Strategies for Expanding the Transactive Flexibility of Demand Response in California

Project Summaries and Key Takeaways from CEC-GFO-15-311

Acknowledgments

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ABSTRACT

The purpose of the California Energy Commission's (CEC) Grant Funding Opportunity (GFO) 15-311 was to fund applied research and development projects that test and assess how groups or aggregations of distributed resources responded to current, planned and potential price signals. The awarded projects fell within four groups: The first and second groups developed and tested demand response (DR) strategies, following the California Public Utilities Commission's (CPUC) "bifurcation" of demand response resources into "supply-side" and "demand-side" resources, (i.e., as resources that qualify for "capacity resource" status under current market rules or as "load-modifying" resources, with the technical capability to communicate with and manage end use loads, distributed generation and energy storage). The third group developed and tested a transactive energy signal that reflects local market system needs and could serve as an alternative proxy price signal for demand-side resources. The fourth group assessed and characterized the costs and benefits of including DR controls as a requirement for lighting retrofits in existing non-residential buildings.

This report provides a high-level illustration of the goals, methodology and results of each project across the four groups, highlights the potential impact of the successfully simulated transactive signal developed by Group 3, and how GFO 15-311 lays the groundwork for the future transactive pricing strategies that could expand and accelerate customer participation in new models of DR and as a result, help meet California's goals for grid stabilization, de-carbonization and the overall evolution of the California retail electricity market.

Keywords
Demand Response, Transactive Incentive Signals, GFO 15-311, Dynamic Pricing

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INTRODUCTION

About This Report

The intention of this technical update is to illustrate the importance of the California Energy Commission's (CEC) Grant Funding Opportunity (GFO) 15-311 research as it relates to the evolution of California demand response (DR) utility retail programs and wholesale energy markets. The goal of this update is to provide a high level yet strategically detailed overview of the ten innovative research projects awarded from the GFO and to provide a comprehensive review of the research through the lens of a future prospective vision of utilizing a transactive energy signal in everyday electric service and delivery. The purpose of the GFO was to examine how a transactive energy signal could enable dynamic customer participation in retail flexible demand response programs using a form of real-time pricing that accurately reflects the current state and needs of the wholesale energy market.

Developing and testing a transactive energy signal was key to the original intent of GFO 15-311 and is the core purpose of the EPIC Project 15-045 in Group 3. But the projects described throughout this paper in Groups 1 and 2 are equally as important as they provide actual use-cases to test the viability of a transactive signal with actual customers. Project 15-045 specifically developed and tested an integrated and inclusive transactive load management (TLM) framework that supports the design and development of a prototypical TLM signaling system. This system is called Transactive Incentive-Signals to Manage Energy Consumption. The project was renamed TIME by the GFO project team that developed the system and is referred to as such throughout this report.

Ten projects in all were awarded funding through the GFO solicitation. Detailed reports have been published by the project leads for each of these ten projects and most are currently available on the CEC's website. Project specific information, language, graphics and data on each project in this report, are pulled directly from these existing reports to ensure accurate representation of the methodology, processes and findings for each project.

The projects funded by GFO 15-311 have successfully proven that a TLM signal can be used in multiple applications across residential and commercial markets. This research supports California's goals of developing new demand response emerging technologies and secure communications that support increased renewable resources on the electric system through the integration of seamless, price-based customer participation in dynamic rates and new models of innovative DR programs.

All reports referenced in this paper are listed in the Appendix and are also available on the collaboration DR web site www.DRET-CA.com.

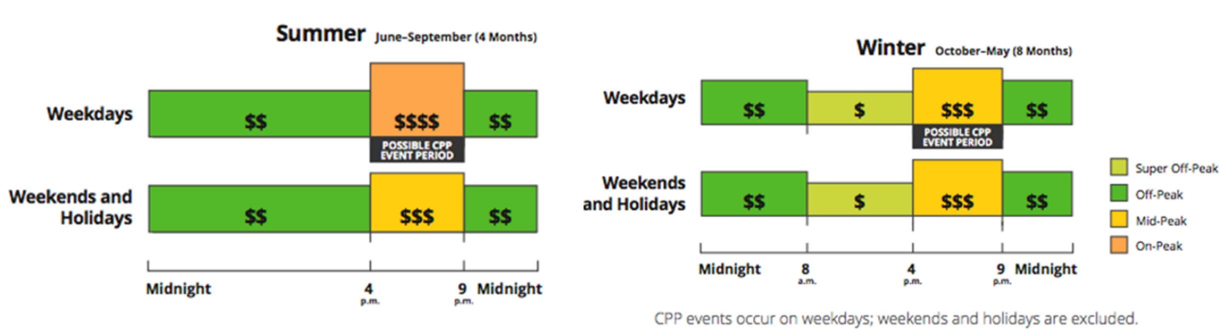
The Changing Electric Energy Market

Regulatory pricing designs for purchasing electricity in the U.S. are based on the annualized system average marginal costs of delivering electricity in a particular region - not the actual locational marginal costs, which can vary dramatically by time of day, shifts in temperature, and change of seasons, as well as localized geography. The result of this averaging is an inefficient electricity pricing model where consumers do not pay for electricity at an average rate that reflects how much or when they use it or what the overall market currently demands. Without being exposed to a dynamic pricing structure to reflect real time needs, most electric system customers are unaware of the real time impact their consumption has on the electric system as a whole, especially on a day where demand is high, supply is constrained, and the overall system is already close to its capacity to serve.

Dynamic pricing is a widely utilized strategy for pricing goods and services based on realistic customer and market demands. Dynamic pricing is now used in industries such as travel (peak season vs. off-season), ride sharing (Lyft) and hospitality (weekend rates and Happy Hour) where prices are determined by the time of day/year or by level of demand.[1] Consumers have come to understand and accept dynamic pricing across many industries, but it has been particularly difficult to implement in the retail electricity market. This is due to a lack of transparency related to wholesale market forces and little or no choice of suppliers to compare or change at the last minute. Consumers make a decision on the price they are willing to pay before they take a Lyft ride or purchase airline tickets or book a hotel room for vacation. They can see a price reduction for going an hour later or knowingly agree to higher prices if they really want to travel during peak season. But electricity is a real-time commodity, and the current relationship with energy providers lacks the ability for consumers to defer a purchase to a less expensive time, similar to when a customer chooses to go to the local pub during Happy Hour in order to purchase less expensive drinks. Interestingly, DR is a form of dynamic pricing “happy hour” strategy in reverse, where customers are encouraged with financial incentives to shift or reduce peak energy demand at specific times only when needed.

A Time Of Use (TOU) rate (or Peak Pricing) is a less dynamic retail electricity pricing model where a unit of retail energy is either more or less expensive at the time of day when prices are set to reflect expected market costs of service. In the California energy market, peak pricing occurs in the afternoons, as the sun moves off of solar installations and more expensive fossil fueled power plants have to be dispatched in order to meet ramping evening needs. But the TOU rate cost is averaged and predetermined, based on season and time of day, not on the actual cost of electricity at the hour of use. TOU is now required for many utilities in California and despite utility outreach and marketing, customers are often unaware of the exact price that they are paying during peak or off-peak times. An example of the TOU Peak Pricing structure is illustrated here in Figure 1-1.

Figure 1-1
CA Time of Use Peak Pricing Summer and Winter



[1] https://www.utilitydive.com/news/6-reasons-why-california-needs-to-deploy-dynamic-pricing-by-2030/578156/

Source: Southern California Edison

Education in energy conservation has helped many consumers understand how their personal actions can reduce their energy use, but engaging customers in a discussion on their options for different pricing strategies has proven to be more difficult. Most consumers understand very little about how the electric system works, and as they are accustomed to the lack of control in deciding when to reduce consumption, the feeling that they are being "controlled" by their utility through complicated rate strategies creates an additional barrier to participation. However, these barriers can be overcome, as advanced metering integration, wireless internet and smart technologies are quickly laying the groundwork for real-time, dynamic r*esponsiveness* that may make participation in TOU both simple and seamless for consumers.

Supporting CA's 100% renewable goals

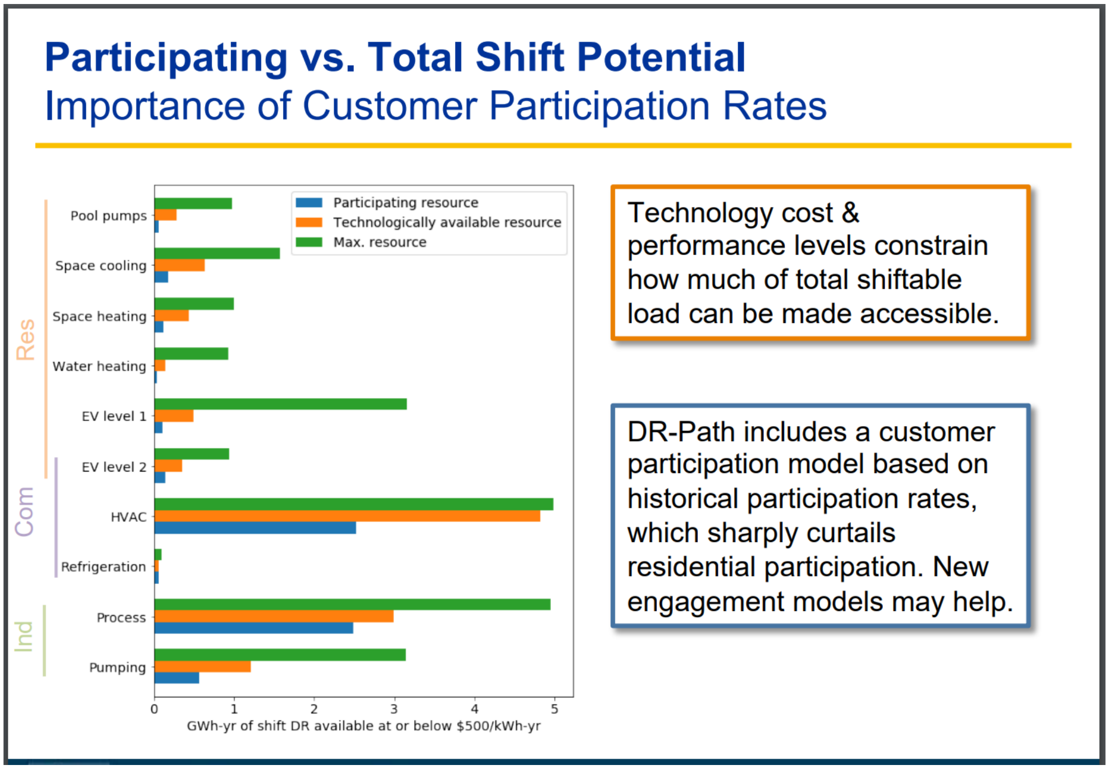
California has been working towards an electric market-based solution to greenhouse gas (GHG) emissions through climate change legislation. The State's Assembly Bill (AB) 32 – Global Warming Solutions Act of 2006 – and Senate Bill (SB) X1-2 – Renewables Portfolio Standard – have been primary drivers for developing sustainable pathways for a clean energy system that could include seamless, dynamic pricing that encourages consumers to participate in demand response programs and enables more accurate pricing of distributed energy resources on the system. AB 32 mandated a GHG reduction goal of returning to 1990 levels by 2020 along with a cap-and-trade program. SB X1-2 requires retail sellers of electricity and local publicly owned electric utilities (POUs) to increase their procurement of eligible renewable energy resources to 20% by the end of 2013, to 25% by the end of 2016, and to 33% by the end of 2020.

On August 29, 2018, the California Legislature made history by passing SB 100, the California 100% Clean Energy Act. California Senate Bill 100 states,

"…it is the policy of the state that eligible renewable energy resources and zero-carbon resources supply 100% of retail sales of electricity to California end-use customers and 100% of electricity procured to serve all state agencies by December 31, 2045. Renewable resources such as wind and solar are expanding rapidly across the state and will provide the foundation for supporting this mandate, but the challenge remains that renewable resources are intermittent and do not respond dynamically to load requirements and changing system conditions. With over 2 million customers in California enrolled in either opt in or opt out TOU rates, and all CA utilities moving to opt out by October of 2020, TOU is proving to be highly effective on the retail side of energy management. But it does not satisfy the pricing variations that occur in the wholesale market. Technology enabled dynamic pricing will be critical when California moves to 100% renewable generation."

Expanding customer participation in TOU rates is important but facilitating increased adoption of more innovative DR programs will also be critical to the success of a 100% renewable generation future. Figure 1-2 illustrates current customer participation vs. the total load shift potential if all customers participated in DR.[2]

[2] https://buildings.lbl.gov/slides-california-demand-response-potential-study



Source: Lawrence Berkeley National Laboratory

Figure 1-2
Customer participation vs. total shift potential

Widespread installation of advanced metering infrastructure (AMI) by the state's investor-owned-utilities (IOUs), along with mass consumer adoption of wi-fi enabled smart thermostats, digital appliances, and battery storage through PV panels and EV charging stations, are providing the technological foundation to develop, test and implement new models of dynamic pricing. These activities might also facilitate implementation of the State's policy mandates through the dissemination of real time transactive energy signals at the system and individual consumer level.

The CEC recognized the need for increased usage of resources (both supply side and demand side) to facilitate a more dynamic approach to DR and end use load management. CEC GFO 15-311 was issued through the Electric Program Investment Charge (EPIC) program, calling for applied research to assess how such resources could respond to dynamic price signals. CEC GFO 15-311 was designed to determine if a transactive signal could be established and if so, could it interact with residential and commercial based technologies that would potentially provide customers with seamlessly delivered, least cost energy options, increased system reliability, and proof that technology enabled dynamic pricing is a viable solution to meet the carbon reduction and system reliability goals of the world's 5th largest economy.

Purpose of CEC GFO 15-311

The core objective of GFO 15-311, issued by the CEC in 2015, was to identify, inform and develop strategies for overcoming technical, institutional and regulatory barriers to expanding DR participation in California. The main purpose of the research outcomes were to enable high renewable resource penetration and to meet carbon emissions goals by proving the viability of a transactive incentive signal and the potential for this signal to enable a more effective use of DR and Distributed Energy Resources (DER) by all sectors of California's IOU customers. This effort also supported the California Independent System Operator's (CAISO) Demand Response and Energy Efficiency Road Map.[3]

This document reviews the goals and objectives of GFO 15-311 as it relates to technology enabled dynamic pricing and details the purpose, methodology and key outcomes of all ten of the selected applied research and development projects funded through the GFO. While all EPIC program projects are required by the CEC to provide technology transfer of key findings as part of the project deliverables, the goal of this technical update is to do so through the following actions:

1. Define California's strategy for dynamic pricing and how GFO 15-311 supports this strategy.
2. Illustrate how transactive incentive signals/pricing signals could increase customer participation in demand response programs.
3. Detail the development and viability of a simulated transactive incentive signal that could be used to provide real-time pricing for California's energy consumers.
4. Highlight how each of the projects in Groups 1 and 2 provide a market based, use case for utilizing a transactive incentive signal to expand consumer participation in DR programs.

The development and testing of a framework for a Transactive Load Management (TLM) system, and a subsequent TLM pricing and signal design structure requires collaboration and in-field tests of multiple technology applications. GFO 15-311 was structured specifically to facilitate this collaboration and testing by funding DR and DER applications that might replicate real world use-cases and if successful, would lay the foundation required to determine the potential of a seamless dynamic pricing model and a clearer path towards implementation.

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[3] https://www.caiso.com/documents/dr-eeroadmap.pdf

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CEC GFO 15-311 - ADVANCING SOLUTIONS THAT ALLOW CUSTOMERS TO MANAGE THEIR ENERGY DEMAND

Vision for CEC GFO 15-311

When GFO 15-311 was released in 2015, the number of smaller distributed generation and renewable resources across California was growing rapidly. The potential for these resources to destabilize distribution and transmission grid management was also becoming apparent. At the time, DR programs offered by electric utilities were focused primarily on grid reliability and peak load reduction. There was little flexibility in these programs to avoid curtailments or load shed, and enrolled customers frequently sacrificed productivity or comfort or both. All of this made DR programs less than desirable and as a result, dispatched events tended to be limited in number, event specific, and overall participation across various customers sectors was low.

At the same time, newly developed market options along with a decade of research and breakthroughs in technology development suggested there was immense potential for balancing electricity supply and demand in near-real time through better communications and automatic management of customer loads and distributed energy assets. Aggregation programs developed by California's IOUs and third-party Demand Response Providers (DRPs) were already enabling small customer loads to participate in wholesale markets. "Smart" grid technologies such as sensors, control technologies and meters could generate data to help optimize grid performance and efficiency. The "internet of things" was also emerging as a viable path to controlling a large variety of loads, distributed generation resources and energy storage.

All of these advances pointed to the possibility of a real-time pricing "signal" that might provide a path to DER integration. The GFO 15-311 solicitation stated:

"It is also possible to develop a "transactive" system that combines real-time system information with forecasts of loads and distributed generation production to develop an incentive or price "signal" that reflects actual system needs.[4] A transactive, open, interoperable signal combined with "anytime" DR could provide a basis for achieving demand-side resource integration and achieve the California Public Utilities Commission (CPUC) goal of providing optimal customer and system benefits while achieving California's climate objectives.[5]"

The vision for GFO 15-311 was to fund a series of projects that would research, develop and test the key components necessary to prove the concept that a transactive system, using a real-time pricing signal, could achieve demand-side resource integration that was simple for customers to participate in while also meeting California's clean energy goals. The components would include demand-side

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4 Pacific Northwest Smart Grid Demonstration Project Technology Performance Report Volume 1: Technology Performance, Prepared for U.S. Department of Energy by Battelle Memorial Institute, Pacific Northwest Division, June 2015. https://www.smartgrid.gov/document/Pacific_Northwest_Smart_Grid_Technology_Performance.html

5 See CPUC Decision 15-09-22 in R.14-10-003, 9/17/2015. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M154/K464/154464227.PDF

resource specific projects, supply-side resource projects and the development of a signal that could be used across all projects. If the signal could be created and the system could be proven, the possibility for an integrated resource platform could become more of a solution than a Vision.

Goals and Objectives

One of the key goals for the GFO was to design, develop and test a simulated, transactive pricing signal across a group of demand-side and supply-side resource projects. If successful, the GFO would provide proof of concept that could help California determine the validity of such a system and provide key learnings that would help the CEC and IOUs better understand the next set of activities and research needed to move towards actual market transformation.

The objective of the applied research, development projects and group descriptions are pulled directly from the Solicitation for GFO 15-311:

…to test and assess how groups or aggregations of distributed resources[6] *respond to current, planned and potential price signals. The selected projects fell within four groups: The first and second groups will develop and test DR strategies and will loosely follow the CPUCs "bifurcation" of demand response resources into "supply-side" and "demand-side" resources. The term "loosely" acknowledges that this categorization reflects how the resources are intended to be used under current market structures, (i.e., as resources that qualify for "capacity resource" status under current procurement rules or as "load-modifying" resources, but for which the technical capability to communicate with and manage loads, distributed generation and storage are largely the same). The third group will develop and test a transactive energy signal that reflects system needs and could serve as an initial proxy price signal for demand-side resources. The fourth group will assess and characterize the costs and benefits of including DR controls as a requirement for lighting retrofits in existing non-residential buildings.*

Research topics should include:

- Documenting baseline load impacts under existing tariffs, estimating impacts under newly authorized and planned tariffs—in particular, new residential time of use (TOU) rates authorized under CPUC Decision 15-07-001.
- Developing and testing technologies—with a focus on automation—that facilitate customer control and strategic integration of their loads with their distributed generation and storage resources.
- Developing and pilot testing strategies for customer participation in existing and soon-to-be available wholesale and retail tariffs and programs, with a focus on maximizing the value of TOU rates being developed under CPUC direction.

[6] In AB 327 (2013) the legislature added Section 769 to the Public Utilities Code, which itemizes "distributed resources" as distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies. The purpose of Section 769 is to direct electric corporations to prepare a Distribution Resource Plan Proposal that identifies optimal locations for the deployment of distributed resources. https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?lawCode=PUC&sectionNum=769.

- Comparing participation and performance under different incentive/information structures, using TOU rates being developed under CPUC direction as a baseline.
- Identifying strategies for overcoming existing technical, institutional and regulatory barriers to expanding demand response to large numbers of customers across all sectors and matching load reduction capabilities with system needs.
- Identifying and quantifying the incremental costs and benefits of demand responsive lighting controls as part of general lighting upgrades in existing non-residential buildings.

GFO Categories: Supply Side & Demand Side

Each submitted application for GFO 15-311 was required to fall within one of four applicable project groups. These project categories were designed to encourage a variety of responses that would ideally result in opportunities to test multiple platforms of supply-side and demand-side resources using one of more transactive signals to facilitate. *The project descriptions below are sourced directly from the GFO solicitation.*

Group 1: Load Management Systems that Facilitate Participation as Supply-side Resources

The purpose of research in this group is to develop and pilot-test operational strategies for participation as supply-side resources utilizing onsite renewable generation, CHP, electricity and thermal storage, energy efficiency, electric vehicles and load management systems. Participants in these projects will most likely be large industrial or commercial customers or Demand Response Providers. These projects should comprehensively address the problems facing customers in developing strategies, procuring and installing equipment, commissioning systems, comparing different participation options, and optimizing participation in terms of both energy costs and the opportunity costs of participation, and overall impacts on grid operations and carbon emissions. This research should prioritize development of strategies that maximize customer and system value under CPUC-approved retail and CAISO wholesale tariff structures in addition to identifying tariff structures that could produce higher value.

Group 2: Load Management Systems that Facilitate Participation as Demand-side Resources

The purpose of this project group is to develop and pilot-test behind-the-meter load management systems and operational strategies, program designs and retail tariff options that minimize the cost and complexity of customer participation, while maximizing the potential of large numbers of small loads to improve system load factor, shave peaks, integrate renewable generation and otherwise provide low opportunity-cost resources to the grid. Participants in these projects can be from any customer sector, but residential and small commercial customers should be included in sufficient numbers that both participation forecasts for sector subgroups and initial performance estimates can be made. This research should prioritize development of strategies that maximize customer and system value under CPUC-approved retail and CAISO wholesale tariff structures in addition to identifying tariff structures that could produce higher value.

Group 3: Develop One or More Transactive Signals to Facilitate Demand Response

The purpose of the research in this group will be to develop, test and operationalize one or more transactive signals that can be used by utility customers—and the other Recipients under this solicitation—as a basis for automating their load management strategies. The intent of this work is to test customer response to a dynamic price or informational signal that reflects and anticipates system conditions. Such a signal could be based on California Independent System Operator market prices or utility tariffs as well as including information on other indicators of system conditions. The goal is to begin providing a signal within one year, in time for Group 1 and 2 Recipients to compare system performance potential under this signal with existing programs, and to continue providing and communicating the signal for the duration of those projects. It is expected that the signal development process will involve collaboration with Group 1 and 2 Recipients.

In the development of such signals and evaluation of customer response, the Applicant should ensure that the results can be of use to the CPUC and the CAISO. In particular, where the research includes residential customers, the rates proposed in response to the July, 2015 CPUC decision on Residential Rate Design and a recent ruling providing direction to the Investor-Owned Utilities on pilot Time-of-Use rates beginning in 2016 should be fully evaluated.

Group 4: Value Proposition for Non-Res Building Lighting Retrofits and Demand Response

The purpose of this research project will be to evaluate the costs and benefits of DR control system requirements in the California Energy Code across the existing non-residential building stock in California. The goal is to identify the conditions under which such investments are cost-effective for the customer and to characterize and quantify the value to the grid—including operational and infrastructure benefits—of developing DR capability in the existing non-residential building stock.

High-Level Overview of EPIC Projects Selected for GFO 15-311

The following projects were reviewed and selected for funding from GFO 15-311. The descriptions include the project lead, the amount funded and a brief description of the core objective of the project.

EPC-15-045 - ELECTRIC POWER RESEARCH INSTITUTE, INC. - $498,054 grant to design, develop, test, and implement a system to create and communicate transactive signals that can be used to facilitate demand response provided by California utility customers and other recipients. The signals will be integrated with the other demand response projects awarded under this solicitation.

EPC-15-048 - ALTERNATIVE ENERGY SYSTEMS CONSULTING, INC. - $3,996,560 grant to test and validate an intelligent software solution that continuously learns, adapts, and manages residential energy usage to provide a scalable solution that maximizes value to the utilities, solar providers, and end-users.

EPC-15-051 - DOE-LAWRENCE BERKELEY NATIONAL LABORATORY. - $500,000 grant to identify, quantify and evaluate the costs and benefits of implementing demand response lighting controls as described in the California Energy Code across California's existing, non-residential building stock

EPC-15-054 - UNIVERSAL DEVICES, INC. - $3,187,370 grant to develop and pilot test a Retail Automated Transactive Energy System (RATES) that uses behind the-meter energy management solutions. The goal is to minimize the cost and complexity of customer participation in demand response programs, while maximizing the potential participation of large numbers of small loads that can improve system load factor, shave peaks, integrate renewable generation and provide low opportunity-cost resources to the grid.

EPC-15-057 - UNIVERSITY OF CALIFORNIA, BERKELEY (CIEE). - $4,000,000 grant to improve small and large commercial customer participation in demand response by providing a cost-effective energy management system that allows a wide range of hardware and service offerings and automated price-based management.

EPC-15-073 - UNIVERSITY OF CALIFORNIA, LOS ANGELES. - $2,007,875 grant to assess and demonstrate alternative demand response strategies that will increase residential customer participation in future demand response programs offered by California's Investor-Owned Utilities.

EPC-15-074 - CENTER FOR SUSTAINABLE ENERGY. - $3,960,805 grant to develop co-optimization strategies for distributed energy resources to maximize customer and system value under existing and future retail and wholesale tariff structures, and transactive energy pricing signals.

EPC-15-075 - ELECTRIC POWER RESEARCH INSTITUTE (EPRI). - $3,998,587 grant to fund assessment of transactive tariff effectiveness to influence aggregated demand side resources and consumer behavior to provide grid stability, reliability, and greenhouse gas reductions.

EPC-15-083 - OHMCONNECT, INC. - $3,995,028 grant to develop and conduct experiments evaluating methods of encouraging proactive consumer participation in demand response programs. The project will develop, test, and refine information communication and automation techniques that maximize customer engagement in demand response events and low-cost telemetry solutions that facilitate participation in California Independent System Operator markets.

EPC-15-084 - BMW OF NORTH AMERICA, LLC. - $3,999,900 grant to utilize real-time vehicle information, predictive travel behavior, grid location data, and energy market price data to manage a vehicle's charging.

3
GROUP 1: SUPPLY SIDE RESOURCES

CEC EPC-15-074 (STEEL) – Center for Sustainable Energy: Meeting customer and supply-side market needs with electrical and thermal storage, solar, energy efficiency and integrated load management systems (Bull, 2020).

Goals and Objectives

When CEC EPC-15-074 was first proposed to the CEC in 2015, the status of distributed energy resource (DER) integration as supply-side demand response (DR) in The California Independent System Operator (CAISO) California wholesale market was practically non-existent. Since then, California has taken steps to encourage the participation of DERs in DR programs and mechanisms, such as the CPUC's Demand Response Auction Mechanism (DRAM) pilots and wholesale market integration of the three major investor-owned utilities (IOUs) longstanding load-shed DR programs. However, a lack of developed projects in conjunction with inadequate CAISO wholesale market rules and CAISO and CPUC regulatory barriers continue to limit the deployment of non-DRAM and non-IOU program supply-side DR. As a result, DR continues to play a limited role in addressing supply-side problems in California, e.g., addressing the Duck Curve.

CEC EPC-15-074: Meeting customer and SUPPLY-side market needs with electrical and THERMAL storage, solar, ENERGY EFFICIENCY and integrated LOAD management systems, named STEEL by the project team, illuminates and clarifies the remaining gaps in the understanding of best practices for operationalizing DERs in California that can respond to price signals designed to balance supply and demand in wholesale markets.

The primary objective of the STEEL project was to assess and test how aggregations of DERs could respond to current, planned, and potential wholesale and utility price signals. Operational objectives included the deployment and dispatch of state-of-the-art DER technologies, metering and telemetry, operational strategies, and economic modeling and analysis. Specific objectives of the project included:

- Test and evaluate market operations in CAISO markets.
    - Submit economic bids, receive market awards and coordinate outages by interacting with CAISO grid operations systems.
    - Meter and financially settle market awards.
- Test and evaluate CAISO's baseline methodologies for performance evaluation and settlements in day ahead (DA) market.
    - Including the financial impact of market settlement baselines between the metered generation output (MGO) and 10-in-10 baseline.
- Test and evaluate CAISO's export adjustment rules for financial settlements of PDRs.
    - Develop operational strategies to maximize customer and system value under CPUC-approved retail and CAISO wholesale tariff structures.

- Develop operational strategies to co-optimize between retail and wholesale services including marginal and opportunity costs of limited energy storage resources.
- Develop operational strategies to manage uncertainty of limited energy storage resources based on customer capabilities to manage demand and wholesale participation requirements.
- Install and test communication equipment capable of responding to simulated or actual price signals.
- Evaluate resource responsiveness to price signals through real-time market operations and simulated transactive price signals.
- Evaluate ancillary service market potential by simulating contingent and non-contingent events.
- Facilitate the creation of new markets for DERs, allowing these technologies to become self-sustainable without incentives.
- Examine current and proposed future utility tariffs and rates and identify how these rates encourage or discourage efficient uses of DER technologies.

Project STEEL tested and configured two portfolios of distributed energy resource (DER) aggregations designed to participate in the CAISO energy and ancillary services markets while still providing retail bill management for customers. The two portfolios were: 1) large retail customers and schools using battery storage, solar, and integrated load management, and 2) hotels using passive thermal storage and an energy efficiency package (i.e., central plant, HVAC, pumps, drives, and lighting). Both portfolios participated in an integrated load management strategy with the objective of proving they were capable of responding to price and reliability signals.

The purpose of this project was to develop and demonstrate multipurpose operational strategies for DERs, namely batteries and load controls behind the meter, to simultaneously reduce customer utility retail bill costs and gain revenue by participating in the CAISO wholesale electricity market. This participation would be considered an "invisible intervention," meaning not disrupting or adding risk associated with interrupting the host customer's day-to-day core business and operations. This meant that the two sites would see a reduction in electric utility costs while continuing to operate, with the schools effectively delivering education (K-12) to students and the hotels providing comfortable overnight and other hospitality services to guests.

The two DER portfolios would also participate in the CAISO wholesale electricity and ancillary services markets under a market product construct known as proxy demand resources (PDR). Behind-the-meter DER participation in the CAISO wholesale market is a relatively new use case. To date, the entire process of preparing, registering, bidding and settling behind-the-meter DER participating as PDR in the market has almost entirely been done through existing demand response programs administered through the state's three major investor-owned utilities (IOUs). This has resulted in market participation processes and procedures only being understood by a narrow set of technically educated DER providers, regulators and customers. A second key project goal was identified - to document the strategic set of replicable processes and procedures for PDR to successfully participate in the CAISO wholesale electricity market.

As the results and lessons learned from this project are more widely disseminated, the project team hopes to see increased DER participation in the CAISO wholesale electricity market, which will provide co-benefits of further reducing DER and electricity costs for customers and ratepayers, improve the efficiency of the grid and allow for deeper decarbonization of the electricity grid.

Methodology and Approach

The project team consisted of the Center for Sustainable Energy (CSE), serving as the project manager and interlocutor with the California Energy Commission on behalf of the project team; Olivine Inc., serving as the scheduling coordinator and demand response provider for the DER portfolios; Tesla Inc., managing a portfolio of aggregated battery storage systems at five different school sites (Portfolio 1); Conectric Networks (Conectric), managing a portfolio of networked sensors and load controls at two hotels (Portfolio 2); and DNV GL, providing measurement and evaluation of the project results. Figure ES-1 shows the general roles and construct of the project team. Additionally, the project team recruited and interacted with a technical advisory committee of industry, market and regulatory experts to obtain feedback during project implementation and to interact on lessons learned. Figure 3-1 illustrates the hierarchy of the project participants.

Figure 3-1
EPC 15-074 Project Team Hierarchy

Portfolio 1

Portfolio 1, managed by Tesla, Inc. (who subsumed original partner developer Solar City, Inc. in 2017), consists of five schools aggregated as a single source and located in Chino Hills, CA. The schools are all served by Southern California Edison (SCE). Each site uses battery storage to discharge electricity to the onsite load and reduce electrical demand from the grid to reduce retail bills and to participate in the wholesale market. Each battery can discharge at its rated capacity for up to two hours and is based on the powertrain architecture and components of Tesla's electric vehicles, with optimizations in design and cell chemistry for grid-connected stationary energy storage applications. The batteries were designed to optimally cycle between twenty to eighty percent charging capacity at least one to two times per day.

School District Portfolio - Battery Storage

In addition to energy storage, each school also has onsite solar photovoltaics (PV). Table 3-1 shows a size breakdown of each school site battery and solar PV resources in the portfolio. While the solar PV is used to reduce onsite load, since it is a non-dispatchable resource, it is not used to control and reduce load when bidding into the wholesale market.

Table 3-1
List of Tesla Battery and Solar PV Resources Across Five School Sites for Portfolio 1

Site Name	Battery Resource	Solar PV Carports
Chino Hills High School	250 kW/475 kWh	1,078 kW
Chino High School	250 kW/475 kWh	707 kW
Don Lugo High School	250 kW/475 kWh	904 kW
Ruben Ayala High School	250 kW/475 kWh	1,116 kW
Walnut Ave Elementary School	100 kW/190 kWh	168 kW
Portfolio 1 Total	**1,100 kW/2,090 kWh**	**3,973 kW**

Dispatched load reduction was provided via Tesla batteries installed at each school. As the resource dispatch controller, Tesla chose the market bid prices and quantities that were bid into the wholesale market. Olivine was the Scheduling Coordinator for the aggregation, interfacing with CAISO to submit bids for energy and Spinning Reserves, communicate market awards, relay dispatch instructions, and submit meter and performance data. The batteries were limited to discharging against facility load with safeguards preventing any export across the utility meter. All measured performance was based on load reduction compared to a reference level baseline load.

Portfolio 1 tested several different levels of CAISO market participation: Day-Ahead Energy, Real-Time Energy, Spinning Reserves and frequency regulation (Regulation Up). Real-Time Energy was from market awards from real-time bids that cleared and resulted in 5-minute dispatch instructions.

In order to participate in Spinning Reserves markets, the resource aggregation was subject to CAISO's Full Network Model implementation process and required prior certification tests.[7]

CAISO has a market for procurement of frequency regulation, which is discreetly divided into two market product types, Regulation Up (increased generation/reduced load) and Regulation Down (reduced generation/increased load). Because frequency regulation is not permitted from PDR in CAISO, Portfolio 1 aggregation followed a simulated four-second regulation signal to show technical ability to provide Regulation Up.

In addition to proving out the feasibility of participation by the DER aggregation in several wholesale market products, this project tested the implementation of CAISO's MGO baseline methodology for Demand Response. Standard CAISO baselines for PDR have been based on measuring load reduction compared to whole-premise load. MGO allows for battery storage-based PDR to account for performance only measuring sub-metered battery discharge. Olivine was given access to Tesla's sub-metered battery usage data in order to calculate MGO performance and compare sub-metered load to whole premises meter load.

Portfolio 2

Portfolio 2, managed by Conectric, consists of two medium-large hotels in San Diego County that are aggregated together as a single PDR resource. The PDR resources have a maximum load reduction capacity of 160 kW – 215 kW for 4-6 hours (640kWh – 1,300kWh). The amount and duration of load reduction changes depending on several factors, including season, weather, and time of day.

Hilton Hotel in San Diego

Portfolio 2 deployed a suite of sensors, software, and controls to reduce and shift load as needed (see Figure 3-2). Through the software, sensors, and data analytics, each hotel site could continuously monitor business and occupant energy needs and actively reduce unnecessary energy-consuming loads. The load control software can manage tens of thousands of micro-loads based on actual requirements for energy to operate the building per its business requirements and occupancy comfort.

Each controllable load is considered "available" or "un-available" inventory based on real-time sensor data. Extensive testing and calibration of the software and sensors' data was necessary to maintain a dynamic, optimal balance of maintaining building occupants' comfort, running important business operations, and providing load reduction at moments when wholesale electricity market prices are high.

[7] Ibid; for detailed description of CAISO Full Network Model implementation process and certification testing, see Chapter 2: Project Approach and Chapter 3: Project Results in the Final Project Report.

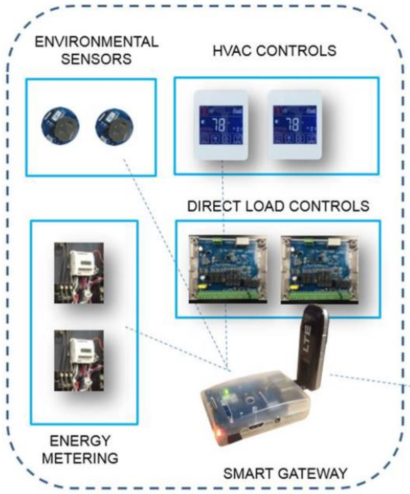

Figure 3-2
General Schematic of Conectric's Sensors, Meters and Load Control Devices Communicating Data within a Dedicated Wireless Network

Overall Results

The project team achieved its primary goal of developing operational strategies to bid behind-the-meter battery and passive thermal storage technologies into the CAISO wholesale electricity market without compromising retail bill savings to customers or disrupting daily critical operations. They also found that the revenues gained as an active participant in the CAISO wholesale electricity market are eventually sustainable. And although no single strategy works for every customer—as each customers' needs, utility rate and electricity demand differ—the project team is confident that it has charted a clear pathway for behind-the-meter DER to prepare, bid and settle as a PDR in the CAISO wholesale electricity market.

Portfolio 2 was unable to register and participate in the CAISO market due to customer engagement challenges that were in part related to the procedural complexity involved in the initial market registration procedures. The hotel's facilities energy manager had been mired in a set of circumstances that seem to represent the most common circumstance for professionals in his role—he had too many other competing priorities taking up his time and attention, including commissioning a new hotel facility and attending to several other equipment and operational emergencies across the scores of hotel sites under his management. He simply did not have the available bandwidth to process the full scope of the project and complete the critical steps on his part, e.g., signing customer utility data release authorization and demand response provider agreement forms needed in order to prepare the two hotel facilities for wholesale market participation. In response to hitting this project implementation barrier, the project team instead modeled the two hotel facilities' demand response potential based on Conectric's IoT energy data and analytics collected through facility diagnostics screening. The project team found that relatively simple and non-operationally intrusive strategies such as precooling chiller water and building envelope at both hotel facilities several hours in advance of a potential market demand-spiking heat wave could yield a compelling financial benefit approaching tens of thousands of dollars in electric utility bill savings. In addition, the project team found that the two hotel facilities qualified for and could yield significantly more electric utility bill savings by enrolling and actively participating in the Capacity Bidding Program (CBP) offered through their IOU, San Diego Gas & Electric (SDG&E).

Portfolio 1 tested the various CAISO market products it enrolled in as a PDR, specifically the day-ahead and real-time energy markets and ancillary services as spinning reserves. It also successfully used the MGO baseline settlement method to determine load reduction performance during market participation events. Though several market policy barriers were identified by the project team, the biggest initial takeaway from Portfolio 1 wholesale market participation was the PDR "no export rule" that does not allow counting grid exports from behind-the-meter DER. The project team suggests a relatively easy to implement partial fix to this barrier by allowing behind-the-meter DER to count grid exports participating as ancillary services such as spinning reserves. Additionally, while this project successfully evaluated resource responsiveness to price signals through real-time market operations, it was not able simulate transactive price signals. This project was not able to simulate transactive price signals due to unforeseen CAISO pre-market integration challenges. These challenges ultimately delayed the project to the point that the project team did not have enough time to conduct the simulations before the project deadline.

Portfolio 1 Day Ahead and Real-Time Energy Market Results

Between September 2019 and February 2020, Portfolio 1 was awarded a total of eight Day-Ahead energy market awards, with each award sized at 500 kWh for one complete hour. Throughout the market operation period, Tesla directly entered and submitted bids to the CAISO day-ahead market. Olivine analyzed the post-market event data and compared the potential financial impact of utilizing MGO baseline versus the typical 10-in-10 baseline methodology. Table 3-2 below shows Tesla's market bids, market revenues and the potential market revenue differences between the whole premise meter 10-in-10 settlement baseline versus MGO.

Table 3-2
Baseline Performance Comparison of MGO to Whole Premise Meter 10-in-10

Event #	Target Performance (kWh)	10-in-10 Performance (kWh)	MGO Performance (kWh)	Market Revenue (10-in-10)	Market Revenue (MGO)
1	500	686.6	638.1	$24.79	$22.93
2	500	244.6	256.9	$16.81	$17.18
3	500	461.8	352.6	$13.73	$15.77
4	500	288.4	257.4	$7.61	$6.59
5	500	403.8	390.8	$17.95	$17.64
6	500	363.0	425.4	$13.32	$15.26
7	500	161.7	264.0	$8.37	$11.24
8	500	359.5	467.0	$15.59	$19.08
Total	**3,750**	**2,969.3**	**3,062.2**	**$118.16**	**$125.69**

Portfolio 1 was also awarded four Real-Time energy market awards between March and April 2020. For Real-Time energy market participation, the resource dispatch instructions were sent in five-minute intervals and each event ended up lasting for a full hour.

A summary of results of Real-Time energy market awards is displayed in Table 3-3 below. Results are shown as the average hourly curtailment compared to baseline load (or generation for MGO) did not consistently bid the aggregation into the wholesale market at a determined strike price, so market results are not necessarily indicative of revenue potential outside of this pilot.

Table 3-3
Real-Time Energy Market Event Performance Summary

Event #	Event Duration (Hours)	Target Performance (kWh)	Average Whole Premises Performance (kWh)	Average MGO Performance (kWh)	Market Revenue (Using Whole Premises) ($)	Market Revenue (Using MGO) ($)
1	1	200	408.0	365.9	$13.65	$12.44
2	1	400	556.0	535.3	$15.92	$15.43
3	1	400	207.1	345.3	$6.18	$9.32
4	1	400	412.2	519.1	$13.82	$16.24
Total	**12**	**5400**	**4552.7**	**4817.8**	**$167.74**	**$179.12**

Overall, the usage of MGO resulted in about a 6% increase in overall measured performance and a 7% increase in market revenues. The difference in measured performance varied from a 24% decrease to 67% increase for MGO versus whole premises measurement. While MGO performance was higher on average, there is not sufficient data to conclude that MGO is a more lucrative baseline methodology.

Spinning Reserves Market Participation

Portfolio 1 was ultimately cleared for real-time energy market participation and Spinning Reserves participation on March 27th, 2020 and bidding began on April 2nd. However, despite offering very low bid prices, none of the initial market bids for Spinning Reserves in April cleared the market. Olivine reached out CAISO to assess the issue. CAISO informed Olivine that a Day-Ahead energy market bid needs to accompany the bid for Spinning Reserves in order for the market optimization to accept the bid. Thus, seven days of bids for Spinning Reserves cleared in May 2020 in the Day-Ahead Market for two hours each.

CAISO calculates Spinning Reserves settlements after assessing both resource availability and dispatch performance. Full settlement data will not be available until August 2020 in CAISO's 55 business day post-market settlement run. Table 3-4 summarizes the award information, initial capacity payment data and availability summary during the award intervals.

Table 3-4
Spinning Reserves Market Awards Summary

Event	Duration (Hours)	DA Award Quantity (MW)	Real-Time Market Award Quantity (MW)	Meter-Before Load (kW)	Average Award Hour Load (kW)	Award Hour Availability	Capacity Payment ($)	Average Price ($/MWh)
1	2	0.3	0	330	556	100%	$6.50	$10.83
2	2	0.3	0	399	553	100%	$5.40	$9.00
3	2	0.3	0	279	538	100%	$5.40	$9.00
4	1	0.5	0	584	579	100%	$6.44	$6.44
5	2	0.3	0	294	535	100%	$5.59	$9.32
6	2	0.3	0.1 (1 hour)	218	518	99%	$6.33	$9.04
7	2	0.3	0	244	523	100%	$5.50	$9.17

Portfolio 1 had to make lower quantity (capacity) bids in the Spinning Reserves market results due to lower school campus' loads starting in March through the end of May. This was driven by a combination of high solar output, low air conditioning loads, and the impact of COVID-19 Shelter-In-Place orders that canceled in-person schooling beginning in mid-March until the end of the project in May. Before COVID-19, the typical aggregated building loads across the entire Portfolio was generally greater than the 300kW available for the 7 PM to 9 PM period that was set aside for the Spinning Reserve bids in April-May.

For the sixth event day, a real-time bid was submitted for 0.4 MW for Energy, with no accompanying Spinning Reserves capacity bid, but CAISO's bid insertion rules for Spinning Reserves resulted in a $0 Spinning Reserves bid getting picked up in real-time for 0.1 MW. This implies that if portfolio managers can properly forecast customer load, they could bid forecasted availability, up to the certified capacity, without risk of an infeasible award quantity. It is also possible that the aggregation could have been certified for a greater capacity than 500 kW, further increasing revenue potential for some hours under normal school operations.

Throughout the entire operational period of this project beginning in September 2019 through May 2020, CAISO only called upon Spinning Reserves resources for two intervals[8] – both instances were before Portfolio 1 had begun bidding into the Spinning Reserves market. CAISO did not conduct any test dispatches for Portfolio 1 after initial certification.[9]

Frequency Regulation Simulation

Because CAISO does not allow PDRs to provide frequency regulation, all regulation tests were performed via a simulated market environment set up by Olivine. Olivine generated simulated 4-second Automated Generation Control (AGC) signals based on historical CAISO Area Control Error

[8] The two periods that CAISO actually called up Spinning Reserves over the past 12 months were 11/21/2019 between 7:20 and 7:50 AM, and 2/3/2020 between 6:39 and 7:05 AM.

[9] Based on information from CAISO's operating messages published in its Open Access Same Time Information System (OASIS)

data, i.e., historical frequency regulation market data. This signal is meant to approximately replicate what a market resource may see if selected for frequency regulation.

After initial connectivity confirmation, the aggregation was tested for frequency regulation in the simulated environment on two days in April from 7-9 PM. The batteries were only tested for regulation within their discharge range. Olivine's simulation environment ensures that batteries are kept within an acceptable state-of-charge range and there is no net export across the grid.

CAISO requires a minimum of 25% accuracy for market resources to remain certified for frequency regulation. Accuracy is calculated based on the average adherence to the 4-second AGC signal for each 15-minute interval. Olivine calculated accuracy values consistent with CAISO methodology in order to assess performance.

