird-connected state by installation of an uninterruptable power supply (UPS), such as battery and inverter or a diesel generator, on the demand side of the critical building to simulate a power grid for the EVSEs.

Connect Electric Vehicle Service Equipment Directly to the Critical Building

A redesign of the EVSE and critical loads supply could be made. Some EVSEs could be connected to the critical building directly and integrated in a secondary emergency power circuit. This would be less costly since it would not require new switchgear or transformer on the distribution side, but could support only 1-2 EVSEs with limited capacity.

Distributed Energy Resources Customer Adoption Model Enhancements for Vehicle-to-Building

Overview

This section details the enhancements that have been made to DER-CAM to allow scheduling of DR resources and integrating them into AS+DR program choice and bidding.

A number of new features were developed and integrated into the existing version of Operations DER-CAM. An overview of this version of Operations DER-CAM is provided in Chapter 1. The program enhancements comprise two modules with separate but interrelated functionality: EV fleet optimization and EV regulation bid planning. Additional modifications to DER-CAM were necessary to integrate these modules into the existing framework, including modifications to the electricity balance equations and total cost equations. A 5-minute time step functionality has also been developed for the specific needs of this project.

The EV Fleet Optimization module takes into account the non-EV electricity load and tariffs to determine charging schedules which minimize total cost. The module allows for consideration of vehicle-to-building discharging to reduce peaks in the total demand profile and reduce monthly demand charges. Reliability constraints are used to incentivize EVs to carry higher state of charge (SOC). This ensures that vehicles will have the necessary energy to accommodate unplanned trips, or to provide vehicle-to-building discharging in the case of outages.

Electric Vehicle Fleet Optimization

The EV Fleet Optimization module simulates an EV fleet by modeling the availability, charging and discharging, and SOC for each individual vehicle, subject to vehicle-specific constraints and requirements. The module relies on a user-defined table of EV properties (such as battery capacity, maximum charging rate) to constrain the charging behaviors implemented by the DER-CAM optimization. The module assumes that the EV fleet is centrally managed, and therefore reasonable advanced schedules can be generated to inform the model when each EV will be available throughout the optimization time horizon, as well as the total energy the EV is likely to expend on each trip. The model employs linear approximations of non-linear charging behaviors to ensure that generated schedules comply with real EV charging constraints. See Chapter 1 for a detailed description of the EV fleet module formulation.

Electric Vehicle Regulation Bid Planning

This module generates hourly bids (up and down) for the day-ahead frequency regulation market, subject to vehicle constraints and usage schedules. The module essentially aggregates the energy and power capacities of connected EVs at each time-step to determine the technical limits for regulation capacities in each hour. The module then applies a number of scale factors, which reduce the submitted hourly bids from the

maximum possible values, which take into account risk and uncertainty in inputs. These include factors related to vehicle return-time and SOC uncertainty and energy deviations associated with asymmetric bidding strategies. During hours where regulation bids are submitted, the module determines self-scheduled energy (for charging the vehicles) and submits as part of the bid.

Regulation bids are subject to EV technical constraints as well as all regulatory constraints specific to the regulation market of the individual resource. One pair of constraints is daily high and low SOC limits (in terms of energy, not percent) for the aggregate fleet, which must be submitted as part of the day-ahead bid.

Critical Load Support at Los Angeles Air Force Base

Within DER-CAM, non-EV load has been disaggregated into critical and non-critical components. An input into the model indicates at which time steps grid power is available. In the case of an outage, the service of non-critical loads, EV charging, and upcoming EV trips are suspended. DER-CAM is subsequently required to dispatch the available energy in the plugged-in EV fleet to serve the critical loads for as long as possible. In situations where outages are not known in advance, DER-CAM can be constrained to maintain a fleet SOC, such that critical loads can be met for a specified amount of time. This may introduce infeasibility issues if a large portion of the EV fleet is out on trips, because aggregate available energy for critical loads is constrained by plugged in EV capacity. At every time step, DER-CAM can also report the duration the plugged in fleet could serve critical loads, should an outage occur at that point.

Vehicle-to-Grid Providing Ancillary Services and Participating in Demand Response Programs

The enhanced version of DER-CAM described above was used to run simulations to determine and compare the potential cost benefits of using the full EV battery storage resource at the LAAFB for providing ancillary services (AS) regulation up and regulation down, V2B to minimize time-of-use (TOU) electric utility costs, and two retail demand response (DR) programs offered by SCE. While providing DR as a form of V2B, each type of DR will be referred to by its program name, and V2B will refer only to the DR that minimizes TOU costs. The following scenarios were examined:

1. Demand Bidding Program (DBP)
    a. with V2B for TOU only
    b. with V2B for TOU and AS (except on DBP event days)
2. Critical Peak Pricing (CPP)
    a. with V2B for TOU only
    b. with V2B for TOU and AS

The DER-CAM simulations necessary for this analysis require, among others, three main inputs of whole base demand, EV activity, ancillary service regulation up and down day ahead prices, and the base electric utility tariff including DR program rates and credits.

Rather than make a simulation with one set of input data with results that would represent that single snapshot of conditions, LBNL attempted to capture the impact of the variability of the inputs on the total cost output by simulating cases made of combinations of minimum, median, and maximum representations of each of the three main inputs, as described in the next section. The resulting ranges of utility costs and revenues and wholesale day ahead regulation revenues are presented for the combinations of use cases listed, assuming the full EV resource capacity is available for travel and V2G and V2B services.

