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1. Executive Summary

With a vision of safely providing a more reliable and affordable electric system, Southern California Edison Company (SCE) was awarded up to $39.6 million in matching funds from the U.S. Department of Energy (DOE) to conduct the Irvine Smart Grid Demonstration (ISGD). This demonstration tested the interoperability and effectiveness of key elements of a modernized electric grid—from the transmission level through the distribution system and into the customer premises. This end-to-end demonstration of smart grid technologies is helping SCE address several profound changes impacting the electric grid's operation, including increased use of renewable resources, more intermittent generation connecting to the distribution system, the ability of customers to actively manage the way they use electricity, and policies and mandates focused on improving the environment and promoting energy security.

Project Overview

ISGD operated primarily in the City of Irvine (Irvine) in Orange County, California, and many of the project components are located on or near the University of California, Irvine (UCI) campus. Key project participants included UCI, General Electric (GE), SunPower Corporation, LG Chem, Space-Time Insight (STI), and the Electric Power Research Institute (EPRI).

ISGD's evaluation approach included four distinct types of testing: simulations, laboratory tests, commissioning tests, and field experiments. ISGD used simulations and laboratory testing to validate a technology's performance capabilities prior to field installation. Commissioning tests ensured the field installation was effective and that the respective component was working as intended. The purpose of the field experiments was to evaluate the physical impacts of the various technologies on the electric grid and to evaluate the associated benefits.

The project included four domains. Each domain included one or more sub-projects with distinct objectives, technical approaches, and research plans. There were eight sub-projects within these four domains.

Domain	Sub-project
Smart Energy Customer Solutions	1. Zero Net Energy Homes 2. Solar Car Shade
Next Generation Distribution System	3. Distribution Circuit Constraint Management Using Energy Storage 4. Distribution Volt/VAR Control 5. Self-healing Distribution Circuits 6. Deep Grid Situational Awareness
Interoperability & Cybersecurity	7a. Secure Energy Net 7b. Substation Automation 3
Workforce of the Future	8. Workforce of the Future

Each of these domains is described below in terms of what the team wanted to learn from them, the design and approach, key observations and findings, and how these results will inform future demonstrations and deployments.

Smart Energy Customer Solutions

Background

Customers are modifying how they consume and generate electricity. They are migrating from being passive consumers of fixed-price energy toward being conscious users—and sometimes generators—of energy that varies in price throughout the day. The technologies enabling this transition are emerging rapidly, presenting utilities with many questions. How will these customer technologies affect the electric system and how can they be coordinated to benefit the grid? What type of communication infrastructure will best enable these technologies? How can energy storage provide benefits to both the customer and the grid? To explore these types of questions, this domain evaluated a number of customer-facing energy technologies in both residential and workplace settings.

Approach

Sub-project 1 took place in a residential neighborhood on the UCI campus used for faculty-owned housing. ISGD equipped three blocks of homes with varying combinations of advanced energy components, including energy efficiency upgrades, electric vehicle supply equipment (EVSE), energy storage, rooftop solar photovoltaic (PV) panels, thermostats and smart appliances capable of demand response, and in-home displays. The project used one block of homes to evaluate strategies and technologies for achieving zero net energy (ZNE). A home achieves ZNE when it produces at least as much renewable energy as the amount of energy it consumes on an annual basis. The project also sought to understand the impact of ZNE homes on the electric grid. The team performed energy simulations to determine the energy efficiency measures for each home. The project team performed laboratory testing on the smart appliances, EVSE, and other home area network (HAN) devices prior to field deployment. In the field, the team performed demand response experiments on the EVSE, smart appliances, and the heating and cooling systems. To evaluate the ZNE technology and strategies, the team collected detailed energy usage information, by circuit.

ISGD evaluated two types of energy storage devices in this neighborhood. The team installed residential energy storage units (RESUs) in 14 homes, and evaluated them using a variety of control modes. In addition, one block of homes shared a community energy storage (CES) device. The team also evaluated the CES using a variety of control modes. Both devices can provide a limited amount of backup power during electricity outages. These energy storage devices underwent extensive laboratory testing prior to commissioning. The team then installed the devices and performed field experiments, including demand response events, an islanding test, and a series of tests to shift and smooth load, capture solar PV generation, and provide volt-ampere reactive (VAR) support.

To evaluate the impact of charging plug-in electric vehicles (PEVs) in the workplace, sub-project 2 installed and operated a Solar Car Shade system within a parking garage on the UCI campus. The system includes 48 kilowatts (kW) of rooftop solar PV, 20 EVSEs, and a 100 kW/100 kilowatt-hour (kWh) energy storage device. The objective was to reduce or eliminate the grid impact of PEV charging during peak periods. The team performed component testing of the energy storage device and EVSEs prior to installation. The team then commissioned the system and performed experiments such as permanent load shifting (PLS) and other schemes to minimize grid impact of PEV charging over the demonstration period.

Outcomes and Next Steps

The project successfully demonstrated how customer technologies with demand response capabilities could help—both individually and in concert with each other—to manage customer load and reduce circuit peaks. Residential and neighborhood energy storage were helpful in shifting loads, leveling demand, and providing backup power. Energy storage was also helpful in achieving ZNE under one of the ZNE methods evaluated. When operating energy storage to optimize for ZNE, five of the nine homes achieved ZNE. Solar PV and light emitting diode (LED) lighting upgrades had the greatest impact in achieving ZNE.

Maintaining the communications between the various HAN devices was an ongoing challenge throughout the project. Inconsistencies among vendor implementations of the ZigBee Smart Energy Profile standard also created challenges for conducting demand response tests. Smart appliances have limited demand response potential and low customer value. Residential energy storage substantially increased customer energy use due to the roundtrip AC/DC conversion losses and, if not operated to optimize for ZNE, had a negative impact on customers' ZNE performance.

Collaboration among industry stakeholders is necessary to improve communications interoperability for key customer loads, such as electric vehicles and air conditioning. A key objective for future demonstrations would be to evaluate methods to monitor and control the growing number of distributed energy resources (DERs) to resolve grid challenges.

Next-Generation Distribution System

Background

For more than a hundred years, utilities such as SCE have brought electricity from large, centralized power sources to its customers, with electricity only flowing in one direction. Today, an increasing number of residential and business customers are changing the grid with solar PV generation, energy storage, electric vehicles, and other types of DERs. These new technologies are transforming the grid into a two-way system, forcing utilities to answer a number of questions about how they plan, design and operate the distribution grid. How can energy storage help to mitigate circuit overloads? Can centralized control of capacitors banks help achieve energy savings through conservation voltage reduction? How might utilities configure and operate distribution circuits differently to improve system reliability?

To investigate answers to these and other questions, the ISGD team used 12-kilovolt (kV) circuits fed from MacArthur Substation to demonstrate a set of advanced distribution automation technologies in four sub-projects.

Approach

Sub-project 3 consisted of operating a 2 megawatt (MW) energy storage device to help relieve distribution circuit constraints and to mitigate overheating of the substation getaway. The team performed lab testing of the battery system to prepare for field deployment. The team then performed a field test to demonstrate the ability of the battery to reduce circuit loading at the substation.

Sub-project 4 demonstrated a distribution volt/VAR control (DVVC) application to optimize customer voltage profiles in pursuit of energy savings through conservation voltage reduction (CVR). DVVC can also provide VAR support to the transmission system. The DVVC application underwent multiple rounds of factory acceptance testing and site acceptance testing, and operated on seven distribution circuits out of MacArthur Substation during this demonstration.

A self-healing distribution circuit demonstration, consisting of two circuits operated in a looped configuration, and intended to improve reliability by identifying and isolating faults with greater speed and precision, was deployed in sub-project 5. This scheme isolates faults within a smaller section of the looped distribution circuits while preserving service to the remaining customers. The self-healing looped distribution circuit configuration was enabled by universal remote-controlled circuit interrupters (URCIs). During a fault, the URCIs coordinate their operations using Generic Object Oriented Substation Event (GOOSE) messaging through high-speed, low-latency radios. The team performed simulations of the URCI system operating under a variety of grid conditions to evaluate its performance prior to field deployment. The team also performed pre-deployment testing of the URCI and radio components in preparation for field deployment. However, difficulties with the radio system prevented full field demonstration of the system.

In sub-project 6, the team used the 2-MW battery from sub-project 3 along with phasor measurement technology installed within MacArthur Substation to attempt to detect changes in distribution circuit load from an aggregation of DERs such as demand response resources or energy storage. The team attempted to explore the potential of this approach for validating the dispatch of distributed resources to support their participation in energy and ancillary services markets without having to monitor each resource separately.

Outcomes and Next Steps

The project successfully demonstrated that centralized control of substation and distribution capacitors under DVVC could substantially reduce overall system voltage and customer energy use without requiring any change in customer behavior. Depending on the type of distribution circuit, DVVC can provide energy savings of 1% to 4%. Energy storage sited on a distribution circuit was also effective in helping to reduce distribution circuit constraints.

However, the battery system itself required ongoing effort to overcome operational issues and its energy capacity would need to be sized appropriately to help defer grid capacity upgrades. Persistent challenges with the low-latency field area network (FAN) prevented the team from placing the URCIs into service during this demonstration period. Detection of DER dispatch using phasor measurement technology in the substation functioned, but considerable additional work is necessary to determine the practicality of this capability.

SCE is beginning a system-wide implementation of DVVC due to the successes achieved by ISGD. Future versions of DVVC may also include control of smart inverters, which could support the participation of a larger number of utility- and customer-owned DERs in providing voltage and VAR support. Additional capabilities worthy of further investigation include control systems that use DERs for volt/VAR control, power flow optimization, and microgrid support. SCE is continuing to evaluate FAN technologies that could support future distribution automation needs. SCE is also continuing to work with energy storage vendors to improve the reliability and functionality of energy storage devices.

Interoperability & Cybersecurity

Background

The electric grid is evolving to include an increasing number of distributed and interconnected grid resources, both utility- and customer-owned, as described in the first two ISGD project domains. The need for near plug-and-play interoperability within a secure environment is therefore of critical importance. This technology is emerging with bewildering speed and complexity, confronting industry stakeholders with myriad questions about interoperability, cybersecurity, and implementation of industry standards. Is it feasible to achieve a practical level of interoperability between components from different manufacturers? What does conformance with standards such as IEC 61850 really mean and how do you ensure interoperability? Can industry expectations of widespread interconnectivity be reconciled with the need for vigorous cybersecurity? How can legacy systems be integrated with new systems and is there a feasible migration path?

Approach

To gain insight into these types of questions, the team designed a single sub-project consisting of two related parts, Secure Energy Net (SENet) and SCE's next generation of substation automation (SA-3). SENet consisted of a modern, routable fiber network using client-server architecture to provide the advantages of modern networks with equal or better security than the legacy host-RTU architecture of existing control systems. Technologies demonstrated included Multiprotocol Labeling Switching (MPLS) routing and SCE's Common Cybersecurity Services (CCS).

The project used SCE's MacArthur Substation to pilot SA-3. The SA-3 platform integrates with both SENet and the legacy control system, and enables IEC 61850 standard-based communications, automated configuration of substation devices, and an enhanced system protection design. The team set up a complete duplicate of the equipment installed in MacArthur Substation at SCE's Advanced Technology Labs in order to perform real-time simulations and component testing prior to field installation. Real-time simulation allowed testing of thousands of scenarios to verify proper operation under various grid conditions. The team installed SA-3 components at MacArthur Substation and placed the system into service in late 2013.

ISGD also represents the first field deployment of SCE's CCS platform. The project is using CCS to provide high-assurance cybersecurity for substation devices and communications between the various field devices and ISGD back office systems. The team assembled various communications and security components in the laboratory environment for end-to-end integration testing prior to field deployment. The team then installed the various components in the field and commissioned the system.

Outcomes and Next Steps

The project team successfully demonstrated that it could fully configure an SA-3 human machine interface (HMI) within minutes instead of weeks. It also demonstrated the viability of the SA-3 substation gateway as a means for configuring substations, performing password management, and retrieving relay fault files.

Integrating the various computing infrastructure and communications technologies required that SCE assume the system integrator role, which was a major undertaking. Incompatibilities in vendor implementations of the IEC 61850 standard contributed to the need for SCE to perform this role. While the CCS worked as intended, cybersecurity standards (such as NERC CIP v. 5) themselves are still evolving, so more work will be required in this area.

SCE is beginning a system-wide implementation of its SA-3 platform as a result of the success achieved by ISGD. Project team members are also collaborating with vendors and standards development organizations for standards updates that will help address some of the interoperability challenges the team faced on ISGD. SCE is also expanding the substation gateway functionality to satisfy NERC CIP v.5 requirements.

Workforce of the Future

Background

Deploying smart grid technologies on a larger scale would affect the utility workforce, and it could have implications for the utility's organizational structure. This raises a number of questions about how utilities will identify, retain, train and organize their workforce in the future. What skills will workers need and how will utilities need to modify their processes for recruiting, training, and motivating these employees? What are the implications for the current job classifications, and how might the organizational structure need to change to manage new types of grid technologies?

Approach

Sub-project 8 developed and delivered workforce training for the relevant ISGD technologies and performed an assessment of the potential workforce implications of these technologies.

Outcomes and Next Steps

The project team successfully developed and delivered the necessary training to SCE personnel who worked with the various ISGD technologies. This effort highlighted the broader implications of a larger scale deployment of similar technologies. Some job classifications will likely need new types of skills, while new jobs classifications will also probably emerge. For example, a Data Scientist could help manage and gain insights from the large volume of data generated by the various smart grid components.

As the industry continues to evolve at a rapid pace, it will be important for utilities to inculcate a culture of continuous learning by offering cross-training opportunities and other types of on-demand learning. This will help utilities to attract and retain employees who thrive in the industry's rapidly evolving environment.

Utilizing the Results of the ISGD Project Work

Lessons learned and information gained during the ISGD project were discussed as part of the "Building California's Flexible Grid – The Irvine Smart Grid Demonstration Closing Symposium" held in Huntington, Beach on October 27, 2015. This symposium, sponsored by SCE in conjunction with the DOE, gave an overview of the ISGD project and hosted four panels discussing key areas of the project. The panels, based on the key project areas described above, were composed of representatives from SCE, DOE, EPRI, utilities and others involved with the project. This symposium served to help disseminate lessons from the project to the industry to help advance new technologies.

Results from the ISGD project are also informing several follow-on projects at SCE as part of its Grid Modernization program. These follow-on projects include:

- Further deployment of SA-3 at other SCE substations
- Deployment of DVVC across the SCE distribution system
- The *Integrated Grid Project,* which will demonstrate the equipment and control systems needed in the future to accommodate high penetration of DER devices. This demonstration extends learnings from the ISGD project to a larger area in preparation for system-wide deployment.
- The *Preferred Resource Pilot,* which is working to acquire greater amounts of environmentally-preferred DERs for South Orange County
- A set of pilot demonstrations under the California Public Utilities Commission (CPUC) mandated *Distribution Resources Plan* intended to show how higher levels of DERs can be integrated into SCE's distribution system planning and operations
- Deployment of several distribution battery energy storage systems under the CPUC energy storage mandate

Reporting Overview

Over the course of the project, SCE filed two Technology Performance Reports (TPRs) and this Final Technical Report (FTR). This FTR covers the entire two-year demonstration period. It also provides benefit calculations and an appraisal of the commercial readiness and scalability of the technologies demonstrated.

Final Technical Report Organization

Chapter 2 provides general information about the project, including overviews of the project team, location, schedule, and milestones. This chapter also provides additional details about the four project domains introduced above, and it summarizes the potential benefits that could result from the ISGD technologies.

Chapters 3 through 6 describe the objectives, technical approach, research plan, summary field test results, observations, metrics, and benefits for the four domains. The research plan describes the relevant technology evaluation activities including simulations, laboratory tests, commissioning tests, and field experiments for each of the technology components. The observations section includes lessons learned, commercial readiness, and calls to action. Lessons learned are also summarized by technical domain in Appendix 15.

Chapter 7 provides a more detailed discussion of the demonstration results for the twenty-four months of field experimentation—from July 1, 2013 to June 30, 2015. Detailed discussion of particular subjects are included as appendices.

2. Scope

SCE was awarded up to $39.6 million in matching funds from the U.S. DOE to conduct a Regional Smart Grid Demonstration Project, an end-to-end demonstration of numerous smart grid technologies that SCE believes are necessary to meet federal and state policy goals. The ISGD project tested the interoperability and efficacy of key elements of the grid, from the transmission level through the distribution system and into customer homes. SCE's experience with smart grid technologies, gained through the Avanti distribution circuit (co-funded by the DOE[1]), synchrophasor development, and the Edison SmartConnect® smart meter program, to name a few, provided an important foundation for this project. ISGD was a deep vertical dive that tested multiple components of an end-to-end smart grid. Thus, the project provided a living laboratory for simultaneously demonstrating and assessing the interoperability of, and interaction between, multiple smart grid technologies and systems. ISGD operated in the City of Irvine (Irvine), a location that typifies some heavily populated areas of Southern California in climate, topography, environmental concerns, and other public policy issues.

2.1 Project Abstract

ISGD was a comprehensive demonstration that spanned the electricity delivery system and extended into customer homes. The project used phasor measurement technology to enable substation-level situational awareness, and demonstrated SCE's next-generation substation automation system. It extended beyond the substation to evaluate the latest generation of distribution automation technologies, including looped 12-kV distribution circuit topology using URCIs. The project team used DVVC capabilities to demonstrate CVR. In customer homes, the project evaluated HAN devices such as smart appliances, programmable communicating thermostats, and home energy management components. The homes were also equipped with energy storage, solar PV systems, and a number of energy efficiency measures (EEMs). The team used one block of homes to evaluate strategies and technologies for achieving ZNE. A home achieves ZNE when it produces at least as much renewable energy as the amount of energy it consumes annually. The project also assessed the impact of device-specific demand response (DR), as well as load management capabilities involving energy storage devices and plug-in electric vehicle charging equipment. In addition, the ISGD project sought to better understand the impact of ZNE homes on the electric grid. ISGD's SENet enabled end-to-end interoperability between multiple vendors' systems and devices, while also providing a level of cybersecurity that is essential to smart grid development and adoption across the nation.

The ISGD project includes a series of sub-projects grouped into four logical technology domains: Smart Energy Customer Solutions, Next-Generation Distribution System, Interoperability and Cybersecurity, and Workforce of the Future. Section 2.3 provides a more detailed overview of these domains.

2.2 Project Overview

2.2.1 Objectives

The primary objective of ISGD was to verify and evaluate the ability of smart grid technologies to operate effectively and securely when deployed in an integrated framework. The project also provided a means to quantify the costs and benefits of these technologies in terms of overall energy consumption, operational efficiencies, and societal and environmental benefits. Finally, ISGD allowed the project team to test and validate the applicability of the demonstrated smart grid elements for the Southern California region and the nation as a whole.

2.2.2 Project Team

Project participants, led by SCE, consisted of a combination of industry leaders, with each one bringing essential expertise to the project. In addition to SCE, major participants included UCI's Advanced Power and Energy Program, GE,

[1] This is a 12 kV distribution circuit that became operational in 2007 and serves more than 1,400 residential and business customers.

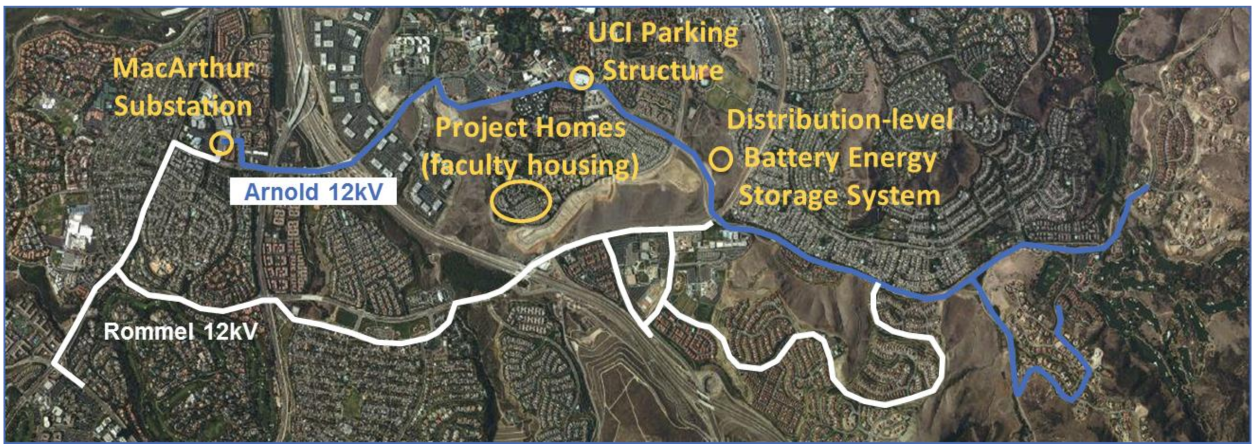
SunPower Corporation, LG Chem, STI, and EPRI. SCE coordinated the efforts among project participants to capture and document lessons learned and to help share this knowledge with the broader industry.

2.2.3 Project Location

ISGD operated primarily in Irvine, in Orange County California, approximately 35 miles south of the City of Los Angeles. With a population of nearly 250,000 people, Irvine is widely recognized as one of the safest master-planned, business-friendly communities in the country. It is home to UCI and a number of corporations, including many in the technology sector.

ISGD was carried out on two 12 kV distribution circuits (Arnold and Rommel circuits) that are fed by MacArthur Substation located in the City of Newport Beach, California. MacArthur Substation is supplied by Santiago Substation located 10 miles east in Irvine. In addition to the two circuits fed by MacArthur Substation, portions of the ISGD project were conducted within 38 homes on the UCI campus (faculty housing), and at a UCI parking facility. **Figure 1** provides a graphical depiction of this smart grid system.

Figure 1: High Level Project Map



2.2.4 Project Schedule and Milestones

The following table represents a summary of ISGD's key milestones.

Table 1: Key ISGD Milestones

Key Milestones	Milestone Dates
Submit National Environmental Policy Act application and receive Categorical Exclusion from DOE	07/19/2010
Submit Interoperability & Cybersecurity Plan to DOE	10/24/2011
Submit Project Management Plan to DOE	07/31/2012
Complete engineering design and specifications	12/31/2012
Begin 24 months of measurement and verification activities	07/01/2013
Submit updated Metrics & Benefits Reporting Plan to DOE	12/12/2013
Submit first Technology Performance Report	06/03/2014
Submit second Technology Performance Report	01/31/2015
Completed field testing	06/30/2015

Key Milestones	Milestone Dates
Complete data analysis and submit Final Technical Report	12/29/2015

2.3 Project Domains

The ISGD project included the following four domains: Smart Energy Customer Solutions, Next-Generation Distribution System, Interoperability & Cybersecurity, and Workforce of the Future. Each domain included one or more sub-projects with distinct objectives, technical approaches, and research plans.

2.3.1 Smart Energy Customer Solutions

This project domain included a variety of technologies that help empower customers to make informed decisions about how and when they consume (or produce) energy. ISGD evaluated these customer technologies through the following two sub-projects:

- Sub-project 1: Zero Net Energy Homes through Smart Grid Technologies
- Sub-project 2: Solar Car Shade

2.3.2 Next-Generation Distribution System

The electric grid is evolving into an increasingly dynamic system with new types of distributed and variable generation resources and changing customer demands. This project domain included technologies designed to support grid efficiency and resiliency within this changing environment. ISGD evaluated these electricity distribution technologies through the following four sub-projects:

- Sub-project 3: Distribution Circuit Constraint Management Using Energy Storage
- Sub-project 4: Distribution Volt/VAR Control
- Sub-project 5: Self-healing Distribution Circuits
- Sub-project 6: Deep Grid Situational Awareness

2.3.3 Interoperability & Cybersecurity

Electric utilities, customers and other third parties are interconnecting an increasing number of distributed energy resources to the electric system. The need for seamless interoperability within a secure environment is of critical importance. This project domain is a foundational element that underpins the development of smart grid capabilities. ISGD evaluated interoperability and cybersecurity through sub-project 7, which is composed of two elements:

- Secure Energy Network
- Substation Automation 3

2.3.4 Workforce of the Future

This project domain consisted of a single sub-project, Workforce of the Future (sub-project 8).This domain included the workforce training tools and capabilities necessary to operate and maintain the various ISGD components. The sub-project also evaluated the potential impacts of smart grid technologies on the utility's organizational structure. This assessment related specifically to SCE, but it also provides insights applicable to the whole electric utility industry.

2.4 Smart Grid Functions and Energy Storage Applications

2.4.1 Smart Grid Functions

In providing guidance to demonstration grant recipients for preparing TPRs and the FTR, the DOE presented a list of "Smart Grid Functions."[2] **Table 2** indicates which of these smart grid functions ISGD is demonstrating, by sub-project.

Table 2: Summary of Smart Grid Functions by Sub-project

DOE Smart Grid Functions	Sub-project							
	1	2	3	4	5	6	7	8[3]
Fault Current Limiting								
Wide Area Monitoring, Visualization, & Control							✓	
Dynamic Capability Rating								
Power Flow Control			✓					
Adaptive Protection					✓			
Automated Feeder Switching					✓			
Automated Islanding and Reconnection	✓							
Automated Voltage & VAR Control				✓				
Diagnosis & Notification of Equipment Condition								
Enhanced Fault Protection					✓			
Real-time Load Measurement & Management						✓		
Real-time Load Transfer					✓			
Customer Electricity Use Optimization	✓	✓						

2.4.2 Energy Storage Applications

The DOE's guidance for preparing TPRs included a list of potential "Energy Storage Applications."[4] **Table 3** indicates which of these energy storage applications ISGD demonstrated, by sub-project.[5]

Table 3: Summary of Energy Storage Applications by Sub-project

Energy Storage Applications	Sub-project 1 RESU	Sub-project 1 CES	Sub-project 2 BESS	Sub-project 3 DBESS
Electric Energy Time Shift	✓	✓	✓	✓
Electric Supply Capacity	✓	✓	✓	✓
Load Following	✓	✓	✓	✓
Area Regulation				
Electric Supply Reserve Capacity				
Voltage Support	✓	✓		
Transmission Support				
Transmission Congestion Relief				
T&D Upgrade Deferral		✓	✓	✓
Substation Onsite Power				
Time-of-Use Energy Cost Management	✓		✓	

[2] Guidance for Technology Performance Reports, Regional Demonstrations, V1 – Draft Submittal, June 17, 2011 (page 2).
[3] Sub-project 8 relates to the workforce training and organizational impacts associated with smart grid technology, and therefore does not perform a smart grid function.
[4] Guidance for Technology Performance Reports, Regional Demonstrations, V1 – Draft Submittal, June 17, 2011 (page 2).
[5] **Table 3** summarizes the operational uses of the RESU, CES, battery energy storage system (BESS), and distribution-level battery energy storage system (DBESS).

Energy Storage Applications	Sub-project 1 RESU	Sub-project 1 CES	Sub-project 2 BESS	Sub-project 3 DBESS
Demand Charge Management	✓		✓	
Electric Service Reliability	✓	✓		
Electric Service Power Quality				
Renewables Energy Time Shift	✓	✓	✓	
Renewables Capacity Firming				
Wind Generation Grid Integration, Short Duration				
Wind Generation Grid Integration, Long Duration				

2.5 Potential Benefits

The ISGD project demonstrated smart grid technologies meant to improve the performance and resilience of the electric system. These performance improvements provide four categories of benefits: economic, reliability, environmental, and security. **Table 4** below summarizes the types of benefits the ISGD team expected to observe within the project. Evaluating an individual smart grid technology requires establishing linkages between the technology and the associated impacts. Moreover, these impacts should be measurable and verifiable. When deploying multiple technologies, the associated impacts must be isolated and assigned to the individual technologies. Evaluating the impacts of complementary technologies (or foundational technologies which enable other technologies) also requires careful consideration and evaluation. Limiting the project to a discrete and well-defined area removes many confounding sources of variation that can complicate isolating and measuring individual impacts. Nevertheless, the smart grid technologies may demonstrate considerable variability in their impacts or benefits due to factors outside the control of testing protocols.

Chapters 3, 4, and 5 contain the ISGD research plans for each domain, and they define the linkages between these technologies, the physical impacts they have on the system, and the potential corresponding benefits. The ISGD team worked with researchers from Lawrence Berkeley National Laboratory, who ran the DOE's Smart Grid Computational Tool to estimate the potential benefits resulting from ISGD. Appendix 11 summarizes the results of this effort.

Table 4 summarizes the benefits that may be attributable to the smart grid technologies and capabilities demonstrated on ISGD. This table includes each of the smart grid benefits identified in the DOE benefits framework, as well an additional benefit identified by SCE.[6]

[6] The DOE benefits framework was obtained from the DOE's "SGDP Smart Grid Demonstration Program, Guidance for Technology Performance Reports," June 17, 2011, page 3.

Table 4 Summary of ISGD Benefits by Sub-project[7]

Benefit Category	Benefit	Measurable Impacts	Sub-project							
			1	2	3	4	5	6	7	8
Economic Benefits (Continued)										
Market Revenue	Arbitrage revenue		D							
	Capacity revenue									
	Ancillary service revenue									
Improved Asset Utilization	Optimized generator operation									
	Deferred generation capacity investments	Demand (kilowatts or kW)	D	D	D				I	I
	Reduced ancillary service cost									
	Reduced congestion cost									
T&D Capital Savings	Deferred transmission capacity investments		D	D	D				I	I
	Deferred distribution capacity investments	Demand (kW)	D	D	D				I	I
	Reduced equipment failures	• Demand (kW) • Customer voltage # of equipment operations/failures	D	D	D	D	D		I	I
T&D O&M Savings	Reduced distribution equipment maintenance cost	Equipment maintenance cost	D	D	D	D	D		I	
	Reduced distribution operations cost									
	Reduced meter reading cost	Identify sub-metering solution	D							
Theft Reduction	Reduced electricity theft									
Energy Efficiency	Reduced electricity losses	Feeder loading (kW)	D	D	D	D			I	I
Electricity Cost Savings	Reduced electricity cost	• Electricity use (kilowatt-hours or kWh) • Demand (kW)	D	D		D		P	I	I
Reliability Benefits										
Reduced Service Interruption	Reduced sustained outages	• # of outages • Average outage duration	D				D		I	I
	Reduced major outages									

[7] The following is a legend for the sub-project benefits:

D Benefit is a direct result of this sub-project.

I Benefit is an indirect result of this sub-project (i.e., sub-project enables the relevant capability within a different sub-project).

P Benefit could potentially result from this sub-project. For example, sub-project 6 is demonstrating the potential for "deep grid situational awareness," a capability would have no immediate or direct benefit, but could provide benefits over the longer term.

Benefit Category	Benefit	Measurable Impacts	Sub-project							
			1	2	3	4	5	6	7	8
	Reduced restoration cost	Time required to identify fault					D		I	I
Improved Power Quality	Reduced momentary outages	• # of outages • Average outage duration	D				D		I	I
	Reduced sags and swells	Customer meter voltage				D				I
Environmental Benefits										
Reduced Air Pollution	Reduced carbon dioxide emissions	• Plug-in Electric Vehicle (PEV) charging (kWh) • Solar PV generation (kWh) • Reduced electricity use (kWh) • Reduced electricity	D	D	D	D			I	I
	Reduced SOx, NOx, and PM-2.5 emissions	• PEV charging (kWh) • Solar PV generation (kWh) • Reduced electricity use (kWh) • Reduced electricity loss (kWh)	D	D	D	D			I	I
Security Benefits										
Improved Energy Security	Reduced oil usage	PEV charging (kWh)	D	D					I	I
Improved Cybersecurity[8]		• Higher reliability • Increased resiliency • Improved situational awareness							D	I

Sections 2.5.1 to 2.5.4 describe how the benefits identified in **Table 4** could eventually result from the technologies demonstrated within the ISGD project.

2.5.1 Economic Benefits

<u>Deferred Generation Capacity Investments</u>: Utilities determine their generation capacity requirements based on the need to serve the maximum forecasted load. Efforts to reduce peak load through demand response and other load management capabilities could ultimately defer the need for incremental generation capacity investments.

<u>Deferred Transmission Capacity Investments</u>: Efforts to reduce peak load through demand response and other load management capabilities may reduce the load and stress on transmission infrastructure. This may result in deferring the need for incremental transmission capacity investments, if utilities expand these load management capabilities to large customer populations. Enabling distributed generation resources may also reduce the need for transmission capacity.

[8] This benefit is not included in the DOE benefit framework.

Deferred Distribution Capacity Investments: Distribution capacity requirements are generally determined based on non-coincident peak load. To the extent that new load management capabilities result in peak load reductions, it may be possible to defer distribution capacity investments.

Reduced Equipment Failures: Reducing the stress placed on distribution equipment has the potential to extend these assets' useful lives and reduce the number of equipment failures. Peak load reductions and enhanced fault protection can help to reduce distribution equipment stress.

Reduced Distribution Equipment Maintenance Cost: To the extent that enhancing circuit protection or reducing peak load reduce strain on distribution equipment, it may be possible to reduce the cost of maintaining this equipment.

Reduced Electricity Losses: As electricity travels from a generation source through the transmission and distribution system, a small portion of energy is lost due to system impedances. Conversely, locating generation resources closer to energy consumers can reduce energy losses. Lowering average customer voltage levels can also reduce electricity losses (i.e., CVR).

Reduced Electricity Cost: Energy efficiency measures installed within project participant homes, and CVR achieved through DVVC in sub-project 4 may contribute to overall reductions in electricity usage. Likewise, load management programs using direct load control of programmable communicating thermostats (PCTs), smart appliances, PEVs, and RESUs may support utility efforts to reduce peak load. Customers who enroll in time-of-use retail electricity rates or participate in load management programs would benefit financially from shifting their electricity use to off-peak periods.

2.5.2 Reliability Benefits

Reduced Sustained Outages: A sustained outage is an outage lasting more than 5 minutes. The self-healing distribution circuit in sub-project 5 may minimize the number of customers impacted by a fault condition. This should result in fewer sustained outages for customers served by this looped circuit. In addition, sub-project 1 includes two energy storage devices, the RESU and CES, which may help reduce the number of outages. The RESU is configured to support a household circuit with secure loads (e.g., the garage door and refrigerator), such that these loads may continue to receive energy from the RESU during outages. Likewise, later in the project the team configured the CES to provide an "islanding" capability to the homes on the CES Block for a few hours.

Reduced Restoration Cost: The self-healing distribution circuit (i.e., the looped circuit in sub-project 5) has the potential to reduce the labor cost associated with restoring service following an outage. The looped circuit should automatically recognize when a fault occurs, identify and isolate the segment of the line that contains the fault, and reenergize the remaining segments of the looped circuit. This could result in less crew time in the field and lower vehicle fuel consumption since the field personnel would only have to search for the fault on the isolated circuit segment.

Reduced Momentary Outages: A momentary outage is an outage lasting less than 5 minutes. The looped circuit in sub-project 5 should identify the location of fault events and isolate the fault to a specific line segment, resulting in fewer momentary outages for customers on the looped circuit. The RESU and CES in sub-project 1 also have the ability to reduce momentary outages through their islanding and secure load backup capabilities.

Reduced Sags and Swells: Sags and swells refer to customer voltage levels that are above or below a defined range for a momentary duration. The DVVC capability in sub-project 4 dynamically controls customer voltage levels. However, since the DVVC algorithm operates every 5 minutes, it may not provide the voltage support necessary to mitigate all sags and swells on the associated distribution circuits.

2.5.3 Environmental Benefits

Reduced Carbon Dioxide Emissions: The ISGD project team expects to demonstrate three ways to reduce carbon dioxide emissions.

- Energy efficiency measures in the customer homes, and reducing the average customer voltage profile through DVVC both have the potential to reduce overall household energy usage. Reducing energy use would also reduce carbon dioxide emissions.
- Load management programs using PCTs, smart appliances, PEVs, and RESUs may help utilities avoid using "peaker" power plants (which generally burn natural gas) by reducing energy use during critical peak periods, and by shifting some energy consumption from peak to off-peak periods. Shifting energy consumption to off-peak periods has the potential to reduce carbon dioxide emissions, depending on the relative generation resource mix between these two periods.
- Replacing internal combustion vehicles with PEVs also has the potential to reduce carbon dioxide emissions.

Reduced SOX, NOX, and PM-2.5 Emissions: Reducing energy consumption, reducing peak demand, and shifting from internal combustion engine-based vehicle to PEVs may reduce SOX, NOX, and PM-2.5 emissions.

2.5.4 Security Benefits

Reduced Oil Usage: Reducing energy consumption, reducing peak demand, and shifting from internal combustion engine-based vehicle to PEVs, thereby decreasing consumption of petroleum-based fuels, would likely improve our nation's energy security.

Improved Cybersecurity: Protecting the communication between smart grid devices, the utility, third-party service providers, and customers by incorporating an appropriate level of cybersecurity is a basic requirement and fundamental enabler of the smart grid.

2.6 Project Stakeholder Interactions

The ISGD project had a number of stakeholders, including the DOE's National Energy Technology Laboratory (NETL), vendors, internal SCE stakeholders, and the participating homeowners. **Table 5** summarizes the major project stakeholders and the nature of their interactions with the project team.

Table 5: Summary of Stakeholder Interactions

Stakeholder	Interaction	Frequency
NETL	Since the project's inception, the team provided project updates to the Technical Project Officer during regularly scheduled meetings or more frequently as issues arise.	Bi-weekly and ad hoc
ISGD Project Team (*SCE internal*)	During the design and commissioning phases, each sub-project held regular meetings with the sub-project teams and any other relevant subject-matter experts. The project team also held regular meetings with all sub-project leads to share project updates or issues across sub-projects.	Bi-weekly
Advanced Technology Management (*SCE internal*)	The team provided project updates to the managers and directors in SCE's Advanced Technology organization on a regular basis.	Bi-monthly
ISGD Steering Committee (*SCE internal*)	The team provided project updates to directors of other SCE organizations that had touch points with ISGD (e.g., Field Engineering, Customer Programs and Services, etc.)	Quarterly
Vendors	The team met with vendors either remotely or on-site to facilitate completing project deliverables.	Periodic project execution meetings
Industry Research Organizations	The team met with UCI faculty and student researchers periodically to discuss research progress and test planning and execution. The team met with EPRI periodically to discuss project progress, and SCE provided annual project updates at EPRI-hosted webinars.	Bi-weekly (UCI) Quarterly (EPRI) Annual (EPRI)

Stakeholder	Interaction	Frequency
CPUC	The team met with CPUC commissioners and staff on a periodic basis to provide general project updates.	Ad hoc
Homeowners	During project deployment, the team interacted with the project homeowners on a frequent basis (daily, during field installation). During the measurement and verification period, the team prepared customized energy usage analysis reports for each homeowner on a monthly basis.	Monthly

3. Smart Energy Customer Solutions

ISGD evaluated a variety of technologies designed to help empower customers to make informed decisions about how and when they consume (or produce) energy. Such technologies have the potential to better enable customers to manage their energy costs, while also improving grid reliability and stability. ISGD evaluated these customer technologies through two sub-projects: sub-project 1: Zero Net Energy Homes and sub-project 2: Solar Car Shade.

In the past, energy consumers have assumed a largely passive role of consuming energy as desired at fixed rates. The variability in the cost of providing this service to customers was not visible to them. As a result, customers had neither the incentive nor the information necessary to make energy use decisions that would help control utility costs. Correspondingly, this has reduced customers' ability to control their own energy costs. As the cost of energy has gone up and the cost of providing customers information and control options has gone down, this model has become inappropriate for the future. In particular, new technologies offer improved ways for customers to generate, manage and use electricity. These technologies likewise offer opportunities for utilities to design programs that optimize how these resources interact with the electric system. Finally, public policies also incentivize—and in some cases require—increased adoption of these technologies. These various drivers of change are grouped and listed below:

Market Drivers

- The cost and time for constructing traditional central generation, transmission, and distribution systems are increasing dramatically.
- Any or all of these technologies could potentially participate in energy and ancillary services markets with appropriate aggregation.
- Such IDSM could also provide better load shedding options during system capacity emergencies. Targeted loads could be curtailed rather than entire circuits.

Technology Drivers

- It makes little economic sense for utilities to invest in little used generators and network components to serve infrequent load peaks if these peaks could be managed from the demand side using Integrated Demand Side Management (IDSM) at much lower costs.
- Energy Efficiency Measures (EEM) such as better insulation and higher efficiency appliances are more cost-effective rather than just increasing delivery capacity up to some point.
- DER, principally solar PV generation and battery storage, located at or near customer premises can serve load without network line losses and capital expense.
- Local energy storage solutions could also moderate system load peaks and shift local solar generation to match load peaks.
- As Electric Vehicles (EV) become more popular, charging them presents new challenges (and perhaps opportunities) to the existing electric distribution system.
- Widespread deployment of DER and storage could lead to the development of larger numbers of microgrids capable of continued operation if service from the utility grid were lost for significant periods of time due to events such as earthquakes and storms. This could improve grid resiliency.

Regulatory Drivers

- ZNE homes are expected to be mandated for new residential construction projects beginning in 2020 and new commercial projects beginning in 2030.
- SB 350 will extend the existing mandate for a 33% RPS by 2020 to 50% by 2030.
- AB 32 launched a GHG cap and trade program in 2012.
- GO Solar California umbrellas three programs: the California Solar Initiative has a goal of installing 1,940 MW of solar capacity by the end of 2016; the New Solar Homes Partnership (NSHP) program provides 360 MW of solar on new homes; and another 700 MW is funded for publicly owned utility customers, all totaling 3,000 MW.

- A CPUC Distribution Resource Plan Order Instituting Rule-making R.14-08-013 (DRP OIR) mandates distribution system planning that is DER friendly consistent with the Governor's 12,000 MW LER goal.

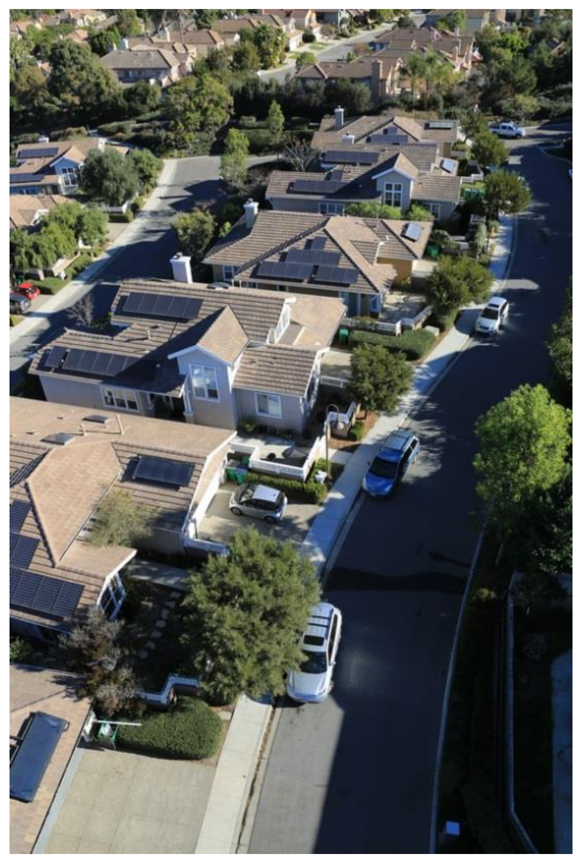
The sub-projects in this domain were conceived to explore emerging technologies designed to support IDSM, EEM, DER, Storage, and EVs and the associated mandates. Some of the high-level questions explored in this domain include:

- Are communication and control products marketed as enabling these functions sufficiently mature to do so? Do DSM features work as advertised?
- What are the impacts of PV and EV in particular on distribution transformers?
- What are the relative merits of customer side storage (RESU) and secondary distribution circuit storage (CES)? What is the best way to use the storage?
- What is ZNE and what are the preferred approaches to achieving it?
- How well do predictions of Zero Net Energy (ZNE) homes made by a model such as eQUEST match actual performance? How large a factor is changes in customer behavior on the results?
- How well does a combined solar and battery storage EV charging station succeed in minimizing the adverse impact of on-peak charging of EVs from the grid? What is the best strategy for using the storage to this end?

3.1 Sub-project 1: Zero Net Energy Homes

Various state and federal policies, technological innovations, and customer interest are likely to drive changes in residential energy consumption patterns by the year 2020. Sub-project 1 evaluated multiple combinations of integrated demand side management (IDSM) technologies to better understand their impacts on the electric grid, and their contributions toward enabling homes to achieve ZNE.[9] ISGD includes four groups of project participant homes, including three test groups equipped with a variety of energy technologies, and a fourth group of homes used as a control group for experiment baselining purposes. All homes are located in the University Hills community on the UCI campus. The homes have two or three stories and range in size between 1,900 and 2,900 square feet. They have three to six bedrooms, three to three and a half bathrooms, and all have two-car garages. These homes were built between 2001 and 2002, and are located on a hillside with the lower floors built into the hill below street-level.