Simulation results demonstrated accuracy between 70% and 90% with an average rating of around 80% over two simulation periods that spanned nearly four hours in total. Accuracy percentages were calculated based on the total deviation from four-second control signals in each 15-minute interval. This result compares favorably to Regulation Up accuracy reported by CAISO for existing resources. According to a 2018 report, the Regulation Up accuracy was 61% for front-of-the-meter battery storage resources and as low as 40% for steam turbines.6 Participation of front-of-the-meter batteries has increased significantly since. However, while the simulated results for Portfolio 1 do show sufficient performance to meet minimum CAISO standards, this was under simulated conditions for a limited period of time when the batteries were fully available to perform Regulation Up. Figure 3-3 shows the four-second battery telemetry compared to the simulated regulation for one of the test periods. Tesla did not wish to test frequency regulation on the charging side (i.e., Regulation Down) from modulated charging.

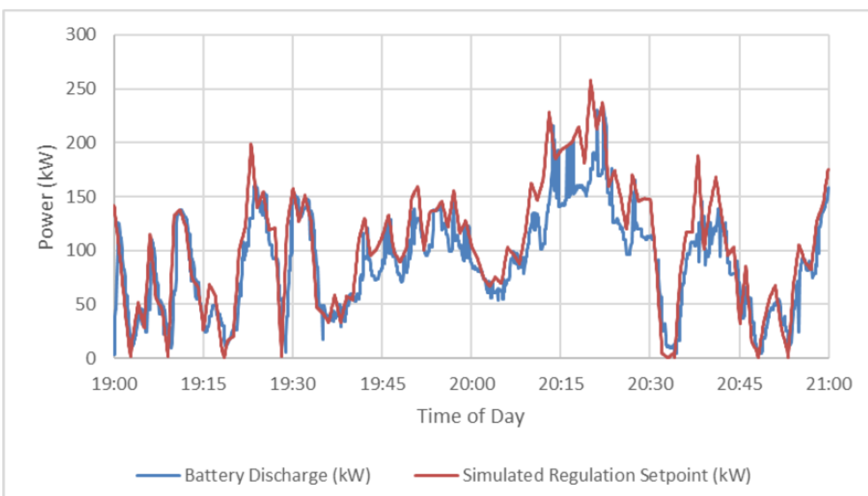

Figure 3-3
Frequency Regulation Simulation Results

Aside from the current restriction prohibiting frequency regulation market participation for PDR in CAISO, these results show that behind the meter batteries are capable of providing frequency regulation services in the wholesale electricity market.

In summary, Portfolio 1 demonstrated real-world operational capabilities of behind-the-meter batteries to participate in wholesale energy and ancillary services markets. Olivine worked with Tesla to aggregate five schools with behind-the-meter installed batteries in California ISO wholesale markets, including certification for Spinning Reserves. Because the market participation events occurred during relatively mild weather (spring) conditions, further analysis is warranted that would span a longer time horizon to observe the changes in resource potential during a variety of different weather conditions and different customer usage scenarios.

Project Innovations

While DERs have participated in the CAISO market since 2014, the STEEL project is innovative in several different areas. Specifically, the DER portfolios were participating directly in CAISO markets while bypassing traditional utility demand response programs, the portfolios are leveraging the meter generator output (MGO) baseline methodology, and Portfolio 1 is providing different types of ancillary services. These are described in greater detail below.

Direct CAISO participation of behind the meter resources

The STEEL project portfolios participate directly in the CAISO energy and ancillary services markets without going through a utility supply-side demand response or pilot program, such as the Supply-Side Pilot or Demand Response Auction Mechanism. To date, most DER portfolios have participated in the market through utility programs rather than directly into the market. These programs typically call the events or define parameters on how/when resources can participate in the market. Participating directly into the CAISO markets gives the resources more flexibility to bid into the markets when desired according to onsite needs and conditions.

However, participating directly into the CAISO markets does not provide a capacity payment, as many utility supply-side demand response programs and pilots do, so the flexibility of direct market participation must be weighed with potential economic loss of not receiving a capacity payment.

Meter Generator Output

The MGO methodology calculates demand response performance by relying on a sub-meter that directly measures the contribution (energy delivered) by the registered generation device (i.e. batteries storage systems) located behind the whole-premises revenue meter. The CAISO tariff currently allows only batteries to use the MGO methodology. MGO was approved by the CAISO Board of Governors in February 2016 as part of the Energy Storage and Distributed Energy Resources (ESDER) Phase 1 Initiative and was subsequently incorporated into the CAISO tariff in November 2016. However, since then the MGO method has not been widely used by industry as utility demand response programs use whole premises meter baselines rather than MGO. Thus, this project provides an opportunity to demonstrate MGO and share lessons learned.

Portfolio 1 leveraged the MGO method by directly submetering the batteries at each site and comparing market results to the whole premises meter method. Portfolio 2 is also directly metering controllable loads, but the CAISO does not allow these types of DERs to use the MGO methodology. Thus, Portfolio 2 uses the whole premises 10-in-10 baseline methodology and can compare load reduction estimations to actual measured load reduction from the loads.

Ancillary Services

Portfolio 1 participated in the ancillary services market by providing spinning reserves. Most DERs have typically provided energy in either the day-ahead or real-time energy markets but have not provided ancillary services. This project seeks to test DERs' ability to provide spinning reserves and potentially spinning reserves coupled with MGO.

Benefits to California

The project delivered an improved understanding of the benefits of and barriers to expanding DR participation in California. Specific benefits include:

- Increased understanding of options and best practices for supply-side DR to integrate and operate in CAISO wholesale markets. The improved understanding can potentially lower technical, institutional and regulatory barriers for wholesale integration.
- Increased understanding of the economics for supply-side DR to participate in CAISO markets with the benefit of developing strategies that maximize value to customers and the grid.
- Facilitated development of new value streams for DERs that help these technologies become more cost-effective for customers.
- Increased understanding of options and best practices for behind-the-meter storage to participate in the wholesale market. The improved understanding can serve to lower technical, institutional and regulatory barriers for wholesale integration.
- Increased understanding of the avoided costs and benefits of large-scale supply-side DR deployment. This may influence policymakers, regulators and CAISO to effectively leverage the benefits of DR to plan for the grid and design wholesale market rules.
- Increased understanding of the effects of large-scale behind-the-meter storage deployment, which may influence policymakers and regulators on grid planning and policy setting.

Informing Clean Energy Policy

The project team applied extensive policy research to better understand existing market and policy barriers and proposed workable solutions with the goal of expanding behind the meter DER participation in the wholesale market. Figure 3-4 illustrates areas where the project provided valuable research and input into several ongoing proceedings and working groups at the following regulatory agencies and market operations institutions:

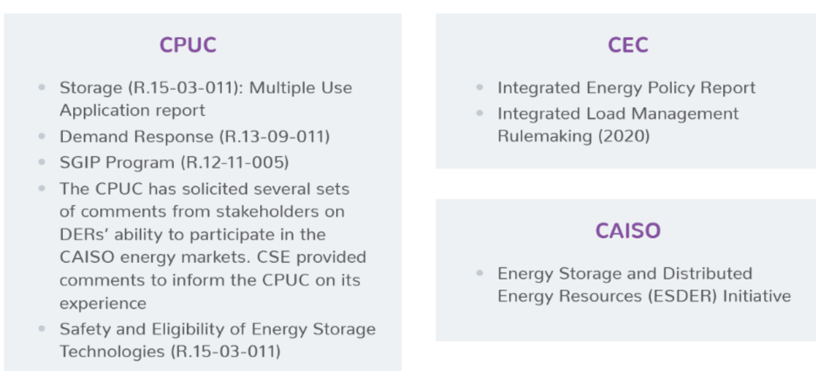

Figure 3-4
Areas where project provided valuable research

EPC-15-083 – OhmConnect: Empowering Prosumers to Access Wholesale Energy Products (Gillan, 2018).

As California transforms from a centralized, unidirectional grid to a localized, distributed grid, the State's policy objectives of affordability, decarbonization, and reliability have created a need to expand DR resources and to include them in California's wholesale energy markets. But the market for third-party DR is constrained, severely limiting non-utility resources from contributing to the grid. Even though a bi-directional grid is now technically possible, neither prosumers (customers who can both draw from and contribute energy to the grid) or their devices can be integrated into the energy markets.

OhmConnect, Inc. (OC) is a third-party Demand Response (DR) provider in California awarded EPC Project 15-083 in collaboration with the team from the Energy Institute at Haas and Claire Tomlin's lab in the Electrical Engineering and Computer Science department at University of California Berkeley. OC offers a DR product to residential consumers where they can get paid for reducing their electricity consumption during DR events called #OhmHours. The events can be originated by OC for internal reasons or from a scheduling coordinator dispatching OC if it is awarded a bid in the Proxy Demand Resource market or from the Demand Response Auction Mechanism designed to procure DR capacity.

OC's product has two features that made studying it unique from previous residential DR studies. First, it calls events more frequently and with shorter notice than the day-ahead studies of the past, which focused on critical peak pricing during a limited number of summer events. Second, OC offers a unique automation technology that shuts off appliances that households have chosen to connect to OC's platform during DR events. While direct load control is not a new concept in DR more broadly, there has been little work studying an automation technology with these features within the residential setting. Further, while OC calls #OhmHours with day-ahead notice outside of the experiment, OC restricted the DR events to occur with hour-ahead notice.

The project ran from November 15, 2016 to June 1, 2018 with the primary period of analysis falling between January 1, 2017 and December 31, 2017. The period of November 15, 2016 to December 31, 2016 consisted of a pilot period and the period from January 1, 2018 to June 1, 2018 consisted of an unplanned continuation of two of the experimental phases.

Goals and Objectives

The goal of EPC Project 15-083 was to transform and leverage this need for integrated DR by directly empowering residential customers to participate in and benefit from the wholesale market utilizing a new generation of DR products. The project contains three elements to provide data for policymakers and businesses to explore this market:

1. Determines prosumer (product/consumer) interest in a 3rd party DR market by testing user acquisition via direct and non-direct engagement strategies.

2. Experiments with behavior and automated users to analyze a variety of conditions and extract a set of shadow curves that inform how much energy load shifting can be expected under various price incentives.

3. Creates a novel solution for using residential telemetry to connect prosumers and their Internet of Things (IoT) devices to the market operators.

This project provides critical evidence that residential customers are willing to manage their electrical loads for the purpose of meeting grid needs when presented with meaningful, actionable information and salient incentives.

Methodology and Approach

There were three phases which defined the experimental regime a customer experienced based on the number of days that had passed since they enrolled. Phase 1 consisted of the first 90 days for all users. Phase 2 consisted of days 91-180 for users that were not assigned to the control group. Phase 3 consisted of days 181-270 for users that experience Phase 2.

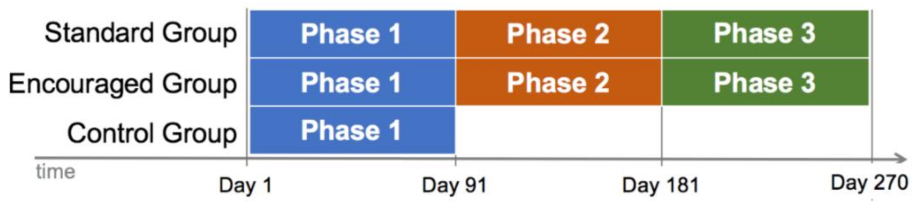

Figure 3-5
Phases of Project

Phase 1 had several dimensions for randomization designed to understand the effect of varying incentive levels and automation on DR responses. First, users were assigned to three groups that varied along two treatment dimensions as shown in Figure 3-5. The dimensions were:

- Pricing Events: Users received an average of 25 Demand Response (DR) events

  over 90 days communicated via email and SMS. Each incentive level for a particular DR event was selected at random with equal 20% probability from the set of all possible reward levels {5, 25, 50, 100, 300} points/kWh.

- Automation Rebate: Users were offered a rebate of up to $240 for purchasing a smart home automation device, which is paid out to the user upon successful connection of the device to their utility account.

Users were assigned to three treatment groups upon enrolling with OC. With 40% Probability Users were assigned to “Standard Enrolled,” the standard OC experience where they received Pricing Events and had the option to connect their Smart Home devices to OC’s automation service. With 40% Probability Users were also assigned to receive the Automation Rebate “Enrolled + Encouraged”. With 20% Probability Users were assigned to a recruit and delay “Control” group that did not receive either treatment arm, but instead received an email telling them they would not receive any events for about 90 days and offering them a $10 reward for remaining enrolled over the period. (Check marks indicate households in that column received the treatment for that row and X marks denote they did not.)

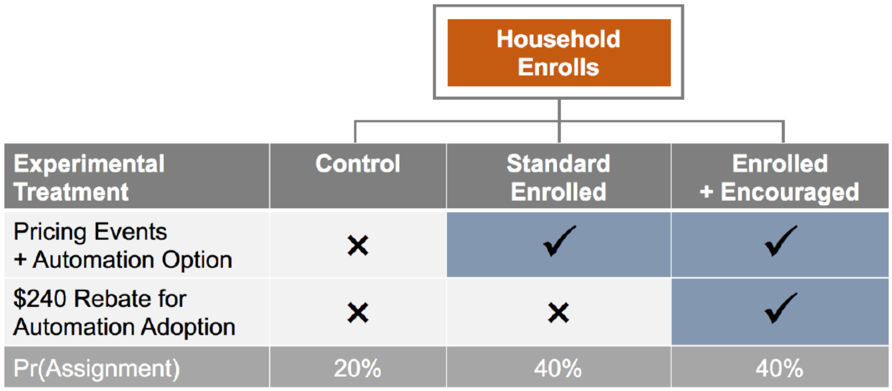

Figure 3-6
Phase 1 Experimental Design

The design allowed OC to address three key empirical questions:

1. What is the effect of DR events on electricity consumption for those enrolled versus those who were delayed?
2. What is the effect of varying incentive levels?
3. What is the effect of adopting automation on DR responses?

After 90 days, users in the Standard Enrolled and Enrolled + Encouraged groups were pooled and randomly assigned to two groups to understand how targeting users based on estimated responses could improve the efficiency of dispatch. Figure 3 shows the design where users are assigned after 90 days to a "Targeted" and a control "Non-Targeted" group. Targeted users were ranked by a machine learning individual treatment effect (ITE) estimator as most or least responsive and then sent either low or high incentives accordingly. Non-targeted users continued to receive all five incentive levels the same as they had been receiving during Phase 1. Figure 3-7 shows the tree-diagram for Phase 2's experimental design.

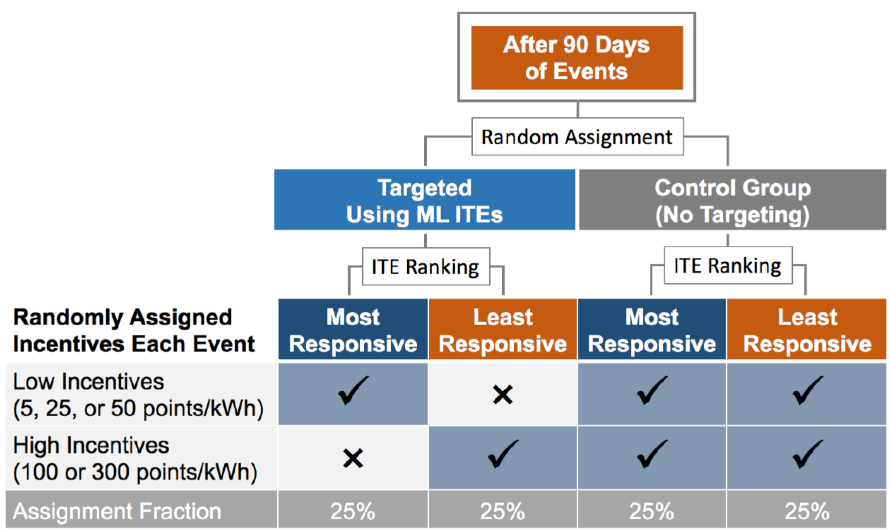

Figure 3-7
Phase 2 Experimental Design

Phase 3 was the final phase of the experiment and was meant to understand if moral suasion and environmental priming had a differential effect from financial incentives. After Phase 1 enrolled users had concluded Phase 2 and control users had completed Phase 1, they were pooled into an experience for 90 days where each event was randomized between four treatments with equal 25% probability as shown in the assignment diagram pictured in Figure 3-8.

Event Called

Experimental Treatment	Control	Price Only	Moral Suasion Only	Price + Moral Suasion
$1/kWh Incentive	✗	✓	✗	✓
Moral Suasion	✗	✗	✓	✓
Pr(Assignment)	25%	25%	25%	25%

Figure 3-8
Phase 3 Experimental Design

Lastly, all users that have reached 90 days of age in Phase 2 are then rolled into Phase 3 of the experiment, which is concerned with the effect of moral suasion on the reduction in electricity consumption during a DR event (see Section 5). Interventions in this group occur on an event-by-event level, that is, for a particular event, each user has the same likelihood of experiencing one of the following four treatments:

- Control: Users did not receive a DR event.
- Price Only: Users received a DR event with a 100 point/kWh reward level and the same language as in Phase 1 and 2.
- Moral Suasion Only: Users received an event with no financial reward but included the language such as "Environmental #OhmHour today from 6PM-7PM!
- Saving energy now could keep a dirty power plant turned off!"
- Price + Moral Suasion: Users received an event that had environmental priming language and a 100 point/kWh financial incentive.

Upon completing Phase 3, users were given the opportunity to complete a survey to reflect on their experiences and preferences formed during the experiment. These users are offered a monetary incentive for successfully completing the survey.

Participant Statistics

The pilot period recruitment ran from 11/14/2016 to 12/31/16 and the study period recruitment from 1/1/2017 to 8/14/2017. Due to a technical implementation problem, the recruitment period was cut short two weeks and ended prior to the originally planned 9/1/2017. While this represents an unfortunate loss in data, it did not seriously affect the statistical power of the study.

Figure 3-9 illustrates the number of study participants that were recruited for the RCT broken out by time of enrollment. This is done separately for users assigned to the three different experimental groups of Phase 1 (Control, Encouraged, Non-Encouraged). Recruitment began on November 15, 2016 and ended on August 15, 2017. We observe lower enrollment figures from April 2017 – June 2016 with a noticeable peak towards the end of the recruitment period. As can be seen from the figure, the height of the red and green bars for a particular vertical slice appear to have approximately the same height, indicating that encouraged and non-encouraged users are balanced in size. In contrast, the blue bar is about half as large as the green or red bar, which is consistent with the 40/40/20 assignment of users into encouraged, non-encouraged, and control groups we elaborated on in Section 1 of this report.

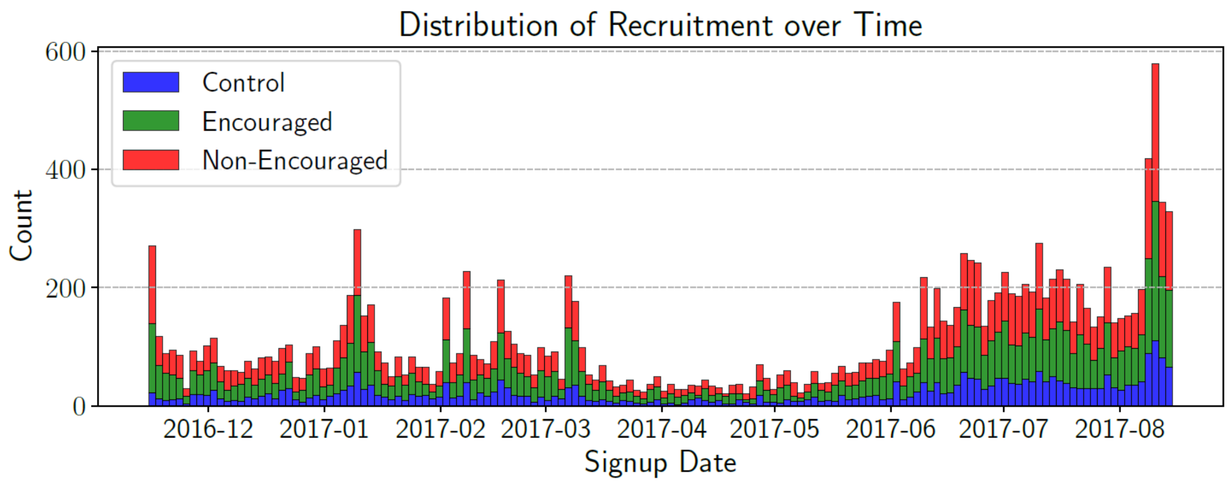

Figure 3-9
Recruitment of Participants Over Time

In a similar fashion, Figure 3-10 plots the number of users that were recruited into the study and successfully connected their electric utility accounts. About half of all recruited users connected their utility accounts. We were unable to use the recruited users who did not connect their utility accounts because we have no energy data for them. We observe that the shape of the boxplot looks similar to the one in Figure 3-8, suggesting that users across the three different experimental groups were equally likely to connect their electric utility accounts. The average number of recruits per day was 58 with a standard deviation of 48, a minimum of 5, and a maximum of 295.

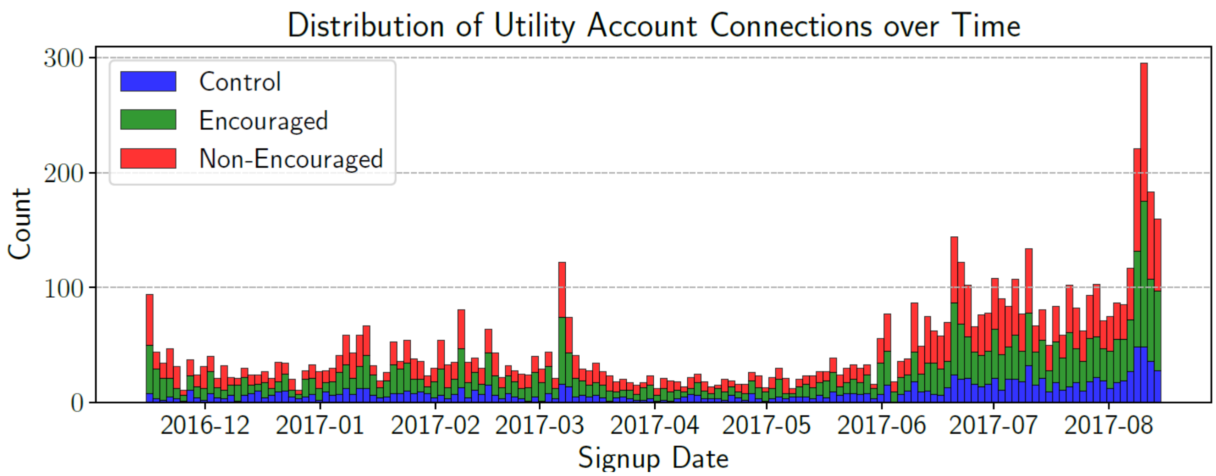

Figure 3-10
Distribution of Utility Account Connects over Time

The study sample consisted of users who connected their utility accounts and survived a data-cleaning process. Figure 3-11 below describes this process. Step 1 shows users were deemed recruited by creating an account with their email. After recruitment, users were randomly assigned to their Phase 1 experience assignment– designated Step 2. Note again, users were not notified of any assignment other than the Control group delay messaging. Step 3, users completed the enrollment process and connected their utility accounts. Step 4, the research team cleaned the data, removing users with insufficient pre-enrollment energy data or erroneous meter data.

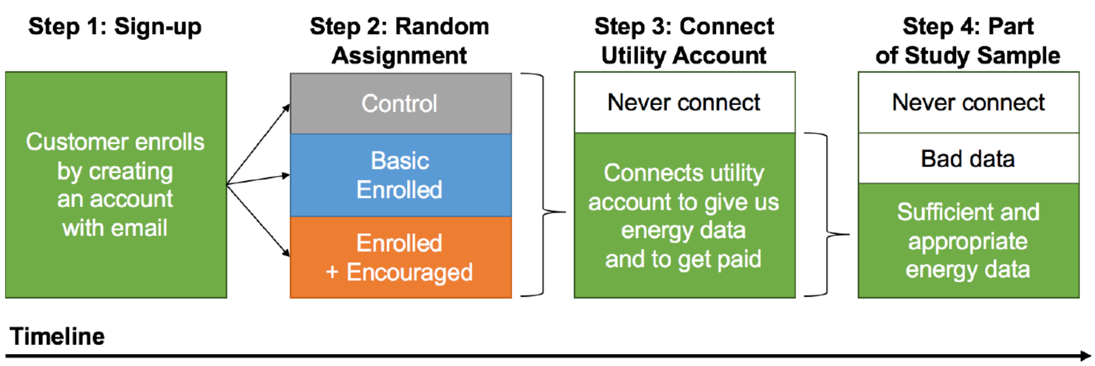

Figure 3-11
Sample construction process

Characteristics of Participants

Figure 3-12 illustrates the distribution of the lengths of available historical smart meter data among all users that have successfully connected their utility accounts. Users from Southern California Edison (SCE) have the shortest availability and those serviced by San Diego Gas & Electric (SDG&E) have the longest. We observe peaks at 365 days and 730 days, which correspond to 1 or 2 years of data availability. The black dashed lines reflect the median availability of historical smart meter data, which is 374 days for PG&E, 273 days for SCE, and 403 days for SDG&E.

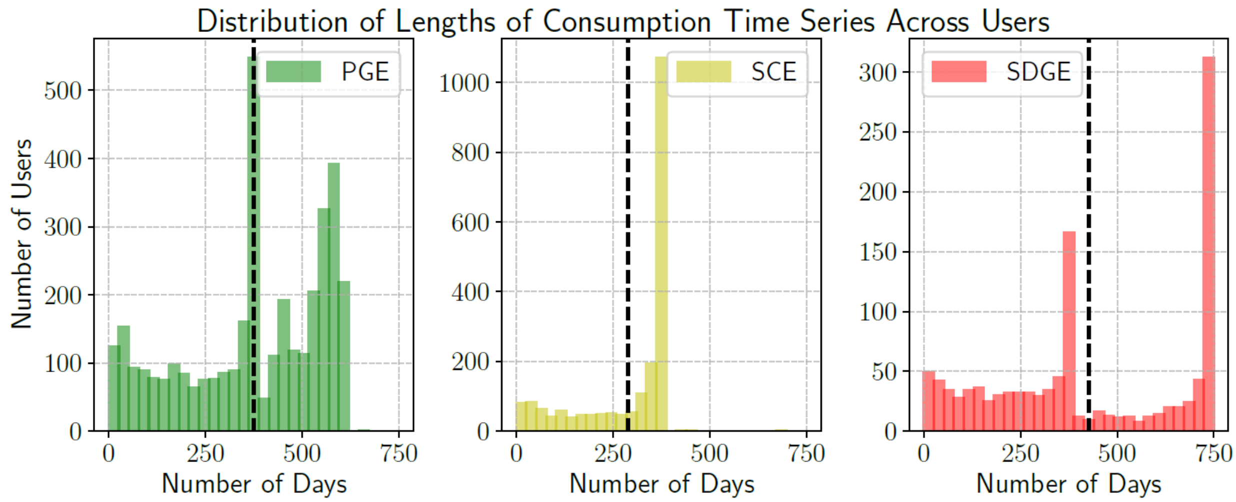

Figure 3-12
Availability of Smart Meter Data Across Experimental Users

Figure 3-13 provides a scatter plot of the geographic distribution of control, encouraged, and non-encouraged users broken out by electric utility. As expected, most users are concentrated in the urban areas of the San Francisco Bay Area, San Diego, and Los Angeles. It is visually striking that there appear to exist no structural differences in the distribution of users across either treatment group or electric utility, which is an intuition to be confirmed in the balance checks provided in Sections 3 and 4.

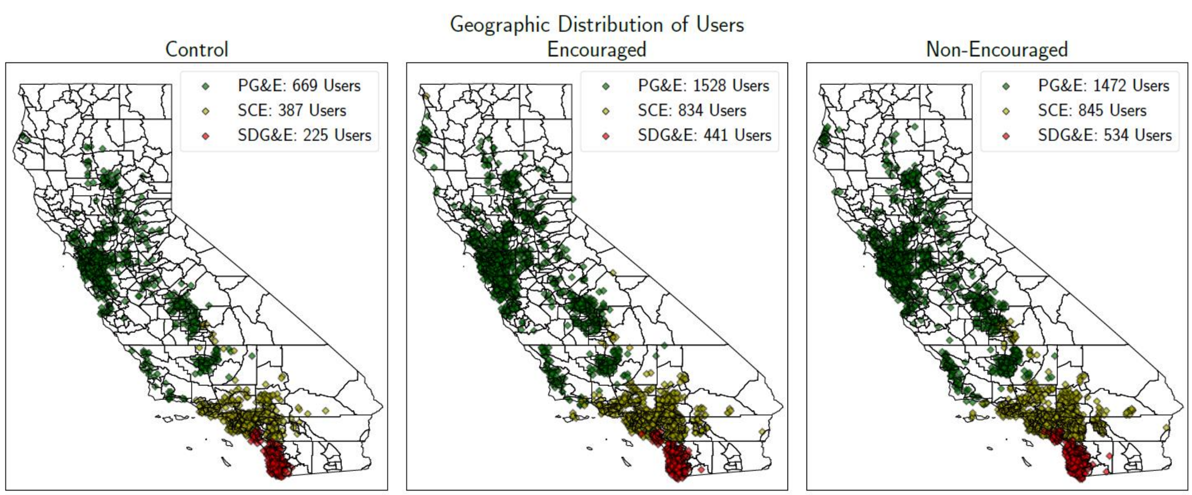

Figure 3-13
Geographic Distribution of Enrolled Users

Phase One – Monetary Incentives and Automation

Phase 1 investigated two primary questions: 1) How do participants respond to varying monetary incentives during DR events and 2) how does adopting automation affect those responses.

The main dimension of randomization in Phase 1 was the assignment to receive DR messages as compared with the 90-day delayed Control Group which received no messages. The control group received an email with the following message: “Due to overwhelming demand for our service, there will be a delay before we can send you #OhmHours. We estimate this delay will last approximately 3 months. In return for your patience, we'll issue you an extra $10 bonus when your account delay is over.”

Figure 3-14 shows sample event language for the Phase 1 DR events as experienced by Standard (also interchangeably referred to as Non-Encouraged) and Encouraged respondents. This language was consistent across all Phase 1 messages. The only difference was that during Phase 1 DR events, the incentive level was randomized between levels of 5, 25, 50, 100 and 300 points per kWh. The example figures show language for an event of 100 points per kWh. The point reward for each event was calculated as follows:

$$Reward = Incentive * (Forecast - Consumption)$$

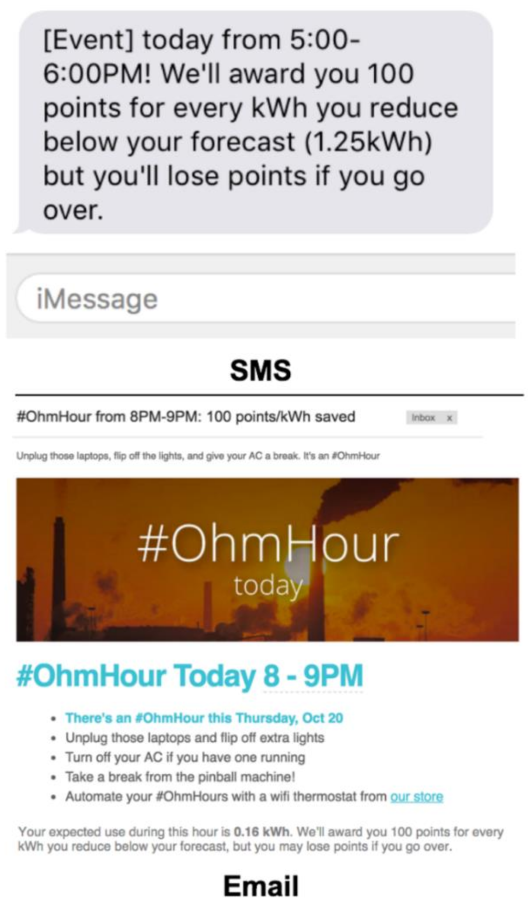

Figure 3-14
Sample SMS and Email language for Phase 1 DR Events

The other dimension of randomization during Phase 1 was assignment to an automation encouragement. In order to measure the causal effect of adopting an automation technology, the Encouraged households were offered a rebate for the full purchase price of a new smart home device up to $240 in value. Upon creating an account, these households were shown a pop-up notification on the web-portal in addition to being sent an email notifying them they had been selected to receive a rebate for purchasing a new smart device. The household was offered a choice between 3 smart thermostats ranging in retail prices from $198 to $240 or one package of two smart plugs with a retail price of $80. The households were told that they would have the purchase price equivalent of points added to their balance when they connected the device as to ensure rebates encouraged automation.

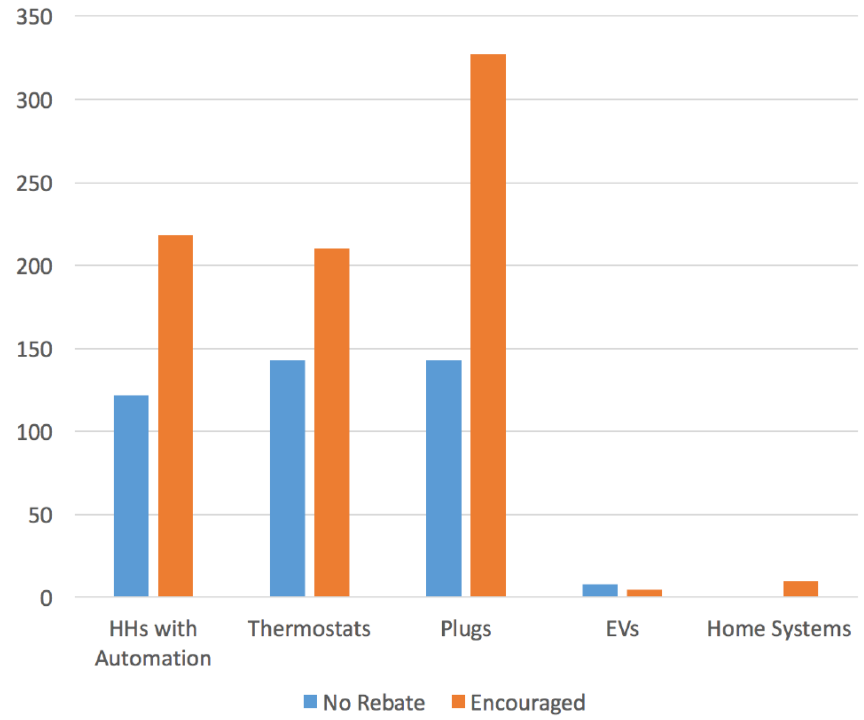

Figure 3-15
Effect of Rebate Encouragement on Automation Take-up

Table 3-5 summarizes the effect of the encouragement on automation take-up, reporting the number of devices in each of the Standard and Encouraged groups in Panel A. Panel B reports estimates of the instrument's "first stage", showing that the fraction of automation take-up increased a statistically significant amount of 4.5 percentage points (83 percent) over the baseline take-up of 5.3 percentage points.

Table 3-5
Summary of Encouragement Results

	Standard (S) (1)	Encouraged (E) (2)	Difference (E−S) (3)
Panel A: Automation Type and Counts			
Households	2,246	2,202	-
Households with at least one connected device	122	218	96
Total connected devices	295	554	259
Total connected thermostats (subsidized)	143	210	67
Total connected plugs (subsidized)	143	327	184
Total connected home systems (not subsidized)	0	10	10
Total connected electric vehicles (not subsidized)	8	5	-3
Panel B: Automation Take-up			
Households with any automation	0.053	0.097	0.045*** (0.008)
Take-up by consumption level:			
1^{st} quartile (0-0.34kWh)	0.022	0.103	0.080*** (0.015)
2^{nd} quartile (0.34-0.55kWh)	0.064	0.103	0.039** (0.016)
3^{rd} quartile (0.55-0.85kWh)	0.066	0.098	0.031* (0.016)
4^{th} quartile (0.85-6kWh)	0.060	0.091	0.031* (0.016)

Standard errors in parentheses
* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$

Table 3-6 illustrates the results for estimating the average effect of being enrolled in the program during an event hour and the effect of being called. The first two columns report results in terms of kWh and the third and fourth in terms of log which approximately represent percent changes. The results show statistically significant effects at the 99 percent level and estimates on the order of 0.12 kWh or 13 percent pooling across all incentive levels. The standard errors are clustered two-ways by household and hour-of sample. Because only around 10 percent of household opted-out the OLS and the IV estimates are similar with the OLS being closer to 0 due to the averaging across households that were not called during that event hour.

Table 3-6
Effect of DR Events

	kWh	kWh	log(kWh)	log(kWh)
Enrolled x DR Hour vs. Control (OLS)	-0.107*** (0.012)		-0.117*** (0.009)	
Called x DR Hour vs. Control (IV)		-0.120*** (0.014)		-0.132*** (0.010)
Enrolled x No DR vs. Control	-0.017 (0.006)	-0.017 (0.006)	-0.017 (0.006)	-0.017 (0.006)
Households	5,491	5,491	5,491	5,491
N (observations)	22,926,631	22,926,631	22,926,631	22,926,631

Phase Two – Targeting Household Incentives

Phase 2 investigated the question: Can the incentives sent during Phase 1 be modified and targeted to improve program cost efficiency? The targeting strategy studied was developed by UC Berkeley to reduce costs by identifying the largest responders and sending them lower incentives but does not reflect the optimal cost-reducing dispatch of individuals due to constraints in the experimental structure.

Phase 2 explored whether the incentives could be targeted based on Phase 1 responses in order to reduce the cost to the DR provider of calling events. We achieved this by estimating household-level responses using a ML model to predict each individual's counterfactual consumption during an event and then averaged the difference between these counterfactuals and observed consumption to come up with what we termed the Individual Treatment Effect (ITE). Each week as users reached 90 days, we would estimate each eligible household's ITE and then rank them within the cohort to be transitioned. Phase 2 lasted for a duration of 90 days for households assigned to the Standard or Encouraged groups initially. On day 181 households were transitioned out of Phase 2.

Phase 2 Results

Table 3-7 shows the results of the targeting by comparing the averages between the two groups. We examined the reductions from baseline and the number of points paid out per event as outcomes. Each column represents a separate regression. Rows 1-3 report the difference in the groups which is the effect of targeting and rows 4-6 report the means in the non-targeted control group to facilitate interpretation. Rows 1 and 4 report the effect for both types of households and Rows 2-3 and 5-6 break out the effect by the Most and Least Responsive types.

Columns 1 and 2 of Table 3-7 show the effect of targeting on reductions from baseline. The results show reductions were on average 0.070 kWh smaller, but on the order of the effects found in Phase 1 and that the targeting strategy made these reductions smaller by 0.013 kWh. This represents a 19 percent reduction, although the difference is not statistically significant at 1 and 5 percent levels. We also see the most responsive types reduce around 0.102 kWh versus 0.035 kWh which also suggests that the ITE estimation replicates the reductions as measured by the baseline. Columns 3 and 4 of Table 4.5.1 show the effect of targeting on points paid per event. The results show on average all participants were paid 6.3 points per event in the control.

group and that the targeting strategy decreased this payout by 3.1 points, a reduction of 49 percent. Households designated as most responsive households were paid 8.7 points per event in the control group and targeting (offering only 5, 25, and 5 point per kWh incentives) reduced this payment by 6.3 points and lowered the payout by 72 percent. Conversely, the least responsive households are paid 3.8 points per event and targeting (offering only 100 or 300 point per kWh incentives) did not significantly change payouts.

Table 3-7
Effect of Targeting on kWh Reduced and Points Paid per Event

	Reduction from BL (kWh)	Reductions from BL (kWh)	Points per Event (1 pt = $0.01)	Points per Event (1 pt = $0.01)
Difference from Targeting Strategy	-0.013* (0.008)		-3.06*** (0.82)	
Difference for Most Responsive		-0.012 (0.013)		-6.30*** (1.07)
Difference for Least Responsive		-0.014*** (0.007)		0.41 (1.23)
Mean for Non-Targeted Group	0.070*** (0.011)		6.31*** (0.65)	
Mean for Most Responsive		0.102*** (0.010)		8.67*** (1.05)
Mean for Least Responsive		0.035*** (0.005)		3.76*** (0.72)
Households	2,725	2,725	2,725	2,725
N (observations)	73,165	73,165	73,165	73,165

The results in Table 3-7 suggest the cost of payouts can be dramatically reduced by sending lower incentives to those designated as most responsive with little effect on the reduction. Dividing the points paid by the kWh reduced gives a rough metric on the average cost of the events. These suggest the 85 points per kWh cost of the most responsive types can be reduced to 26 points per kWh. Further, the least responsive types have a cost of 107 points per kWh. While we do not verify that these payments are cashed out, they can be roughly translated to dollars as 1 point for $0.01.

Phase 3 – Incentives vs. Moral Suasion

Phase 3 explored how households respond to different event messaging. Specifically, the question: "Are responses to financial incentives different from responses to messages with moral suasion in the form of green/environmental messaging?"

Phase 3 occurred 180 days after enrollment for the Standard and Encouraged users and lasted for 90 days, after which the household was transitioned out of the experiment. The randomization for Phase 3 was by event so that each time a DR event occurred, households had a 25% probability of being in a control group that did not receive an event that hour or equal 25% probability of receiving one of three messages.

One of the messages was a 100 point per kWh message identical to the Phase 1 messaging – "Points Only". The other two included messaging that suggested there were potential environmental benefits to reducing electricity consumption. Specifically, there was a "Suasion Only" message that included the environmental messaging and no potential for a monetary reward in points and a "Price and Suasion" that included the messaging and a 100 point per kWh incentive level.

Phase 3 Results

Figures 3-16 and 3-17 summarize the results visually in kWh consumed and log(kWh), respectively. The leftmost estimates show the effect of suasion and no monetary incentives, the middle estimate is the effect of points only consistent with Phase 1 and the rightmost estimates are for the combination of points plus suasion. The black circles are estimated from the equation described in 5.2 and the blue X's and orange triangles break that effect out by automated and non-automated households. All estimates can be interpreted as causal for the sample cut described, but comparisons between automated and non-automated cannot be causally interpreted.

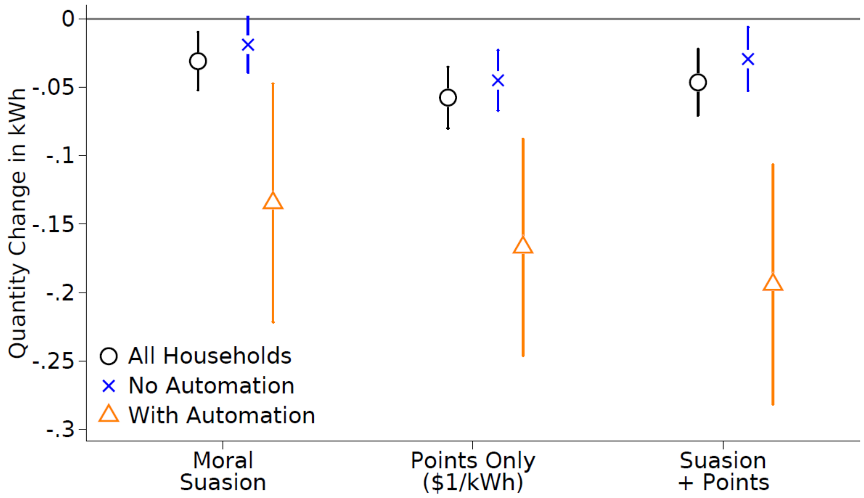

Figure 3-16
Effect of Moral Suasion Versus Points in kWh

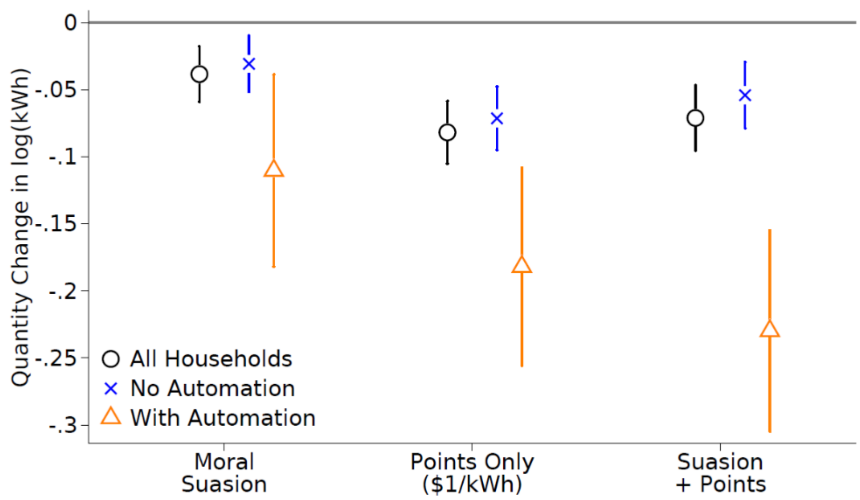

Figure 3-17
Effect of Moral Suasion Versus Points in log(kWh) (approximately percent)

The results show that moral suasion has a smaller impact on consumption than the messages with the monetary incentives and this is driven in large part by the nonautomated households that are making active decisions. Table 3-8 reports the estimates for Figures 3-15 and 3-16 along with the p-values on statistical tests that the coefficients are the same. The first row Moral = Points tests that the MoralOnly coefficient is equal to the PointsOnly. In all models for the pooled estimates or the non-automated households, the Moral Suasion estimates are statistically significantly different at the 99 percent level. The results are generally consistent with the Moral and Combined as well. The test that Points is the same as Combined on the other hand is insignificant for the pooled estimates and less significant for the non-automated, although still borderline significant at the 90 and 95 percent significance levels.

Table 3-8

	kWh	kWh		log(kWh)	log(kWh)	
Moral Suasion Only	-0.031*** (0.011)			-0.038*** (0.011)		
Moral Suasion Only x No Automation		-0.132*** (0.011)			-0.030*** (0.037)	
Moral Suasion Only x Automation		-0.117*** (0.011)			-0.110*** (0.011)	
Points Only ($1/kWh)	-0.058*** (0.011)			-0.082*** (0.012)		
Points Only ($1/kWh) x No Automation		-0.147*** (0.012)			-0.071*** (0.012)	
Points Only ($1/kWh) x Automation		-0.124*** (0.009)			-0.182*** (0.038)	
Suasion & Points	-0.046*** (0.012)			-0.071*** (0.012)		
Suasion & Points x No Automation		-0.147*** (0.012)			-0.063*** (0.013)	
Both Suasion & Points x Automation		-0.124*** (0.009)			-0.230*** (0.038)	
p-values on null hypothesis:	Pooled	Auto-mated	No Auto	Pooled	Auto-mated	No Auto
Moral = Points	0.000	0.302	0.001	0.000	0.011	0.000
Moral = Both	0.043	0.054	0.201	0.000	0.000	0.010
Points = Both	0.104	0.343	0.055	0.158	0.073	0.038
Moral + Points = Both	0.001	0.029	0.008	0.000	0.152	0.000
Households	3,391	3,391		3,391	3,391	
N (observations)	6,836,711	6,836,711		6,836,711	6,836,711	

Effect of Moral Suasion vs. Monetary Incentives

Taken together, we suggest these estimates imply moral suasion yields smaller reductions and that there is something unique to the monetary incentives. Further, the fact that automated users respond to all messages could be evidence of a default effect in the automation technology.