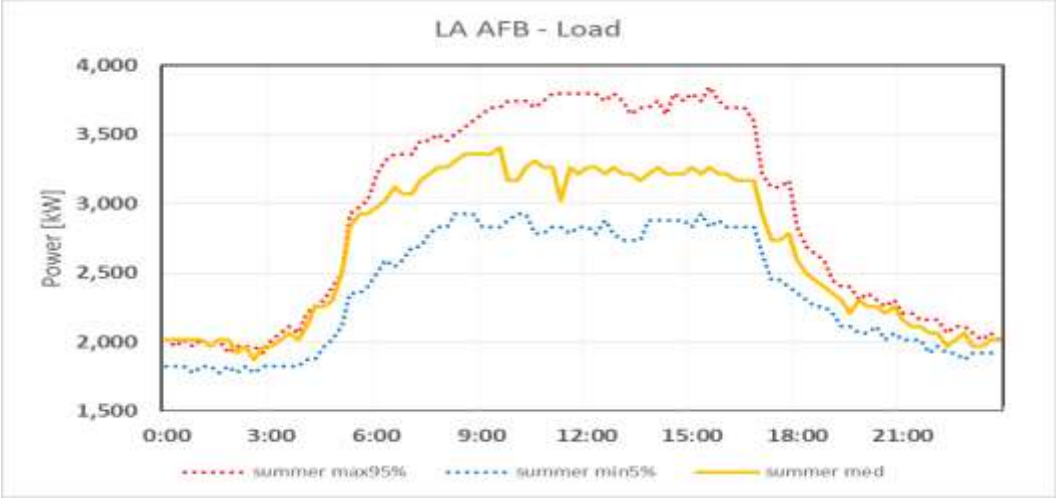
Method

All simulations were performed with the optimization tool Operations DER-CAM version 6.4 with enhanced EV module described in various parts of the report above. Inputs were based on statistics of historic whole base demand data and day-ahead regulation up and down price data from 2014. Based on daily sums, days representing the minimum (5 percent percentile), median (50 percent percentile), and maximum (95 percent percentile) were selected and used in the simulations. The annual historic data was split into a summer (June to September) and winter (January to May and October to December) period, which correspond to how the seasons are defined in the utility electric tariff described more below. Weekend and holiday days were excluded. All analysis focuses on the summer period where additional incentives from load shifting or demand response programs are available. The generated scenarios of whole historic days are representative for historic events, but also show variances for higher and lower boundary scenarios. All scenarios consisted of the base inputs, i.e. building loads, EV activity and regulation prices, where applicable. Statistics were developed for each input and simulated in all combinations, resulting in 27 scenarios. The 27 scenarios are composed of three (minimum, median, maximum) representations of each a) whole base load, b) day-ahead regulation up and down prices, and c) EV activity. The averages and standard deviations of the relevant cost and/or revenue outputs from the simulations of the set of min, med, and max combinations are presented.

Base Inputs-Whole Base Demand

The LAAFB has a single meter for the whole base (about a dozen major buildings and facilities). The meter demand data was acquired through SCE's Energy Manager with the permission of base staff. The 15-minute time step data for all of 2014 was analyzed. Figure 28 shows the resulting scenarios for the summer period.

Figure 28: Representative Whole Base Demand Profiles for Los Angeles Air Force Base for 2014



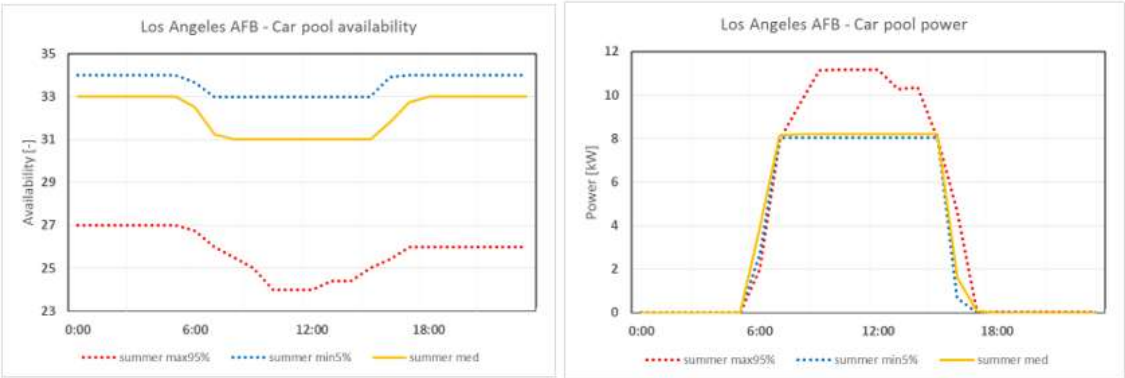
Source: Lawrence Berkeley National Laboratory

The summer period shows a typical office load profile with steep ramps in the morning and evening hours. The ramping starts early at about 5 AM and from a base load of about 2 MW (60 percent of peak load). The median energy consumption is 64 MWh with a median peak load of 3.4 MW in mid-August. The highest peak of 3.8 MW occurred in mid-September.

Electric Vehicle Activity Data

The EV fleet was structured to be made up of sedans, vans, pickup trucks, work trucks, and a shuttle bus. At the time of this analysis, the fleet EVs, other than the Nissan LEAFs, and EVSEs were in a fairly long period of commissioning and were not fully available for travel. Historic trip data, from January 1, 2015 to July 16, 2015, from the gasoline-powered fleet was used and trips were assumed to represent what would be the actual activity of the full EV fleet. Figure 29 shows the different inputs for the fleet availability and trip energy consumption. The scenarios were determined by the daily sum of the availability.

Figure 29: Assumed Fleet Electric Vehicle Availability (left) and Energy Demand (right)



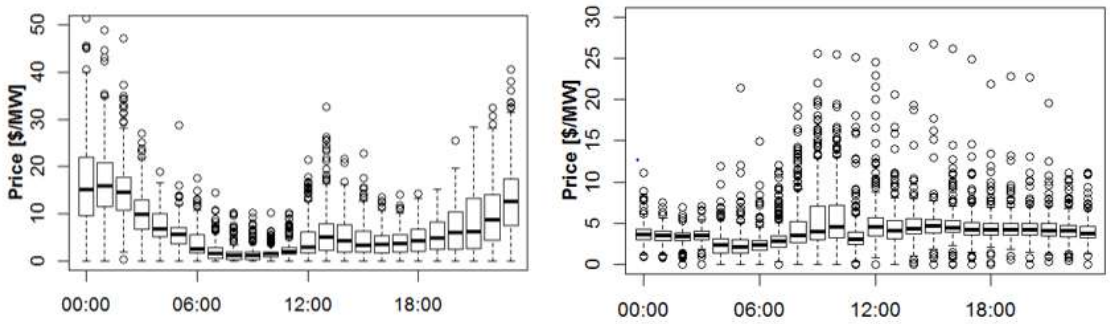
Source: Lawrence Berkeley National Laboratory

The number of vehicles connected to charging stations and available for grid/DR services on a summer day is shown in the left figure. Minimum assumed vehicle usage in blue, median in orange and maximum in red each have similar profiles with most events occurring in the daytime from 6 AM to 6 PM. The aggregated average power consumed for trips for each of the use case assumptions is shown in the right figure. The profiles are an inverted function of the availability. While overall, the fleet vehicles at the LAAFB are used relatively lightly, due to the compact size of the base and being relatively close to common destinations, the vehicle connected availability data used here are likely higher than what would be seen in actual use, and similarly the energy demand is lower than expected. The results presented for each case below may overestimate any benefits provided by the full EV fleet when in actual use.

Regulation prices

The day ahead regulation up and regulation down prices for 2014 were downloaded from California ISO's Open Access Same-time Information System (OASIS) and are shown in Figure 30.