Figure 2: Aerial View of ZNE Block



3.1.1 ZNE Homes - Technical Approach

3.1.1.1 Objectives

The objectives of this sub-project were to evaluate the impact of IDSM measures on customers' net energy consumption and usage patterns, and to assess the impact of these technologies on the grid.

3.1.1.2 Approach

This sub-project demonstrated the integration of several IDSM measures intended to help customers achieve ZNE or near-ZNE. The measures can also help customers manage their energy use. For example, customers can store solar PV generation for later

[9] IDSM measures include energy efficiency measures, demand response capabilities, solar PV, and storage.

use with energy storage devices, and they can reduce their peak energy consumption by participating in demand response events. IDSM measures include the following:

- Energy Efficiency Measures (EEM) such as advanced lighting technologies, heating, ventilating and air conditioning (HVAC) technologies, water heating, smart appliances, and "building envelope" measures
- Demand Response (DR) components such as PCTs, smart appliances, electric vehicle supply equipment (EVSEs), in-home displays (IHDs), and home Energy Management Systems (home EMS).
- Solar PV and Energy Storage such as in home Residential Energy Storage Units (RESU) or distribution transformer level Community Energy Storage (CES).

The project team assessed the impacts of these measures by tracking consumer use of the individual components, in terms of both total energy consumption and usage patterns. Appendix 3 summarizes the approach to collecting this energy usage information.

The following tables summarize the measures applied to each sub-project 1 test group.

Table 6: Sub-project 1 Test Group Designs

Test Group 1: ZNE Block
This represents the flagship test group for sub-project 1. The team outfitted these homes with a complete set of IDSM solutions, including energy efficiency upgrades, devices capable of demand response, a RESU, and a solar PV array. **Table 7** summarizes these upgrades. In addition to DOE, the CPUC will also likely find these outcomes informative for developing a strategy to establish ZNE as a goal for new residential buildings built beginning in 2020. A home achieves ZNE when it produces at least as much renewable energy as the amount of energy it consumes annually, including both natural gas and electricity. This would require homes to consume approximately 65% less energy than homes built with the 2005 California Building Energy Efficiency Standards. The team installed solar PV panels on the rooftops, sized to make these homes ZNE or near-ZNE, given the project's budget and roof-space limitations. The array sizes are approximately 4 kW based on the results of eQUEST simulations and the roof-space and budget limitations. After applying the cost-effective energy efficiency improvements and DR measures, the team sized the solar PV array to offset the remaining customer load. The RESUs are comprised of automotive-grade lithium ion cells, have nominal continuous power output ratings of 4 kW, and usable stored energy of 10 kWh. Additionally, the team installed plug load monitors and an electrical panel circuit monitoring system to measure energy consumption and demand. The team uses an Edison SmartConnect meter to measure EVSE energy use, and an Edison SmartConnect meter (smart meter) to monitor total household energy use. These meters are separate from SCE's production billing meter. Homes had their gas furnaces replaced with electric heat pumps. The smart appliances (refrigerator, dishwasher, and washing machine), communicating EVSE, PCT, and RESU all have demand response capabilities. These homes also have an IHD and a home EMS, which enable customer energy monitoring and control. IHDs are able to communicate instantaneous energy use, DR program status and pricing signals to customers in real-time.
Test Group 2: RESU Block
All homes in this test group include identical components, including a RESU, rooftop solar PV array, IHD, home EMS, and a set of DR-capable HAN technologies, including PCTs, smart appliances, and communicating EVSEs. The team is using a sub-meter to monitor the EVSE branch circuit, and plug load monitors and an electrical panel load monitoring system to monitor other important loads. These homes have not received any of the energy efficiency upgrades included in Test Group 1.
Test Group 3: CES Block

All homes in this test group include identical components, including the same solar PV generation and HAN technologies as Test Group 2. However, instead of having a RESU in each home, the homes share a CES device (25 kilovolt-amps (kVA)/ 50 kWh) installed near the distribution transformer. These homes are equipped with a communicating EVSE and sub-meter on the EVSE branch circuit. Additionally, plug load monitors and an electrical panel circuit monitor system capture end use device energy and demand. Similar to Test Group 2, these homes did not receive any of the energy efficiency upgrades included in Test Group 1.
Test Group 4: Control Block
These homes act as a control group to provide baseline data for analysis purposes. These homes received no advanced energy technologies, except for a smart meter and device power monitors used to record end-use demand and energy consumption information.

Table 7 summarizes the IDSM measures for each of the sub-project 1-test groups.

Table 7: IDSM Measures by Test Group

Test Group		Vendor	ZNE Block	RESU Block	CES Block	Control Block
Participating Homes/ Homes on Block			**9/9**	**6/8**	**7/9**	**16/20**
Demand Response	Energy Star Smart Refrigerator	GE	8	6	7	0
	Energy Star Smart Clothes Washer[10]	GE	8	6	7	0
	Energy Star Smart Dishwasher	GE	9	6	7	0
	Programmable Communicating Thermostat	GE	13	8	10	0
	Electric Vehicle Supply Equipment	BTC Power & Clipper Creek[11]	9	6	7	0
	Home Energy Management System (home EMS)	GE	9	6	7	0
	In-Home Display	Aztech	9	6	7	0
Energy Efficiency Measures	Central Air Conditioning Replacement (Heat Pump)	Carrier	13	0	0	0
	Lighting Upgrades	Cree & George Kovacs	8	0	0	0
	Insulation	commodity insulation	8	0	0	0
	Efficient Hot Water Heater	A.O. Smith	2	0	0	0
	Domestic Solar Hot Water and Storage Tank	Heliodyne & Bradford White	7	0	0	0
	Low Flow Shower Heads	High Sierra Shower-heads	29	0	0	0

[10] Although this table lists the three smart appliances in the demand response section, these appliances support both demand response and energy efficiency.
[11] The project originally installed EVSEs from BTC Power in 2013. In Q4 2014, the ISGD team removed these EVSEs and installed new EVSEs manufactured by Clipper Creek.

Test Group		Vendor	ZNE Block	RESU Block	CES Block	Control Block
Participating Homes/ Homes on Block			9/9	6/8	7/9	16/20
	Plug Load Timers	Belkin	40	0	0	0
Solar PV & Energy Storage	Community Energy Storage Unit	S&C Electric	0	0	1	0
Solar PV & Energy Storage	Residential Energy Storage Unit with Smart Inverter	LG Chem	9	5	0	0
Solar PV & Energy Storage	3.3 – 3.8 kW Solar PV Panels	SunPower	0	5	7[12]	0
Solar PV & Energy Storage	3.9 kW Solar PV Panels	SunPower	9	0	0	0

3.1.2 ZNE Homes - Research Plan

3.1.2.1 Energy Simulations

The team has conducted energy simulations on the ZNE Block homes using the eQUEST modeling tool and the Site Energy metric. The team performed these simulations in conjunction with the design process for the ZNE Block homes. The purpose of these simulations was to estimate the impact and cost-effectiveness of the various EEM options. After incorporating energy efficiency measures into the retrofit plans for each home according to the results of the eQUEST model, solar PV of sufficient capacity was identified for the project homes to achieve ZNE (or near ZNE) on a forecasted basis. Similar analyses were run on homes on the RESU and CES blocks to predict their performance even though they were not specifically designed to achieve ZNE.

3.1.2.2 Laboratory Tests

Individual technology components were laboratory tested before installation in the field to verify performance and functionality based on the manufacturer specifications. These tests are detailed in section 7.1.1.2.

3.1.2.3 Commissioning Tests

The team performed a series of tests in the field to verify that the devices and components would perform their required functions per the manufacturers' specifications. The team performed these tests on four classes of field devices: monitoring devices, HAN devices, the RESU, and the CES. Details of these tests are included in section 7.1.1.3.

The monitoring devices consisted of the plug load monitors, temperature sensors, branch circuit monitors, project smart meters, and transformer monitors. These devices collected the data required for the field experiments. The commissioning tests consisted of verifying the ability of these devices to monitor and collect data generated by the project participant homes.

The HAN devices included three smart appliances (refrigerator, dishwasher, and clothes washer), IHDs, PCTs, and EVSEs. These devices present energy usage information to the project homeowners and enable utility load management capabilities. The commissioning tests consisted of verifying the ability to send and receive demand response event signals using ZigBee Smart Energy Profile 1.x.

RESU commissioning included the following two tests:

- Utility Load Control: The intent of this test was to demonstrate SCE's ability to send remote signals to the RESUs to control the full spectrum of charge and discharge capabilities, as well as static VAR absorb/supply functionality.

[12] Some homes on the CES Block already had rooftop solar panels prior to ISGD. The team installed between 1.3 kW and 3.8 kW on each CES Block home, such that each home now has between 3.3 kW and 3.8 kW.

- Secure Load Backup: The homes with RESUs were able to connect pre-determined circuits to the RESU Secure Load connection. The RESU should protect these circuits from outage for a short duration. The team evaluated the RESU performance during an outage on July 8, 2014 (Field Experiment 1C, Test 1).

The CES commissioning included the following two tests:

- Utility Load Control: The intent of this test was to demonstrate SCE's ability to remotely control the CES's full spectrum of charge, discharge, and VAR inject/absorb functionalities. The team controlled the CES to charge and discharge real power, and to inject and absorb reactive power. Power quality monitors installed near the CES record data, confirmed proper operation, and analyzed the impact on the local grid. Part of the commissioning test was to verify that these data acquisition capabilities were operational.
- Islanding: The intent of this test was to confirm that the CES is able to provide an "islanding" capability following a grid outage. In the event of an outage, the CES may support the block's distribution transformer load using stored energy, and allow the homes' solar PV to continue generating energy. During any grid outage (or other event, such as short duration voltage sags or swells), locally installed power quality monitors and smart meters would record data. This data should confirm that the CES disconnects from the grid and begins supplying the required power to homes connected to the distribution transformer, provided the load is within the CES's 25-kVA rating. Upon grid power restoration, the monitoring devices would confirm that the CES has reconnected to the grid without causing any power quality disturbances. This islanding feature was tested in June of 2015 (Field Experiment 1E, Test 3).

3.1.2.4 Field Tests

The ISGD team performed the following experiments to evaluate the impacts of the sub-project 1 capabilities. Detailed reports of these tests are contained in Chapter 7, section 7.1.1.4.

Field Experiment 1A: Impact of Integrated Demand Side Management Measures on Home and Grid

The objective of this experiment was to quantify the impact of energy efficiency upgrades and other IDSM measures on the home and transformer load profiles. Energy efficiency measures (EEM) were only implemented on homes on the ZNE block. The specific measures implemented varied by home based on homeowner preference. The EEM measures included some or all of the following: light emitting diode (LED) lighting, heat pump, high efficiency hot water heater, domestic solar hot water system, plug load timers, low flow showers, duct sealant, and increased attic insulation. Homes on the ZNE, RESU, and CES blocks all received ENERGY STAR smart appliances, solar PV array, and other HAN devices. Homes on the ZNE and RESU blocks received the RESUs.

This experiment helped the team determine how the homes on the three blocks performed against the goal of achieving zero net energy, measured over a one-year period. The savings were determined by comparing the collected data to past billing cycles, simulation results, and the Test Group 4 (Control Block) electricity usage. The experiment also helped the team assess the impact of the energy efficiency upgrades and the other IDSM measures on the distribution transformer temperature and load profile.

Field Experiment 1B: Impact of Demand Response Events on Smart Devices, Homes, and Grid

The objective of this experiment was to quantify the impacts of DR[13] events on the load profiles of smart devices, the homes, and the secondary transformers. The following is a summary of ISGD's various components and types of load control tests.

[13] Demand Response signals use the ZigBee Smart Energy Profile 1.x protocol via the project smart meters.

Table 8: Demand Response Components

Device	Demand Response Mode	Price Signal
Programmable Communicating Thermostat	• Degree offset • Degree set point • Duty cycle	None
Smart Appliances (clothes washer, dishwasher and refrigerator)	• Low power mode (all) • Delayed start (clothes washer and dishwasher)	None
In-home Display	None	Price displayed on screen
Residential Energy Storage Unit	• Calculated discharge	None
Electric Vehicle Supply Equipment	• Reduce/stop charging	None

SCE performed these experiments multiple times in order to evaluate performance under a variety of conditions, and to verify the consistency of results in terms of demand reduction. The team performed these tests during summer months when the weather is warmer and the potential for load reduction is greater.

Field Experiment 1C: RESU Peak Load Shaving

The objective of this experiment was to quantify the ability of the RESU to shift coincident peak load to the off-peak period by discharging during the peak period. The team placed a group of RESUs into a relatively simple operating mode that scheduled the RESUs to charge during a pre-defined off peak period and discharge during the pre-defined peak period. Locally installed power meters and the customer's smart meter recorded data throughout a test period of at least one week. The team captured data to validate that the RESU charged and discharged in accordance with this traditional schedule intended to reduce the peak demand and energy consumption during peak hours. The team evaluated the impact of the RESU using data from the control homes and the experiment homes for prior dates, over test periods of at least one week.

Field Experiment 1D: RESU Level Demand

The objective of this test was to quantify the ability of the RESU to automatically level demand over a 24-hour period. This involves a relatively sophisticated algorithm, which learns the load curve from operating history, and computes a charging and discharging schedule intended to make the load curve more level over a 24-hour period. The team compared the customers’ smart meter data with baseline data (loads without battery power) to determine how well the algorithm was able to achieve its objective.

Field Experiment 1E: CES Permanent Load Shifting

The objective of this experiment was to quantify the CES’s ability to shave demand on the secondary transformer. The CES charged and discharged in accordance with a manually programmed schedule. This control was expected to reduce the demand on the transformer during periods of peak energy use. The team analyzed data collected from the power quality meter on the transformer to verify that the CES system reduced peak demand, and investigated other impacts of this peak reduction (such as transformer temperature). The team also tested the CES’s ability to support islanding.

Field Experiment 1F: Impact of Solar PV on the Grid

The objective of this experiment was to quantify the impacts of rooftop solar PV generation on the load profile of the secondary transformer. This was a data collection and analysis activity only. Power quality meters installed on the local transformers recorded transformer duty cycles (including load and temperature profiles). The team compared this data to baseline duty cycles to analyze the impact the solar PV generation had on the transformer.

Field Experiment 1G: EVSE Demand Response Applications

The objective of this experiment was to demonstrate the utility's ability to modify PEV charging behavior by communicating demand response event signals to a PEV's EVSE. This experiment tested charging curtailment (i.e., reducing charging to 0 kW), as well as "throttling" whereby charging is partially reduced.

Field Experiment 1H: EVSE Sub-metering

The objective of this effort was to demonstrate the utility's ability to generate and transmit PEV-specific energy consumption data to the utility back office using both an EVSE integrated device and a utility owned device.

3.1.3 ZNE Homes - Summary of Field Experiment Results

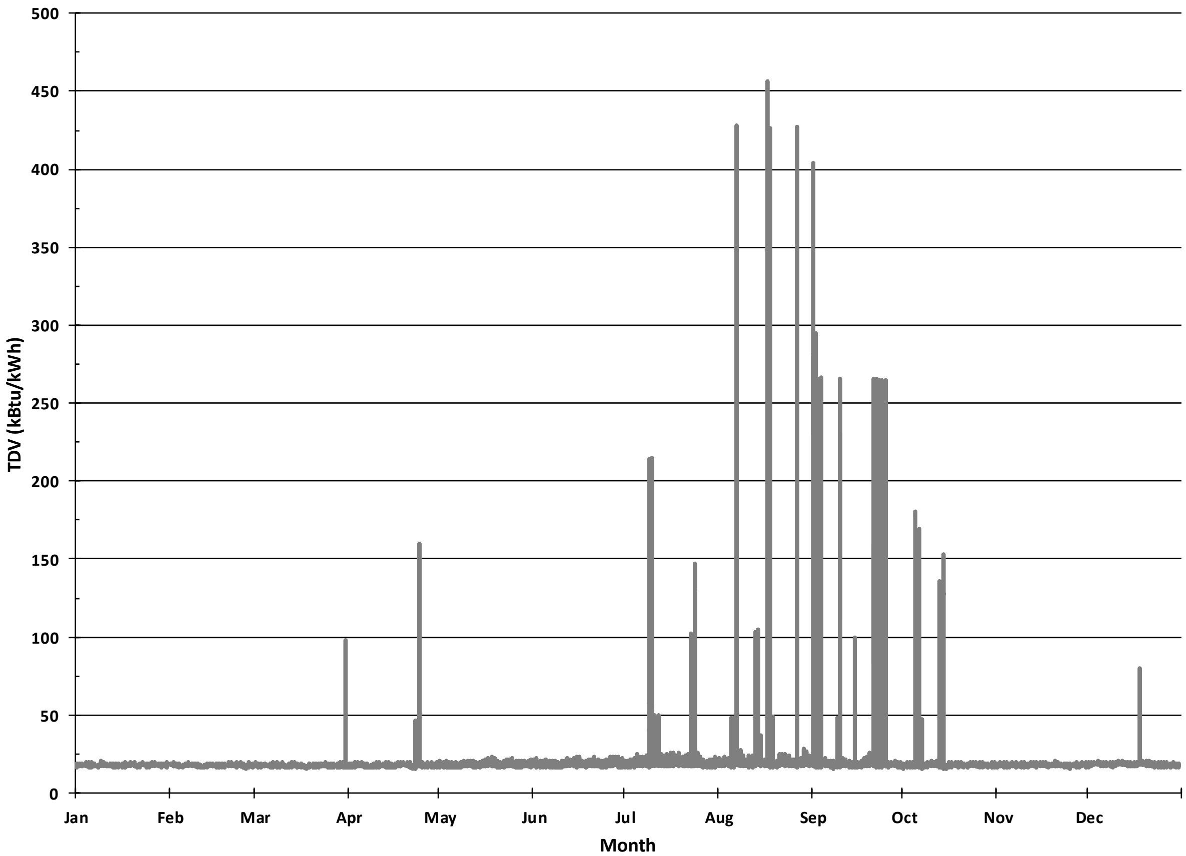
Impact of ISDM on Home and Grid (Field Experiments 1A, tests 1 to 3)

Field experiments demonstrated less energy savings for homes than predicted by the eQUEST model. This is attributed to several factors including smaller solar panel arrays than assumed in the model, energy losses in the RESU (that were not included in the model) and apparent changes in customer behavior possibly associated with the perception of "free energy" from their solar PV system. Notable impacts on the grid were observed from the interaction of traditional PLS and solar PV generation. Traditional PLS only considers customer loads and does not consider customer PV generation. As a result, the combination of RESU or CES battery discharge and PV generation partially overlapped during a portion of peak hours, subjecting the distribution transformer to higher thermal stress than normal. An alternate load shifting profile called PV capture diverted some solar generation into battery charging for later discharge after sunset. This PV capture load shift mode resulted in less impact on the distribution transformer than normal.

The impact of EVSE charging varied from an additional 10% to a near doubling of household energy consumption. In fact, the variation in usage patterns between the homes was substantial making it difficult to draw definitive conclusions from this small sample of homes.

An evaluation of the ability of the homes, especially those on the ZNE block to achieve ZNE was instructive. The particular ZNE metric used, whether Site Energy, Source Energy, or TDV energy made a large difference in performance. These different ZNE metrics are described in section 7.1.1.4, Field Experiment 1A, Test 3. ZNE Site Energy was the most difficult to achieve while ZNE TDV energy was the easiest. The TDV approach provides a multiplier Factor for the value of energy consumption or production for each hour of the year, and the multiplier varies dramatically as shown in **Figure 3**.

Figure 3: CEC TDV Multiplier Factors



The TDV factors are very high for those hours in a year when electric demand peaks. Therefore, both energy produced by PV and electrical energy consumed by loads count toward the ZNE TDV metric with an extraordinary weight during these times. In contrast, the Site or Source energy metrics value all hours the same. It appears the overlap of PV generation with these times is high, resulting in homes equipped with PV achieving favorable ZNE TDV energy results.

The presence of a RESU was detrimental to ZNE performance under the site energy and source energy methods since there is about a 20% round trip energy loss for battery storage. It was also detrimental using ZNE TDV energy since the RESUs were operated in traditional PLS mode. Subtracting the effects of the RESU improved performance for all three metrics. However, when the RESU operates using a permanent load shifting strategy whereby it charges at night and discharges during peak times, ZNE TDV energy performance improved, despite the 20% energy loss penalty. If operation in this mode is limited to the four months, with the highest TDV factors "spikes" the performance improves even more. The following table provides the ZNE performance for the average ZNE block home for each of these metrics and modes of operation.

Table 9: ZNE Achievement by Metric Type and RESU Use

ZNE Metric	Site	Source	TDV	TDV minus RESU	TDV plus RESU PLS	TDV plus RESU 4 Mo. PLS
Avg. ZNE Home	44%	67%	88%	106%	118%	121%

This finding indicates a very positive role for in-home storage to achieve ZNE using the TDV method.

Demand Response Events (Field Experiment 1B, tests 1 through 9)

The team conducted numerous demand response tests involving EVSE, HVAC and smart appliances. Most devices operated as expected. Two notable observations were the inability of the PCTs to accept a "pre-cooling" signal to cool homes down during off peak in anticipation of later curtailment during the peak hours and the fact that EVSE percentage curtailments applied to the EVSE rating and not the actual vehicle charging rate. Thus, an EVSE 50% curtailment signal might reduce charging by 50% on a vehicle with a high capacity charger and not at all on one with a low capacity charger. Another issue was that the EVSE and PCT interpreted a "100% DR Event" in an opposite manner, with the PCT doing a 100% curtailment and the EVSE doing a 100% charge rate. Although the team was able to demonstrate a variety of DR applications, the team had to perform a significant amount of workarounds.

RESU Peak Load Shaving (Field Experiment 1C, tests 1 through 4)

The ability of the RESU units and their associated PV systems to supply power to emergency loads (refrigerator and garage door opener was demonstrated during a utility outage on July 8, 2014. The RESUs successfully managed their battery SOC and power from the solar panels to supply these emergency loads, consistent with available energy.

The team performed extensive field testing of the RESUs operating in a time-based permanent load shifting mode. The RESUs performed well, although it was clear that simple time-based load shifting creates difficulties when solar PV generation, electric vehicle charging, and TOU rates used together. Time based load shifting must be carefully coordinated with these variable factors to achieve the desired benefits.

Efforts to operate the RESUs using a price-based load shifting scheme were unsuccessful due to incompatibilities between the NMS and Smart Meter system that was to provide the price signals and the RESUs which were to execute a charge and discharge strategy based on these signals. The RESUs were designed to receive day ahead pricing information while the NMS was designed to send price updates several times a day. This led to the RESUs trying to retrieve data from Smart Meter registers that were empty.

The RESUs were tested in VAR support mode by having them absorb inductive VARs during high voltage conditions. They could not be tested in a capacitive voltage support mode due to existing high voltages on their circuits. The RESUs were effective in bringing voltage down about 2.4 volts, but at a price of significantly increased transformer loading.

RESU Level Demand (Field Experiment 1D, tests 1 through 3)

This experiment consisted of three tests. The first was a test of the RESU's response to demand response signals. The RESUs performed as expected by discharging and contributing to the overall reduction in household demand. The second test was of the RESU's ability to calculate charging and discharging behavior to level the load demand automatically based on historic load data. Performance was limited by battery capacity, the unpredictability of some loads, and the fact that some loads could start and stop faster than the response time of the RESU controls. The final test was PV capture, in which the RESUs were operated so as to capture as much solar generation for in-home consumption and export as little to the grid as possible. This mode enabled in-home consumption of between 60% and 88% of PV generation, the percentage limited primarily by battery capacity.

CES PLS (Field Experiments 1E, tests 1 through 7)

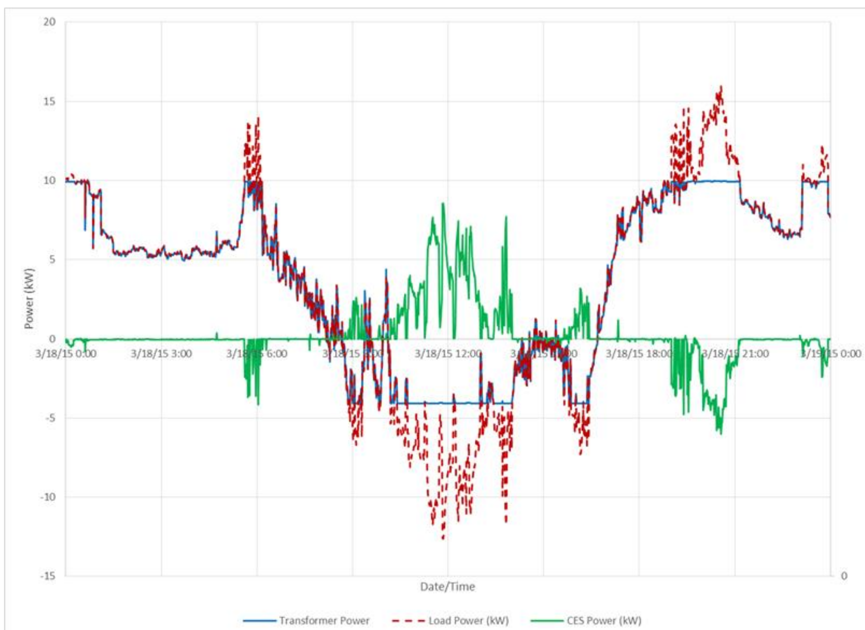
The team measured actual transformer loading on the CES block and developed a custom load-shifting schedule to reduce both the evening peak load and mid-day peak PV generation load on the transformer. This involved charging the CES during the solar peak and discharging it during the load peak. This method of operation proved effective in reducing transformer loading. On the other hand, operation of the CES in accordance with a traditional PLS schedule (charge from midnight to 6 am, discharge from noon to 6 pm) aggravated loading on the distribution transformer due to the impacts of PV generation combining with battery discharge and the occurrence of load peak after 6 pm.

The team operated the CES in *islanding mode* for short periods of both net load and net generation conditions for the CES block homes. The CES operated properly in both modes and transitioned between them without incident. The length of the experiment was limited due to the fact that block load can occasionally exceed the 25 kVA rating of the CES, and possibly trip it and cause an unintended outage for the customers.

The CES was operated in *power smoothing mode*. This mode is intended to smooth the impact of solar generation and load changes on the grid by having the CES battery charge and discharge to act as a buffer. The CES attempts to have any load or generation step changes ramped onto the grid in about five minutes. It also acts to keep the battery's SOC near a target value. The system worked as expected, but the gain setting for maintaining SOC was left at the default maximum. This resulted in transient power events to maintain the target SOC that were of larger magnitude than those mitigated. Better results could be obtained over time by determining a more appropriate value for the SCO maintenance function gain (KpSOC).

The team operated the CES in a *load limiting mode* in which the CES charged and discharged as necessary, subject to its capacity limits, to limit both imported and exported power at the transformer to a preset value such as 10 kW. The CES performed as expected, however the anticipated benefit in terms of limiting transformer heating were not observed owing primarily to the fact that the transformers were not heavily loaded relative to their nameplate ratings in the first place.

Figure 4: CES Load Limiting Behavior



The team tested the CES VAR support capabilities in May of 2015. The system worked as designed and was effective in limiting voltage rise by absorbing VARs, but was less effective in supporting voltage by supplying VARs. This was primarily due to the relatively high voltage on the circuit, which only dropped a little below 120 volts. Using VARs to lower the voltage also has the drawback of increasing current in the distribution transformer and raising its operating temperature.

Figure 5: CES VAR Support Behavior

The nominal 50 kWh CES was tested for capacity in the laboratory in July 2013 at 50.8 kWh AC. The team conducted an in-situ capacity test at the conclusion of the demonstration period in August 2015. The test showed that the system retained 90% of its initial capacity. This indicates a loss of 10% of capacity over a two-year period.

Solar PV Impact on the Grid (Field Experiments 1F, tests 1 and 2)

To determine the impact of solar PV without energy storage on the grid, the ZNE and RESU Blocks were operated as standard solar inverters with no charging or discharging of the batteries for 26 days. Distribution transformer temperature and power flows for these two blocks and the Control Block were compared. Because the ZNE Block homes all had 3.9 kW inverters and little load during the daytime, power flow from this block out to the grid through the transformer was considerable. This power flow occurred coincident with direct solar heating of the transformer, resulting in temperatures of 45C, in contract with peaks of 35C for the other two blocks. This test was performed in October and November, suggesting the transformer heating issue for high penetration would be even more significant in the summer.

EVSE Demand Response (Field Experiment 1G, tests 1 and 2)

EVSE response to a variety of Demand Response events was tested both alone and in combination with other loads. The EVSE response were for the most part as expected. It was noted that they respond in terms of their nameplate rating rather than in terms of the current charging level of the connected EV. Thus a 50% DR signal reduced charging to 50% of the EVSE rating rather than 50% of the current charging rate of the connected EV. Operational problems necessitated replacing the EVSEs with units from another manufacturer late in the project.

Sub-Metering (Field Experiment 1H)

Sub-metering for the EVSEs functioned as expected. The project team did not attempt the subtractive metering stretch goal due to project resource limitations.

3.1.4 ZNE Homes - Observations

3.1.4.1 ZNE Homes Lessons Learned

Smart Inverter Standards are Too Immature to Support Product Development and Market Adoption

The ISGD project originally intended to use smart inverters to support DVVC and the integration of rooftop PV solar panels and energy storage devices. The project was unable to use smart inverters due to the absence of standards and UL certification of these devices. The IEEE 1547 standard (standard for interconnecting distributed resources with electric power systems) has been modified to include some provisions for smart inverters. UL has not yet updated the relevant testing standard (UL 1741) to meet the revised interconnection standard and certify devices for home and business installations. SCE and other utilities are also modifying interconnection procedures to understand, verify, and possibly control these advanced inverter functions.

Proper Integration of Components from Multiple Vendors is Critical to the Successful Operation of Energy Storage Systems

Many energy storage systems use components from multiple manufacturers. The two most significant components, the battery and inverter, are typically produced by different manufacturers, which can present significant compatibility issues. For example, the CES unit used in sub-project 1 uses a lithium ion battery and BMS from one vendor, and a power conversion system from another vendor. When integrating these devices, careful evaluations must be performed to verify that the systems' control mechanisms are compatible. In the case of the Solar Car Shade BESS, the inverter draws energy from the battery at a level that the BMS cannot detect. Since the BMS does not detect the low level of current drawn by the inverter, it cannot consider this lost energy when determining the BESS's state of health. More detailed testing by the vendors could have identified and resolved this issue before deployment.

Customers or device end-users typically do not choose a battery or BMS vendor and a PCS vendor, and then perform the integration themselves. Instead, the battery/BMS vendor, PCS vendor, or an independent integrator chooses the components and performs the final integration. Whichever entity performs the integration should conduct a final system evaluation prior to selling the device to customers. The integrator should be responsible for ensuring the various subsystems in their final product are compatible. In the case of the emergent technologies and integration techniques used in energy storage systems, it may also be wise for the customer (if technically capable) to work with the integrator to perform their own customized system acceptance testing on the completed product prior to final acceptance and payment.

Manufacturer Implementations of the SAE J1772 EVSE Standard Limit the Usefulness of Electric Vehicle Demand Response

PEVs have the potential to increase customer electricity demand substantially during peak periods. Peak periods include times of high electricity demand on the entire electric system or on particular distribution circuits. To help mitigate the potential impacts of PEV charging activity, ISGD is evaluating DR functions that specifically target PEV load. The eventual development of utility load management programs for PEVs may be helpful in empowering customers to better manage their PEV charging costs while also helping to preserve grid stability.

One of the prerequisites for conducting effective PEV load management is being able to send DR signals that reduce PEV load on a consistent and reliable basis. For example, if a vehicle is currently charging at 7.2 kW, a 50% duty cycle DR event should reduce the charging rate to 3.6 kW. During ISGD's commissioning tests, SCE determined that EVSE manufacturers have implemented the DR function in a way that may limit the effectiveness of PEV load management. Currently, when a DR event signal[14] is sent to an EVSE to reduce the charging level by a certain percentage (e.g., 75% of current output), the EVSE reduces the charging level based on the maximum charging capacity of the EVSE, not by the

[14] SCE uses SEP duty cycle messaging to perform PEV demand response.

actual PEV charging level. The project EVSE has a maximum capacity of 7.2 kW, so a 75% duty cycle DR event signal would cause the EVSE to reduce its charge level to 5.4 kW (75% of the 7.2 kW maximum charge level).

Meanwhile, PEV charging levels are also constrained by the vehicles themselves. For example, the Chevrolet Volt's maximum charging level is 3.3 kW, while the BMW ActiveE's is 6.6 kW. To illustrate why this matters, suppose both vehicles are charged using an EVSE with a maximum charging capacity of 7.2 kW. A 75% duty cycling DR event signal would reduce the current charging level to 5.4 kW for both vehicles. This would reduce the BMW Active E charge level from 6.6 kW to 5.4 kW, but the Volt would continue to charge at 3.3 kW (since the Volt's maximum charge level is below the 75% duty cycle level of 5.4 kW). The inconsistency and unpredictability of the impact of this type of DR event limits its usefulness as a tool for managing PEV load.

DR signals that reduce PEV charging levels based on the current charging rate would make PEV load management more effective for managing grid conditions in real-time. Using the example above, a 75% duty cycle DR signal would reduce the charging levels of both vehicles to 75% of their current charging levels. To accomplish this objective, the EVSE or PEV should actively monitor the charging load and use the SAE J1772 and the relevant Smart Energy Profile (SEP) communications standards to determine the desired charging rate.

EVSE manufacturers can enable DR on a "percentage of load" basis by incorporating a meter to provide the real-time charging level and a microcontroller to convert DR event signals into a demand setpoint that corresponding to the setpoint defined by the SAE J1772 standard. The EVSE can then use its "pilot wire" to reduce the charging level to the desired rate.[15]

PEV manufacturers could also leverage their existing vehicle metrology to implement this capability in the same manner. In this case, the meter and microcontroller would be located within the vehicle. Upon receiving a utility DR signal (via a smart meter or an internet connection to the vehicle), the vehicle would read the current vehicle load, use a microcontroller to convert the DR signal into the desired power level, and then modify the vehicle charging to the desired level. The Smart Grid Interoperability Panel (SGIP) and the ANSI Electric Vehicle Standards Panel are two standards organizations that could facilitate PEV and EVSE manufacturer efforts to develop these solutions. The industry would also benefit from a service bulletin from SAE that clarifies the terminology used in the J1772 standard (e.g., the duty cycle of the pulse width modulation versus the PEV charging rate), and explains the limits of the standard for constructing demand response capabilities within EVSEs and PEVs.

Distributed Energy Resources Should be Designed and Tested to Ensure Communications and Operations Compatibility with Utility Control Systems

During a demand response event using a group of RESUs, two RESUs that should not have responded to the DR event signal did so by exporting PV power to the grid. Following a battery error in October 2013, the two RESUs turned off their internal battery chargers and inverters. These RESUs did not charge or discharge for several weeks. However, both of these RESUs received the DR event signal on November 7, 2013. When the event began, the RESUs began delivering PV power to the grid. This was unexpected, since the team believed that the battery error would prevent the inverter from operating. Based on discussions with the manufacturer, the team determined that the manufacturer had incorrectly programmed the RESUs to allow PV operation during the battery error. The manufacturer addressed this programming bug in a subsequent software release that was installed in all the RESUs. This experience highlights an important issue with respect to the potential future development of utility programs for managing DERs. Device manufacturers must design and test their products to ensure that any utility-provided signals do not lead to erroneous device behavior. This should be the manufacturer's responsibility, since certifications (including UL standards, communication protocol specifications, etc.) cannot address the wide range of functionality of the various devices. This is true for energy storage, DERs, smart inverters, smart appliances, electric vehicles, and other equipment that may interact with the electric grid in the future.

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[15] SCE has leveraged this ISGD finding by working with an EVSE manufacturer to implement this capability with EVSEs used for the "Smart Charging Pilot," a CPUC-funded DR pilot project. This is outside of the ISGD project.

Remotely Monitoring New Technologies after Field Deployment is Critical to Timely Identification and Resolution of Unknown Issues

Technology components that have undergone laboratory, commissioning, and other forms of testing may still encounter operational issues following field deployment. This may be due to environmental or other factors. For example, ISGD demonstrated multiple HAN devices in an integrated environment using multiple communications networks. Maintaining the communications of these components was more difficult in the field that in the lab environment prior to deployment. It is thus important to continue monitoring these devices following deployment to assess their interoperability and potential for interference with each other. Refer to the RESU Battery Error discussion in 7.1.1.4, Field Experiment 1D, Test 1.

Targeted "Behind the Meter" Data Collection Will Help Future Demonstration Analytics

The team implemented an approach for monitoring energy usage in the project homes to measure the potential impacts of the energy efficiency measures and demand response events. This data acquisition system allows the team to monitor up to 21 individual circuits in each home (watts, watt-hours, amps, and voltage), the total household energy usage, and the RESU loads. The system also measured loads plugged into the wall, and temperatures on each floor and within the air conditioning duct system. Over the course of the design, installation, commissioning, and operation of this system, the ISGD team identified a number of lessons for how to improve such a system in future demonstrations. These findings are summarized in Appendix 3.

Consistent Implementation of Smart Energy Profile Demand Response Messaging Across Customer Device Types Would Simplify Aggregated Demand Response

During the ISGD team's DR testing of the EVSEs and PCTs, it discovered that these devices interpret duty cycle percentages differently. For example, PCTs typically interpret a 100% duty cycle event as a command to shut down the AC operation completely. Conversely, the EVSEs used on ISGD would interpret the same signal as a request to charge at 100% of their operating capacity. Thus, these two devices would have the opposite reactions to the same duty cycle signal. The PCTs and EVSEs used on ISGD are SEP 1.x compliant. This standard provides discretion to the manufacturer in implementing DR duty cycle communications. This flexibility has led to inconsistent implementation of this standard among the ISGD devices.

For utilities to perform DR events using multiple sources of customer load—such as PCTs and EVSEs—signals should be interpreted consistently across all DR-capable customer devices. Inconsistent interpretations of DR signals would result in some devices responding properly and other devices not responding properly. For example, a 100% duty cycle using the ISGD devices would result in the PCTs shutting down the AC units, but also commanding the EVSEs to charge at their maximum capacity. For utilities to maximize the resources available for demand response within a simultaneous DR event, the utility and device manufacturer community should agree on a common interpretation of duty cycle percentages. This challenge could be addressed by the ZigBee Alliance, the organization responsible for developing the SEP 1.x standards, IEEE P2030.5, and the SEP 2.0 standards.

Assessing the Impacts of Energy Efficiency Measures Requires Isolating Customer Behavioral Changes

The primary benefit of installing EEMs at a customer premises is improved energy efficiency. This reduces the energy required to perform a specific function, such as lighting a customer home. It also reduces a customer's energy costs. To evaluate the impact of an EEM on a home's energy consumption, it is necessary to isolate the effects of the technology from any changes in customer behavior that may occur over time. For example, the homes in sub-project 1 received rooftop solar PV panels as part of the ISGD project. Some homeowners have acknowledged that they increased their AC usage because they now have "free energy" available during the day. Therefore, simple comparisons of these homes' energy usage before and after installing the EEMS mask these types of potential behavioral changes. Other changes may include changes in occupancy, vacation or work schedules, and weather-driven changes.

The ISGD team addressed this challenge by comparing the ZNE simulation results to the actual energy consumed within each home. The simulations estimated how much energy each home would consume after installing the EEMs, under similar conditions (e.g., weather and customer behavior). The difference between the simulation results and the actual ZNE performance should identify some of the changes in customer behavior. Another potential method for evaluating EEMs that isolates the impacts of human behavior involves installing the EEMs in a test home with no occupants. Scheduled on /off cycles for various appliances, lighting, heating and cooling could allow experimenters to compare the energy usage patterns with a comparable test home without the EEMs.

This lesson also reveals the impact of cost on how customers use electricity. Installing free solar PV on customer homes created an incentive for these customers to increase their energy use. This finding reinforces the notion that customers respond to price incentives.

When Deploying Systems with Components from Multiple Vendors, Construct a Careful Commissioning Plan

Several months after completing the rooftop solar PV installations on the sub-project 1 homes, the ISGD team performed an analysis of the solar PV output on the ZNE and RESU block homes. The purpose of this analysis was to assess the homes' solar PV output over time and across all the project homes. This analysis revealed that three homes (out of the 14 homes on the ZNE and RESU blocks) were generating substantially less solar PV than their peers. During a subsequent on-site visit to two of these homes, the team identified and resolved issues from the original solar PV installations. The solar PV output of both of these homes immediately improved after fixing these two installations. The problem with the third home resulted from shading.

The problems with these solar PV installations revealed several important issues. Because the solar PV was from one manufacturer and the RESU units, which contained the solar PV inverters, were from another manufacturer, it was unclear which company was responsible for the performance of the solar PV system. When the ISGD team found issues with the solar PV performance on a home, it had to identify the source of the problem and then work with the vendor to fix the problem. Commissioning the PV in this multi-vendor environment fell to the project team. With this knowledge, the team would design a more rigorous commissioning process for similar future projects to help ensure greater performance of the overall system.

Energy Storage Degradation Should be Factored into Device Control Algorithms and Relevant Utility Load Management Tools

Since the ISGD project commissioned the RESUs in 2013, the amount of energy these devices can store has decreased. The team first noticed a side effect of this decline during a demand response experiment on September 15, 2014, in which the RESUs discharged over a five-hour period during the afternoon peak period. As the RESUs neared the end of the DR event, their rates of discharge declined more quickly than the team expected. These discharge rates were lower than what the team observed during the initial lab testing prior to ISGD deployment, and resulted from the RESUs having less energy available than expected during the initial power calculation at the beginning of the DR event (i.e., when the RESU calculates the average rate of discharge over the course of the event). In order to continue discharging throughout the duration of the DR event, as the event progressed the RESUs' internal control systems began reducing power to extend the discharge period of the remaining available energy. This behavior was due to the RESUs' batteries having a lower capacity than during their initial lab tests.

Energy storage manufacturers should ensure that their batteries' control algorithms properly understand that battery degradation will occur and adjust their operation accordingly. The ISGD RESUs have some limited information about battery state of health, including the current battery capacity, which they use to control their discharge rates. Utilities should also be aware that performance does not remain constant over the life of battery products, and they should factor this battery degradation into their load management tools. Failure to account for the actual capacity available in an energy storage device may result in ineffective load management planning and execution.

Demand Response Devices Should Be Capable of Decreasing and Increasing Energy Demand

Utilities have traditionally used demand response resources to reduce energy demand during periods of peak energy use, such as hot summer afternoons when AC use is highest. This helps to lower the critical generation peaks, which normally occur only a few days per year. However, DR resources may be useful in helping grid operators manage other types of challenges and opportunities. For example, DR could provide relief to local distribution circuit peaks—such as when demand climbs above the capacity of a distribution transformer. DR resources could also absorb surplus solar PV through pre-heating, pre-cooling, or by charging electric vehicles or stationary energy storage devices. To provide these types of services to grid operators, DR resources need to become more flexible. They should be able to both reduce energy demand (their traditional function) and increase energy demand.

The ISGD team attempted to perform a pre-cooling DR event with the PCTs in the project homes. The purpose of this experiment was to evaluate the viability of using the project PCTs as a load source. If the team could use DR event signals to turn on AC units to pre-cool a group of homes in the morning and midday periods, then it could potentially reduce the AC energy use in the afternoon peak-period. This capability could potentially be useful for load shifting and other applications such as absorbing surplus solar generation, which could help avoid curtailing renewable generation.

Unfortunately, the project PCTs do not allow pre-cooling. These PCTs ignore commands to reduce their temperature set point below their current set point. The PCTs treat all DR events as "load shedding" events and, therefore, do not respond to DR signals that increases their energy use.

The failure of the PCTs to allow pre-cooling demonstrated the need for vendors to build flexibility into their DR-capable devices. With changing loads in California resulting from the proliferation of renewable energy resources like rooftop solar, there may be times when the electrical grid can benefit from surplus renewable energy. Designing DR-capable equipment with the flexibility to either increase or reduce electricity use depending on the needs of the grid will best serve the future needs of the electric grid.

Energy Storage that Supports Islanding Should be Sized Appropriately and Should Only Island during Actual Grid Outages

One source of potential value for energy storage is to use it to provide energy to customers during grid outages. However, it is important that the energy storage device is sized to support the expected maximum customer load. For example, the distribution transformer can support loads as high as 100 kVA while grid connected, but the CES cannot support loads this high[16]. The CES will trip under the following conditions when operating in islanded mode: (1) when the load exceeds 62.5 kVA, (2) when the load is between 25 kVA and 62.5 kVA for longer than three seconds, and (3) when the CES battery becomes fully discharged. The daily peak load of the CES Block is usually less than 25 kW, but it exceeds 25 kW at least twice per month. If the CES islands and one of these trip conditions is met, then the CES will trip. If an energy storage device has power capacity that is less than the maximum demand that it is expected to serve during an islanding event, then it would subject to tripping following a grid outage.