Overall Results

Over 450,000 utility customers have signed up with OhmConnect, and about 35,000 of those participated in the experimental treatments conducted under the EPIC grant. About 15% of the enrolled customers live in Disadvantaged Communities. The recipient tested a number of different incentive structures--including a proxy-price "transactive" signal, including those provided by the customer's utility, the CAISO, and EPRI. Over the course of the project, the experimental subgroup saved 27.8 MWH over 1.3M #OhmHours (1-hr long participant events) for which they were paid a total of $668,000. Avoided CO2e emissions were estimated at about 122 metric tons over the course of this project.

Key findings that should be interesting to regulators, DRPs, and academic researchers include:

1. Households respond to hour-ahead DR events by reducing their consumption on the order of 12-14%. This shows the potential for very short notice DR events to generate load reduction.

2. Households appear to be insensitive to the variable pricing as studied here. This suggests without innovation to the messaging, there is little ability for varying incentive levels to marginally change household consumption. Future work should try to understand if conveying relative value or providing information on the dollar value of a kWh could change the insensitivity.

3. Heating and cooling load are the primary drivers for responses. This confirms the previous literature and the general motivation of many residential DR programs to get customers to reduce cooling load in the summer.

4. Offering rebates can increase take-up of automation technologies and this automation causes significantly larger responses to DR events. Future work should explore whether the generally low take-up rates were due to the rebate design studied here or if there are other costs to consumers when considering adoption.

5. Targeting events using an initial set of interventions can dramatically lower the cost of the program. Future work should understand the persistence of these types of targeting strategies.

6. Lastly, the social value of the DR events calculated here was small, but this number could change if DR events were targeted more effectively to high price hours. Future work should include more elements of the social value calculation and understand if targeting events is feasible.

Benefits to California

OhmConnect produced significant financial, environmental, grid, and community benefits from this project. Simply due to the nature of the OhmConnect platform, project participants earned money by responding to DR events as well as saved energy during times of peak demand, reducing stress on the grid and offsetting the need to ramp up natural gas peaker plants. Moreover, the design of the OhmConnect platform contributed to significant community engagement around DR and the associated environmental impacts. Most importantly, OhmConnect had strong penetration in California’s Disadvantaged Communities, a valuable area for future user growth and social impact for residential DR in the near future.

Specific benefits include:

- Lower costs: This project lowered costs by reducing peak demand on the State’s energy generation facilities and grid, thus avoiding the need for expensive peaker plants, and by increasing energy efficiency across IOU territories, thereby reducing electricity costs for project users.

- Greater reliability: By utilizing a DR software platform, this project created virtual power plants that did not run the typical the risk of failure associated with transmission and distribution lines and traditional generators. Moreover, as a residential DR aggregator, the technology developed in this project allowed residential participants to access energy markets and engage with the grid, providing value through individual load reduction and increased pool of accessible grid resources.

- Economic development: This project allowed OhmConnect to overcome existing barriers to facilitating residential aggregation of DR, which in turn enabled OhmConnect users to receive payments for participating in DR events. Over the course of this project, OhmConnect users earned over $544k for reducing a total aggregated 164 MWh during the times when the grid needed reductions the most.
- Environmental benefits: OhmConnect avoided 122 metric tons CO2e of greenhouse gas emissions over the course of this project.
- Consumer appeal: Platform upgrades, user acquisition strategies, and participation incentives were geared towards consumer appeal for a software-based approach to residential DR. Specifically, this project leveraged consumer appeal approaches to address needs within DR to increase user participation and reduction in DR events. Additionally, over 15 percent of project OhmConnect users were located in Disadvantaged Communities.

EPC-15-084 – BMW North America - Total Charge Management: Advanced Charge Management for Renewable Integration (Nibler, 2019).

Smart charging is a means of managing electric vehicle charging within a particular charging or parking event, usually at work during the day or at home during the night. The future electricity grid will face new balancing needs that change throughout the day and night as utilities and grid operators attempt to align renewable generation with customer load. As the grid becomes more dynamic, optimizing vehicle charging will require moving charging from night-to-day, from hour to hour, or from one grid location to another. Add to this California's steadily increasing electric vehicle population, outfitted with larger capacity batteries and influenced by mandates for more renewables across the State, the need for advanced strategies to manage vehicle charging is growing rapidly.

EPC Project 15-084 tested the benefits and opportunities of renewable integration using BMW's Total Charge Management system, where electric vehicle charging is managed across multiple charging events to maximize vehicle load flexibility. Figure 3-18 illustrates BMW's vision for electric vehicle integration enabling a more sustainable energy grid.

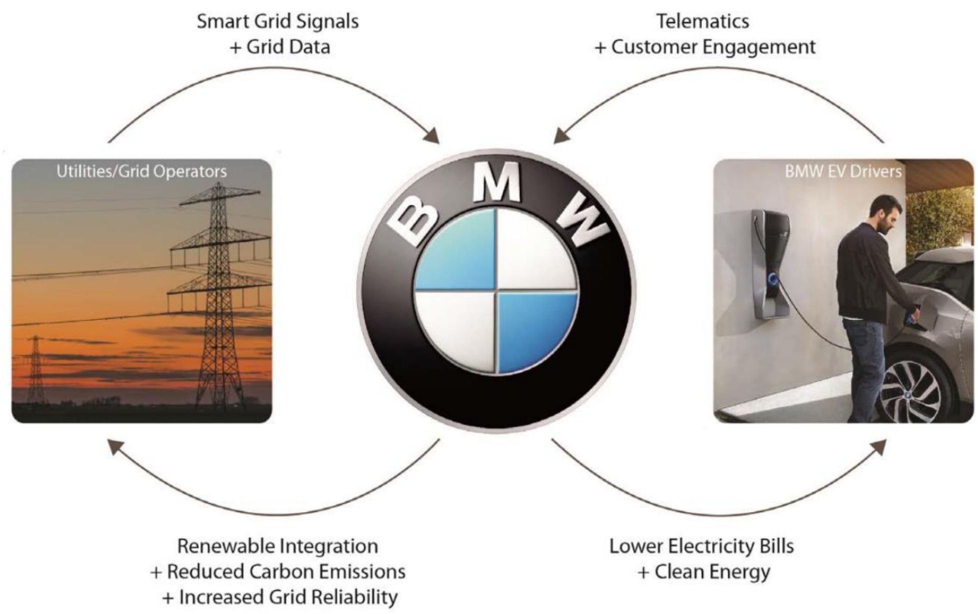

Figure 3-18
Electric vehicle-renewable-grid integration

The project tested strategies for managing flexible electric vehicle load across a driver's daily or weekly charge events. This flexibility utilizes several pricing mechanisms to estimate the benefits of the Total Charge Management approach.[10] The research developed and evaluated advanced vehicle telematics for utilities and grid operators to align vehicle battery status, driver mobility needs, and grid conditions. Collaboration between the grid and the driver can yield a charging load profile that minimizes energy costs by aligning daily and weekly charging events to best meet grid needs.

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[10] https://olivineinc.com/wp-content/uploads/2019/04/Olivine-EV-RE-Integration-Report-for-BMW.pdf

Partner Olivine, Inc. applied multiple use cases, including vehicle charging optimization, at home and away from home, and load increase demand response events with day-ahead dispatch. Several new functions of Olivine's vehicle-grid-integration optimization engine were also explored through these use cases, which were executed from October 15, 2018 to November 10, 2018, using Pacific Gas and Electric Company's excess supply data feed.

Goals and Objectives

Total Charge Management presents an opportunity to significantly increase the functionality of vehicle charging to meet grid reliability. New tools will be needed to incentivize drivers to modify their charging behavior to the dynamic needs of the electric utility 'duck curve' or load shape, where system demand is highest in the morning and evening hours, when solar generation is not available. The California Independent System Operator (CAISO) predicts that the growth in renewables will create new dynamics in the daily load curve. They anticipate the need to add load during the solar peak in the afternoon, use responsive load to follow nighttime wind power, and reduce load during the new peak load hours in the evening (5-9pm). Doing so will give utilities and the CAISO a new tool to help integrate intermittent renewables. The load shape that results from Total Charge Management can be designed to not only support renewables, but also optimized to address congestion on the local distribution system.

The functionality enabled by Total Charge Management allows vehicles to serve as a cost-effective alternative to other grid management resources. Controlled charging is likely much cheaper than stationary storage. Vehicle charging will require no capital investment on the part of ratepayers and, under Total Charge Management, could provide similar advanced functionality as stationary storage. The fact that vehicles move around on the grid is an additional attribute that allows utilities far greater flexibility than any non-mobile resource. As the knowledge gained from this project enters the market, there are likely to be cost savings associated with charge optimization that result in lower costs to end users, increasing the penetration of electric vehicles and furthering the state's environmental goals.

The objectives of EPC 15-084 were defined as follows:

- Measure the total megawatt of flexibility that can be enabled from Total Charge Management.
- Define the limitations to Total Charge Management as a factor of the total time of day and total load (kilowatt) that can be moved without interfering with a customer's mobility needs.
- Measure the cost savings to the utility from utilizing Total Charge Management to incorporate renewables into the grid.
- Measure the cost savings to the utility from utilizing Total Charge Management to minimize Locational Marginal Price (LMP) cost.
- Analyze the potential ways that Total Charge Management can be incorporated into utility programs, such as demand response, or investments, such as plug-in electric vehicle charging stations.

Methodology and Approach

The implementation of the vehicle-renewable integration use case builds upon previous work by the research team that enabled and assessed optimization of vehicle charging schedules using locational marginal price (LMP) and renewable (RE) supply mixture on the grid. BMW optimized their smart charging system using grid pricing and constraints tests for residential nighttime charging with 50 drivers, with the goal of guiding the expansion to away-from-home charging and daytime charging (locational marginal pricing and renewable generation). Kevala (subcontractor) developed and integrated a tool to identify the subLAP (sub-load aggregation point) and LMP node locations to facilitate vehicle charging management when vehicles are away from home.

The TCM process works as follows: when a vehicle owner plugs in and sets a target departure time for their vehicle, a request for an optimized charging schedule is triggered. That request is transmitted to Olivine DER, and in response, Olivine DER uses data from several sources to derive the optimal vehicle charging schedule. The optimal schedule takes into account the vehicle's charging location and applicable rate schedule, in order to maximize value to the grid without adversely affecting the cost of charging for the vehicle owner. The charging schedule is sent back to the vehicle from Olivine DER through the protocols defined with BMW and Sulzer, a partner on the EPIC BMW TCM project. Key variables used in the optimization include:

- Vehicle plug-in time.
- Vehicle target departure time.
- Vehicle remaining charge time.
- Applicable rate schedule, whether time-of-use (TOU) or flat rates; away-from-home charging defaults to a flat rate schedule.
- Vehicle location indicator to flag whether charging at home or away from home.
- Optimization type, of which LMP, RE, and Excess Supply are currently enabled.
- Hourly day-ahead forecasts, which differ for each optimization type.
- Any special optimization rules. In the case of excess supply optimizations, a tie-breaker was implemented using LMP to address situations in which the excess supply signal alone did not yield one optimal schedule (e.g., during periods when the probability of excess supply is zero or one for multiple consecutive hours). Also, the weekday hours from 3:00 PM to 9:00 PM were de-prioritized in the optimization to avoid increasing load during the evening ramp.

Optimization Participation

Of the 279 cars enrolled for TCM optimizations during this period, 172 vehicles (62%) opted in for at least one optimized charging session during the study period. The count of vehicles by vehicle type, categorized by all-electric models and plug-in hybrid electric models (PHEV), is shown in Table 3-9. Of the 279 active TCM participants during the study period, 224 are all electric vehicles and 55 are PHEVs. Optimization participation rates were similar across these two vehicle types (62% for electric compared to 60% for PHEV).

Table 3-9
Optimization Participation Rates by Vehicle Type

	Electric	(%)	PHEV	(%)	Total	(%)
Opt-In Vehicles	139	(62%)	33	(60%)	172	(62%)
Opt-Out Vehicles	85	(38%)	22	(40%)	107	(38%)
Active Vehicles	**224**	**(100%)**	**55**	**(100%)**	**279**	**(100%)**

For those 172 vehicles that opted in during the study period, the total number of optimized charging sessions was 1,631 over the study period, as shown in Table 3-10. An optimized charging session is triggered when a TCM participant plugs a vehicle in and sets a target departure time. Of the 1,631 optimized charging sessions, 75 percent were fulfilled by all-electric vehicles and 25 percent by PHEVs.

Table 3-10
Optimization Charge Sessions by Vehicle Type

Charge Location/Rate	Electric	(%)	PHEV	(%)	Total	(%)
At Home	742	(45%)	322	(20%)	1,064	(65%)
TOU rate	592	(36%)	170	(10%)	762	(47%)
Non-TOU rate	150	(9%)	152	(9%)	302	(19%)
Away from Home	488	(30%)	79	(5%)	567	(35%)
Total Optimized Charge Sessions	**1,230**	**(75%)**	**401**	**(25%)**	**1,631**	**(100%)**

The algorithm for optimized charging takes into account a vehicle's location and applicable electricity rate. If the vehicle is charging away-from-home, the optimization defaults to a non- TOU rate structure. Thus, this report presents results for three optimization categories:

1. At Home – TOU
2. At Home – Non-TOU
3. Away from Home

Table 3-10 above shows that 47 percent of optimized charging sessions occurred at home under a TOU rate, 19 percent at home under a non-TOU rate, and 35 percent away from home. Roughly two-thirds (65 percent) of the optimized charging sessions took place at home. Using a box and whisker chart and a cumulative distribution function, Figure 3-19 further explores the diverse number of optimized charging sessions for those vehicles that participated in excess supply optimizations during the study period. The electric vehicles had an average of nine optimized charging sessions with half of the vehicles having between four and twelve optimized charging sessions. The PHEV vehicles charged more frequently than the all-electric vehicles, with an average of twelve optimized charging sessions and with half of the vehicles having between four and seventeen optimized charging sessions. The box and whisker chart identifies some outliers, with a maximum of 42 optimized charging sessions from a single vehicle in the study period.

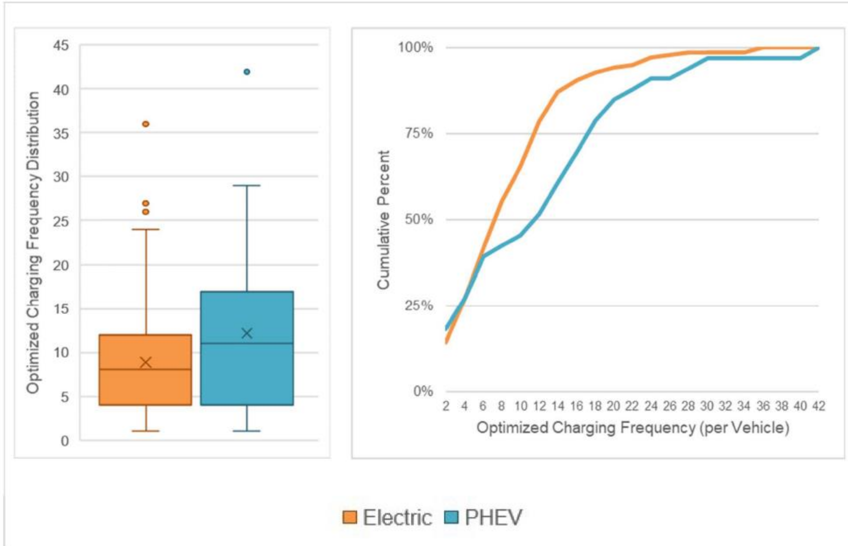


Figure 3-19
Distribution of Vehicle Optimization Requests by Vehicle Type

Figure 3-20 shows how the number of optimized charging sessions for the vehicles are distributed by charging location and rate. The frequency of optimized charging is similar for vehicles charging at home, whether on TOU or non-TOU rates. Both populations had an average of about eight optimized charging sessions, with over half of the vehicles at home having between three and twelve optimized charging sessions. In contrast, that number of away from home optimized charging sessions was lower, with an average of six, and with half of the vehicles having between two and eight optimized charging sessions.

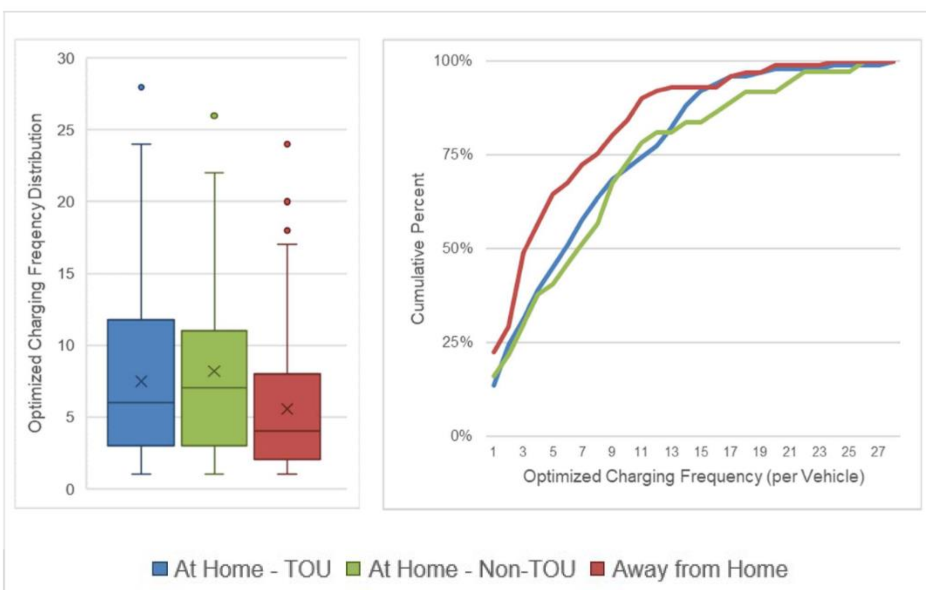


Figure 3-20
Distribution of Vehicle Optimization Requests by Charging Location and Rate

Figure 3-18 and Figure 3-19 show the distribution of plug-in time and target departure time, with Figure 3-20 showing the times for at-home charging and Figure 3-21 showing the times for away-from home charging. The plug-in times represent measured data, captured by Sulzer US when the vehicle plugs in, and sent to Olivine DER. The pattern for plug-in times aligns with expectations. For both home and away-from-home charging, people primarily plug in at home in the evening hours (6:00 PM peak) and they plug in away from home during the day (8:00 AM peak).

The target departure times represent user-provided inputs set through a phone application (app). Vehicle owners use their phone app to identify when they will need their vehicle to be fully charged; they can set these schedules in advance and they do not need to update the target time each time they plug in. To better understand charging behaviors, Figure 3-21 and Figure 3-22 also show the target times, divided into two groups: same-day target time (where plug-in date equals target date) and next-day target time (where target date is greater than plug-in date).

At-home charging behavior aligns with expectations: most vehicles are plugged in during the evening and target departures are primarily set for the next morning (7:00 AM peak). Away-from-home target departure times appear to be approximately evenly split between same-day and next-day target times. In fact, over half (58 percent) show target times for the next day (8:00 AM peak) and the next-day charging pattern resembles at-home charging. This suggests that when plugging in away from home, many vehicle drivers are not updating the default target departure time in their phone app to reflect expected departure times from the away-from-home charging station. It is possible that vehicle drivers are choosing to keep departure times for the next day knowing that they have enough range to meet their mobility needs until their next set departure time; however, further analysis is needed to confirm this hypothesis.

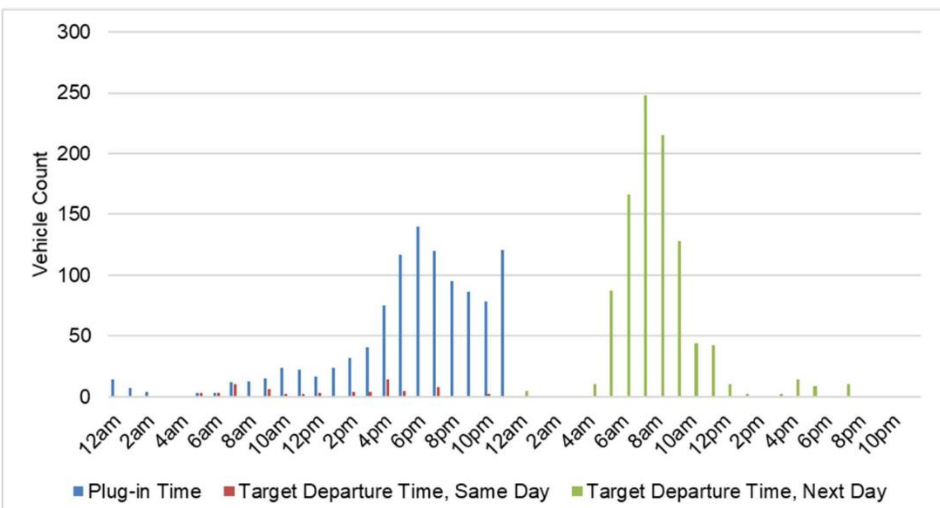


Figure 3-21
Distribution of Vehicle Plug-In and Target Times – At Home

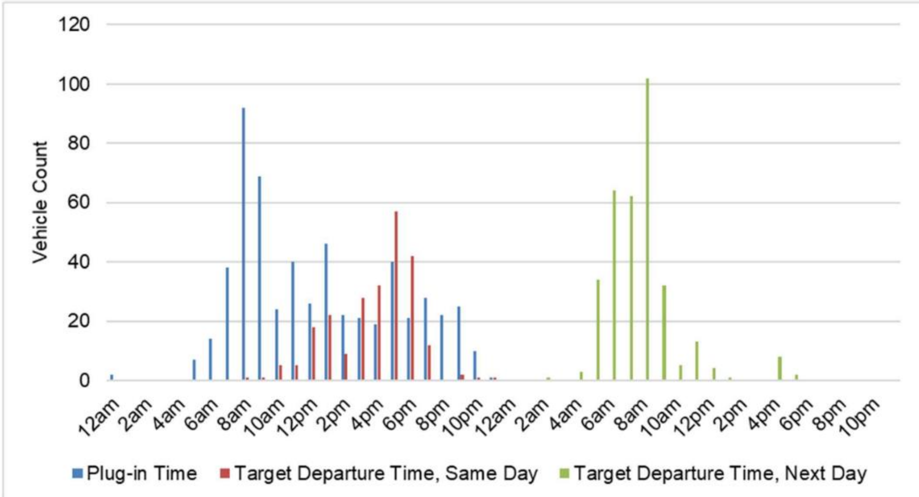


Figure 3-22
Distribution of Vehicle Plug-In and Target Times – Away from Home

Results of Optimization

Hourly charging profiles were derived to show the optimized vehicle charging patterns in response to the excess supply signal. To determine the impact of optimized charging, the research team compared the optimized charging schedule with a baseline charging schedule that was derived based on the assumption that, if not for requesting an optimization, the vehicles would have started charging immediately after plugging in. For baseline (nonoptimized) charging, the charging start time is assumed to be the plug-in time and the stop time is assumed to be the start time plus the remaining charge time.

Figure 3-23 contrasts optimized charging (green line) with baseline charging (blue line) for all vehicles that were optimized on 11/7/2018 and 11/8/2018. These days were chosen to illustrate how the excess supply optimization shifts daily charging patterns. Any two consecutive dates could have been selected to provide an illustration of how optimized charging shifts the charging from early evening hours into the late evening and early morning hours. The lines show the vehicle count by hour over the 48-hour period. The green line represents the actual aggregate charging pattern of the vehicle population, based on optimized charging schedules that were sent to individual vehicles. The blue line is a hypothetical aggregate baseline, illustrating what would have happened had the vehicles started charging immediately upon plugging in. In general, vehicle charging patterns in this chapter are presented as vehicle counts. Olivine DER does not have information on vehicle charging energy use. To translate vehicle counts into energy use, an estimate for average energy use per hour for vehicle charging could be applied.

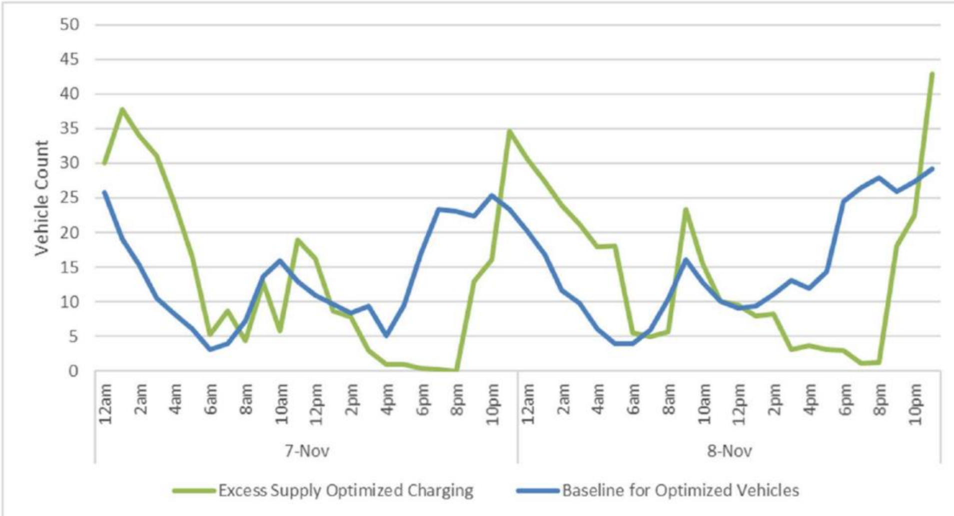


Figure 3-23
Optimized versus Non-Optimized Charging Patterns

In Figure 3-24, a stacked bar chart shows optimized charging, with the blue portion showing home charging on TOU rates, the green portion showing home charging on non-TOU rates, and the red portion showing away-from-home charging. The left axis shows the vehicle counts associated with optimized charging. Note that the stacked bar charts in Figure 3-24 correspond with the green line in Figure 3-23 depicting total optimized charging on these dates. In Figure 3-24, the optimized charging is overlaid with the excess supply probability curve (purple line with values displayed on the right axis). This figure shows how charging patterns are influenced by choosing excess supply for the optimization. Again, 11/7/2018 and 11/8/2018 were chosen to illustrate how the profiles differ on a day-by-day basis.

The data show that using excess supply for optimization is primarily influencing charging patterns from around 8:00 AM to around 2:00 PM and that vehicles are charging both away from and at home during this period. The presence of away-from-home charging in the middle of the night (i.e., the red portion of the bars from 11:00 PM to 5:00 AM) illustrate the challenge described earlier when vehicle drivers use default next-day target times for away-from-home charging. The analysis in this report was structured using data available from the Olivine DER VGI optimization engine, which relies upon vehicle plug-in times, target times, and remaining charge times to identify optimal charging schedules.

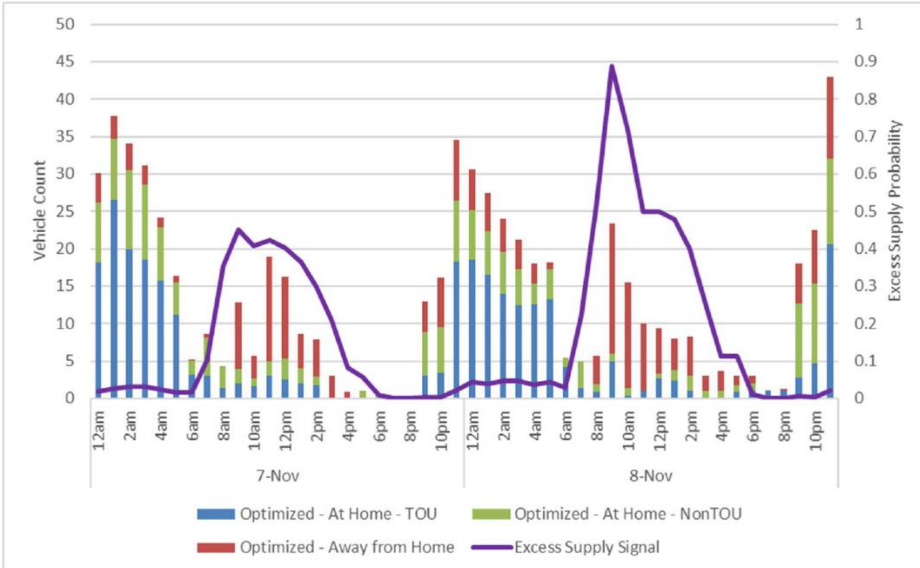


Figure 3-24
Charging Optimized for Excess Supply

The goal of the vehicle-renewable integration optimization is to shift vehicle charging from periods when the probability of renewable excess supply is low to periods when excess supply is high. The approach for calculating optimization impacts is to compare what would have happened had the vehicle started charging immediately upon plugging in (i.e., baseline) with the optimized charging schedule that was sent to the vehicle.

To quantify increased charging during periods of renewable excess supply, a weighted excess supply curve is derived by multiplying the vehicle count (per hour per day) and excess supply probability (per hour per day). This value is calculated for the baseline and optimized charging profiles to determine the percentage increase (or decrease) from optimized charging. The percentage change between the baseline and optimized weighted excess supply curves provides a consistent metric for how much charging was shifted from periods of low excess supply to periods of high excess supply.

$$Weighted\ Excess\ Supply\ (Baseline)_t = Excess\ Supply\ Signal_t \times \#\ vehicles\ (Baseline)_t\ , \qquad t = 1 - 24\ hours$$

$$Weighted\ Excess\ Supply\ (Optimized)_t = Excess\ Supply\ Signal_t \times \#\ vehicles\ (Optimized)_t\ , \qquad t = 1 - 24\ hours$$

As shown in Figure 3-25, the comparison of baseline to optimized charging using the excess supply signal resulted in a 16 percent increase for all vehicles optimized during the study period. This increase shows that the optimizations successfully shifted charging to periods when excess supply is high. The largest impacts are seen from 10:00 AM to 2:00 PM (i.e., where the red curve exceeds the purple curve) also shows a period from 3:00 PM to 6:00 PM during which benefits for optimized charging are lower than the baseline (i.e., where the purple curve exceeds the red curve). This is attributable to a rule implemented in the optimization logic to de-prioritize hours between 3:00 PM and 9:00 PM to avoid ramping hours. Because some relatively high renewable excess supply probabilities occur in the afternoon (as previously seen in Figure 3-24) this imposed optimization rule lowers the impact of using excess supply signal for optimization. Going forward, grid value could be increased by using a signal that combines grid constraints with probability of excess supply to capture all available value.

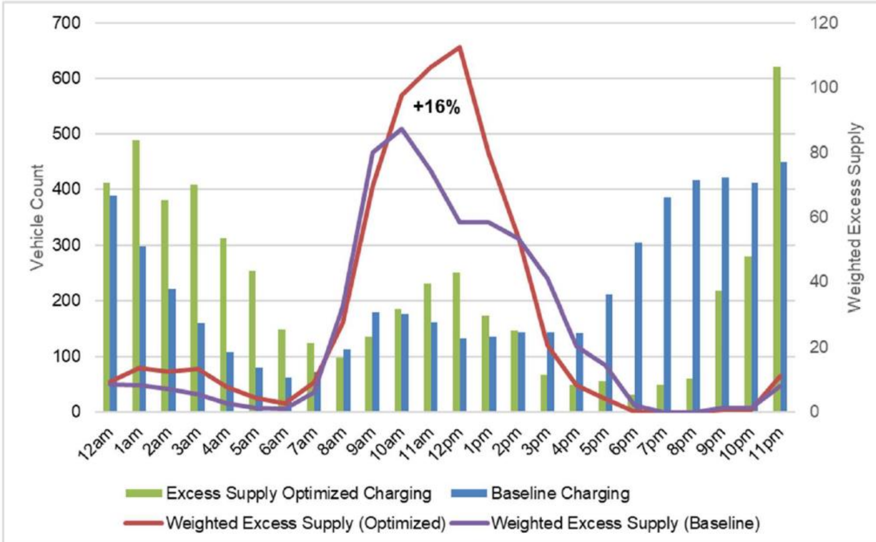


Figure 3-25
Benefit of Shifting Charging to Match Excess Supply

Table 3-10 summarizes the incremental relative benefits from the vehicle-renewable integration optimization use cases by charging location and rate type, whether TOU or other. As seen previously, the increase was 16 percent for all vehicle charging sessions over the study period. The values of incremental relative benefits range from a high of 48 percent for non-TOU participants charging at home, to a low of 6 percent for charging away from home.

Table 3-10
Use Case Benefits by Charging Location and Rate Type

	Increase (%)
At Home (All)	32%
At Home – TOU	19%
At Home - Non-TOU	48%
Away from Home (All)	6%
Overall Benefit	16%

Relative to their respective baselines, non-TOU participants realize the most incremental benefit because the optimization does not factor in TOU peak- and off-peak periods for these participants. As a result, vehicle charging can be shifted into high excess supply periods without adversely affecting electricity bills. Away-from-home charging results in the least incremental benefit because the baseline profile is already quite favorable to excess supply, given the pattern of plugging in during the morning hours, as previously shown in Figure 3-25.

It is important to note that the results (percentages) in Table 3-10 cannot be directly compared across the different participant groups to assess the overall (absolute) grid impact. This is due to two reasons. First, the number of participating vehicles is different for the different groups. Second, charging patterns and profiles are quantified in terms of vehicle count, not total charging capacity; the latter may differ across the participant groups due to different charging rates.

When considering the results for the TOU participants, one question is what the charging behavior would have been if not for the optimization. This analysis assumes that the vehicle would have started charging immediately upon plugging in, regardless of whether the plug-in time was during a peak, partial-, or off-peak period. It could be more realistic to assume that TOU customers would respond to TOU rates and schedule vehicle charging to minimize their electric bills. Identifying the most accurate baseline for TOU participants is noted as an area for future research.

Load Increase Events

The load increase events were assessed using premise-level metered data from the 241 eligible TCM participant households. In order to get a better understanding of what was happening within the household with the vehicle, the vehicles were segmented into categories for each of the seven event hours based on the following questions:

- Was the vehicle at home? (Yes or No)
- Was the vehicle plugged in? (Yes or No)
- Was the vehicle charging? (Yes or No)
- Did the vehicle have an optimized charging schedule? (Yes or No)

All TCM vehicles charging at home and away from home were able to respond to DR events via the BMW vehicle telematics system. Using vehicle telematics, it is possible to document whether, when, and how a vehicle modified its charging behavior in response to DR events, regardless of location. Due to current CAISO constructs for PDR participation and performance measurement, however, vehicles that were away from home during the DR events were not included in an aggregation.

Figure 3-26 shows the number of vehicles by segment and event date, with the event dates clustered by day of week. For the vehicles that are at home during these events, non-optimized charging is consistently the largest segment, with the exception of Tuesday, October 30th, the date that had the lowest overall participation and was the only event to be scheduled for 12:00 noon. The Saturday events had the most participation, which is likely due to the increased likelihood that people are at home. The weekday events occurred during typical working hours when many people are likely to be away from home.

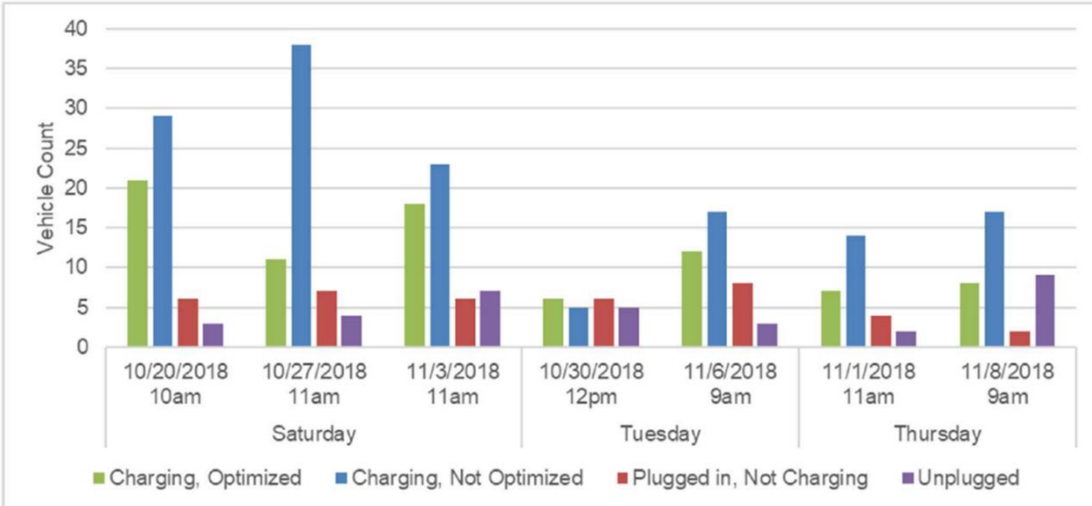


Figure 3-26
Vehicle Charging Status at Home for Load Increase Events

To assess the overall impact of the load increase events for both at-home and away-from-home charging, the average per vehicle kW increase results for at home vehicle charging were applied to vehicles that were charging away from home during the events. This assumes that charging rates and participation patterns are similar on average between at-home and away-from-home charging. BMW telematics data could be used to test this assumption and further analysis will be shared in subsequent reports.

Figure 3-27 shows the results from the load increase event by day (grouped by day of the week). The figure shows a high value of approximately 66 kW on Saturday, 10/27/2018 and a low value of approximately 36 kW on Thursday, 11/8/2018. Generally, the load increase results are highest on Saturdays, when more vehicles were using optimized charging at home. Further, based on BMW charging profiles for the TCM project, there is generally more charging at the beginning of the week and people do not charge every day. Of note, during the one DR event called for noon on a weekday (10/30/2018), the data show the highest number of vehicles using optimized charging away from home.

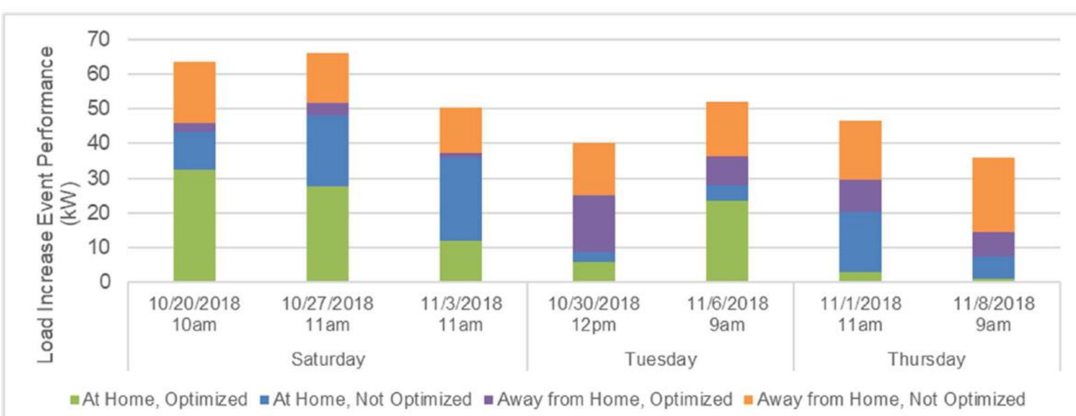


Figure 3-27
Overall Load Increase Event Performance – All Charging Vehicles

Overall Results

The results of comparing optimized and baseline vehicle charging patterns show that charging based on the excess supply signal has the potential to provide benefits to the grid, such as better balance of demand and renewable energy supply. The benefits were highest for at-home charging for those participants not on time-of-use rates. Financial benefits could be achieved from shifting vehicle charging to times of day with negative wholesale market pricing. New incentive mechanisms or improved pricing signals for electric vehicle drivers may help realize the benefits associated with shifting electric vehicle load to grid-friendly periods, including by better aligning electric vehicle charging load with excess generation from renewables.

Relative to the participating groups' respective baseline performance, the incremental benefits were highest for at-home charging by those participants not on time-of-use rates. Given the flat rate structure, those participants did not incur higher costs to charge during daytime hours when excess supply probability is high. New incentive mechanisms or improved pricing signals may help realize additional benefits.

Ultimately, EV rate design and smart, managed charging can complement one another to capture the full value of balancing several important considerations, including and beyond excess renewable generation, such as energy cost and carbon intensity, transmission and distribution grid conditions, equity, and customer behavior.

Benefits to California

Total Charge Management can increase the flexibility of vehicle charging to meet the dynamic needs of the grid. The development of advanced vehicle telematics presents a new opportunity for utilities and grid operators to align vehicle battery status, driver mobility needs and grid conditions. Collaboration between the grid and the driver can yield a charging load profile that minimizes energy costs by aligning daily and weekly charging events to best meet grid needs. While the mobility of a vehicle is typically viewed as a constraint in its role as a grid resource, under a holistic charge management approach, mobility enhances grid functionality by supporting the grid when and where it is needed most.

This project will help California advance the flexibility of electric vehicle charging as a flexible grid resource and vehicle charging cost savings to the driver. Optimal charging load patterns will be identified that can capture ratepayer and grid benefits using a variety of grid price signals. The project supports demand response and smart charging technology advancement of not only the temporal benefits of controlled charging, but also the possible benefits that can be derived from being able to influence the location of charging.

4
GROUP 2: DEMAND SIDE RESOURCES

EPC-15-048 – Alternative Energy Solutions Consulting (AESC) - Residential Intelligent Energy Management Solution: Advanced Intelligence to Enable Integration of Distributed Energy Resources (Clint, 2020).

Goals and Objectives

California's single-family residences have become the front line in a market transformation that includes the proliferation of photovoltaic (PV) solar roofs, the advent of smart thermostats, the early stages of an inexorable shift to electric vehicles (EV) and the recognition of advanced energy storage as a major part of California's future. As a result, load volatility and grid reliability challenges are growing in California, in part due to the amount of renewable resource generation, photovoltaic solar roofs, electric vehicles, and other distributed energy resources (DERs).

With the growth of these resources, it is creating two-way power flows, adding to increasing load volatility, as well as creating problematic load shapes like the duck curve in California. While these resources give customers more control over their energy use, these resources can also dramatically change customers' impacts on the state's transmission electricity grid. Managing this volatility requires innovation and practical applications of emerging technologies.

To combat the load volatility and problematic load shapes, EPC 15-048 aimed to advance objectives to identify, inform, and develop strategies for overcoming technical, institutional, and regulatory barriers to expanding demand response (DR) participation in California. Specifically, this project aspired to flatten the demand-curve imbalance, or duck curve, through new technology that enables alleviation of heightened electric load volatility and grid costs. This project shifted load shapes and minimized customer utility costs for 100 homeowners in San Diego Gas & Electric (SDG&E) territory.

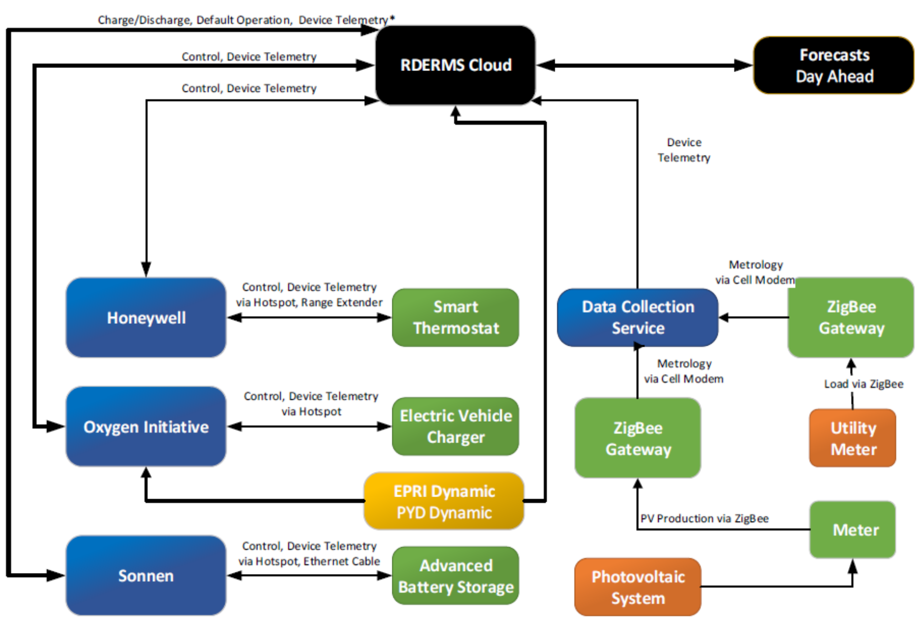
As part EPC Project 15-048, all participants with central air conditioning received a Honeywell Wi-Fi web-programmable thermostat, 30 participants received Webasto Level 2 EV charging stations, and 30 received Sonnen battery energy storage systems (BESS). Study participants were grouped into four tiers. A tier 1 participant received a smart thermostat. A tier 2 participant received a smart thermostat and an electric vehicle charger. A tier 3 participant received a smart thermostat and a BESS system. And a tier 4 participant received a smart thermostat, electric vehicle charger, and BESS. Table 4-1 shows the distribution of equipment for the 100 homes chosen to participate in the Smart Home Study.

Table 4-1
Smart Home Study Tier Distribution

Tier	Number of Participants	Equipment received
Tier 1	50	Smart thermostat

Tier 2	20	Smart thermostat and electric vehicle charger
Tier 3	20	Smart thermostat and BESS
Tier 4	10	Smart thermostat, electric vehicle charger, and BESS

To communicate with these resources, the project team installed Itron’s Residential Distributed Energy Resource Management Systems (RDERMS) platform. The RDERMS system is a cloud-based system built on proven demand-response software and infrastructure. This system leverages continuously updated information to allow smart, efficient, energy use. Its web-connected hub analyzes price and weather data to communicate with end-use devices and regulate electricity consumption to deliver low consumer energy costs. The system consolidates day-ahead loads and facilitates dynamic price signals by transmitting forecasts to a demand clearing house that is ultimately connected to grid operators. This platform was installed in all 100 homes to communicate with a spectrum of DERs over different climate zones and behavioral patterns to determine the feasibility of the pre-commercial technology. The DERs and the component architecture of RDERMS are shown in Figure 4-1**.**



Source: Itron

Figure 4-1
RDERMS System Architecture

The project used RDERMS to shift electric loads and minimize customer costs while maintaining customer comfort. The project used time-of-use (TOU) utility rates and, later, simulated dynamic pricing signals to support load shifting models that were intended to minimize customer costs. This project documents the benefits of RDERMS, including energy savings to users without impacting comfort and convenience. It also demonstrates the ability to stabilize aggregate demand on the grid by allowing load to react to dynamic pricing and eliminating the negative effects of integrating more renewable energy sources into the electric grid.

For this project, Alternative Energy Systems Consulting (AESC) was the lead for this effort. Itron Inc., was the lead technologist and developer of a RDERMS, handled integration planning and readiness assessments. SDG&E provided subject matter expertise over the course of the project including analysis of dynamic tariffs, price signals, and DR programs. KnGrid was responsible for managing its demand clearinghouse technology and providing other subject matter expertise. The Center for Sustainable Energy (CSE) conducted sample design, tariff analysis and modeling, and knowledge transfer.