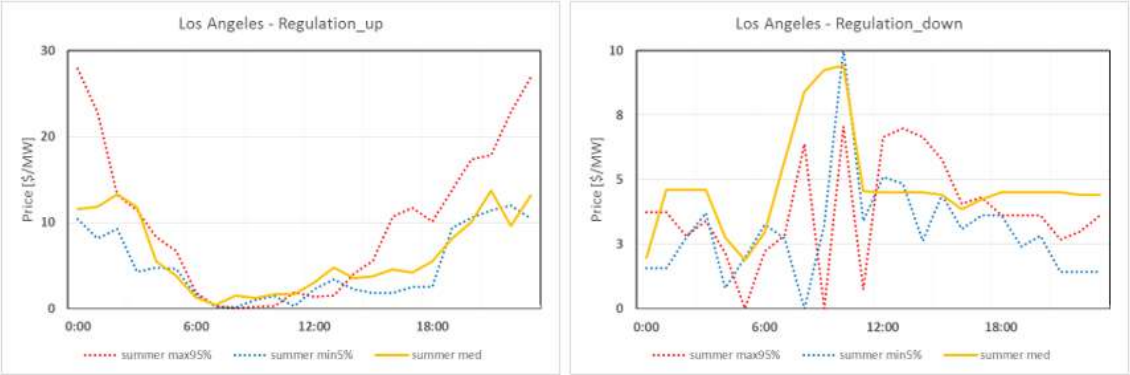
Figure 30: Hourly Distributions Over 2014 for California Independent System Operator Day Ahead Prices for Regulation Up (left) and Regulation Down (right)



Source: Lawrence Berkeley National Laboratory

The median prices for regulation up on the left plot were significantly higher in the morning and evening hours ($13.5/MWh) than during daytime ($4/MWh). In comparison, the median prices for regulation down on the right plot were fairly steady during the day ($4/MWh). The minimum, median and maximum daily sum of regulation up and down prices define different profiles as shown in Figure 31.

Figure 31: Ranges of Regulation Up (left) and Regulation Down (right) Day Ahead Prices



Source: Lawrence Berkeley National Laboratory

The resulting cases show the dynamics of the real time market. Since cases were chosen by the sum of up and down prices, the minimum and maximum plots, as the dotted lines, are not restrictively below or above the average. All cases are within the respective area of lower, median and upper whiskers of the hourly price plots and, therefore, are representative for the summer period.

The LAAFB electric utility tariff is the SCE TOU-8. The consumption and demand costs for 2015, shown in Table 14, were used in all base-case DER-CAM simulations. In all cases, the optimization objective includes minimizing total energy costs.

Distributed Energy Resources Customer Adoption Model Constraints

The analysis required additional constraints of the optimization model. The demand charge was already set to correspond to the peak of the building load to keep the model from peak shaving. Peak shaving was deactivated for all scenarios because the model

Table 14: Los Angeles Air Force Base Electric Utility Tariff—Southern California Edison TOU-8 (2015)

	TOU-8 (Option B)			
	On-Peak*	Mid-Peak**	Off-Peak	Non-Coincident
Demand charge - winter [$/kW]	—	0	0	14.88
Demand charge - summer [$/kW]	23.74	6.55	0	14.88
Electricity - winter [$/kWh]	—	0.087	0.067	—
Electricity - summer [$/kWh]	0.139	0.085	0.061	—

*** 12 PM to 6 PM, ** 8 AM to 12 PM, 6 PM to 11 PM**

Source: Lawrence Berkeley National Laboratory

was forced to keep a high SOC as safety margin in case of errors between simulated and actual SOC or in case of unpredicted trips, during daytime from (6 AM to 5 PM). A penalty of $0.4/(1 - SOC) per hour was applied for a deviation from fully charged. A minimum SOC of 20 percent (approximately 200 kWh for the entire fleet) was reserved as a safety limit to not discharge batteries completely. The initial SOC was set to 50

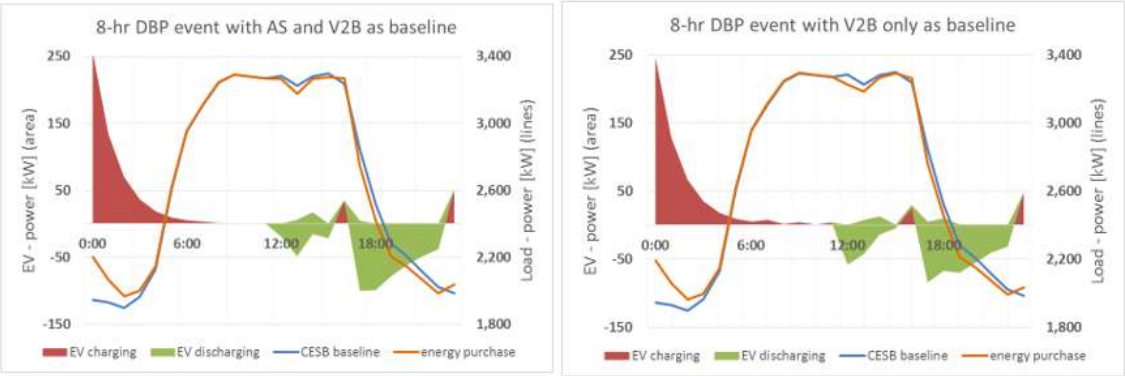
percent for all scenarios. This results in an initial aggregated storage condition of approximately 500 kWh, or available energy of 300 kWh for the entire feet.

Demand Bidding Program

The demand bidding program (DBP) is a year-round risk free demand response program for customers with a minimum demand of 200 kW. DBP events can occur between 12 PM to 8 PM on weekdays and are called at 12 PM on the previous day. After calling, bids of desired load reduction can be submitted until 4 PM, with a minimum of 30 kW for each hour and at least two consecutive hours. Reductions are determined by a customer-specific energy baseline (CSEB), which is an average of the last 10 similar weekdays. Bids are awarded if the actual reduction was between 50 to 200 percent of the bid amount. If bids were not met, no penalties are billed. If bids were awarded, the actual hourly reduction is compensated at $0.5/kWh minus the real-time market energy price. The notification time of 12 PM the day before presents a logistical challenge to dual participation in AS and DBP since AS bids must be submitted to California ISO by 10 AM the day before. LBNL examined potential DBP revenue with the scenario of V2B load shifting to minimize TOU costs. Although logistically not feasible at this point, LBNL looked at potential DBP revenue while participating in AS regulation. In the simulations, the EV battery storage does not provide AS regulation on DBP event days, but does on all other days, and the AS has an impact on the CSEB used to measure the DBP load shed.

Figure 32 shows the averaged result of all cases during an 8-hour event as electricity load plot and the total stored energy of all plugged-in vehicles.