Another consideration when deploying energy storage to support islanding is to make sure the energy storage device only islands during actual grid outages. If the device identifies grid outages incorrectly and islands itself, this increases the risk of service interruptions to customers. Since energy storage devices trip under certain conditions while islanded—such as when demand is too high—it is possible that energy storage could cause a customer outage even when a grid outage has not occurred. Thus, it is important that the energy storage device's islanding settings are set correctly such that it only causes the device to island during actual grid outages.

[16] The original transformer on this block was 50 kVA. The team upgraded the transformer to 100 kVA at the beginning of the project in order to accommodate the CES across the street.

Backup Power for Data Acquisition Systems Should be Provided When Data Collection is Needed during Power Outages

During a grid outage event on July 8, 2014, the RESUs provided secure load back up using both the stored energy and the solar PV output. However, during this event the ISGD project's data acquisition system components and 4G radios turned off since they were not connected to the RESU secure load circuits. As a result, the team's only data source during the event was the RESU internal data logs. If data collection is necessary during grid outages, then backup power should be provided for the relevant data acquisition systems.

Minimizing Impact on Distribution Transformer Requires Coordination of Solar PV, Electric Vehicle Load, and Energy Storage Strategies

Solar PV generation, electric vehicle charging, and energy storage system operation all affect the net load shape. In some PLS tests, the afternoon discharge of the battery added to the solar PV output to aggravate transformer loading. Similarly, electric vehicle charging during the early evening peak increases this peak load. Integration of these technologies requires proper coordination of their operating times.

Islanded Microgrids Require Coordinated Management of Distributed Generation, Energy Storage and Customer Load, which requires Forecasts of Each

ISGD islanding test highlighted several factors that should be considered when designing an "islandable" microgrid. Successfully operating a microgrid that is islanded from the electric grid requires coordination of the various components that either supply power to the microgrid or rely on the microgrid for power. Major sources of load such as electric vehicles, energy storage and air conditioning would need to be managed, since they provide a large amount of electric load that could potentially exceed the microgrids available power. Likewise, sources of generation such as solar PV and energy storage would also need to be managed in order to avoid oversupplying power to the microgrid. Having a more effective ability to forecast generation and load would help to manage these resources, such as the mode of operation and set points for energy storage.

Reliability of HAN Device to Back Office Communications May be Improved with Simpler Communications Approaches

The project team encountered a number of persistent challenges in maintaining the communications among the HAN devices in the sub-project 1 homes. This was largely due to the communications approach used for ISGD that used a communications hub between the project meter and the other respective HAN devices. When the team issued a DR command to the smart appliances, for example, the project meter would receive the signal from SCE's NMS, then route this message to the communications hub, which would then route the message to the respective HAN devices. Whenever the meter lost its connection to the hub, the team also lost its ability to communicate with the respective HAN devices. It is likely that simplifying the communications path by routing the messaging directly from the meter to the HAN devices would have improved communications reliability.

The Toyota Pilot, which is summarized in Appendix 14, faced similar communications challenges. In this case, communications between the utility back office and the Toyota back office involved a circuitous communications path whereby information would flow from the utility back office to the home gateway, to the EVSE, to the electric vehicle, then back through the home gateway, and finally to the Toyota back office. Simplifying this communications path by having the utility back office communicate directly with the Toyota back office would have improved communications reliability.

3.1.4.2 ZNE Homes Commercial Readiness Assessment

There are a number of issues that limit the commercial readiness of ZNE home technology. Foremost is the lack of consistent communication and interoperability of the elements. Difficulties the team experienced in establishing reliable communications highlight this issue. Differing responses to the same DR signal between the PCT and the EVSE and the inability of the PCT to accept a pre-cooling signal also demonstrate the lack of commercial readiness.

The storage element, whether inside or outside the home, suffers from a lack of tariffs allowing the resource to be economically utilized. An option involving paying real time prices coupled with a daily forecast of real time prices would allow the storage element to engage in economical arbitrage.

3.1.4.3 ZNE Homes Calls to Action

Tariff design

Regulators and utilities should explore the best way to allow real time costs of energy to flow through to end use customers to allow storage to be used in an economic manner.

Home Area Network Standardization

NIST, standards writing bodies and other stakeholders should cooperate on establishing applications level standards for smart homes which accommodate both wireless and power line carrier based communications.

3.1.5 ZNE Homes - Metrics and Benefits

This sub-project included a number of customer facing technologies intended to improve the energy efficiency of the homes, reduce peak energy use on the electric grid, generate on-site renewable energy, and substitute petroleum-based fuels with electricity. The following table summarizes the impacts of these measures:

Table 10: Sub-project 1 Impact Metrics Summary

Metric	Base Year (2012)	Test Year (2014)	Change
Available energy storage at annual peak time (kW)	0	81	81
Distributed generation at annual peak time[17] (kW)	0	76.65	76.65
Total customer peak demand (kW)	17.01	3.73	(13.28)
Annual energy use (kWh)[18]	134,904	124,646	(10,259)
Annual solar PV generation (kWh)	0	95,244	95,244
Electric vehicle energy use (kWh)	0	20,325	20,325

Table 4 in chapter 2 summarizes the types of benefits that would result from this sub-project. The ISGD team collaborated with Lawrence Berkeley National Lab to perform a cost-benefit analysis with using the DOE's Smart Grid Computational Tool. Appendix 11 summarizes the results of this effort. It is worth noting that this cost-benefit analysis reflects component costs from several years ago. Using current costs for this analysis would likely result is a more favorable outcome for many of the ISGD technologies, particularly energy storage.

3.2 Sub-project 2: Solar Car Shade

If plug-in electric vehicles achieve widespread adoption, it is likely that drivers of pure electric vehicles (EVs)—as opposed to plug-in hybrids, which can use both electricity and gasoline—will want to charge at work during the day to reduce "range anxiety," a driver's concern that an EV would run out of energy before reaching their destination. However, daytime car charging would increase electricity demand during the day, and may increase local or system peak demand. This sub-project demonstrated a PEV charging system designed to minimize the net consumption of

[17] This represents the distributed generation, including both solar PV and demand response resources available to meet annual peak demand, which occurred at 4:00 pm on 9/15/14. At this time, the 22 homes were generating 42.99 kW of solar PV. They were also consuming 31.74 kW of HVAC and 1.92 kW of electric vehicle load, both available as demand response resources.

[18] The annual energy use was derived by adding the solar PV generation and metered energy use, and then subtracting the electric vehicle and heat pump use (since these are new forms of electric load that merely substituted for other fuel types), and subtracting the energy losses from operating the RESUs.

energy from the grid due to PEV charging. The team expected the system to reduce or eliminate the impact of PEV charging during on-peak periods.

Figure 6: Workplace Electric Vehicle Chargers and Solar PV Structure

3.2.1 Solar Car Shade - Technical Approach

3.2.1.1 Objective

The objective of this sub-project was to demonstrate how distributed solar PV generation, battery energy storage, and smart charging capabilities can help minimize the grid impact of PEV charging during peak periods.

3.2.1.2 Approach

The team installed solar panels above a parking garage on the UCI campus. The installation included a 48 kW solar PV array that generated renewable energy during daylight hours and 20 parking spaces with EVSEs for PEV charging. SunPower supplied the solar PV array and BTC Power supplied the EVSEs[19]. Anyone who had a UCI parking permit could charge a PEV in one of these spaces. Each EVSE was capable of receiving demand response messages and sending relevant energy consumption data to the manufacturer’s back-office systems. Each EVSE had a maximum rating of 6.6 kW. The solar PV array received support from a stationary BESS sized for 100 kW of power output and 100 kWh of energy storage. The energy storage system supported PEV charging during on-peak periods and cloudy days, and charges itself from the solar PV array and/or off-peak grid energy. Princeton Power Systems supplied the BESS.

3.2.2 Solar Car Shade - Research Plan

3.2.2.1 Laboratory Tests

The team performed laboratory testing to simulate all BESS field tests in a controlled environment to ensure proper functionality and to prepare for the field tests. This testing helped the team determine whether the hardware and software operate according to the project’s specifications. Testing helped to ensure that remote commands could control the system. The team also performed integrated system testing with a PV simulator to evaluate the PV functions.

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[19] The original EVSEs were removed and replaced with different units during the course of the project. Refer to section 7.1.1.2 for additional details.

3.2.2.2 Commissioning Tests

To commission the EVSEs and BESS, the team performed a series of tests in the field to verify that these components can perform their required functions.

- EVSE remote load control: The intent of this test was to verify that the EVSEs are capable of responding to remote load control signals to modify their charging behavior.
- Remote battery dispatch: The intent of this test was to verify that the BESS is capable of responding to a DR event signal. Power meters that record demand at the point of common coupling between the solar car charging system and the UCI grid were analyzed to ensure the BESS dispatched energy as requested and returned to its previous operation afterward.

3.2.2.3 Field Experiments

The ISGD team performed the following experiments to evaluate the impacts of the sub-project 2 capabilities.

Field Experiment 2A: Minimize Peak Period Impact of PEV Charging

This mode attempts to reduce demand from the charging system to zero during peak periods. The objective of this test was to quantify the impact to the grid of charging electric vehicles using a charging system supported by solar PV and energy storage. The team performed this experiment by placing the BESS in a mode that minimizes the grid impact of electric vehicle charging. Local power meters recorded EVSE loads, solar PV generation, battery usage, and net demand. The team used this data to analyze the behavior of the BESS and to verify its ability to minimize the impact of the PEV charging during peak periods.

Field Experiment 2B: Cap Demand of PEV Charging System

The objective of this test was to quantify the BESS's ability to limit demand of the PEV charging system at the interface with the electric grid. The team conducted this experiment by placing the BESS in a mode that limits demand to a specified threshold throughout the test period (24 hours a day) whereby it discharges whenever the load exceeds this setting. Power meters record EVSE loads, solar PV generation, battery usage, and net power. The team used this data to analyze the behavior of the BESS.

Field Experiment 2C: BESS Load Shifting

The objective of this test was to quantify the impact of the PEV charging system while the BESS performs load shifting. The team performed this experiment by remotely configuring the BESS to shift load by charging during off peak periods and discharging during peak periods. Local power meters recorded EVSE loads, solar PV generation, battery usage, and net power. The team used this data to analyze the behavior of the BESS and to assess the PEV charging system's impact on the grid.

3.2.3 Solar Car Shade - Summary of Test Results

The project team placed the Solar Car Shade System into service between September and December 2013, and ran the system continuously until the end of August 2015 (excluding a one-month period around November 2014 when the EVSEs were replaced). For this 24-month period, total EVSE load was 109 MWh, total supply from the BESS and PV array was 70 MWh, and total supply from the grid was 39 MWh. The BESS and PV array thus supplied about 64% of the EVSE load. In general, the battery charged from the grid overnight and supplied EVSE load in conjunction with solar generation with some support from the grid during the day (depending on the experiment being run). When the battery was fully charged and PV generation exceeded EVSE loa,d the excess generation flowed to the grid.

Minimize Peak Period Impact (MPPI) of EV Charging (Field Experiment 2A)

MPPI mode seeks to regulate any demand from the grid during peak hours. In the experiment, this regulation point was set to zero for the period from 9:00 am to midnight. This was demonstrated successfully.

Figure 7: Solar Car Shade MPPI Experiment

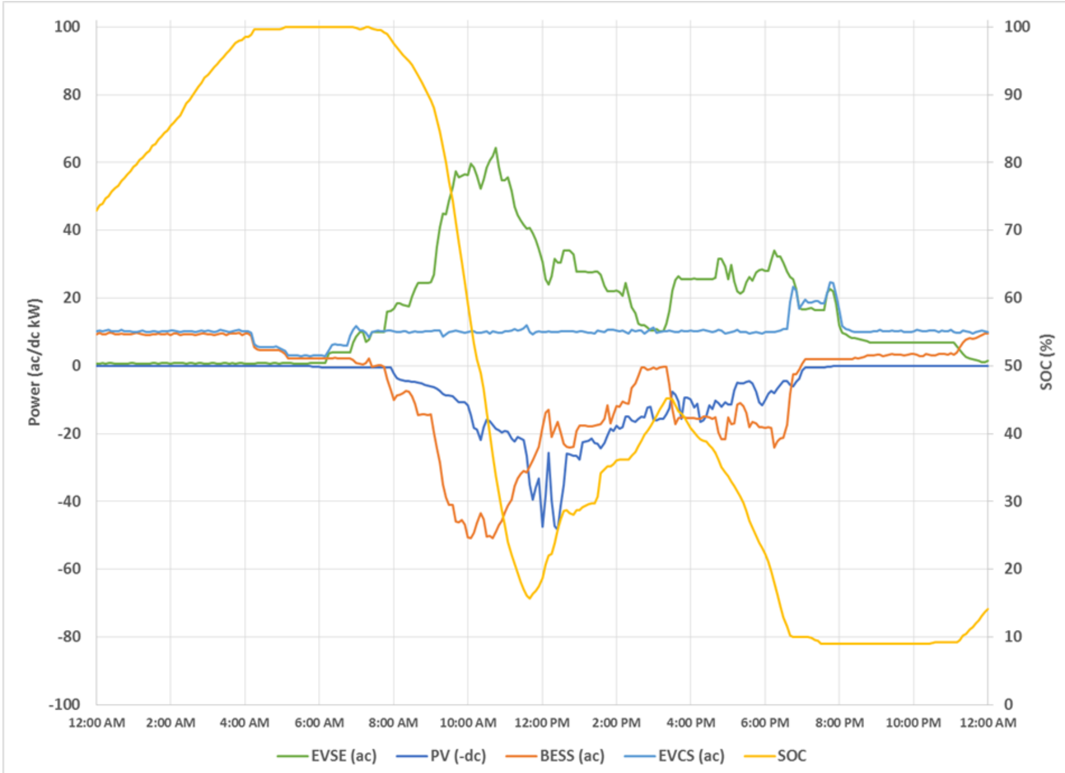
This mode also curtails solar generation if necessary to keep the grid interchange at zero. This satisfies certain tariffs that prohibit export from solar systems including storage. If tariffs permit export, a separate cap demand mode allows the export of excess generation. This experiment highlights the problem of determining the optimal discharge period for the battery, which requires an accurate forecast of the day's generation and demand.

Cap Demand of EV Charging (Field Experiment 2B)

From April to July of 2015 the BESS operated in Cap Demand mode. In this mode, the BESS operates to cap the amount of power drawn from the grid to a given limit subject to power available from the PV and the battery. In contrast to MPPI mode there is no limit on solar export when EVSE and battery charging load permits.

If the cap is set too low, the battery may not be fully charged overnight and may be exhausted before the afternoon and evening peak has passed. If the cap is set too high, the battery may be under-utilized. Operation with a 10 kW cap produced the first scenario while operation with a 20 kW produced the second. Operation at 15 kW produced near optimal battery utilization. The graph below shows operation with the 10 kW limit, and as can be seen, there is not enough battery energy available to prevent exceeding the 10 kW limit from about 6:30 to 8:00 pm.

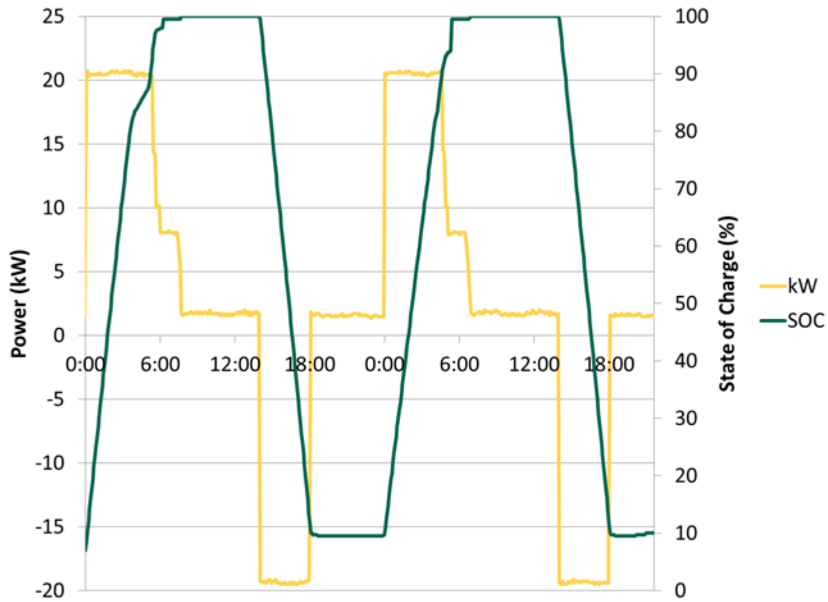
Figure 8: Solar Car Shade Cap Demand Experiment



BESS Load Shifting (Field Experiment 2C1 through 2C2)

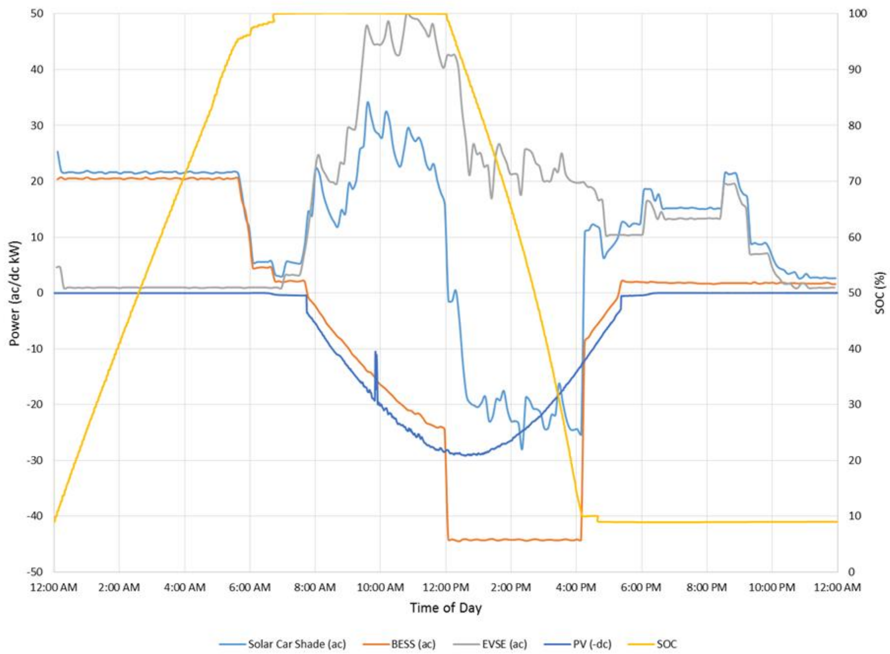
The team perform two load shifting experiments. The first experiment, conducted between September 10 and November 7, 2013, involved the battery alone since the EVSEs and the PV system were not yet in service. In this experiment, the battery charged at 20 kW from midnight to about 7:00 am, with the charge rate tapering off near full charge, and discharged from 2:00 pm to about 7:00 pm, again at 20 kW. An apparent rapid degradation of the battery's capacity during this experiment was traced to the software in the Battery Management System (BMS), which calculated its State of Health (SOH). The software erroneously calculated a greater degradation than actual, and after corrected software was installed, it calculated the SOH correctly.

Figure 9: Solar Car Shade Battery Only Load Shift



The second experiment had the solar PV and EVSE charging stations in service. The EVSE charging occurred as needed (based on customer use). The battery was charged from the grid from midnight to about 6:00 am. Solar power offset the EVSE demand from the time solar generation began until noon, when the battery began discharging such that the combination of PV and battery power was a constant 45 kW. This continued until the battery reached its minimum (10%) SOC and stopped discharging, which occurred about 4:00 pm. PV power continued contributing until it ceased with sunset about 5:30 pm. The net result of this form of operation was to allow a high system demand in the morning, provide an export to the grid from noon to 4 pm, and allow the grid to carry full EVSE load from 4 pm from then on. This uncoordinated operation did not utilize the PV and battery resource very well in terms of minimizing grid impact of EV charging. The MPPI and cap demand strategies, and especially cap demand at 15 kW, did a much better job in this regard.

Figure 10: Solar Car Shade Whole System Load Shift



3.2.4 Solar Car Shade - Observations

3.2.4.1 Solar Car Shade Lessons Learned

Improved System Diagnostic Capabilities Are Required to Help Identify the Causes of Failures

In October 2013, the sub-project 2 BESS tripped, causing the battery to shut itself down using protections built into the system. The ISGD team immediately downloaded the diagnostic data collected by the BESS and investigated the issue with the manufacturer. However, the manufacturer was unable to identify the cause of the trip. The system had followed a self-protection scheme designed and implemented by the manufacturer, but it did not record enough diagnostic information for the manufacturer to understand exactly what had happened. Although the system returned to normal operation, the manufacturer made no changes that would prevent a similar trip in the future since they could not determine the cause of the trip. In the event of failures or unexpected events, battery systems should capture detailed information to properly identify the cause of the event. This type of issue is not limited to this device or manufacturer, and is characteristic of emerging technologies and applications where manufacturers' design and integration techniques are still maturing.

3.2.4.2 Solar Car Shade Commercial Readiness Assessment

There appear to be no major technical obstacles to deploying systems of this type. Since the ISGD project demonstrated early stage technologies, there were a number of software and control issues to overcome. However, none of these would prevent commercialization under the proper economic conditions. Electric vehicles are generally considered to be beneficial for the electric grid since they would typically charge at night, off peak, thereby improving grid asset utilization. If, however, they were also charged during the daytime, they might aggravate peak demand. The idea behind the solar car shade is to use solar and battery power to prevent this. Employers might receive incentives to provide such facilities for their employees to encourage adoption of EVs. Special electric rates for such stations might be provided, offset by reduced need for utility infrastructure upgrades otherwise caused by aggravated peak demand.

3.2.4.3 Solar Car Shade Calls to Action

Potential developers of solar car charging stations should study how best to manage the charging and discharging of the battery component to minimize grid impacts during peak times. This would likely involve solar generation and load forecasting and perhaps artificial intelligence to adjust behavior over time.

Regulators and utilities should consider an appropriate rate structure for such facilities that accurately reflects their value in terms of preventing or deferring system upgrades.

3.2.5 Solar Car Shade - Metrics and Benefits

This sub-project was designed to offer electric vehicle charging in the workplace, and to support this charging activity with on-site solar PV generation, while also using energy storage to minimize the impact to the electric grid. The following table summarizes the impacts of this solar car shade system:

Table 11: Sub-project 2 Impact Metrics Summary

Metric	Base Year (2012)	Test Year (2014)	Change
Available power at annual peak time (kW)	0	100	100
Solar PV power at annual peak time (kW)[20]	0	20.22	20.22
Annual solar PV generation (kWh)	0	51,506	51,506
Electric vehicle energy use (kWh)	0	42,946	42,946

Table 4 in chapter 2 summarizes the types of benefits that would result from this sub-project.

[20] This represents the power output of solar PV array at the moment of annual peak demand in 2014 (4:00 pm on September 15, 2014).

4. Next-Generation Distribution System

The electric grid is evolving into an increasingly dynamic system with new types of distributed and variable generation resources and changing customer demands. ISGD evaluated technologies designed to support grid efficiency and resiliency within this changing environment. The team evaluated these technologies in four sub-projects: sub-project 3: Distribution Circuit Constraint Management Using Energy Storage, sub-project 4: Distribution Volt/VAR Control, sub-project 5: Self-healing Distribution Circuits, and sub-project 6: Deep Grid Situational Awareness.

Existing distribution circuits are nearly all radial circuits designed for one-way power flow from the utility substation to the customers. This provides a relatively inexpensive yet highly reliable delivery system.

The proliferation of DER on distribution circuits, and pressure to add still more, is prompting a reconsideration of the traditional radial design. DER implies two-way power flow, which suggests modifications to present circuit topology, and features to better accommodate such flows.

All of these considerations led the ISGD team to devise sub-projects under the Next-Generation Distribution System domain to answer questions including the following:

- Can stored energy systems be used to shave peak load from distribution circuits during periods of very high loading?
- Can centralized control of distribution capacitors provide superior CVR?
- Can distribution circuits be operated in a looped configuration as a step toward a networked distribution system?
- Can radio communications facilitate the two-way protection needed for looped distribution circuits?
- Can PMU and PDC technology reliably detect the operation of aggregated DER such that this type of resource can participate in markets?

4.1 Sub-project 3: Distribution Circuit Constraint Management Using Energy Storage

4.1.1 Distribution Circuit Constraint Management - Technical Approach

4.1.1.1 Objectives

The objective of this sub-project was to demonstrate the use of battery energy storage to help prevent a distribution circuit load from exceeding a set limit and to mitigate overheating of the substation getaway.

4.1.1.2 Approach

This sub-project demonstrated a mobile, containerized DBESS connected to the Arnold 12 kV distribution circuit. This circuit receives power from MacArthur Substation and is the same circuit from which the project test homes in sub-project 1 are powered. The DBESS has a rating of 2 megawatt (MW) of real power and 500 kWh of energy storage. The system included supporting equipment such as a thermal management system and an interconnection skid to the 12 kV distribution system. Members of the ISGD team monitored and controlled the DBESS locally.

4.1.2 Distribution Circuit Constraint Management - Research Plan

4.1.2.1 Laboratory Tests

The team tested battery controls and all auxiliary system components prior to field installation to verify performance and proper functionality. The team also performed integrated system testing in the lab setting. To ensure that each component performs as expected, the team evaluated and repeatedly exercised the energy storage component, the power conversion system, and the control system. The team conducted real and reactive power import and export testing at various levels and durations to measure the response speed and to verify the precision and stability of the output. The team measured and analyzed cell voltage, state of charge (SOC), cell temperature, and inverter temperature to determine the relationships among these parameters.

4.1.2.2 Commissioning Tests

Prior to regular operation of the DBESS in the field, the team performed a series of tests to verify that the components could perform their required functions. The intent of these tests was to verify that the device could synchronize with the grid, and that the protection elements were set properly. The team also demonstrated SCE's ability to control the DBESS to inject or absorb power on the Arnold circuit.

4.1.2.3 Field Experiments

The ISGD team performed the following experiment to evaluate the impacts of the sub-project 3 capabilities.

Field Experiment 3A: Peak Load Shaving/Feeder Relief

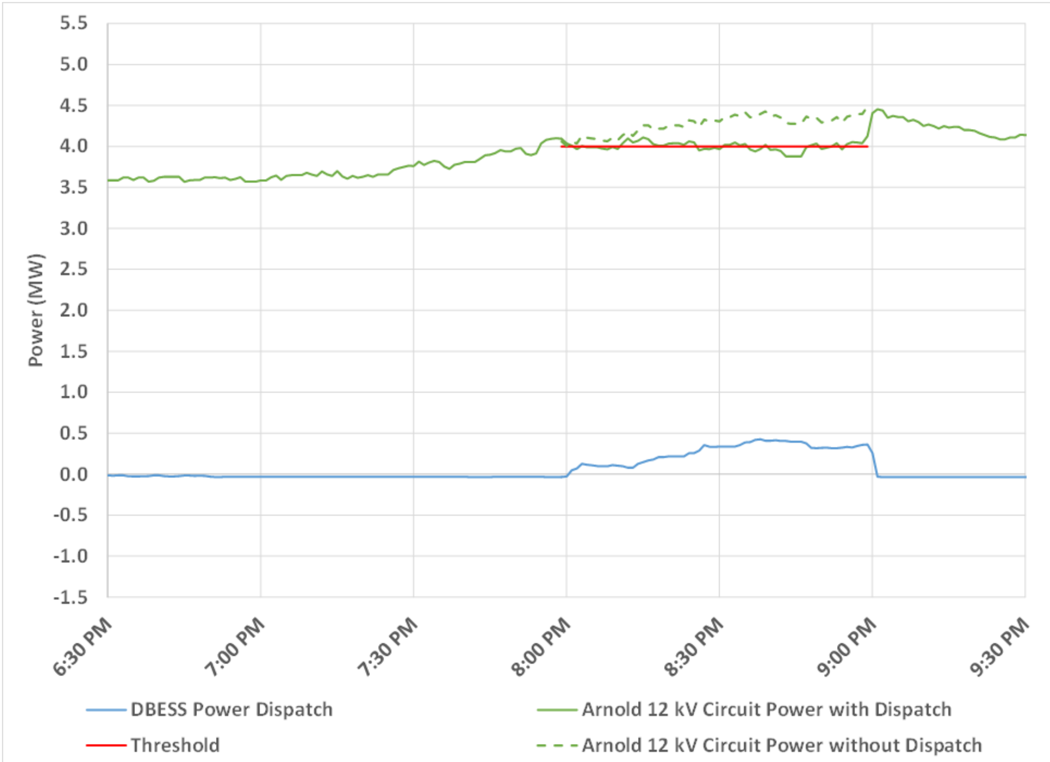
This experiment demonstrated the DBESS's ability to prevent the circuit load from exceeding a set limit and mitigate overheating of the substation getaways. This experiment was conducted by injecting or absorbing real power as necessary (up to 2 MW) to keep the circuit load from exceeding a set limit. The storage device was charged when conditions permitted. The team recorded and analyzed circuit load, circuit voltage, battery SOC, and system power input/output to determine if the system was capable of performing the required peak load shaving/feeder relief function, subject to the battery's capacity limits.

4.1.3 Distribution Circuit Constraint Management - Summary of Test Results

Peak Load Shaving/Feeder Relief (Field Experiment 3A)

In this experiment, the battery was discharged as necessary to keep the circuit peak load at 4 MW until its 500 kWh capacity was exhausted. This was successfully demonstrated in the summer of 2015.

Figure 11: Field Experiment 3A



As can be seen from the graph, the battery was exhausted before the peak had passed. The 2 MW rating of the conversion equipment appears sufficient for meaningful relief while the 500 kWh capacity of the battery appears inadequate. It should be noted that this battery system was not originally designed and sized for this type of application. Rather, it was designed to participate in energy markets to provide ancillary services (e.g., frequency regulation).A system suitable for practical relief would require several times this capacity.

4.1.4 Distribution Circuit Constraint Management - Observations

4.1.4.1 Distribution Circuit Constraint Management Lessons Learned

The battery system used for this experiment was not explicitly designed for this purpose. It had been designed to support frequency regulation services. As such, the battery was designed with relatively high power output and small energy capacity. These operational characteristics and overall system integration required a large supplemental cooling system and other supporting equipment on its own skid. The large footprint of a battery container, auxiliary equipment/cooling skid, and interconnection skid with step-up transformer and protection, was too large to be practical in this application considering the limited energy storage capacity. An alternate design using higher energy density battery integration and a lower discharge rate would be more appropriate for providing distribution circuit relief.

4.1.4.2 Distribution Circuit Constraint Management Commercial Readiness Assessment

While this design lacked the capacity to provide practical circuit relief, commercial systems are now available in a range of energy capacities and footprints suitable to be integrated with the distribution system. Following the ISGD project, SCE installed its first battery energy storage system dedicated to support a distribution circuit. The 2.4MW, 3.9MWh system had a total footprint of less than 1,600 square feet.

4.1.4.3 Distribution Circuit Constraint Management Calls to Action

Battery and other storage technology providers are encouraged to develop portable products with higher energy capacity, smaller footprint, and easier installation and commissioning processes. Distribution system owners and operators are encouraged to consider the feasibility of integrating such systems in their planning process.

4.1.5 Distribution Circuit Constraint Management - Metrics and Benefits

This sub-project consisted of using a 2 MW/500 kWh battery sited to provide distribution circuit constraint relief during potential overload conditions. The following table summarizes the impacts of these measures:

Table 12: Sub-project 3 Impact Metrics Summary

Metric	Base Year (2012)	Test Year (2014)	Change
Available power at annual peak time (MW)	0	2	2
Available energy storage at annual peak time (KWh)	0	500	500

Table 4 in chapter 2 summarizes the types of benefits that would result from this sub-project. The ISGD team collaborated with Lawrence Berkeley National Lab to perform a cost-benefit analysis with using the DOE's Smart Grid Computational Tool. Appendix 11 summarizes the results of this effort.

4.2 Sub-project 4: Distribution Volt/VAR Control

This sub-project demonstrated the use of DVVC to optimize customer voltage profiles. Delivering energy with customer voltage in the lower half of the American National Standards Institute (ANSI) C84.1 range can result in energy savings. This practice is known as conservation voltage reduction (CVR). Many devices that use electricity operate satisfactorily at the lower end of their voltage range while also tolerating higher voltage. As a result, reducing customer voltage can yield energy savings while not compromising service. Energy savings as a function of reduced voltage vary by equipment type and by loading.

Lightly loaded induction motors are particularly significant in this regard. At higher voltages, such a motor draws more magnetizing current than needed, resulting in additional losses. When the same motor is heavily loaded, it may require higher voltage for adequate torque. Many electrical loads involve lightly loaded induction motors. Reducing the voltage supplied to these motors may therefore result in energy savings without any loss in motor function.

A distribution circuit may supply over a thousand individual customers with a mix of residential, commercial, and industrial users. The connected loads would likewise be a mix of motors, lighting, heating, electronic, and other types of loads. The effectiveness of CVR depends on the mix of loads on a particular circuit and their responses to changing voltage.

Previous work at SCE under the Distribution Capacitor Automation Project (DCAP) program (described below) measured CVR at two distribution substations (Walnut Substation and Villa Park Substation) with a total of eighteen 12 kV distribution circuits and 72 switched capacitor banks (68 field capacitor banks and four substation capacitor banks). The results indicated that a 1% voltage reduction produced about a 1% energy savings. This ratio, which measures the decrease in power associated with a 1% voltage decrease (% power reduction/% voltage reduction) is often called the CVR factor. In March 2012, EPRI released the results of a survey of 52 utilities, which reported measured CVR factors ranging from 0.4 to 1.0. The ISGD team reviewed available data to determine whether DVVC achieves the expected savings and whether the assumed CVR factor of 1 is still justified.

SCE currently uses technology that was developed many years ago to maintain customer voltage within its required voltage range, as designated in the ANSI C84.1 standard and modified by California Rule 2 (114 to 120 volts at the residential customer service connection). SCE uses load tap changer (LTC) transformers and capacitors to regulate system voltage and VARs, depending on the grid voltage level. LTC transformers typically control sub-transmission system voltage. These devices reside between the bulk power system (500 kV – 220 kV) and the sub-transmission system (115 kV – 66 kV). SCE's 12 kV and 16 kV distribution systems that are supplied by a 66 kV sub-transmission system, such as the ISGD system, use switched capacitors located along the circuits and within each substation connected at the distribution bus. Nearly all of these capacitor controls operate based on the locally sensed primary circuit voltage at its connection point. Each capacitor controller has a control bandwidth that switches a capacitor off when the primary voltage exceeds the upper band limit and switches the capacitor back on when primary voltage drops below the lower band limit.

To compensate for additional voltage drop during peak conditions in the secondary system (e.g., 120/240 volt) many of SCE's capacitor controllers use time bias and/or temperature bias. The bias will raise (or lower) the entire bandwidth during specific times of the day or temperature conditions as a means to provide additional voltage support during peak conditions. The problem is that this bias attempts to estimate (and compensate for) secondary voltage drop based solely on time of day and/or temperature. It does not sense load or customer voltage directly. While this system has provided adequate customer voltage control, it does not allow for optimal control that might be obtained by sensing voltages and actively coordinating capacitor switching in a system.

SCE demonstrated CVR and a superior method of coordinated central capacitor control in a project called DCAP. From 1992 through 1994, SCE demonstrated DCAP at two distribution substations with a total of eighteen 12 kV distribution circuits and 72 switched capacitor banks. The scheme centralized the switching of field and substation capacitors to achieve the lowest average customer voltages possible without violating minimum voltage requirements at any measured point and without violating substation power factor limits. The system relied on special purpose secondary voltage monitors, which provided a direct measurement of customer voltage via radio. The team turned the DCAP system on and off for alternate time-periods and observed a CVR factor of approximately 1.0.

The ISGD DVVC capability is based on the approach previously used in DCAP. Like DCAP, the heart of this algorithm is a Voltage Rise Table (VRT), which tabulates the expected increase in voltage for each capacitor location when a given capacitor is switched on. This allows the system to take a given voltage snapshot of the system and consider the effect of all possible capacitor switching combinations on voltage at every measured point. DVVC selects the combination which results in the lowest average voltage without violating any constraints—substation power factor, excess switching, minimum and maximum voltages at any point. The process repeats at preset intervals or whenever any voltage measurement is outside an expected range.

DVVC uses primary voltages measured by capacitor controllers rather than secondary (customer) voltages as the feedback (controlled) parameter. The ISGD team made this choice because special purpose secondary voltage monitors (such as the ones used in DCAP) are too expensive and Advanced Metering Infrastructure (AMI) meter voltage information is not available on a real-time basis. As a result, unlike DCAP, DVVC does not directly measure customer voltage, which is the ultimate target of CVR. DVVC must allow for the voltage drop between the measured primary voltage and the customer voltage. DVVC accomplishes this by targeting a minimum primary voltage with an offset two to four volts higher than the minimum required at the customer meter. This offset should vary based on load conditions on the secondary. Since DVVC does not directly measure secondary load, it uses substation transformer load as a proxy. Substation load is simply the sum of all the secondary loads, so this should be an effective proxy. **Table 13** shows the primary voltage control range as a function of substation transformer loading used by DVVC. The lower voltage limits are intended to maintain customer voltages at no lower than 114 volts on a 120 volt nominal basis. This is achieved by keeping primary voltage progressively higher as load increases.

Table 13: Primary Voltage Control Ranges

Transformer Loading Levels	Minimum Voltage – Maximum Voltage
≥ 100%	120 – 125
80% ≤---< 100%	119 – 125

< 80%	118- 125

Even though AMI meter voltage information is not available in real time, it is available for download and engineering analysis. The team retrieved and used this AMI data to verify the DVVC's overall effectiveness.

4.2.1 Distribution Volt/VAR Control - Technical Approach

4.2.1.1 Objectives

The objective of sub-project 4 was to test the DVVC as an advanced method of distribution system volt/VAR control against the legacy method to better inform future deployment of VVO schemes system wide.

4.2.1.2 Approach

SCE built on its experience with DCAP to incorporate advanced volt/VAR control in the ISGD project. The ISGD team used circuit load flow models to determine voltage rise as a function of capacitor switching in order to populate the VRT. The team modeled the capacitor switching-decision algorithm using Excel.

The ISGD DMS hosts the DVVC algorithm. The ISGD DMS communicates with the production DMS and uses its services to establish communication with field components such as circuit capacitors using Netcomm radios. The ISGD DMS communicates with substation elements via the production DMS's link to the Energy Management System (EMS) and its SCADA system. The ISGD DMS can also communicate with substation elements directly via the substation gateway. System operators retain the ability to disable this ISGD DMS link and regain normal control at any time. The ISGD DMS, production DMS, and EMS all run on the GE XA/21 system.

The approach to deploying and testing the DVVC involved concept validation through simulation, integration laboratory testing on the ISGD DMS at both the factory and the site, commissioning on the ISGD-DMS, and field experiments.

4.2.2 Distribution Volt/VAR Control - Research Plan

4.2.2.1 Simulations

The team modelled the substation operating bus and its seven circuits, including the ISGD circuits (Arnold and Rommel), using the Positive Sequence Load Flow (PSLF) program. Capacitor switching recommendations from the Excel version of DVVC were applied to this model. The team simulated a representative set of loading scenarios. The system model responded to these capacitor-switching recommendations as expected.

4.2.2.2 Laboratory Tests

The team evaluated the field apparatus and systems comprising the DVVC at SCE's Advanced Technology Labs to determine whether the DVVC system is capable of meeting voltage requirements and to assess system performance. Technology component testing occurred before field installation to verify performance and proper functionality. The team also performed integrated system testing in the lab setting.

4.2.2.3 Field Experiments

The ISGD team performed the following experiments to evaluate the impacts of the sub-project 4 capabilities.

Field Experiment 4A: DVVC VAR Support

This experiment used the DVVC application to supply additional VAR support to the transmission system. The team demonstrated this capability by verifying that the transmission system received additional VAR support upon raising the customer target voltage to the highest allowable level (without exceeding upper regulatory limits). SCE's grid operators would make the emergency request in real life, but the ISGD team simulated this request for the ISGD project. Test protocols and data collected from substation relays and customer meters were used to measure the DVVC impacts.

Field Experiment 4B: DVVC Conservation Voltage Reduction

This experiment consisted of operating the DVVC algorithm to determine if it satisfies DVVC's main objectives. These objectives included meeting substation VAR requirements (when possible), minimizing average customer voltage, and minimizing capacitor controller switching. DVVC was turned on and off on alternate weeks. When DVVC was turned on, the field capacitors were set to wider "backup" on and off voltage settings. When it was turned off, the field capacitors were reset to normal control values. In this way, the team could perform a valid comparison between voltage behavior with and without DVVC.

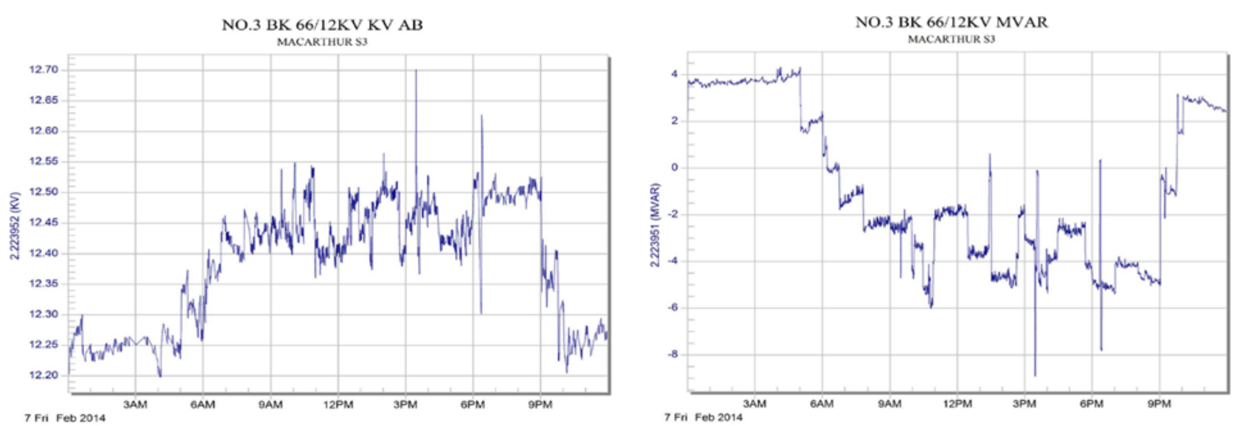
The team observed energy consumption for sixteen two-week periods, each with DVVC on one week and off the next, in an effort to estimate the CVR. The energy consumption for the week with higher average peak temperatures was adjusted downward to compensate for the known temperature sensitivity of load. The calculated CVR was 1.56. This is higher than generally observed in industry. The method of adjusting weekly load based on weekly average high temperatures is less rigorous than one using the daily three-day weighted training average of peak temperature for load adjustment. The more rigorous approach yielded a CVR of about 1.0 during the DCAP project and even lower figures reported by other utilities. The team considered the current results to confirm the continuing validity of the DCAP measurement.

4.2.3 Distribution Volt/VAR Control - Summary of Test Results

DVVC VAR Support

Maintaining voltage in a low CVR range is a proven and cost-effective way to reduce unnecessary energy consumption at the appliance level. However, there may be times of heavy power flows on the transmission and subtransmission system when providing VAR support at the transmission bus in the distribution substation has higher priority. The DVVC was therefore designed to provide VAR support when necessary by connecting capacitors as available subject to the constraint of not exceeding customer maximum voltage. This capability was demonstrated in February of 2014. Voltage was raised an estimated 2.5 volts (on a 120 volt basis) and substation reactive power changed from a 4 MVAR demand to a 4 MVAR supply to the 66 kV subtransmission system.

Figure 12: DVVC VAR Support



DVVC Conservation Voltage Reduction

The DVVC was operated with DVVC active for one week and then inactive for one week over most of the demonstration period. When the DVVC was off, capacitors were returned to their normal settings. This gave a clear comparison of voltage control in the two modes. Energy consumption for each week was recorded and temperature adjusted allowing a calculation of the CVR ratio. In general, DVVC operation achieved a two volt reduction on a 120 volt basis and reduced voltage fluctuations. The average CVR ratio observed over 32 weeks of testing was 1.56.