Methodology and Approach

To participate, each residence was required to have broadband internet access and a utility smart meter. To calculate benefits of the technology, the project team evaluated the baseline period data before installation and surveyed existing end-use appliances. Lab configurations and scenarios were developed and studied under current block tariffs, time-of-use (TOU) tariffs, and future dynamic price-signal tariffs. Under various scenarios, data was collected on an ongoing basis; collected data included smart meter interval data, end-device data (whole home and disaggregated), and interval data. Analysis of the collected data allowed the project team to conduct a full assessment and develop conclusions.

Demonstrations

To test and understand the impact of RDERMS control under two different scenarios—traditional TOU tariff rate and advanced price-signal optimization—the demonstration was broken into two phases:

- Phase 1: Optimization and response to existing SDG&E TOU rates. So that optimization and behavior would have direct impacts on customer utility bills, participants were asked to switch to one of three TOU rates: DR-SES, EV-TOU-2, or EV-TOU-5. Phase 1 started in December 2018 and the field demonstration lasting one year.

- Phase 2: Optimization and response to the EPRI transactive signal server to receive and respond to a transactive load management (TLM) signal. This consisted of two, two-week periods when the project team optimized thermostats, batteries, and electric vehicle charging based on the EPRI price signal. Note that these rates and signals do not directly impact customer utility bills. Phase 2 experiments were performed in September and November 2019 with the hopes of catching variable weather and Southern California's hot Santa Ana winds conditions.

Phase 2 thermostat and EV charger controls could not be completed as planned. The project team attempted to initiate controls in response to dynamic signals across all devices but was unable to fully control thermostats and EV chargers in response to the TLM signal. However, EV charger control was demonstrated in a test case on one charger. The lack of a common communication standard across vehicle manufacturers proved to be a significant barrier in this study. Without the current state of charge and the planned leave time (information from the vehicle), it is very difficult to develop an optimized charging strategy in a dynamic pricing scenario. It was less impactful to the TOU demonstration because the vehicle could start charging the moment the EV tariff super off-peak rate initiated and the vehicle was generally assured to be fully charged. The CEC and the CPUC are currently considering common EV communication standards which, if adopted, could be integrated into future DER studies.

Phase 1 (TOU Rate) Demonstration and Implementation: TOU demonstrations in Phase 1 formed the bulk of the one-year field data collection period. This provided the opportunity to test and refine communications and controls and develop a baseline for comparison with Phase 2 operations. Response to an energy based TOU rate is simpler than the response required in Phase 2 because the rates are static and change on an established schedule rather than receiving a new rate schedule daily. Figure 4-2 shows the energy rates for the two TOU rates selected for the study: EV-TOU-2 and DR-SES TOU.2 Summer is June through October and winter is November through May.

Source: SDG&E

Figure 4-2
SDG&E EV-TOU-2 and DR-SES TOU Rates

Some key aspects of this rate are listed below.

- No tiers. All energy consumed or produced is credited3 at the same rate schedule, regardless of kilowatt-hours (kWh) used.
- No demand charges. The electricity bill is dependent on the amount of electricity consumed by a participant in each period during a billing month.
- Rates differ greatly from summer to winter; winter rates are relatively flat for all times of the day.

Phase 2 (Dynamic Rate) Demonstration and Implementation: Phase 2 of the SHS automated technology to the EPRI TLM tested a day-ahead dynamic rate. This rate aligns utility and customer costs, benefitting both the customer and the grid. The dynamic EPRI TLM varies in price for each hour of the next day and differs from TOU rates used in Phase 1. Figure 4-3 shows the average EPRI TLM summer prices for 2017 and 2018, and Figure 4-4 shows those prices for winter.

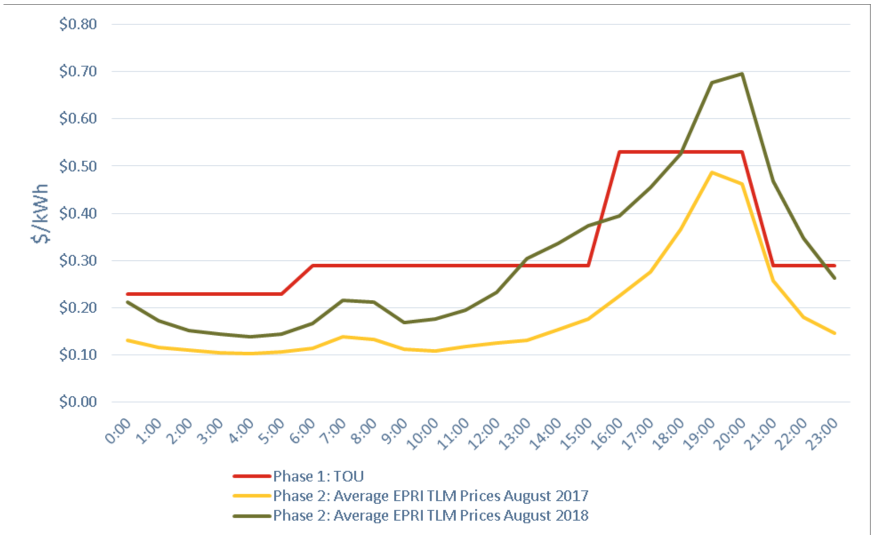


Figure 4-3
Average EPRI TLM summer prices for 2017 and 2018

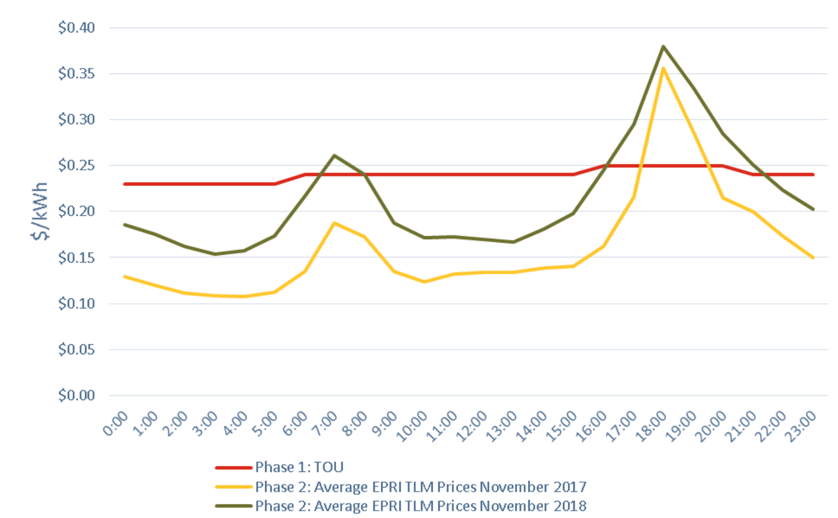


Figure 4-4
Phase 1 vs. Phase 2 Energy Prices in Winter

In the summer, a small morning peak appeared in Phase 2 that is not reflected in Phase 1 TOU pricing. Additionally, peak prices rise in the later part of the TOU on-peak period. Also evident in Figure 4-3 and Figure 4-4 is that, year over year, dynamic prices can vary substantially between years, with 2018 showing much higher prices, likely caused by a hot, dry year.

Summer in San Diego is different from many other parts of the state. The early summer marine layer (known as the "June gloom" to residents) tends to drive temperatures and energy consumption down in the early part of summer. Higher temperatures are more likely in late summer. Largely for this reason, the project team chose the first test period to be in September to catch part of the hot spell when the Santa Ana winds drive up temperatures and demand, and therefore energy prices.

Winter prices show a more substantial difference between phases 1 and 2. Phase 1 TOU prices are nearly flat, whereas Phase 2 dynamic prices show both morning and afternoon peaks. To allow comparison between these rates, the project team performed the final experiment late in the month of November.

The control strategies for Phase 2 were more complex than the relatively simple strategies required to minimize cost in Phase 1. However, similar to Phase 1, the Phase 2 logic behind shifting loads varied by device.

Sample Design and Recruitment

A sample design for 100 participants who could reasonably represent SDG&E residential, single-family homeowners was established, and a detailed sampling plan was developed. The plan identified the objective for diverse participant profiles, how to maximize research value while accounting for specified limitations, potential recruitment pools and data sources, and outreach methods. An outreach plan was then developed and implemented. Due to significant recruitment challenges, outreach efforts were adapted and revised until the desired sample size was achieved. Despite the recruitment challenges, the study only had one participant drop out during the pilot phase.

Overall results

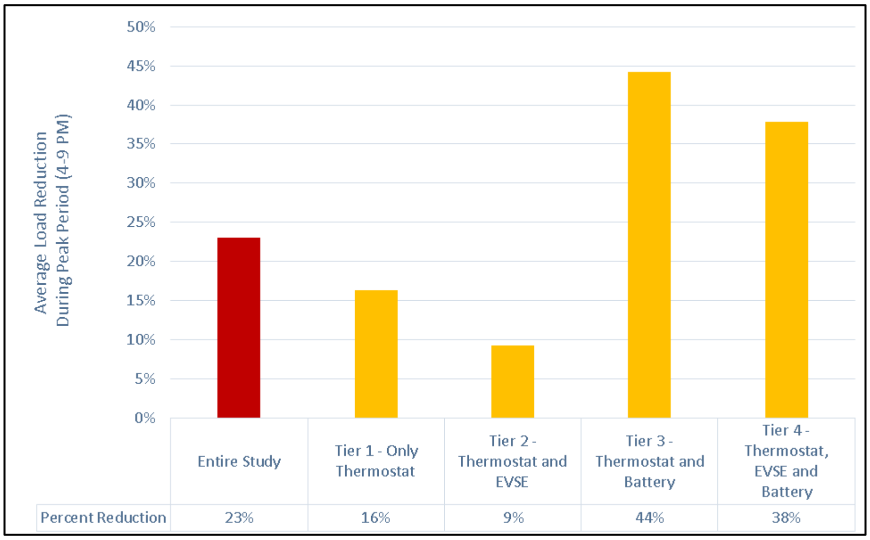
The project successfully recruited 100 participants and installed thermostats, electric vehicle chargers, and battery energy storage systems at those test homes. The primary intent with these devices was to shift load from high-cost and high-carbon periods to periods with lower energy costs (and likely lower carbon content). During the recruitment and installation processes, the project team identified three specific issues that may hinder broader implementation or adoption of some intelligent distributed energy resources:

- Available space to install new equipment and electrical capacities in customer electrical panels
- Physical space in an appropriate location for the equipment (such as, a garage)
- Existing utility rates and tariff rules

After recruitment and installation, tariff modeling results confirmed that current time-of-use rate structures offered by SDG&E benefit customers and the grid through planned electric vehicle charging and energy storage dispatch. This indicates that current rate structures offered by the utility reward customers who use distributed energy resources that provide grid benefits. However, greater grid benefits can likely be achieved by further aligning distributed energy resource operations with dynamic (real-time) price signaling.

Additionally, two types of price signals that encourage residential customers to shift electric demand to periods of high renewable resource generation were investigated: retail rates and a wholesale market mechanism. Rewarding customers who shift loads to these periods through price signals could increase consumption of renewable energy generation without increasing utility costs. Although this research showed that compensation from negative prices in the wholesale market alone does not offer a strong economic incentive for behind-the-meter customers to participate in the CAISO’s proposed load shift resource product, relatively minor adjustments to existing time-of-use rates in SDG&E service territory could reduce emissions by increasing load during these hours.

During the field demonstration periods, the project team successfully showed that control of electric vehicle charging, batteries, and thermostats contribute to dynamic pricing that better reflects cost and carbon content. The project team also successfully demonstrated a reduction in demand during peak hours, as shown in Figure 4-5.

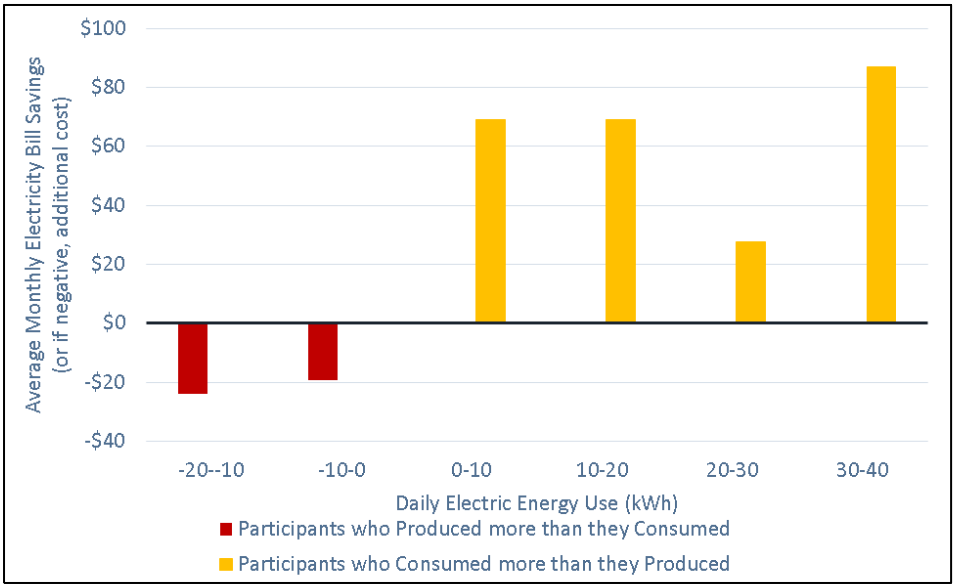


Source: Itron

Figure 4-5
Average Reduction During Peak Hours

These reductions helped drive customer energy bill reductions by moving energy demand away from high-cost, high-demand periods. Participants given only thermostats saw minimal change but participants in equipment tiers that received EV chargers and/or batteries displayed, on average, increase in consumption as many participants began either charging their electric vehicles at home or charging their vehicles more frequently at home. The battery energy storage system participant sites also increased their daily electricity consumption because of inherent energy losses as electricity is charged and then discharged from the battery.

The study showed dramatically different impacts on different household DER configurations. Ninety percent of participants in this study had existing solar PV. These households where the solar generation more often exceeded electrical demand, especially during the peak afternoon hours, offered the greatest potential to reduce energy bills and shift load to minimize peak demand. Figure 4-6 shows the relationship between monthly electricity bill savings during the study and monthly electricity consumption before the study.



Source: Itron

Figure 4-6
Monthly Bill Savings Versus Monthly Electricity Bill Before Study

Participants with higher energy use showed, on average, higher monthly savings during the study and switching to a TOU rate. These are the households that are most likely to benefit from this technology and switching to TOU rates. Conversely, participants who produced more energy per month than they consumed, on average, lost money. These are participants with a large solar system that produces more energy than their home consumes. This is an important consideration for policymakers since participants with large PV systems on a grandfathered volumetric tiered rate will likely lose financially by actively shifting their loads. These are the very customers that may be the more environmentally minded early adopters who would otherwise be more receptive to innovative load shifting technologies and rates that would benefit society.

The study demonstrated energy reductions during the 4 to 9 PM peak hours (the "head" of the duck curve). The study did not show substantial reductions in midday energy export (during the "belly" of the duck) since current time-of-use rates and net-energy metering policies do not provide the financial motivations to do so. As a result, the existing operation is financially optimized by charging the battery energy system at night during super off-peak rather than during the daylight hours when the batteries could have been used to help mitigate grid overgeneration.

In summary, two types of price signals that encourage residential customers to shift demand to periods of high renewable generation in SDG&E service territory were investigated: retail rates and a wholesale market mechanism. Incentivizing customers to shift loads to these periods through price signals could increase the consumption of renewable energy without increasing utility costs. Although this research showed that compensation from negative prices in the wholesale market by themselves currently do not offer a strong enough economic signal for behind-the-meter customers to participate in the California ISO's proposed Load Shifting Resource product, relatively minor adjustments to existing TOU rates in the SDG&E territory could build load during these hours and also reduce emissions.

Benefits to California

The RDERMS has shown its potential to provide California system operators, regulators, and utilities with the ability to promote electric consumption that reduces peak demand through automation, intelligent control, and price signals. Based on this study's results and conclusions, a fully developed and broadly applied system should provide the following benefits:

- Lower customer electricity costs: The RDERMS optimizes customer electricity use flexibility to minimize customer cost and reduce peak demand based on time-of-use or other dynamic electricity rates. This system incorporates predictive algorithms to forecast customer consumption and electric vehicle charging requirements while accounting for customer comfort levels. In turn, it allows the system to transparently control distributed energy resources and intelligent loads within predetermined customer constraints.

- Greater reliability and resiliency: Wide-scale adoption of this residential distributed energy resources management system in California will increase grid reliability by efficiently managing electricity usage in millions of homes. This will improve reliability on multiple feeders and reduce the risks associated with a single point of failure at a large battery-energy-storage farm. It also provides the opportunity to preserve and effectively manage energy use, storage, and load during public safety power shutoff events and other disaster-related outages.

- Environmental benefits: This RDERMS will contribute to California's state-mandated goal of 50 percent renewable resource energy by 2030 by intelligently using the residential electricity market to help balance energy supply and demand. Benefits of 50 percent renewable energy production will reduce greenhouse gas emissions and other pollutants that contribute to climate change.

EPC-15-054 (RATES) – Universal Devices Inc.: Complete and Low-Cost Retail Automated Transactive Energy System (Cazalet, 2020).

Goals and Objectives

California has an aggressive policy (Senate Bill 100) directing that renewable and zero-carbon energy resources will supply 100 percent of all retail electricity sales by December 31, 2045. Senate Bill 350 increases energy efficiency and electrification of buildings and transportation to reduce carbon emissions. The result is rapidly increasing variable renewable solar and wind generation, with decentralized ownership and location and increased electrical demand.

California ratepayers generally do not yet have any automated means and signals to help them use more electricity to heat or cool, charge their electric vehicles and storage, pump water, and use appliances when clean, renewable electricity is abundant and cheap, and use less when it is scarce, expensive, and less clean.

It is difficult and expensive to achieve California's clean energy goals without automated systems, a dynamic price tariff, and a transaction system to support customer self-management of their electricity use.

Customer self-management of electricity must be coordinated with other retail and wholesale generation and use, hour-by-hour and minute-by-minute throughout the day. This coordination challenge is increasingly difficult, with more distributed generation and storage, more community choice aggregators (CCAs), and more microgrids required for forest fire resiliency.

Two approaches are currently being attempted in California for this coordination:

- A supply-side approach, where retail customers contract with aggregators to offer their demand response, retail generation, and storage to an aggregator to be sent or dispatched as a virtual power plant by the California Independent System Operator (California ISO).
- A demand-side approach, using time-of-use retail tariffs with typically three different prices for blocks of time during each day.

The supply-side approach is complex and unable to completely capture the full customer use, distribution, retail energy, and wholesale transmission and energy benefits. And, many customers do not want to turn over control of their electrical devices to aggregators, or to the California ISO, thus limiting participation.

The time-of-use retail tariff, demand-side approach cannot provide the necessary price variability to cover the full range of prices, from negative to thousands of dollars per Megawatt-hour.

One demand-side solution for a real-time retail price is the California ISO wholesale real-time price plus a fixed retail adder. However, the wholesale real-time price variability is modest, and a fixed retail adder likely would not provide a sufficiently variable and locational price signal for distributed storage, electric vehicle charging, and heating, ventilation, and air conditioning (HVAC) operation.

Pure retail real-time pricing raises resource adequacy concerns if the result is reduced investment in resources. Measuring the contributions of renewable generation and batteries is difficult because the definition of capacity used is typically fixed over time. Such pricing also raises market and grid stability concerns, including potential overresponse to a large price change, as well as customer bill and utility revenue volatility.

Finally, the operation of devices to shift and shape usage to increase the use of midday solar generation and reduce evening fossil generation requires real-time hourly and sub-hourly prices, and hourly prices for at least the next 24 hours, with prices often changing during the day as weather and supply and demand change.

For nearly two decades in California, progress toward retail real-time pricing has stalled. Advances in information technology, Internet of Things (IoT), and low-cost off-the-shelf smart devices currently being used by customers for convenience, entertainment, and security can now be leveraged for automated and optimized management of electricity use in response to real-time and other dynamic retail electricity prices.

No single vendor, utility, or agency has been able to implement a solution. Hence, ratepayer support is required to fund the research that no one entity has the scope or funds to support.

The purpose of the project is a proof-of-concept demonstration of a demand-side solution to the challenges and research gaps described above, which the team calls the Retail Automated Transactive Energy System (RATES). The team's goal was to prove the RATES concept with ratepayers and their devices, interfaces to Southern California Edison (SCE) and the California Independent System Operator (California ISO), a subscription transactive tariff approved by SCE and the California Public Utilities Commission (CPUC), and actual tenders and transactions.

The proposed solution includes an innovative retail tariff with real-time, actionable prices and bill stability. The solution also offers a platform to communicate the price offers (buy and sell tenders) to customers so that operation of their electrical devices can be automated for their benefit. The platform interfaces with SCE and the California ISO, including scheduling, metering, and billing calculations for the tariff. The solution also provides a low-cost, off-the-shelf, and IoT energy management system that interfaces with SCE smart meters, off-the-shelf customer devices, photovoltaics, electric vehicles, and artificial intelligence assistants and controls devices in response to prices, while considering customer comfort and convenience.

Ratepayers or customers should care about this research because it can reduce their cost of electricity as California transitions to its 100 percent clean energy goals, and because RATES promotes leveraging existing and/or low-cost off-the-shelf customer devices. In this way, customers can easily manage all their appliances for convenience, comfort, cost savings, and environmental interests, while using user-friendly voice assistants.

The technical objectives included demonstration of the following:

- An end-to-end RATES with prices from the California ISO, SCE distribution operator, and SCE load-serving entity to customer facilities and devices.
- Low-cost, off-the-shelf end devices that can feed back and sum device kilowatt (kW) usage to the facility, SCE load-serving entity, SCE distribution operator, and the California ISO.
- Use of the subscription transactive tariff, including the development of subscriptions for each customer.
- Calculation of hourly, 15-minute, and 5-minute tender (offer) prices based on the California ISO, SCE distribution operator, and SCE load-serving entity marginal costs.

- Metering of actual facilities, using existing SCE smart meter infrastructure, at 5- or 15-minute granularities and the calculation of customer bills based on the subscription transactive tariff.
- Voice assistants for device management.
- Real-time optimization agents for each device class or category.
- The feasibility of leveraging a low-cost, off-the-shelf, IoT-based energy management system for integrating devices, SCE smart meters, artificial intelligence assistants and, more importantly, with the transactive energy platform.

Methodology and Approach

The team for this project combined the capabilities of Universal Devices, a leading manufacturer of home automation, IoT, and energy management systems with the capabilities of TeMix Inc., a leading provider of transactive energy systems and services. The team also included experts and resources from SCE, the CPUC, the California ISO, and the California Energy Commission (CEC).

In this project, the team completed the design of RATES, and:

- Implemented the RATES design, including the transactive energy platform and the in-home use of an energy device control hub and smart devices.
- Installed RATES in about 100 homes on an SCE distribution circuit.
- Interfaced RATES to the SCE load-serving entity and distribution operator and the California ISO.
- Implemented a subscription transactive tariff and obtained CPUC approval for it as an experimental tariff.
- Adapted the TeMix transactive energy platform to support RATES.
- Adapted Universal Devices' low-cost energy management system and software to support RATES

The RATES tariff uses a customer-specific subscription quantity (kW) for each hour for a year or more at a fixed monthly cost. (kW denotes the rate of energy flow. One kW for one hour is equivalent to one kilowatt-hour [kWh]. One kW for a day of 24 hours is 24 kWh. One kW for five minutes is 1/12 kWh.)

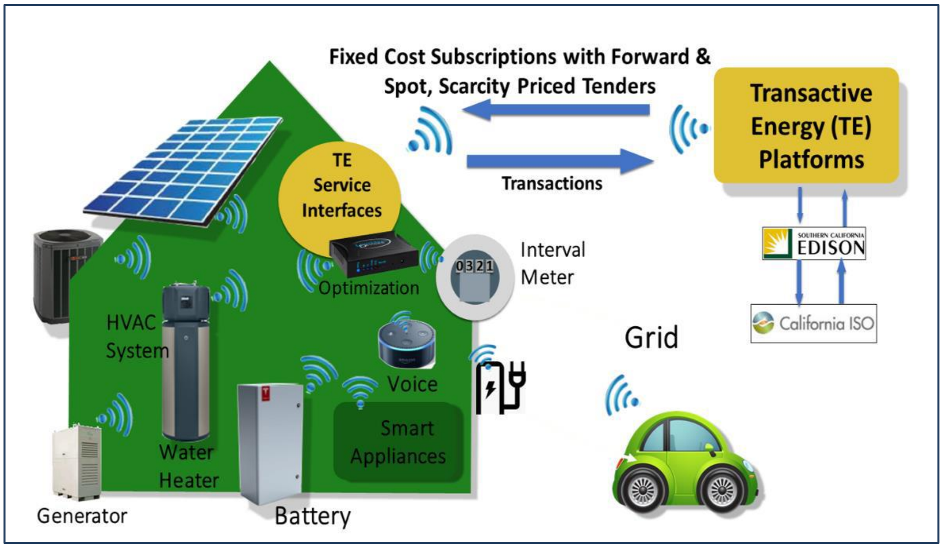


Figure 4-7
RATES High-Level Overview

The customer's historical metered usage determines the hourly subscription quantities, and the current SCE tariff applied to the subscription quantities determines its monthly fixed cost. If the customer uses about the same energy in each hour as subscribed, the customer's bill will be about the same.

Within RATES, load-serving entities and distribution operators, such as SCE, act as "market makers," frequently posting kW quantity, buy and sell tenders (offers) to each retail party. The tenders are based on wholesale market prices plus retail adders that recover other fixed and variable costs at higher prices when the distribution circuit and generation load is high.

RATES' optimization agents and low-cost energy management system work hand-in-hand to automatically adjust usage and generation based on hourly, 15-minute and 5-minute tender prices while taking customers' preferences into consideration. RATES automatically transact portions of the buy and sell tenders for these intervals so that their planned net usage and generation balances their net purchases in each interval for which tenders are available. To provide customers with the most flexibility, they are not required to respond to tenders with transactions and, therefore, RATES enables considerable flexibility for market designers in the granularity of implementation for different customer sectors.

RATES tariff settlement is straightforward. The monthly bill is the sum of the payments for the transactions in the month, taking account of whether the transaction is a buy or sell transaction. There is no need for overlaying the RATES tariff with demand charges, additional demand response programs, signals, and baseline estimates because customers are already using the correct marginal costs.

After meetings with SCE to ascertain how best to interface with the utility, the team then developed formal requirements for the key components and interfaces to customer devices, SCE customer meters, historical meter data, the California ISO, and weather service. Interfaces were developed for team members to configure the TeMix Platform and Universal Devices' ISY994 series low-cost and off-the-shelf energy management system for RATES, then to register customers and provide real-time systems for monitoring the operation of all systems from the California ISO to devices in the customer facilities, including resulting transactions.

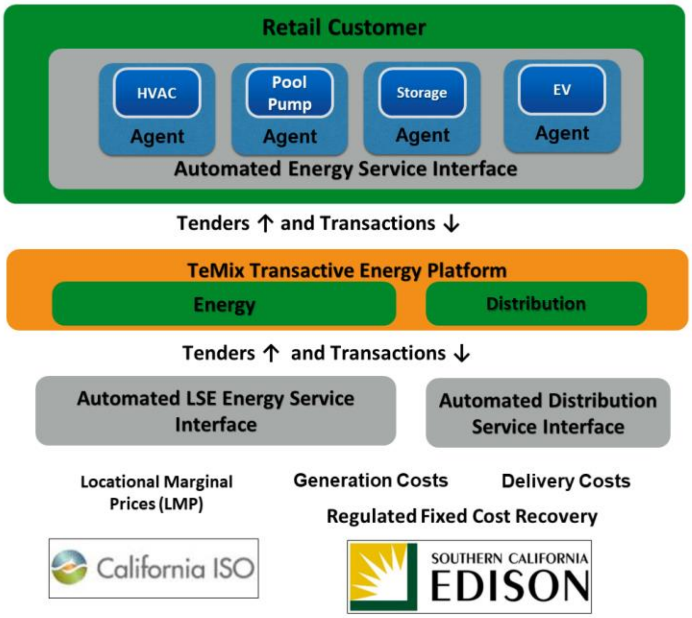


Figure 4-8
Informational Architecture of Interactions Among Parties

The transactive platform development began with a prototype of the TeMix Platform created by TeMix over several years but not yet put into commercial operation. The platform uses standard protocols for tenders, transactions, positions, and delivery. These standards were developed several years ago for the Smart Grid Interoperability Panel and are found in OASIS, "Energy Market Information Exchange (EMIX) Version 1.0" 2012, and OASIS, "Energy Interoperation Version 1.0" 2014.

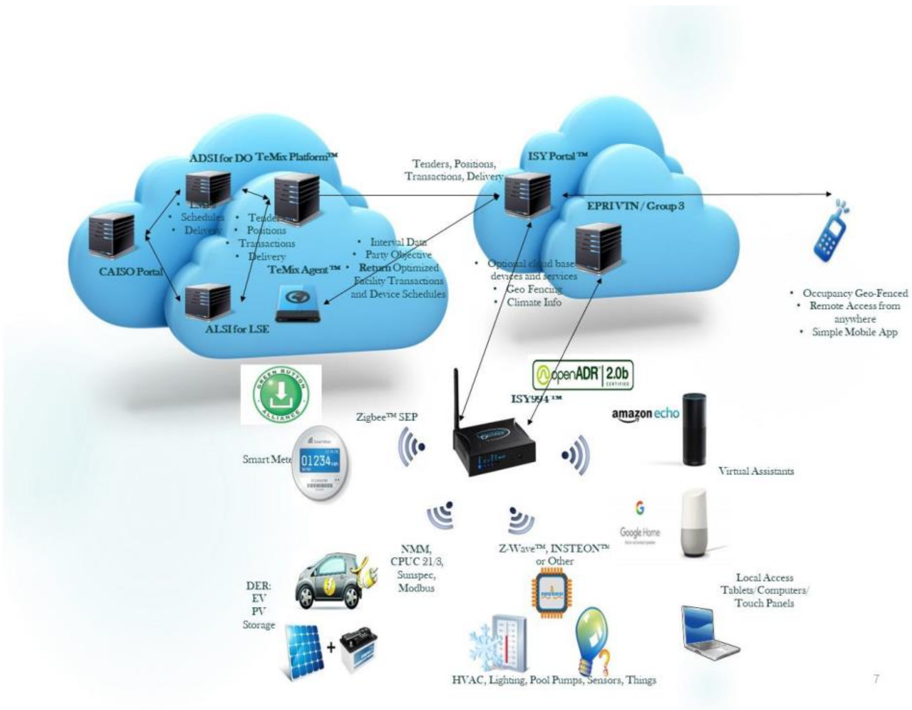


Figure 4-9
Technical Architecture of RATES Interactions

Major efforts were expended to harden cybersecurity, support many parties, and provide scalability for a production environment.

Early in the project, the team developed the interface to the California ISO to retrieve locational prices for any transmission substation and particularly SCE's Moorpark substation, where the pilot was conducted. The interfaces between the energy management system and the transactive energy platform were developed to ensure cybersecure receipt of tenders and creation of transactions. For more than 18 months, RATES was operated end-to-end at five-minute granularity, with over 100 participants, and under a wide range of failure and recovery conditions, seasonal conditions, and weather changes.

The TeMix Agent is several software agents each for a type of device: HVAC, pool pump, battery, electric vehicle, and appliances; and uses real-time energy and state information from the smart meter and other sources for optimization. TeMix Agent is platform independent, and therefore it can run locally on the energy management system or independently in the cloud. Extensive design efforts were conducted to model each device and develop mathematical optimization routines that can solve in sub-second times. Machine-learning algorithms were designed, tested, deployed, and iteratively improved to provide parameters to model the thermodynamics of HVAC and the associated facility.

Working with SCE, the RATES team designed, developed, and obtained SCE and CPUC approval for an experimental subscription transactive tariff. The tariff uses scarcity pricing curves to recover the fixed costs of delivery and generation with dynamic prices that are higher when the use of the system is high.

A major effort was made to recruit participants on SCE's Moorpark circuit, including passing out fliers, calling individually, using social media marketing, and going to the city council meetings. The result was 170 candidates, out of which 40 were intimidated by SCE's customer information request (CISR) form or did not have a two-year history and dropped out. Eventually, 115 residences and businesses were recruited to participate in the pilot. At least five customers have a solar system. The team installed for each customer a Universal Devices ISY 994 energy management system, Amazon Alexa voice assistant, and a thermostat. Also installed were 18 pool controllers and three battery storage units.

Overall Results

The RATES project achieved what Universal Devices was expecting and met the goals of the EPIC grant. The team demonstrated the feasibility of integrating wholesale and retail market operations using a transactive system.

As importantly, the project showed that low-cost, off-the-shelf, and even existing customer IoT devices, Photovoltaics, and electric vehicles can be leveraged and incorporated into RATES.

Validating the core principles and concepts of RATES has spawned independent projects, including using dynamic variable prices provided by RATES to enable agricultural energy users to efficiently self-manage irrigation scheduling. In addition, SCE is examining an extension of this project to continue research objectives that may not have been addressed in the original scope.

Operational Example Results

The information below presents a *small sample* of operational results of RATES.

1. Tender Price Components

RATES uses granular scarcity pricing to develop the prices of the tenders for the SCE DO and SCE LSE. The concept is simple: recover more of SCE's fixed costs when the associated systems are most heavily loaded. The scarcity pricing curves, together with the actual and forecasted MW associated with each curve, determine the prices below.

Currently, there are four components to the delivered tender price. For Monday, June 9, 2019, the four components are shown below, followed by the bundled price (that is the sum of the four prices). The prices of all components and the bundled price vary considerably across all hours of the year.

The locational marginal price, Figure X, is posted by the California ISO for each hour, 15 minutes, and five minutes. The LMP shown here is for the Moorpark transmission substation pricing node (pNode). The LMP drops from $25.00 per MWh during the first hour after midnight to near $0.00 from about 9 am to about 1 pm, and then increases to about $57.00 at about 8 pm before declining to about $24.00 at midnight. The low midday LMPs reflect the high solar generation MW at that time.

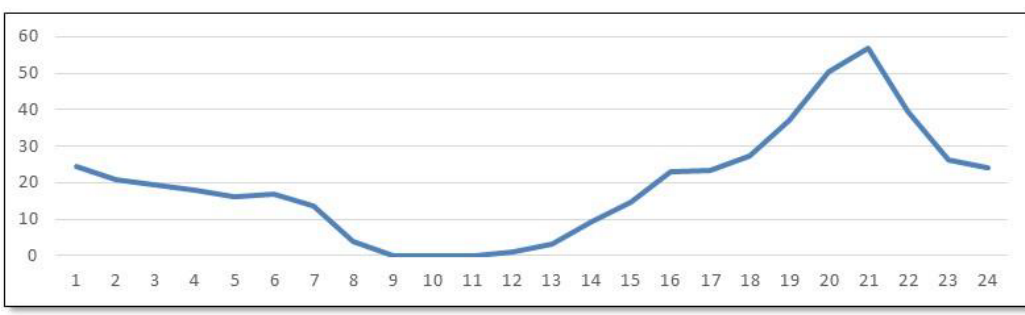


Figure 4-10
Hourly $/MWh Locational Marginal Price for Moorpark on 6/9/19

The recovery of the long-run marginal costs of bulk generation, as shown in pm.

Figure 4-11 begins the day at about $13.00 per MWh and declines to $0.00 at about 8 am, and then further declines to negative $14.00 from about 9:00 am to about 3:00 pm. The negative price reflects the cost of keeping the bulk generation available to be increased rapidly. Then the price increases to about $43.00 at about 9:00 pm.

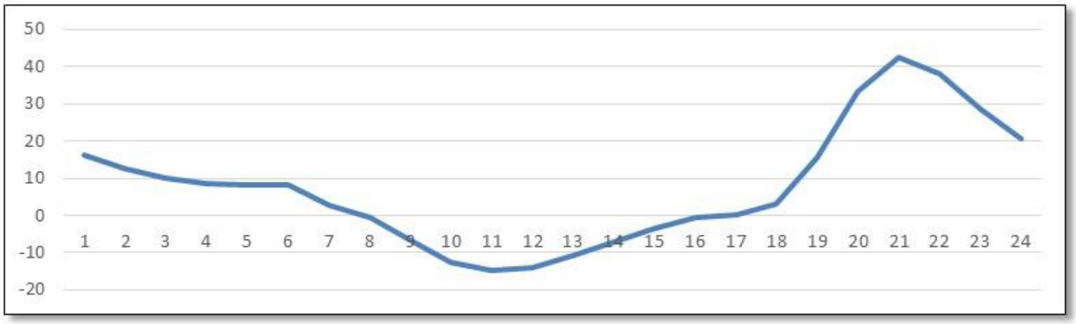


Figure 4-11
Hourly $/MWh Bulk Generation Scarcity Price for Moorpark on 6/9/19

The flex generation price in Figure 4-12 begins increasing at about 1:00 pm and peaks at about 8 pm at $1,263.00. The timing of this peak is affected by the greater number of hours of sunshine in June; in the winter, the peak would be earlier.

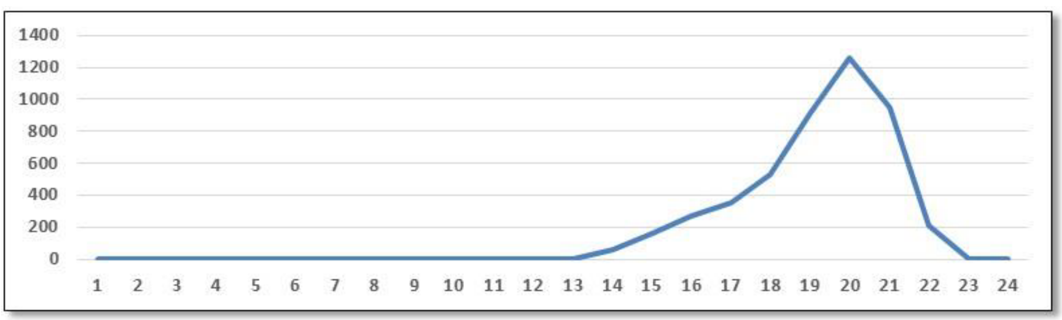


Figure 4-12
Hourly $/MWh Flex Generation Scarcity Price for Moorpark on 6/9/19

The delivery scarcity price in Figure 4-13 recovers the cost of moving the energy at the Moorpark pNode to each facility. The recovery of costs is lowest in the middle of the day when the production of solar energy on the Moorpark circuit almost offsets the midday usage of the customers on the circuit.

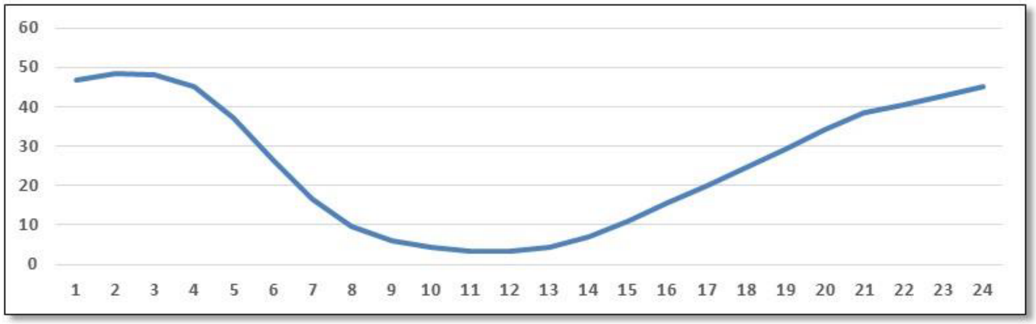


Figure 4-13
Hourly $/MWh Delivery Price for Moorpark on 6/9/19

Finally, in Figure 4-14, the total of the components is the bundled delivered price. The bundled price is about $82.00 at 1 am, declining to negative $11.00 at $11 am and then increasing to $1381.00 at 8:00 pm. Clearly, on this day, flex scarcity price is the dominant contributor to the bundled price.

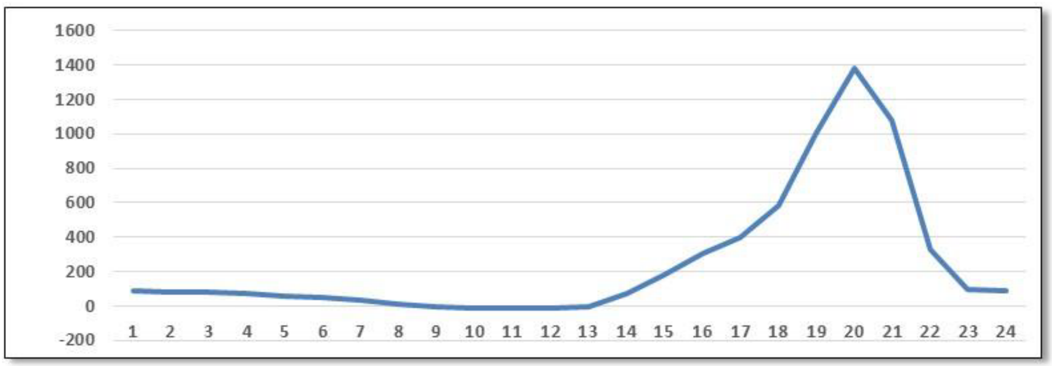


Figure 4-14
Hourly $/MWh Bundled Tender Price for Moorpark on 6/19/19

2. Bundled Tender Price Examples

The hourly bundled tender prices for Moorpark, as described above, is shown below for March 2019.

The March tenders show a secondary price ramp about 7 am most mornings, but other than the large evening ramp peaking at about 6 pm, there are generally low prices all day.

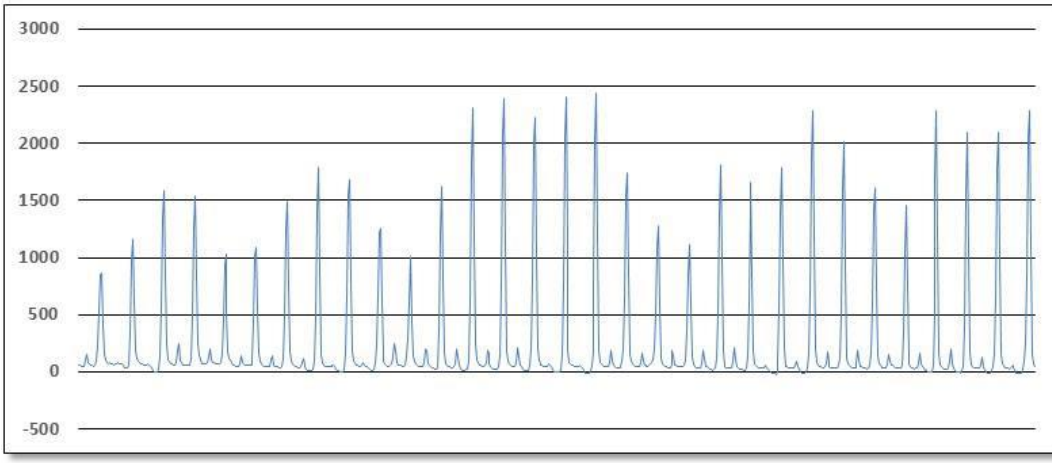


Figure 4-15
Bundled Tender Prices ($/MWh) for Moorpark for 31 Days of March 2019

3. Experimental Tariff Billing for 24-Hour Day

Figure 4-16 shows the hourly net-metered kW of a solar facility for 24 hours of January 27, 2019. The actual net-metered kW is shown in red, and the subscription net kW is shown in blue, based on averaged historical meter readings. Since this customer has solar, the midday net kW can be negative, as shown in the figure. When red metered kW is less than the blue subscription kW, the customer sells the difference versus actual meter load.

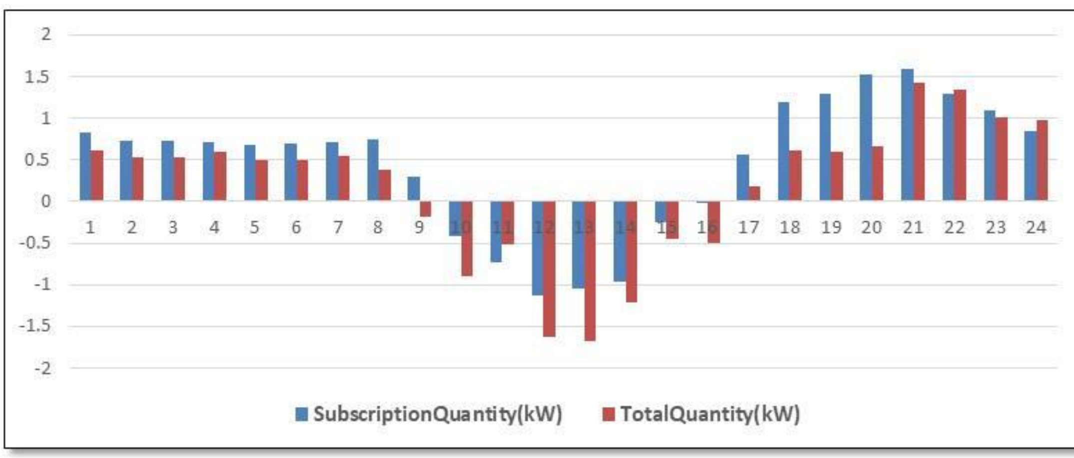


Figure 4-16
Solar Customer Subscription and Actual Hourly kW for January 27, 2019

Figure 4-17 shows the hourly TOU Plan A prices (blue) for a customer and the hourly transactive tender prices (red). As of April 12, 2019, SCE has new TOU rate plans, and TOU Plan A has since been grandfathered. The new TOU SCE Rate plans were out of scope for this project.

The figure illustrates the large differences between the TOU and the transactive prices.

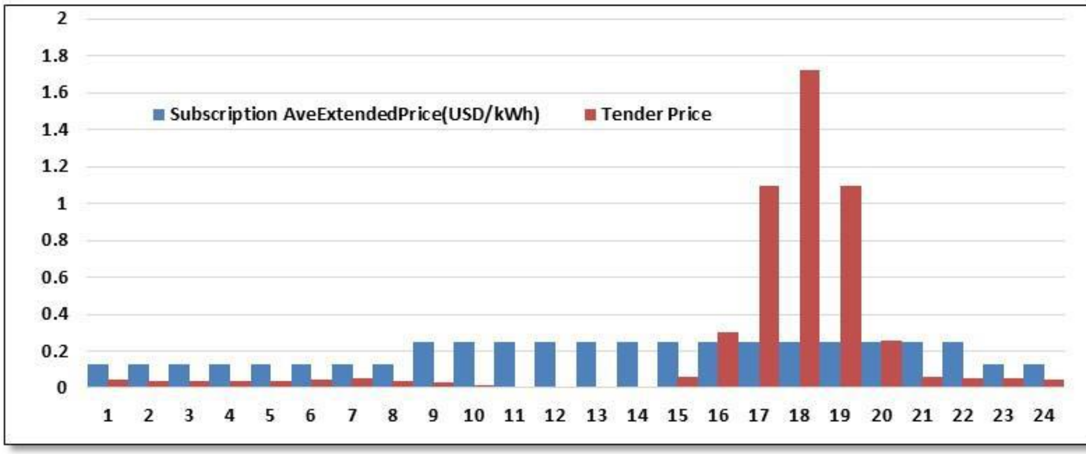


Figure 4-17
Time-of-Use versus Transactive Prices for January 27, 2019

Figure 4-18 shows the net hourly cost (blue) of the subscription portion of the subscription transactive tariff and the total net hourly cost of the subscription and the transactions to satisfy the netload.