Figure 32: Aggregate Whole Base Load and Electric Vehicle Charging and Discharging for Demand Bidding Program Event with Ancillary Service and Vehicle-to-Building and Vehicle-to-Building Only



Source: Lawrence Berkeley National Laboratory

The energy use for both baseline cases, AS and V2B on the left and V2B only on the right, is similar during the DBP event from 12 PM to 8 PM. The model tries to feed-in most of the stored energy, the green area, to achieve energy cost reduction and maximize the DBP revenue. The discharging power starts low with a maximum of 50 kW and then decreases due to returning EVs with a low SOC and a lower CESB. The

penalized low SOC is charged up, the red area, and after reaching a break-even point, the optimization discharges the EVs until 11 PM to decrease whole base demand during the mid-peak price period to arbitrage the battery energy that was charged during the previous off-peak period. All energy discharged from the batteries between 12 PM to 8 PM is below the CESB and is compensated by the full $0.5/kWh. Table 15 shows the average daily savings for one DBP event day. The peak demand and the demand charge are the same in the base case and the DBP event day. The daily savings (mean ± 1 standard deviation) for one 8 hour DBP event is $222±67 for a V2B baseline and $273±58 for an AS and V2B baseline.

Table 15: Utility Cost Savings and Revenue for Demand Bidding Program with Vehicle-to-Building Only and Ancillary Services and Vehicle-to-Building

	Base Case		DBP	
	V2B	AS + V2B	V2B	AS + V2B
Daily Energy Savings / Revenue [$]	**25** ±1	**108** ±19	**222** ±67	**273** ±58
Total Savings / Revenue Summer[1] [$]	**2,156** ±9	**9,426** ±177	**4,415** ±212	**11,046** ±248

[1]**10 DBP Event Days**

Source: Lawrence Berkeley National Laboratory

Table 15 also shows the aggregated results for the summer period. Summer period (June 1 to September 30) totals for each base scenario were calculated by multiplying by the total number of weekdays, 87, in the period. The total cost for the four-month summer period was calculated with 77 non-event days and 10 DBP events, as recorded in 2015. The non-event days are respectively average AS and V2B or V2B only days. Bidding into the DBP can generate revenue in addition to the cost savings from V2B load shifting and revenue from AS market participation. The average predicted revenue from participating in 10 DPB event days that would be earned in addition to the savings from V2B alone is $2,259 and in addition to that earned from AS and V2B is $1620 with AS.

Critical Peak Pricing

Critical peak pricing (CPP) is an option in the SCE TOU-8 tariff schedule of SCE. It incentivizes costumers who can reduce their summer demand during called events from 2 PM to 6 PM. Events can be called by a California ISO alert, forecast of SCE emergencies or high day load forecast, and are announced at 3 PM on the previous day. Similar to DBP, the notification time of 3 PM the day before presents a logistical challenge to dual participation in AS and CPP since AS bids must be submitted to California ISO by 10 AM the day before. Potential CPP savings with the scenario of V2B load shifting to minimize TOU costs will be examined. Although logistically not feasible at this point, this section looks at potential CPP revenue while participating in AS regulation. The number of CPP events is limited to 12 during summer, and none during winter. During CPP events, energy charges increase significantly from about $0.14/kWh to about $1.35/kWh, which incentivizes energy reduction during the event period. In compensation, the summer on-

peak demand charge is reduced from $23.74/kW to $11.92/kW. Table 16 highlights the differences between CPP and the standard Option B schedule.

Table 16: Demand and Energy Charges for TOU-8 Option B and TOU-8 CPP (2015)

	TOU-8 (Option B)				TOU-8 (CPP)			
	On-Peak*	Mid-Peak**	Off-Peak	Non-Coincident	On-Peak*	Mid-Peak**	Off-Peak	Non-Coincident
Demand charge - winter [$/kW]	—	0	0	14.88	—	0	0	14.88
Demand charge - summer [$/kW]	23.74	6.55	0	14.88	**11.92**	6.55	0	14.88
Electricity - winter [$/kWh]	—	0.087	0.067	—	—	0.087	0.067	—
Electricity - summer [$/kWh]	0.139	0.085	0.061	—	0.139	0.085	0.061	—
Electricity - CPP event [$/kWh]	—	—	—	—	**1.345**	—	—	—

***12 PM to 6 PM, *8 AM to 12 PM, 6 PM to 11 PM**

Source: Lawrence Berkeley National Laboratory

The prices for the demand charge are split into the non-coincident peak load, which is the peak of the whole month at any time, and the time-of-use (TOU) variable rates. The electricity consumption is priced by TOU rates only. For this analysis, the cost impact during a CPP event and without a CPP event, for the scenarios AS and V2B and V2B only were analyzed. Table 17 shows the daily energy cost savings for the non-CPP base case and the loss from energy costs on the CPP event day.

Table 17: Daily Energy for Base Case and Critical Peak Pricing Event

	Base		CPP	
	V2B	AS + V2B	V2B	AS + V2B
Daily Energy Savings [$]	**25** ±1	**108** ±20	**-14,770** ±718	**-14,697** ±734
Monthly Demand Savings [$]	**39,526** ±1,954			
Total Savings Summer* [$]	**2,156** ±9	**9,426** ±177	**-17,261** ±4,632	**-10,940** ±4,639

***12 CPP Event Days**

Source: Lawrence Berkeley National Laboratory

The loss is from the ten times greater energy charge on CPP event days. This is offset by the lower overall demand charge resulting in a net gain in demand costs of nearly $40,000 per month. So, even with a $14,000 loss due to energy charges for a single CPP event day, over a summer period with 12 CPP event days the demand cost savings nearly offset and result in seasonal losses of $17,300 and $10,900 for V2B only and AS plus V2B, respectively. With 10 CPP events called, there would be a net gain of $12,300 and $18,800 for V2B only and AS plus V2B, respectively.

Overall, the energy storage capacity of the bi-directional EV fleet at the LAAFB that could be counted on to be available during CPP event hours (2 PM-6 PM) is not great enough to provide enough of a load shed, through discharge of the batteries, to overcome the much higher event day energy charge even with a lower monthly demand charge.

Conclusion and Outcomes

This project was ambitious in its attempt to push the envelope to use EVs to provide grid services. The focus of this report is on the control software and market interactions, the significant challenges faced and solutions devised to address them, and examining the potential of using the EV fleet as an energy storage resource for the base buildings, also known as vehicle-to-building (V2B), in providing demand response (DR) and emergency backup power. The following are a brief description of the central outcomes of the project:

- Market participation and gaining a better understanding of how California ISO handles a battery storage resource with varying capacity to bid into the ancillary services (AS) regulation up and regulation down markets.
- Identification of and addressing challenges related to controlling storage resources made up of EVs with a range of storage capacity and EVSEs with a range of charge and discharge power.

Key Findings

The LAAFB V2G demonstration successfully provided frequency regulation to the California ISO market for a total of 255 MWh of regulation up and 118 MW-h of regulation down from January 30, 2016 to September 30, 2017.

Based on LBNL implementing the California ISO accuracy metric, the EV fleet generally performed well, exceeding the minimum required performance of 0.25 in all months, with accuracy scores ranging from 0.66 to 0.91 for regulation up, and 0.54 to 0.90 for regulation down, when all observations were included.