4.2.4 Distribution Volt/VAR Control - Observations

4.2.4.1 Distribution Volt/VAR Control Lessons Learned

Distribution Volt/VAR Control Applications Should Be Aware of System Configuration Changes to maximize CVR benefits

During the second reporting period, there were instances of circuits being switched from the DVVC controlled bus to the other operating bus in the substation for load balancing. Because the voltage readings continued to be as expected with DVVC on and off, it was some time before the project team discovered this configuration issue. The lesson learned is to design the DVVC system to automatically track configuration of the substation and its circuits. This in turn may require re-running load flow programs to re-populate the voltage rise table.

Distribution Volt/VAR Control Capabilities Can Achieve Greater Benefits When Combined with Management of Transmission Substation Voltage Schedules

The team discovered that some transmission substation voltage schedules and transformer tap settings created voltages at the higher end of the C84.1 range. Changing these transformer settings allowed the DVVC to achieve better results. Utilities need to consider transmission substation voltage schedules even after installing a system such as DVVC.

4.2.4.2 Distribution Volt/VAR Control Commercial Readiness Assessment

The successful deployment and operation of DVVC shows that systems such as these are ready for commercial deployment. Similar systems are being broadly deployed by utilities. Experience in ISGD pointed to several areas for future improvement in these systems.

- The systems work on a given distribution system operating bus and its connected circuits. Since these are subject to reconfiguration in the field, means should be provided to automatically update the Volt/VAR control system with the current configuration. The system must be able to then adjust its truth table to reflect this configuration. This may require the ability to perform load flow calculations after a configuration change.
- A positive CVR ratio may not exist on all circuits. Under some circumstances, such as a circuit with heavily loaded induction motors, the CVR ratio may be negative and a lower voltage may result in increased power consumption. In addition, consumer products such as power supplies and motors controllers are constantly improving, and their behavior with respect to voltage may change over time. For these reasons, a Volt/VAR control system should include provision for automatically testing the circuit to ensure the assumption of a positive CVR ratio remains true. This can be done by raising and lowering the voltage on successive days for some period to observe the effect. Such a test could be performed perhaps twice a year and the target voltage changed based on the results.

4.2.4.3 Distribution Volt/VAR Control Calls to Action

Industry should address the issues identified under the commercial readiness assessment.

- Volt/VAR Optimization should be deployed as part of a larger integrated DMS system. This system should have access to a single grid model that is automatically kept up to date. Most EMS systems keep track of substation configurations and most OMS systems keep track of distribution circuit configuration. This information should cause the Volt/VAR database to update in real time as well.
- A Volt/VAR system should recognize that not all circuits may have a positive CVR ratio at all times, so means should be included to measure the ratio and make appropriate adjustments to system behavior.

4.2.5 Distribution Volt/VAR Control - Metrics and Benefits

This sub-project implemented a centralized volt/VAR control system that improved control of voltage at the customer site and reduce customer energy use. The following table summarizes the impacts of using the DVVC capability to reduce overall system voltage and customer energy use:

Table 14: Sub-project 4 Impact Metrics Summary

Metric	Base Year (2012)	Test Year (2014)	Change
Average voltage reduction while running DVVC (%)	0	1.58%	1.58%
Average energy savings while running DVVC (%)	0	2.53%	2.53%

Table 4 in chapter 2 summarizes the types of benefits that would result from this sub-project. The ISGD team collaborated with Lawrence Berkeley National Lab to perform a cost-benefit analysis with using the DOE's Smart Grid Computational Tool. Appendix 11 summarizes the results of this effort.

4.3 Sub-project 5: Self-healing Distribution Circuits

This sub-project was designed to demonstrate a self-healing, looped distribution circuit that used low-latency radio communications to locate and isolate a fault on a specific circuit segment. This protection scheme isolates the faulted circuit section before the substation breaker opens. This functionality should lead to improved distribution circuit reliability by reducing the number of customers exposed to momentary outages and easing the circuit restoration burden on system operators and equipment.

4.3.1 Self-healing Distribution Circuits - Technical Approach

4.3.1.1 Objectives

The objective of this sub-project was to demonstrate an advanced circuit protection capability that reduces the number of customers impacted by outages, and reduces the service restoration time for customers impacted by outages.

4.3.1.2 Approach

When a fault occurs on a standard radial distribution circuit, a circuit breaker opens, which causes the entire circuit to lose power, affecting all customers served by that circuit. While automated switching can sometimes restore part of the circuit within a few minutes, all customers experience at least a short outage. This can negatively affect reliability statistics and extend outage restoration times for radial circuits.

ISGD's self-healing distribution circuit includes a looped topology, four URCIs,[21] and low-latency, high-speed radio communications between individual URCIs and the substation protection relays via a substation gateway. This communication system allows the URCIs and the substation protection relays to collaborate by isolating and managing faults that occur on two circuits fed by the substation. Quickly isolating a smaller circuit segment during fault events (before the substation breaker opens) can reduce the extent and duration of distribution outages, thereby improving electricity service reliability. A secondary benefit of this sub-project is demonstrating radio as a low cost alternative to fiber optic communications. This is a more cost-effective way to perform retrofits on existing substations and circuits.

This sub-project used two 12 kV distribution circuits (Rommel and Arnold) out of Macarthur Substation to form a single looped circuit. Each of these circuits includes two URCIs. The URCIs communicated with each other and the substation feeder relays using standard IEC (International Electrotechnical Commission) 61850[22] Generic Object Oriented

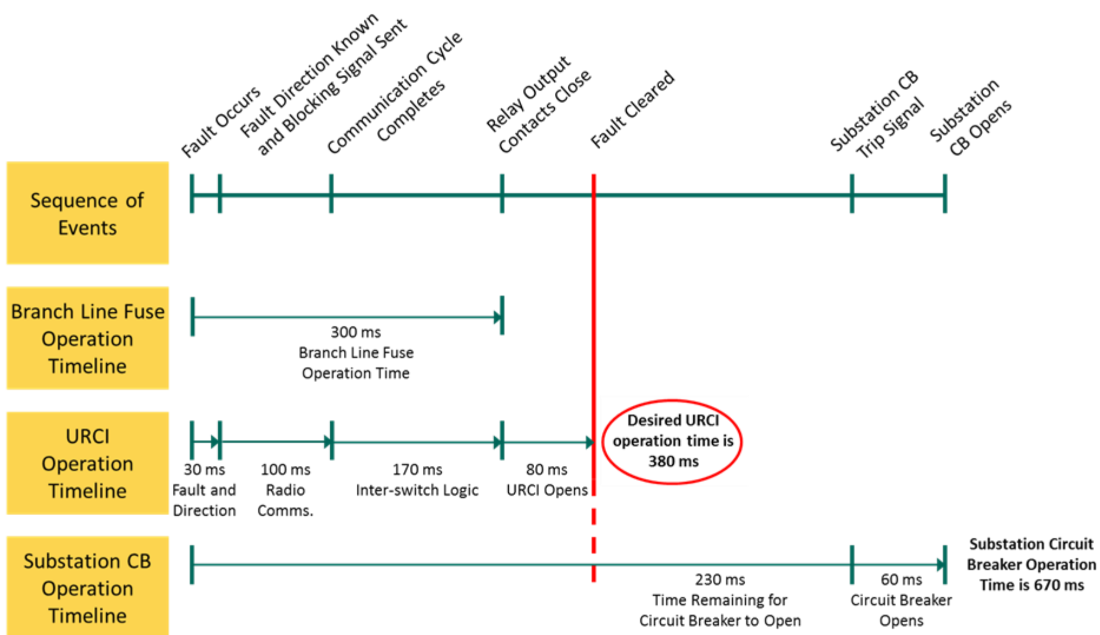
[21] Each URCI contains four key hardware components: G&W Viper-S Padmount Recloser, SEL 651R Recloser Controller, S&C Electric Intellicom Radio, and an Elastimold Control Power Transformer. These components provide power monitoring, device control, communications, and fault interruption.

[22] The IEC 61850 standard provides an internationally recognized method of communications for substation circuit protection, monitoring, control, and substation metering. The standard was specifically designed to provide a utility

Substation Event (GOOSE) messaging for protection coordination. This protocol supports the high-speed messaging required for this protection scheme. Since the purpose of this distribution protection system is to only interrupt the faulted section of a circuit, the protection communications and control operations need to operate faster than the substation circuit breaker. Substation circuit breakers currently operate within 500 to 600 milliseconds (ms) of a fault event. If the URCIs take longer to isolate a fault, the substation circuit breaker will open, causing the entire circuit to lose power.

Figure 13 depicts the timeline of a hypothetical fault on a distribution circuit, including the time required to clear the fault.

Figure 13: Distribution System Protection Event Sequence and Timeline



Detecting the fault and determining its direction requires approximately 30 ms. The time required may be longer, depending upon the time/overcurrent curve in operation and the fault magnitude. An additional 100 ms is required for the radio communications to send the blocking signals between the URCI relays, and an additional 170 ms is needed for communications retries and execution of the logic within each URCI relay. This equates to 300 ms, the same amount of time allowed for circuit branch line fuses to operate for a high-current fault. Branch line fuses limit outages to branches lines, which are smaller than segments that the URCIs are designed to isolate. Thus, the URCI logic intentionally waits 300 ms to allow the branch fuses to operate.

Once the URCI logic is complete, the URCI relays send signals to open the vacuum interrupters—this only applies to the two relevant URCIs involved in isolating the fault. The interrupter needs approximately 80 ms to physically open. If the protection scheme operates correctly, the system would clear the fault within about 380 ms. If the protection scheme does not operate properly, the substation circuit breakers would open and interrupt the fault within another 230 ms. The circuit breaker needs an additional 60 ms to physically open. In this case, the system would clear the fault within 670 ms.

standard for object-oriented development, resulting in simplified system configuration and integration, and increased processing speeds.

This protection scheme necessitates communications fast enough to send and receive GOOSE messages within 100 ms. Since GOOSE messages are small, the communications system does not need to be broadband. However, it must be low-latency. The radio system also requires sufficient propagation to minimize the need for repeater radios, since these radios increase latency. ISGD is using a system that operates in the 2.4 gigahertz (GHz) unlicensed spread-spectrum band, which requires several repeater radios to cover the area where the URCIs are located. A 900-megahertz (MHz) system that met the team's latency requirements was not available.

The URCIs were intended to be universal, with all four URCIs having the same logic[i]. When a fault occurs, each URCI needs to determine whether the fault is either "upstream" or "downstream" from it. The team accomplishes this by properly setting the polarity of the connections to the current transformers at each location. Each URCI must also be able to communicate with the adjacent URCIs. The team accomplishes this by configuring each URCI to "subscribe" to messages from the neighboring URCIs.

During an actual fault event, once the URCIs determine the fault location and direction, the relevant URCIs send trip or block-trip messages to the neighboring URCIs using the IEC 61850 GOOSE messaging protocol. The URCIs use internal logic to identify a fault and its direction. The URCI senses both phase and neutral instantaneous and time-overcurrent and determines which neighboring URCI to send the GOOSE blocking message. When a URCI receives a blocking message, it stops its vacuum interrupter from opening. The URCI maintains this block as long as the blocking message is from an adjacent relay. When the time-overcurrent element of any unblocked relay times out (one on each side of the fault), its vacuum interrupter opens. Because of different impedances for each of the two ways the current can flow around the circuit loop, the current feeding the fault will differ for each URCI. The direction with the higher current will trip its interrupter more quickly. To ensure that the URCI on the other side of the fault trips quickly and speeds fault isolation, the tripped URCI sends a signal to the URCI on the other side of the fault instructing it to open its interrupter.

4.3.2 Self-healing Distribution Circuits - Research Plan

4.3.2.1 Simulations

The team conducted simulations to verify the fault isolation logic, timing, and successful tripping of URCI devices under a wide range of operating conditions, including failure of equipment (N-1) configurations. The team used RTDS to conduct these simulations. The actual protective relay inputs and outputs (three phase voltages and currents, trip contacts, close contacts, and breakers status input) interfaced with RTDS.

4.3.2.2 Laboratory Tests

The team assembled and tested the technology components (e.g., relays and radios) before field installation to verify performance and proper functionality. The team imposed actual circuit fault conditions (derived from simulations) on the assembled components and recorded the protection system responses. The team also verified high-speed communication performance. This included assembling and testing the new substation automation system to verify the communications between the substation and the URCIs.

The team did not induce actual faults on the live circuit given the presence of customers on the circuit. Lab testing served as a proxy for this type of field testing. However, the team installed instrumentation to record any actual faults that occur on the circuit. The team expected that actual faults would provide additional verification of the design and operation of this advanced protection system.

4.3.2.3 Commissioning Tests

Prior to commissioning the self-healing circuit capability, the team verified the functionality of the system by validating the operation of the low-latency communication system and the URCIs in a bypassed condition. These tests were performed a number of times by simulating faults on each of the looped circuit segments. Since the URCIs would operate in bypassed mode, there would be no service interruptions to SCE's customers.

4.3.2.4 Field Experiments

The ISGD team performed the following experiments to evaluate the impacts of the sub-project 5 capabilities.

Field Experiment 5A: Self-healing Circuit

Since the circuits involved serve actual customers, no faults could be imposed on them to test proper operation of the URCI system in the field. This experiment consisted of monitoring and evaluating performance including during any faults which may occur.

Field Experiment 5B: De-looped Circuit

In this experiment, the circuits were to operate in a radial configuration to verify that the URCIs function properly under that configuration. A looped circuit may need to be de-looped to a radial configuration for test purposes, when high loads create the potential for cascading failure, or during other abnormal system conditions.

4.3.3 Self-healing Distribution Circuits - Summary of Field Experiment Results

Self-healing Circuit

The radios used in the ISGD project for establishing the communications necessary for URCI operation failed to operate satisfactorily. The available radios operated at 2.4 GHz and required more repeaters than expected. Securing permits from the city to install these repeaters proved extremely difficult. The radios themselves experienced a large number of lock-ups that required local action to reboot. All of these factors combined to prevent placing the URCI system in service during the field demonstration period. A subsequent root cause report from the supplier found that the radio chipset frequently locked up when changing from transmit to receive mode, and the supervising firmware did not automatically reboot under these circumstances. Revised firmware to correct this issue was not available in time for field installation and testing.

De-looped Circuit

Due to the radio issues described above, the Arnold and Rommel circuits were not operated in the looped configuration during the demonstration period.

4.3.4 Self-healing Distribution Circuits - Observations

4.3.4.1 Self-healing Distribution Circuits Lessons Learned

Low-latency Radios are in an Early Stage of Commercial Development

During the design and engineering phase of the project, the ISGD team identified no radio vendor that satisfied all of the project's requirements for this equipment and only one radio vendor partially satisfied the project's requirements for sub-project 5 (the self-healing distribution circuit). This limited the team's procurement flexibility. The team would like to see the vendor community develop radios with latency low enough to satisfy SCE's protection requirements, operate at a radio frequency with sufficient propagation characteristics to obtain adequate coverage (e.g., 900 MHz), and which communicate using the IEC 61850 standard. For the ISGD project, SCE used 2.4 GHz radios that satisfied the project's latency requirements, but did not have sufficient coverage. As a result, the project team used multiple radio repeaters to obtain the coverage needed to satisfy the project requirements. This was particularly challenging due to the terrain, distance, and permitting requirements for the demonstration location. The radios were located in an area with a high concentration of hills, buildings, and trees. The team had to install more radio repeaters than originally planned.

Permitting Is a Significant Challenge for Siting Smart Grid Field Equipment Outside of Utility Rights-of-Way

A substantial challenge faced by the sub-project 5 team involved obtaining the necessary permits for siting and installing field equipment (e.g., the pad-mounted cabinets for the URCIs and bypass switches, and the radio repeaters). The URCI field installation was delayed by several months as the team navigated the permitting process with the City of Irvine.

The team originally planned to affix all the repeater radios installed on SCE light poles, which are installed on city land pursuant to a license that restricts the equipment that SCE can install on them. After finalizing the repeater radio network design, the team met with the City of Irvine, which denied the installation of all the radios on the SCE light poles. The final design consisted of installing radios only on Irvine Campus Housing Authority and UCI property, since the project team was able to obtain permission to perform these installations. This required a larger number of radio repeaters than the original design, since the optimal locations on City of Irvine property were not available.

Permitting may represent a potential challenge to the broad scale deployment of smart grid technologies. Depending on the equipment required, the installation location, and the local jurisdiction's requirements, utilities may need permission from the local authority. If local jurisdictions do not actively facilitate siting, this may limit which smart grid technologies they can implement.

Radio Communications-assisted Distribution Circuit Protection Schemes are Difficult to Implement

Advanced communications-assisted distribution protection schemes require reliable communications links between distribution protection elements to shield equipment from damage. Several years ago, SCE demonstrated advanced communications-assisted protection using fiber optic links to the field elements, but found it to be costly and difficult to implement. As part of the ISGD project, the team attempted to demonstrate wireless communications for this purpose. Wireless has many potential benefits over fiber in terms of cost and installation time, but it also has challenges. During the process of installing and commissioning the wireless links for the URCIs, the team encountered several challenges. These included finding locations for radios and repeaters, obtaining permission for radio repeater installation (antenna aesthetics are important), unreliable communications links due to interference and obstructions and design of the network's topology so sufficiently low message latency can be assured. Unless the team can overcome these challenges, the more expensive fiber optic communications might be the only way to put these advanced distribution protection schemes into operation.

4.3.4.2 Self-healing Distribution Circuits Commercial Readiness Assessment

The team conducted an extensive search for radio systems with the range and low-latency needed to implement the URCI scheme. The only radios meeting the low-latency requirement operated in the 2.4 GHz band, which is not optimal for the distance and interference between URCIs. In addition, the radios experienced performance problems. The team limited its search for radio systems to those operating in an unlicensed band based on the need to keep costs low for distribution level equipment. The inability to establish a functioning system in the timeframe of this project indicates that appropriate radio systems are not yet commercially available.

4.3.4.3 Self-healing Distribution Circuits Calls to Action

Distribution system owners and operators may wish to pursue alternative solutions to distribution reliability and DER penetration in the near future other than the looped circuit scheme attempted in this sub-project.

4.3.5 Self-healing Distribution Circuits - Metrics and Benefits

Table 4 in chapter 2 summarizes the types of benefits that would result from this sub-project. There were no measurable metrics or benefits from this sub-project since the capability was not cutover to operations due to the challenges with the radios.

4.4 Sub-project 6: Deep Grid Situational Awareness

4.4.1 Deep Grid Situational Awareness - Technical Approach

4.4.1.1 Objectives

The objective of this sub-project was to demonstrate how high-resolution power monitoring data captured at a substation can detect changes in circuit load from a distributed energy resource (DER) such as demand response resources, energy storage, or renewables. This capability could help enable aggregators of such resources to participate in energy markets by providing a means of verifying resource performance. This capability would obviate the need for additional and potentially costly metrology equipment for each individual participating resource.

4.4.1.2 Approach

To fulfill this task, the team used a 2 MW battery installed on a 12 kV distribution circuit (the same DBESS used in sub-project 3) to perturb the load signal intentionally by dispatching the battery at various ramp rates and magnitudes. Synchrophasor data acquired at MacArthur substation, which feed the 12 kV circuit, were analyzed to see to what extent the DER perturbation (battery dispatch signal) could be isolated from the rest of the circuit load data. The plan was to run simulations to find a threshold (size of the battery or signal amplitude and/or ramping rate magnitude) that could be detected successfully at MacArthur Substation, a distribution-level substation. The MacArthur Substation relays were part of SCE's next generation of substation automation (SA-3) upgrade. These relays were equipped to provide high-speed data to a dedicated phasor data concentrator (PDC) at the MacArthur Substation.

The team reviewed several methods for phasor measurement data acquisition and analysis and identified an appropriate filter as a viable option for filtering the signal and removing noise. Noise, in general, is a corruption of the measurement that may be due to a number of phenomena including sensor inaccuracies, interference from other signals, and data processing errors. In this particular case, noise also includes the small magnitude and short duration distribution circuit-level load perturbations (e.g., switching large loads that are not the DER of interest on or off) that are not the large magnitude, longer duration perturbations that the algorithm is designed to detect. An adaptive filter approach is useful for sensing DER in the distribution system because it can adapt to variations that are typical on the circuit (e.g., diurnal load profiles that are characteristic but vary from day to day) so that data without DER dispatch can be retained and identified as "normal" (business as usual) circuit behavior.

The next step was to design an algorithm capable of forecasting the short-term filtered load signal when the DERs are not dispatched/charged. An artificial neural network (ANN) algorithm is appropriate for this purpose. An ANN algorithm is a type of statistical learning algorithm that can estimate or approximate functions that can depend upon a large number of inputs that are generally unknown. This is the case, for example, in distribution circuits with a large number of unknown loads for which on/off dynamics cannot be predicted a priori. The ANN algorithm can compute expected near term future values from a statistical understanding of previous inputs, and is capable of learning how the circuit typically varies, recognizing typical patterns due to its adaptive nature.

To fully implement this algorithm, a large amount of data was required to train the algorithm. This data consisted of phasor measurement data collected while the DER is not operating. During the second TPR period, the UCI team trained the algorithm with phasor measurement data covering one day from MacArthur Substation. The team then used this data to implement and train a preliminary ANN algorithm and to show how the algorithm would work.

The final step was to separate the battery signal from the filtered signal (without noise), in other words, to detect a change in the signal that is associated with the dispatch/charging of the battery. To accomplish this, the team performed various tests to study the overall change in the signal collected by synchrophasor measurements under various dispatch and charging operations of the battery.

The overall approach was to 1) pass the load signal collected by synchrophasors through an appropriate filter to remove the noise in the signal, 2) use an ANN to forecast the signal, and finally, 3) determine if DER operation has occurred. If the collected signal was similar to the forecasted one, DER has not operated. If the actual and forecasted signals were significantly different, DER operation has occurred. Comparing the determinations made by this data analysis to the know operation of the 2 MW battery should allow the team to assess the algorithm's capabilities and limitations.

4.4.2 Deep Grid Situational Awareness - Research Plan

4.4.2.1 Field Experiments

The ISGD team performed the following experiment to evaluate the impacts of the sub-project 6 capabilities.

Field Experiment 6A: Verification of Distributed Energy Resources

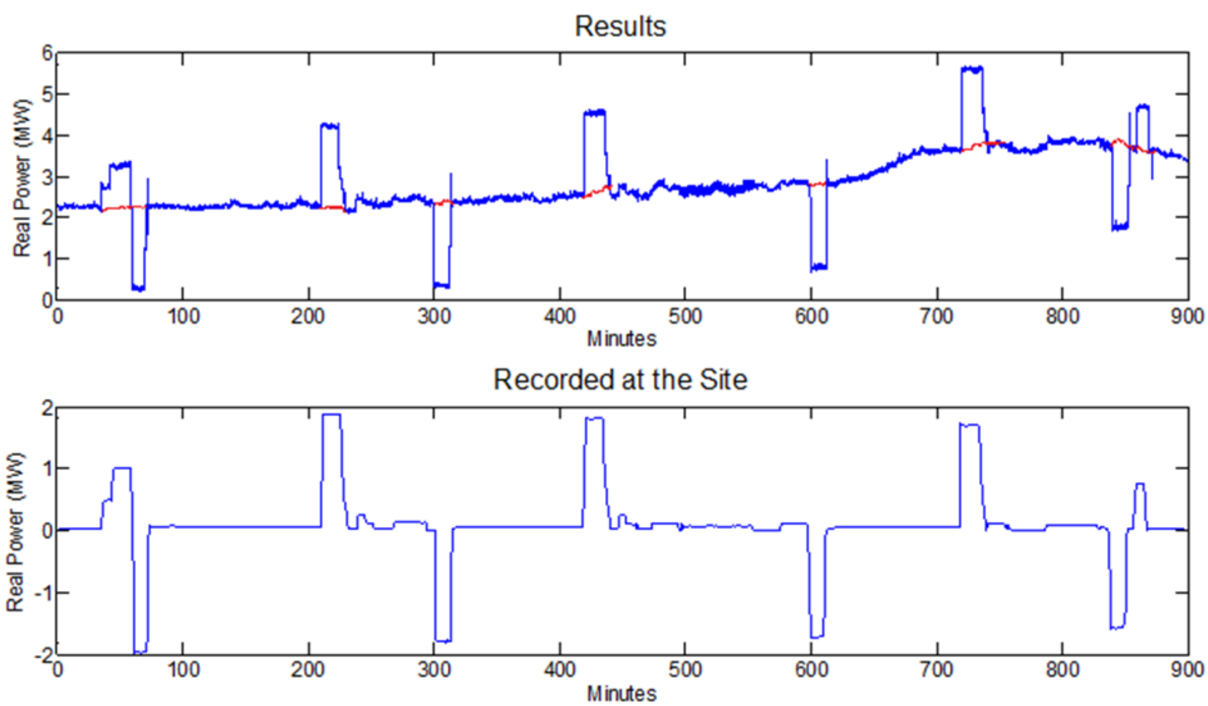
This experiment consisted of operating a 2 MW battery powered inverter to produce load changes of various magnitudes and durations, and at various ramp rates. The magnitude of these changes were up to 4 MW, spanning from a maximum charge rate of 2 MW to a maximum discharge rate of 2 MW. UCI then analyzed high-speed data from MacArthur Substation and attempted to identify the specific load change resulting from operation of the 2 MW battery. A comparison of the DER operation detected at the substation by the algorithm to the known charge and discharge operation of the battery was used to determine the viability and limitations of this method.

4.4.3 Deep Grid Situational Awareness - Summary of Test Results

Verification of Distributed Energy Resources

A wide range of magnitude and ramp rates of both charging and discharging the battery allowed calibration and testing of the UCI algorithm. The algorithm is described in Appendix 7. The chart below shows an example of the processed signal for the Arnold circuit from the substation PDC against the locally recorded battery activity.

Figure 14: Field Experiment 6A



This example shows DER activity so large as to be obvious, but overall the test program determined that DER activity was reliably detected down to the level of 250 kW in the presence of 3 MW circuit loading. With more tuning of the algorithm constants, and for longer duration operation of the DER, it appears this limit could be reduced to as little as 50 kW.

4.4.4 Deep Grid Situational Awareness - Observations

4.4.4.1 Deep Grid Situational Awareness Lessons Learned

- Overall the synchrophasor data are quite reliable; however calibration tests are required.
    - Data should be collected before a DER is installed in a circuit and after installation, several tests should be performed to calibrate the parameters of the filter and neural network for that specific DER and its physical characteristics.
    - Operation of the battery at 250 kW and higher was detectable.

    - A combination of DER size and the duration of its operation determines whether it can be detected or not.
    - DER detection has lowest accuracy during the times in the day when the gradient of power is high (e.g., before the afternoon peak)
    - DER operation with very slow ramp rate cannot be detected
- PMU data collected at 30 samples per second were used in detecting a DER; however, whether high resolution of data is necessary or higher resolution results in better outcome has not been established in this research.
- The current method could establish a criteria for the utility or the ISO to accept these resources to participate in the market or be compensated for the services they provide to the grid without additional measurement. More tests and analysis on other circuits, however, are required to verify the results.
  This ANN method is computationally intensive so it is recommended that a simpler method such as step detection algorithms be used in real time with ANN used to "verify" the dispatch.
- As the number of DERs increase on a circuit, it is necessary to add a pattern detection component to the algorithm to distinguish different DERs.
    - This can be done by identifying the "footprint" of DERs on various components of the circuit. As was shown here, the battery also impacts the reactive power at the substation in a specific way that "might" be unique to technology type.
    - If there are two or more similar DERs on the same circuit, a statistical approach needs to be added to the methodology to determine the probability of each of these DERs contributing to the change in the signal observed.

This method is an alternative to metering the DER at their location. Synchrophasors in general are used for system reliability and using them for DER detection can be an added bonus; however, synchrophasors only record and keep the data associated with an "event", using them in the manner specified here requires keeping the data and analyzing it. This cost should be compared with the cost of direct metering to weigh pros and cons.

4.4.4.2 Deep Grid Situational Awareness Commercial Readiness Assessment

The use of synchrophasor technology for reliably detecting the performance of aggregators and thus facilitating their participation in the market is promising, but much work needs to be done before it can be considered ready for commercial deployment.

4.4.4.3 Deep Grid Situational Awareness Calls to Action

Regulators should encourage exploration of various means of facilitating the participation of aggregators in the market. Synchrophasor technology, while a possible solution, appears to require much more development before it can be considered commercially viable.

4.4.5 Deep Grid Situational Awareness - Metrics and Benefits

There are no metrics or benefits associated with this sub-project.

5. Interoperability & Cybersecurity

The electric grid is evolving to include an increasing number of distributed and interconnected grid resources, both utility and customer-owned. The need for near plug-and-play interoperability within a secure environment is therefore of critical importance. This project domain is a foundational element that underpins the development of smart grid capabilities. The ISGD team evaluated interoperability and cybersecurity through sub-project 7, which was composed of two elements: Secure Energy Network and Substation Automation 3.

The early deployment of information and communication technology in utilities, much as in business in general, followed a host-RTU (remote terminal unit) architecture, with communication between a mainframe host computer and RTUs flowing over a hierarchical radial network. This resulted in SCADA systems that were purpose built, stand alone and siloed. For example, substation RTUs were connected to a mainframe host Energy Management System (EMS) while Automated Meter Reading consisted of individual automated meters similarly connected to a mainframe via radios. As computing power shrunk into smaller devices such as desktop computers and Intelligent Electronic Devices (IEDs), peer-to-peer networks and client-server architecture emerged. The special purpose siloed systems made it difficult to integrate new functionality requiring communications across silos, both physically and in terms of protocols which were often proprietary.

The net result is a challenge in three parts: (1) How to achieve greater interoperability, (2) How to ensure cybersecurity when "everything can talk to everything," and (3) How to migrate from the old architecture to the new one. The two sub-projects in this domain explored these questions (and their many sub-questions). SENet explored the system wide network architecture using routable protocols and an innovative approach to a CCS. The SA-3 project pioneered the deployment of Edison's third-generation substation automation system focusing on the IEC 61850 standard. Some of the questions asked included:

- Can an Enterprise Service Bus (ESB) effectively integrate information from a diversity of systems into an integrated situational awareness display?
- Can the CCS software be deployed on a variety of client platforms supported by a common CCS server effectively?
- Can the Multiprotocol Label Switching (MPLS) approach taken in SENet provide the performance expected and required?
- Can the integration of legacy systems be accomplished in a process that supports planned, systematic migration?
- To what extent are "61850 compliant" devices for the substation truly interoperable? Where they are not fully interoperable, how difficult is it to overcome inconsistencies?
- What lessons are there to be learned in deploying such advanced systems?

5.1 Sub-project 7: Secure Energy Net

5.1.1 Secure Energy Net - Technical Approach

5.1.1.1 Objective

The objective of SENet was to implement a secure communications and computing architecture to enable the interoperability of all ISGD sub-projects throughout the project lifecycle. The legacy Control Network System utilized a host-RTU architecture, which largely relies on physical separation of the network from other less critical networks such as the Administrative Network. This limits the interoperability required for many Smart Grid applications. SENet demonstrated a routable client server architecture achieving security through a Common Cybersecurity Service that utilizes encryption, authentication and related features.

5.1.1.2 Approach

Secure communications between smart grid devices, the utility, and customers is a basic requirement and fundamental enabler of smart grid functionalities. The smart grid requires information sharing between many utilities and system operators, across electric reliability regions, to support the U.S. energy policies described in the 2007 Energy Independence and Security Act, Title XIII. A secure telecommunications infrastructure linking regional transmission and utility operations across the U.S. and North America will provide the essential information technology backbone for a smart grid.

Information demands include not only those from the utility to support operations, but also from customers and third parties looking to support their own near real-time decision making needs such as DR.

Smart grid sensing and control devices require secure communications capabilities between utilities' central control centers and offices, across backbone networks out to the new in-substation networks, field area networks (FAN), and HANs. Finally, since the requirements for secure utility communications are emerging and evolving, a key challenge facing utilities is meeting these security requirements in a way that allows flexibility and avoids having to replace IT infrastructure repeatedly.

The ISGD team designed SENet to include five communications network domains. (ISGD also uses certain legacy networks such as CNS, 3G AMI, public internet and Netcomm that are not part of SENet per se. SENet does include firewall and segmentation services to integrate these networks). These communications networks utilize emerging technologies categorized in four groups of capabilities that SENet should demonstrate. These communications networks and capability groups are described in additional detail below.

The ISGD team designed a secure telecommunications infrastructure linking the following five network domains:

1. Intra-utility Network: This network connects back-office data systems with grid control centers and to substation gateways. It also supports control, protection, and measurement functions using a high-speed fiber backbone leveraging MPLS (Multiprotocol Label Switching) routers.
2. Substation Local Area Network: This provides communications between devices within a substation that support control, protection, and measurement functions for substation automation.
3. Field Area Network: This provides communications between a substation, circuit-connected devices, and HANs. This network supports wireless broadband, protection, and interfaces to the Intra-Utility network.
4. Internet and Public Carrier: This network provides non-critical monitoring data such as energy related information exchange over secure connections. This network may use wireless carriers and commercial Internet providers.
5. Home Area Network: This network connects to customers' two-way devices to send, receive, and collect energy information. Gateways within the customer premises will provide connectivity to diverse networks.

To help satisfy the SENet objective of providing a secure communications and computing environment for ISGD, the team has implemented emerging technologies in the following four capability groups.

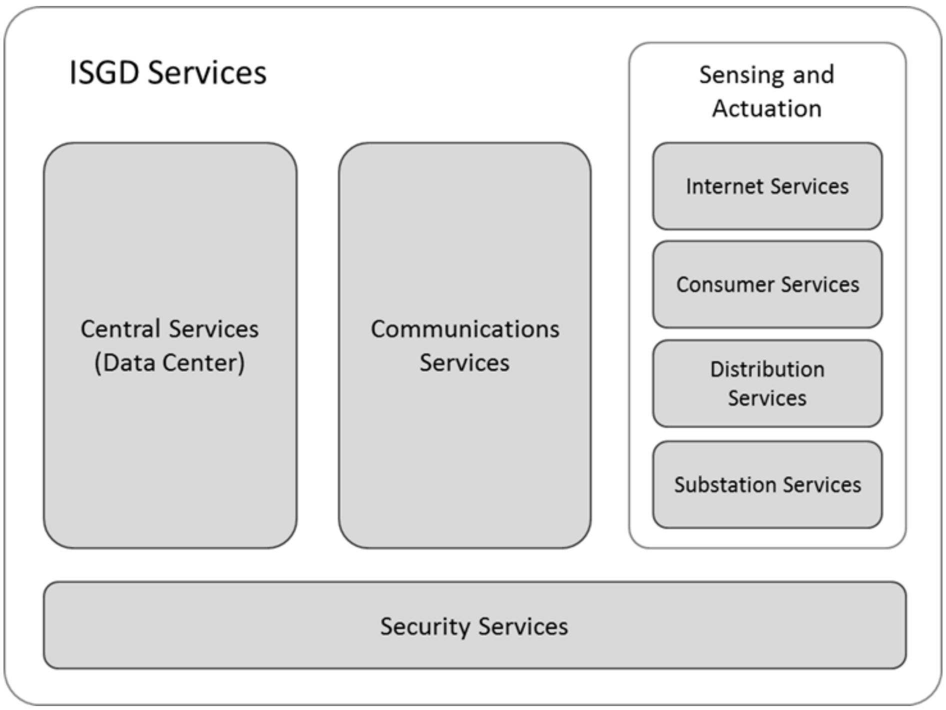
1. Modern Infrastructure and Communications: Implement and test the viability, compatibility, and resiliency of next-generation networking protocols, and deploy grid control applications on modern, virtualized platforms, to enable faster detection and resolution of issues, while minimizing down time to business operations.
2. High-Assurance Cybersecurity: Implement advanced security across the various smart grid domain networks. ISGD has implemented SCE's Common Cybersecurity Services (CCS) platform, which the team expects to be scalable for a mature smart grid environment.
3. Standards-driven Interoperability (communications and interfaces): Utilize standard system interfaces and communications protocols, where possible, to facilitate integration and interoperability between back-office systems and field components. ISGD has implemented a services oriented architecture using GE's Smart Grid Software Services Infrastructure (SSI) as a services integrator and broker, enabling interoperability across multiple vendors' software applications.

4. Visualization: Enhance situational awareness by facilitating real-time decision making as well as after-the-fact investigation of catastrophic events by co-relating data elements from a disparate set of data sources, both historical and real-time, to serve a unified view to grid operations.

5.1.1.3 Design

ISGD used a structured systems engineering process that began with developing a logical architecture of system services. The team then decomposed service domains into lower level service components to develop system specifications and interfaces. Each new level of decomposition inherited the requirements of the higher-level service (within the logical structure), resulting in clear traceability and interoperability across components with shared services. **Figure 15** shows the grouping of functional services into seven domains, each representing different logical processing environments.

Figure 15: ISGD Services Domains



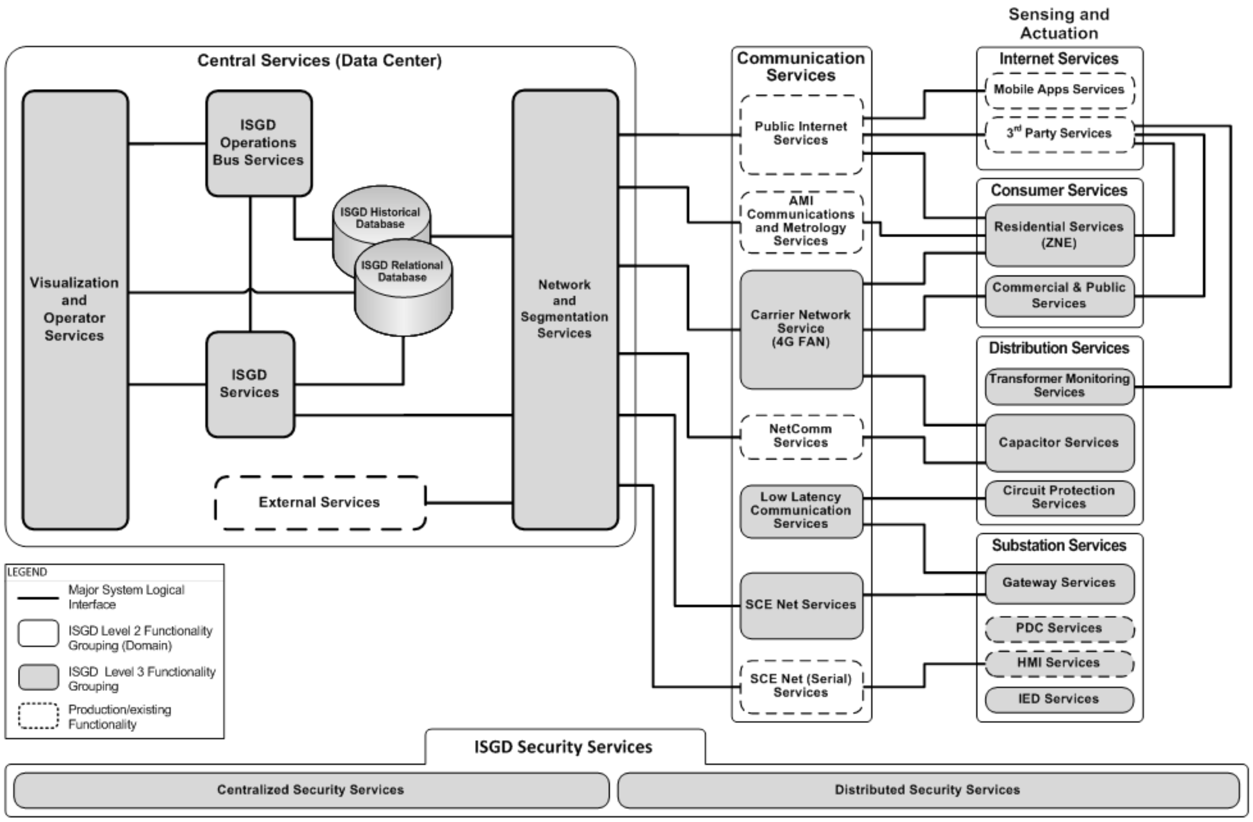
Security is a foundational service, which supports the other service domains. A general design principle was to share resources and services wherever possible, including the areas listed in **Table 15**.

Table 15: SENet Resources and Services Sharing

Functional Area	Technology Sharing or Reuse
Computing	• Server operating system virtualization (VMware)
Networking	• Packet switched networks (Internet protocols) • Multiprotocol Label Switching (MPLS)
Storage	• SAN (storage area network) • Relational Database Management System • Time-series data historian (point/time/value)
Integration	• Web service application containers/platform • Queuing

Figure 16 shows the second level decomposition of the ISGD logical system architecture.

Figure 16: ISGD Logical System Architecture



Decomposing the ISGD services domains into more discrete services, defining their requirements, and preparing detailed designs for each component provided the basis for selecting systems, equipment, and applications. Designs were prepared for each component, including processing, storage, and communications.

The resulting ISGD physical architecture was complex, and included over 100 applications and 50 integrations (i.e., information exchanges between components).

Interoperability

ISGD attempted to implement smart grid protocols and interfaces wherever possible to support interoperability and to help facilitate integration. The level of standards adoption was an important consideration when selecting products. The following table lists the primary smart grid and other general-purpose standards specified and used by SENet.

Table 16: ISGD Use of Interoperability Standards

Standard	ISGD Use of Standard
IEC 61850	IEC 61850 was used for substation device configuration and communications. GOOSE messages were used for high-speed transfer of events between URCIs and the substation gateway.
IEC CIM (61968/61970)	ISGD used the Common Information Model for integrating data from measurement devices. Primarily, some of the schemas in the central database were CIM-based. In addition, a set of CIM-based views allowed for reading retrieval from various systems in a consistent form.
ZigBee Smart Energy	The programmable communicating thermostats, plug-in electric vehicle chargers, and smart appliances receive demand response event signals to automatically reduce consumption during peak periods.

Standard	ISGD Use of Standard
ICCP	The Inter-Control Center Communications Protocol (ICCP or IEC 60870-6/TASE.2) was used to exchange capacitor, transformer, and URCI data between the ISGD DMS and production systems.
DNP3	This protocol was used by the ISGD DMS for measurement and control data to and from capacitor bank controllers and the CES device and by the EMS substation SCADA system.
IEEE 802	This was used for wired (802.3) and wireless (802.11) networking in all ISGD communications links.
IETF Standards	Many internet protocols were specified by IETF RFCs (Internet Engineering Task Force Request for Comments). Such standards include IPv4, IPsec (Internet Protocol Security), HTTP, etc. These standards were used throughout ISGD for all IP-routable communications.
W3C-WS-* (or REST)	HTTP, SOAP (Simple Object Access Protocol), and XML (Extensible Markup Language) for web services interface definitions, were used in several exchanges between back-office servers, and with "cloud" services including On-Ramp, TrendPoint, ALCS, and SSI.
Smart Grid Software Services Infrastructure	Visualization, reporting, and analysis integration retrieved data using Structured Query Language (SQL).

Enterprise Service Bus Overview

An enterprise service bus (ESB) is a software architecture model used in corporate environments to integrate multiple disparate software applications and systems. The cost of this integration can be prohibitive when each application or system requires a separate and unique interface. An ESB addresses this problem by using a Common Information Model (CIM) to support standard interfaces such that each application can communicate with each other through the ESB, which acts as an interpreter. An ESB should enable easy integration and secure, standards-based interoperability of third-party products and legacy systems, providing an ecosystem for smart grid operations. The key benefits of an ESB include:

- Increases flexibility (easier to adapt to changing requirements)
- Moves from point-to-point solutions to enterprise deployments
- Emphasizes configuration while reducing integration coding
- Leverages legacy systems to participate in future architectures

As utilities consider incorporating an ESB into their smart grid roadmaps, they should evaluate the following priorities to determine whether an ESB architecture is appropriate.

- Distributing information across the utility enterprise (including the grid control center), quickly and easily
- Creating a unified architecture among multiple underlying platforms, software architectures and network protocols
- Providing flexibility to accommodate future smart grid applications (both planned and unforeseen)

The level of effort required to integrate the ESB with legacy systems can be significant. Once a utility invests in an ESB, it should ensure that it has both the in-house skills and third-party vendors mature enough to realize the full potential of an ESB. This recommendation is discussed in detail in 5.1.3.3.

Enterprise Service Bus Role within ISGD

SCE implemented GE's SSI as an ESB for ISGD. SSI supports high-speed command and control of a fully integrated smart grid with interoperability and cybersecurity. SSI is based on a service provider framework that enables modular applications to "plug in" to the infrastructure using well-defined, IEC CIM-driven services (such as IEC 61850, IEC 61968, IEC 61970, etc.). Adapters were developed and implemented to interface with legacy systems that do not conform to standard service definitions. These adapters were available as standard adapters from SSI, or were prepared by GE or SCE. SCE demonstrated the following services using SSI:

- Advanced metering infrastructure
- Transformer monitoring
- Home area network access via Internet
- Advanced load control
- Power outage/restoration messaging
- Distribution automation

ISGD's SENet architecture is comprised of both new and legacy devices and information systems. The legacy systems may use a variety of standards and protocols as well as proprietary technologies. The SSI adapters enable interoperability among these devices and systems. The adapters translate communications protocols as well as data formats between systems, regardless of which hardware platforms and operating systems they run on. In addition, the SSI adapters, in conjunction with SCE's Common Cybersecurity Services, enforce the correct level of security to the connected systems at the point these systems interface with SENet.