The net day cost of the SCE TOU tariff with net metering is $4.81. The net day cost of the RATES subscription transactive tariff is $4.62. In this case, there are slight savings to the customer with the subscription transactive tariff even before responding to the transactive tender prices.

Additionally, since the SCE and RATES net cost (bills) for the day are about the same, this illustrates that the RATES subscription transactive tariff retains the net metering benefit of higher midday TOU prices and high energy returned to the grid under the SCE tariff for this customer. This means if the customer can add flexibility using storage or other means, the customer will receive the full benefit of storage plus the preexisting net metering benefits of solar under their current SCE tariff.

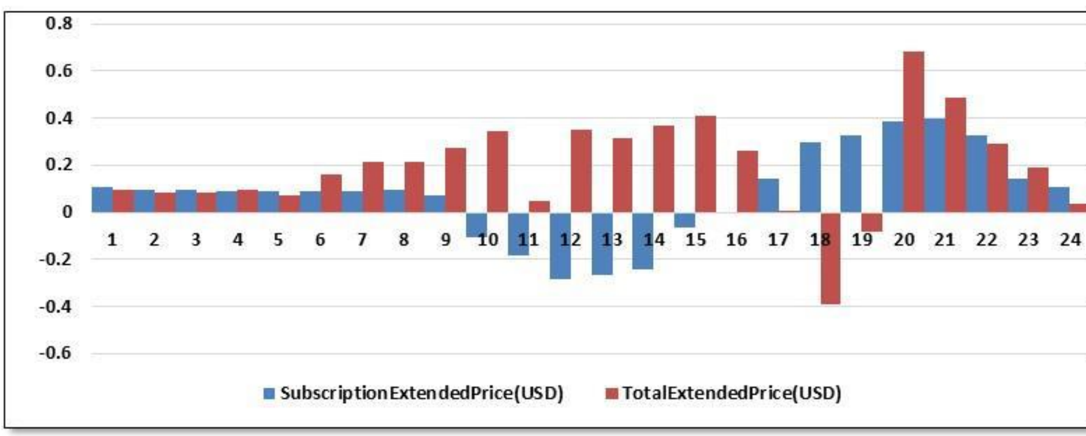


Figure 4-18
Solar Customer Net Hourly RATES Bill for January 27, 2019

4. Experimental Tariff Billing for Several Facilities for a Month

Figure 4-19 shows the RATES tariff bill (blue) and the SCE tariff bill for February 2019 for five sample customers. Four of the five customers have a RATES bill that is lower than the SCE bill. One customer (#5)—the customer analyzed in the previous two sections—has a RATES bill that is higher than the SCE bill. Customers #4 and #5 have solar.

The SCE bill and the RATES bill for a customer depend on many factors, such as weather and occupancy.

The RATES bills do not show the effect of the RATES tariff transactive prices on usage because, during February, none of these customers used air conditioning or other flexible devices.

Any conclusions about the relative volatility of the SCE bills and the RATES bills over a year will require more analysis of actual results, which was not possible within the project completion deadline of March 2019 and due to implementation delays, as explained elsewhere in this report. However, these results demonstrate the billing functionality of RATES.

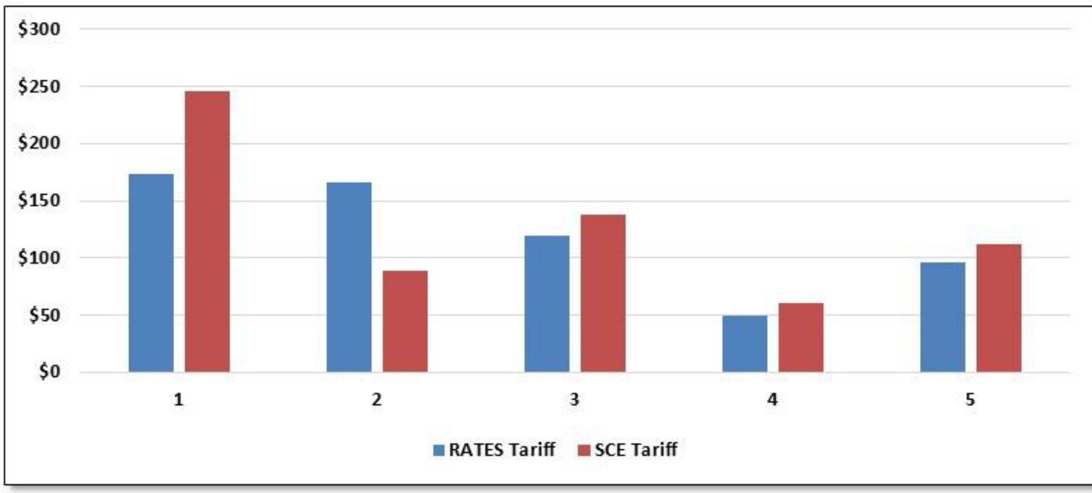


Figure 4-19
RATES Bill and SCE Bill for Five Customers for February 2019

5. TeMix Agent Results: Battery Storage Agent

Shown in Figure 4-20 is the kW hourly charge, discharge, and the stored kWh over two days. Shown in Figure 4-21 are the tender prices for February 7 and 8, 2019.

This battery has a capacity of 9.8 kWh but is set to operate between 1.5 kWh and 8.5 kWh to reduce wear on the battery and provide some reserve kWh. The maximum discharge rate is 5 kW, and the maximum charge rate is 3.5 kW. The battery discharges, optimally, twice per day at about 6 am and 5 pm. It charges just after midnight and again around noon, with two round trips per day for the battery. The round-trip efficiency is 90 percent.

The net revenue for the battery is about $17.00 for the first day and $13.50 for the second day. The revenue includes wholesale, distribution (from reversing flow), and ramping revenues. Because of the scarcity pricing formula, capital and operating costs savings are included in the prices and daily savings.

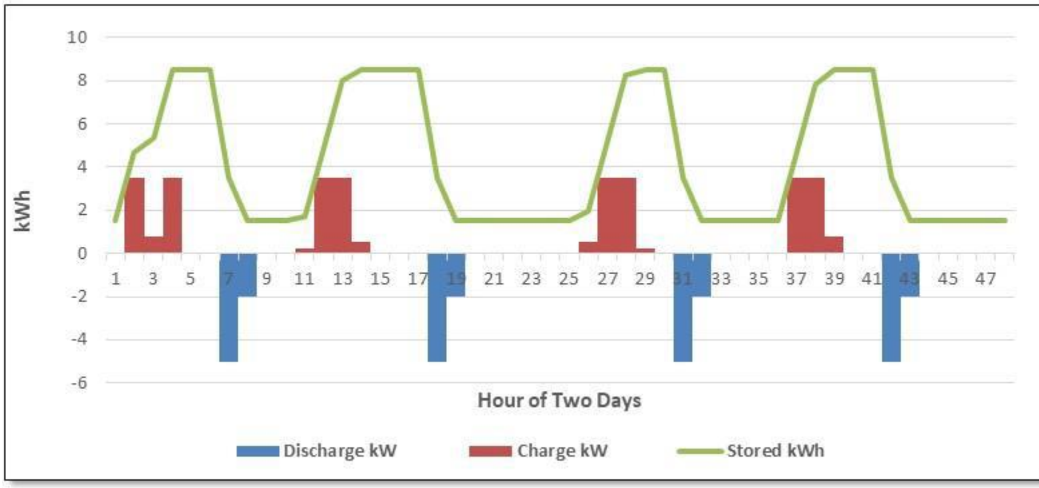


Figure 4-20
Battery Operation for February 7 and 8, 2019

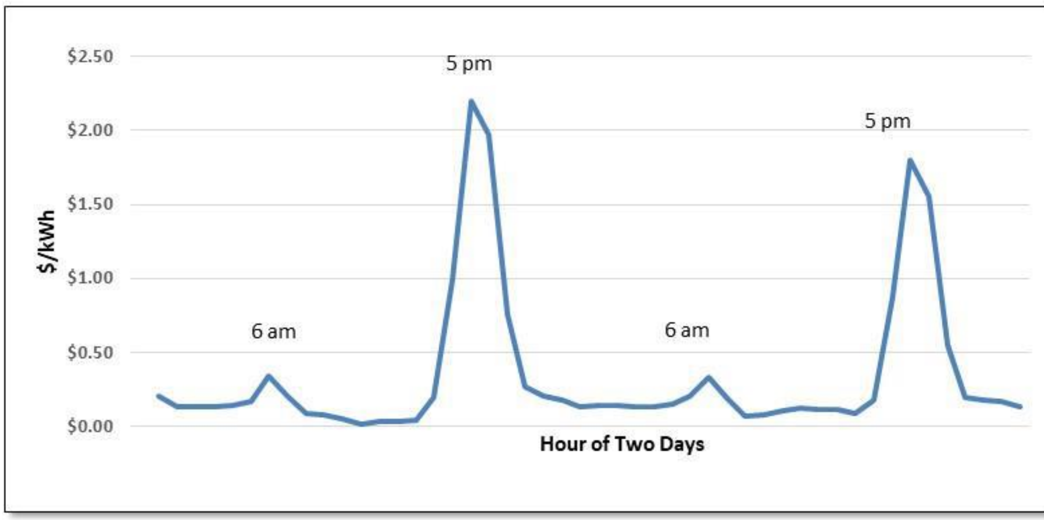


Figure 4-21
Tender Prices for February 7 and 8, 2019

6. EPRI OpenADR Price Events

The EPIC grant for the overall CEC EPIC project required that this project also be able to receive and process OpenADR price events. The OpenADR price events are based on California ISO locational marginal prices times a multiplier of 3.62 to convert to retail $/MWh. The RATES prices use the California ISO locational marginal prices plus scarcity prices for delivery, generation fixed costs, and ramping fixed costs RATES tender prices.

A comparison of RATES prices and the OpenADR prices is shown Figure 4-22 and Figure 4-23 below. The RATES prices are much lower when there is plenty of supply and much higher when there is a higher net load after renewables and higher 3-hour ramping for net loads. The RATES prices will therefore elicit more price responsiveness. The RATES tender prices are binding forward tenders that are updated hourly, whereas the OpenADR prices are indicative, nonbinding prices published once per day. The OpenADR Alliance has a working group in place to support binding RATES tenders and transactions.

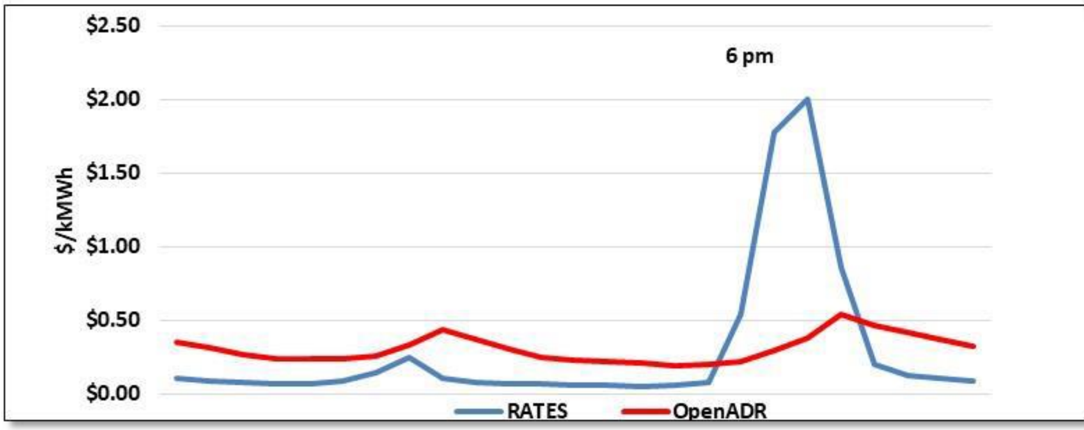


Figure 4-22
RATES Tender Prices and OpenADR Prices for February 22, 2019

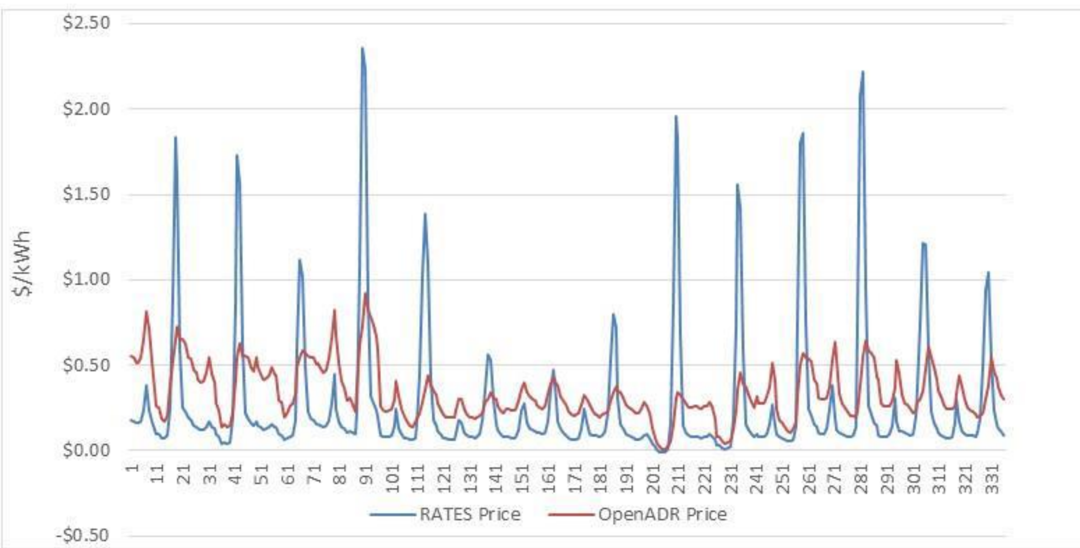


Figure 4-23
Comparison of RATES and OpenADR Prices for February 8 to 21, 2019

7. RATES 24/7 End-to-End Operation

Since late 2017, RATES has been operating 24/7 end-to-end (California ISO to distribution operator to load-serving entity to retail customers and their devices) with return transactions and scheduling.

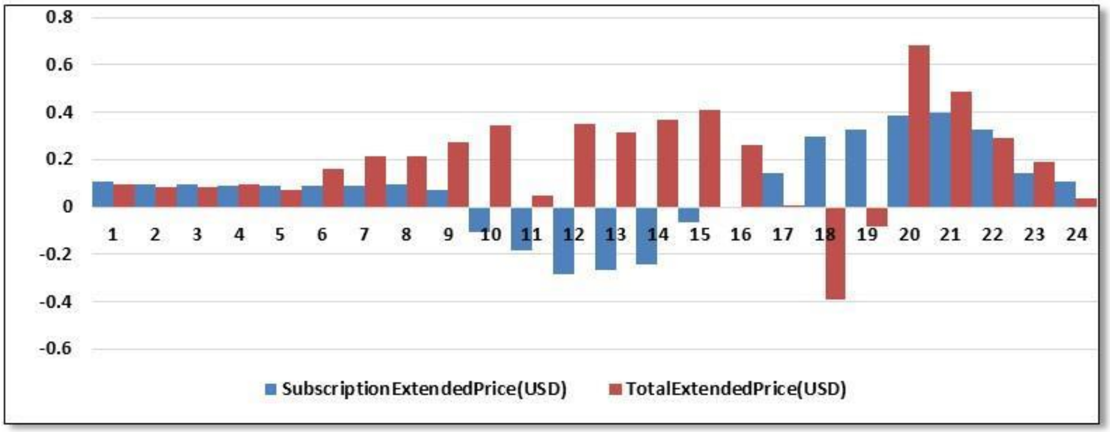


Figure 4-24
RATES 24/7 Operation

During this period the team has continuously improved the algorithms used to manage customer devices, dealt with many hardware, communications, and software issues, learned about the customer and grid requirements by observing the customer's use of electricity and devices under widely varying weather and grid conditions during the year.

At a detailed five-minute level, RATES was interfaced with the California ISO and individual customers and their devices. The team demonstrated the feasibility of integration of wholesale and retail operations using a transactive system.

In this pilot, to stress test the end-to-end systems of RATES, the team has configured each facility to receive a full complement of subscription, hourly, 15-minute and five-minute tenders per hour. Tenders are inexpensive to create and communicate and need not be retained after they expire. Optimization is fast, and only about 10 percent of tenders result in transactions. Most of the communication traffic is for tenders. The settlement is also fast because each transaction quantity is multiplied by the price to get the transaction cost, and the bill is the sum of the transaction costs over a period, such as a month.

Benefits to California

California is committed to a clean energy electric grid and the electrification of transportation, buildings, and other sectors using clean energy. This transition will require ratepayer and non-ratepayer investment, for which ratepayers eventually pay. Such investments should be coordinated and not wasteful of energy and money. It is also important that customer energy-using and producing devices, including storage, be operationally coordinated with wholesale solar, wind, storage, and other generation.

The RATES platform offers the potential for coordination of most retail and distribution investments and operations with wholesale and transmission investment and operations. Operations are coordinated at hourly, 15-minute, and 5-minute granularity via locational transactive tariffs that recover costs in a way that reflects scarcity and abundance of energy. Each party responds to these priced tenders, and the resulting operational supply and demand influence the wholesale and transport prices, thereby continuously coordinating supply and demand.

Investments can be coordinated by years-ahead tenders and transactions in the same way operations are coordinated by spot tenders and transactions. The load-serving entities, distribution operators, or third parties would be market makers in these forward markets hosted on RATES. This project considered such long-term transactions as out of scope.

Ratepayers (electricity customers) will benefit from RATES in several ways:

- Opportunities to reduce bills through better energy management, informed and automated by RATES.
- Increased bill stability with electricity subscriptions.
- Targeted subscriptions for low-income customers and fairness.
- Opportunities to monetize the flexibility of grid services for energy management, smart appliances and controls, storage, and solar technologies, including heat pumps, space conditioning, and water heating.
- Opportunities to reduce the cost of electric vehicle charging for the customer.
- Reduced costs of billing through RATES billing automation.
- Increased transparency for the customer in energy use and costs.

Adaptation of RATES to Other Retail Electricity Customers and Costs

Any business or resident can use RATES as currently designed. The basic RATES platform costs were estimated above at about 0.25 percent of a customer's bill, excluding control and communications systems.

For business, residential, agricultural, transport, and other customers who adopt the Internet of Things to manage, control, and maintain devices via the internet for a wide range of reasons, interface to RATES to receive and act on tenders should be required. This would mean that the incremental cost per facility of adopting RATES would be minimal at the scale of millions of facilities.

Potential Money, Energy, and Emissions Savings from RATES

For California, emissions will be primarily policy-driven to essentially zero by 2045. Electrical energy use is likely to increase substantially as a result of a shift to less use of natural gas and more use of clean electricity. The potential savings from RATES in this context, in the long run, will be monetary as a result of lower investment and more efficient operation of the grid. The assumption is that policy will drive greenhouse gas emissions to the low targeted levels.

Another benefit of RATES is increased customer management of their energy use and investment, helping them to achieve customer benefits and bill reductions.

RATES can replace much of the retail billing and transaction systems now in use. Since the current systems are typically not fully dynamic, they must be modified or replaced. The RATES system can handle a wide range of tariffs at a much lower cost than conventional transaction and billing systems.

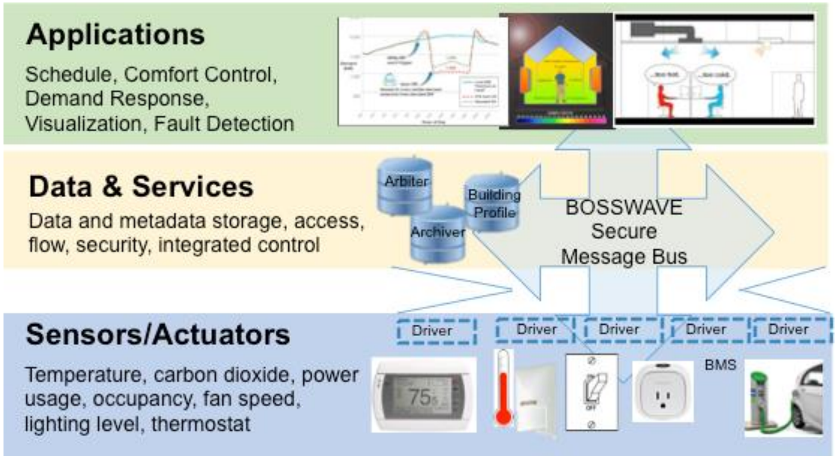
EPC-15-057 – UC Berkeley: Customer-Controlled, Price-Mediated, Automated Demand Response for Commercial Buildings (Peffer, 2019).

Goals and Objectives

The services demanded of commercial building customers—heating, cooling, ventilating, lighting, computing, and so on—require significant energy and contribute to peak energy demand. In fact, while demand response solutions abound for residential customers—communicating thermostats, for example—few solutions address the complexity and heterogeneity of the needs of commercial customers. Large commercial customers (consuming 1 megawatt (MW) and greater than 50,000 square feet (sf) typically have a Building Management System (BMS) that can control Heating, Ventilation, and Air-Conditioning equipment and often lighting in order to respond to price signals, although this requires some communication and controls infrastructure. Small commercial customers (consuming less than 100 kW and smaller than 50,000 sf, however, typically do not have BMS, and thus cannot easily participate in demand response.

The team of researchers led by UC Berkeley's California Institute for Energy and Environment includes the Building Energy Transportation Systems research group in Computer Science, Siemens, Carnegie Mellon University—Silicon Valley, and Quantum Energy Services & Technology (QuEST). The team proposed to create a *Customer-controlled, Price Mediated, Automated Demand Response for Commercial Buildings* (XBOS-DR). This project proposed to develop a Demand Response manager based on the eXtensible Building Operating System (XBOS/DR) (an open source and open architecture platform) that can interface with multiple hardware devices from different vendors as well as include software applications from various vendors. With its ability to create a virtual BMS for small commercial buildings by networking thermostats and other controllers, XBOS-DR can provide large and small commercial customers with a variety of choices for demand response capability.

The XBOS platform provides an open software "layered" architecture, similar to that found in a smart phone, where different applications (Apps) are supported by an Operating System and data management services and interacts with the hardware. With this open-source tool, any time-series data stream—whether online weather, third party sensors, hardware devices, or data from the BAS—can be labeled or tagged and stored in a fast, easily queried database. One can add new data streams by writing a simple "driver" interface. Applications can access this rich database and provide improved actuation, visualization, or optimization. An open source and open architecture enabling platform runs counter to the business model of many companies, who want to maintain a single vendor, proprietary solution.



Horizontal layers define interoperability compared to vertical silos.

Credit: Carl Blumstein, Therese Peffer

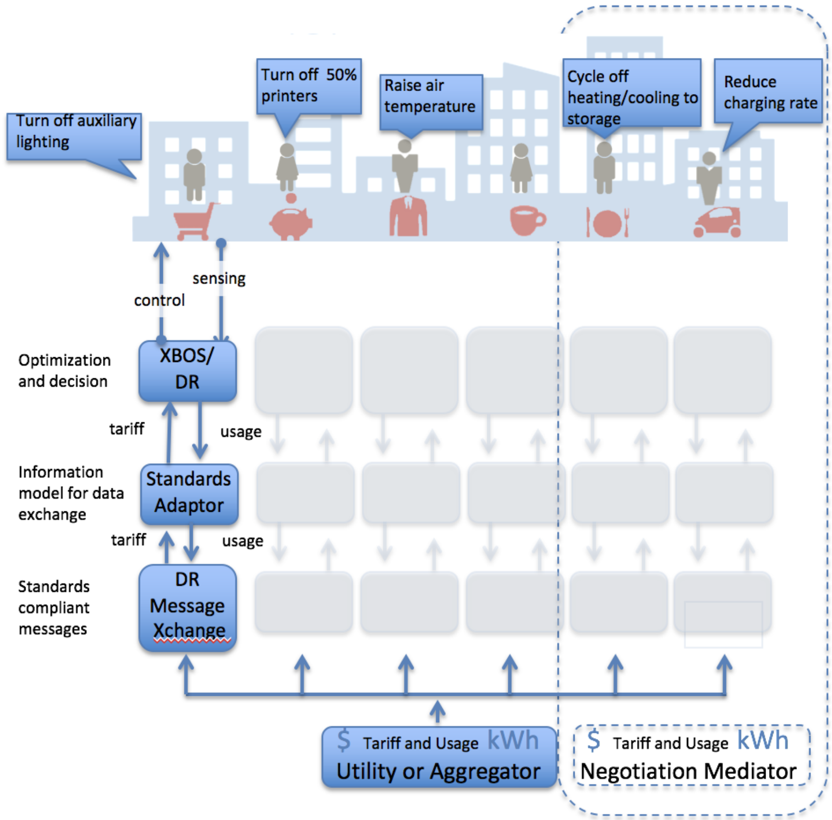
Figure 4-25
Horizontal Layers of an Open Software Architecture

The goal of the project was to improve commercial customer participation in demand response by providing customer value: engaging service choices such as lowered demand charges and improved comfort and convenience and an easy-to-use interface at a low cost.

The objectives of this project were to:

- Design and develop customer value, with user surveys and use cases to develop applications and the user interface.
- Define, design, and develop all components of the system architecture, including:
    - a negotiation mediator that coordinates among several building sites,
    - a messaging system to convey pricing schedules to the BMS and the BMS demand requirements to the rate supplier,
    - an information exchange module to manage disparate message content,
    - developments within the XBOS context to support a variety of networked devices, and
    - applications such as optimization to manage demand based on pricing schedules.
- Test the alpha version at the laboratory scale in order to develop a beta version that is robust and secure.
- Pilot test XBOS/DR in at least 20 commercial buildings in California in order to measure and verify energy savings.
- Evaluate project benefits and technology,

- Develop knowledge transfer activities and
- Produce a product and market readiness plan.



Credit: Therese Peffer and Jack Hodges

Figure 4-26
Components of XBOS-DR Platform

Small commercial customers (top) have different needs and different values regarding reducing peak electrical loads. Price information (tariff and demand response event signal) from the utility is received by the price messaging system, and relayed to the XBOS-DR platform, which sends control signals and receives information (e.g., electrical power consumption, indoor temperature). The Negotiation Mediator can take a subset of buildings and control based on a desired aggregated load profile.

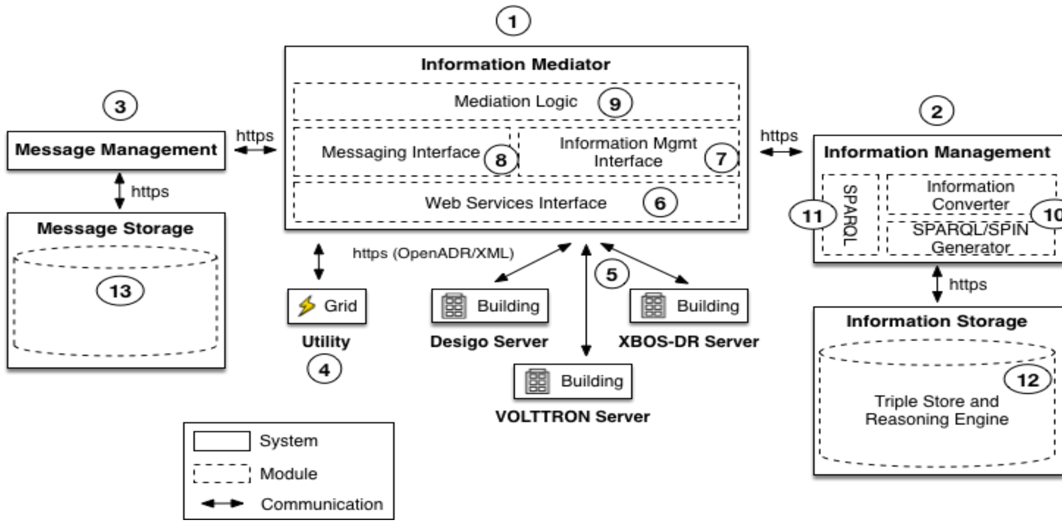
This project provides a holistic solution in addressing nine key requirements that a customer-controlled, price mediated, automated demand response manager should:

1. Receive pricing signals, evaluate energy demand, and respond with managed demand requirements, while complying with regulatory requirements.
2. Enable heterogeneous customers to adapt demand response with individual preferences for each commercial building.
3. Track, evaluate, and control multiple heterogeneous devices.

4. Interoperate with various building systems, such as Building Management System (BMS) in large commercial and networked thermostats in small commercial to enable coordination of building management with the operation of other building systems and to take advantage of sensors connected to the BMS, enhanced by the use of emerging smart grid standards.
5. Retain the electrical usage history of connected devices. An electrical energy data historian, or means of storing energy data, provides the basis for understanding usage patterns, which is essential for effective demand optimization and management.
6. Provide pricing-based load management algorithms based on a variety of metrics including load type, existing schedules, service prioritization, and historical demand.
7. Coordinate to maintain load diversity. Coordination can be achieved through price signals but if many consumers automatically and simultaneously respond to the same price (e.g., a TOU price), loads may become synchronized — switching on and off simultaneously in ways that destabilize the system.
8. Provide security. The system must be secure from disruptive intrusions or theft of confidential information.
9. Provide customer value. Because demand-response is implemented at a relatively small scale in many commercial buildings, software must be inexpensive (preferably free) and easy to install and maintain. To enhance this value the software should also provide other services such as management of demand charges and turning off equipment during non-business hours.

Methodology and Approach

The California Institute of Energy and Environment at UC Berkeley was the prime recipient and managed the project and developed the user interface. The UC Berkeley Computer Science research organization (the Software Defined Buildings group later renamed the Berkeley Energy and Transportation Systems (BETS) research group) developed the XBOS-DR platform including the microservices, building models, and advanced controls. Researchers at Siemens and Carnegie Mellon University-Silicon Valley worked closely to develop the price messenger, information exchange module, and negotiation mediator (see components below). QuEST recruited the small commercial customers, installed the system, and managed the relationship with the customer.

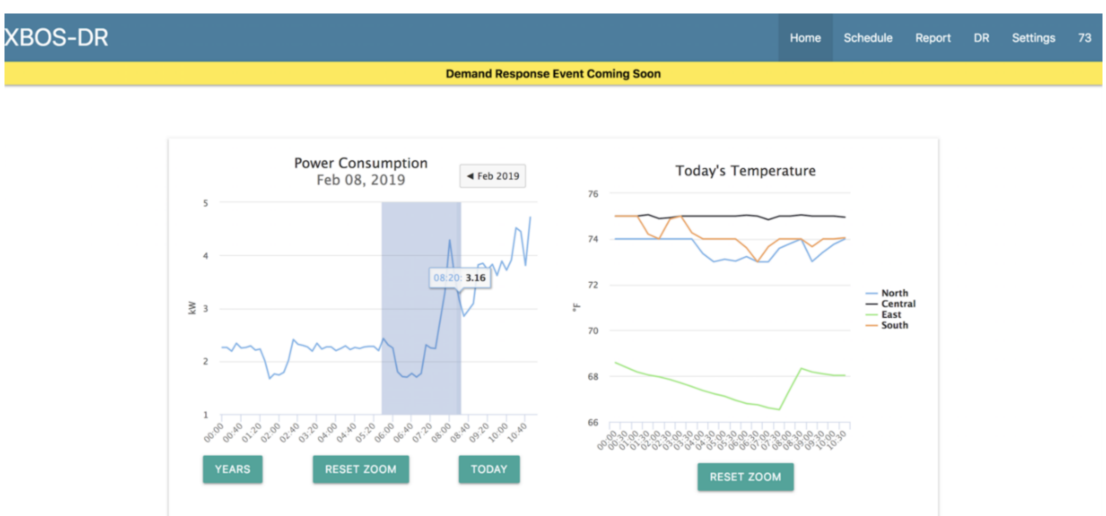


The components of the Negotiation Mediator include the Information Mediator that looks at predicted energy consumption data from multiple buildings, Information Management and Storage, and Message Management and Storage.

Credit: Jack Hodges

Figure 4-27
Components of Negotiation Mediator

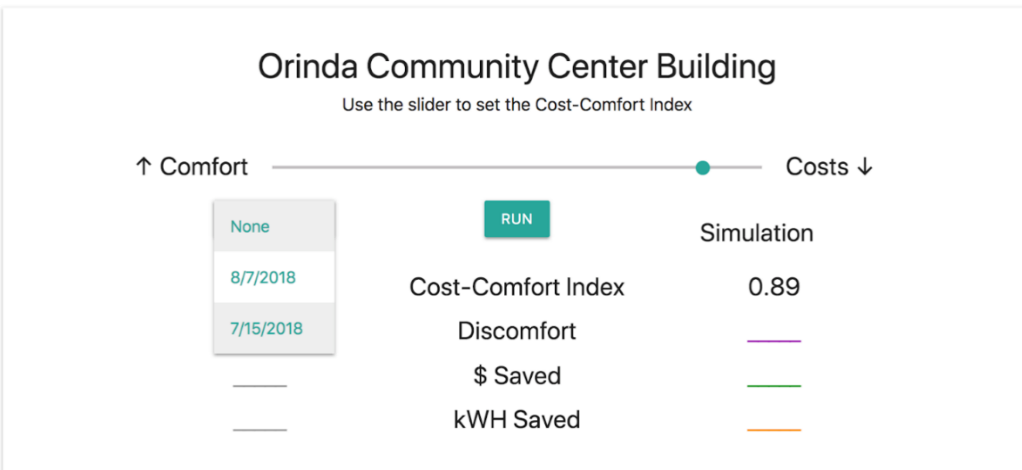
In identifying and developing value to the customer, the research team employed a literature review and interviews to understand the types of users of the platform (e.g., business owner, employee, janitorial staff) and a range of values (e.g., comfort, convenience, cost-savings). The team then developed use cases and developed a user interface that showed the energy consumption, indoor temperature, provided a slider bar for the customer to select the desired balance of cost savings versus comfortable conditions, and provided simulations so the user could understand the implications of the cost-comfort selection.



The home screen shows notification of events as well as basic energy and temperature information.

Credit: Therese Peffer and Brandon Berookhim

Figure 4-28
Home Screen of User Interface



The cost-comfort index allows one to select and simulate the desired level of balance between saving money or remaining comfortable during a demand response event.

Credit: Therese Peffer and Brandon Berookhim

Figure 4-29
Cost-Comfort Index on DR screen of User Interface

The system architecture of the XBOS-DR was modular, so that the various components could be developed and tested separately. The Siemens and CMU team developed the price messenger and tested it with both simulated and real utility event signals. The information exchange module included many standards-based information models. The BETS team developed the XBOS-DR platform: creating the drivers (interfaces) for various hardware, such as the thermostats, outlining and developing more than 10 microservices, and upgrading security services. They helped install, integrate, and maintain the hardware and software, developed an improved method of storing, categorizing, and acquiring the data through the Brick schema, and developed models for each building, and tested advanced control algorithms such as Model Predictive Control.

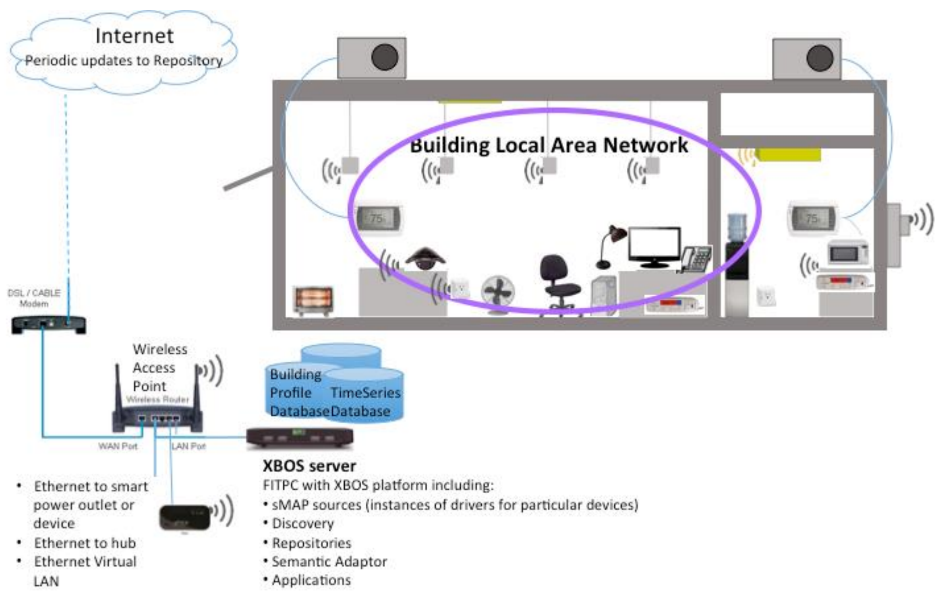
The research team used laboratory spaces on campus and three offices off campus as initial laboratory testing of the networked thermostats, and electric utility meter, and in one case, Electric Vehicle charging and various kitchen appliance loads. After recruitment and initial building audit of several buildings, the team installed the platform consisting of a miniature computer, networked thermostats, and metering in 16 small commercial buildings: 14 in Pacific Gas and Electric territory and two in Southern California Edison territory.

Table 4-2
Buildings Recruited for the Project

Site Name	Area	Classification	Tariff	IOU	Climate Zone
CSU Dominguez Hills (SAC2)	15,548 SF	Business (Higher Ed., Offices/Classrooms)	Master Metered	SCE[¥]	8
Orinda Community Center	20,488 SF	Multi-use assembly spaces (Theater, Meeting rooms)	HA10SX	PG&E[¥]	12
North Berkeley Senior Center	20,834 SF	Senior center (banquet hall & kitchen)	HA10SX	PG&E	3
The Local Butcher Shop	2,850 SF	Mercantile (Commercial Mixed-Use)	HE19S	PG&E[¥]	3
Avenal: Animal Shelter	4,132 SF	Animal Shelter (with storage)	HA1X	PG&E[¥]	13
Avenal: Movie Theatre	15,820 SF	Assembly (Movie Theater, meeting rooms)	HE19S	PG&E[¥]	13
Avenal: Veterans Hall	8,683 SF	Senior center (banquet hall & kitchen)	HA1X	PG&E[¥]	13
Avenal: Recreation Center	2,417 SF	multi-use community center with IT training facility	HA1X	PG&E[¥]	13
Avenal: Public Works Department	12,700 SF	Moderate Hazard Storage	HA1X	PG&E[¥]	13
Fire station 1, Hayward	8,700 SF	Business (with storage, kitchen, and sleeping areas)	HA10SX	PG&E	3
Fire station 8, Hayward	6,500 SF	Business (with storage, kitchen, and sleeping areas)	A6	PG&E	3
Berkeley Corporation Yard	9,600 SF	Business (offices)	A10SX	PG&E	3
Richmond Field Station, Bdg 190	1,850 SF	Business (Higher Ed., Offices/Classrooms)	Master Metered	PG&E[¥]	3
South Berkeley Senior Center	10,427 SF	Senior center (banquet hall & kitchen)	HA1X	PG&E	3
Jesse Turner Fontana Community Center	43,193 SF	Assembly (Banquet Hall, Indoor Gymnasium)	Master metered	SCE	10
CIEE	8,424 SF	Business (offices)	A1X	PG&E[¥]	3

LBNL building 90C	18,500	Business (offices)	Master Metered	PG&E¥	3
Word of Faith Christian Center	19,733 SF	House of Worship and Accessory School Spaces	HA1X	PG&E¥	12
Orinda Library	24,250 SF	Library	HA10SX	PG&E	12

For each building, the team procured historical electricity usage for the previous 24 months. After the system was installed, the team commissioned the equipment and monitored the data. In the summer of 2018, the team conducted several tests during peak day events in many of the buildings; some buildings were not able to participate. The team worked to analyze the data, correct data quality issues, build models, develop simulation tools, and develop zone-level analysis tools. In summer 2019, the team conducted a couple of tests to refine the procedure.



Schematic of XBOS in a small commercial building

Credit: Therese Peffer

Figure 4-30
The XBOS-DR Platform Installed in a Small Commercial Building

The technical barriers included intermittent Internet and other networking issues, data quality, insufficient Application Programming Interface for the networked thermostats, and the short range of the environmental sensors. Non-technical barriers included misunderstandings and miscommunication between the subject customers and the project team, unanticipated length of time to develop the user interface, and difficulty in obtaining the utility price signal directly from the utility.

The networking issues caused the XBOS-DR development team to reconstruct the secure data bus to accommodate local control; a couple of times, the customer's IT team made changes to the internal networked which removed the connection of the research team's system. The Green Button data was continuously collected throughout the project, but often had missing data; the team developed a script to detect the missing data. The team also had to find ways to work around the thermostat API to achieve the needed functionality (e.g., access the programmed schedule, force the system into first stage cooling). One of the TED meters was wired backwards and needed to be rewired; another TED meter malfunctioned and needed to be replaced. One of the customers informed us that the building was a designated cooling center, so the team could only control six of the HVAC zones; two customers (fire stations) asked that the team not change the temperature setpoints, which essentially eliminated those buildings from the study. The project team found a couple of ways of receiving the price signal, including scraping the data from the internet.

The research team presented the project in a number of venues to industry that included technical advice. The feedback included the need for security, desire to use other databases, ability to add other diagnostic and control modules, and need for some training to use the system.

Overall Results

In general, the researchers achieved project goals in using networked thermostats to reduce energy consumption, demonstrating the prototype XBOS-DR platform to reduce peak loads on event days in small commercial buildings, and demonstrating the price messaging and information exchange module functionality. The team was able to integrate lighting reduction in one building and EV charging and appliance loads in another building. The research team was not able to integrate photovoltaics and storage in the commercial buildings due to the insufficiency of the interface of the existing systems.

The research team identified several major lessons learned. There is an incredible value in incorporating real-time building energy data with thermostat data: one can achieve building system identification, conduct diagnostics, and improve control. The research team also learned the difficulties in commissioning and managing multiple buildings. The team acknowledges more time is required to develop a user interface and address data quality issues.

Additional research that would further the goals of the project would be to continue testing of the user interface, testing the system with a different networked thermostat with an API that provides the functionality desired, and to continue to deploy and test different control and diagnostic strategies.

Benefits to California

This project is anticipated to result in the ratepayer benefits of greater electricity reliability and lower electricity costs through enabling more effective use of DR and distributed generation resources. Greater reliability and lower costs are expected to help manage anticipated issues resulting from: 1) the increasing integration of intermittent power generation into California's grid under the state Renewable Portfolio Standard program, and 2) related issues from increasing electric vehicle charging. The project technology is also expected to increase penetration of building management systems in smaller commercial buildings, resulting in energy cost reduction through improved end-use energy efficiency. In addition, increased safety is expected for energy end-use equipment through increased capability for remote monitoring and potential integration with alarm services.

The technology could be adapted for the residential sector at minimal costs; different drivers would need to be developed depending on the types of hardware included.

The project estimated the following specific impacts and benefits of the proposed aggregated demand-response and integrated energy management program, with supporting rate design and open-architecture software platform for large and small commercial sectors:

- Greater reliability of the electricity infrastructure, reducing frequency of outages.
- $260 million per year reduction in energy costs for ratepayers in 2024 derived from: lower demand charges (reflected for the utility as lower electricity infrastructure upgrade and operating costs), increased electric grid energy efficiency, reduced energy end-use from persistent efficiency in parallel with DR, and lower electricity generation costs (from lower-cost intermittent greenhouse gas (GHG)-free electricity generation with less need for spinning reserve, storage or high-cost supplemental peaking generation).
- 450 MW of avoided or shifted peak electric demand in 2024. This is a 150% increase beyond the 293 MW of DR from a combination of nonevent-based programs, critical peak pricing, and peak-time rebates estimated by the California Energy Demand 2016-2026 Revised Forecast [15].
- 180 million kWh per year and 18 million therms per year of reduced energy use in 2024 from persistent end-use energy efficiency achieved in parallel with demand-management.
- 930,000 metric tons of carbon dioxide (CO_2e) emissions per year avoided in 2024 from: increased electric grid energy efficiency, increased end-use energy efficiency in parallel with demand-management, and increased fraction of intermittent operationally GHG-free renewable electricity generation (and decreased need for GHG-intensive supplemental peaking generation).

EPC-15-073 – UCLA - Identifying effective demand response program designs for small customer classes (Gattaciecca, 2020).

Goals and Objectives

This study tested the effectiveness of innovative design strategies, also known as “treatments,” for residential demand response programs using behind-the-meter customer engagement platforms. This study focuses on four main goals to advance understanding of demand response intervention design. These include (1) evaluating the effectiveness of different timing and format of messages, including economic benefits messages and environmental messages; (2) assessing different fixed and nonlinear financial incentive mechanisms; (3) assessing current baseline methodology and the effect of different baselines level on customers’ electricity conservation; and (4) anticipating the effectiveness of TOU based on the project team’s research findings.

These alternative demand response program designs are tested on subsets of customers within Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric service territories. These tests include identifying how customers’ responses to alternative demand response strategies differ, depending on their socioeconomic, demographic, and geographic characteristics.

This study used behind-the-meter customer engagement platforms from two demand response providers, Chai Energy and OhmConnect, to test the research questions made possible by the different capabilities of each platform.

The first half of this study, which took place from August 28, 2017, to October 31, 2017, used a behind-the-meter customer engagement platform developed by Chai Energy. Chai Energy provides a free smartphone application for Android and iOS smartphones. This application had capabilities that allowed researchers to perform a randomized control trial to test the effectiveness of different demand response program incentives and messages. Specifically, this analysis included testing the effects of nonfinancial and financial incentives (ranging from $0.05 to $5.00 per kWh saved) and positive and negative message framing. This analysis also assesses how these effects differ across customers’ socioeconomic, demographic, and geographic characteristics.

Chai Energy's customer engagement platform uses smart meter data to provide households with energy analytics through their smartphones, illustrated in Figure X. There are two levels of service: 1) the Chai Lite energy analytic service is based on 15-minute interval data, and 2) the Chai Pro energy analytic service is based on continuous and appliance-disaggregated data. Customers receiving either service level receive energy analytical insights aimed at increasing awareness of consumption habits and recommendations of ways to save. These insights include energy consumption visualizations, forecasted monthly bills based on rate structure and consumption trends, and periodic emails with cost minimizing advice tailored to specific customer contexts. Customers with Chai Pro also receive appliance-specific information that suggests how to save energy.