While California ISO is one of the most advanced markets for DER integration, the fundamentally varying resource availability parameters of a vehicle fleet aggregation add complexity in providing ISO market systems accurate resource inputs, such as state of charge (SOC), which can impact day-ahead market award eligibility or real-time resource optimization using the Regulation Energy Management model which controls SOC based on a fixed energy capacity.

For continuous regulation provision over long periods, it is necessary to have an automated method for communicating hour-ahead energy bidding to maintain the stored energy in EV batteries. Because this was unavailable through the scheduling coordinator, LAAFB reduced the hours in the market to create break periods in which the fleet energy storage could be recharged without impacting regulation performance.

A large spread of battery capacity and charge/discharge rates presented a challenge for setting proportional individual dispatch setpoints.

Per vehicle, monthly settlement revenue not including fees with regulation up and regulation down was encouraging. To be able to offer the full capacity to regulation markets, future EVs should have a ratio of useable battery storage to charge/discharge power of at least 2.

There was an observed overall battery capacity loss of 5 percent-10 percent from May 2016 to August 2017 but it could not be determined if providing regulation had an impact on degradation since there was so little variation in using the EV batteries in providing regulation and travel.

The full LAAFB EV fleet could provide emergency backup power to the base's emergency operations center for ~80 hours, but infrastructure changes would be necessary for actual implementation.

Revenue from using the EV fleet to participate in SCE's demand bidding program (a retail demand response (DR) program) could generate about $2,200 per summer season.

The EV fleet storage capacity is too small relative to the whole base load to make participation in SCE's critical peak pricing DR program a net gain for the base.

These findings and suggestions could greatly increase the performance and success of using bi-directional EVs and EVSEs in vehicle-to-grid or vehicle-to-building configurations providing ancillary services or demand response and should be considered in future applications.

GLOSSARY

Term	Definition
AB	Assembly Bill
AC	Alternating current electricity
AGC	Automatic generation control
ARFVTP	Alternative and Renewable Fuel and Vehicle Technology Program
ARIG	Aggregated remote intelligent gateway
AS	Ancillary services
California ISO	California Independent System Operator
CHP	Combined heat and power
COD	Commercial operations date
CPP	Critical peak pricing
CSEB	Customer-specific energy baseline
CTC	Concurrent Technologies Corporation
DA	Day-ahead
DAM	Day-ahead market
DBP	Demand bidding program
DC	Direct current electricity
DER	Distributed energy resources
DER-CAM	Distributed Energy Resources Customer Adoption Model
DG	Distributed generation
DISA	Defense Information Systems Agency
DNP3	Distributed Network Protocol 3
DoD	U.S. Department of Defense
DR	Demand response
DRQAT	Demand Response Quick Assessment Tool
EBP	Emergency backup power
ECN	Energy communication network
EMCS	Energy management control system
EPS	Emergency power supply
EV	Electric vehicle
EVSE	Electric vehicle supply equipment, i.e. charging station
FMS	Fleet management system

Term	Definition
Frequency Regulation	A continuous ancillary service in which a fast-responding reserve resource responds to four-second dispatch signals from the California ISO that fall within the capacity awarded to the resource in the day-ahead and real-time markets.
GHG	Greenhouse gas
GRDT	Generator resource data template
HA	Hour-ahead
HLS	Hardware load separation
HVAC	Heating, ventilation, and air conditioning
ICE	Internal combustion engine
IEEE	Institute of Electrical and Electronics Engineers
kW	Kilowatt, a measure of power: 1,000 W
kWh	Kilowatt-hour, a measure of energy: 1,000 Wh
LAAFB	Los Angeles Air Force Base
LBNL	Lawrence Berkeley National Laboratory
LCFS	Low Carbon Fuel Standard
LESR	Limited Energy Storage Resource
MCP	Market clearing price
MW	Megawatt, a measure of power: 1,000,000 W or 1,000 kW
MWh	Megawatt-hour, a measure of energy: 1,000,000 Wh or 1,000 kWh
NaN	Not-a-number
OASIS	CAISO's Open Access Same-time Information System
OB-EVI	On-Base Electric Vehicle Infrastructure
OBD	On-board diagnosis
OCPP	Open Charge Point Protocol
OMS	Outage management system
PID	Proportional integral differential
PPS	Princeton Power Systems
PV	Photovoltaic
RIG	Remote intelligent gateway
RMF	Risk management framework
RMSE	Root-mean-squared error
SC	Scheduling coordinator
SCE	Southern California Edison Company
SEP2	Smart Energy Protocol 2.0

Term	Definition
SLS	Software load separation
SOC	State of charge
STIGs	Security Technical Implementation Guidelines
TOU	Time-of-use
UPS	Uninterruptable power supply
V2B	Vehicle-to-building
V2G	Vehicle-to-grid
VCO	Vehicle Control Officer
W	Watt, a measure of power: 1 joule per second
Wh	Watt-hour, a measure of energy: 1 watt sustained over 1 hour, i.e. 3,600 joules

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APPENDIX A: Guide to Vehicle-to-Grid for Ancillary Services on California Military Bases

This guide outlines the steps necessary for implementing vehicle-to-grid (V2G) to participate in the California Independent System Operator (California ISO) ancillary services (AS) market. Information presented in this guide is based on the experiences and lessons learned from the Los Angeles Air Force Base (LAAFB) V2G demonstration project.

There are currently no commercially available bi-directional capable electric vehicles (EVs) and electric vehicle service equipment (EVSEs) in California, or in the rest of the U.S. This guide assumes that bi-directional EVs and EVSEs will someday be available for a military facility to procure. All references to EV and EVSE presented in this guide assume that they are both bi-directional, specifically the vehicles have drivetrain batteries that can charge and discharge.

The main steps to configuring a V2G system on a California military base are:

1. Determine the number of EVs that will be in the fleet.
2. Calculate fleet V2G capacity.
3. Install electrical infrastructure.
4. Install V2G controls and communications.
5. Follow California ISO New Resource Implementation Guide and Checklist.
6. Test and commission EV/EVSE control.
7. Complete certification testing with California ISO.
8. Operate the V2G project.

Fleet Size and EV and EVSE Characteristics

1. Determine the fleet size and EV and EVSE characteristics. To accomplish this task, conduct an assessment of historical trip data performed with or by the fleet manager along with requirements specified by the fleet manager.
2. Use this information to determine the number of EVs that will meet the transport demands of the facility.
3. The following factors should be considered when determining the number of EVs:
    a. The number of EVs that a facility will install depends on the staff travel and cargo transport needs both on and off-site of the facility.

   b. Key use factors include trip distance, the number of simultaneous trips that occur hourly/daily, maximum one-way and round trip distances, and the number of overnight trips.
   c. The capacity of the V2G resource depends directly on the number of EVs, the battery capacity, and the EV/EVSE charge and discharge rate.