ISGD's SSI implementation centered on creating a data store called the ISGD central database. This store serves as the basis for applications to exchange data. The team used SSI as an execution platform in which applications retrieve and store data in the database. Storing data in the database was an integration approach, but it also supports ISGD's advanced visualization capabilities. SSI was used to access various services, retrieve data, and serve the data to a situational intelligence visualization service. This service provides a single operational view from multiple systems, allowing the team to visualize grid conditions using multiple data sources. This constitutes a lesson learned, which is discussed in detail in 5.1.4.1.

The SSI integration toolset integrates devices, applications, services and processes, which supports interoperability and secure communications across ISGD. SSI incorporates the emerging National Institute of Standards and Technology (NIST) smart grid standards across ISGD, while providing the flexibility to upgrade, extend, and scale the solution in the future so that the system can evolve as standards and technology evolves. The translation of communication protocols and data formats from legacy systems to SSI interfaces demonstrates an incremental migration path that allows the systems to mature and evolve, while also accommodating new system components to interact. It is likely that adapters will be developed for the most common standards, and that these will be reusable across the industry.

Cybersecurity

As is the case in many industries, the cybersecurity landscape for utilities is changing rapidly. Increased use of automation, and the communications that support it, brings a new class of adversary and more malicious threats. A cybersecurity solution is needed that will keep pace with the latest technologies, supporting current and future as well as legacy systems and devices. It must support all application architectures, comply with all relevant standards and regulations, and enable operational efficiency through reuse.

SCE recognizes that redundant services (such as databases and web services) have the potential to create incompatibilities and duplicative expense. SCE has defined security as a common service, and implemented it using a common platform for most ISGD applications. The solution met all project objectives, and SCE is implementing CCS more widely within the enterprise for additional locations and functions.

ISGD's security services were provided by SCE's Common Cybersecurity Services platform. CCS is a specification developed by SCE following cybersecurity guidance from NIST, NERC, DHS, and FIPS. All of the underlying protocols are public specifications from IETF and other standards bodies. The list below provides a brief overview of some of the standards used.

- Public key infrastructure (PKI) – Security certificate management
    - Simple Certificate Enrollment Protocol (SCEP) – Certificate issuance, revocation
- Network Configuration Protocol (NETCONF) – Network interface configuration management

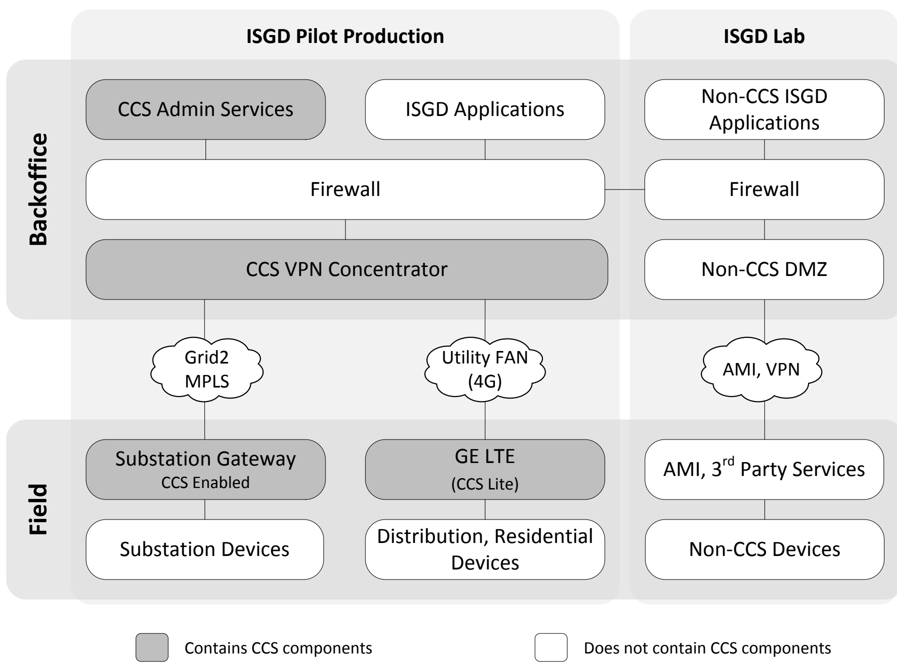
- Internet Protocol security (IPsec) – Secure communications path establishment
    - Internet Key Exchange (IKEv2) – Mutual authentication and security associations
    - Encapsulating Security Payload (ESP) – Header encapsulation for security functions

IPsec was used to create virtual private network (VPN) tunnels with session encryption keys, through which all application communications are transmitted. Since these keys change rapidly, even if a session key is obtained using brute force, only the communications sent in that session could be decrypted, and it would take a long time to obtain it due to the key size, so the information would be quite old. Each end node is given a unique identity certificate, so that network traffic can originate in the field or in the back office, and still provide the following protections.

- Confidentiality – Network communications are encrypted with strong cryptography
- Data Integrity – Changes to communications are detected and quarantined
- Authentication – Communications from untrusted sources are rejected
- Access Control – Authenticated identities can be used to determine permissions

The following figure provides an overview of ISGD's system security architecture. This figure includes a number of abbreviations that are defined in Appendix 1.

Figure 17: ISGD System Security Architecture



The system security architecture diagram shows that network communications between devices in the field and servers in the back office using the Grid2 and Utility FAN networks are protected by CCS. The communications are encrypted by the connected CCS endpoint (either VPN Concentrator, substation gateway, or GE LTE), transmitted across the network, and then decrypted by the CCS endpoint on the other side. The system supports MPLS, which allows for expedited routing through the network. Communications outside of the VPNC tunnels are protected by other electronic and/or physical security.

Applications that provide their own network services make it more difficult to use CCS. For these applications, OnRamp Transformer monitoring and the AMI system for ISGD, the native security implemented by the application system is used instead of CCS, and they are also guarded by a DMZ. The DMZ (demilitarized zone / perimeter network) guards internal networks and services from intrusions by external entities.

Centralized control of back office and edge device security is one of the key features of CCS. Through a central management console, operators can see all managed devices along with their quality of trust, providing awareness of and allowing response to cyber-attacks. **Figure 18** shows a view of the central management console.

Figure 18: Common Cybersecurity Services Management Console

Administrative operations, such as changes to credentials, network routing, or other network configurations, are carried out using a control plane separate from the data plane, with separate credentials and security. These can be thought of as separate channels within the network infrastructure. This separation allows for centralized recovery and control of credentials and configurations, even in the case of compromised devices. For example, if the configuration of a device is changed without authority, it is no longer trusted until it can be updated to an authorized configuration. The quality of trust of each communication link and device are tracked and managed centrally, providing the information needed in order to isolate and defend against attacks.

Additional aspects of the ISGD security solution include the following:

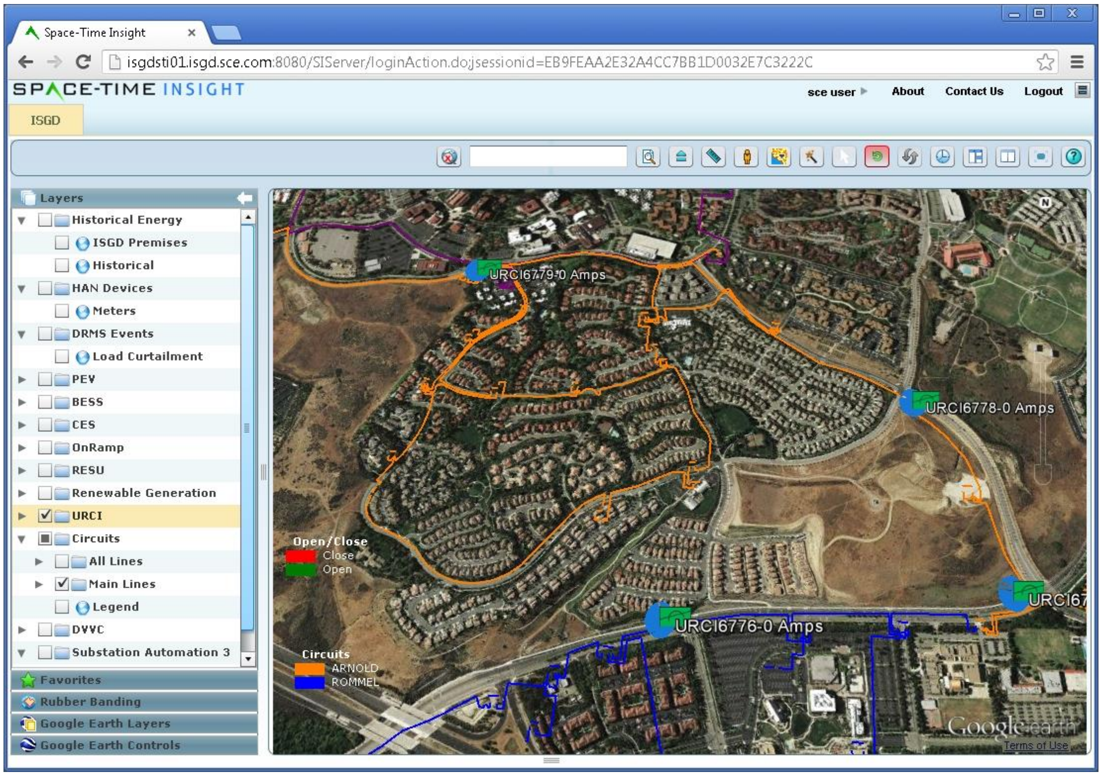
- No shared accounts or passwords are allowed
- Each user session requires authentication (proof of identity, via password and/or additional factors)
- Passwords must change periodically and meet minimum complexity requirements
- All unnecessary services are turned off, such as communications ports for unused remote access methods
- All communications take place over secured channels; all other channels are blocked
- Communications traffic is denied by default, and only allowed if it is specifically enabled
- Default accounts are removed or changed so that no simple or shared passwords exist
- Access to devices via external interfaces is explicitly controlled using CCS-provided, device-specific certificates, unique IDs, connection configuration files, and firewall rules
- Industry standards are used to harden client and server operating systems to prevent “back door” access and changes to installed software

The Information Sciences Institute (ISI) of the Viterbi School of Engineering, University of Southern California, reviewed the key documents defining the ISGD security solution. The team incorporated recommendations of this ISI Report as appropriate.

Visualization

Most ISGD applications (e.g. ALCS, AMI, CES, RESU, BESS, and TrendPoint) have graphical user interfaces containing views of system measurement trends, system data, and configuration. The ISGD team also implemented a visualization application that provides integrated views of the various ISGD components in operation. ISGD is using this application for demonstration purposes only. Although it would be possible to build controls into this environment, ISGD is only using it as a situational awareness tool. **Figure 19** provides a sample screen view from the visualization application.

Figure 19: ISGD Visualization System Sample View



5.1.1.4 Deployment

ISGD is using two environments for SENet.

- Lab Test Environment: This environment resides within SCE's Advanced Technology Labs. Test equipment was assembled and configured to resemble the production environment, to the extent possible.
- Pilot Production Environment: This environment resides within an existing grid control center, within a new network domain.

The team used both environments to conduct three phases of testing per system. The team performed each series of tests in the Lab Test Environment before performing them in the Pilot Production Environment. The systems were accepted and commissioned only after all tests were either successful or withdrawn.

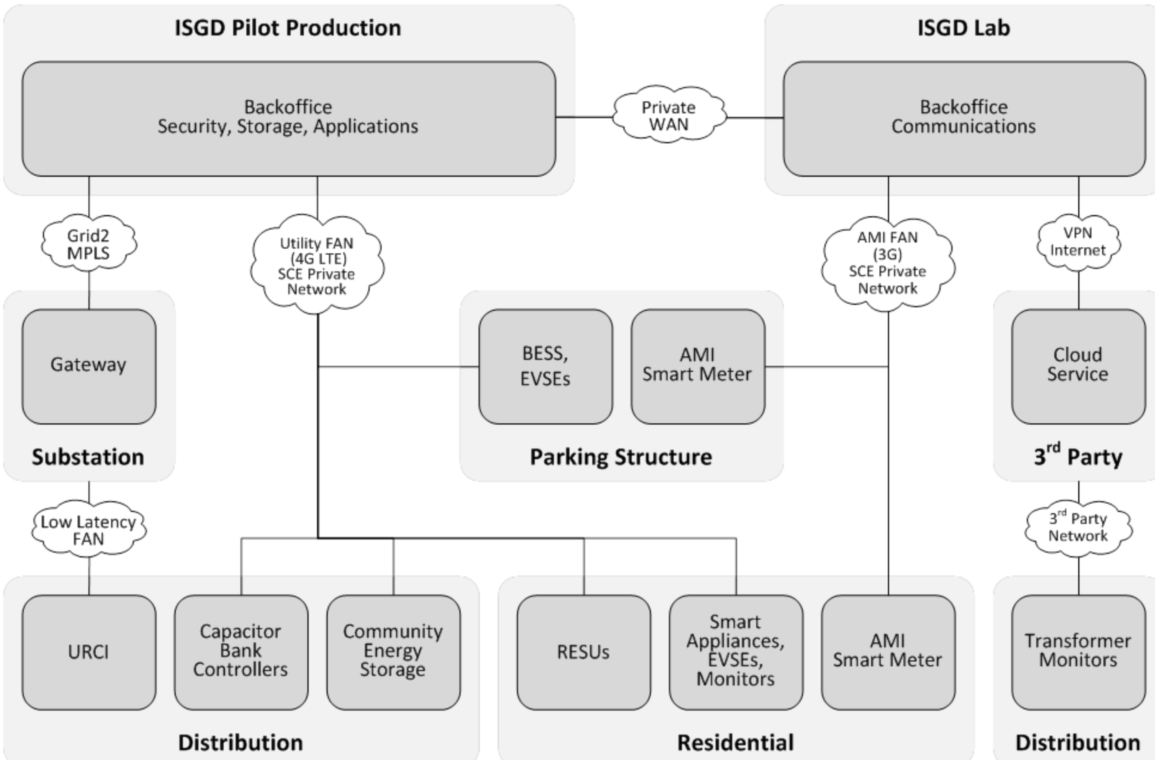
- Component Testing was performed by the component developer. All tests were documented and issues were identified prior to attempting any testing with other components.
- String Testing involved testing data flows between components, starting with simple exchanges, and then progressing to more complex or longer scenarios.
- End-to-end Testing helped the team to verify that business requirements were satisfied with all equipment, communications, and required functionality.

In addition to the above testing, in certain cases the team performed simulations in order to run scenarios that would be difficult or impossible to run with the actual equipment in the field.

Network Infrastructure

Figure 20 provides an overview of the equipment, locations, and network links involved in the system.

Figure 20: ISGD System Network Infrastructure Overview



Customer Home Area Network

HAN devices in the customer premises and plug-in electric vehicle chargers at the Solar Car Shade parking structure both support the Smart Energy Profile 1.x (SEP 1.x) protocol. These devices are capable of receiving demand response signals through project smart meters, or through a home energy management gateway device, which receives the signals through a project smart meter. The home EMS is used in the sub-project 1 customer homes (not the solar car shade). The home EMS is a gateway that may be joined with a customer Wi-Fi network to allow controlled access to HAN devices via a customer device using a smartphone app. This gateway may also use a public carrier secure connection to store data from the HAN devices on a “cloud” home EMS server (if the customer elects to register with the home EMS vendor for this service).

Field Area Network

There are four field area networks: the 3G AMI FAN, the 4G Utility FAN, the Low-Latency FAN, and the legacy Netcomm radio network.

The AMI FAN is a secure radio frequency (RF) mesh network with an SCE private network over a 3G wireless public carrier backhaul, using a demilitarized zone (DMZ). The DMZ is a network set up specifically to provide only the functionality needed for communications to external systems (in this case, the AMI system), prevent unauthorized access, and pass authenticated electronic communications along to back office systems in higher security level networks. This network provides communication of usage measurements from project smart meters and EVSE sub-meters, and demand response event signals.

The RESUs, CES, BESS, and TrendPoint circuit monitoring systems are securely connected to the back office via the Utility FAN (an SCE private network over 4G public carrier backhaul). This Utility FAN provides a secure, high bandwidth connection for transmitting data with higher sample rates, and for sending frequent commands.

The Low-Latency FAN connects the URCIs, which are outside of the substation, to the substation gateway. The Low-Latency FAN uses a secure RF network with an access point on the URCI LAN at the substation. Devices on the Low-Latency FAN communicate through the substation gateway to the ISGD Pilot Production network. These FAN devices and networks support enhanced situational awareness of the distribution system. The Netcomm radio network supports the field capacitor controllers for DVVC and the Remote Controlled Switch (RCS), which makes and breaks the looping of the Arnold and Rommel circuits.

Internet

On-Ramp Wireless devices monitor the distribution transformers on each of the four blocks of customer homes. These devices connect to the vendor's cloud server via a secure wireless network. The ISGD Vendor DMZ retrieves data from the cloud server using a site-to-site VPN over the public Internet. The ISGD Vendor DMZ provides a secure connection to the ISGD back office systems.

Substation LAN

The substation LAN supports control, protection, and measurement applications for devices located within MacArthur Substation. The substation gateway provides support for legacy and proprietary systems, potentially handing all Ethernet communications to and from the substation connections. Devices on the substation LAN can connect with legacy communications links (principally the EMS SCADA) via the substation human-machine interface (HMI) to support both channels during testing.

Intra-utility WAN

Devices connected to the Intra-Utility wide area network (WAN) high-speed backbone have fiber connectivity to other such devices, substations, and head-end systems in data centers and grid control centers. The high-speed backbone supports control, protection, and measurement applications with MPLS, DMZs, and VPNs to assure the integrity and confidentiality of ISGD data/control from other SCE users on this backbone.

Computing and Storage

Hardware

The ISGD project used 16 blade servers with storage area network (SAN) storage as the main computing environment in the back-office. The Lab Test and Pilot Production back office environments had similar hardware. ISGD is also used online and tape backup equipment, network switches, routers, management and monitoring equipment, a virtual desktop user interface server, and two additional rack-mounted application servers.

In addition to the back-office locations (Lab Test and Pilot Production), the project installed equipment in MacArthur Substation, on two 12 kV circuits fed by MacArthur Substation, in the project neighborhood and participant homes, and within the Solar Car Shade parking structure.

Software

Table 17 summarizes the major software applications used for ISGD.

Table 17: ISGD Software Applications

Application	Functionality
Circuit Monitoring	Monitors energy usage on multiple circuits within a home. Supports analyzing the effect of smart appliances and other energy efficiency measures.
Demand Response	Manages, dispatches, and tracks DR events and programs.

Application	Functionality
Advanced Metering Infrastructure	Captures 5-minute directional usage and voltage from smart meters, and supports ZigBee Smart Energy 1.x for sending DR signals to smart appliances.
Residential Energy Storage Unit	Contain energy storage and inverters for the rooftop solar panels.
Battery Energy Storage System	Paired with 20 electric vehicle charging stations and a rooftop solar PV system to support PEV charging.
Community Energy Storage	CES is a distribution scale battery for peak shifting, islanding, and other functions. It can be controlled by remote Distributed Energy Manager (DEM) software.
Transformer Monitoring	The On-Ramp Wireless system provides transformer measurements securely over the Internet.
Substation Gateway	The substation gateway provides an interface between the back office FAN and substation LAN. Functionality includes configuration management, password management, remote access, and data to the historian.
Distribution Management System and Energy Management System	Model the distribution and bulk power systems to provide a variety of operational functions. The URCI and DVVC functions were added for ISGD.
Universal Remote Circuit Interrupter	URCIs provide self-healing functionality to preserve power to segments of a looped circuit not containing a fault.
Distribution Volt/VAR Control	Operates in the ISGD DMS system to optimize voltage by controlling capacitor banks based on monitored grid inputs.
Enterprise Service Bus	Integrates AMI, meter data services, TrendPoint, On-Ramp Wireless, BESS to Oracle for visualization.
Visualization	Contains custom views of project data integrated within Google Earth.
Cybersecurity	See section 4.3.1.1.2 for a description of the cybersecurity functions.
Operating System	Manages physical resources (memory, disk, and network) for the software resources running on the hardware.
Relational Storage	Stores general-purpose tabular data.
Data Historian	Stores numeric values as time-series data.

5.1.1.5 Design Considerations and Findings

The ISGD design went through a number of revisions during design and engineering phase. This section describes aspects of the design and implementation that required the team to consider alternatives and the associated tradeoffs.

Field Area Network Backhaul (4G)

Secure and reliable communications with field devices is a critical foundational element of a smart grid. Communications networks typically require a combination of technologies, depending upon the number of communicating nodes and the required bandwidth. Mesh networks are often cost-effective if the nodes are close enough together. Mesh networks allow multiple devices to share a longer-range backhaul communications links, potentially avoiding duplicate expenses.

- Short range, broadcast: Wi-Fi, Wi-Max, and other home area wireless networking technologies, as well as home wired standards such as Ethernet, are appropriate over short distances, or longer distances if linking them together with a mesh network. However, long-range, point-to-point links are necessary for transferring large amounts of communications traffic from central servers to these network devices.
- Long-range, point-to-point: Fiber-optic, copper, point-to-point wireless (using parabolic dishes), satellite, line-of-sight optical, and cellular (3G or 4G) communications can all support long distance communication. However, these technologies may be expensive to install, and/or could require a service provider with monthly

fees. Certain applications may be able to justify exclusive using this type of communications (applications used for grid control, for example). But for general-purpose coverage, sharing these links may be necessary.

A number of factors contribute to the preferred FAN design, including bandwidth and latency requirements, existing spectrum and other communications infrastructure, technology maturity, and capital investment constraints. The design needs to balance cost, performance, and schedule requirements.

The ISGD team elected to use a dedicated 4G LTE cellular data backhaul due to its versatility, technological maturity, coverage, cost, and availability. Since deploying this 4G network, the team has found that 4G provides more bandwidth than most smart grid applications require; 3G may be viable in some scenarios. Future projects may explore the use of mesh networks (e.g. Wi-Fi or Wi-Max) in addition to 4G communications.

Hardware and Environment

Wireless communications are sensitive to a number of environmental factors. Achieving consistent and reliable connections requires attention to a number of factors, including the following:

- Optimization of radio and antenna placement
- Use of external antennas or repeaters in areas with low signal strength
- Antenna extension cables of the correct length
- Power supply and correct circuit protection sizing
- Regulation of temperature to rated limits
- Control of dust and humidity
- Interference or signal degradation from enclosures
- Disruption of transmission due to reflections from walls and other objects

Radio form factor is another design consideration. In general, smaller enclosures are more expensive, while large enclosures may be difficult to fit within existing equipment. Weatherproofing and physical security is required if equipment is outside.

Multiple components span the communications paths between field devices and back office systems. Such components include incoming links to communication rooms, internal networks and security components (e.g., switches, routers, firewalls, VPNs, and the connections between them). These components each represent potential points of failure that could disrupt communications. Common causes of disruptions to network equipment include power interruptions, wear due to improper operating conditions such as heat or dust, use of equipment beyond its recommended life, and incompatibilities following upgrades and configuration changes.

Software and Firmware

ISGD has a large number of communications nodes. Manually executing configuration commands (e.g. upgrading firmware) for each node is time consuming, and therefore requires management software. Since communication links are sometimes unreliable, this software must monitor command successes and (if necessary) retry to ensure completion. Since configuration files can be complex, the software must also be capable of managing each version of each configuration.

The team discovered a number of issues among the components that connect to the field devices, including incompatible versions or implementations of protocols such as Transport Layer Security (TLS), IPsec, SCEP, and Dynamic Host Configuration Protocol (DHCP). When using new devices with custom features, time and effort is required to work through these issues.

Integrating individually developed modules or components into a single unit can also present challenges. For example, interactions between the internal components or modules can cause conditions that are difficult to diagnose and might not be possible to fix in the current component versions. For example, the 4G functionality in the 4G radios was implemented in a circuit board module that was integrated with other radio components such as Wi-Fi and CCS. Since the code for the 4G module was not under the radio vendor's control, brute force (such as rebooting a module) was sometimes necessary to resolve problems. Temporary workarounds may be necessary to resolve these types of issues, but this can cause stability problems until the underlying issues are resolved.

Network Congestion

Field devices connect directly to the 4G network, where they are provisioned and tracked using vendor SIM cards. To connect the 4G network to the back office, the project uses a private network connection from the wireless network provider to the internal SCE network. However, the 4G network itself is still shared across all devices connecting to the 4G towers and is therefore subject to service degradation during times of peak usage.

Troubleshooting

Maintaining the signal strength of the 4G network was a challenge during deployment. To address this challenge, the team prepared daily reports on the received signal strength indicator (RSSI), and events such as cell disconnections. This helped the team to optimize the antennas for the best reception. When planning field installations, projects should try using alternate equipment placement, antennas, and configurations—while also monitoring signal strength. Projects should also test communications with enclosures both open and closed. This helps to ensure that communications are stable before leaving the site.

Network equipment in the field should operate continuously and autonomously. However, this type of equipment is not immune to rare, complex memory management or timing bugs, electromagnetic disturbances, or other long-term abnormalities. When problems occur, traditional methods of troubleshooting (such as power cycling) are not available for this equipment, since it is not physically accessible (i.e., the devices are located in the field, inside electrical equipment enclosures). If the equipment has stopped communicating, options are limited. If possible, a secure method for remotely rebooting equipment that has stopped communicating would decrease downtime. If a remote reboot is not possible, a method for securely rebooting from a nearby location, but without having to open enclosures or enter customer residences or facilities, would be useful.

In an effort to monitor and maintain network stability, the team evaluated several network monitoring tools. While there are many viable network monitoring tools available, configuring them to provide an appropriate level of reporting and notification is challenging. In order to receive alerts if the production network is down, it is necessary to establish a monitoring mechanism outside the production network. ISGD is using HP System Insight Manager and Solar Winds Network Performance Monitor to monitor the systems and send e-mail alerts when they detect problems.

Guaranteed Delivery of Communications

A common misconception about communications networks is that they guarantee message delivery. Communications networks will attempt to resend messages if a delivery failure occurs. However, the message will "timeout" if communications are lost for too long. To avoid this problem, applications require strategies for queuing and retrying, which requires storing unsent messages in case the network is down for an extended period. These strategies should consider the business requirements around loss of data. The following is a list of issues to consider when designing communications capabilities:

1. Applications require a retry strategy for when network communications fail
2. Applications must not simply log an error when a communication link is not responding
3. Devices must contain some storage of historical readings or data in order to support retry
4. Exponential back off (waiting successively longer intervals between retries) is useful for recovering quickly while not wasting resources during longer outages
5. Applications must not store or report false (or estimated) values without indicating they are false (or estimated)

Interoperability Design Approach

The electric utility industry has focused on interoperability standards as a way to reduce smart grid implementation costs. Such standards should enable applications to communicate and react to information exchanged with other applications. The ISGD project team has found that interoperability continues to be a challenging aspect of smart grid deployments.

Two approaches to achieving interoperability include using standard interfaces and performing custom integrations. Both approaches require careful consideration of the associated design decisions and tradeoffs.

Standard Interfaces

While it may be possible to procure a number of smart grid capabilities from a single vendor, SCE prefers to procure open and standards-based interoperable system components from multiple vendors. This approach promotes market competition and innovation. A vision embraced by many in the utility industry is that vendor software should implement standard interfaces, enabling devices and applications from multiple vendors to interoperate without requiring costly integration services.

Intellectual property law is one reason why vendors are cautious towards this approach. The threat of patent infringement lawsuits makes vendors cautious about implementing standards. Vendors often rely upon proprietary communications to mitigate this risk, restricting their use of standard communications to where it is necessary.

Standards are typically most effective when vendors form an industry alliance or consortium that requires legal agreements between parties, and defines and enforces governance processes. Alliances can certify products as interoperable, usually for specific exchange scenarios defined by profiles. Examples of multi-vendor alliances include Wi-Fi, Bluetooth, and ZigBee.

Custom Integration

Integrating applications that were not designed to interoperate with each other requires substantial effort. Various technical approaches may be useful, such as using messaging middleware or service oriented architecture, extracting, transforming and loading files, or using database gateway tables. Regardless of the tools and platforms used, translating between data formats and orchestrating the exchanges requires custom code. Vendor-supported application programming interfaces (APIs) are preferred for integrating applications, over use of native database or file formats. Likewise, standards-based interfaces (such as web services) help to reduce the complexity of adapters.

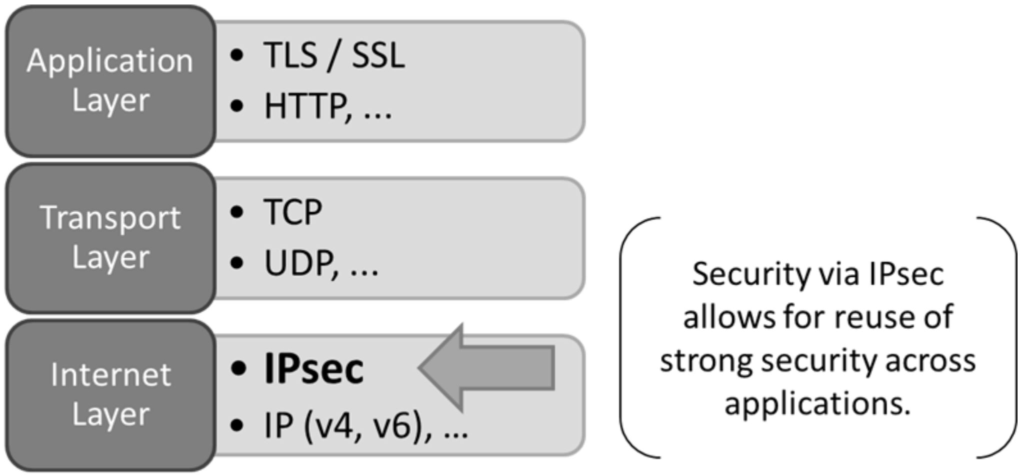
Integration work is generally divided among vendors, system integrators, and in-house developers. Dividing the integration responsibilities inevitably leads to disagreements and misunderstandings. Assigning overall responsibility to a single entity can mitigate this challenge. Custom integrations require highly effective communication and collaboration among diverse groups.

NERC CIP v5

The North American Electric Reliability Corporation (NERC) is responsible for ensuring the reliability of the bulk power system in North America. NERC's Critical Infrastructure Protection (CIP) standards provide guidance and requirements for securing the bulk electric system. The latest version of this standard clarifies the applicability of cybersecurity protections to serial (non-routable) connections. One of the goals of ISGD is to demonstrate implementation of the recommended cybersecurity measures to and from a substation through a secure communications gateway. This approach uses routable protocols over a WAN fiber link to the grid control center. Although this substation is not classified as part of the bulk electric system, SCE's goal is to eventually implement high-capacity, secure, IP-routable electronic communications capabilities for all substations.

SCE developed the CCS specification to meet the requirements of NISTIR 7628, the National Institute of Standards and Technology Interagency Report on Guidelines for Smart Grid Cybersecurity. The CCS specification was used as a set of requirements for the vendors that implemented the central security services in the back office, as well as the software clients in the substation gateway and the 4G radios used for certain field devices. The solution uses IPSec instead of TLS or Secure Sockets Layer (SSL), allowing security to be built into a lower layer of the Internet protocol suite (as shown in **Figure 21**). This allows application traffic protection without requiring those applications to be specifically designed to use IPsec.

Figure 21: IPSec in the Internet Protocol Suite



Scalability

In order for smart grid capabilities to be widely deployed, they must be scalable. Certain ISGD components are scalable, including off-the-shelf software applications and database hardware. Other ISGD components require further evaluation to assess their scalability, including the networking infrastructure. Network performance was observed for any unexpected behavior during the demonstration period but was not be subjected to any deliberate attacks or stress tests since it supported actual operations.

IT Capability Maturity

The smart grid requires mature communications and computing capabilities to support the advanced use of operational technologies (e.g., physical grid equipment such as transformers, capacitor banks, relays, and switches). Utilities have long thought of operational technology as separate from IT, which initially focused on financial records, billing, and other “non-operational” functions. However, most operational equipment now includes some amount of electronic monitoring, communication, and even automated remote control functions. This automation requires an increased role for IT.

Each of these automated functions requires hardware and software that must be maintained and integrated with other applications or hardware. They also require databases for reporting. Maintaining this IT infrastructure is especially complex given the need to periodically add functionalities, perform upgrades, and change hardware, networks, or security. The following is a list of key questions that IT departments should be able to answer:

1. **Vision** – What are the long-term goals of the company, and how will customers, shareholders, regulators, company business units, and projects support it?
2. **Business Case** – How are projects evaluated and selected?
3. **Governance** – Who makes decisions about resources used by multiple business units?
4. **Requirements management** – What should each component do, specifically? What if a requirement changes?
5. **Configuration management** – Which versions of the software and hardware are in use?
6. **Test equipment and environments** – How are changes evaluated to ensure they will not cause problems?
7. **Manage process changes** – How is confusion from and resistance to change minimized?
8. **Customer communications** – How are customers included in managing these changes?

Advancing the maturity of the IT organization can improve the efficiency and effectiveness of smart grid technology rollouts.

5.1.2 Secure Energy Net - Research Plan

Following the architecture and design phase, vendors built the individual ISGD sub-systems. Once these successfully passed factory testing, they were installed at the SCE lab for further testing and full system integration. Following SCE lab installation, the team conducted comprehensive performance testing on the integrated production networks. The team conducted performance testing during the measurement and verification period. This testing addressed performance of the ISGD networks, security, interoperability, and visualization. This results of this testing are presented in Chapter 7.

5.1.3 Secure Energy Net - Summary of Field Experiments

Performance Testing

The field experiment for the SENet consisted of operating the system and observing its performance. No performance issues were noted.

Cybersecurity Testing

The cybersecurity approach used for SENet is described in 5.1.1. The field experiment consisted of observing the performance of the system during the demonstration period. The team did not identify any performance issues with the cybersecurity system.

5.1.4 Secure Energy Net - Observations

5.1.4.1 Smart Energy Net Lessons Learned

An Enterprise Service Bus Can Simplify the Development and Operation of Visualization Capabilities

ISGD coupled SSI with the STI visualization capability to design a situational awareness capability that presents major ISGD elements on a geospatial map in near-real time and on a historical basis. This capability provides grid operators with a greater understanding of the state of the distribution network, distribution circuits, and behind-the-meter devices and applications. This enhanced situational awareness has the potential to diagnose and correct grid events with greater accuracy and speed than what is available today. Key functions of the visualization system include the ability to replay historical events to perform root-cause analysis, drill down to obtain device-level information, and aggregate data into summary information at the circuit or substation levels. This system also eases integration by allowing data to reside within the “system of record,” and then being able to retrieve it for presentation when requested by a user.

It is important to use an iterative approach to solicit feedback from end-users when developing and integrating visualization tools. SCE used SSI and STI to develop its visualization capabilities in six to eight week sprints. Initial attempts to gather requirements and deliver the visualization screens provided the end-user with unsatisfactory results. The subsequent adoption of an iterative approach provided a path for end-user buy in.

Utilities Need to Perform a System Integrator Role to Realize Smart Grid Objectives

One of ISGD’s key interoperability goals is to implement service definitions (i.e., APIs) in an ESB to ensure that CIM compliant interfaces are explicit, testable, and broadly available to the industry. Standardization of the service definitions, together with standardization of the data (i.e., Common Information Model), would create an interoperable grid control environment for smart grid applications.

SCE had some significant success incorporating GE’s SSI, an ESB, into ISGD’s SENet architecture. Specifically, SSI helped SCE break down system and operational barriers so that a grid control operator can see information from substations, distribution circuits, energy storage devices, and even beyond the meter applications such as smart appliances, solar panels, and plug in electric vehicles. This yields a level of situational awareness not available historically. This could become valuable to grid operators as larger amounts of DERs interconnect with the distribution system.

The ESB is a concept that requires careful consideration when choosing smart grid implementation partners. For utilities to realize their smart grid objectives while maintaining an open architecture using standards, utilities must become the systems integrator (or be able to take on at least some of the systems integrator role). The utility as the systems integrator requires certain key elements:

- Developing a core competency of programming APIs, where necessary (this is crucial since relying on third-party vendors can become cost prohibitive as requirements change or are updated as the architecture matures)
- Understanding the standards at a detailed level with the ability to identify conflicts and gaps early can avoid development pitfalls
- Dedication to working within a CIM framework across the utility can be a long adoption process among internal utility stakeholders
- Demand that vendors use standard service definitions when they have flexibility in their design (although this is difficult to enforce when managing multiple vendors)
- Understanding the utility architecture at a low enough level to anticipate and budget for the level of integration is necessary to manage costs and expectations

Effective Communication with Software Vendors Is Critical for Smart Grid Deployments

Software vendors often lack a detailed understanding of the electric utility business. Likewise, utilities often do not understand the software development business. Problems often arise when utilities attempt to communicate their requirements to software vendors. Utilities and software vendors (or other industries) can understand or interpret identical words differently. This results in a false sense of mutual understanding, creating flawed expectations, and incomplete or misunderstood assumptions.

Utilities can accelerate or improve their smart grid deployment efforts by becoming more effective communicating with software vendors. Specifically, utilities should capture and articulate all assumptions made during the design and architecture phases of the software development lifecycle. Since different industries often assign different meanings to identical words, it is important to reach a common and complete understanding of how software should function. This understanding should also include the required capabilities, and interoperability and cyber security features.

Since the electric utility industry is challenging to understand and design software for, larger utilities should prepare themselves to become the systems integrator. This requires a commitment to develop the necessary project management and software development lifecycle skills. These skills would need to be paired with a detailed understanding of the electric grid in order to deploy sophisticated, integrated smart grid capabilities. Smaller utilities may find this integrator role burdensome, and could benefit from waiting until the market for complex smart grid systems and integration services is more mature. This would allow them to adopt smart grid software at a lower cost and with less implementation complexity and risk.

Acceptance Testing Should Include Integrated Testing of Software Products and Field Devices in a Lab Environment

One of the standard practices used by utility software developers is to validate system functionality with hardware simulators. This practice is extremely common for many reasons, including the fact that hardware is expensive, bulky, and varies significantly across utilities. Unfortunately, some of the simulators used do not realistically represent actual hardware, which often leads to erroneous factory acceptance testing. Simulation testing places the burden on the utility to validate software performance using real hardware during site acceptance testing.

Vendors that develop distribution substation software that controls field equipment should conduct simulations using these field devices. These simulations should be part of the development and factory acceptance testing procedures.

Equipment vendors should also conduct lab testing with actual fixed devices (e.g., relays, programmable logic controllers, and gateways). This testing should include voltage and current injection testing equipment. Real-time digital simulator controlled injection testing, although expensive, would also improve the simulation quality.

Utilities should use a real-time digital simulator to build a model of the distribution grid to conduct “closed loop” testing as part of a more thorough acceptance testing process. This simulator should connect to the actual devices in order to perform test scripts prior to field deployment. SCE uses the RTDS and Opal-RT products for this purpose and it is a powerful tool for system acceptance testing.

5.1.4.2 Smart Energy Net Commercial Readiness Assessment

As noted in the lessons learned, there is still a steep learning curve for utilities wishing to implement a similar system. Systems and equipment certified as 61850 compliant by various manufacturers will not in general thereby interoperate in a “plug and play” manner. Indeed, the 61850 standards do not have “plug and play” interchangeability as an objective. The standards still allow for considerable manufacturer defined parameters. Add to this the fact that any implementation needs to integrate the substantial legacy systems operating at a given utility, and it can be seen that the utility must be ready to take on the role of system integrator.

5.1.4.3 Smart Energy Net Calls to Action

The following next steps are recommended from the lessons learned section:

1. The relevant 61850 working groups (IEC TC WG 10 and WG 14) are encouraged to work toward greater consistency in the implementation of optional features between manufacturers.
2. Utilities are encouraged to increase their participation in these working groups to ensure their needs are being met.
3. Utilities are encouraged to develop internal system integrator capabilities and not expect to be able to successfully outsource this role.

5.2 Sub-project 7: Substation Automation 3 (SA-3)

5.2.1 SA-3 - Technical Approach

5.2.1.1 Objectives

The goal of SA-3 is to transition substations to standards-based communications, automated control, and an enhanced protection design. Achieving these goals will support system interoperability and enable advanced functionalities such as automatic device configuration and backward compatibility with legacy systems.

5.2.1.2 Approach

The MacArthur Substation SA-3 pilot demonstrated the following:

- An open standards-based human-machine interface (HMI), which helps avoid vendor lock-in; advanced functional includes automatic graphical user interface generation
- Password management (user-specific, role-based passwords)
- Fully-automated substation device configuration
- Configuration management
- Secure local and remote access
- Automated IEC 61850 data transfer and configuration to the data historian
- IP-based data and control communications
- Integration of CCS

- Process improvements
  - Project engineering (project file creation) efficiencies due to SEMT (Substation Engineering Modeling Tool) improvements
  - Factory acceptance testing and on-site testing process improvements due to standards-based device auto-configuration processes
  - Remote visibility and control of field devices
- Centralized distribution volt/VAR control
- Integration of DMS with substation control

The SA-3 design incorporated IP-based intelligent electronic devices (IEDs), a programmable logic controller (PLC), an industrial hardened HMI, and substation gateway integrated with CCS. One of the advantages of SA-3 is to enable device auto-configuration, compliant with the IEC 61850 standard, eliminating the need for manual configurations. The substation gateway also securely integrates the low-latency FAN to the substation local area network (LAN), enabling the self-healing circuit capabilities of sub-project 5. Lastly, SA-3 allows SCE to compare the advantages or disadvantages of operating DNP3 (Distributed Network Protocol) over Ethernet communications in lieu of the current DNP3 over serial communications.

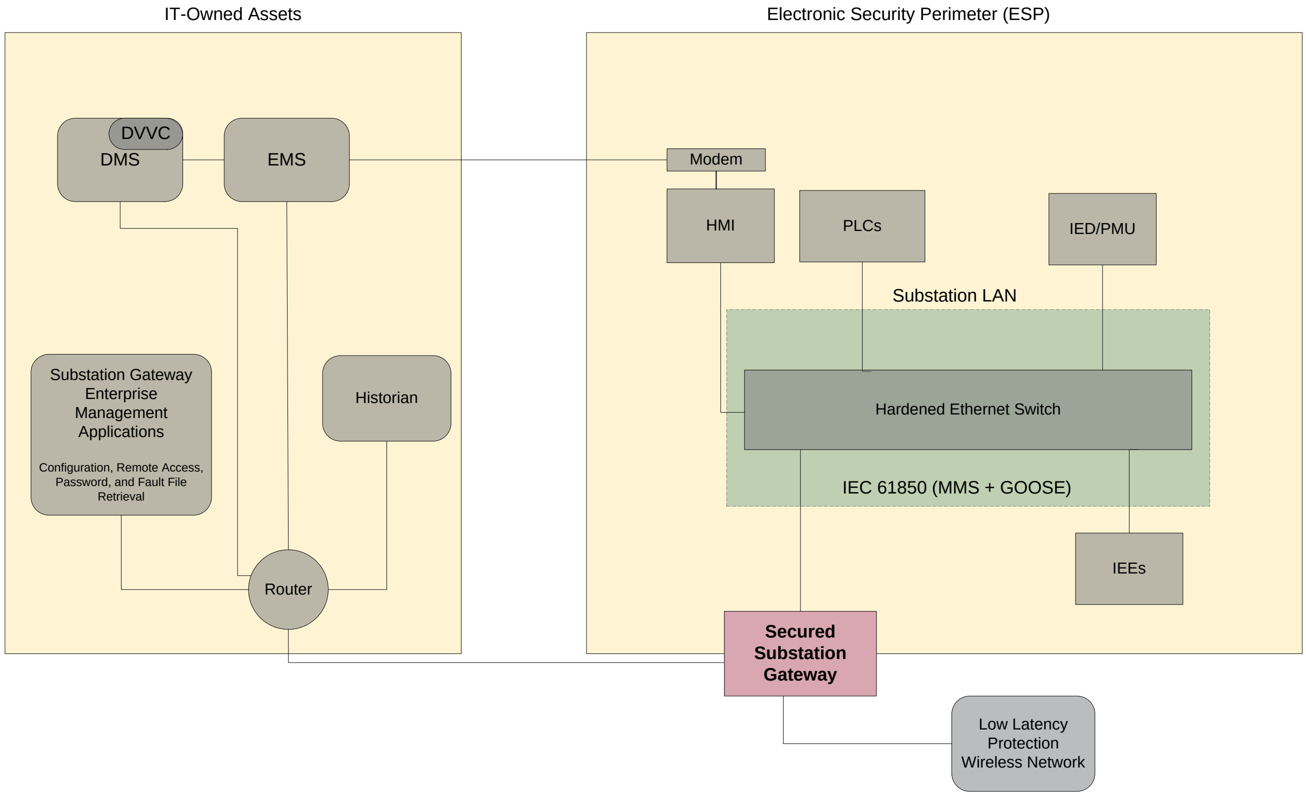
SA-3 is a foundational element required for ISGD to implement sub-projects 3, 4, 5 and 6. SA-3 provides the secure communications, remote monitoring, and control schemes necessary for these sub-projects.