Source: Chai Energy

Figure 4-31
Chai Energy Analytics Example

Chai Energy users have implemented the following methods of saving energy during demand response events:

- Increasing the thermostat setting to a higher temperature or turning off the AC system
- Turning off or unplugging electronics, appliances, lights, or pool pumps or a combination
- Delaying doing laundry or charging electric vehicle.

The second half of this study relied on OhmConnect, Inc., a large San Francisco-based demand response provider with more than 100,000 users in California. OhmConnect encourages users to reduce energy consumption with the goal of reducing residential user demand on the grid using a behind-the-meter engagement platform. OhmConnect provides financial incentives for users of its service to reduce electricity consumption during critical energy periods, called #OhmHours.

Through OhmConnect, researchers tested several questions made possible by OhmConnect's large user base and its use of nonlinear incentive programs, which provide users with increasing incentives for consistent behavior. Using detailed electricity consumption, event performance, sociodemographic, and geographic data on a random sample of 20,000 users from OhmConnect, the second half of this study focused on three primary research questions examining how to encourage increased participation and improve the cost-effectiveness of demand events. Specifically, researchers used regression discontinuity design12 methods to test (1) how users responded to demand response program designs like streaks and statuses, (2) How important the baseline calculation is for consumption, and (3) how consumption reductions varied by demographics.

Figure 4-32 shows the OhmConnect engagement online platform, which is used by residential electricity customers to receive information about demand response events. During #OhmHours, users earn points for each kWh reduced relative to what their estimated consumption would have been without a demand response event, known as a baseline. Users can cash out points (on PayPal, Amazon, Target, and the OhmConnect store), donate points to a charity, or send them to another OhmConnect user at any time. Users can also use their points to purchase items at the OhmConnect store, including automation devices that can be used during #OhmHours such as smart thermostats or smart appliances.

OhmConnect users also can receive engagement bonuses. Examples include payments for reaching certain levels within the platform, responding proactively to others on forums, connecting additional devices for automation, and referring others. OhmConnect works to keep users engaged with the platform to reduce their energy consumption regularly, including by using gamified features, such as streaks and status levels.

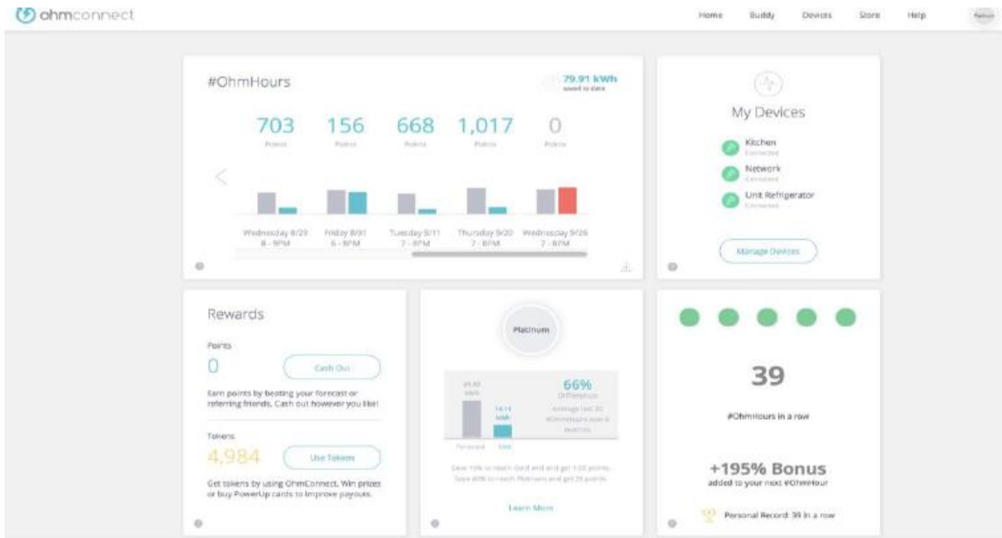


Figure 4-32
OhmConnect Platform

During #OhmHours, users receive points by reducing energy consumption through ‘behavioral’ or ‘automated’ responses. Based on a dispatch signal, OhmConnect dispatches users either via behavioral notifications or device automation or both. ‘Behavioral’ responses are when users take actions in response to #OhmHours by turning off lights, waiting to do laundry until after the #OhmHour event, or any other direct, energy-saving activity.

OhmConnect users can also automate their participation by using their smart home, smart appliances, or smart thermostats. Users that “connect” their devices to the OhmConnect platform allow OhmConnect to turn off or change the temperature level of the thermostat during #OhmHours. Across all OhmConnect users, more than 30,000 smart devices (smart plugs, smart thermostats, and smart appliances) are turned off during each energy-saving event and turned back on when the #OhmHour is over. OhmConnect observes that users with automation devices reduce their energy usage 100-300 percent more than users without devices. In addition, users with automation devices typically continue to reduce electricity consumption during #OhmHours over time for longer than users that do not connect devices. OhmConnect notes that device saturation has increased among OhmConnect users over time, and its users adopt additional devices over time.

Methodology and Approach

The two behind-the-meter customer engagement platforms from OhmConnect, Inc. and Chai Energy allowed researchers to test two sets of research questions made possible by the different capabilities of each platform. OhmConnect’s large user base and multiple incentive designs were used for most of the nonexperimental analyses, and Chai Energy’s smartphone application has capabilities that allowed researchers to perform a randomized control trial. To conduct this study, a sufficient number of customers needed to be recruited to each customer engagement platform.

These customers needed to be representative of different household characteristics – including income, household structure, climate zone, and utility13 – to study the effect of different demand response strategies across California. This section describes the methods used to recruit users.

OhmConnect Engagement Platform

To conduct the identified analyses identified in this report, the research team needed access to energy consumption data for a large sample of users. OhmConnect provided the UCLA team with detailed data on energy consumption, event performance, and sociodemographic and geographic characteristics for 20,000 OhmConnect users. All analyses were carried out nonexperimentally on already-performed #OhmHours using non-personally identifiable information (non-PII) energy-related information for OhmConnect users across California. This section describes OhmConnect's strategies for user acquisition.

User acquisition refers to getting users to sign up for the OhmConnect service. Demand response programs naturally have greater potential to reduce energy consumption during demand response events with more participants. Moreover, OhmConnect user acquisition ensured UCLA has adequate data to perform analysis on demand response behavioral patterns and general engagement. The sample of customers used in this study were recruited by OhmConnect using three user acquisition methods related to paid channels: social media campaigns, third-party paid leads, and direct mail marketing.

Social media campaigns: Social media forums allow companies to buy advertising campaigns so that their marketing targets a specific demographic. Specifically, OhmConnect used Facebook and Nextdoor, a community-based email newsletter and online posting network. The Facebook advertisements explained that participants could get paid for saving energy while helping the environment, while the Nextdoor ads emphasized earning money.

Third-party paid leads: OhmConnect uses third-party marketing organizations to generate paid customer leads, which target promising customers. Paid leads help identify potential users via social media tools, and the marketing service provides data analytics to help focus advertising campaign efforts in channels that have higher user acquisition rates, making recruitment more cost-effective. These ads focused predominantly on the financial aspect of OhmConnect and targeted potential new users interested in ways to earn money or to become more financially savvy.

Direct mail marketing: OhmConnect also acquired users using coupon mailers. One example using this method used the Valpak coupon book. This coupon book contains a variety of coupons from many different companies and is mailed directly to people's homes based on a propriety list curated by Valpak. OhmConnect described its service within the coupon. Most coupons were combined with other financial incentives, such as a $20 gift card to Target upon signup. The "coupon" encouraged IOU users to use the URL to sign up for OhmConnect.

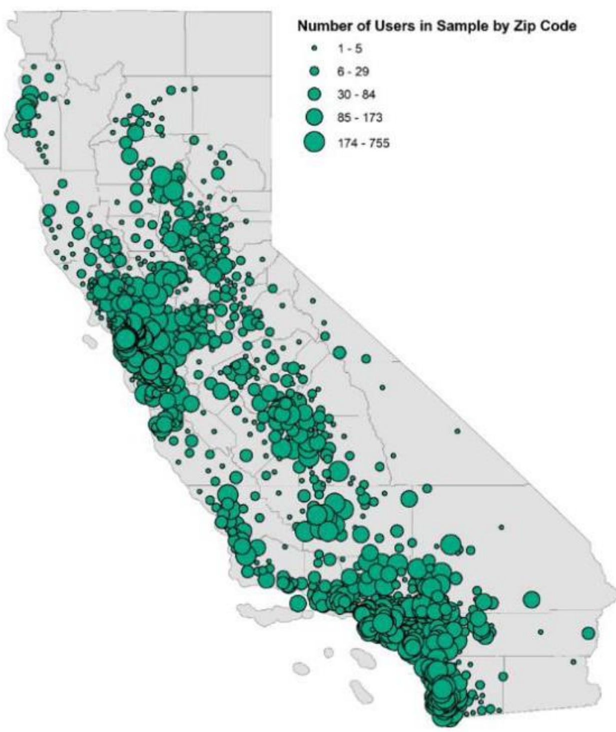
Based on overall cost of acquisition, social media was the most expensive user acquisition method, followed by mail marketing. Third-party paid leads were the least expensive. The average cost of recruitment by customer for each of these methods is summarized in Table 4-3.

Table 4-3
OhmConnect Costs of Acquisition

Method of Recruitment	Cost per Customer
Facebook	$89
Nextdoor	$34
Direct Mail Marketing	$15
Third-party Paid Leads	$5

Study Participant Demographics for OhmConnect Sample

In this study, UCLA used a randomly drawn sample of 20,000 OhmConnect users. These customers represent a variety of sociodemographic characteristics and geographic locations. Figure 4-33 shows the geographic distribution of OhmConnect customers across the state.



Source: UCLA Luskin Center for Innovation.

Figure 4-33
Geographic Distribution of OhmConnect Customers

Table 4-4 shows the average sociodemographic characteristics of the study sample compared to the California population. To protect customer privacy, the demographics of each customer in the sample was unknown to researchers. This table, therefore, represents the average demographics based on the zip code in which each user is located.

This table summarizes five key demographic variables by the average demographics of the zip code in which the users in the sample are located: percent white, percent homeowner, median income, proportion of California Alternative Rates for Energy (CARE) customers, and percent single-family home. Among represented zip codes in the sample, the mean is 44 percent white, and 81 percent single-family home ownership, both above the California mean of 38 percent and 58 percent, respectively. The average median annual household income of represented zip codes is slightly above the California median of $67,739.

Table 4-4
Demographics of OhmConnect Sample

Demographic	Sample	California
Home Ownership	55%	55%
Median Income	$73,246	$67,739
Single-Family Home Share	81%	58%
Average Annual Energy Use (kWh)	5,798	7,266

Source: Sample statistics from UCLA and OhmConnect. California population statistics from United States Census Bureau and American Community Survey as of January 2019.

In the OhmConnect sample, 12 percent are CARE customers, 8 percent are on a TOU rate, 15 percent own a PEV, 8 percent have solar PV panels, and 25 percent own automation devices.16 Solar PV customers, PEV owners, users with automation devices, and TOU customers make up a minority of the overall sample. One major goal of the analysis in this report is to observe if these "energy-engaged" customers behave differently in response to events than less-engaged customers. About 4 percent of users adopt automation devices immediately upon joining, and about 14 percent adopt automation after 18 months. Finally, there is a large variation in customers' average consumption during an event. Although mean consumption is around 1 kWh, the median is 0.74 kWh, suggesting there are outlier high-energy users. Consumption during an event also varies dramatically by season. In summer, usage is closer to 1.5 kWh per event, while in winter consumption falls to 0.5 kWh per event.

Chai Energy's smartphone application provided participants with energy analytics and feedback that enables them to participate in demand response events. Researchers used this engagement platform to implement a multi-treatment randomized control trial to identify the most effective demand response incentives and messaging for different customer classes.

Adaptation of Chai Energy's Platform and Implementation

For this study, Chai Energy upgraded and modified its application to support the functionalities necessary to run a randomized control trial on thousands of customers. As described in more detail in Chapter 3, each demand response event delivers different types of messages, incentives, and formatting to different groups of study participants to test the identified strategies. Chai Energy developed its smartphone application capabilities to support the delivery of different financial incentives, messaging, and messaging times depending on a study participant's assigned treatment group for this study. Chai Energy developed a system to allow alternative treatments to be distributed simultaneously and at different times to understand how the timing of messages could affect customer's behavior, depending on the study participant's assigned treatment group. Moreover, each demand response event has several event-specific push notifications at preset times. Chai Energy developed the capability of the application to send notifications to study participants at various times and for the various treatments.

Furthermore, in support of this study, the Chai Energy team incorporated the ability to distribute financial incentives to study participants, when applicable. Chai Energy also developed a researcher portal specifically for this study to allow researchers to view and export anonymized data from the different treatments and events at the study participant level. Researchers also manage and adjust the different treatments and groups through this portal.

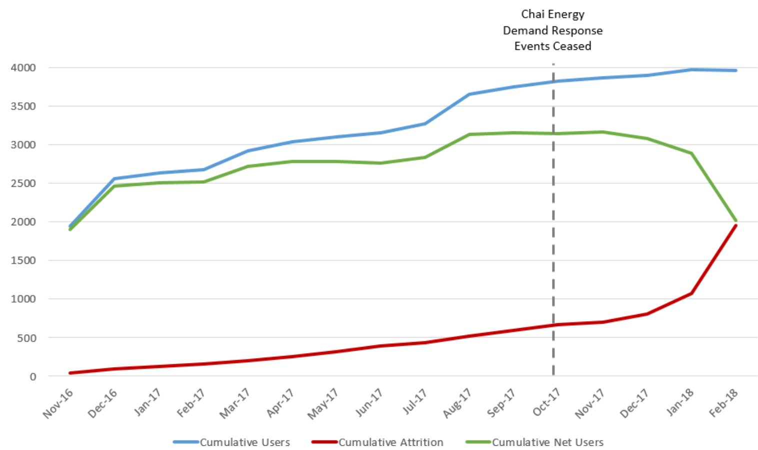
Study Participant Recruitment and Attrition for Chai Energy

The project team recruited 2,989 participants for the Chai Energy study. The goal of recruitment was to have a large enough sample to (1) have sufficient power to determine with statistical significance the expected effects of each treatment group and (2) be representative of different household characteristics, including income, household structure, climate zone, and investor-owned utility (IOU) territory, to study the effect of different demand response signals across California.

Chai Energy used several strategies to recruit study participants: targeted advertisements on Facebook and Google, advertisements on multiple radio channels, and advertisements on local media: KTLA (the local television news station in Los Angeles). About 9,500 users downloaded the application on their smartphones, but only 6,100 users registered for Chai Energy during the study recruitment period between December 2016 and August 2017. The average cost of recruitment per customer who registered for Chai Energy was roughly $7, which is lower than the market benchmark.17 However, to be enrolled in the study, each registered customer needed to provide Chai Energy with access to his or her energy consumption data, through Green Button Data. Green Button Data allows residential customers to access their 15-minute interval energy consumption information. The process for granting a third-party access to these data was arduous for customers, which resulted in only 24 percent of registered customers successfully providing data. This low registration rate increased the cost of customer recruitment to about $29 per customer. The Green Button Data presented an obstacle to Chai Energy, who lost several thousand customers when it was forced to migrate its existing customers toward the Green Button Data registration process, affecting the sample size of the study. The California Public Utilities Commission (CPUC) has since improved the process to make it simpler for customers to share their data with third parties, like demand response providers, which is discussed more in a later section.

Customer recruitment faced unanticipated challenges, especially regarding the cost and method of recruitment. For example, because of the way the Facebook marketing platform is designed, Chai Energy reported that these advertisements seem to reach saturation rapidly (where people repeatedly see the same advertisement), diminishing the effectiveness of recruitment. Chai Energy used a slow to moderate rate of advertisements to address market saturation. However, this action limited daily customer recruitment. Some other marketing channels such as third-party paid leads have brought down the cost per acquisition but also potentially resulted in a biased customer sample. In terms of the success of the digital advertisements, only about a quarter of clicks resulted in registrations. While the advertisements may have been enough to pique a potential customer's interest, it may have been insufficient to motivate action.

A large number of participants were lost to attrition over the recruitment and study period because of a lack of engagement, illustrated in Figure 4-34. During months that researchers were administering demand response events, customer attrition averaged 2 percent per month. After demand response events ceased in October 2017, attrition increased rapidly. Forty-three percent of users left the platform after four months of inactivity. The main reason for attrition is likely associated with a lack of demand response events during the winter.



Source: UCLA Luskin Center for Innovation

Figure 4-34
Chai Energy Customer Recruitment and Attrition Over Time

Study Participant Demographics for Chai Energy Sample

To protect customer privacy, identifying characteristics of participants are unavailable to researchers. Demographic and economic estimates are therefore based on a user's zip code of residence. This means that a customer is assigned the 'mean' demographics of the zip code. Table 4-5 shows the average demographic, economic, and energy-use characteristics for the customers in this sample compared to the California average.

The marketing campaign resulted in a sample that was over representative of white populations and under representative of Hispanic and African American populations relative to the California population as a whole. On average, the customers in the sample live in zip codes that are well-off, with median incomes above $80,000 and median home values above $500,000.

Finally, participants are heavy adopters of solar PV; about 20 percent have solar PV panels installed on their homes. This large share of solar PV customers suggests that study participants may be more energy-conscious than the average California consumer. It is likely that these customers who enrolled through the general marketing campaign may be representative of those who are early adopters of other technologies. As such, some populations may need to be targeted specifically to promote future demand response or energy conservation programs. These populations may not be as accessible through general marketing campaigns, and additional resources may be needed to recruit these underrepresented populations more directly.

Participants recruited from the general marketing strategy could also reflect those who are more likely live in zip codes with higher proportions of single-family homes or own a smartphone. For example, participating with Chai Energy necessitates that customers own a smartphone to download the application and have internet access. As of 2016, an estimated 77 percent of adults in the United States owned a smartphone, and 64 percent of lower-income adults owned a smartphone.

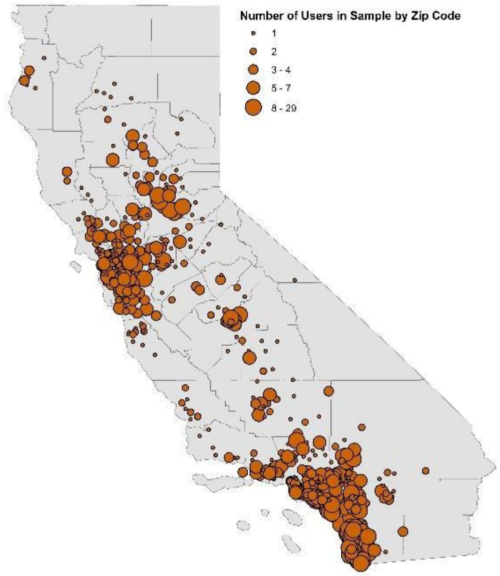
Chai Energy's customer recruitment relied primarily on digital advertisements through Facebook and Google. Social media advertising algorithms could also affect the sample. If this is the case, other recruitment strategies or media need to target those that may be underrepresented as a result of a more general marketing strategy. One solution could be reducing the need to have a smartphone to participate. For example, OhmConnect's service requires only access to the internet and does not necessitate the use of its smartphone application, which makes it more accessible to a wider audience.

Table 4-5
Chai Energy Sample Energy Characteristics and Demographics

Demographic	Sample	California
White	52%	38%
Hispanic	26%	39%
African American	4%	6.5%
Home Ownership	62%	55%
Median Income (by Zip Code)	$81,802	$67,739
Single Family Home Share	63%	58%
Average Annual Energy Use (kWh)	7,469	7,266
Has Solar PV Panels	20%	-
Has Automation Device(s)	10%	-

Source: Sample statistics from UCLA and Chai Energy. California population statistics from the United States Census Bureau as of January 2019. Average annual energy use (kWh) estimated based on the most recently available (2017) California Energy Commission "Electricity consumption by County" for all residential customers and the United States Census Bureau's estimate for occupied housing units.

The study sample is geographically representative of the state, shown in Figure 4-35. While there are concentrations of customers in Los Angeles County, San Diego County, Orange County, and the San Francisco Bay Area, the concentrations of the study participants fall similarly to the population density of California. Forty-three of the 58 counties in California have at least one customer included in this sample. The eight most represented counties are Los Angeles, San Diego, Orange, Santa Clara, Riverside, San Bernardino, Alameda, and Contra Costa.



Source: UCLA Luskin Center for Innovation.

Figure 4-35
Geographic Distribution of Chai Energy Customers

Overall Results

This study is not a performance evaluation of effective demand response providers. Both OhmConnect and Chai Energy are registered non-utility demand response providers with the California Public Utilities Commission (CPUC). This UCLA analysis is distinct from any performance evaluations or methods required by state agencies like the CPUC or California Energy Commission (CEC) for demand response providers.

Rather, this study aims to further understand the behavioral components of energy conservation. Because demand response is needed when the marginal price of electricity is high, researchers examined if customers respond to marginal price to inform how demand response providers can make it more salient to users. For example, researchers tested responsiveness to changes in marginal prices through OhmConnect's streak and status programs and to different financial incentive levels with Chai Energy.

Effect of Demand Response on Energy Conservation

Researchers found that demand response events are effective at reducing consumption, but reductions vary by user characteristics and other factors. This analysis investigated the differences in the propensity of customers from different demographic and energy-use segments to reduce consumption during critical energy periods. It is important to highlight that the consumption reductions estimated in these analyses are different from those traditionally used to evaluate demand response programs, which calculate savings beneath a California Independent System Operator (California ISO)-estimated baseline. In this analysis, researchers do not use that baseline because the accuracy of the baseline differs across groups and would lead to bias in the project team's estimations of differing responsiveness. With that caveat in mind, researchers estimate the effect of a demand response event on consumption for different types of users. The effect is defined as the amount a user consumes beneath what he or she would have consumed in the absence of the demand response event.

Across all users, researchers found that on average throughout the year, users reduced their energy consumption by 0.15 kilowatt-hours (kWh), or 18 percent, during an OhmConnect demand response event relative to what they would have consumed without an event. Users reduced consumption by similar amounts even when they received demand response events two days in a row; this result suggests that individuals are not merely shifting usage to the next day when an event occurs. Furthermore, users do not increase their consumption in the hours or days before or after a demand response event. This finding provides additional evidence that users are conserving energy in response to demand response events rather than shifting their energy consumption to other times. More importantly, users have larger reductions in energy consumption during demand response events when they first join the demand event platform. Customers reduce energy consumption by 22 percent during their first 20 events relative to 17 percent after. This finding suggests that user engagement falls over time.

Although users reduced consumption during demand response events throughout the year, the greatest consumption reductions occurred in the spring and summer, and especially on hotter days. This conclusion suggests that it is easier for customers to reduce consumption when they have a greater capacity to do so, that is, when they can turn off their air conditioners. On average, customers reduced electricity consumption during demand response events by 21 percent on days hotter than 90 degrees Fahrenheit and only 15 percent on cooler days. Similarly, energy conservation during demand response events is about 1.8 times and 3.5 times greater in absolute terms during spring and summer, respectively, compared to the rest of the year. The time of day that a demand response event began was less important, however, than the time of year. Researchers found that the effectiveness of demand response event timing may be context-specific and may rely more on messaging or financial incentive than on the time.

Moreover, researchers found customer responsiveness varied by user characteristics. Engaged energy users, or those with solar photovoltaic (PV) panels, plug-in electric vehicles (PEVs), or automation devices (such as smart home, smart thermostats, or smart appliances) or a combination are more likely to reduce consumption during #OhmHours. Specifically, PEV owners reduce consumption 2.5 times more than non-PEV owners, while users who have ever adopted automation reduce three times more relative to never-adopters. Users who have automation devices used 47 percent less energy during a demand response event relative to 13 percent reductions for those who do not. This finding suggests that energy engaged users could be targeted for more focused demand response programs.

There were relatively minor proportional differences among most demographic subgroups. California Alternative Rates for Energy (CARE) customers proportionally conserved less than non-CARE customers, although this difference was driven largely by differences in solar PV, PEV, and automation ownership between those two customer classes. Similarly, when looking at non-energy-engaged customers, time-of-use users reduce less than users on other tariffs. However, these results are inverted when looking at energy-engaged customers. Favoring energy technologies such as automation seems essential to maintain high-demand response efficiency, even as California transitions more customers to time-of-use pricing.

Baseline

Demand response providers typically reward users during a demand response event based on their conservation relative to an assigned baseline. The baseline represents a user’s energy consumption in the absence of a demand response event. Baselines are set based on the average of consumption in the same hour of the demand event during the previous 10 non-event, nonholiday weekdays. With OhmConnect, customers receive information about their baseline when they are notified of an event, and how this baseline compares to their electricity consumption for the previous week.

Customers modify the magnitude of their conservation depending on their baseline level. Customers reduce their energy consumption more when their baseline is set lower, all other factors held constant. Customer responsiveness to baseline changes varied by demographics. Only customers without automation respond to changes in baseline, likely because behavioral responses require active engagement by customers. Furthermore, customers in low-income zip codes responded the most to changes in baseline both proportionally and in absolute terms. These findings suggest that in information environments such as OhmConnect where a large emphasis is placed on meeting a goal, the level at which the goal is set may be a useful lever for changing conservation behavior.

Streak and Status Programs

This analysis assesses how nonlinear pricing strategies can influence consumers' willingness to reduce energy consumption during peak periods. OhmConnect employs a novel incentive structure to motivate consumers to conserve electricity during critical energy events (#OhmHours). Here, researchers focused on two of OhmConnect's programs offering nonlinear incentives: streak and status. Individuals build "streaks" by consuming less than their baseline in consecutive demand response events. OhmConnect participants can earn different statuses (silver, gold, or platinum) based on the percentage of energy saved relative to the baseline over their past 10 #OhmHours.

Researchers did not find that maintaining a streak or status (and the corresponding financial bonuses) induced greater energy conservation than missing a streak or status. Researchers found no effect of extending the status or streak when compared to users who lost the status or streak, despite differences in marginal financial incentives. When looking at a user's first 20 events, researchers found that individuals who extend their streak to reduce electricity consumption more than those who lost it, but only if their streak was five events or longer. For status, researchers observed that moving from silver to gold had an effect on consumption and increased the likelihood that a user would invest in automation technology. Those effects were not seen for platinum status.

These results do not find evidence that marginal financial incentives provided by streak and status induce greater conservation behavior in the general population. This finding is consistent with the results from the Chai Energy analysis in this report and in a previous study (Gillan 2017) that found very low additional responsiveness to higher marginal rewards. However, the lack of marginal price effect does not necessarily imply that these programs are not shifting behavior. It could be that the presence of streak or status rewards induces all users to try harder, whether they have an active streak or status. To test this, researchers would need an additional experiment in which only some users had access to the streak and status programs. This experiment is outside the scope of the current study but is an important area of potential future research.

Financial Incentives and Messaging

In the experiment with Chai Energy, researchers uncover how different types of financial incentives and messaging affect consumers' willingness to reduce energy consumption during peak periods. Providing a financial incentive was more effective than not, although the size of the incentive was relatively unimportant.

As a secondary analysis, researchers found that economic benefits messaging emphasizing cost savings was the most effective framing for demand response events, with and without financial incentives. Even on hot days, which saw greater consumption reductions, the moral messages (which emphasized how health and the environment are affected) reduced consumption only by 1 percent to 2 percent compared to the economic benefits message, which reduced consumption by 6 percent.

User Engagement

Finally, user engagement falls over time. Users have larger reductions in energy consumption during demand response events when they first begin participating. Researchers found that users reduced consumption about 30 percent more during their first 20 demand response events relative to later events. Moreover, researchers found that streak length and status level decreased over time, suggesting users were less engaged over time. With Chai Energy, researchers observed high levels of customer attrition after only a few months without receiving demand response event notifications. Users are difficult to recruit in the first place. In order to participate, customers needed to provide demand response providers with access to his or her energy consumption data, through Green Button Data. The process for granting a third-party access to these data was arduous for customers, which resulted in only 24 percent of registered customers successfully providing data. A central challenge of all demand response providers is how to attract customers and ensure that they remain active conservers in the long term. OhmConnect's strategy of emphasizing automation may be an effective way to accomplish this goal.

Benefits to California

According to the U.S. Department of Energy, "the most important benefit of demand response is improved resource efficiency of electricity production due to closer alignment between customers' electricity prices and the value they place on electricity." This results in a variety of economic, health, environmental, and operational benefits for California, its residents, and its ratepayers.

Greater Energy Reliability and Increased Safety

As the share of renewable energy increases in California, the need for demand flexibility increases to ensure reliable, safe, and stable grid operations. Demand response providers have the ability to aggregate customers and reduce their electricity load at the most important times, adding flexibility to the load when most needed and avoiding risk of outages and electricity interruption. Moreover, the participation of electricity customers in maintaining grid operation helps defer further infrastructure investments. Finally, demand response provides wholesale market improvement as it helps reduce price volatility and diminish the market power of some energy providers at times of high stress on the grid and highly volatile prices. One study showed that a 5 percent reduction in demand during the California energy crisis could have reduced costs by 50 percent.

Health and Environmental Benefits

Demand response programs avoid the consumption of electricity when demand is abnormally high and requires a lot of expensive power supply, including peak power plants and other old fossil fuel generators. By reducing electricity consumption at those times, California helps reduce the emission of greenhouse gas and criteria air pollutants into the atmosphere.

In this specific solicitation, the CEC assumes that each kWh of electricity saved results in 0.73 pounds of avoided carbon dioxide emissions. The demand response events conducted with OhmConnect and Chai Energy over this study period resulted in about 200 megawatt-hours (MWh) of cumulative electricity consumption reduction during peak times. This reduction resulted in an estimated 66 metric tons of carbon dioxide (MTCO2e) in avoided emissions.

The burning of fossil fuels for electricity generation also results in criteria pollutant emissions. Exposure to criteria pollutants is associated with adverse health impacts, including respiratory and cardiovascular issues. Disadvantaged communities have the most significant exposure to these emissions, including communities in nonattainment air basins for ozone, particulate matter (PM) 10 and PM 2.5; those with high poverty, minority populations, unemployment rates, or a combination thereof; and those with a high percentage of age-sensitive populations. The energy consumption reductions that occurred during this study period reduced the need for electricity generation at times when it was most needed, thereby avoiding the emission of these criteria pollutants. A reduction in these pollutant emissions can improve public health of the most vulnerable Californians.

Study Participant Benefits

First, electricity customers who participate in demand response events reduce their electricity usage, resulting inevitably in bill savings compared to what it would have been if they consumed more electricity. These financial savings are even higher for customers consuming electricity in higher consumption tiers and customers enrolled in TOU rates. In total, participants saved 200 MWh during the study. Based on the monthly average price of electricity calculated by the California Public Utilities Commission, this collective reduction in consumption would result in $34,700 in direct bill savings for participants.

Then, participants who successfully reduce their consumption compared to their baseline could earn money if the demand response provider offers a financial incentive for successful participation. In the study conducted with Chai Energy, $1,700 incentives were distributed to a portion of the study participants and paid for with CEC funds. In the study conducted with OhmConnect, participating customers earned about $1 million over two years without any financial contribution from the CEC.

Nonparticipant Benefits

The benefits of this study and demand response in general are considerable for nonparticipants as well. Demand response results in better use of existing generation resources (including renewable energy and fossil fuel) and transmission and distribution assets. A more efficient use of the infrastructure defers investments that California ratepayers will not have to pay. A reduced load at critical times, when prices are high, not only results in cheaper wholesale rates for all customers, but reduces the need for short-term capacity, resulting in fewer investments in generation capacity. In some regions of the grid that are congestion-constrained, one could also imagine that demand response can reduce the cost of congestion as well as defer distribution and transmission infrastructure investment. All these avoided costs are reflected in the price of electricity for participants and nonparticipants. For example, OhmConnect claims that each demand response it has in summer displaces four power plants. Finally, to the extent that demand response avoids greenhouse gas emissions in the electricity sector, it may also reduce the amount of allowances that electricity distribution utilities have to purchase in the cap-and-trade auction market. This reduction also reduces the overall cost for electricity customers in California.

EPC-15-075 (DSRIP) – EPRI - Customer-centric Demand Management Using Load Aggregation and Data Analytics (Clarin, 2020).

Objective and Goals

The objective of this project is to demonstrate the effectiveness of transactive and dynamic pricing tariffs and the readiness of Behind the Meter (BTM) DER technology today in management of the demand-side resources in residential and small commercial segments. The project intends to accomplish this by completing the following objectives:

- Design a flexible and Open Demand Side Resource Integration Platform (OpenDSRIP) enabling integration of residential and small commercial customers and his/her devices. Understand technical and market barriers to scaling such a platform and approach.
- Demonstrate how a wide variety of BTM devices such as smart thermostats, heat pump water heaters (HPWHs), electric vehicles (EVs), Photovoltaic (PV) systems, customer-sited energy storage, etc. and other technologies found in smart homes and communities today can be aggregated to provide aggregate load response, leveraging emerging technologies that are connected and provide a better customer experience. Load response will primarily be triggered through dynamic rate signaling (e.g. TOU) with insights into enabling transactive energy signaling. To establish feasibility, the intent is to complete this using current infrastructure provided by: (1) BTM DER providers today and (2) leveraging infrastructure provided by residential and small commercial providers as part of "smart home/smart building" offerings.
- Establish feasibility and test operational strategies for load management using resources behind the meter with specific focus on coordinated load management of these in a concerted effort to help California ratepayers manage TOU and other dynamic energy rates. Establish feasibility in laboratory and field settings with varying levels of communication and controls infrastructure.
- Develop frameworks on how to better understand individual preferences for residential and small business customers for load management, and measure using data from the connected devices.
- Demonstrate advanced telemetry possible using circuit-level, smart meter data and data from other BTM DERs.
- Develop a framework to understand scalability of such a solution in its high-level objective of developing a platform to provide California residential and small commercial customers tools to help customers manage California's shift to more dynamic energy rates.
- Create a path to technology acceleration and commercialization of the resultant tools and benefits through open sourcing tools.

Objectives of this project are met through the exploration and development of the following key innovations. Key innovations that will be developed as part of this project are:

- Creating an open, flexible software framework in the form of OpenDSRIP that is widely accessible through opensource code base and an open Application Programming Interface (API) interface that allows integration of diverse customer and end device segments to be managed through aggregation and coordinated responses driven primarily by dynamic rate signals.
- Development of a framework and infrastructure to collect data from BTM DERs with the focus on leveraging these "DERs as sensors" to better understand customer usage and its effects on building and community load shapes.
- Development of interfaces to test feasibility of various operational strategies that accomplish the customer preference constrained optimization of grid demand and energy use in response to transactive pricing tariffs.

- Understand nuances in addressing these challenges in disadvantaged communities such as lack of reliable broadband connectivity and opportunities to address using tools enabled by OpenDSRIP.
- Create a framework to better understand feasibility and scalability of leveraging BTM DERs to: (1) help customers manage dynamic energy rates and (2) as DERs to enable overall grid flexibility.

Project Approach

The section describes the development of the OpenDSRIP platform including functional requirements development, platform development and functional testing of OpenDSRIP in laboratory environments. This section will also discuss the project's approach in developing a framework on how the integration of BTM DERs can be used as a grid resource from a practitioner's perspective.

OpenDSRIP Development – Platform Architectural Choices

OpenDSRIP development follows a conceptual framework that attempts to integrate utility/ Distribution System Operation (DSO)/Independent System Operator (ISO) side data with customer-sited (behind-the-meter) data from IoT devices representing various flexible loads and DER and Advanced Metering Infrastructure (AMI) data. The integration of these different sides of the utility-customer interaction is accomplished using a layered function model. This layered function model is depicted in Figure 4-36.

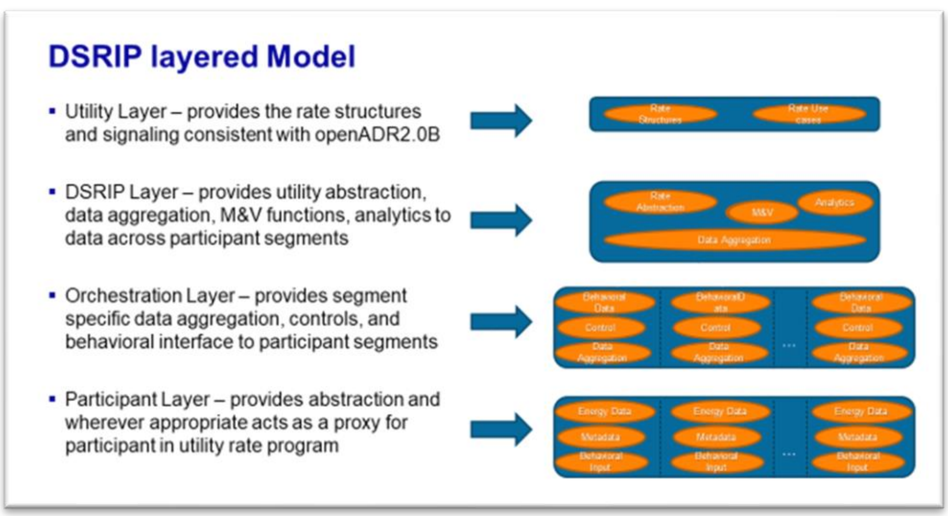


Figure 4-36
Architectural Choice Summary for OpenDSRIP

OpenDSRIP Development – Solution Architecture

OpenDSRIP is being developed as a large-scale project combining "market-based" hardware and software products integrated together into a coherent solution. To this effect, OpenDSRIP will be integrated with utility rate signaling systems (e.g., EPRI Transactive Load Management (TLM)), commercial Building Energy Management Systems (BEMS), EV aggregation platforms such as Open Vehicle to Grid Integration Platform (OVGIP), and Home Energy Management System (HEMS) (e.g., Residential Orchestration Module). The proposed OpenDSRIP solution approach is provided in Figure 4-37.

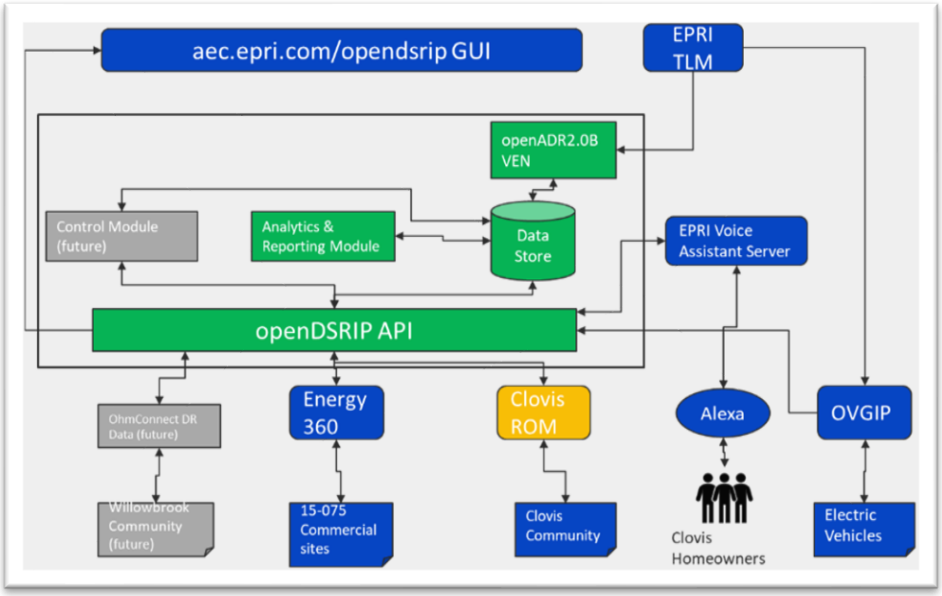


Figure 4-37
Solution Architecture Diagram for OpenDSRIP

The solution developed two distinct systems, namely, the core DSRIP platform (component shown in green with a thick black boundary) and an adjunct Residential Orchestration Module (ROM – shown in orange) for control and aggregation of residential communities into the DSRIP platform. Customer messaging and feedback is enabled via a form of applications: mobile applications, web applications and/or voice-assistant (Alexa-based).

OpenDSRIP Development – System Architecture

The system architecture for DSRIP is shown in Figure 4-38. To allow for flexibility in data models and to ensure long-term scalability for the number of customers, variety of end-user devices, and associated data models, the system uses a Microsoft Azure Data Lake based architecture**.**

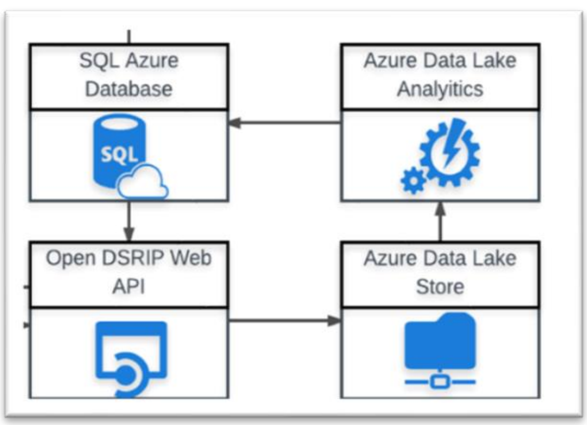


Figure 4-38
System Architecture for the OpenDSRIP system

OpenDSRIP Development – Platform Configuration & Design

The OpenDSRIP platform configuration and design consists of three main components: (1) a normalized data mapping module, (2) interface design plan and (3) a data visualization plan.

- **Normalized data model:** The implementation of the OpenDSRIP platform uses a normalized data model that maps various entities that are designed using an approach depicted in Figure 4-39.

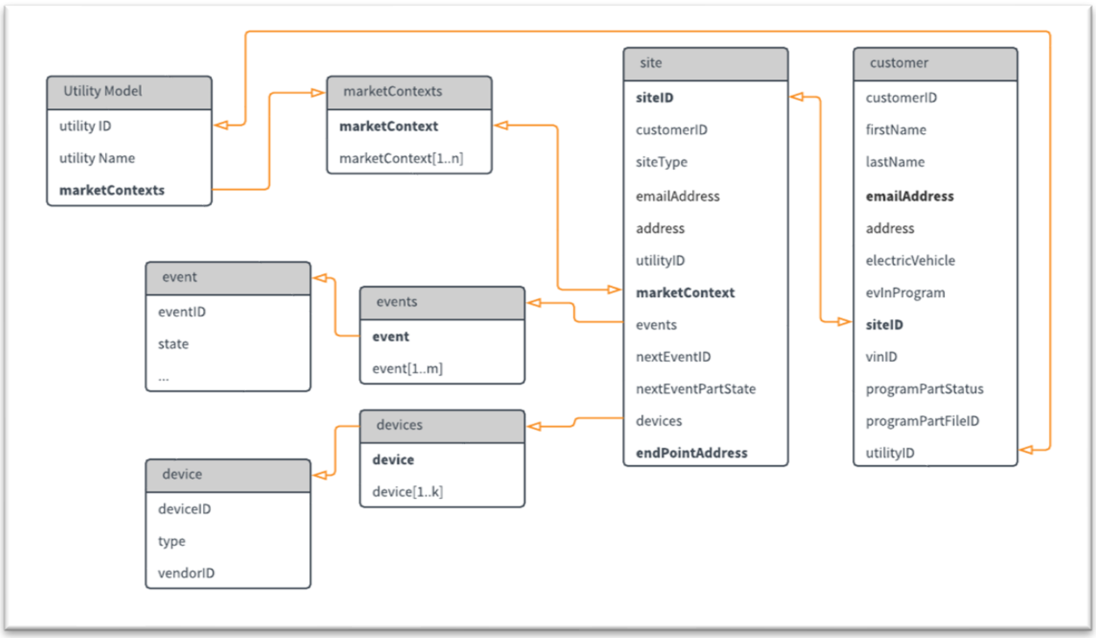


Figure 4-39
Mapping of Entities that are Part of the OpenDSRIP Design

OpenDSRIP Interface Design: OpenDSRIP provides a single point-of-access for all data that includes the ability for orchestration modules to post, get, and modify data in the DSRIP data store using an authenticated and authorized access mechanism. OpenDSRIP provides a range of APIs that encompass both energy and non-energy (operating data) from IoT devices and DER. The OpenDSRIP interface provides the ability to perform a variety of tasks dynamically.

OpenDSRIP Data Visualization Configuration: Data visualization is configured with pre-processed data for a variety of research questions and use cases. Each use case allows the user to explore data in a guided, high-level manner in multiple contexts, such as the community level and the appropriate sub-community level (eg. floorplan, residence, building), depending on the site. The typical layout of the visualization dashboard is shown below.

Figure 4-40
OpenDSRIP Visualization Layout

Functional Testing of OpenDSRIP

OpenDSRIP system level functional testing uses test data for emulating data delivery from behind-the-meter sources and a set of high-level use cases.

Table 4-6
Test data for OpenDSRIP functional testing

Test Data Set	Source
Sites data	1. Residences: Anonymized data from 10 different residential sites. 2. Commercial: Anonymized data from 3 different commercial facilities. 3. EV: Data from 5 different EVs provided by a previous EPRI EV Study with anonymized VIN information.
Customer data	Simulated customer data with random 1:1 assignment between customer and site.
Utility data	Simulated utility data for 2 different utilities each with 2 different market contexts.
User data	Simulated user accounts for testing purposes. Two users each belonging to different simulated utilities.
Devices data **1. HVAC Data** **2. HPWH Data** **3. Inverter Data** **4. Circuit level Data** **5. AMI Data**	1. HVAC Data – re-purposed ecobee data from another EPRI thermostat study for 3 months. 2. HPWH Data – re-purposed skycentrics data from another EPRI HPWH study for 3 months. 3. Inverter Data – simulated data based on SolarEdge API. 4. Circuit level data – data from ZNE homes for 3 months 5. AMI Data – anonymized data from ZNE homes for 3 months.
Events data	4 different rate structures Tiered, ToU, CPP, and day-ahead Locational Marginal Pricing (LMP) resulting in dynamic day-ahead pricing changes; 20 events generated randomly within the 3-month window for which data is defined;

	includes rate scenario specific pricing signals generated in openADR2.0B XML structure.

Table 4-7
Test use cases for OpenDSRIP

Test Use Case	Definition
DSRIP reacts to a TIME Server signal	This tests the openADR2.0B VEN functionality where DSRIP reacts to receiving a TIME Server (VTN) signal.
DSRIP receives data from Orchestration Modules	This tests the ROM and commercial BEMS sending data to OpenDSRIP and having the data in the data store.
ROM reacts to a pricing event	This tests a ROM that reacts the receipt of a pricing signal event from OpenDSRIP.
ROM schedules control actions	These tests the ability of the ROM to schedule control actions on devices in behind-the-meter IoT and DER.
Customer gets notified of upcoming rate-change events	These tests the customer receiving notification based on a scheduled rate-change event.