4. When assessing the EV range necessary to meet transport needs, determine if there are EVSEs at the off-site facilities. Typically, military fleet vehicles travel within and between bases. If EVSEs are available at the off-site locations and the time typically spent at that location is long enough to charge an EV for the return trip, the EV travel distance effectively doubles. To make this calculation, assume that an EV sedan can travel 3 miles per kWh of charge and that the off-site EVSE will be a level 2 with a charging rate of 6 kW. The EV will gain 18 miles of range for each hour of charging, which is a conservative estimate for a sedan, but may not be for a larger vehicle.
5. Also take into account the EV manufacturer's stated range which should be reduced by a 10-20 percent safety margin to account for terrain, weather, or driving style that may reduce efficiency.
6. Bi-directional EV and EVSE technology is in early generations. Be sure to budget for comprehensive service and maintenance agreements for all EVs and EVSEs.

Calculating Fleet V2G Capacity

1. After determining the type and number of EVs, the next step is to calculate the usable battery capacity available for V2G.
2. The usable portion of the battery capacity is 70 percent of its rated capacity. When providing both up and down regulation, half of the usable capacity will be dedicated to each regulation direction. For example, an EV with a battery rated at 30 kWh will have a usable capacity of 21 kWh with half of that (10.5 kWh) available for each direction of regulation.
3. The minimum requirement for participation in the California ISO AS regulation market is a capacity of at least 0.5 MW that can be held for 1-hr, in each direction, up and down.
4. If the aggregate fleet EV battery capacity or charge/discharge rates are insufficient to meet the minimum market requirements, ask the electric utility that serves the base if the EVs being planned for the site can be aggregated with other battery storage resources in their service territory, or if there is an aggregator that could facilitate such an arrangement.

Electrical Infrastructure and Interconnection

1. After the number and type of EVs and EVSEs is specified, work with the Civil Engineering Department at the facility to determine electrical infrastructure needed to support the specified EVSEs.
2. With the assistance of the Civil Engineering Dept., initiate the interconnection agreement process with the electric utility serving the facility. Start on interconnection as soon as possible because it can be a lengthy process.

V2G Controls and Communications

1. Work with IT staff at the base to identify a vendor to provide V2G controls and communications (probably best to do this as part of the EV and EVSE needs assessment). System must operate on an on-site controller (cloud based control is not allowed).
2. Assume that a turn-key solution is installed and all control operations are performed on site without the necessity for remote access from outside the base.
3. All computer servers, routers, switches, back-up power supplies, etc. must be on the Defense Information Systems Agency (DISA). See the Security Technical Implementation Guidelines (STIGs) list of approved devices: https://iase.disa.mil/stigs/Pages/a-z.aspx.
4. Have controls vendor work with IT staff to navigate the many facets of the Risk Management Framework (RMF) for the V2G control and communication system. Go to https://rmf.org/ for additional information on the RMF process.
5. Have control vendor create detailed control software specifications covering all control and data sharing commands between controller and EVSEs, EVs, scheduling coordinator, and California ISO. Make sure these specifications go all the way through from the EVSEs to the EVs and back and cover all foreseeable operation needs.
6. Ask EV and EVSE vendors, if there are any special vehicle considerations for charge management, such as frequency, duration, or conditions necessary for cell balancing. Also, ask if any additional safety measures to prevent full discharge of batteries or over-charging of batteries is required beyond EV's own self-protection measures.

California ISO New Resource Implementation

Follow the California ISO New Resource Implementation guide at www.caiso.com/participate/Pages/NewResourceImplementation/Default.aspx (Figure A-1)

Figure A-1: New Resource Implementation

Source: Lawrence Berkeley National Laboratory

EV/EVSE Control Testing and Commissioning

1. Have controls vendor develop a thorough testing and commissioning plan.
2. Check with electric utility to see if any testing or evaluation of first generation EV or EVSE equipment will be necessary.
3. Follow the plan to test all operation scenarios and conditions.
4. Characterize charging and discharging curves from minimum to maximum state of charge (SOC) and maximum to minimum SOC. Further, characterize charging and discharging at different charge rates, at least at minimum, mean and maximum EVSE charge/discharge rates.
5. Get accurate measure of individual and aggregate minimum SOC.
6. If possible, assign EVs to dedicated EVSEs.
7. Use the vehicles for normal operation and charging.
8. Test for the maximum charge and discharge rates that can be held for 60 minutes to determine specification values for California ISO resource implementation.
9. Work with SC to make sure all data sharing between the resource controller and the SC's remote intelligent gateway (RIG) meets operational specifications.

Certification Testing with California ISO

1. California ISO will administer a certification test of the resource, in which, for frequency regulation, they will take remote control of the resource with a discharge setpoint equal to the Pmax specified in the generator resource data template (GRDT) held for 30 minutes and then followed by a Pmin setpoint held for 30 minutes.
2. To qualify as a regulation resource, the average Pmax must be equal to or greater than 0.5 MW. Similarly, the average Pmin must be equal to or less than -0.5 MW.
3. Upon passing certification, California ISO will issue a Commercial Operations Date (COD).
4. Starting on the COD, the resource can commence bidding in the AS regulation market.

Operations

1. Work with fleet staff to maximize compliance with advance reservation of EVs. Two days in advance is ideal for determining EV availability for AS market participation.
2. If a two-day-ahead reservation schedule is not feasible, re-optimizing of charge plans day of market operations is necessary. Alternatively, a bidding safety factor can be built in to account for the probability of unscheduled trips.
3. Vehicles assigned to units that do not get dispatched through a central fleet command, are at risk for low reservation compliance.
4. If using rules based bidding, for example. fixed bids for only certain hours of the day, examine historical regulation market prices to determine which hours are highest to maximize revenue from fixed bidding. Note that these hours may change by season.
5. If operating with some form of optimized bidding, acquiring prices from the previous day is required as a persistence forecast for prices the next day. Find them at http://oasis.caiso.com/mrioasis/logon.do
6. Weather forecast data may also be necessary to forecast facility load and can be accessed at http://www.noaa.gov/weather
7. Work with SC to set up automated bidding and automated award delivery for control system processing to minimize operational intervention by base staff.
8. Watch the system and tracking of the automatic generation control (AGC) setpoint from California ISO. The SC should help with this.
9. Confirm with the SC and California ISO that the service intended to be provided is actually being observed by California ISO, especially in the early days of operation, and then occasionally, possibly monthly later.
10. Configure charge scheduling to keep batteries at less than or equal to 80 percent maximum SOC, especially on hot days to increase battery life.