This section provides an overview of the primary SA-3 components, and describes the new features and capabilities of the system. This section also summarizes the challenges the team faced during deployment.

5.2.1.3 Design

ISGD's SA-3 design includes several key components, which are identified in **Figure 22** and described in further detail below.

Figure 22: SA-3 Network Architecture



Enterprise Management Applications

The enterprise management application suite provides centralized configuration management and automated configuration support for the substation gateway. This software suite includes the following:

- Repository for substation metadata and equipment inventory
- Version controlled repository for device configuration files
- User access and change control for specific configuration elements
- Automatic capture of field configuration changes (in conjunction with the substation gateway)
- Remote, secure engineering and maintenance access to substation IEDs using vendor tools
- Password management of access to individual substation devices such as the substation gateway, managed switches, HMI and IEDs
- Automatic capture of device fault records

Substation Gateway

The substation gateway consists of software running on an environmentally, substation hardened computer. This provides a single, secure, point of access to substation data. This provides the following capabilities:

- Automatically retrieves all substation event and disturbance records for secure, centralized processing and storage
- Hosts integrated Common Cybersecurity Services to enforce corporate security policies
- Acts as the substation communications hub by enabling local or remote access to field devices

Engineers and technicians have secure, local access to the substation gateway via Terminal Services using a dedicated Ethernet access port. The substation gateway enables secure two-way pass through to the substation IEC 61850 LAN. Authorized users are therefore able to access individual device configurations and settings. This is the primary process for configuring SA-3 system relays.

Human Machine Interface

Authorized operations and maintenance personnel use the HMI for local supervisory control of substation apparatus (circuit breakers, capacitor banks, etc.). The HMI acquires and presents real-time operational data locally and remotely to the EMS (Energy Management System). The HMI can be modified automatically via the substation gateway using Substation Engineering Modeling Tool (SEMT) configuration files.

Managed Gigabit Ethernet Switches

The substation managed switch network consists of an array of managed gigabit Ethernet switches connected in a ring configuration. This allows for rapid network reconfiguration in the event of a network link failure.

IEC 61850 Protective Relays

IEC 61850-compliant protection IEDs were installed at MacArthur Substation. They function as protection, control, and telemetry devices.

The IEC 61850 protective relays introduce new communications protocols to the SA-3 system design: MMS (Manufacturing Message Specification) for reporting, polling, controls, and GOOSE messages for publishing and subscribing to relay data.

Phasor Data Concentrator

MacArthur Substation used a SEL-3373 PDC to archive phasor data locally at the substation. This PDC stores data from the 66 kV lines coming into MacArthur Substation (GEUR D60), the two 66/12 kV transformer banks (GEUR T60 relays), and from the Arnold and Rommel 12 kV distribution circuits (GEUR F60 relays). This data supported the deep grid situational awareness capability in sub-project 6.

Substation Engineering Modeling Tool

The SEMT is a software application developed by SCE to create files required to configure substation automation devices including IEDs, managed switches, the substation gateway, and the HMI. Primary SA-3 improvements involve the creation of files, which are now IEC 61850 standards-based, and Substation Configuration Description (SCD) file, which drive the SA-3 substation gateway configuration process. The SEMT will remain backwards compatible with earlier versions of substation automation, and can support point list generation for substations based on these earlier versions. The SEMT also generates reports such as point list and test scripts for the HMI and EMS test set.

5.2.1.4 Key Features of SA-3

The SA-3 System introduces the following new features and functionality to SCE's existing Substation Automation system design.

Configuration Management

Configuration management introduces an array of tools to configure, compare, and secure settings on system devices (e.g. relays, HMIs, etc.). Specifically such tools include:

- Automated generation of substation device configuration files in IEC 61850 format
- User-initiated automatic configuration of devices when updating a substation
- Substation gateway interoperability with the enterprise management applications enables local and remote monitoring of system devices for operating status, configuration changes, and access authorization
- Identification and notification of file changes, also known as "incremental differencing" (i.e., system identification of any change to any device configuration or setting)
- Device password management for IEDs, HMI, managed switches and the substation gateway

Automatic Event and Fault File Recovery and Management

This function centralizes access to event files (such as system faults). This is achieved by a variety of methods such as by enabling automatic device polling and reports to the substation gateway. The gateway detects, downloads, and then uploads the files to the back office for data archiving. Protection engineers currently access these files locally at the substation.

Remote Secure Engineering Access

Substation engineers are able to remotely access substation device data. This can be valuable to protection engineers in validating specific in-service protection settings following a fault and troubleshooting problems. The ISGD team used this capability to access and upload PMU data from the PDC and troubleshoot the substation gateway.

New Human Machine Interface

The SA-3 HMI automatically generates substation one-line diagrams based on the SEMT output, resulting in completely data-driven configuration. These diagrams are linked to SCADA systems for operations and maintenance. This system eliminates the time and expense of having a HMI vendor generate project configurations based on SCE-generated point lists. This time consuming and error prone process required additional subject matter expert support to debug vendor-provided HMI configurations.

Protection Schemes

Recent advances in energy and information technologies allow for improved circuit protection schemes that were not possible with legacy devices. For example, protection schemes for the 66 kV and 12 kV circuits into and out of MacArthur Substation have been migrated to IEC 61850-compliant relays. These relays use peer-to-peer GOOSE messaging for circuit breaker failure and bus differential protection.

Common Cybersecurity Services

The substation gateway has implemented CCS, providing secure communications paths between MacArthur Substation and the back office.

5.2.1.5 Deployment Challenges

Back Office Integration

Depending on a utility's current back office functionality, introducing a substation automation system may pose integration challenges. Specifically, the additional data provided by SA-3 may impact operational systems such as the Energy Management System and Outage Management System. Other systems such as data historians, circuit protection repositories, and fault file databases will also need to establish interfaces with the new substation automation application. Utilities considering an advanced SA-3 system should establish key system requirements and identify the impacts to any existing systems. Some systems may be unable to interface with SA-3, and these could require replacement.

Interpretation of IEC 61850

When deploying complex systems, utilities typically procure hardware and software from a single vendor. This helps utilities avoid having to manage device interoperability, thereby mitigating deployment challenges. However, avoiding vendor lock-in requires that multiple potential vendors exist for these products.

SCE's SA-3 design incorporated IEC 61850-compliant software and hardware from multiple vendors. The primary objective of this standard is to achieve interoperability among devices from multiple vendors. The effort required to integrate these components into one system highlights the current lack of interoperability within the industry. Many manufacturers claim to offer products that are IEC 61850-compliant. However, their interpretations of the standard are inconsistent. This made their devices unable to communicate with one another.

The IEC 61850 suite of standards is also intended to be flexible. This flexibility was instrumental in allowing SCE to create the necessary “private data,” which enables interoperability between most vendor devices. However, this flexibility increases the standard’s complexity, while also introducing the potential for different interpretations among various vendors. The ISGD team experienced this issue when it received relays from two vendors. Although these relays were both IEC 61850-compliant, they would not interoperate. This lack of interoperability led to longer than expected laboratory testing and coordination with product manufacturers.

The ISGD team coordinated the development and evaluation of solutions for these integration challenges among the ISGD vendors. The team also invested a substantial amount of time testing the functionality and interoperability of the SA-3 system in SCE’s Substation Automation Lab. This lack of interoperability caused schedule delays and budget overruns, while the team also had to make some compromises on functionality due the limited amount of time available to address these technical challenges. While two devices may conform to a standard, this does not automatically ensure interoperability. Interoperability certification by an independent testing laboratory would ease this problem.

Old versus New Processes

Instituting a substation automation system not only affects systems, it also influences the operational processes associated with these systems. As SA-3 integrates with or replaces operational systems, it will lead to procedural changes. For example, to configure the protection settings of substation protection devices, protection engineers currently load protection setting files to a database. Field personnel then manually download these files, take them to the substation, and manually input them into the substation devices. SA-3 enables authorized field personnel to download these files directly to the substation gateway and to auto-configure the substation devices directly from within the substation. Although such procedural changes may seem trivial, the ramifications across system operations can be significant. SA-3 impacts back office processes as well as processes within the substation. Substation test technicians and other field workers are now required to operate a new HMI with active directory password management. Device configuration occurs via a substation gateway rather than directly through the device. The primary reason for this process change is that the substation gateway (with CCS) now enables secure user access to IEDs. The impacts to operational processes can be challenging to identify, and even more difficult to implement. Utilities planning to adopt a substation automation system should obtain stakeholder buy-in early in the process. They should also obtain support from corporate training.

5.2.2 SA-3 - Research Plan

5.2.2.1 Simulations

The team performed steady-state circuit modeling to support the development and debugging of the SA-3 system.

5.2.2.2 Laboratory Tests

The ISGD team tested the system components before field installation to verify performance and functionality. Laboratory testing included component communication, password management, protection settings, logic configuration, and auto-configuration. By using a Real-Time Digital Simulator, the team was able to simulate operating conditions in a laboratory environment, which was helpful in testing, troubleshooting, training, and demonstrating the system to SCE stakeholders. Following these simulations, the team performed end-to-end interoperability and system integration testing at SCE’s Advanced Technology facility. The final stage of testing included interface simulations with the Energy Management System (EMS), DMS, eDNA (archiving software), enterprise configuration management software (i.e., PowerSYSTEM Center), and the FAN.

5.2.2.3 Commissioning Tests

The deployment strategy for the SA-3 system followed SCE’s existing construction and commissioning standards. These standards require qualified electrical workers to validate circuits, protection settings, and control logic. The introduction of new SA-3 functionalities requires additional testing, which had not been performed previously. For example, new test plans had to be created for testing GOOSE protection schemes.

5.2.3 SA-3 - Summary of Field Experiment Results

5.2.3.1 Performance Testing

The field experiment test for the SA-3 performance consisted of observing its satisfactory operation over the demonstration period.

GOOSE message subscription and publication performance was problematic in supporting sub-project 4. Due to non-determinstic behaviors of CPU performance, latency sometimes exceeded requirements. However, after fine-tuning the system and CPU parameters, the latencies were observed to be acceptable.

5.2.3.2 Cybersecurity Testing

The field experiment test for the SA-3 cybersecurity consisted of observing its satisfactory operation over the demonstration period. The SA-3 system primarily relied on CCS for cybersecurity.

5.2.4 SA-3 - Observations

5.2.4.1 SA-3 Lessons Learned

Continued Development of the IEC 61850 Standard and Vendor Implementations of This Standard Are Required to Achieve a Mature State of Interoperability

SCE has implemented an IEC 61850 standard based substation automation system at MacArthur Substation. During this implementation, SCE had to develop temporary workarounds to overcome vendors' design decisions. For example, configuring a substation IED requires both a CID file to configure IEC 61850-related settings and a proprietary file to configure all other settings. Each file typically requires a separate configuration tool provided by the manufacturer. This makes the configuration process cumbersome, especially when a substation uses IEDs from multiple manufacturers. The IEC 61850 standard allows manufacturer-specific data to be included in the CID file. However, manufacturers are using these vendor-specific fields on a limited basis, instead including this information within a proprietary configuration file.

To overcome the challenge of using multiple configuration files, SCE embedded the proprietary configuration files into the manufacturer's CID file. This allows the IED configuration to be managed using a single CID file. A long-term solution is to require that manufacturers adopt the CID file as their configuration format for all settings, and for the standard to further define the structure of the CID file to minimize incompatibilities between device CIDs. Incompatibilities can result from different interpretations of the IEC 61850 standard.

Another challenge SCE encountered with the IEC 61850 implementation involved configuring the IEDs for sending GOOSE messages. Since GOOSE messages are sent between IEDs, each IED pair/GOOSE message combination must be configured. This configuration process requires that the IEDs' CID files be imported into the manufacturers' IEC 61850 configuration tools. This process must be performed for each GOOSE message, resulting in several iterations of importing and exporting CID files between manufacturers' configuration tools. This process becomes difficult to perform when there are incompatibilities between the manufacturers' CID files.

The IEC 61850 standard also includes many optional features covering many types of IEDs. In practice, these optional fields limit the interoperability between devices from different manufacturers. Since each manufacturer chooses which optional fields to implement, manufacturers may implement different optional fields, restricting interoperability to a very basic level. Greater consistency in the implementation of optional features between manufacturers would improve interoperability.

SCE intends to share its learnings with the UCA International Users Group to help influence the future standard updates.

Achieving Interoperability Requires Concentrated Market-Based Development and Enforcement of Industry Standards

Interoperability among devices and systems from different manufacturers requires industry standards. The development of standards requires the guidance and enforcement of either a centralized governance body or the market. It appears that the market is currently driving the industry slowly toward interoperability.

One of the recommendations coming out of the ISGD team's experience with SA-3 is that utilities could provide more leadership in bringing third parties (other utilities and the vendor community) together to develop and enforce interoperability standards. The following recommendations to other electric utilities, if acted upon, would help promote the development of interoperable products:

- Demand that vendors design interoperability within their devices by adhering to the IEC 61850 standard; utilities could enforce this by only purchasing devices that are interoperable
- Use relevant electric utility industry forums to promote the idea that standards be implemented in a manner consistent with utility interest, which is that products should be vendor agnostic
- Encourage or require vendors to provide a single configuration tool which produces a single IEC 61850-compliant configuration file
- Encourage IED vendors to support the IEC 61850 standard by developing logical nodes that are compliant, thereby reducing the level of propriety configuration workarounds
- Obtain electric utility representation on recognized organizations such as IEEE and the IEC Technical Committee Working Group (IEC TC WG 10)

In the interim, utilities should establish procedures for verifying and validating equipment interoperability prior to deployments. The ISGD team used SCE's substation automation lab to build the entire SA-3 system remotely and commission the functionality of the system prior to deployment. Although this process may not be efficient for every deployment, it allowed the team to thoroughly evaluate and debug the SA-3 system prior to deployment to MacArthur Substation.

5.2.4.2 SA-3 Commercial Readiness Assessment

Commercial readiness comments for SA-3 are the same as those for SENet in section 5.1.4.2.

5.2.4.3 SA-3 Calls to Action

Recommended next steps for SA-3 are the same as those for SENet in section 5.1.4.3.

6. Workforce of the Future

This project domain provided the workforce training tools and capabilities necessary to operate and maintain the various ISGD components. The sub-project also evaluated the potential impacts of smart grid technologies on the organizational structure of the utility.

Deploying advanced energy technologies—such as the ones used for ISGD—has a number of utility implications in terms of the workforce and organizational design. In particular, many devices such as manually operated distribution switches are being replaced with automated devices containing IEDs and radio communications. Systems and components are more likely to interact with other systems and devices than in the past. Changes in the skills required for the workforce will affect how utilities recruit, train and organize employees. Questions explored in this domain include;

- What training do existing job classifications need to be able to design, build, operate and maintain the equipment and systems deployed in ISGD?
- What implications does this have for the job classifications themselves? Are different classification needed or appropriate for the emerging technology?
- Is the current organizational structure best suited to manage the emerging technology, or are other structures more appropriate?

6.1 Sub-project 8: Workforce Training

The ISGD team developed training materials for the ISGD project in accordance with the ADDIE process. This process enables the authoring of training content through five major stages: (1) analysis, (2) design, (3) development, (4) implementation, and (5) evaluation.

Stage 1: Analysis

The team conducted a training needs analysis by identifying the transmission and distribution (T&D) personnel impacted by ISGD, and then assessing how ISGD would affect their roles. The job classifications included Linemen, Troublemen, System Operators, Substation Operators, Distribution Apparatus Test Technicians, Substation Test Technicians, and Field Engineers. Each of these personnel has specific roles with respect to operating and maintaining MacArthur Substation and the Arnold and Rommel 12 kV circuits. Therefore, at a minimum, these personnel need to understand ISGD's scope and its various field components.

Through discussions with ISGD subject matter experts (SMEs) and field personnel, the team determined that many tasks these personnel are responsible for would not change substantially due to the technologies introduced by ISGD. However, these personnel would need to understand how these technologies work. They would also need to understand how to work with these components if they experience a failure in the field. The ISGD technologies are not introducing fundamental changes in the required knowledge, skills, or abilities. However, in some instances there is a convergence of information technology with operations technology skills due to the communications capabilities of the field devices. In most cases, the ISGD technologies represent a logical extension of current technologies.

Stage 2: Design

To ensure that field personnel are properly equipped with the knowledge necessary for working with the ISGD technologies when performing their daily duties, the team decided to produce introductory classes and role-specific reference content. Key reference documents are also available to personnel on an as-needed basis.

There are three deliverables associated with the project: (1) role-specific job aids, (2) introductory classroom training, and (3) an online training repository.

Role-Specific Job Aids: Job aids help to describe specific installation, operations, and maintenance activities in detail for specific job classifications.

Introductory Classroom Training: Impacted field personnel and their supervisors received classroom-training sessions led by the ISGD project managers and engineers, in partnership with the T&D Training organization. These classroom sessions covered overviews of the ISGD project, as well as details associated with the ISGD components affecting T&D.

Online Training Repository: A training repository tool provides personnel with fast, organized access to electronic versions of the ISGD training content, vendor documentation, and related internal SCE standards. This tool covers a self-guided basic overview of the project, as well as an intuitive user-interface, enabling the learner to find content quickly and efficiently.

Stage 3: Development

The team developed the three workforce training deliverables as follows:

Role-Specific Job Aids: SCE personnel developed job aids and captured all of the images during equipment mock-ups or actual installations.

Introductory Classroom Training: The team developed classroom-training sessions with heavy input from SMEs and project personnel.

Online Training Repository: The team developed the online training repository using an eLearning authoring software package. This software provided flexibility in designing the user interface, as well as the capability to effectively organize the content.

Stage 4: Implementation

The classroom training occurred between November 2013 and January 2014 for all personnel impacted by the CES device, DBESS, DVVC, URCI, and SA-3. During the classroom training, all personnel received hard copies of the training content for their reference and review.

Stage 5: Evaluation

The team performed informal evaluations throughout the training courses by collecting feedback from employees. Formal evaluations forms were provided during a few training sessions, and the feedback was generally positive. A feedback survey option will be included for any personnel accessing the online training tool.

6.1.1 Lessons Learned

Impacts to Department Boundaries and Worker Roles and Responsibilities that Result from Smart Grid Deployments Need to be Identified and Resolved

Deploying smart grid capabilities has the potential to create new roles and responsibilities for utility workers, especially related to high-speed, secure communications, and advanced field applications and devices. For example, field devices that are monitored and controlled using high-speed communications would require that field personnel have additional IT and communications skills (that they do not currently possess). Sometimes these new requirements impact multiple departments, so it is important to resolve inter-departmental boundary issues early. Some of these new requirements may be difficult to identify, and may not be apparent until installation. These changes may be met with resistance, and they may result in skill gaps. Utilities should address these changing requirements and any potential skill gaps during the design phase, prior to commissioning

Build Training Development Time into Smart Grid Deployment Planning

The most significant challenge the team encountered while developing training materials for the smart grid technologies deployed on ISGD is that the materials were developed in parallel with the design and deployment of the technologies themselves. This was particularly difficult for software components with graphical user interfaces. Training best practices helped the team overcome this challenge. Such best practices include:

- Engaging the workers and their supervisors early on in the process
- Building awareness among the stakeholders
- Involving the stakeholders in the technology development/deployments
- Conducting training sessions that allow participants to touch and feel the technologies
- Providing easy access to training materials for workers

It is highly recommended that time buffers for training development activities be built into project plans between technology stabilization and deployment to ensure that content development is based on as complete a product as possible.

The Large Volumes of Data Generated by Advanced Grid Components Will Require Data Scientists to Help Manage and Convert It into Meaningful Information

Advanced grid technologies are capable of generating extremely large amounts of data. A new class of utility worker with both power system engineering and statistical analysis skills will be necessary to help manage this information, develop algorithms and other analytic tools, and ultimately convert this data into information that can be used to plan and operate the electric system.

Software Project Management Requires Specialized Expertise

Large software projects present challenges that differ from those of other large projects. Communication between project team members from diverse backgrounds is more difficult owing to the abstract nature of software. It is often difficult for business subject matter experts and IT experts to communicate about requirements and issues. The software project manager must be able to facilitate this communication. Such project managers would ideally have a strong background in both the business and IT side of the project. A separate classification of Software Project Manager could be established with educational and experience requirements balanced in both areas.

6.2 Sub-project 8: Organizational Assessment

The objectives of the organizational assessment were to analyze the organizational impacts of implementing new technologies, and to develop recommendations and industry best practices for addressing these impacts. The assessment addressed organizational impacts, organizational design, organizational readiness, and associated lessons learned from the ISGD project. The team developed an organizational assessment report that includes the following:

- Identifies the most effective future organizational structure
- Compares the current and future organizational structures to identify the largest gaps and potential obstacles
- Specifies how future organization functions and responsibilities will differ from current ones, including changes in workforce size, organizational hierarchy, and the organizational functions
- Identifies policies and procedures necessary to facilitate the identified changes
- Identifies industry best practices for designing organizations that adequately support smart grid technologies

6.2.1 Lessons Learned

Impacts to Department Boundaries and Worker Roles and Responsibilities that Result from Smart Grid Deployments Need To Be Identified and Resolved

Deploying smart grid capabilities has the potential to create new roles and responsibilities for utility workers, especially related to high-speed, secure communications, and advanced field applications and devices. For example, field devices that are monitored and controlled using high-speed communications would require that field personnel have additional IT and communications skills (that they do not currently possess). Sometimes these new requirements impact multiple departments, so it is important to resolve inter-departmental boundary issues early. Some of these new requirements may be difficult to identify, and may not be apparent until installation. These changes may be met with resistance, and they may result in skill gaps. Utilities should address these changing requirements and any potential skill gaps during the design phase, prior to commissioning.

7. Detailed Experiment Results

This chapter summarizes the simulations, laboratory testing, commissioning tests, and field experiments used to assess the various ISGD technologies. This Final Technical Report summarizes the ISGD commissioning activities and field experiments for the entire twenty-four month period of performance.

7.1 Smart Energy Customer Solutions

7.1.1 Sub-project 1: Zero Net Energy Homes

ISGD deployed a number of IDSM technologies to understand their impacts on the customer homes and electric grid and to assess their contributions toward enabling homes to achieve ZNE. This section summarizes the energy simulations, laboratory tests, commissioning tests, and field experiments used to assess these technologies.

7.1.1.1 Energy Simulations

Energy simulations served a key role in helping the ISGD team identify the IDSM measures to be used for the customer homes, and to estimate the potential effect of the various EEM options. Simulations helped the team evaluate the effects of the IDSM measures chosen for each of the homes on the ZNE Block. The team used the eQUEST modeling tool to perform these simulations.

The initial step in this process was to obtain information about each of the 38 project homes within the four residential blocks to develop a baseline annual energy usage for each home. The homes include four distinct home styles that vary from a 1,900 square foot, two-story home to a 2,900 square foot three-story home. The home information was gathered through a series of online homeowner surveys and on-site energy audits. These included the following steps:

- Gathering monthly historical electricity and gas utility data for the past three to five years
- Gathering hourly historical weather data for the past three to five years
- Understanding the home envelopes, including floor and ceiling plans for the four home styles
- Analyzing the homeowner surveys and on-site energy audits

The team then updated computer-aided design drawings of each home, developed models for home energy simulations for each model type, and calibrated the energy models using energy usage information gathered from the utility bills, historical weather data, homeowner surveys, and home energy audits. The weather data was collected from a SCE weather station about five miles north of the homes.

The models aided the team in generating a list of potential EEMs for each home within the ZNE Block. The team reviewed these EEMs and created a final list of measures that balanced the project budget with the desire to maximize the homes' energy efficiency.

Based on the cost-benefit information for the final bundle of EEMs and the results of the solar PV analysis, the team developed flyers for each home on the ZNE Block of customer homes. These flyers provided a list of the EEMs and the associated savings for electricity and gas consumption. Appendix 5 includes an example flyer. Using the flyers, the project team met with the homeowners to discuss their options and preferences for installing the EEMs. The homeowners then made their final selection of the EEMs for installation. **Table 18** summarizes the final EEM selections. The homes on the ZNE Block were randomly assigned numbers one through nine in order to conceal the confidential customer information.

Table 18: Energy Efficiency Measures by ZNE Block Home

Energy Efficiency Measures	ZNE 1	ZNE 2	ZNE 3	ZNE 4	ZNE 5	ZNE 6	ZNE 7	ZNE 8	ZNE 9
Central Air Conditioning Replacement (Heat Pump)	✓	✓		✓	✓	✓	✓	✓	✓
Lighting Upgrades	✓	✓		✓	✓	✓	✓	✓	✓
Insulation	✓	✓		✓	✓	✓	✓	✓	✓
Efficient Hot Water Heater	✓	✓	✓	✓	✓	✓	✓	✓	✓
Domestic Solar Hot Water and Storage Tank	✓	✓		✓	✓	✓		✓	✓
Low Flow Shower Heads	✓	✓	✓		✓	✓	✓		✓
Plug Load Timers	✓	✓	✓	✓	✓	✓	✓	✓	✓
Duct Sealing	✓	✓		✓	✓	✓	✓	✓	✓

The team then performed simulations to estimate the energy savings that would result from the selected EEMs and the expected ZNE attainment (on a Site Energy basis) given the assumed 4 kW solar PV installation. The effect of RESUs and EV charging were excluded from the analysis. The estimated combined gas and electricity energy savings ranged from 38% to 48%. **Table 19** summarizes the simulated energy savings by project home.

Table 19: Simulated Energy Savings by ZNE Block Home

Energy Savings	ZNE 1	ZNE 2	ZNE 3	ZNE 4	ZNE 5	ZNE 6	ZNE 7	ZNE 8	ZNE 9
Energy Savings (%)[23]	40	47	38	39	38	46	48	39	43
ZNE Goal (%)[24]	84	73	90	76	83	89	72	87	64

The EEM installations were completed, and the team collected the energy consumption data. Once the team accumulated a full year of data, it performed the energy simulations again to evaluate the effectiveness of the EEMs in helping the project homes achieve ZNE. A full year of energy use is necessary to perform ZNE calculations.

7.1.1.2 Laboratory Tests

Smart Appliances

The ISGD project demonstrated three smart appliances bearing the ENERGY STAR logo: a refrigerator, a clothes washer, and a dishwasher. Prior to installing these appliances in the customer homes, the ISGD team tested and evaluated them in a laboratory setting. The purpose of this testing was to quantify the demand reduction potential of these devices, and to characterize their responses to DR signals under various operational scenarios. SCE's Design & Engineering Services Technology Test Centers performed functional testing. SCE's HAN laboratory complemented this testing with communications testing.

The dishwasher's DR strategy consists of delaying the operating wash mode, or eliminating the heated dry mode. During testing, the team determined that the dishwasher has the potential to eliminate or delay up to 1 kW of demand. The team also determined that the DR delay scenario does not affect the dishwasher's energy consumption. However, the heated dry element increases the dishwasher's energy consumption of a normal wash mode by 40%. The dishwasher was able to consistently demonstrate compliance with its intended DR strategy.

The refrigerator's DR strategy consists of raising the freezer set point temperature (causing the refrigeration components to turn off for a time), disabling the anti-sweat heaters, and delaying the defrost cycle. Overall, the refrigerator performed as anticipated for longer duration high and critical DR events. Under normal operating conditions, the refrigerator's demand reduction was approximately 90 W. This value depends on a number of factors,

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[23] This reflects the percentage energy savings (combined both electricity and gas) by comparing historical energy usage to estimated energy usage (based upon simulations), after all recommended energy efficiency measures are accepted by the homeowners and installed in the project homes.
[24] A goal of 100% means that a home produces at least as much energy as it consumes within a year.

including the operational status of the various components, ambient conditions, and the type of DR signal received. The time duration of the response also depends on several variables. However, the load reduction appeared to last no longer than 60 minutes.

The clothes washer's DR strategy consists of delaying its start during high or critical DR events, or reducing its load during critical DR events. The load reduction varied depending on the DR event signal, the duration, and the timing of the DR event within the wash cycle. DR event signals to delay the start of the clothes washer must be received before the clothes washer begins operation, otherwise the event signal is ignored by the device. The clothes washer could reduce its load by nearly 50% during critical DR events (and during various stages of the clothes washer's operation). Overall, the laboratory testing demonstrated that the clothes washer was able to execute its intended DR strategies.

Electric Vehicle Supply Equipment

The vendor delivered its EVSEs to SCE in April 2013. SCE evaluated the EVSEs at its Electric Vehicle Technical Center (EVTC) during the same month, prior to field installation. This testing is critical to understanding charging system performance from the standpoint of the electric grid, the vehicle, and the safety and interface with the end-user. The EVTC laboratory evaluation consisted of functional tests (e.g., general operation, safety, grid events, and power quality), and ergonomics tests. This testing used a 2012 Toyota RAV4 EV.

The laboratory testing identified a few areas of concern, which the team is addressing with the manufacturer. For example, the Ground Integrity test revealed that the EVSE began charging while the service ground was not connected. The ISGD EVSEs were all grounded, so this issue was not a concern for this project. The current "total harmonic distortion" and the power factor of the EVSE operating in "no battery mode" (i.e., the EVSE is idle and not connected to a vehicle) were both above recommended limits. However, since the EVSE load is very small when operating in this mode, these were not serious concerns.

During initial physical inspection prior to the EVSE evaluation, the primary power cables were loose and not properly connected to the terminal block. EVTC personnel reattached these wires prior to lab testing. If left uncorrected, such loose connections could cause arcing or a circuit short, leading to potential shock or fire hazards. The ISGD team notified the manufacturer about the issue and its resolution.

Additionally, after periodic inspection of the sub-project 2 EVSEs, EVTC personnel observed signs of thermal degradation on the primary power cables. The ISGD team notified the manufacturer about the issue. The manufacturer determined that the issue resulted from improper termination. The team corrected the issue in the field.

By October 2014, the ISGD team had worked with the EVSE vendor to resolve more than 20 software and hardware problems with these units. Although most of these issues related to EVSE operation, in three instances the EVSEs posed an electrical hazard by demonstrating excessive heat buildup resulting in heat damage on both wires and terminal blocks. These three cases occurred with three different EVSEs, all located within the parking structure used for sub-project 2. These events occurred on June 2, 2014, October 14, 2014, and October 21, 2014. The team determined the cause of the first event and resolved it within a few days. Due to the persistent challenges with these EVSEs, the team decided to disable and replace them with EVSEs from a different vendor. By December 2015, the team replaced the EVSEs in the sub-project 1 homes with EVSEs from a different manufacturer. The team also replaced the EVSEs in the sub-project 2 parking garage with EVSEs manufactured by a different manufacturer.

Residential Energy Storage Unit

The vendor completed Underwriters Laboratories (UL) listing of the RESU in February 2013 after nearly three years of evaluating and refining various pre-production units. Upon receiving four "production" RESUs with UL certification in February 2013, SCE evaluated these units to ensure compliance with technical requirements. This lab testing consisted of three phases: functional testing, performance testing, and system protection testing.

During the testing, the ISGD team identified issues and reported them to the vendor. To address these issues, the vendor provided several updates to the RESU control system software and one hardware modification. Following each update, the team assessed the potential impacts of the update and repeated tests, when necessary. The RESUs passed all of the tests following the updates. This testing confirmed that the RESU satisfied the project's technical requirements, and the team approved the RESU for deployment.

Community Energy Storage

Prior to field deployment, SCE performed functional and performance testing of the CES device at EVTC. The purpose of this testing was to ensure that the unit operates safely and reliably. The lab testing consisted of two phases: performance and safety. Both phases consisted of examining device operation under various conditions by simulating real-world grid scenarios.

A range of tests allowed the team to characterize how the CES performs in a variety of modes and under a variety of grid conditions. The team used these tests to determine system efficiencies, including standby power consumption and inverter efficiency. The tests also helped the team to evaluate the CES's reaction to grid events and to identify its operating limits. These tests provided a baseline characterization of the CES.

Phase 1 testing confirmed the basic functionality of the unit. The unit responded accurately to real and reactive power commands. It successfully islanded upon grid outages and reconnected when stable grid voltage returned. The CES internal measurements—voltage, current and temperature—were compared to data collected from instruments connected to the CES output; the internal measurements were reasonably accurate.

Phase 2 consisted of evaluating the CES's ability to protect itself, the grid, and the load it serves. These tests included attempting to operate the system beyond its specified limits. Performing these tests in a controlled setting allowed the team to identify the CES's actual limits, and to verify that its protection mechanisms operate properly.

The CES exceeded the safety requirements in phase one and phase two testing. In addition to protecting itself from erroneous user input, the power control system shut down when the CES exceeded standard operating limits. The accuracy of the grid measurements ensured that the CES disconnected well before it exceeded utility voltage requirements.

7.1.1.3 Commissioning Tests

Home Area Network Devices

The ISGD team completed the HAN device field installations in August 2013. The devices came from two different vendors. One vendor produced the IHDs and another provided the smart appliances, PCTs, plug load monitors, and home EMS. The smart appliances consist of a refrigerator, dishwasher, and clothes washer. These appliances communicate with the home EMS via an Appliance Control Module (ACM). Each smart appliance requires a separate ACM.

The ISGD HAN devices support two key functions. They support load management capabilities, including demand response, and they provide customers with real-time energy usage information that they can use to make informed decisions about their energy use. **Table 20** summarizes the HAN device details.

Table 20: HAN Device Communications and Control

Function	Equipment	Refrigerator	Dishwasher	Clothes Washer	Thermostat	Plug Loads & IHD
		Communications/Control Paths				
Load Management	• Project meter • Home EMS	Generate load control signal in ISGD Advanced Load Control System, which sends message to the home EMS via the project meter; the home EMS then broadcasts the message to the relevant device class.				N/A
Customer Energy Usage Information	• Plug load monitors • Home EMS • IHD (total home demand and usage) • Solar PV[25] tool	• Smart appliances, plug load monitors and PCTs communicate data to the home EMS using a ZigBee connection; this data can then be provided to the customer's computer via Wi-Fi or Ethernet) • IHD receives total household energy use information from project meter • Solar PV tool collects data from solar PV installations, presents data to customers via the vendor portal			See smart appliance description at left	See smart appliance description at left for plug load comms. path. The IHD receives information from the project smart meter

The various HAN devices in the customer homes receive communication signals via smart meters. However, these meters can only pair with a limited number of devices. The team therefore used the home EMS to consolidate the PCT, refrigerator, dishwasher, and clothes washer. The meter paired with the home EMS, which then relays load management signals to these HAN devices.

The project team is using both the home EMS and a separate IHD to present energy usage information to the project homeowners. The home EMS is capable of presenting device specific load and energy usage information on both a real time and historical basis. However, it is not capable of measuring the discrete output of rooftop solar PV and displaying it on the home EMS screen. In addition, the home EMS reflects the net household load only if it is positive (i.e., if energy consumption is greater than the energy being generated by the solar PV). If the solar PV output exceeds the household load, although the total household load is actually negative, the home EMS displays zero household load. In order to provide customers with net demand and energy usage information that reflects their solar PV generation, the team is using the IHD.

The team installed 64 smart appliances in the 22 project homes within eight working days. These installations coincided with the deployment of the other HAN devices. One of the key tasks for deploying HAN devices is pairing them with the appropriate smart meters. Each ISGD project home had a project-specific meter that was managed by a project-specific Network Management System (NMS). Having a project-specific NMS allowed the team to kit the HAN devices for each home and pair them to the correct meter prior to field deployment.

During deployment the team discovered that the refrigerators delivered by the vendor were different from the ones delivered several months earlier for the project team's lab testing. The most notable difference was the ACM. The refrigerator that the ISGD team laboratory tested had a built-in ACM. The refrigerators delivered for field deployment did not have a built-in ACM. Rather, they required a different version of the ACM that used different hardware and software, and attached externally to the refrigerator.

[25] The solar PV is not a HAN device, but it is included here to show the complete list of smart energy technologies that customers can monitor.

Following commissioning, the project team has had difficulty maintaining the communications between the refrigerators and the home EMS. The team worked closely with the vendor to determine the root cause of the device drops. The team determined that the refrigerator loses communications more frequently than the other two appliances due to a difference in the ACM software. If the refrigerator ACM lost communications with the home EMS, after a short time period the refrigerator "timed out" and would not continue attempting to restore communications. Since the primary need for this communication link is to support the exchange of demand response signals between SCE and the refrigerator, the team's strategy for addressing this issue was to ensure that the communications are stable prior to conducting load management tests.

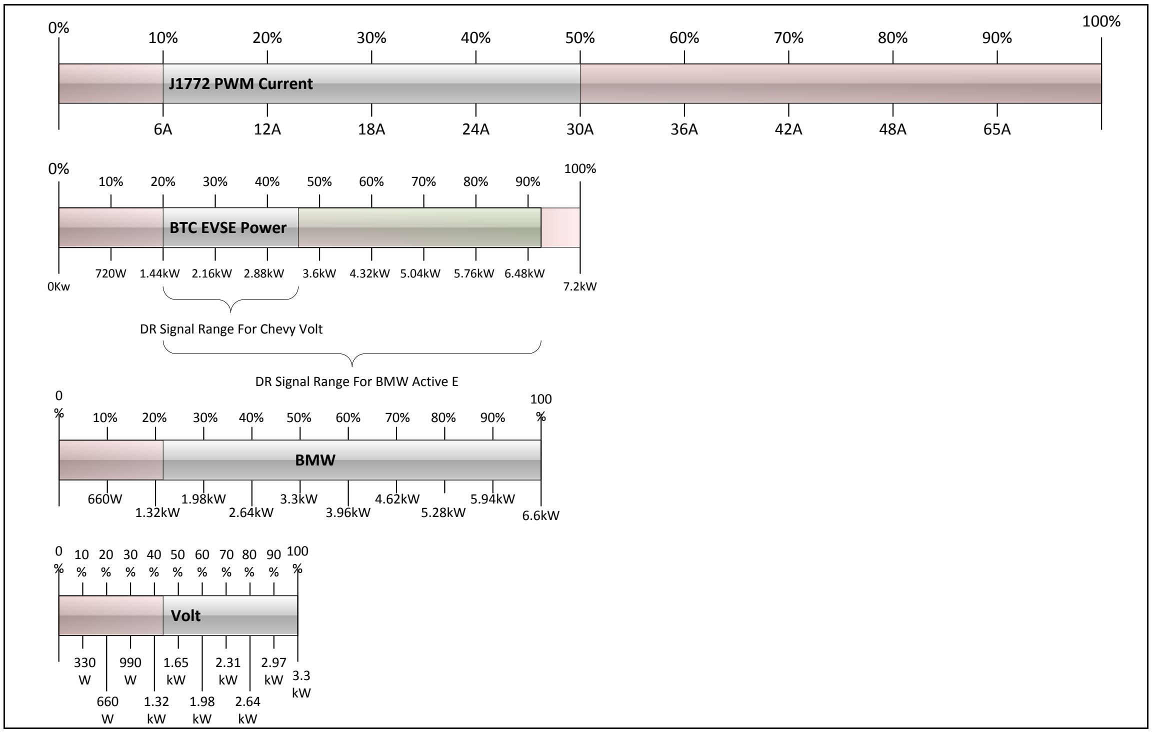
Prior to field deployment, the team understood that it would have no visibility of whether the HAN devices are connected to the meter or functioning properly unless a team member is physically at the project homes. This motivated the team to develop a mechanism for monitoring the communications status of the HAN devices. This mechanism consisted of a ZigBee communications traffic "sniffer" that passively monitors the communications between all the HAN devices and identifies when one of these devices has ceased communicating. The team has used this capability throughout commissioning and following deployment to assess the stability of HAN device communications. Prior to conducting load management experiments, the team uses this device to identify and resolve any communications issues that could affect the test. This device has also been helpful in managing the relationships with the project's 38 homeowners. Being able to remotely diagnose and resolve communications problems is less disruptive than scheduling regular visits to the customer premises.

Electric Vehicle Supply Equipment

The ISGD team completed the EVSE field installation in 22 project homes in May 2013. The team subsequently performed two series of commissioning tests to evaluate all aspects of the EVSE charging profile, and to examine the outcomes prior to field experimentation.

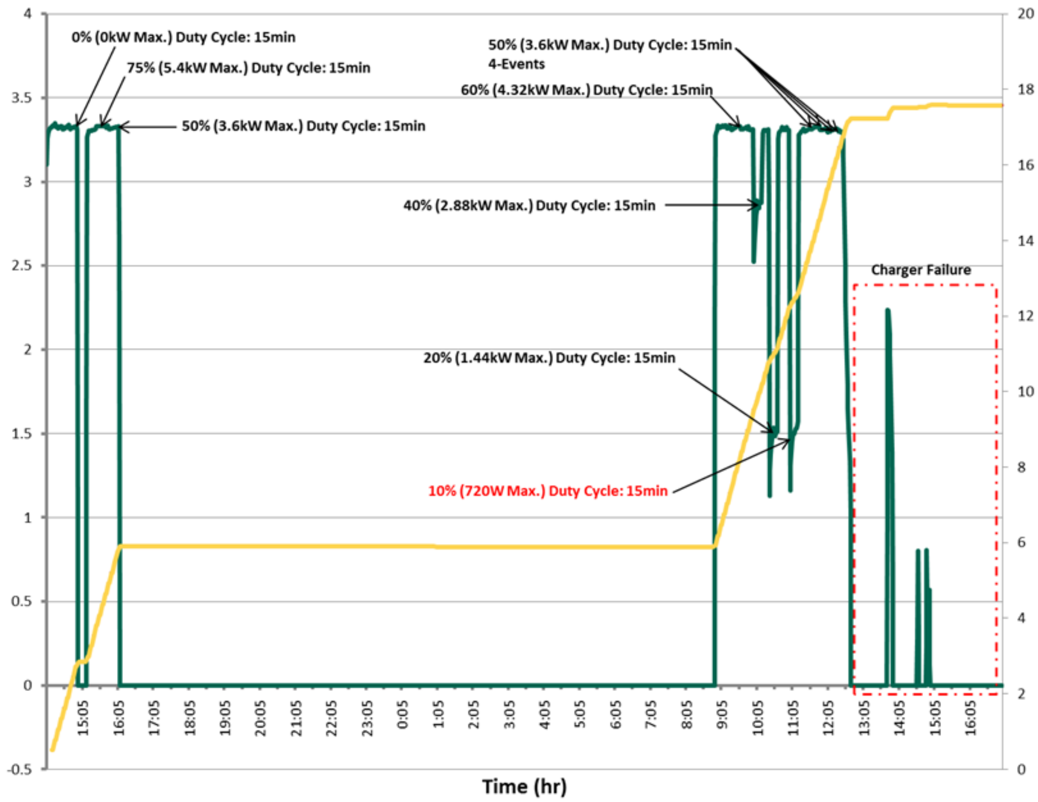
The first series of tests used a Chevrolet Volt (Volt) and the original EVSE. This evaluation consisted of sending multiple duty cycle DR events to the EVSE over a 24-hour period, with the goal of reducing the charging level to 75%, 60%, 50%, 40%, 20%, 10%, and 0% of the current charging levels. These tests revealed a limitation in how the Society of Automotive Engineers (SAE) J1772 standard for EVSEs has been implemented for DR by EVSE manufacturers. The SAE J1772 standard defines the acceptable PEV charging levels. The top of **Figure 23** depicts these PEV charging levels.

Figure 23: EVSE Duty Cycle Range Limits



Currently, when a DR event signal is sent to an EVSE to reduce the charging level by a certain percentage (e.g., 75% of current output), the EVSE reduces the charging level based on the maximum charging capacity of the EVSE, not by the actual PEV charging level. The originally installed EVSE had a maximum capacity of 7.2 kW, so a 75% duty cycle DR event signal would cause the EVSE to reduce its charge level to 5.4 kW (75% of the 7.2 kW maximum charge level). However, a PEV's charging level is also constrained by the vehicle itself. For example, the Chevrolet Volt's maximum charging level is 3.3 kW. Thus, when the ISGD team sent a DR signal to reduce the PEV charging level to 75% (equivalent to 5.4 kW) the Volt did not reduce its charging level. Rather, it continued to charge at 3.3 kW, since the 5.4 kW was above the Volt's maximum charging level. **Figure 24** summarizes the EVSE power levels over the course of these various duty cycle events.