Signal Dispatch and Demonstration

To finalize an end-to-end test of the overall flow of information from the OpenDSRIP VTN all the way to the behind-the-meter DER through OpenDSRIP and orchestration modules, TIME Server signal dispatch and demonstration scripts were setup. The demonstration setup is shown in Table 4-8.

Table 4-8
Demonstration Setup for TIME Server Signal Dispatch Demonstration

Site Location	Site Name	Market Context	Type of event	Control Entity	Control Action
Pleasanton, CA	R&D Office	DLAP_PGAE_APND	PG&E DR Event	Energy360 & User Behavior	1. Rule based offset for thermostats when DR event is called. 2. Notification when price exceeds threshold.
Clovis, CA	Envision Homes by DeYoung	DLAP_PGAE_APND	Peak price	Residential Orchestration Module	Coordinated control of: 1. smart thermostat, 2. connected Waterheater, 3. customer batteries.

Laboratory Evaluation of Coordinated Control of DERs

The laboratory evaluation of coordinated control was conducted using a setup shown in Figure 4-41.

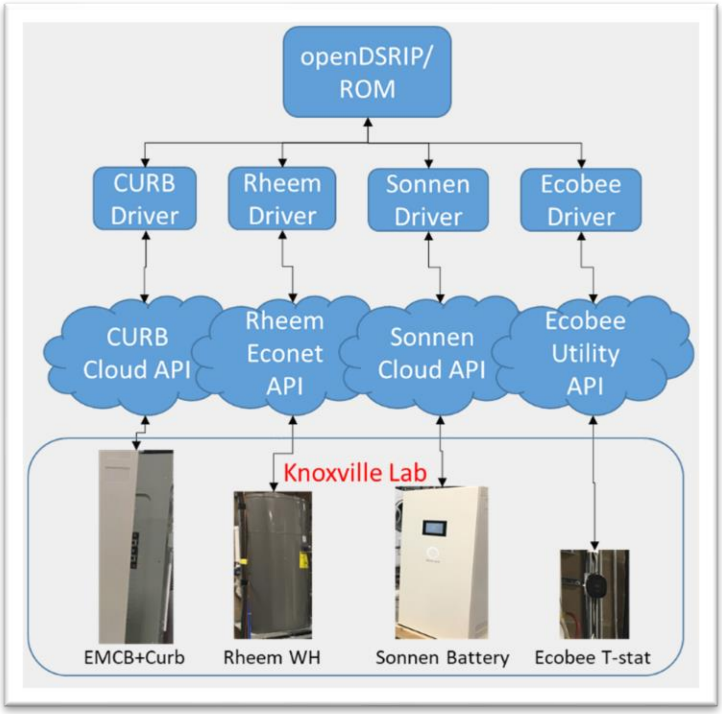


Figure 4-41
OpenDSRIP Coordinated Control Laboratory Setup

Project Evaluation Metrics

The project team then developed an approach to evaluate how an integrated set of customer-sited DER can provide grid flexibility and how this can be done at scale. The project team proposed a framework in which to evaluate various combinations of mass-market BTM DERs and how they can be aggregated together to provide grid or customer services – primarily driven by dynamic rate signaling. The proposed framework uses the following equation:

Evaluating Building and System Flexibility using Behind-the-Meter
Distributed Energy Resources

$$F(x,t) = Obj(x,t)*\lambda(x,t)$$

- Where F(x,t) is grid functions or energy services,
- Obj(x,t) is objective functions and strategies to enable buildings, devices and communities as flexible grid resources, and
- $\lambda(x,t)$ are practical and market factors that proxy opportunities and challenges to solution scalability

Note that the equation is a function of both time(t) and location(x). This represents that this assessment and framework recognizes the need to understand when and where buildings and communities will need to be grid resources as California moves to its decarbonization goals.

Overall Results

The following results are associated with functional testing of OpenDSRIP:

OpenDSRIP Needs to Split into Two Generic Layers: Original depictions of OpenDSRIP represented it as a single platform/layer architecture. Lessons learned when developing functional requirements using demonstration test cases found that in order to accommodate for wide variations in the availability and capabilities of BTM DER technologies, infrastructures and deployment scenarios, OpenDSRIP was split into two layers. The top layer was referred to as the DSRIP layer is largely comprised of invariant components that implement a set of grid-supporting functions. The bottom layer, referred to as Orchestration Layer, is comprised of DER management systems, DER aggregation systems, energy management systems, fleet charging control systems, and optionally custom developed open-source orchestration modules (e.g., ROM). This layer provides a pipeline for acquisition of energy and operating data from behind-the-meter IoT and DER as well as supporting control functions.

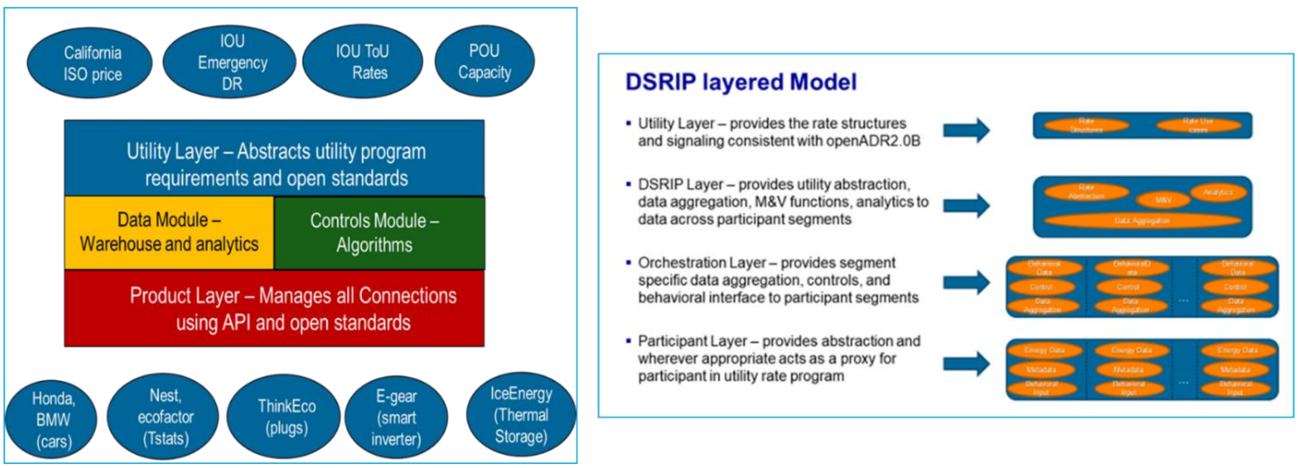


Figure 4-42
Comparison of DSRIP conceptual models before and after functional requirements

- **Security and Privacy are Important:** Personally, Identifiable Information (PII) needs to be handled appropriately. Given that most of the data collected in DSRIP comes from behind-the-meter IoT and DER, the potential for this data to contain customer PII is high. To prevent any exposure of PII, all customer identifiers were scrambled using Globally Unique Identifiers (GUID)/Universally Unique Identifiers (UUID) v4.

The following results are associated with implementation of OpenDSRIP:

- **Availability of Open 3rd Party Energy-Focused Control Mechanisms is Limited:** Few BTM DER provide mechanisms to enable 3rd party coordinated energy management functions. Most IoT device expose this information to HEMS or BEMS providers in agreements for home automation or other energy-related services. Aggregators also play a role in coordinated control with various assessments ongoing in California as well across the country. This is important to note as control infrastructure development is different for each case when considering security and privacy requirements discussed above. It will be important to understand how automation leads to energy management when thinking about how rate-based energy management solutions scale.

- **Understanding Evolution of Energy-Related Standards:** While there are many standards in the market today, it will be important to understand how these standards and the flexibility of these standards are in keeping up with rapid technology change. As BTM IoT is a rapidly evolving market that is primarily customer-facing, is it important to minimize cost and complexity of customer participation.

- **Leveraging Pseudo-Standards, Based on Market Adoption, Offer Interesting Opportunities for IoT and DER Aggregation:** See Figure 4-42 and Figure 4-43

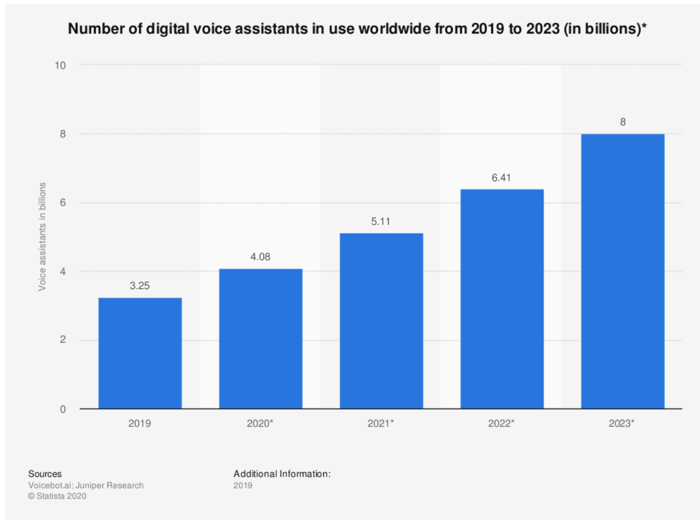


Figure 4-42
Smart speaker adoption worldwide

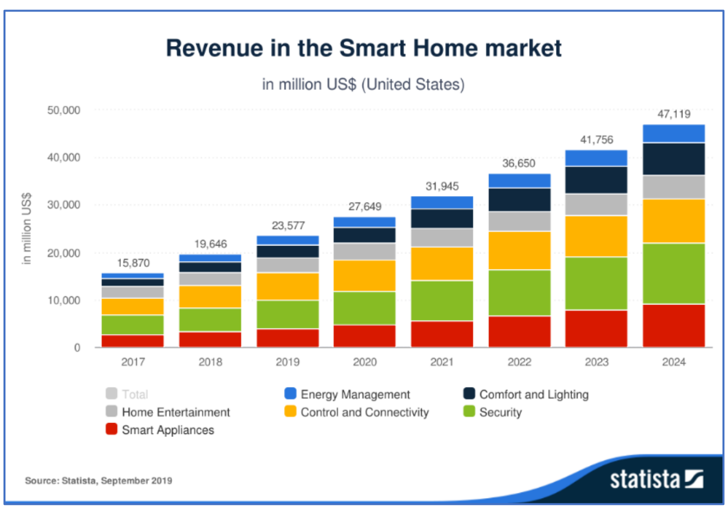


Figure 4-43
Projected growth for smart-home products in the US

- ***Personalization through Tiered-Control, Customer-Driven, Energy Management Strategies (see Figure 4-44 and Figure 4-45) Provide a Viable Basis for Market-Driven Energy-Efficient Behaviors*:** The role of customer's own energy efficient behaviors takes prominence as operating technologies become more energy efficient (e.g., heat pumps, heat pump water heaters, smart plugs, etc.). This necessitates a tiered-control strategy (preferably opted-in by the customer) that spans the full-spectrum of customer personas when it comes to energy usage. The role of customer's own energy- impacting behaviors takes prominence as operating technologies become more energy-efficient (e.g., heat pumps, heat pump water heaters, smart plugs, etc.).

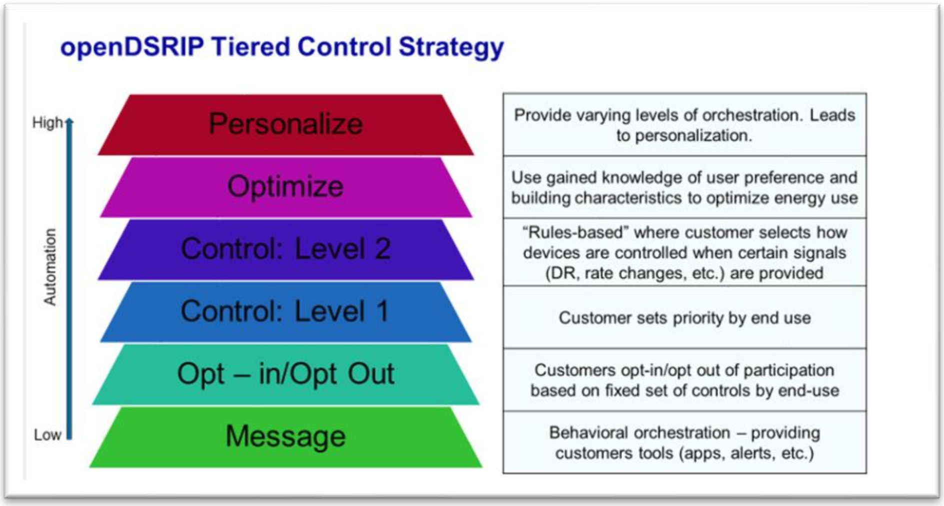


Figure 4-44
Orchestration and Optimization Tiers (Based on Level of Complexity)

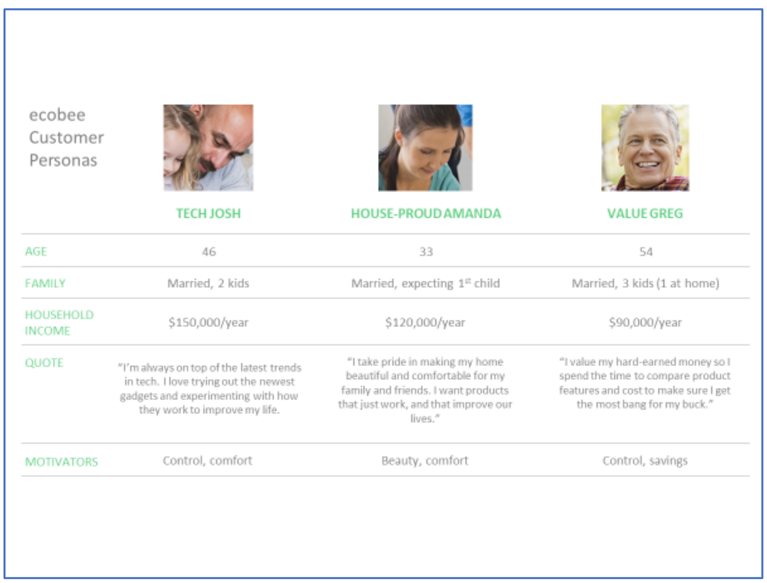


Figure 4-45
Segmentation of Customer Base into Personas

- ***Metrics and Frameworks are Needed to Understand Solution Scalability:*** The role of small loads and devices as a low-opportunity cost grid resource is a relatively nascent space. However, it will be more important in buildings as the State of California tries to meet its overall decarbonization strategies through the efficient electrification of buildings, personal transportation such as EVs. The project team presents a framework (F(x,t) = Obj(x,t)*λ(x,t)) that : (1) assesses and discusses enablement of building and community flexibility through BTM DER (Obj(x,t)) but also (2) understand customer adoption and market infrastructure opportunities and challenges to enable scale (Obj(x,t)).

The following results are associated with lessons learned from laboratory and field demonstrations:

- ***Technology Solutions are Needed to Address Disadvantaged Community:*** Many of the BTM IoT solutions made available today require technology and building infrastructure such as advanced HVAC systems or reliable WI-FI connectivity that is not as available in disadvantaged communities. It is important to test and evaluate strategies to enable, develop and assess technology solutions that provide low-income property managers and tenants tools to manage California's shift to TOU rates.

- ***Customers Prefer a Notification Mechanisms to Inform them of Dynamic Rate Events. Customer Appetite for third party automated control is still in not high:*** In general, the home builders and tenants expressed interest in informing homeowners of dynamic rate events based on the homeowner's rate plans. However, these same demonstrations identified that rate management technologies do not appear to be high in the priority list for homeowners**.**

- ***Price Differentiation between Periods of High and Low Rates may Ultimately Stimulate Customer Action:*** Beyond automated-response of BTM DER through optimized load management, effective messaging of actual $/kWh rates and price differentiation provided in the form of multipliers or percentage-difference over/under a baseline could potentially spur customers into action. Energy companies in Arizona have found success in changing behaviors of customers through TOU rate signaling where customers have become bill-conscious enough to change their behavior, e.g., pre-cooling homes using programmable thermostats. However, this requires additional research and investigation to understand how these solutions could scale.

Benefits to California

Using the lessons learned from the OpenDSRIP project, significant energy savings and demand reduction can be realized in California in small commercial buildings and residential buildings. Energy savings (estimated at 1089.4 GWh per year) will reduce the cost of procuring energy and will therefore translate to a lower cost to all ratepayers in California. With a potential reduction in demand of 10% during critical events, reliability in California will be increased, benefitting all California ratepayers. The project takes a consumer-market approach to this problem by focusing on technologies available in the market today to better understand feasibility and help baseline future potential studies with current technology and infrastructure gaps to scaling. The intended result is an actionable approach that minimizes capital investment risk in the development of programs through reduced market uptake (sometimes a challenge in historic DSM program delivery) or unforeseen product development costs. Additional ratepayer benefits include:

- The demonstration mimicked realistic adoption scenarios of emerging technologies that require first feasibility of widespread adoption followed by enablement of the technology. This gives a better idea of market readiness and how consumer-adopted technologies can be leveraged as grid resources, while minimizing capital investment in technologies with no scalable consumer market.

- Results of the project and continued efforts by the project team look to inform utility service planners, program designers, and manufacturers to tailor the service & program for the customers through operational data.
- This project has and continues to explore developing tools for low-income customers to help manage California IOU transition to time-of-use rates.
- By developing frameworks and open-source tools for evaluating flexibility on the utilization side employing buildings and the built environment, the project provides a more realistic understanding of the potential for flexibility as a pathway to decarbonization.

5
GROUP 3: EPC 15-045: DEVELOPMENT OF A TRANSACTIVE INCENTIVE SIGNAL TESTED ACROSS BOTH SUPPLY SIDE AND DEMAND SIDE PROJECTS IN THE GFO (JOHNSON, 2018).

California's electric grid is undergoing a massive transformation from a centralized to distributed generation, combined with a high penetration of variable renewable generation. This transition will lead to extreme locational and time variability in where and when gigawatts (GW) of electricity can be over- or under-generated. Without expanded balancing, using strategies such as DR resources responding to actual (*real-time*) system needs, the systemwide integration of variable renewable energy could further increase costs. Renewable curtailment, maintaining system reliability and stable power-quality, managing baseload generation or resource adequacy, etc., will likely add to grid management costs. However, being able to access the grid's system- and market-based economics would enable stakeholders to leverage flexibility from distributed energy resources and market systems and support efficient grid operations, enabling Transactive Load Management (TLM).

The California policies related to the project are the Global Warming Solutions Act (Assembly Bill 32, Nuñez, Chapter 488, Statutes of 2006) and Renewables Portfolio Standard (Senate Bill X1-2, Simitian, Chapter 1, Statutes of 2011). To attain the state's policy goals requires the engagement of customer-side resources and market-based programs to collectively address the generation variability posed by renewables—a focus the state of California is pursuing.

As expressed in California's research vision, a TLM system combines actual system information with forecasts of loads (demand) and distributed generation to derive an economic incentive or TLM price signal that reflects electric system needs and market conditions. In support of California's policy and research goals, the project designed, developed, and operated a prototype **T**ransactive **I**ncentive-signals to **M**anage **E**nergy-consumption (TIME) system to understand better how TLM pricing signals could benefit DR programs and customers. As a result, the project team renamed the project TIME.

Goals and Objectives

EPC 15-045 is the only project in Group 3 of GFO 15-311. It was designed to develop and test a simulated transactive pricing signal that could then be applied across projects in Group 1 and Group 2.

The design and architecture of the TLM-based system are based on an integrated grid and markets and includes many electric grid stakeholders. The project utilized quantitative analyses and feedback from experts to develop and test the design of a grid-integrated TLM signaling framework and system deployment techniques along with a reference design using open standards that utilizes existing electricity market practices to accelerate stakeholder acceptance and adoption.

TIME focused on the development and implementation of an innovative software system that calculates and communicates TLM signals, expressed in the form of proxy prices reflective of current and future grid conditions. The project utilized proven and available protocols and networks to transport these signals and tested the efficacy of the TLM signals through demand response Group 1 and Group 2 projects, also awarded under GFO-15-311, led by multiple partners, with Group 1 efforts focused on supply-side resources and Group 2 efforts focused on demand-side resources. Successful development and implementation of EPRI's TLM signals software systems will facilitate communication on both sides of the meter. Overarching goals for the project are illustrated here in Figure 5-1.

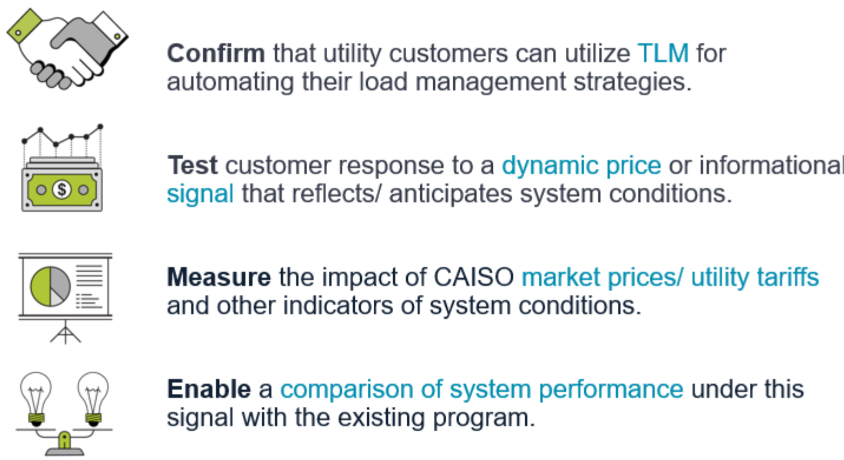


Figure 5-1
TIME Project Goals

As outlined in the solicitation for GFO-15-311, a TLM system combines actual system information with forecasts of loads (demand) and distributed generation (DG) production to develop an (economic) incentive or price "signal" that reflects system needs. The design of the TLM System and resulting prices consider existing electricity markets and stakeholders within the regulated structure and identify enhancements needed to transition California to a TLM future.

"The purpose of the research…will be to develop, test and operationalize one or more transactive signals that can be used by utility customers – and the other Recipients under this solicitation – as a basis for automating their load management strategies. It is expected that the signal development process will involve collaboration with Group 1 and 2 Recipients."

The critical questions raised by the solicitation relative to the TLM signal included the following:

- What should the signal design be?
- What elements should the signal be made up of, and in what proportion?
- How do variations in the signal's composition affect consumer behavior?
- How can the design and operation of TLM signals and systems integrate supply- and demand-side markets in California?

The collaborative approach, which was requested by the solicitation, was initiated via a survey sent to all Group 1 and 2 recipients. This survey solicited input from the associated projects with respect to many of the potentially salient characteristics that a TLM Signal to communicate TLM Prices might possess. The project then reviewed and grouped the responses to identify common elements and characteristics that were of interest to most of the recipients. A note was also taken of unique or infrequently requested features (referred to as "outliers"). Figure 5-2 describes the "design" activity for "implementation" and "operation" of the TLM signals.

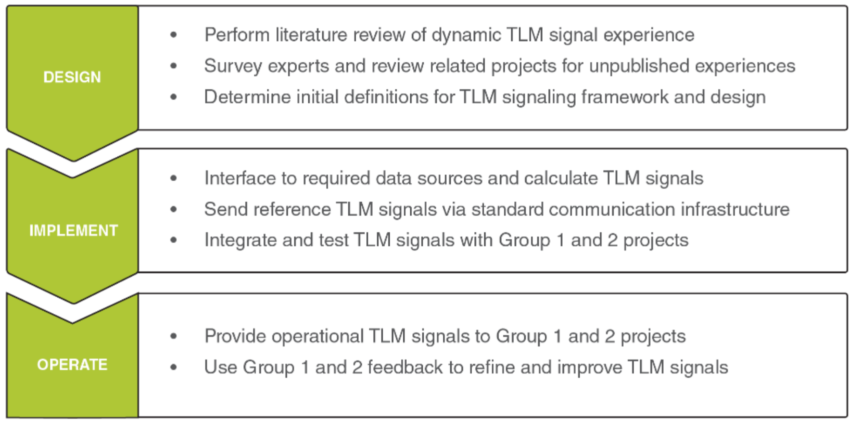


Figure 5-2
TIME Project Design Activities

Methodology and Approach

California's regulated market structure limits most customers' DR participation in retail programs within the distribution system (referred to as demand-side DR or load-modifying DR) to those that are offered by California's investor-owned utilities (IOUs). Early-stage advanced DR markets and automation systems for retail markets have shown an average of 8% site specific demand reduction in response to price signals. To maximize these benefits from DR in the bulk generation and transmission system, which is managed by the California Independent Systems Operator (CAISO), this regulated market structure must also consider customers' options for load integration and participation in the wholesale DR markets (referred to as Supplyside DR).

To design TLM signals that are representative of and that can be readily leveraged by, electric grid stakeholders and consumers, the study reviewed the existing California electricity market, regulatory structures, and electric grid. This included the consideration of operations of existing electricity markets, DR programs and related electricity rate tariffs, and plans for a future electricity system with high penetration of renewables and advanced real-time, price-based demand response that leverages "price-elastic" demand.

The project team reviewed the Group 1 and Group 2 project proposals and literature on existing supply-side and demand-side DR programs and advanced pilots that leverage DR as a grid resource. The findings were used to propose the TLM signaling and pricing framework and the TLM signal design. This methodology is shown in Figure 5-3 below.

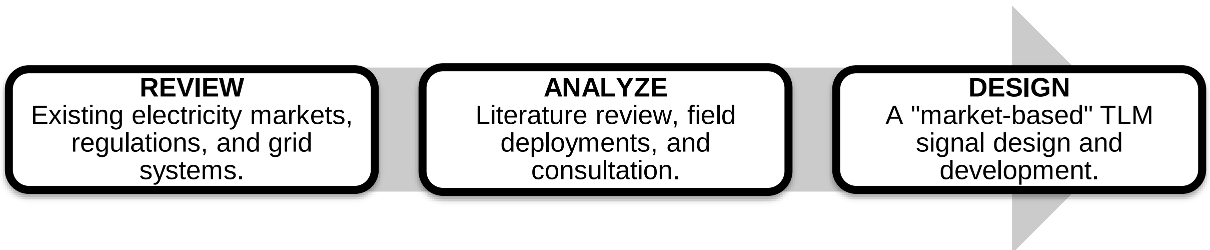


Figure 5-3
Design Methodology of Transactive Load Management Signals and Prices

The methodology was then used to propose an integrated and inclusive TLM framework that could be used for the design and development of a prototypical TLM signaling system. The project team named the project TIME - Transactive Incentive-signals to Manage Energy consumption.

Framework for Transactive Load Management Design

The framework for the design of the TLM System and Prices was primarily based on analysis of the Group 1 and Group 2 project requirements. The California market structure and electricity pricing system that consider clean energy system mandates were used to provide the context for proposing an analytical framework to calculate the TLM Prices and disseminate the TLM Signals using a standardized platform that supports the TLM Data Model reference design.

The evolution of the electricity system from centralized to distributed generation and the variability of renewable generation resources are leading to a customer-centric strategies for flexible energy-use. A pricing system that encourages such flexibility within the regulated electric grid must fully account for the following:

1. Demand response, as both a supply-side and demand-side resource
2. Fixed and variable generation from resources within the transmission grid, the distribution system, and behind-the-meter customer sites (electricity consumers who produce electricity, termed *prosumers*)
3. Linkages between real-time wholesale and retail electricity market prices
4. Account for greenhouse gas or carbon component of the generation resources (as a proxy for the social cost)

The proxy prices and system to communicate the TLM Data Models in the project utilized the reference demand response (DR) communication standard used by the California utilities to publish prices to the Group 1 and 2 participants. The objectives of the Group 1 and 2 projects are summarized in Table 5-1:

Table 5-1
Objectives for Group 1 and Group 2 Projects Scheduled to use TLM Signals

GROUP 1	
EPC-15-074 - Center for Sustainable Energy (CSE)	Demonstrate the resource model for CAISO Proxy DR (PDR).
EPC-15-083 – OhmConnect	Generate load changes from large numbers of residential customers at specific times and in specific geographic areas.
EPC-15-084 - BMW	EV smart charge management and optimization based on cost and carbon savings.

GROUP 2	
EPC-15-048 - Alternative Energy Systems Consulting (AESC)	Demonstrate optimization of residential energy consumption based on day-ahead hourly pricing posted to the HEMS or aggregation.
EPC-15-057 – University of California Berkeley	Use real or projected prices to initiate control sequences in small to large commercial building HVAC, lighting, and plug loads.
EPC-15-075 – (DSRIP) Electric Power Research Institute (EPRI)	Demonstrate aggregation of a wide variety of load types and products for residential and small- and medium-business (SMB) customers.
EPC-15-073 - University of California Los Angeles (UCLA)	Study how consumer response to incentives varies with weather, the day of the week, and time of day.
EPC-15-054 – (RATES) Universal Devices	Demonstrate residential and commercial automated and self-managed energy use and storage.

The design of the TLM System and Prices is independent of any data communication standard. This means that the TLM Signals can be transported by an existing standard, by extending an existing one, or by developing a new standard. (Analysis of standard type was outside the scope of the project.) The TLM Signal design and proposed framework are generic. At a minimum, the determination of prices would include data inputs for pre-market planning and real-time analytics for both wholesale (supply-side), generation sources (for GHG), and retail (demand-side) markets. The day-ahead analysis is similar to the current wholesale electricity market planning and operations.

Figure 5-4 shows both these analytical needs and the integration with Group 1 and 2 project participants. The analysis of forecasting models and real-time TLM Prices based on the actual system and market conditions should consider both supply and demand sides, including the environmental considerations of the generation sources, as inputs at the "point" (dotted rectangle on the left). This point can be a generic construct within the grid based on potential future advanced TLM System designs that may account for spatial granularity. Examples of this may be Pnodes, LAPs, substations, etc.

It is imperative that the TLM Prices can influence the transmission and distribution system deferral costs by the efficient use of the network. Hence, such factors are not discussed. The information determination for the TLM Price output forms the basis to communicate the TLM Signal to a Price Service Interface (PSI). The Group 1 and 2 projects' PSI would receive the published TLM Signal (dotted rectangle on the right). This activity of determining analytical needs for price determination is outside the scope of this project. However, as mentioned earlier, for this project, the study considers a generic TLM Signal for loads that participate in supply-side or demand-side resources through an OpenADR 2.0 based communication signal, as a standards-based reference model. Thus, for this first release, the projects can use the reference communications and prices to make an adjustment to the signal to more closely reflect the value of energy at a specific customer location.

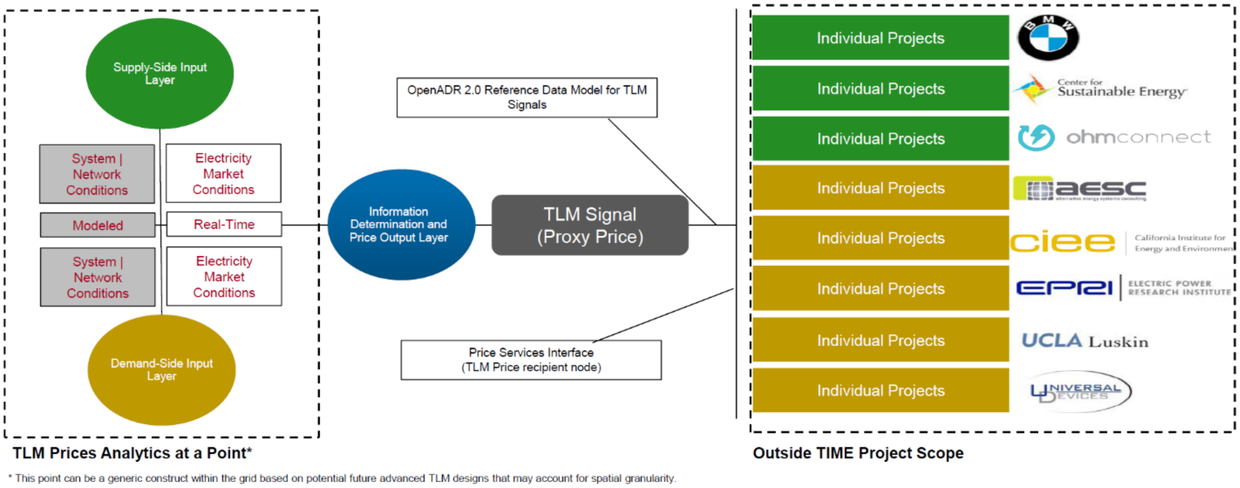


Figure 5-4
Framework for TLM System and Prices and Integration with Projects*

The analysis of the requirements from the Group 1 and 2 projects and the TAC survey resulted in the identification of the following quantitative determinants, which are further explained below. These determinants were used to propose a generic design framework for the TLM Price(s) and TLM signal(s) that is described in the following sections.

1. Price and generation source
2. Locational targeting
3. Source of generation or social costs
4. Notification period and intervals.

Price and Generation Sources

Consideration of the social costs, such as environmental or GHG contributions of California's electricity generation sources, is one of the objectives for the projects. Such a need was highlighted in the recent evaluation of impacts from California's energy storage mandate, Assembly Bill (AB) 2514, through the Self Generation Incentive Program (SGIP) that is required to meet the State's Renewables Portfolio Standard (RPS) goals[11]. The evaluation report findings conclude that while SGIP benefits customers by reducing the electricity costs, it is not meeting the program goal of reduction in GHG emissions. To reflect the GHG component in the TLM Prices, the economic incentives and variability in electricity prices are used for cost optimization, and the electricity generation source is used for carbon optimization. In support of economic principles, as a key motivation for TLM Prices, the study focused on communicating the TLM Prices and basic TLM estimation methods, as opposed to advanced methods that determine the TLM prices based on the real-time system and market conditions.

[11] https://www.cpuc.ca.gov/rps/

The CAISO LMPs at the pricing nodes (Pnodes) are used to determine the wholesale market electricity prices [12].[12] The day-ahead market, the 15-minute market, and real-time dispatch are used to compute the three variations of LMPs. The Pnodes are updated when the CAISO physical network model changes. For example, a creation of a new injection or withdrawal point would trigger the need for a new Pnode and vice versa.

The components used by the CAISO to determine the LMP are:

$$LMP = Energy + Congestion + Losses$$

An Aggregated Pnode (APnode) is used to define a group of Pnodes.[13] The CAISO publishes the APnode prices for each of the three California IOUs and other APnode prices are published for the custom Sub-LAPs used by certain DR aggregations.

These Pnode LMPs, as shown in Figure 5-5, reflect prices at points within the electric grid where the supply resource connects to the grid and where the CAISO high-voltage transmission system connects to the medium- and low-voltage substations to supply power to customers using the distribution grid network.

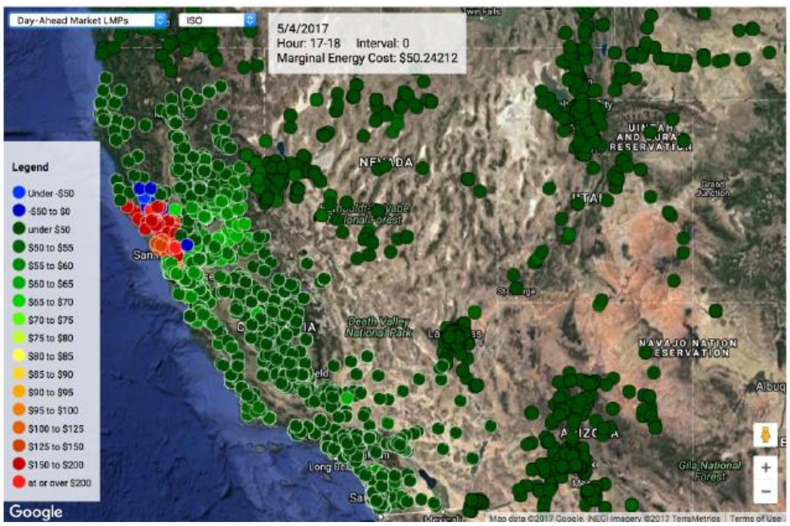


Figure 5-5
CAISO's Locational Marginal Price Nodes

Locational Targeting

Locational targeting enables technologies and platforms to identify grid congestion areas and take actions to alleviate it. In this instance, variable prices can be a proxy for grid health and a customer incentive to exercise demand flexibility. One of the CAISO's challenges related to multi-location aggregated load bidding into the wholesale DR markets is determining the Pnode location of a responding resource. Another axiomatic CAISO challenge is congestion management via targeting

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[12] **Pnode:** "A single network Node or subset of network Nodes where a physical injection or withdrawal is modeled and for which a Locational Marginal Price is calculated and used for financial settlements." (Source: CAISO). Pnodes are created (if needed) in response to new interconnection requests. **LMP:** "The marginal cost ($/MWh) of serving the next increment of demand at that Pnode consistent with existing transmission constraints and the performance characteristics of resources." (Source: CAISO)

[13] **APnode:** "A Load Aggregation Point, Trading Hub or any group of Pricing Nodes as defined by the California ISO." (Source: CAISO)

resources within the multi-location and single-location aggregated loads and individual loads within a distribution network.

The Pnodes can be within any of the CAISO's single sub-load aggregation points (sub-LAPs), which some of the projects reference.[14] A sub-LAP is a subset of Pnodes within a default LAP. Figure 5-6 shows the CAISO-determined twenty-four sub-LAP regions that have aggregate patterns of supply congestion and price volatility within each utility territory.

(Source: CAISO Reliability Demand Response Product)

Figure 5-6
CAISO-Determined Sub-LAPs

Source of Generation or Social Costs

California has set aggressive renewable generation policy objectives of having 33% and 50% of all generation coming from renewable sources by 2020 and 2030, respectively. Customers' elasticity to loads that account for the source of electricity and are responsive to the generation mix is being considered in the optimization strategy under select Group 1 and 2 projects. For example, in addition to economic optimization, the vendor BMW plans to optimize demand, as a supply-side resource, based on renewable generation source. The UCLA project considers social cost of carbon, wherein the cost of generating electricity from coal is weighted more heavily than the cost of generating from solar. The study recognizes that the social costs are broader than the fuel sources and can account for other factors such as air quality, health, etc. This study uses greenhouse gases (GHG) as a proxy for social costs and focuses on the economic motivation.

The CAISO runs an energy imbalance market (EIM) at the bulk generation and transmission system level to make generation within the western U.S. a dispatchable resource. This larger pool extends beyond the state's boundaries and is intended to address the variability of renewable generation on a

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[14] **LAP:** "A set of Pricing Nodes that are used for the submission of Bids and Settlement of Demand." (Source: CAISO)

Sub-LAP: "A California ISO defined subset of Pnodes within a Default LAP. (Source: CAISO) least-cost basis. While the details of the EIM are outside the scope of this study, the important part of this activity is the consideration of GHG as another price adjustment component within the LMPs (since the California GHG regulations apply to imported electricity). The GHG component allows the cost recovery of the dispatched generation resource resulting from meeting the compliance obligations inside the CAISO territory [13].

Presently the CAISO LMPs consider energy, congestion, and losses, and these are the only components that determine California's wholesale electricity market prices. Since the congestion and loss components are defined by the physics of the grid itself, the only price component that could possibly account for GHG (or other social costs) is the energy price, which is determined

Notification Period and Intervals

Any signal that notifies customers to exercise demand flexibility must account for the notification period and intervals. The notification period begins with the publication of the TLM Signal and ends when the proxy price becomes valid. The TLM Signal intervals include one or more durations for which the particular proxy TLM Price is valid. Most of the projects can use day-ahead (DA) notification of hourly price intervals for a 24-hour duration since it provides an ability for forward planning of demand-side operations. To ensure efficient integration with disparate technologies and architecture of Group 1 and 2 projects, the DA hourly price signal shall be standardized and published, as a proxy TLM Price. Additional granularity in the notification period (for example, intra-hour) and shorter intervals (such as 15- and 5-minutes) will be considered, as needed.

Transactive Load Management Pricing and Signal Design

The Pnodes and LMPs are critical factors in enabling granular price communications and allowing new flexible loads, such as electric vehicles, to leverage the benefits of smart charging and load shifting – both temporally and spatially. The Pnodes represent the lowest spatial disaggregation of TLM Prices for the wholesale electricity markets. California's day-ahead and real-time electricity price indicators represent the state of the transmission system at the wholesale level (Wholesale Market Pnode LMP). For distribution electricity customers, the study proposes distribution service provider or operator-level distribution system and supply-demand variation adjustments (Distribution System Price Adjustment) for the retail electricity prices that reflect actual system and market conditions. These adjustments should consider utility-specific needs and existing market and tariff requirements. The resulting integrated and the inclusive market-based price is termed, as the "Integrated TLM Price."

To produce the integrated TLM Price and corresponding TLM Signal, the design and price determination considers both the existing Pnode LMPs from the wholesale electricity markets and adjustment within the distribution system. This is similar in concept to the VGI pilot tariff that was proposed by SDG&E. The design framework to determine the TLM Price is shown in Figure 5-7.

While the reference components of TLM Price on the wholesale markets exist, the distribution system adder can be a multiplier that is indicative of the state of the distribution system and markets and expressed in $/kWh. This ensures a common representation of both wholesale proxy costs from electricity markets and the existing system of cost recovery of energy services provided to the generation resources and customer's energy use. However, as requested by select Group 1 and 2 project participants, these proposed determinants could also consider that the GHG or social cost may be another component of the TLM Signal. Additionally, supply and demand variability that will result from renewable generation at different domains within the electric grid can be considered for advanced TLM Price determination. The resulting integrated TLM Price would be a wholesale and retail market integrated price that is indicative of the T&D systems and market conditions.

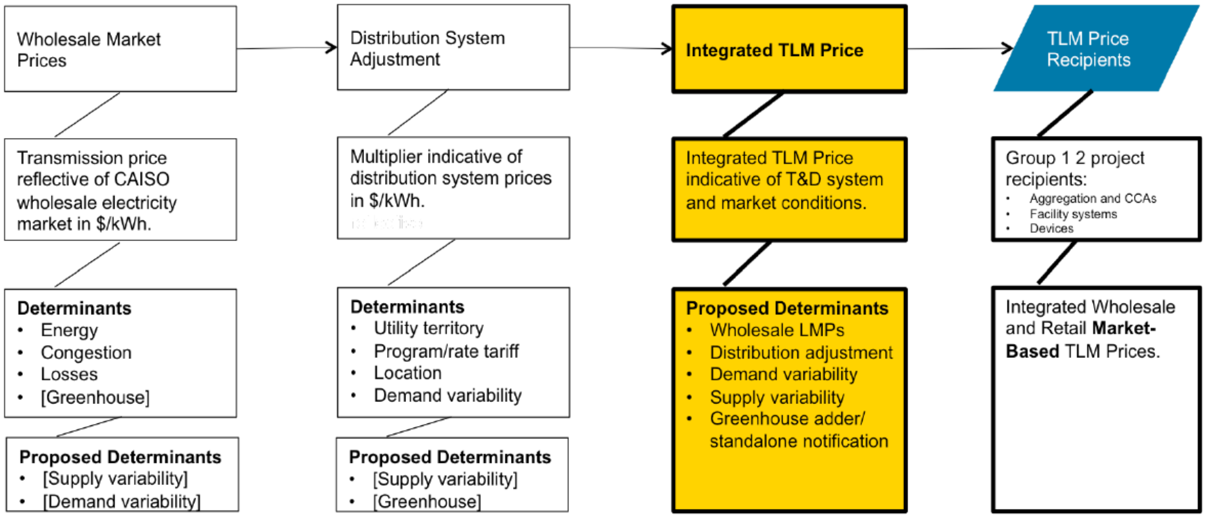

Figure 5-7
Design Framework for TLM Price Analysis at each Point within the Grid

The current and proposed determinants for the TLM electric price analysis framework are defined as shown in tables 4-1 and 4-2 for wholesale market prices and distribution system adjustment, respectively. The proposition behind this framework reflects the goals and objectives of the project, as well as the consideration of current California's bifurcated wholesale and retail electricity prices and stakeholders under the regulated environment and utility business models. The end goal is to ensure that the electric customers and stakeholders benefit by leveraging the real-time prices and advanced technologies to better manage the grid, energy-use, and save costs.

Table 5-2
Determinants of Wholesale Market Price or Cost[15]

[15] The consideration for distribution system conditions is due to the distributed generation model and the paradigm shift from the traditional centralized bulk generation. This change can be the proxy through demand-side variability analysis.

Wholesale Market Price: Reflects the current state of pricing determinants for wholesale electricity markets, including the proposed new determinants that consider intra-hour supply-side variability and any changes in the distribution system conditions.[11]	
Energy	The CAISO analysis of DAM and hour-ahead energy prices calculated, as $/MWh
Congestion	The CAISO analysis of congestion costs based on the feasible power flows in the transmission network calculated, as $/MWh
Losses	The CAISO analysis of loss costs based on the feasible power flows in the transmission network calculated, as $/MWh
Demand Variability	The CAISO analysis of DA and hour-ahead demand forecasts calculated, as MW
Supply/Generation Variability (Proposed)	Includes intra-hour variability analysis for high penetration of renewable generation to meet the policy mandates of 33% and 50% renewable portfolio standards for 2020 and 2030, respectively; and any resulting transmission system changes, calculated, as MW.
Greenhouse Gas or Carbon (Proposed)	Proxy for social costs that aligns with the Group 1 and Group 2 projects and GHG consideration in the CAISO-run EIM for the bulk generation and transmission system, calculated as $/MWh

Table 5-3
Determinants of Distribution System Adjustment

Distribution System Adjustment: An adjustment that is reflective of a localized distribution system and market conditions that accounts for generation and demand.	
Utility Territory	From the DR programs that are tailored to specific utility territories
Programs and Rate Tariffs	DR market design that is tailored specifically to a utility territory's electricity rate tariffs (such as peak-day pricing or demand bidding).
Location	From the DR programs that are tailored to a utility territory's location-specific needs (such as zones or substations).
Supply/Generation Variability (Proposed)	Includes inter-hour and intra-hour variability analysis for behind-the-meter and DG to meet the policy mandates of 33% and 50% renewable portfolio standards by 2020 and 2030, respectively, and any resulting distribution system conditions, calculated as kW.
Demand Variability (Proposed)	Includes intra-hour demand variability based on components, such as the weather and behind-the-meter and distributed generation (DG), and CAISO analysis of DA and hour-ahead demand forecasts, calculated as kW
Greenhouse or Carbon (Proposed)	Proxy for social costs that aligns with the Group 1 and Group 2 projects for the distribution system generation system, calculated as $/kWh

The “Integrated TLM Price” output from these existing and proposed determinants for generation, transmission, and distribution systems reflects the integrated grid conditions and utility objectives (distribution adjustment) that proactively considers the following: variability in demand and supply/generation, the greenhouse/carbon considerations, and distribution system conditions based on both forecast and real-time conditions.