APPENDIX B:
Data Points Shared Between LAAFB and the Scheduling Coordinator (SCE)

Table B-1: Shared Data Points Between LAAFB and SCE

SCE ARIG Tag Name	Station Name	Description
D_DNPIN_LAAFB_HEARTBEAT	LAAFB -> SCE ARIG	DNP – LAAFB Heartbeat
D_DNPIN_LAAFB_CB	LAAFB -> SCE ARIG	DNP – LAAFB Breaker
D_DNPIN_LAAFB_AGC_AVAIL_ONOFF	LAAFB -> SCE ARIG	DNP – LAAFB AGC CTRL AVALABILITY ONOFF (SCE)
D_DNPIN_LAAFB_UCON_GENX	LAAFB -> SCE ARIG	UNIT CONNECTION STATUS
D_DNPIN_LAAFB_UASW_RIGX	LAAFB -> SCE ARIG	UNIT AUTHORITY SWITCH (ISO)
D_DNPIN_LAAFB_UAGC_GENX	LAAFB -> SCE ARIG	CALCULATED AGC STATUS (ISO)
D_DNPIN_LAAFB_UCTL_GENX	LAAFB -> SCE ARIG	UNIT LOCAL REMOTE CONTROL
D_DNPIN_LAAFB_PORT1_ALMX	LAAFB -> SCE ARIG	COMMUNICATION ALARM (REVENUE METER)
D_DNPOUT_LAAFB_AGC_ISO	SCE ARIG -> LAAFB	DNP – LAAFB AGC model – ISO AGC
D_DNPOUT_LAAFB_AGC_SFM	SCE ARIG -> LAAFB	DNP – LAAFB AGC model – SFM
D_DNPOUT_LAAFB_AGC_MAN	SCE ARIG -> LAAFB	DNP – LAAFB AGC model – MAN
D_DNPOUT_LAAFB_AGC_OFF	SCE ARIG -> LAAFB	DNP – LAAFB AGC model – OFF
D_DNPOUT_LAAFB_HEARTBEAT	SCE ARIG -> LAAFB	DNP – LAAFB GMS Heartbeat
R_DNPIN_LAAFB_HOL	LAAFB -> SCE ARIG	DNP – LAAFB High Operating Limit
R_DNPIN_LAAFB_LOL	LAAFB -> SCE ARIG	DNP – LAAFB Low Operating Limit
R_DNPIN_LAAFB_POD_MW	LAAFB -> SCE ARIG	DNP – POINT OF DELIVERY MW (NOTE 1 AND 2)

SCE ARIG Tag Name	Station Name	Description
R_DNPIN_LAAFB_POD_MVAR	LAAFB -> SCE ARIG	DNP – POINT OF DELIVERY MEGAVARS (NOTE 2)
R_DNPIN_LAAFB_GROSS_MW	LAAFB -> SCE ARIG	DNP – GROSS MEGAWATTS
R_DNPIN_LAAFB_LOW_SIDE_BUS_ VOLTAGE	LAAFB -> SCE ARIG	DNP – TRANSFORMER LOW SIDE BUS VOLTAGE (KV)
R_DNPIN_LAAFB_ENG_AVAIL_MWH	LAAFB -> SCE ARIG	DNP – LAAFB Available Energy (SOC) in MWh
R_DNPIN_LAAFB_MAX_CHARGE	LAAFB -> SCE ARIG	DNP – MAX CHARGE ENERGY
R_DNPIN_LAAFB_MAX_CHARGE_MW	LAAFB -> SCE ARIG	DNP – MAX CHARGE POWER
R_DNPIN_LAAFB_MAX_DISCHARGE_MW	LAAFB -> SCE ARIG	DNP – MAX DISCHARGE POWER
R_DNPIN_LAAFB_MSRR	LAAFB -> SCE ARIG	DNP – MAXIMUM SUSTAINED RAMP RATE MW/min
R_DNPIN_LAAFB_CHG_RR	LAAFB -> SCE ARIG	DNP – ENERGY CHARGE RAMP RATE MW/min
R_DNPIN_LAAFB_DISCHG_RR	LAAFB -> SCE ARIG	DNP – ENERGY DISCHARGE RAMP RATE MW/min
R_DNPIN_LAAFB_SETPT_CNTRL_FDBK	LAAFB -> SCE ARIG	DNP – SETPOINT CONTROL FEEDBACK
R_DNPOUT_SCH_HA_MW_LAAFB_C	SCE ARIG -> LAAFB	DNP – LAAFB Dispatch Energy Schedule
R_DNPOUT_LAAFB_SCH_REGUP_MW_C	SCE ARIG -> LAAFB	DNP – LAAFB Reg Up Awarded MW
R_DNPOUT_LAAFB_SCH_REGDOWN_ MW_C	SCE ARIG -> LAAFB	DNP – LAAFB RegDownp Awarded MW
R_DNPOUT_LAAFB_SCH_SPIN_MW_C	SCE ARIG -> LAAFB	DNP – LAAFB Spin Awarded MW
R_DNPOUT_LAAFB_SCH_NONSPIN_ MW_C	SCE ARIG -> LAAFB	DNP – LAAFB Non-Spin Awarded MW
R_DNPOUT_LAAFB_RR	SCE ARIG -> LAAFB	DNP – LAAFB Ramp Rate (MW/M)
R_DNPOUT_LAAFB_SCE_SETPT	SCE ARIG -> LAAFB	DNP – LAAFB SCE Set Point (MW)