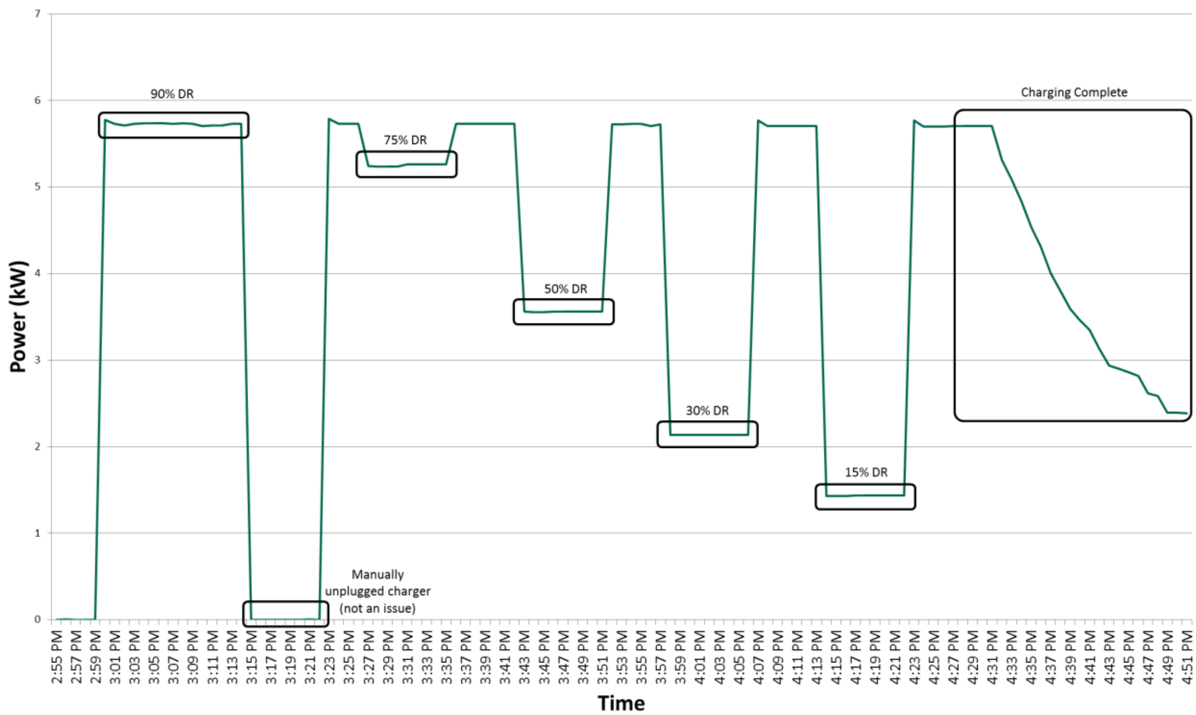
Figure 24: Chevrolet Volt Duty Cycle Power Profile



This testing improved the team's understanding of the vehicle limitations and the SAE J1772 standard constraints. This understanding allowed the team to identify the potential range of charging levels for each relevant vehicle EVSE combination. The Chevrolet Volt can charge at between 20% and 45% of the EVSE's capacity. Anything over 45% is above the Volt's maximum charge level, while anything below 20% is below the SAE J1772 minimum charge level. **Figure 23** summarizes the range of possible PEV charging levels based on the J1772 standard constraints. This figure also includes the range of possible charging levels for the originally installed EVSE, and for the Chevrolet Volt and BMW ActiveE when charged with the EVSE.

A second series of tests used the originally installed EVSE and a BMW 1 Series Electric (ActiveE). The ActiveE has a larger battery capacity and an internal charger rating (6.6 kW), which allowed the team to test a greater number of charging level scenarios. The team used this vehicle/EVSE combination to send duty cycle DR event signals to reduce the vehicle's charging to 15%, 30%, 50%, 75%, and 90% (again, the EVSE provides a maximum charge level of 7.2 kW.) Duty cycle DR events reduce the charging level based on this 7.2 kW rating (e.g., a 75% duty cycle would reduce the maximum charge to 5.4 kW). However, duty cycle events using the EVSE only affected the charging level of an ActiveE when they were below 6.6 kW (the ActiveE maximum charge rate). **Figure 25** summarizes the EVSE power levels during over the course of these various duty cycle events.

Figure 25: ActiveE Duty Cycle Power Profile



This second round of commissioning tests confirmed the results of the first round, that an EVSE's ability to perform duty cycle DR events is constrained by the charging capacity of the EVSE and the vehicle's onboard charger. Chapter 5 discusses this finding in more detail.

Residential Energy Storage Unit

Between July and October 2013, the team installed RESUs in 14 project homes, nine on the ZNE Block and five on the RESU Block. Following installation, each RESU underwent commissioning procedures and tests to ensure that all required electrical and communications connections were working properly and that the RESU could perform the required functions.

The team configured each RESU to communicate with the RESU Server, registered them, added them to a test group, and paired them with each home's project smart meter. The team also placed the RESUs in various operating modes to ensure they would charge and discharge as expected. These commissioning activities were successful for each RESU and the team identified no issues.

SCE identified three major operational issues with the RESUs within a few months of commissioning. These issues are described below. The team worked closely with the vendor to identify the root causes and develop solutions. These three issues were resolved, and the ISGD team continued to monitor the RESUs closely to identify and resolve any additional issues.

Battery Error: The first issue involved the RESUs erroneously reporting a battery error. RESUs typically report this error when they reach an over-discharged state. However, the RESUs began reporting this error while operating in a normal state. After identifying the issue, SCE immediately provided all available data to the vendor. The vendor determined that the RESU falsely reported this error due to an advanced safety diagnostic process that was susceptible to noise interference. The vendor provided a firmware update that disabled this specific mechanism. Several redundant safety mechanisms remain in place. SCE verified these mechanisms through laboratory testing prior to updating the units in the field with the new firmware. This update allowed the RESUs to operate without sacrificing any performance or functionality.

Memory Error: The RESUs have a touchscreen computer that runs custom vendor programs on a Windows CE operating system. After running continuously for approximately one month, the RESU computers reported low memory errors. These errors caused the RESUs to cease operation and required manual intervention to reset. The vendor provided a software update that causes the RESUs to reboot on a weekly basis, which avoids the low memory error. SCE verified the performance of this software update prior to deploying it to the RESUs in the field.

Network Connectivity: The RESU Server provides remote monitoring and control of the RESUs. The RESU Server is located in the ISGD Pilot Production back office environment[26]. The RESUs communicate with the RESU Server using dynamic internet protocol (IP) addresses that they receive from ISGD's 4G radios. Following deployment, the RESUs had difficulty receiving these dynamic IP addresses, leading to loss of communication with the back office server. SCE determined that the cause was due to the RESU (internal) control computer not conforming to the standard Dynamic Host Configuration Protocol process. The vendor confirmed this finding and provided a software update that improved the RESUs' acceptance of IP addresses.

One lesson from this experience is that although laboratory and commissioning tests are critical to assessing the functionality and performance of new technologies, it is important to monitor devices in the field throughout operation to identify other unknown issues. For example, ISGD's extensive laboratory testing did not identify the Battery Error. The team believes that this error notification resulted from specific location and environmental factors that a laboratory setting cannot replicate.

Community Energy Storage

The team installed the CES device on the CES Block in June 2013. The CES is helping to demonstrate utility-controlled, distributed energy storage. The Distributed Energy Manager (DEM) provides CES monitoring and control using a 4G connection to the ISGD Pilot Production back office environment. SCE grid operators also have real-time visibility of the CES. The CES is a four quadrant device (i.e., it can discharge and charge real power, and inject and absorb reactive power), has a power rating of 25 kVA, and may be controlled using real and reactive power commands.

The CES commissioning test helped to verify the basic communication, control and data acquisition features of the CES and DEM. The DEM allows for manual control and can command the CES to operate using a specified charge and discharge schedule. The testing demonstrated three basic features: discharging and absorbing real power, discharging and absorbing reactive power, and islanding. The power tests consisted of discharging and charging real power at 5 kW increments, up to 25 kW. The team performed the same testing for reactive power by injecting and absorbing at 5 kVAR increments, up to 25 kVAR. The islanding test demonstrated the CES's ability to disconnect from the grid upon command while continuing to power to itself.

The CES performed as expected, providing the full spectrum of real and reactive power when commanded. The accuracy and limitations of the CES output were consistent with the laboratory test findings, and the communications were reliable.

SCE identified a number of operational issues with the CES—hardware and software related—within a few months of commissioning. These issues are described below. The team worked closely with the manufacturer to identify the root causes and develop solutions. The ISGD team continues to monitor the CES closely to identify and resolve other issues that arise in the future.

CES Forced Disconnect Test: The team tested the CES's islanding functionality by using the DEM to command the CES to disconnect from the grid and island itself. However, during the test the CES and DEM communication was lost due to radio trouble. The radio was unable to resume communication and the CES remained in the islanded state—powering itself from the batteries—for an extended period.

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[26] The Pilot Production environment consists of the back office computing environment used for ISGD. Section 5.1.1 provides a detailed description of this environment.

Within about a week, the CES's contactors began closing and opening approximately every 30 seconds. This behavior was unexpected and laboratory testing could not replicate it. To identify the root cause of the behavior, SCE worked with the manufacturer, who provided a firmware upgrade to resolve the issue.

<u>DEM Software Failure</u>: After restoring communication on September 4, 2013, the DEM database stopped logging CES data. This prevented data capture and control of the CES. The team installed an additional software component (IntelliLink Human Machine Interface) on the DEM to record more data. However, this resulted in further compatibility issues.

After several days of investigation and troubleshooting, the team re-imaged the DEM with the latest version of software, and the DEM then resumed data logging and normal operation. The team implemented a daily image backup process to mitigate any future occurrences. This issue did not reoccur.

<u>DEM Boot Failure</u>: Within a few months of commissioning, the DEM was not accessible through the ISGD Pilot Production network and was unresponsive to ping-attempts. SCE's Information Technology group visited the DEM and found that the hard disk was no longer accessible. The DEM was power cycled and then resumed proper operation. This happened again after about six months. The manufacturer provided SCE with a replacement DEM, which worked properly.

<u>CES Noise</u>: Laboratory testing and initial field testing revealed that the CES emits a high frequency noise, which varies based on the charge or discharge level. Through discussions with the vendor, the team learned that the noise is due to the CES power electronics and inductor design. Reducing this noise would require a significant hardware re-design.

SCE performed several sound surveys to assess the noise. At maximum power, the CES exceeded the City of Irvine's nighttime noise requirements. However, none of the ISGD field experiments required high power nighttime activity. SCE completed all tests as designed, within the City of Irvine's noise ordinances, while remaining sensitive to any concerns raised by homeowners.

7.1.1.4 Field Experiments

The Team conducted eight field experiments for sub-project 1, each consisting of one or more tests, over the two-year demonstration period. **Table 21** summarizes these experiments.

Table 21: Sub-project 1 Field Experiments

Field Experiment	Description Page
1A	**IDSM Impacts on Homes and Grid**
	Test 1: Home Impacts
	Test 2: Grid Impacts
	Test 3: Reaching the ZNE Goal
	Test 4: Final twelve month demonstration results
1B	**Demand Response Impacts on Homes, Smart Devices, and Grid**
	Test 1: IHD Price Signaling, 8/8/2013
	Test 2: PCT Demand Response - Cooling, 9/16/2013
	Test 3: PCT Demand Response – Heating, 12/20/2013
	Test 4: Smart Appliance Demand Response, 2/19/2014
	Test 5a: PCT and EVSE DR, 7/24/2014
	Test 5b: PCT and EVSE DR, 7/28/2014
	Test 5c: PCT and EVSE DR, 7/29/2014
	Test 6: DR Test of all HAN Devices, 9/15/2014
	Test 7: EVSE DR test, 9/18/2014
	Test 8: Pre-cooling test, 10/3/2014
	Test 9: EVSE Smart Charging
1C	**RESU Peak Shaving**
	Test 1: Secure Backup Load

Field Experiment	Description Page
1C (Continued)	Test 2: Time-based Permanent Load Shifting
	Test 3: Price-based Permanent Load Shifting
	Test 4: VAR Support
1D	**RESU Level Demand**
	Test 1: RESU Discharge, 11/7/2013
	Test 2: RESU Level Demand, 1/13/2014 to 2/25/2014
	Test 3: RESU PV Capture, 2/25/2014 to 10/9/2014
1E	**CES Load Shifting**
	Test 1: CES Peak Load Shaving, 11/18/2013 to 1/13/2014
	Test 2: CES Permanent Load Shifting, 1/13/2014 to 9/20/2014
	Test 3: CES Islanding
1F	**Solar PV Grid Impact**
	Test 1: RESU Transformer Load Profile, 10/11/2013 to 11/6/2013
	Test 2: RESU PV, 3/1/2014 to 10/31/2014
1G	**EVSE Demand Response**
1H	**Sub Metering**

Field Experiment 1A: Impact of Integrated Demand Side Management Measures on Home and Grid

For this Final Technical Report, the team replaced the content of Field Experiment 1A submitted in TPR #2 dealing with impact on the homes and reaching the ZNE goal with updated information from the final twelve months of the demonstration period. The content in TPR #2 dealing with grid impacts is retained since it consists of short-term measurements rather than full year aggregates. The portion on reaching the ZNE goal in this report places more focus on the ZNE TDV metric as that metric has been selected by the state of California as the one to be required for ZNE homes.

The objective of this experiment was to quantify the impact of energy efficiency upgrades and DR strategies on the home and electric grid. This experiment included four blocks of project homes. Three blocks received a series of IDSM measures through retrofits. Of these, the *ZNE Block* homes received the most extensive set of upgrades including EEM. Although the specific measures vary by home, most of the ZNE block retrofits included LED lighting, high-efficiency heat pumps, high-efficiency water heaters or domestic solar hot water heaters, plug load timers, low-flow showerheads, duct sealant, increased attic insulation, ENERGY STAR smart appliances, solar PV arrays, RESUs, EVSEs, and other HAN devices. The *RESU Block* homes received RESUs, ENERGY STAR smart appliances, and EVSEs, but no other energy efficiency upgrades. The *CES Block* homes received the same equipment as the RESU homes, except that rather than receiving a RESU, the team installed a CES near the transformer to help manage load on the block's distribution transformer. The CES may also provide a limited amount of backup power in the event of an outage. The *Control Block* homes received no upgrades. The team assigned random numbers to each project home in order to conceal confidential customer information. For example, the nine homes on the ZNE Block are identified as homes ZNE 1 through ZNE 9.

The team installed power monitoring instrumentation in each home to help evaluate their performance. These monitoring devices consist of branch circuit monitors, plug load monitors, temperature sensors, and project smart meters. Transformer monitors record the loading on each of the four distribution transformers. A more detailed discussion of the team's approach for collecting this data is included in Appendix 3. This instrumentation provides detailed visibility of the project homes' energy consumption patterns, allowing the team to compare energy usage for particular types of load—such as lighting or refrigeration—between individual homes and across blocks. While no monitoring instrumentation was installed to capture natural gas usage, natural gas utility data was collected from the local gas utility (with the customers' consent) for 36 months starting on November 2011.

The following is a list of some general observations originally reported in TPR2. The observations remain valid.

- <u>Variability</u>

- There is a high degree of variation in energy use among the homes and between the four blocks. Over the past 12 months, the electricity consumption of the homes ranged from about 4,000 kWh (ZNE 3) to over 10,000 kWh (RESU 4), while homes in the Control Block consumed nearly 16,000 kWh (CTL 5). Natural gas consumption also varied significantly among the homes and between the blocks. ZNE 6 consumed over 15,000 thousand British thermal units (kBtu), while RESU 6 consumed over 60,000 kBtu, CES 1 over 55,000 kBtu, and CTL 8 nearly 70,000 kBtu (note that the occupants of CTL 8 moved out in February 2015, so this home only reflects a partial year of natural gas use).
- There is also a high degree of energy use variation among individual appliances within each home. Lighting, HVAC, and refrigeration typically represent the most energy use for the ZNE Block homes, although there are exceptions. ZNE 4's television energy use is comparable to its HVAC and refrigerator energy use combined, while ZNE 1's television energy use is nearly zero. ZNE 2's home office equipment energy use is comparable to its HVAC energy use.
- HVAC energy use varied considerably among the homes and between the blocks. Most of the ZNE Block homes received electric heat pumps in exchange for their existing air conditioners and gas furnaces—or just the gas furnace for homes without air conditioning units. The HVAC energy use of the ZNE Block homes varied significantly. ZNE 9 used four times as much energy as ZNE 4 to run its HVAC. CES 1 used 30 times as much energy as CES 3 to run its HVAC. RESU 5 used twice as much energy as RESU 6 to run its HVAC.

- <u>Electric Vehicle Chargers</u>
  - Typically, PEV charging is among the top four energy uses for the ZNE, CES, and RESU block homes. CES 7's PEV charging represents its largest source of energy use.
- <u>Achieving ZNE Status</u>
  - Achieving ZNE status is highly dependent on the metric used to evaluate ZNE. As a result, some homes have achieved ZNE status under one of the metrics, but did not achieve ZNE under other metrics.
  - Comparing the updated forecasted ZNE status of the ZNE Block homes with their actual ZNE status shows that, on average, the homes on the ZNE Block are nearly 15% below what the team predicted. While multiple factors can influence the difference between the forecasted and the actual ZNE status, the team believes there are two primary reasons for the difference. The first relates to the hourly allocation of the RESU losses. Second, the team believes that changes in occupant behavior also contributed to the homes' ZNE performance. Such changes might occur due to changes in weather, occupancy, or other factors. It is also possible that behavior changes could result from the occupants' perception that they are receiving free energy from the solar PV arrays.

Test 1: Impact on the Homes

Figure 26 through **Figure 29** summarize one year of continuous electricity usage between July 1, 2014 and June 30, 2015, for each project home. These figures are organized by project block. The figures illustrate the level of detailed data the team collected to assess the impacts of the various energy efficiency components. For example, energy consumption for lighting is available for all the blocks, excluding the Control Block. Although the ZNE Block received high efficiency LED lighting upgrades, lighting is still a major source of energy usage within these homes. "Other Loads" consist of electricity use that the ISGD team did not monitor discretely. This likely included devices plugged into wall outlets such as laptop computers, routers, cable boxes, floor lamps, microwave ovens, etc.

Figure 26: ZNE Block Electric Energy Use Breakdown (July 1, 2014 to June 30, 2015)

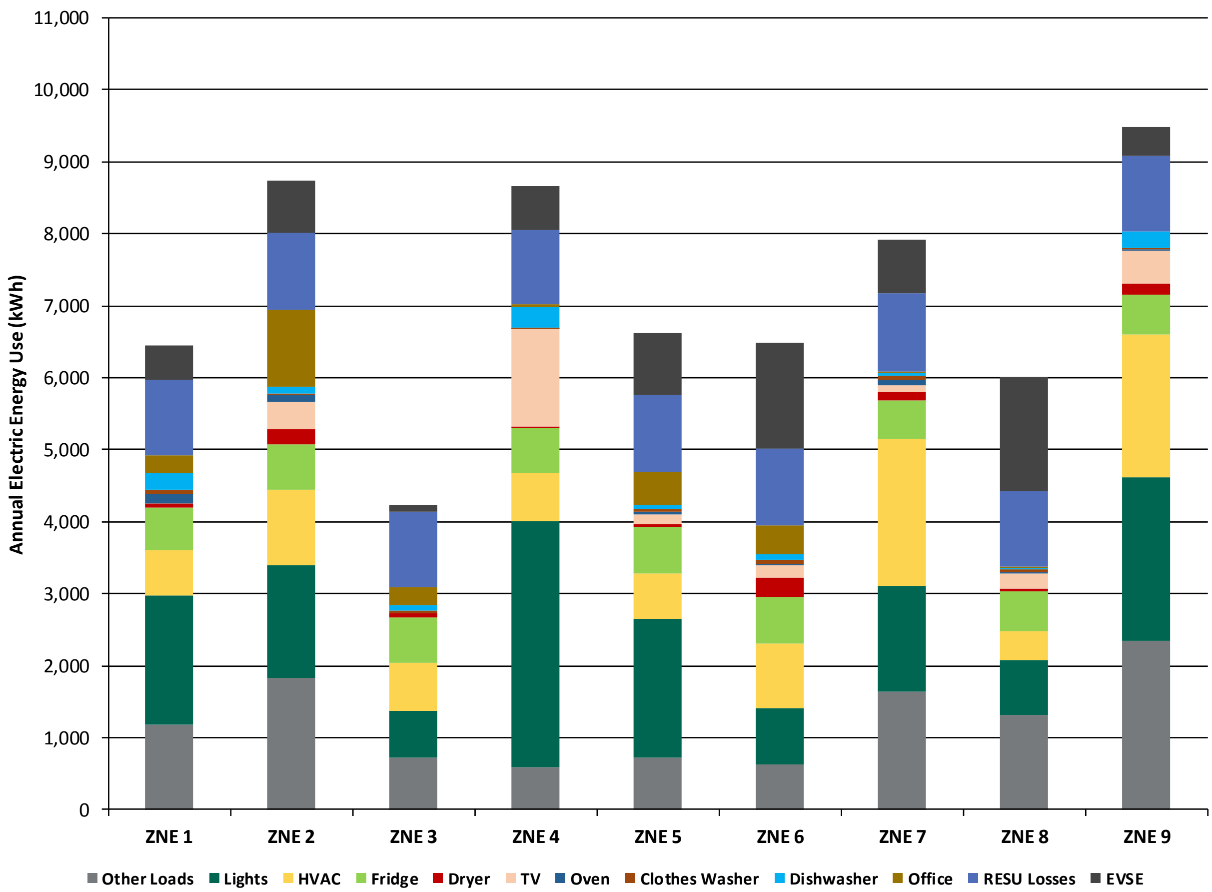


Figure 26 shows the electric energy usage breakdown of the homes on the ZNE Block. In general, lighting and HVAC represent the top two energy consuming components followed by the refrigerator and television. Occupant behavior clearly affects the energy usage of these homes. The impact of occupant behavior can be seen in ZNE 4, where the large television energy usage is the same as the HVAC and refrigerator combined. This impact can also be seen in ZNE 2, where the home office equipment energy usage is comparable to its HVAC energy usage. In ZNE 6, the relatively large clothes dryer energy usage results from the dryer being an electric unit. In ZNE 8, the electric vehicle charging represents a significant share of total home energy. This home has nearly 50% more EVSE use than most of the other homes on the ZNE Block.

Figure 27: RESU Block Electric Energy Use Breakdown (July 1, 2014 to June 30, 2015)

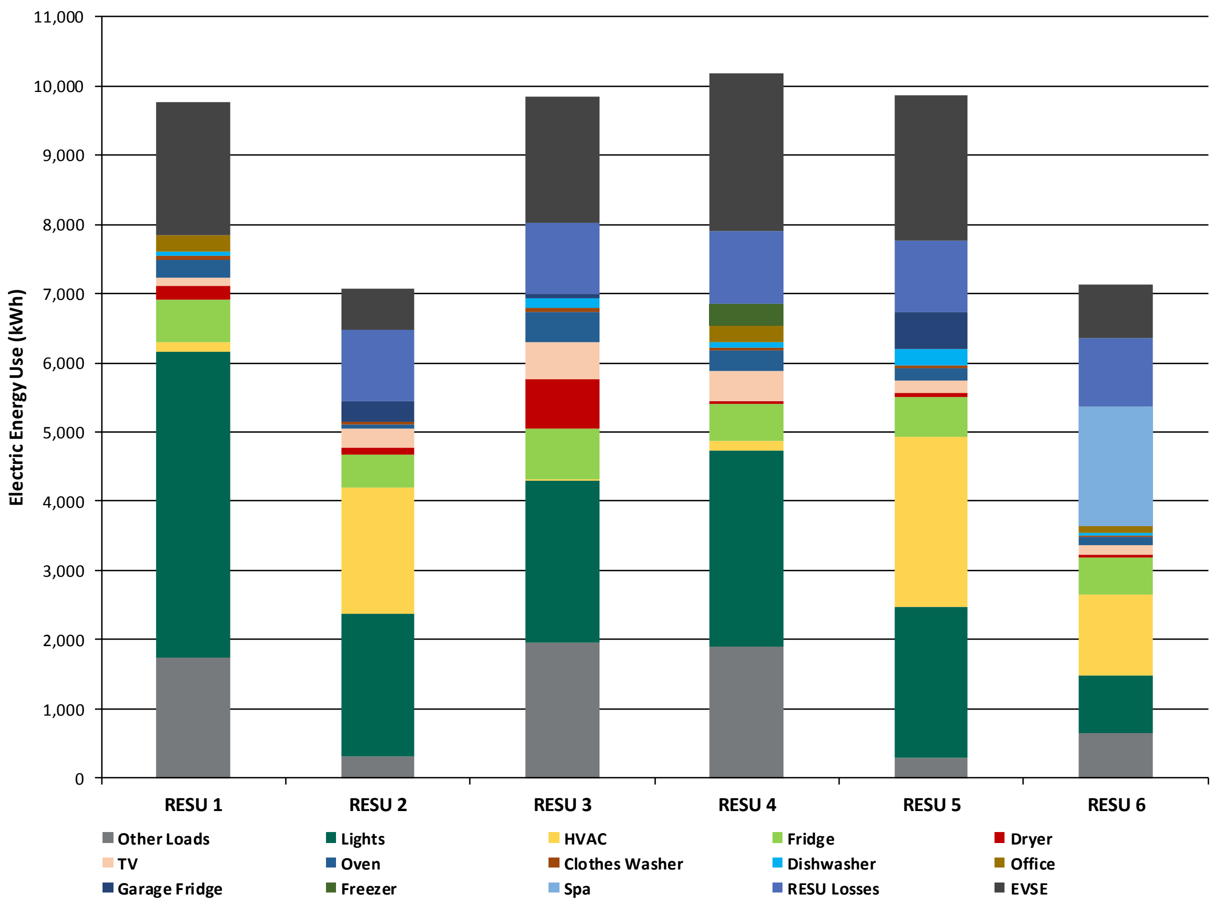


Figure 27 summarizes the energy use breakdown for each RESU Block home. The top two energy-use components are lighting and HVAC, which is consistent with the ZNE Block homes. The next two largest energy use components are the refrigerator and television. It is worth noting that the HVAC energy usage of RESU 1, RESU 3, and RESU 4 are much lower than their television energy usage. These homes use natural gas furnaces for heating rather than heat pumps. In addition, RESU 3 has very high clothes dryer energy use, which is mostly the result of having an electric dryer. RESU 6 is the only ISGD home with a spa, which represents nearly 25% of the home's total energy use. The electric vehicle charging represents a significant share of total home energy usage, with RESU 1, RESU 3, RESU 4, and RESU 5 consuming nearly twice as much as the other RESU Block homes. It is important to point out that a RESU was not installed in the RESU 1.

Figure 28: CES Block Electric Energy Use Breakdown (July 1, 2014 to June 30, 2015)

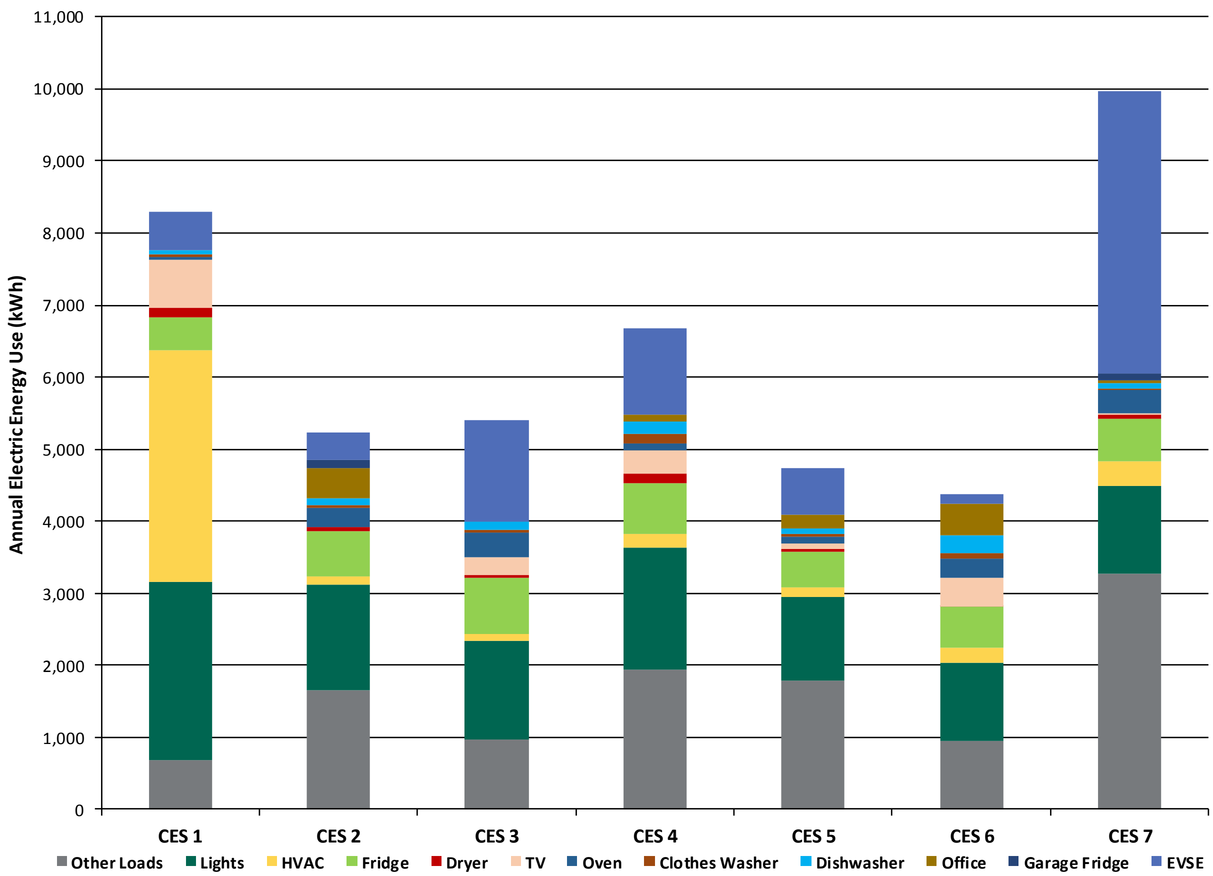


Figure 28 summarizes the electric energy usage breakdown of the CES Block homes. The components with the highest energy use are lighting and the refrigerator, followed by HVAC and television. The largest variability is between CES 1 and CES 7. The HVAC energy usage of CES 1 is nearly 40% of the home total energy use and 10 to 18 times greater than CES 4, CES 6, and CES 7 (CES 2, CES 3, and CES 5 only have natural gas furnaces for home heating). Electric vehicle charging represents almost 40% of CES 7's total energy consumption, and uses approximately 3 to 30 times more energy than the other homes in the CES Block. In these two cases, occupant behavior is the main cause of the large variability. The team confirmed with the residents of CES 1 their high HVAC energy use and the CES 7's high EVSE energy use is a result of this home having up to three PEVs throughout the final year of the project.

Figure 29: Control Block Electric Energy Use Breakdown (July 1, 2014 to June 30, 2015)

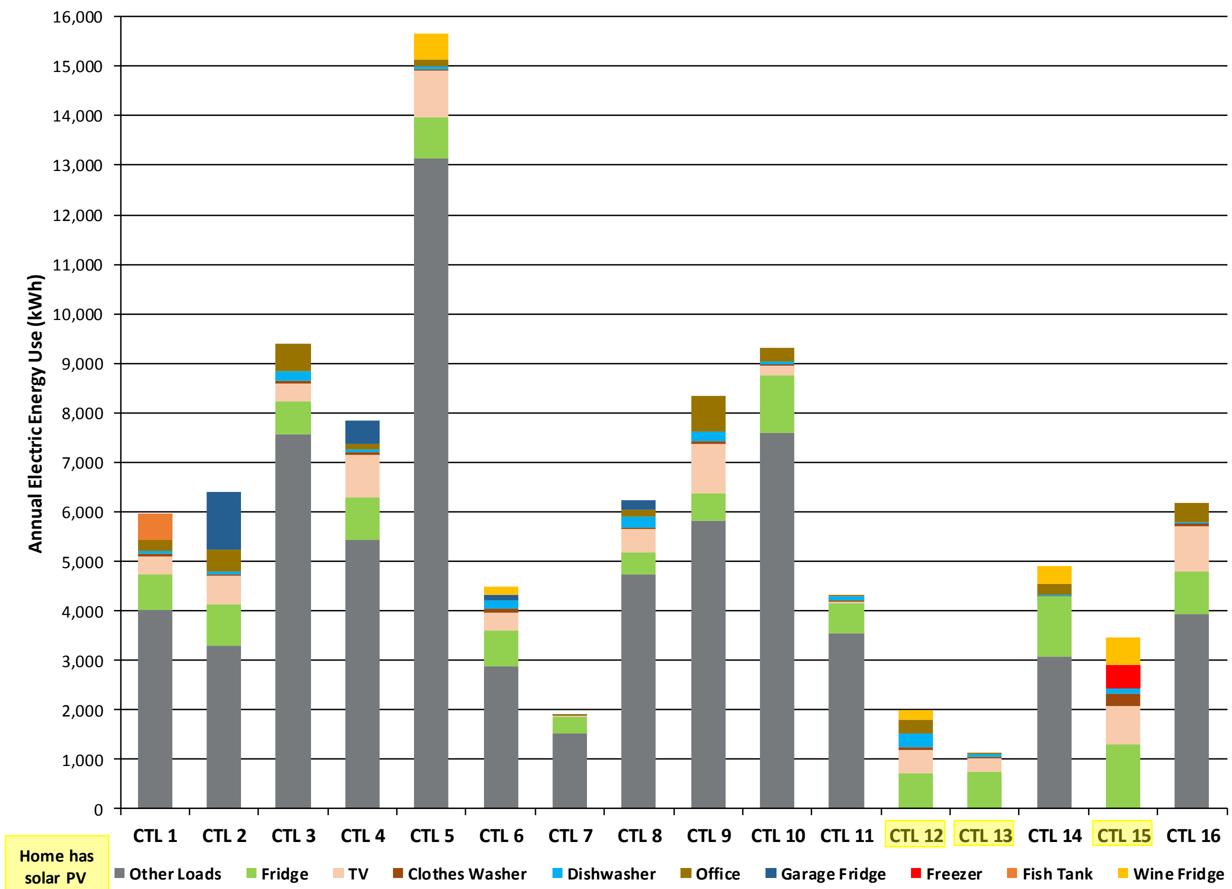


Figure 29 displays some of the electric loads for the Control Block homes. Other Loads represents the largest load in all the homes, excluding CTL 12, CTL 13, and CTL 15, which have solar PV arrays. The team did not equip these homes with the same level of energy usage monitoring equipment as the other project block homes. As such, the Other Loads are determined by subtracting the various monitored loads from the whole-house meter data. In the case of the homes with solar PV arrays, it was not possible to calculate the Other Loads because the solar PV generation was not measured. Still, refrigerator and television are significant loads in these homes, consistent with the ZNE, RESU, and CES blocks.

The natural gas usage for 36 months ending on June 30, 2015 is summarized in **Figure 30** through **Figure 33**. The natural gas data was only available at the utility meter level and was reallocated to fall within monthly calendar periods. These figures are organized by project block and three 12-month periods. The first period covers July 1, 2012 to June 30, 2013, which is before the homes received any energy efficiency upgrades. The second period covers July 1, 2013 to June 30, 2014, encompass a period when most energy efficiency upgrades were being installed (July thru September 2013) as well as a period of performance. The third period covers July 1, 2014 to June 30, 2015, which represents the period of analysis for the FTR. The focus of this analysis is to compare the natural gas usage during each of the three twelve-month periods.

Several factors are worth noting. First, eight of the nine ZNE block homes had their gas heaters replaced with electric heat pumps and therefore this component of gas consumption is mostly absent in the second two twelve-month periods. Second, average temperatures were higher in the second period and higher still in the third, resulting in lower gas consumption. The control block experienced about a 24% reduction while the ZNE block experienced a 31% reduction. This combination of variables combined with individual variability and the small sample set makes it difficult to draw firm conclusions from the gas consumption data alone.

Figure 30: ZNE Block Natural Gas Energy Use

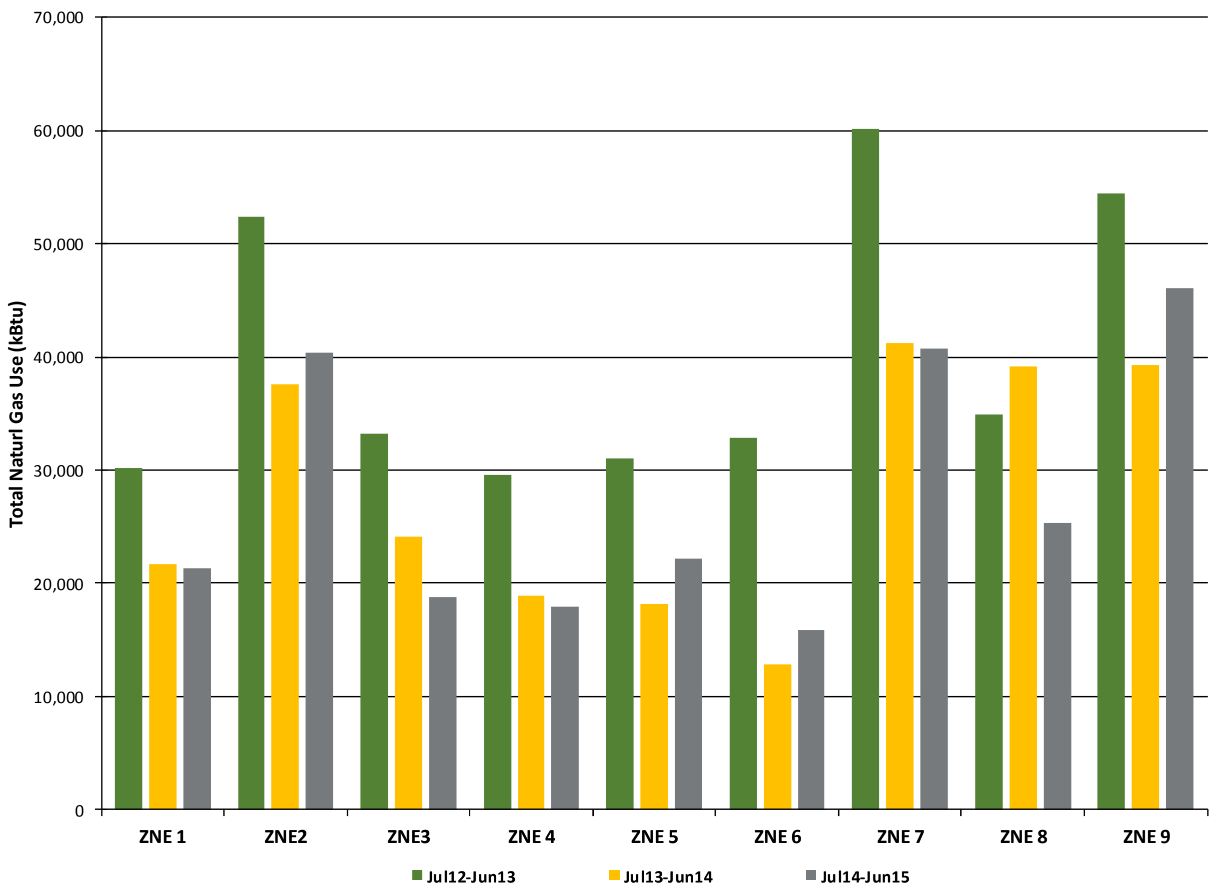


Figure 30 summarizes the natural gas consumption for the ZNE Block homes. While there was a minor increase in natural gas consumption for ZNE 2, ZNE 5, ZNE 6, and ZNE 9 in the period of Jul'14-Jun'15 compared to the period of Jul'13-Jun'14, in general, the natural gas use declined between Jul'12-Jun'13 and Jul'14-Jun'15 by an average of 32% across all ZNE Block homes. For ZNE 1, ZNE 4, and ZNE 7 natural gas consumption has practically not changed between the periods of Jul '13-Jun'14 and Jul'14-Jun'15. The general decline in natural gas use was consistent across all four blocks, including the Control Block.

Figure 31: RESU Block Natural Gas Energy Use

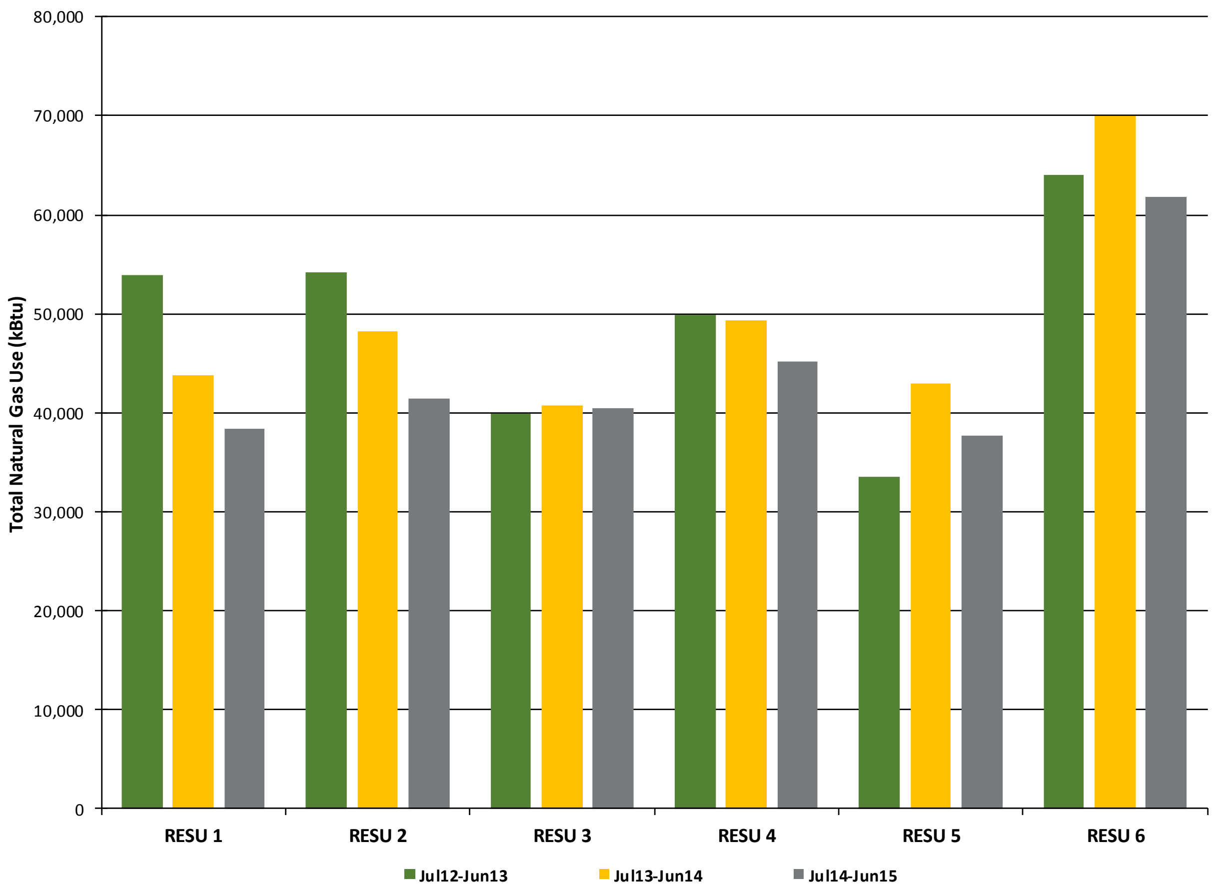


Figure 31 summarizes the natural gas consumption for the RESU Block homes. The only energy efficiency upgrade that these homes received that affects natural gas consumption is ENERGY STAR clothes washers. Over the 36 months, the natural gas consumption of RESU 1 and RESU 2 declined by about 25% and RESU 4 by about 10%, while RESU 3 was practically unchanged. The natural gas consumption of RESU 5 increased by 10%. RESU 6 natural gas consumption increased by 9% in the period of Jul'13 to Jun'14, but then decrease by 12% in the period of Jul'14 to Jun'15.