Generic TLM Pricing Signal Design

Based on consideration of the customer load participation in either demand-side and/or supplyside markets and the needs of the Group 1 and Group 2 project participants, the study proposed a generic signal design without the inclusion of distribution determinants or GHG components. As mentioned earlier, the individual projects could potentially make a price adjustment to the signal to more closely reflect the value of energy at a specific location and such adjustments could also consider these additional components. The final integrated TLM Price, however, must consider the distribution and GHG components to meet California’s clean electricity system goals and current utility electricity pricing structure and business models. This generic signal design was associated with one or many price proxy nodes within California’s transmission and distribution system. The project scope extended to supporting TLM Prices based on the Pnode LMPs (with optional Group 2-supplied distribution adder), as a “proxy” TLM Price. This TLM Price was communicated via a TLM signal. This generic TLM Signal design that maps to existing CAISO wholesale DR market price notification framework and IOU DR programs is shown in Figure 5-8.

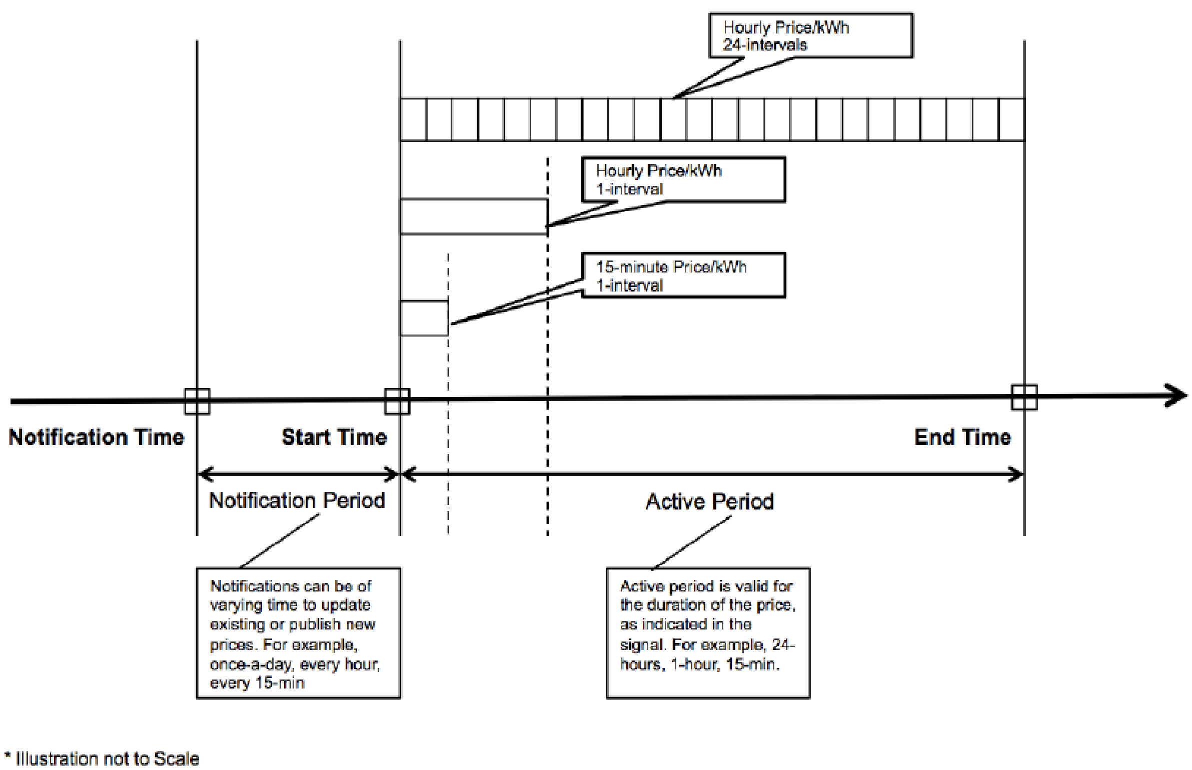

Figure 5-8
Construct for the Design of Generic TLM Signal(s).

This generic signal design includes the elements of the wholesale electricity market prices and the constructs used for the retail DR program design that communicates the prices (as for a peak-day pricing program). While the signal design is agnostic to any specific communication standard or data model representation, this project created a reference design using an existing standard that the project team had expertise in and had deployed infrastructure.

Standards-Based Reference Signal Communication Data Model

For this study, OpenADR 2.0 standard was used, as a reference communication and data model to publish the TLM Signals[16]. This includes the following OpenADR components in support of economic motivation to influence customer's demand flexibility.

1. Market-based economics (DA notification with hourly LMP price schedule for a 24-hour period) in the following format: [*ProgramTariff | Market Context*]

2. Targeted location: The Pnode or APnode locations (for all or select Pnodes across California) will represent the location of the price: [*Pnode | APnode*]

3. Integrated distribution utility service territory (PG&E, SCE, and SDG&E) adjustment: [*DistributionUtilityTerritory*]

Each project's OpenADR clients shall receive one or many of the TLM Signals, including different electric service provider variations of Group 1 and Group 2 projects. These LMP signals are distinguished in the market context in the following format:

[*ProgramTariff | MarketContext*] . [*Pnode | APnode, DistributionUtilityTerritory*]

Although this wholesale electricity market context covers the supply-side prices, a demand-side program may want the LAP (or Sub-LAP) prices. If these were not sent, the project participants would have to subscribe to relevant APnode prices. The project considered a simple distribution system adjustment to either the Pnode or APnode to provide a TLM Price that reflects the demand-side program.

Other mechanisms supported by OpenADR might be useful for some projects. For example, group addressing of VENs or other mechanisms for targeting specific locations might prove to be more efficient. Determination of the exact mechanisms to be used will require further understanding of the architecture of the recipient projects.

Overall Results

The interim findings showed the critical need to integrate California's electricity markets in order to unlock customers' DR resources and enable cost-efficient integration of variable renewable generation. The findings can be used by the industry and research organizations to develop new practices for widespread adoption of economics-driven transactive technologies and systems for an integrated electric grid of the future.

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[16] Organization for Advancement of Structured Information Standards (OASIS); Energy Interoperation Version 1.0, *OASIS Standard*, 2014. Accessible at http://docs.oasisopen. org/energyinterop/ei/v1.0/os/energyinterop-v1.0-os.html.

The detailed project findings are as follows:

1. **System Design, Development, and Operations:** The project proposed a design of the TIME system and the framework and developed and operated a prototype TIME system to communicate the TLM prices to end-use customers and DR resources. A key project outcome is a TIME system design that considers California-centric challenges; (1) generation variability posed by the renewable resources such as solar and wind; (2) account for social costs in the form of GHG or carbon emissions as determinants of the wholesale market price or cost; and (3) include demand variability as an additional determinant of the retail market price or cost.

2. **Implementation by DR Resources:** The TLM signals were implemented by the residential, industrial, and agricultural customers' DR resources that participated in the demand-side and supply-side projects. The system architecture deployed for TLM signals and project requirements were used to recommend and validate results and next steps. The results show that the 24-hourly day-ahead California wholesale market prices constitute a consensus base case for TLM prices.

3. **Integrated TLM signals for DR Resources:** The project reviewed the application of TLM signals for a diversity of DR resources, relative to the regulated electricity markets in California. As a key outcome, the project concluded that the design of the TLM price must include various grid and customer data inputs for forecasting and real-time analytics of supply- (wholesale) and demand-side (retail) markets, generation sources, and generation and demand variability.

The recommendations and research opportunities identified in the project point positively for California's vision to advance TLM-centric research and engage DR resources for grid balancing applications. At the same time, the development of integrated grid models and value assessment that includes grid operators and customers is critical for practical applications.

Application of a Simulated Transactive Signal

The TIME project supported one of the overall objectives of GFO 15-311 which was to test a simulated transactive signal across projects in Group 1 and Group 2. While not all of the projects were able to complete testing, five out of the eight were able to receive day-ahead real-time wholesale market prices from the TIME system, as illustrated in Table 5-4:

Table 5-4
Group 1 and group 2 Applications of a Simulated Transactive Signal

Lead Organization	Application of TLM Signals
BMW North America (NA)	Participated in the supply-side markets to receive Day-ahead real-time wholesale market prices from the TIME system.
Center for Sustainable Energy (CSE)	This project did not utilize the TLM signals.
OhmConnect	Participated in the supply-side markets to receive Day-ahead real-time wholesale market prices from the TIME system.
Alternative Energy Systems Consulting (AESC)	Participated in the supply-side markets to receive Day-ahead real-time wholesale market prices from the TIME system.
California Institute of Energy and Environment (CIEE)	This project did not utilize the TLM signals.
Electric Power Research Institute (EPRI)	Participated in the supply-side markets to receive Day-ahead real-time wholesale market prices from the TIME system.
University of California Los Angeles (UCLA) Luskin Center	This project did not utilize the TLM signals.
Universal Devices	Participated in the supply-side markets to receive Day-ahead real-time wholesale market prices from the TIME system.

Benefits to California

The project provided the following benefits to California and its ratepayers:

1. The design of TLM signals, and development and operations of the prototype TIME system can address a critical need to prioritize the economic value and integrate California's supply- and demand-side electricity markets. Such motivation and integration can unlock the full value from a customer's DR resources to enable efficient integration of variable renewable generation and improve electricity reliability.

2. The TLM price signals can enable DR participation for supply- and demand-side markets under California's aggressive renewable generation goals. Standardized approaches have the potential to value the technology enablement costs and enable customer-chosen DR resources to integrate with utility systems and participate in in DR markets.

3. It is possible to design and deliver hourly or sub-hourly prices, which can reflect real-time grid and market conditions, to customers systems, and their devices—and that, those customers can respond. As a result, the price becomes a proxy to motivate grid operators to offer price-based DR programs, and customers to participate through their chosen methods and under safe system or device operating conditions.

6

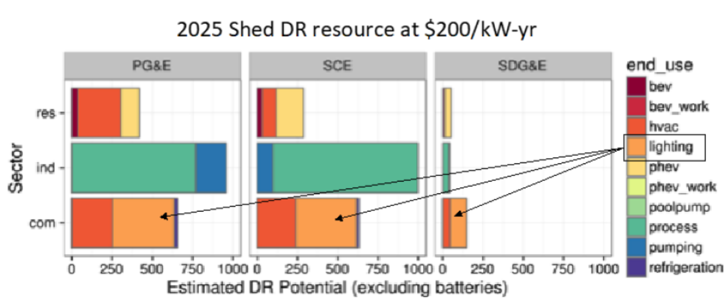
GROUP 4: EPC-15-051 – LAWRENCE BERKELEY NATIONAL LABORATORY - THE VALUE PROPOSITION FOR COST-EFFECTIVE, DR-ENABLING, NONRESIDENTIAL LIGHTING SYSTEM RETROFITS IN CALIFORNIA BUILDINGS (SCHWARTS, 2019).

Goals and Objectives

California's Clean Energy & Pollution Reduction Act (Senate Bill 350, de León, Chapter 547, Statutes of 2015) requires the state's energy-efficiency savings to double by 2030. One strategy to help meet that goal is to focus on demand response-enabled networked lighting controls plus LED lighting fixture retrofits in the commercial buildings. Commercial buildings with networked lighting controls that enable demand response can, when aggregated, provide a distributed energy resource that rivals the annual production capability of California's peaker power plants.

Further, the costs for demand response-enabled networked lighting controls plus LED lighting fixture retrofits can be recovered either through energy savings alone, or in some circumstances through savings associated with additional networked lighting functionality. Costs can also be recovered through the value provided by non-energy benefits that, if quantified, could be ten times greater than energy savings alone. The ability to recover these costs depends on the building type, building size, its location and utility rate structure, but activating this resource would provide great benefits to the state of California.

Among the technologies shown in Figure 6-1, lighting in commercial buildings represents an important but underused demand response resource. To effectively tap this resource, owners need to invest in advanced, networked lighting controls combined with new LED sources, which not only facilitate significant energy savings but also enable dispatchable, responsive building loads for providing electricity grid services. Networked lighting controls or advanced lighting systems are a key responsive building load that represents in aggregate, an important DER that can address grid needs.



Source: LBNL's 2015 CA DR Potential Study

Figure 6-1
Estimated Shed Demand Response Resource Potential by Building Sector

Since 2013, California Title 24 building code mandates demand response-capable lighting for most new commercial facilities. Despite the significant opportunity and regulatory push, few building owners have installed demand response-capable lighting systems because they do not see the value. Networked lighting controls can enable effective demand response and deliver value to customers in the form of reduced energy bills, optimized facilities, and increased revenues, among other non-energy, co-benefits. However, because lighting technologies can serve the dual purpose of providing energy savings and demand response, it has become more difficult to fully quantify their demand response value in California's Building Energy Efficiency Standards (Title 24). Up to now, systematic analysis of those benefits has been incomplete.

This project sought to quantify the value of the energy and non-energy benefits and costs of networked lighting controls, including their demand response and energy-efficiency benefits, and to integrate this value into a broader advanced lighting control value proposition framework. In turn, this framework can provide a tool to better quantify in real terms, the value associated with networked lighting controls for different building types. The analysis and framework will help program implementers promote this technology by:

- Supporting next-generation energy code enhancements.
- Providing a means to fully quantify networked lighting control benefits from a customer's or building operator's perspective, in a marketplace where energy savings benefits potentially are outweighed by non-energy benefits when consumers are deciding what to buy.

This study summarizes the framework development that captures the high customer values from the non-energy benefits of networked lighting controls to help increase demand response adoption. This project sought to:

- Promote wider technology adoption within California to support the state's net-zero energy, sustainability, and electric grid reliability policy goals.
- Identify cost-effective conditions for customer investments.
- Characterize and quantify the electricity grid value of networked lighting controls including operational and infrastructure benefits.
- Quantify the value proposition for implementing code-compliant, demand response-enabling lighting controls in retrofits, including:
    - Identifying key non-energy benefits from automated demand response-enabled networked lighting control systems.
    - Determining the costs and energy savings of automated demand response-enabled, networked lighting control systems.
    - Design a networked lighting control system value proposition framework.
    - Evaluate how adoption of non-energy benefits can lead to greater demand response.

Methodology and Approach

To accomplish the project goals, the research team conducted three major activities. First, the team evaluated the statewide potential at the individual building level for lighting demand response and, based on that information, identified strategies that could overcome market barriers to expanding demand response by better matching load-reduction opportunities with system needs to better inform California's policy makers.

Next, the team quantified the value proposition of implementing code-compliant, demand response-enabling lighting controls for retrofitting multiple nonresidential building types, in an effort to help building owners and contractors better understand all the benefits of using lighting to participate in demand response programs offered by California's investor-owned utilities.

Finally, based on the results of these activities, the team designed a framework for a value proposition for lighting controls, and how adoption of non-energy benefits could enable greater use of demand response. Incorporated in that was an analysis of what needs to occur for that to happen.

The team reviewed more than 130 networked lighting control case studies to quantify the non-energy benefits and develop a benefits value intensity model that captures the energy and non-energy benefits related to building, people and revenue, as illustrated in Figure 6-2.

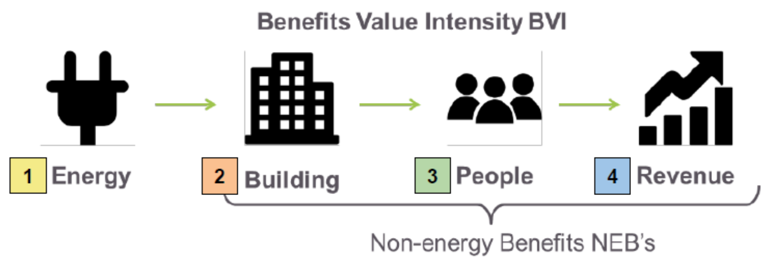


Figure 6-2
"3:30:300:3000" Rule of Thumb Benefits Value Intensity Framework Categories

This approach was built upon the "3:30:300:3000" rule of thumb, which signifies the relative dollar per square foot value associated with building energy, rent, and occupant salary costs, in addition to the potential revenue generated by the people within a building (Table 6-1). Generally, values in the higher benefits value intensity categories (Levels 2 – 4) can be several orders of magnitude higher than energy and demand management (Level 1) values alone.

Table 6-1
Benefits Intensity Value Index

BVI Level	Organization Category	Definition	Example
1	Energy (Ave. cost = $\$3/ft^2$)	The lowest BVI category. Describes the energy benefits that may accompany a NEB.	Reduced energy consumption achieved by reducing unused space
2	Building (Ave. cost = $\$30/ft^2$)	Generalized "costs of rent" to capture all values a NEB can create on a building's operation	Avoided costs by not adding new space since current space is more efficiently used
3	People (Ave. cost = $\$300/ft^2$)	Captures a NEB's impact on people or activities they perform in a building	Employees can find spaces to work and conduct meetings. More efficient use of their time increases satisfaction with their space.
4	Revenue (Ave. = $\$3,000/ft^{2*}$)	The highest BVI category. Capturing additional revenue generated from business activities performed in the building as a result of a NEB.	Increased revenue generated by additional employees added to use the same workspace; increased revenue from using retail wayfinding to increase customer sales

* Revenue represents a very rough estimate, since this metric requires significant exploration. NEB is non-energy benefit.

Source: Lawrence Berkeley National Laboratory

Using quantitative non-energy benefits information and high-influence market barriers and opportunities, the team designed a sample logic model and conceptualized five intervention strategies as part of the market transformation theory for achieving large-scale commercial lighting DR adoption:

1. Lack of user value: Research and normalize non-energy benefit narratives and metrics to standardize their quantification.
2. Perceived impact (user, trade ally): Define demand response strategy best practice, demonstrate, and publish results proving that lighting demand response implementation does not adversely affect performance.
3. Lack of standardization: Develop capability performance specifications for inclusion in programs and by specifiers.
4. Lack of best practices and commissioning: Develop configuration template and commission guides.
5. Lack of integrated program support: Bundle program design linking energy efficiency, demand response, non-energy benefits, and persistence

Analytical Strategy for Office and Retail Buildings

For office and retail buildings, the study employed the "bottom-up" modeling framework for demand response capabilities and availability that was developed in a demand response potential study conducted for the California Public Utilities Commission (Alstone et al. 2017). The framework leverages large customer-level electricity use and demographic datasets provided by each California investor-owned utility to estimate the potential resource for different demand response service types by sector, building type, site size, and end use in 2025. The first step for estimating resource availability is to group customers in similar cohorts, or "clusters." Each cluster represents aggregated real customer consumption and demographic information. Each cluster's consumption time series is disaggregated into its constituent end uses, and these end-use baseline load shapes are forecasted to the study year of 2025.

Commercial lighting load was explicitly disaggregated for clusters representing office and retail buildings. The clustering further subdivided these building types into small, medium, or large site sizes that is consistent with utility practices for assigning rates and demand charges as illustrated in Table 6-2.

Table 6-2
Peak Demand Thresholds for Categorizing Small, Medium, and Large Commercial Customers

Demand Charges	Small Commercial	Medium Commercial	Large Commercial
Peak demand threshold	**< 50 kW**	**50–200 kW**	**> 200 kW**

Modeling Framework

The 2025 California demand response potential study introduced a new broad demand response type categorization that represented a new demand response taxonomy (Figure 6-3).

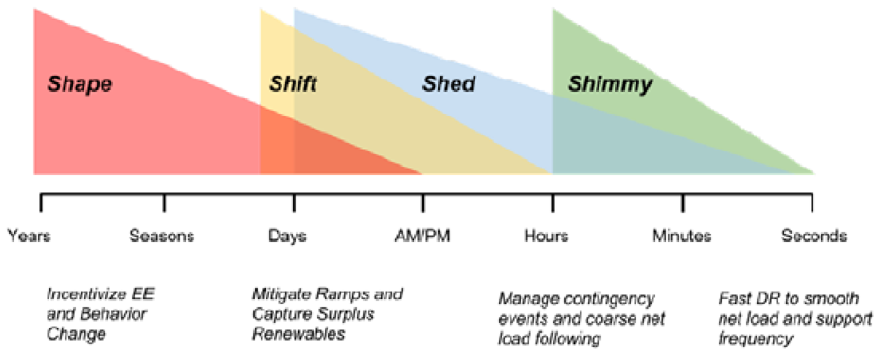


Figure 6-3
2025 California Demand Response Potential Study Demand Response Taxonomy

This study focused on shape, shed, and shimmy regimes[17] when evaluating networked lighting controls demand response value for offices and retail buildings. The team forecasted load shapes to the year 2025, using California's investor-owned utility smart meter data. The analysis includes the following modeling assumptions regarding networked lighting control benefits:

Networked lighting control upgraded lighting energy savings:

- LED upgrades yield up to a 50 percent static reduction in lighting energy intensity as a result of from improved system efficiency and modern illumination level practices.
- Networked lighting controls yield an additional 40 percent to 60 percent energy savings from active control (2017 DLC).
- The present value of energy savings is calculated based on investor-owned utility commercial time-of-use rates.
- Revenue from demand response participation in energy markets is based on the California Independent System Operator's price forecasts.

Overall Results

This research found that networked lighting controls are likely to become a more important distributed energy resource because of the increased efficiency they bring to lighting systems, their flexible control and rapid-response capabilities, and their ease of load aggregation. Adoption of these technologies is expected to grow rapidly as more facilities recognize the non-energy benefits

[17] "Shape" refers to demand that permanently reshapes customer load profiles. "Shed" refers to traditional demand response and loads that can be reduced or restricted to provide peak capacity and support the electric system. "Shimmy" is an emerging service that involves using loads to address short-run ramps and disturbances including frequency or voltage regulation.

of networked lighting control systems, market adoption increases, technology prices fall, and the electricity market becomes more volatile.

Project costs were found to be generally consistent across building types, though small retail is slightly higher due to a higher fixture density. As expected, project costs decrease significantly as project size increases. Table 6-3 displays the net revenue associated with site-level levelized costs and energy-related benefits from installing a demand response-enabled lighting system in six different building categories within each California investor-owned utility service territory. Values in red indicate negative value from energy-related benefits and costs.

Table 6-3
Levelized Annual Costs and Savings, in Dollars per Year

Utility	Building Type	Building Size	Net Revenue
PG&E	Office	Large	$182,769
		Medium	$17,315
		Small	$1,015
	Retail	Large	$173,610
		Medium	$27,780
		Small	$2,095
SCE	Office	Large	$3,951
		Medium	$58
		Small	$44
	Retail	Large	$3,037
		Medium	$415
		Small	$535
SDG&E	Office	Large	$73,374
		Medium	$3,189
		Small	$286
	Retail	Large	$41,510
		Medium	$4,800
		Small	$496

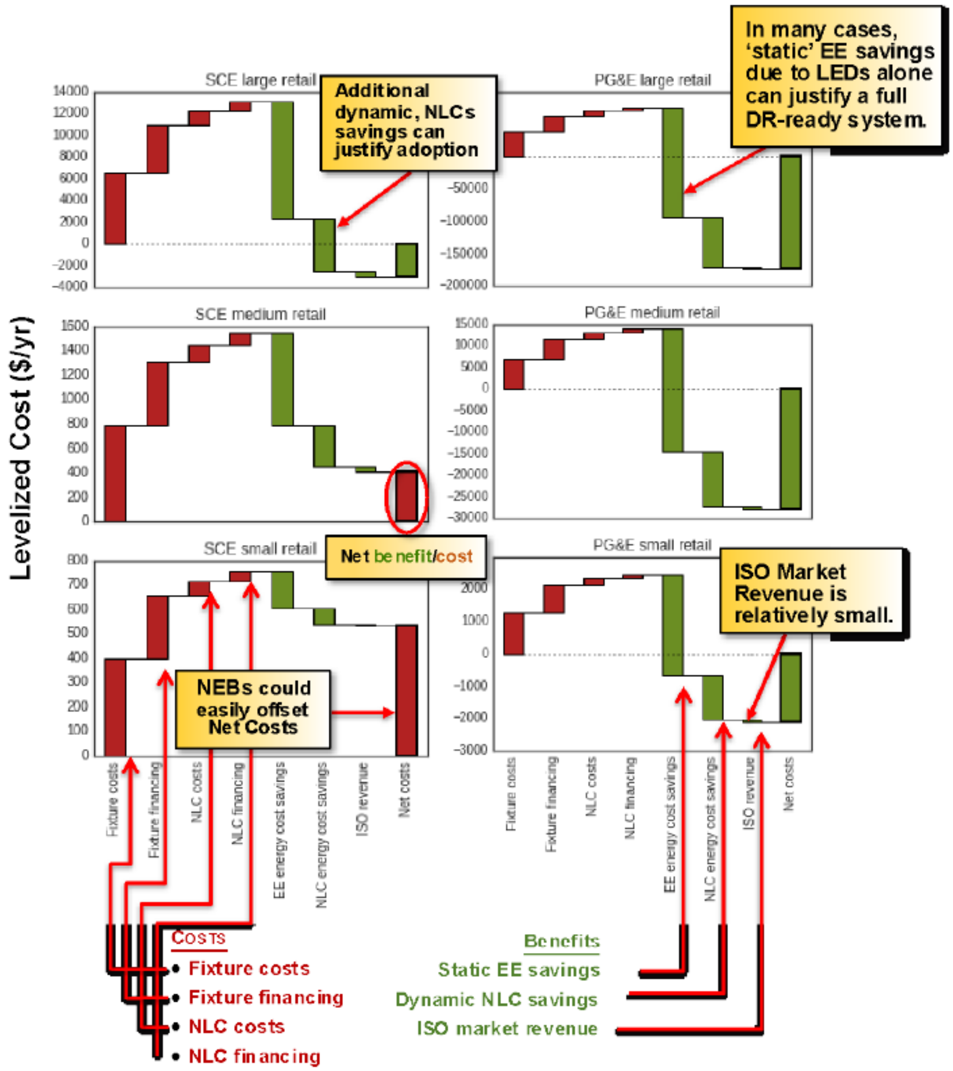
Source: Lawrence Berkeley National Laboratory

Office and Retail Site-level Costs and Energy Benefits

Figure 6-4 displays the site-level levelized costs and energy-related benefits from installing a demand response-enabled lighting system in three different retail building categories within SCE's and PG&E's service territories. The cost and benefit results are presented as waterfall diagrams, displaying:

- Costs as positive red bars that incrementally build up the total cost.
- Benefits are shown as negative green bars that subtract from the aggregated cost to yield a total "energy-only" (that is, exclusive of non-energy benefits) net cost or net benefit.

The figure shows that the energy-only cost-effectiveness of demand response-enabled lighting systems varies substantially depending on building size and service territory. In general, such systems are more cost-effective for larger buildings than for smaller ones, and for offices than for retail sites, across all service territories. In PG&E's service territory, where commercial retail electricity rates are relatively high (especially on peak), there is a substantial net benefit across all building sizes and types, and demand-response-enabled systems can generally be justified based on the static energy efficiency savings alone. The site-level value proposition in this case is straightforward. In contrast, in SCE's service territory where electricity rates are lower, the cost-effectiveness depends strongly on the building size, with a net benefit for large buildings only. In this case, the value proposition for small and medium buildings would likely need to rest on the non-energy benefits, rather than on the energy-related benefits. The results for the SDG&E's service territory are somewhere between these two cases.



Far Right Total: GREEN indicates Positive value; RED is Negative

Source: Lawrence Berkeley National Laboratory

Figure 6-4
Levelized System Installation Annual Costs and Energy-Related Benefits in SCE and PG&E Territories

Notably, the available revenue from independent system operator markets is always small relative to the system costs and overall energy cost savings. This suggests that the primary value proposition for demand response-enabled networked lighting controls comes from the site-level energy savings that will be realized with or without demand response participation. It may therefore be important to develop additional strategies to encourage participation in demand response programs once these technologies are adopted.

Comparing the available networked lighting controls energy savings in gigawatt-hours per year (GWh/yr) in Table 6-5 clearly indicates that the aggregate potential 5,091 GWh/yr resource exceeds the annual 4,425 GWh/yr peaker power output for 2015 reported to the Energy Commission. In fact, the available resource represents about 4-percent of the total 126,919 GWh/year of state natural gas generation.

Table 6-5
Potential Shed and Shimmy Demand Response Resources and Networked Lighting Controls Energy Savings

	Available Average* Shed Resource (MW)	Available Average Shimmy Regulation Resource (MW)	Available Average Shimmy Load-Following Resource (MW)	Available NLC Energy Savings (GWh/yr)
Total	1,026.6	824.2	1,033.6	5,090.7

Note: These are values that would be achievable by universal installation of networked lighting controls in California office and retail buildings.
* The average demand response resource refers to the average load that would be expected to be available for times when the demand response needs to be dispatched.
Source: California Energy Commission QFER CEC-1304 Power Plant Data Reporting

Demand Response Adoption Framework Summary

Networked lighting controls hold the promise of unlocking significant new value by capturing detailed environmental and device level sensory information. They can also implement control strategies to reduce energy consumption and manage building lighting load without affecting lighting characteristics, such as dim level or color, so precisely that user comfort is unaffected. However, these technologies still face adoption barriers, particularly for enabling features such as demand response. The project team developed a framework by which non-energy benefits can be leveraged to enable and support market adoption of energy benefits such as demand response. This adoption framework was used to clarify which cost-effective intervention strategies will increase demand response adoption (enablement and use). The framework leverages four components:

1. Benefits value intensity, which identifies and values non-energy benefits by building and space type.
2. Smart device maturity lifecycle, which explores how system capabilities support identified non-energy benefits while also supporting required demand response functionality and use.
3. Logic model and market transformation theory, to clarify and scope needed market intervention strategies including various activities, outputs and outcomes to remove specific barriers or leverage opportunities.
4. Program design, which evaluates all three elements above to select the most impactful program type to support market transformation

Benefits Value Intensity

The Benefits Value Intensity model helps categorize the magnitude of the impact of non-energy benefits on businesses’ energy costs, building costs, employee productivity, or company revenue, typically in terms of a financial value such as dollars per square foot where such quantification is possible. Actual documented values are highly specific to organizations and industries. For example, "increased facility control" by monitoring and optimizing humidity levels in a manufacturing facility might increase revenue by reducing the number of defective products. A warehouse might increase facility control by using occupancy-sensing heatmaps (Figure 6-5) to optimize stocking practices and boost employee productivity. In both cases, the benefits value intensity framework helps categorize and define value for non-energy benefits that are typically concurrent with demand response enablement.

Source: Garcia (2015)

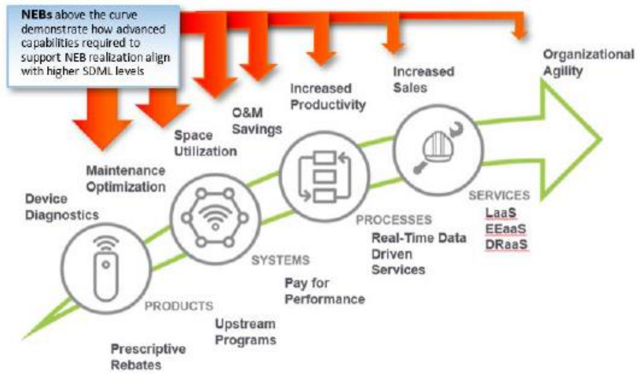
Figure 6-5
Example Occupancy Visualization

Importantly, the average Level 2 Benefits Value Intensity non-energy benefit savings in dollars/square foot/year is comparable to the overall Level 1 realized energy savings resulting from energy-efficiency improvements. This suggests that enabling networked lighting controls to decrease operations and maintenance costs in some cases through employing better operational data capture for things like asset utilization, could achieve equivalent dollar value benefits as energy savings associated with operating the networked lighting controls system for purely lighting alone.

Smart Devices Maturity Lifecycle

While the Benefits Value Intensity focuses on defining business value from networked lighting controls capabilities, the technology and its capabilities are evolving over time to create new and emerging business value. Smart devices typically follow a maturity cycle as they evolve and become increasingly connected and intelligent, and the smart devices maturity lifecycle focuses on this evolution to anticipate future capabilities that may unlock additional value.

The smart devices maturity lifecycle identifies four maturity levels: (1) products, (2) systems, (3) processes, and (4) services as shown in Figure 6-6. As activities move from nascent products (left) to services (right), then the benefits value intensity multiplier increases by factors of 10 described earlier in the 3:30:300:3000 rule of thumb.



Note: LaaS = Lighting as a Service; EEaaS = Energy Efficiency as a Service; DRaaS = Demand Response as a Service

Source: Lawrence Berkeley National Laboratory

Figure 6-6
Smart Device Maturity Lifecycle with Utility Programs and Non-energy Benefits Alignment

Market Transformation

Market transformation theory for demand response-enabled networked lighting controls reflects that consumer interest in non-energy benefits can be used to support grid beneficial capabilities but may have limited customer interest. Utility program support and incentives for networked lighting control demand response-enablement provides a win-win, allowing customers to adopt innovative new systems to obtain the non-energy benefits and utilities to have a persistent measurable supply of energy resources like energy efficiency and demand response. Additionally, this approach can influence actions that in turn will begin to prepare the building stock for more advanced energy benefits such as fast-demand response, for which networked lighting controlled, solid-state lighting is ideally suited.

The market transformation theory statement for networked lighting controls demand response-enablement is as follows:

- By clearly communicating the value proposition for each instrumental stakeholder and demonstrating the appropriate risk/reward, demand response adoption and use will be sought to co-fund initial networked lighting controls system costs and pave the way to significant non-energy benefits.

The market transformation theory statement leverages perception of value, the need to quantify value, the need to identify implicated stakeholders, the need to resolve perceived or real barriers to adoption, the connection between the value of non-energy benefits and the value of energy, and the conclusion of a behavioral change. In this context, each phrase within the statement has specific elements or goals.

- “Clear communication of value” includes defining and quantifying the value in clear terms, such as “dollars saved per square foot”, through efforts such as the Benefits Value Intensity, so that market actors understand the networked lighting control proposition in the context of their own business model lists “Instrumental stakeholders” included in the process of non-energy benefits/energy benefits realization (non-energy benefit-specific).
- “Demonstrating appropriate risk/reward” refers to assessing possible impacts to each stakeholder (through demonstrations, surveys, etc.), and capturing the full list of rewards (or value) they may

receive from the solution. In addition, this element must address perceived adverse impacts such as DR events that affect lighting quality.

- "Adoption and use" refers to configuring the DR capability included in most current NLC systems on the market, installing any remaining hardware/software, commissioning the proper application, receiving commitments to ongoing use through DR program enrollment, and verifying use.
- "Sought to co-fund" implies the knowledge and desire of the building owner or operator to seek the value proposition of NLCs and include utility incentives, in a bundled energy efficiency/DR package, leveraging "clear communication of value" to finance initial system costs to an acceptable level.
- "Initial system costs" include the full system implementation costs to provide all capabilities required to produce the targeted NEB(s) and the DR functionality.
- "Pave the way to significant non-energy benefits" refers to the higher levels of the BVI, including buildings, people, and revenue value generation. Quantification, to a "significant" level, is from the perspective of the targeted stakeholder.

Market actors include building owners, property/facility managers, occupants, trade allies, specifiers, manufacturers and utilities, all residing at different intervention points along the building and smart devices maturity lifecycles. This necessitates innovative program design approaches to eliminate or mitigate any market barriers to technology adoption.

Program Design – New Business Models

As an outgrowth of this study, the project identified that new business models are required to fully implement deployment of demand response-enabling networked lighting controls. Such models include developing pay-for-performance programs that bundle energy and non-energy benefits to support new services-oriented business models. Concepts like lighting as a service fall into this category. By default, this requires defining a new frame of reference rather than using historical energy efficiency/demand response program regulatory boundary conditions because the value of networked lighting controls goes beyond purely energy efficiency benefits to now include non-energy benefits.

Benefits to California

The project team found networked lighting controls have great potential to provide both energy savings and demand flexibility in California. Importantly, these technologies enable demand response capability within buildings that represents a significant distributed energy resource that in aggregate can more than offset peaker power plant production. Further research is required to unlock this potential to create a clearer site level, value proposition.

In many cases, energy savings alone can easily justify adoption of this technology, but in other cases, additional incentives or accounting of non-energy benefits may be necessary to justify investment. A long-term vision is to automate the quantification of non-energy benefits. Doing so would rely heavily on standardized networked lighting control commissioning using uniform nomenclature to ensure a syntactically and semantically meaningful data collection. Leveraging various Internet of Things (IoT) features, such as device data reporting, machine learning, data analytics, and so on, could make it possible to continue expanding and updating the non-energy benefits dictionary to keep up with technology advances and discover new non-energy benefits.

In general, the project team found values in higher benefits value intensity categories (Levels 2-4) could be several orders of magnitude larger than values in energy and demand management alone (Level 1). Using the quantitative information on non-energy benefits and high-influence market barriers and opportunities, the project team designed a sample logic model and conceptualized five intervention strategies as part of the market transformation theory for achieving large-scale commercial lighting demand response adoption.

In addition, the team concluded that where networked lighting controls are installed, additional incentives might be needed to encourage participation in utility demand response programs because typical revenue from bidding lighting demand response into energy markets is comparatively tiny (referencing "Figure 6-4: Levelized System Installation Annual Costs and Energy-Related Benefits in SCE and PG&E Territories").

This research sets the stage for California's investor-owned utilities to offer new pay-for-performance programs to support lighting technologies that create responsive buildings that become viable distributed energy resources able to provide grid services. Further, the research identifies which class of office or retail building can provide significant resource in different investor-owned utility load aggregation points.

More effort is necessary on several market transformation fronts to achieve success in deploying networked lighting controls effectively to create responsive, demand response-enabled buildings in California. This study is an initial effort and indicates the need for further research and utility program support.

https://ww2.energy.ca.gov/2019publications/CEC-500-2019-041/CEC-500-2019-041.pdf

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CONCLUSION AND KEY TAKEAWAYS

The groundbreaking transactive flexibility vision of GFO 15-311 began as a CEC-funded research solicitation in 2015. Six years later, all the projects in the portfolio are completed and the final CEC public reports are available for most of them. As we have seen, the innovative objective of this EPIC research opportunity was to enable the future integration of renewable resources that could help California meet its carbon emissions goals by facilitating a more effective use of DR enabling technologies and real time dynamic tariffs. The vision of developing and proving the viability of a TLM system that would provide customers with real-time energy pricing across a variety of applications has been demonstrated through this portfolio of research projects. These studies and demonstrations funded by the CEC's EPIC program establish the foundation upon which the next wave of DR enabling technologies in coordination with dynamic tariff designs can be implemented across California.

As we have seen, EPC-15-045, the TIME project, successfully developed the TLM system and the eight projects spread across Groups 1 and 2 provided the variety of potential applications and use cases such a dynamic pricing system might facilitate. While not all of the projects were able to test the TLM system during the project implementation period, the majority of projects were able to confirm that such a system would support real-time pricing for each of the residential and commercial customer scenarios. As with all scientific and technological research that is designed to accelerate the transformation of the future of electricity, different pathways to success were revealed. The TIME project was fundamental in directing the development of secure standards for communication and demonstrating the interoperability of appliances and equipment connected to the electric grid, including the ability of customers to engage with the infrastructure serving the grid.

Of significant note is the in-field demonstration (EPC-15-054 “RATES” project) that was able to demonstrate the viability and efficacy of a subscription model transactive pricing signal that provided a customer-facing, real-time tariff for more than 100 retail customers in Southern California Edison’s service territory. Customers were able to allow their in-home energy management system to shift their air-conditioning loads to periods of high solar penetration, which would in a future, real time tariff, reduce their energy costs while enabling an increase of renewables on the system. Customer preferences for savings were enabled through wirelessly connected devices (including a personalized voice-activated speaker interface) that utilized pre-existing AMI and OpenADR infrastructure. This proof of concept shows the high value to customers of being able to choose lower cost energy during high renewable generation and the benefit for utilities of being able to influence customer timing of energy usage that enables more renewable generation on the system, resulting in lower carbon emissions and a more stable grid.

The projects funded by GFO 15-311 have successfully proven that a TLM signal can be used effectively to leverage load flexibility from consumers and provide a unique value proposition in support of efficient grid operations in multiple applications across residential and commercial markets. This research supports California’s goals of developing new technologies that support increased renewables on the electric system through the integration of seamless, price-based customer participation in DR programs. These outcomes will help to increase the use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid, dynamically optimize grid operations and resources, and integrate cost-effective smart and interactive automated technologies into everyday life.

Project Summaries

Below are high level summaries of the key takeaways related to Transactive Load Management projects funded by the GFO.

Group 1

EPC-15-074 – Center for Sustainable Energy: Meeting Customer & Supply-side Market Needs with Electrical & Thermal Storage, Solar, EE and Integrated Load Management Systems

This project met the objective of the GFO and contributed to developing a regulatory pathway for BTM resources to participate in CAISO’s wholesale market. The project was partially successful in developing and pilot-testing operational strategies for participation as a supply-side resource, most significantly with energy storage but was unsuccessful with IoT system. Due to delays with CAISO wholesale market participation eligibility, this project did not have enough time to test TLM signals but was successful in identifying policy and participation barriers related to the CAISO. This project led to technological advancement by providing comprehensive recommendations on how to overcome technical, institutional and regulatory barriers to facilitating DER participation in the CAISO market.

EPC-15-083 – OhmConnect: Empowering Proactive Consumers to Participate in Demand Response Programs

This project met the objective of GFO-15-311 by providing critical evidence that residential customers are willing to manage their electric loads for the purpose of meeting grid needs. The project developed and pilot-tested operational strategies for participation as a supply-side resource by applying a three-phase approach to test customer engagement strategies. Transactive signals were tested through participation in supply-side markets to receive Day-ahead, real-time wholesale market prices from the TIME system. While the project reporting available at the time of writing this report did not single out any specific market barriers, the reporting did emphasize that over 15% of the participants were located in Disadvantaged Communities. It is highly likely that customers with limited access to smart devices may need to be engaged and enabled in the future. The results of this project did lead to technological advancements and can be used to help shape utility tariff and program design and program parameters for third party aggregator participation in demand response.

EPC-15-084 – BMW: Total Charge Management: Advanced Charge Management for Renewable Integration

This project meets the objective of GFO-15-311 by helping California advance the flexibility of electric vehicle charging as a flexible grid resource and as a vehicle charging cost savings to the driver. Operational strategies for participation as a supply-side resource included implementation and testing of control software to assess grid and customer benefits when there was excess supply and DR events. The pilot also participated in the supply-side markets to receive Day-ahead, real-time wholesale market prices from the TIME system. A potential barrier to participation identified a gap in vehicle driver consistency when it came to interacting with the app for away-from-home charging. Overall, increased charging flexibility occurred, regardless of location.

Group 2

EPC-15-048 – AESC: Residential Intelligent Energy Management Solution: Advanced Intelligence to Enable Integration of Distributed Energy Resources

This project met the objective of GFO-15-311 by identifying and developing strategies for overcoming technical barriers to expanding DR participation. BTM load management systems and operational strategies, program designs and retail tariff options were tested through the RDERMS system. A transactive signal was tested with thermostats, batteries, and EV charging. Barriers identified included technical barriers – internet connection, data quality, programming, and environmental sensors and non-technical barriers that included customer messaging and receiving utility price signals. Overall, the project showed it is possible to promote electric consumption that reduces peak demand through automation, intelligent control, and price signals.

EPC-15-054 – (RATES) Universal Devices: Complete and Low-Cost Retail Automated Transactive Energy System

This project met the objective of GFO-15-311 by demonstrating the feasibility of using a transactive system. BTM load management systems and operational strategies, program designs and retail tariff options were considered, and the RATES design was tested with over 100 retail customers on the SCE distribution grid. The team demonstrated the feasibility of integration of wholesale and retail operations using a transactive system. Market barriers identified included limited access to real-time and forecast data on circuit load and SCE net load, a need for more flexible devices, and a need for a fully operational subscription transactive tariff. The technology was proven to reduce barriers to low cost, anytime responsiveness for millions of customers and their devices by solving the cost and complexity of current DR.

EPC-15-057 – UC Berkeley: XBOS-DR: Customer- Controlled, Price Mediated, Automated Demand Response for Commercial Buildings

This project met the objective of GFO-15-311 by using networked thermostats to reduce energy consumption, demonstrating the prototype XBOS-DR platform to reduce peak loads on event days in SMB, and demonstrated the price messaging and information exchange module functionality. The XBOS-DR platform sufficiently pilot-tested BTM load management systems and operational strategies, along with program designs and retail tariff options. It is unclear from the reporting available at the time this paper was written if the project was able to test any transactive signals. Market barriers identified include difficulties in commissioning and managing multiple buildings and issues related to data quality. The project revealed high value in incorporating real-time building energy data with thermostat data: one can achieve building system identification, conduct diagnostics, and improve control.

EPC-15-073 – UCLA: Identifying Effective Demand Response Program Designs for Residential Customers

This project met the objective of GFO-15-311 by identifying and developing strategies for overcoming customer and policy barriers to expanding DR participation in California using BTM customer engagement platforms. This project did not utilize the TLM signals. Market barriers identified include issues related to customer engagement, customer demographics and current DR program design. A central challenge for DR is how to attract customers and ensure that they remain active conservers in the long term. OhmConnect’s strategy of emphasizing automation may be an effective way to accomplish this goal.

EPC-15-075 – (DSRIP) EPRI: Customer-Centric Demand Management Using Load Aggregation And Data Analytics

This project met the objective of GFO-15-311 by designing and testing a BTM system through the development of a flexible platform (OpenDSRIP). The platform provided insights into overcoming technical barriers to scale, including the successful utilization of the EPRI TLM signal. Potential market barriers include customer appetite, data security, solutions for DACs, solutions for scalability, and energy standards. By developing frameworks and open-source tools for evaluating flexibility, the project provided a more realistic understanding of the potential for flexibility as a pathway to decarbonization in CA.

Group 3

EPC-15-045 – (TIME) EPRI: Transactive Incentive Signals to Manage Electricity Consumption for Demand Response

This project met the objective of GFO-15-311 by successfully developing a day-ahead hourly proxy price signal that incorporates system conditions as reflected by wholesale energy markets. The TLM signals are reflective of current and future grid conditions. The project developed and implemented innovative software to calculate such signals. The signal was then tested by the majority of the projects in Group 1 and Group 2. This project has resulted in extended and new research projects to test the transactive signal across additional scenarios and to determine how this technology might influence CA policy.

Group 4

EPC-15-048 – LBNL: Residential Intelligent Energy Management Solution: Advanced Intelligence to Enable Integration of Distributed Energy Resources

This project met the objective of GFO-15-311 by setting the stage for IOUs to offer new pay-for-performance programs to support lighting technologies. The project evaluated the costs and benefits of DR control system requirements in the California Energy Code and developed a framework that can be used to better quantify in real terms, the value associated with networked lighting controls for different building types. The project did not test any transactive signals as the study was focused on shape, shed, and shimmy regimes when evaluating networked lighting controls demand response value for offices and retail buildings. Market barriers identified include an unclear value proposition to customers; perceived impact to trade allies; lack of standardization; lack of best practices in commissioning; lack of integrated program support.

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Additional Resources

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