SCE ARIG Tag Name	**Station Name**	**Description**
R_DNPOUT_LAAFB_CAISO_SETPT	SCE ARIG -> LAAFB	DNP – LAAFB California ISO Set Point (MW)
R_DNPOUT_LAAFB_FINAL_CNTRL_ SETPT	SCE ARIG -> LAAFB	DNP – LAAFB Set Point (MW) (SCE)
SCE ARIG Tag Name	Station Name	Description
D_DNPIN_LAAFB_HEARTBEAT	LAAFB -> SCE ARIG	DNP – LAAFB Heartbeat
D_DNPIN_LAAFB_CB	LAAFB -> SCE ARIG	DNP – LAAFB Breaker
D_DNPIN_LAAFB_AGC_AVAIL_ONOFF	LAAFB -> SCE ARIG	DNP – LAAFB AGC CTRL AVAiLABILITY ONOFF (SCE)
D_DNPIN_LAAFB_UCON_GENX	LAAFB -> SCE ARIG	UNIT CONNECTION STATUS
D_DNPIN_LAAFB_UASW_RIGX	LAAFB -> SCE ARIG	UNIT AUTHORITY SWITCH (ISO)
D_DNPIN_LAAFB_UAGC_GENX	LAAFB -> SCE ARIG	CALCULATED AGC STATUS (ISO)
D_DNPIN_LAAFB_UCTL_GENX	LAAFB -> SCE ARIG	UNIT LOCAL REMOTE CONTROL
D_DNPIN_LAAFB_PORT1_ALMX	LAAFB -> SCE ARIG	COMMUNICATION ALARM (REVENUE METER)
D_DNPOUT_LAAFB_AGC_ISO	SCE ARIG -> LAAFB	DNP – LAAFB AGC model – ISO AGC
D_DNPOUT_LAAFB_AGC_SFM	SCE ARIG -> LAAFB	DNP – LAAFB AGC model – SFM
D_DNPOUT_LAAFB_AGC_MAN	SCE ARIG -> LAAFB	DNP – LAAFB AGC model – MAN
D_DNPOUT_LAAFB_AGC_OFF	SCE ARIG -> LAAFB	DNP – LAAFB AGC model – OFF
D_DNPOUT_LAAFB_HEARTBEAT	SCE ARIG -> LAAFB	DNP – LAAFB GMS Heartbeat
R_DNPIN_LAAFB_HOL	LAAFB -> SCE ARIG	DNP – LAAFB High Operating Limit
R_DNPIN_LAAFB_LOL	LAAFB -> SCE ARIG	DNP – LAAFB Low Operating Limit
R_DNPIN_LAAFB_POD_MW	LAAFB -> SCE ARIG	DNP – POINT OF DELIVERY MW (NOTE 1 AND 2)
R_DNPIN_LAAFB_POD_MVAR	LAAFB -> SCE ARIG	DNP – POINT OF DELIVERY MEGAVARS (NOTE 2)
R_DNPIN_LAAFB_GROSS_MW	LAAFB -> SCE ARIG	DNP – GROSS MEGAWATTS

SCE ARIG Tag Name	Station Name	Description
R_DNPIN_LAAFB_LOW_SIDE_BUS_ VOLTAGE	LAAFB -> SCE ARIG	DNP – TRANSFORMER LOW SIDE BUS VOLTAGE (KV)
R_DNPIN_LAAFB_ENG_AVAIL_MWH	LAAFB -> SCE ARIG	DNP – LAAFB Available Energy (SOC) in MWh
R_DNPIN_LAAFB_MAX_CHARGE	LAAFB -> SCE ARIG	DNP – MAX CHARGE ENERGY
R_DNPIN_LAAFB_MAX_CHARGE_MW	LAAFB -> SCE ARIG	DNP – MAX CHARGE POWER
R_DNPIN_LAAFB_MAX_DISCHARGE_ MW	LAAFB -> SCE ARIG	DNP – MAX DISCHARGE POWERR
R_DNPIN_LAAFB_MSRR	LAAFB -> SCE ARIG	DNP – MAXIMUM SUSTAINED RAMP RATE MW/min
R_DNPIN_LAAFB_CHG_RR	LAAFB -> SCE ARIG	DNP – ENERGY CHARGE RAMP RATE MW/min
R_DNPIN_LAAFB_DISCHG_RR	LAAFB -> SCE ARIG	DNP – ENERGY DISCHARGE RAMP RATE MW/min
R_DNPIN_LAAFB_SETPT_CNTRL_FDBK	LAAFB -> SCE ARIG	DNP – SETPOINT CONTROL FEEDBACK
R_DNPOUT_SCH_HA_MW_LAAFB_C	SCE ARIG -> LAAFB	DNP – LAAFB Dispatch Energy Schedule
R_DNPOUT_LAAFB_SCH_REGUP_MW_C	SCE ARIG -> LAAFB	DNP – LAAFB Reg Up Awarded MW
R_DNPOUT_LAAFB_SCH_REGDOWN_ MW_C	SCE ARIG -> LAAFB	DNP – LAAFB RegDownp Awarded MW
R_DNPOUT_LAAFB_SCH_SPIN_MW_C	SCE ARIG -> LAAFB	DNP – LAAFB Spin Awarded MW
R_DNPOUT_LAAFB_SCH_NONSPIN_ MW_C	SCE ARIG -> LAAFB	DNP – LAAFB Non-Spin Awarded MW
R_DNPOUT_LAAFB_RR	SCE ARIG -> LAAFB	DNP – LAAFB Ramp Rate (MW/M)
R_DNPOUT_LAAFB_SCE_SETPT	SCE ARIG -> LAAFB	DNP – LAAFB SCE Set Point (MW)
R_DNPOUT_LAAFB_CAISO_SETPT	SCE ARIG -> LAAFB	DNP – LAAFB California ISO Set Point (MW)
R_DNPOUT_LAAFB_FINAL_CNTRL_ SETPT	SCE ARIG -> LAAFB	DNP – LAAFB Set Point (MW) (SCE)

SCE ARIG Tag Name	Station Name	Description
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D_DNPIN_LAAFB_AGC_AVAIL_ONOFF	LAAFB -> SCE ARIG	DNP – LAAFB AGC CTRL AVALABILITY ONOFF (SCE)
D_DNPIN_LAAFB_UCON_GENX	LAAFB -> SCE ARIG	UNIT CONNECTION STATUS
D_DNPIN_LAAFB_UASW_RIGX	LAAFB -> SCE ARIG	UNIT AUTHORITY SWITCH (ISO)
D_DNPIN_LAAFB_UAGC_GENX	LAAFB -> SCE ARIG	CALCULATED AGC STATUS (ISO)
D_DNPIN_LAAFB_UCTL_GENX	LAAFB -> SCE ARIG	UNIT LOCAL REMOTE CONTROL
D_DNPIN_LAAFB_PORT1_ALMX	LAAFB -> SCE ARIG	COMMUNICATION ALARM (REVENUE METER)
D_DNPOUT_LAAFB_AGC_ISO	SCE ARIG -> LAAFB	DNP – LAAFB AGC model – ISO AGC
D_DNPOUT_LAAFB_AGC_SFM	SCE ARIG -> LAAFB	DNP – LAAFB AGC model – SFM
D_DNPOUT_LAAFB_AGC_MAN	SCE ARIG -> LAAFB	DNP – LAAFB AGC model – MAN
D_DNPOUT_LAAFB_AGC_OFF	SCE ARIG -> LAAFB	DNP – LAAFB AGC model – OFF
D_DNPOUT_LAAFB_HEARTBEAT	SCE ARIG -> LAAFB	DNP – LAAFB GMS Heartbeat
R_DNPIN_LAAFB_HOL	LAAFB -> SCE ARIG	DNP – LAAFB High Operating Limit
R_DNPIN_LAAFB_LOL	LAAFB -> SCE ARIG	DNP – LAAFB Low Operating Limit
R_DNPIN_LAAFB_POD_MW	LAAFB -> SCE ARIG	DNP – POINT OF DELIVERY MW (NOTE 1 AND 2)
R_DNPIN_LAAFB_POD_MVAR	LAAFB -> SCE ARIG	DNP – POINT OF DELIVERY MEGAVARS (NOTE 2)

Source: Lawrence Berkeley National Laboratory