Figure 32: CES Block Natural Gas Energy Use

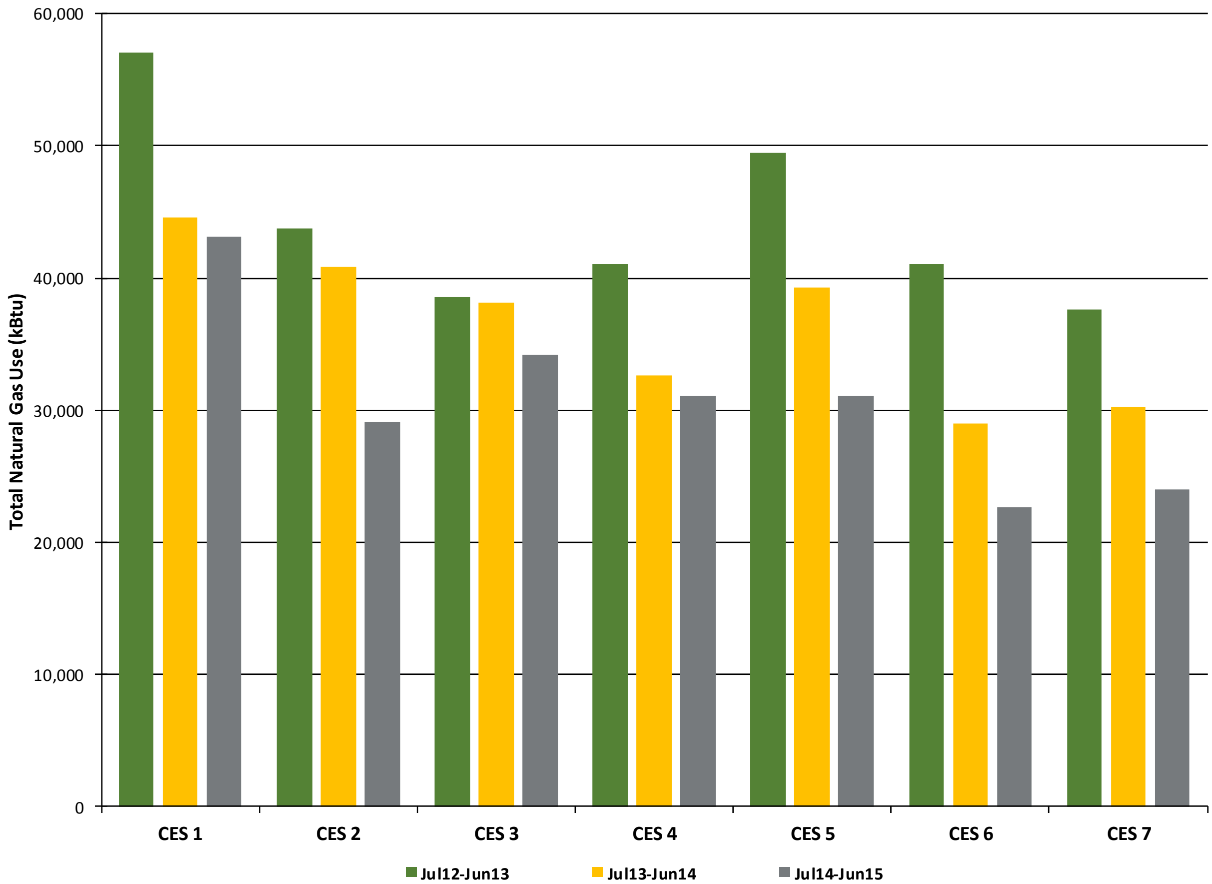


Figure 32 summarizes the natural gas consumption for the CES Block homes. Similar to the RESU Block homes, the only energy efficiency upgrade that these homes received that affects natural gas consumption is ENERGY STAR clothes washers. In general, natural gas consumption declined by 30% across all homes in the CES Block, with the exception of CES 3 with a reduction of about 10%.

Figure 33: Control Block Natural Gas Energy Use

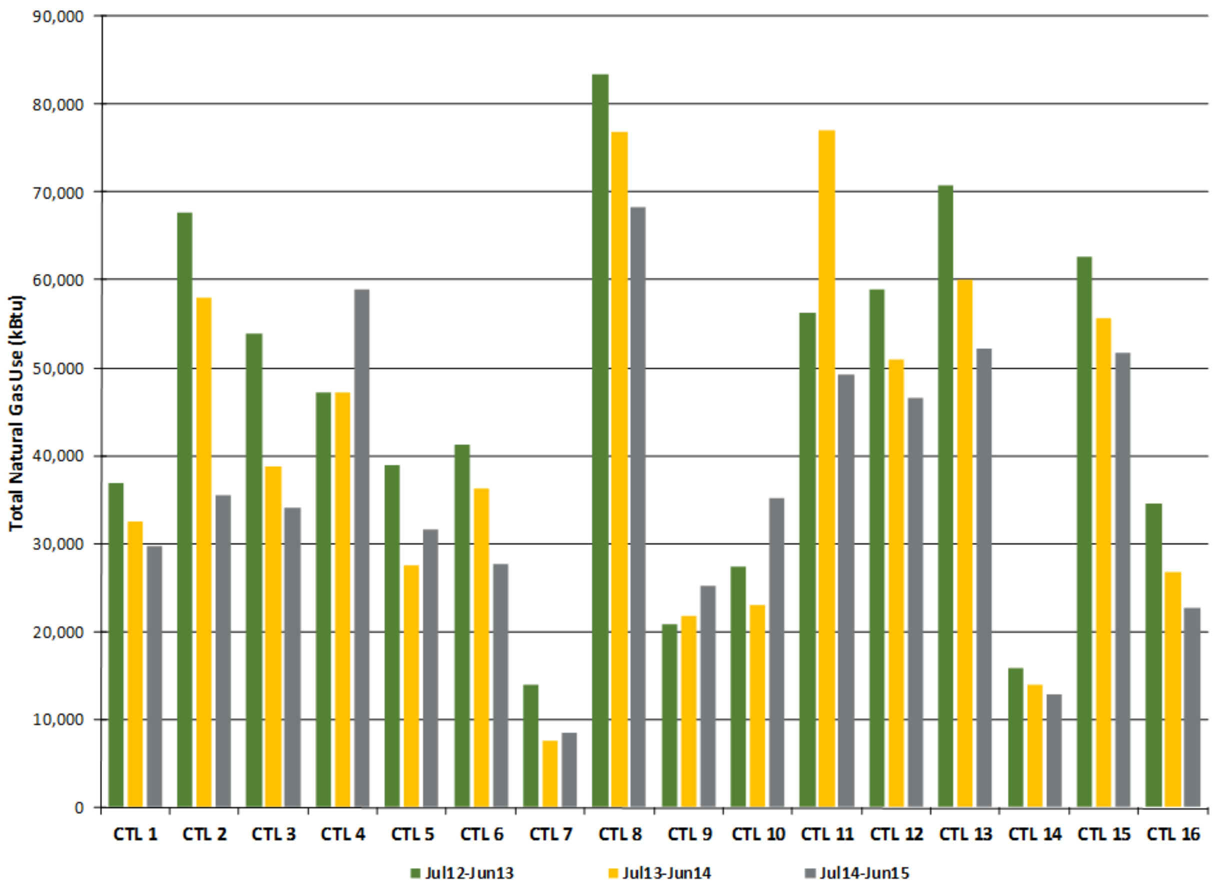


Figure 33 displays the natural gas consumption for the Control Block homes over a 36-month period. In general, natural gas consumption in all Control Block homes declined, with the exception of CTL 4, CTL 9, and CTL 10. There is significant variation in natural gas consumption among the homes, with some consuming 8 times as much as other homes (e.g., CTL 8 versus CTL 7). For the period between July 1, 2014 and June 30, 2015, CTL 8 natural gas consumption data is only for seven months because the occupants moved out in February 2015.

Test 2: Impact on the Grid

Another aspect of this experiment was to evaluate the impact of the energy efficiency upgrades, DR strategies, solar PV, RESU, CES, and PEV charging on the grid. This consists of monitoring the load profiles of the four distribution transformers on the four blocks of project homes. **Figure 34** through **Figure 37** present the load profile of all nine homes on the ZNE Block for December 2013, March 2014, June 2014, and September 2014, respectively. The data in these figures represents the aggregate load for all nine homes (i.e., the load of the entire ZNE Block), averaged for all the days in the respective month. The yellow line represents the block's total load (kW) (i.e., how much power all the homes required at various times throughout the day). The thick gray line represents the ZNE Block's net demand (measured by the project smart meters in each home on the ZNE Block). The net demand is lower than total demand due to the solar PV generation, and the RESU charging and discharging activity (represented by the dotted line). The blue line indicates the demand from PEV charging, while the green line represents the solar PV generation.

Figure 34: ZNE Block Aggregate Home Load Profile (Daily Average for December 2013)

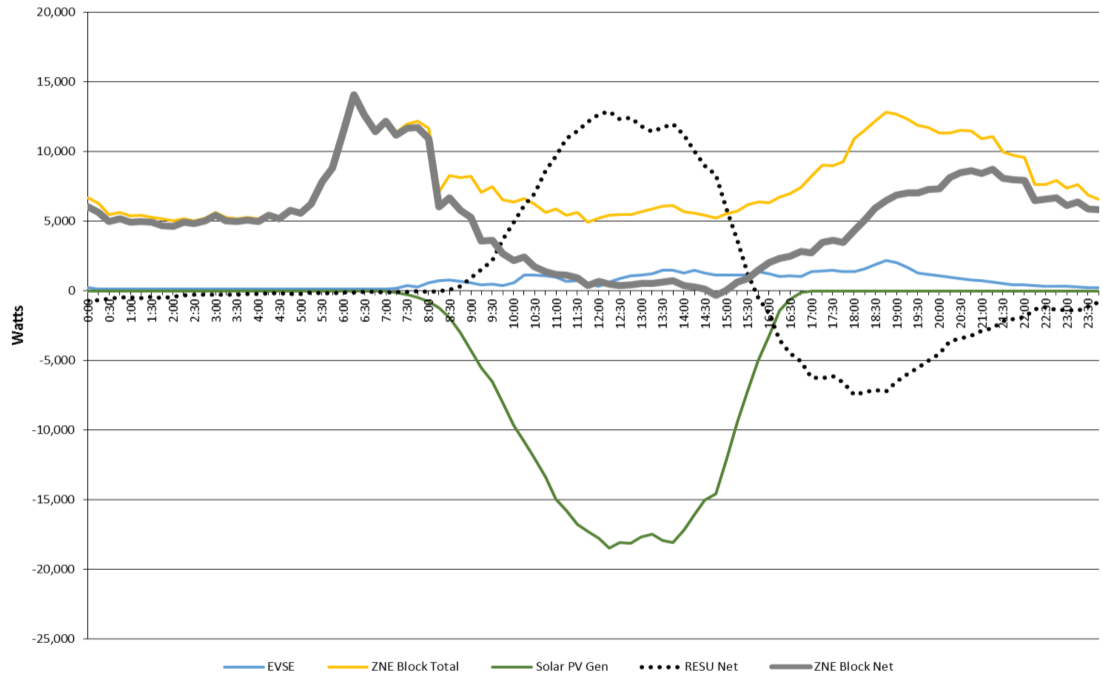


Figure 35: ZNE Block Aggregate Home Load Profile (Daily Average for March 2014)

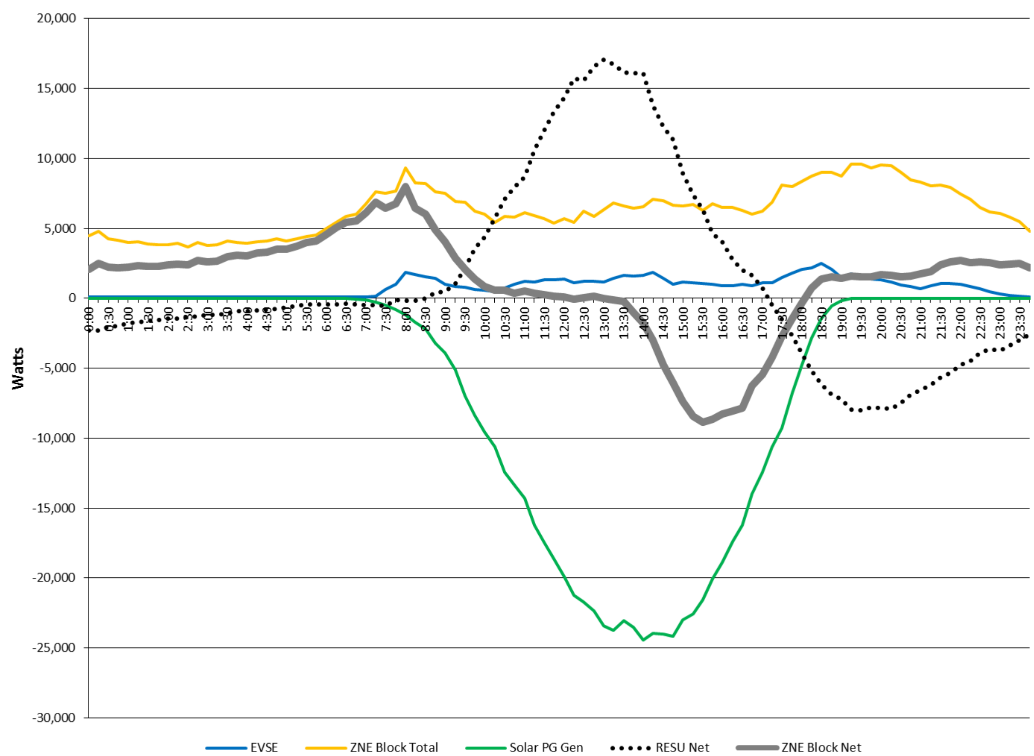


Figure 36: ZNE Block Aggregate Home Load Profile (Daily Average for June 2014)

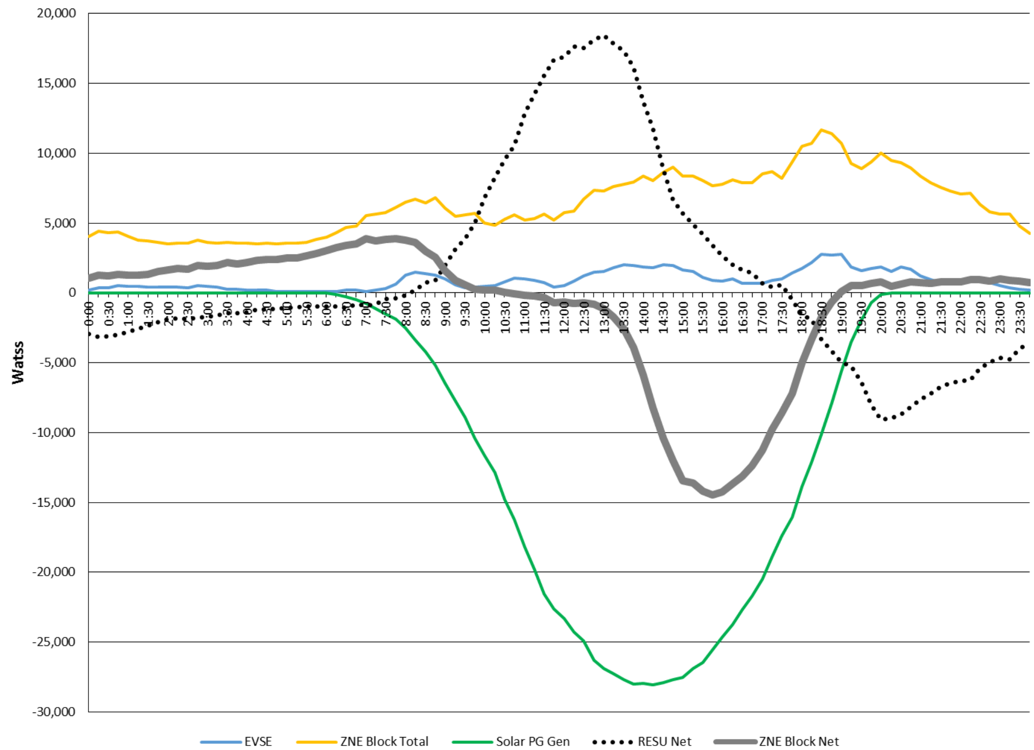
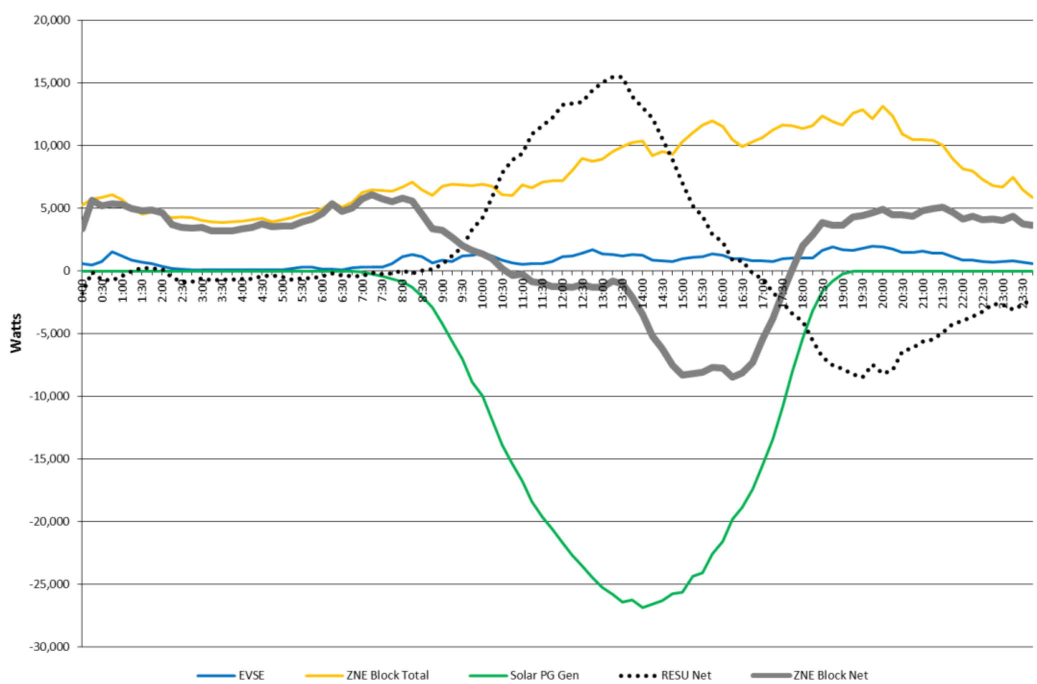


Figure 37: ZNE Block Aggregate Home Load Profile (Daily Average for September 2014)



The RESUs operated in the *PV Capture* mode from February 25, 2014 to October 9, 2014.[27] When operating in this mode, a RESU charges or discharges based on a set point for the net household demand. This set point was set at 0 kW. The RESUs charged anytime the net household demand was below zero (e.g., the solar PV generation was greater than the home's electricity demand). The RESUs also discharged any time the net household demand was above zero. Naturally, the RESUs were constrained by their energy storage capacity (10 kWh), and could only discharge if there was energy in the RESU.

The solar PV generation exhibits seasonal fluctuations throughout the year. The peak solar PV output of the ZNE Block increases from nearly 20,000 W in December to about 25,000 W in March. It then increases to about 30,000 W in June before dropping to about 25,000 W in September. This variation in solar PV generation impacts the load shapes throughout the year. In December, the ZNE Block net demand remains near zero during the peak solar hours, then increases to about 8,000 W during the peak evening load period (see **Figure 34**). The load is near zero during the daytime since the RESU was operating in *PV Capture* mode. In March, the ZNE Block net demand goes from negative (about -10,000 W) during the solar peak hour to positive evening demand of around 2,500 W (see **Figure 35**). In June, the ZNE Block net demand also goes from about zero during the early morning to about -15,000 W during the solar peak hours, and then returns to zero in the evening hours (see **Figure 36**). This near zero demand during the evening is due to the RESUs offsetting most of the homes' loads. During September, the ZNE Block net demand is similar to March, except that it has higher evening demand of about 5,000 W (see **Figure 37**). The combination of solar PV generation and RESU charging and discharging has a significant impact on the net demand level throughout the day.

Unlike the ZNE Block, in which all homes on the block are project participants, not all the homes on the RESU and CES blocks are project participants. To evaluate the grid impact of the RESU and CES block homes-- and to be able to compare their impact with the homes in the ZNE Block—the team used an average home load profile for the ZNE, RESU, and CES blocks. **Figure 38** through **Figure 40** show the average home profiles for the three blocks during December 2013. These load profiles consist of an average of the 31 days in December. The yellow line represents the average home's total load (kW) (i.e., how much power the average home required throughout the day). The thick gray line represents the net demand of the average home. The net demand is lower than total demand due to the solar PV generation, and the RESU charging and discharging activity (represented by the dotted line). The blue line represents PEV charging and the green line represents the solar PV generation.

[27] When operating in this mode, the RESU attempts to decrease a home's maximum demand and increase its minimum demand through charging and discharging. The goal of this mode is to "level" a home's demand throughout the day by removing the peaks and valleys in the home's load profile.

Figure 38: ZNE Block Average Home Load Profile (Daily Average for December 2013)

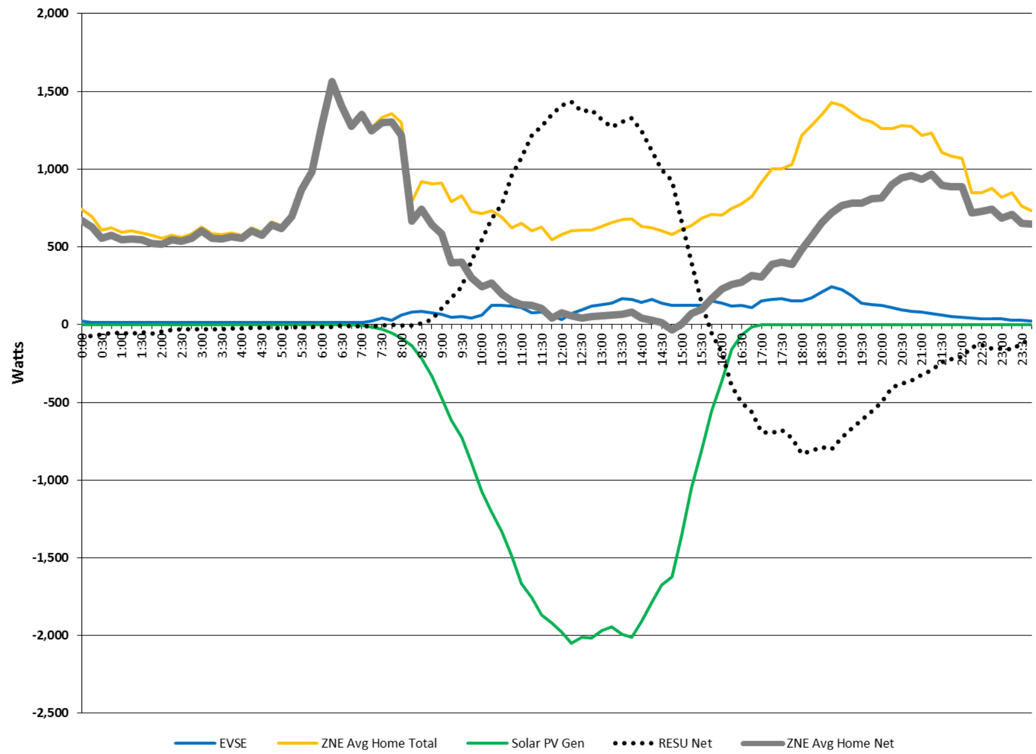


Figure 39: RESU Block Average Home Load Profile (Daily Average for December 2013)

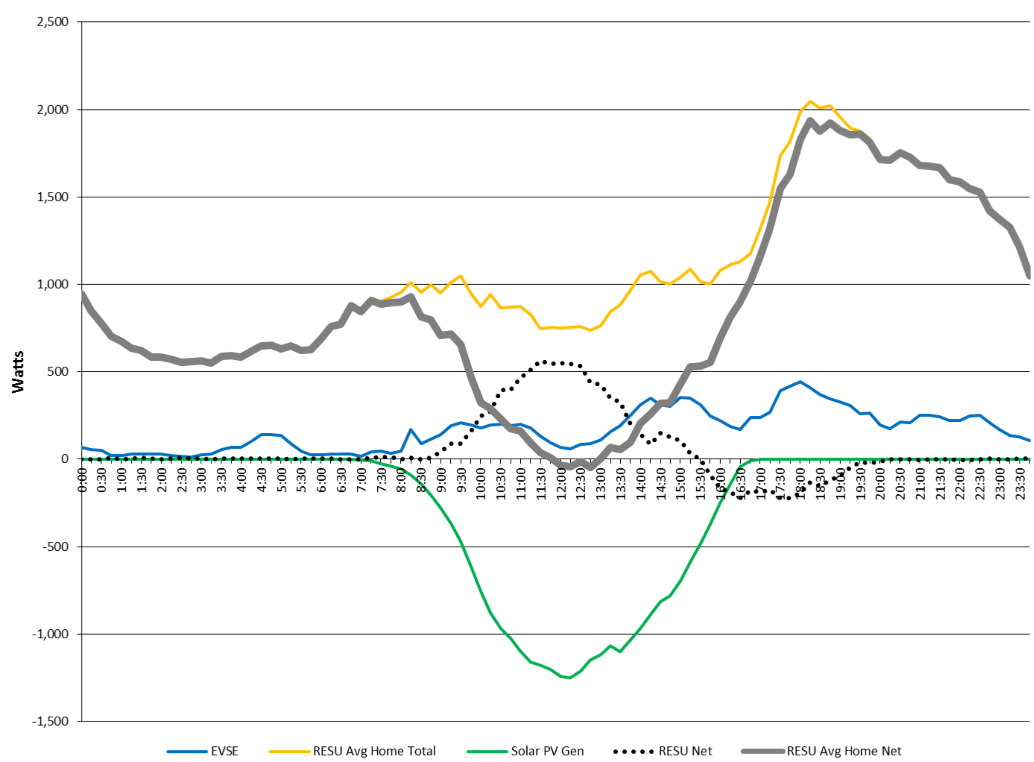


Figure 40: CES Block Average Home Load Profile (Daily Average for December 2013)

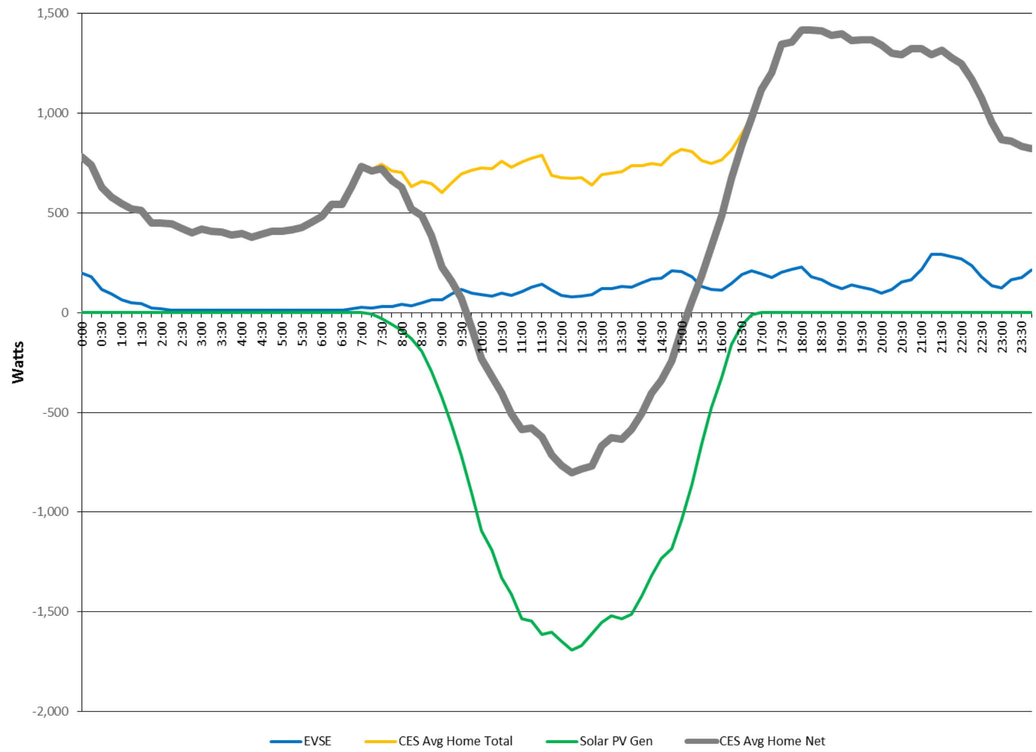


Figure 38 and **Figure 39** indicate a similar pattern between the average ZNE home and average RESU home for December 2013. The average ZNE home net demand goes from about zero (during the peak solar hours) to close to 1,000 W during the evening hours. The average RESU home reaches zero net demand for a few hours (during the peak solar period), and then increases to nearly twice the average ZNE home average net demand during the evening. The difference is a result of the ZNE homes' energy efficiency measures and slightly larger solar PV arrays.

The average CES home has negative net demand during most of the peak solar hours (see **Figure 40**). Unlike the ZNE and RESU block homes, the CES block homes do not have RESUs to absorb the surplus solar PV output. During the evening hours, net demand is the same as the home total demand. Although the CES Block homes do not have RESUs, the CES Block has a CES device capable of producing the same effect as the RESUs when operating in permanent load shifting mode. Thus, the load profiles of the ZNE, RESU, and CES blocks distribution transformers are similar.

Figure 41 through **Figure 50** show the average home profile for the ZNE, RESU, and CES blocks during the months of March 2014, June 2014, and September 2014, respectively. The seasonal variation in the solar PV generation has a significant impact on these load profiles. This is evident in the substantial increase of the number of hours when net demand is near zero or negative during the spring and summer months.

Figure 41: ZNE Block Average Home Load Profile (Daily Average for March 2014)

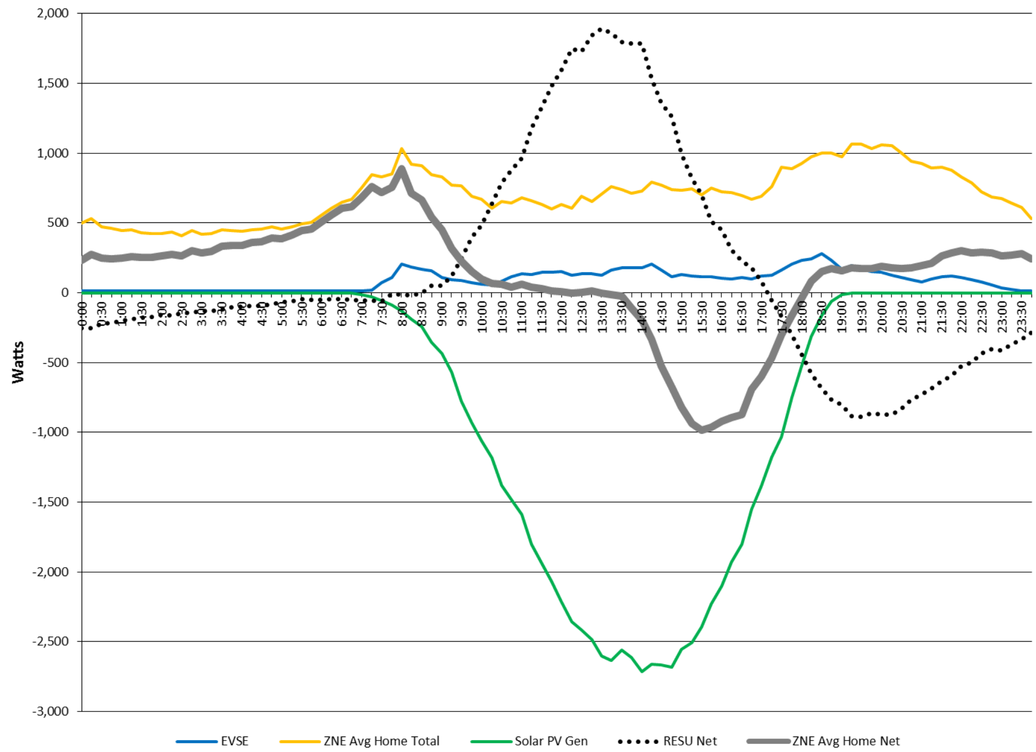


Figure 42: RESU Block Average Home Load Profile (Daily Average for March 2014)

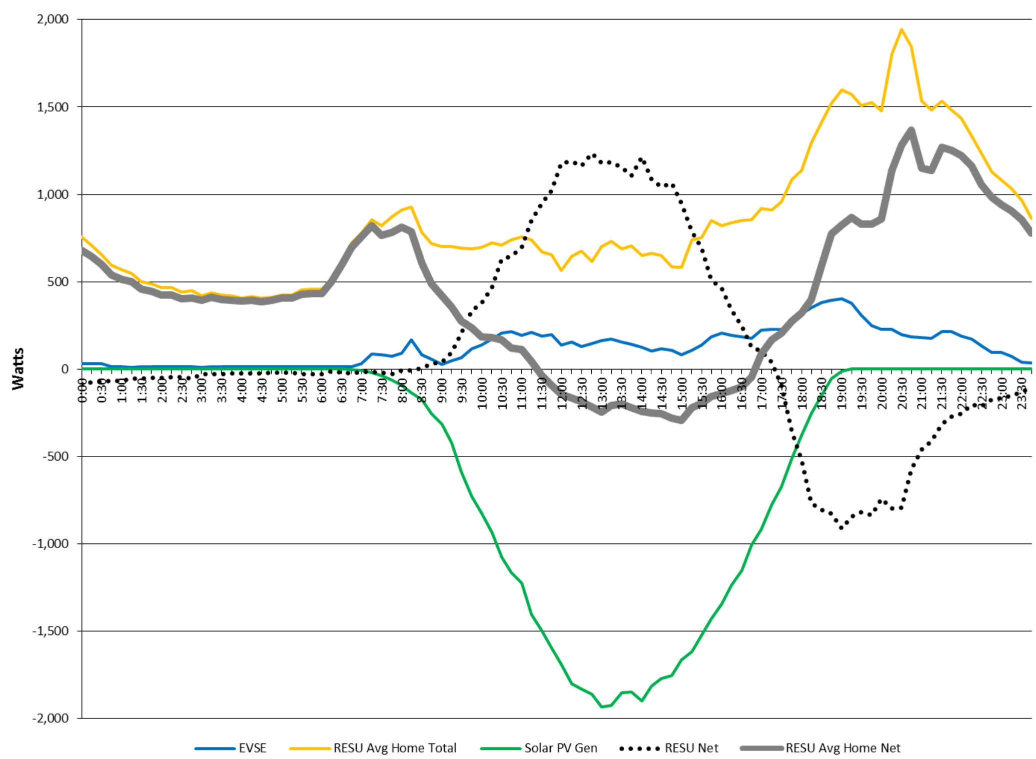


Figure 43: CES Block Average Home Load Profile (Daily Average for March 2014)

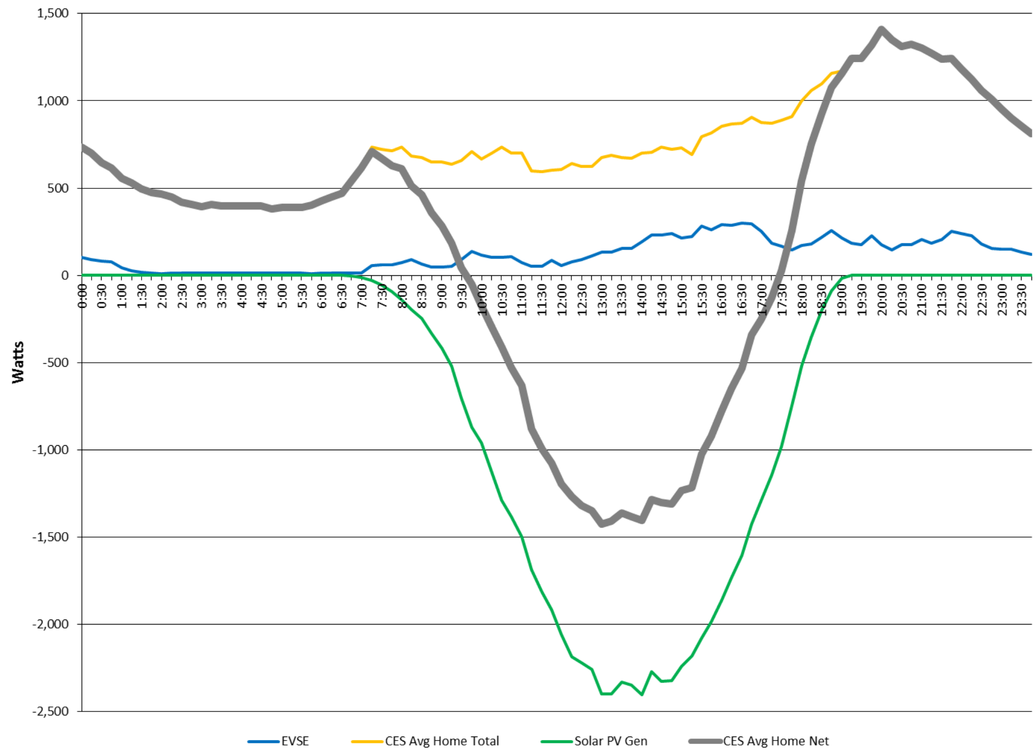


Figure 44: ZNE Block Average Home Load Profile (Daily Average for June 2014)

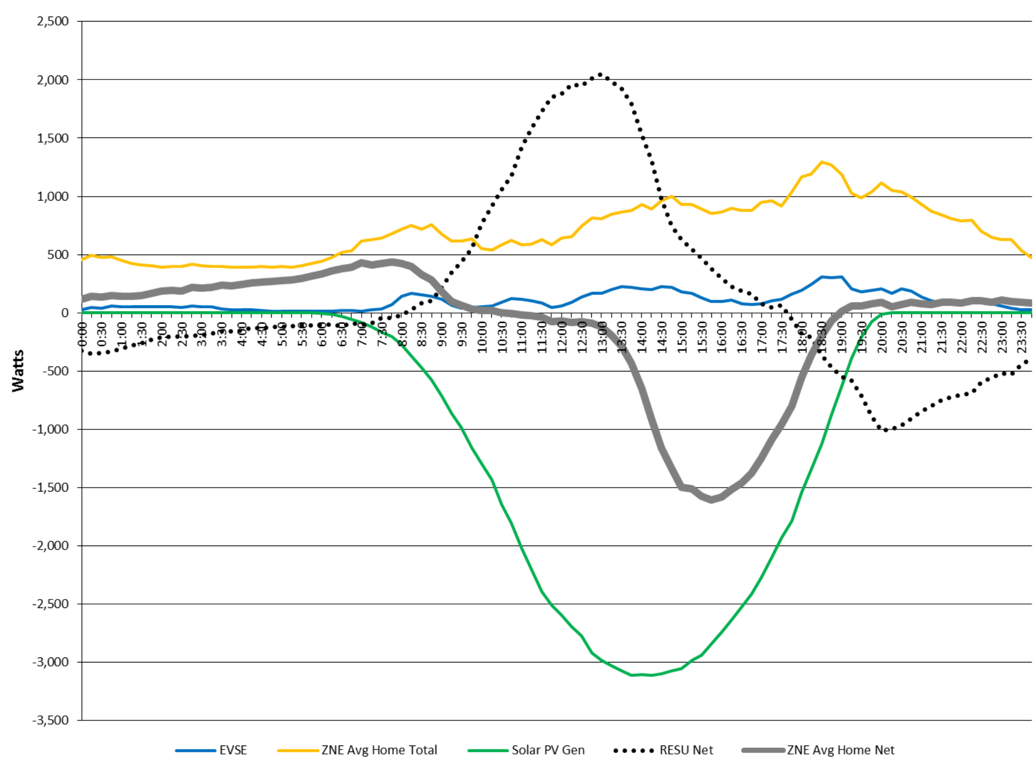


Figure 45: RESU Block Average Home Load Profile (Daily Average for June 2014)

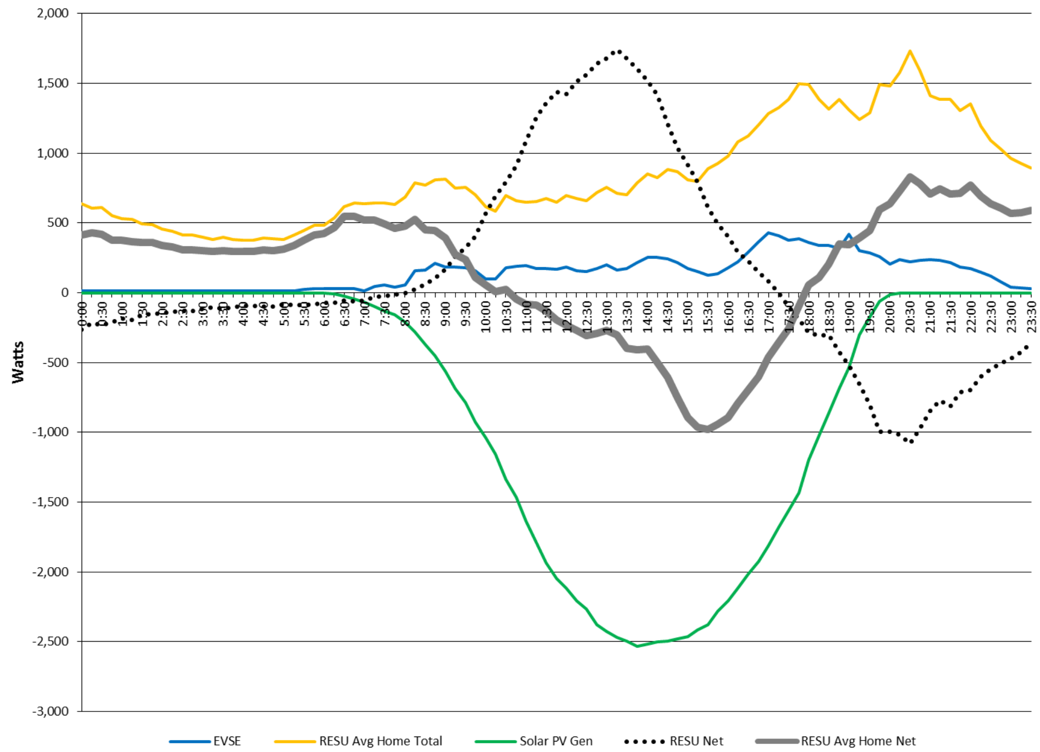


Figure 46: CES Block Average Home Load Profile (Daily Average for June 2014)

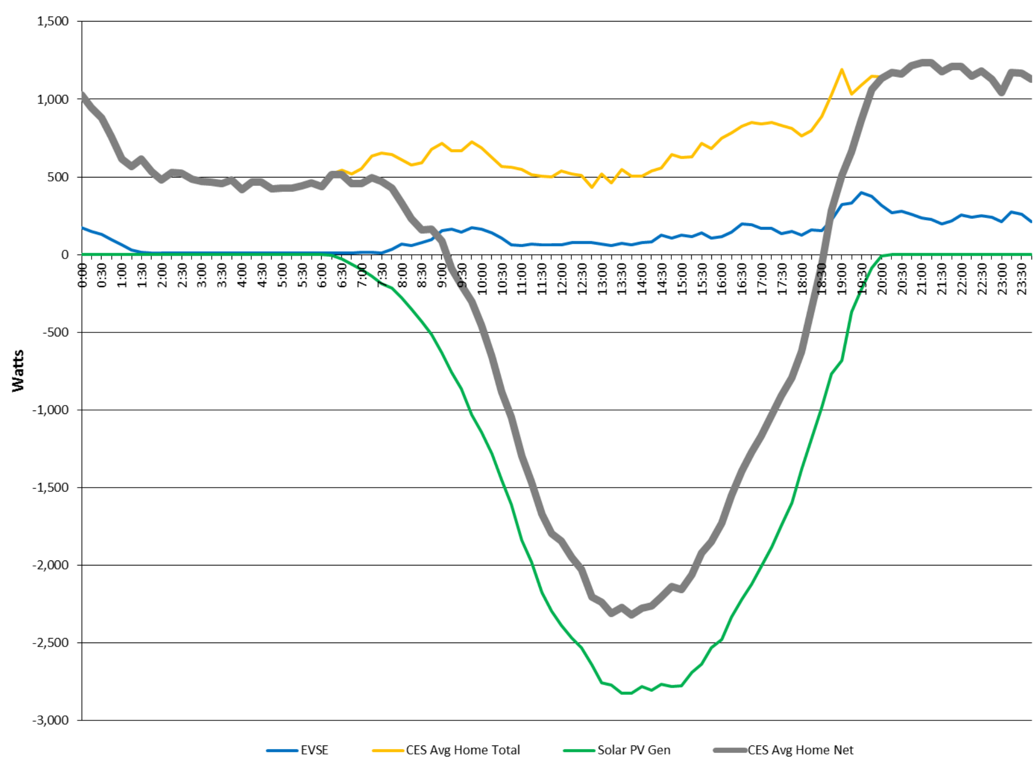


Figure 47: ZNE Block Average Home Load Profile (Daily Average for September 2014)

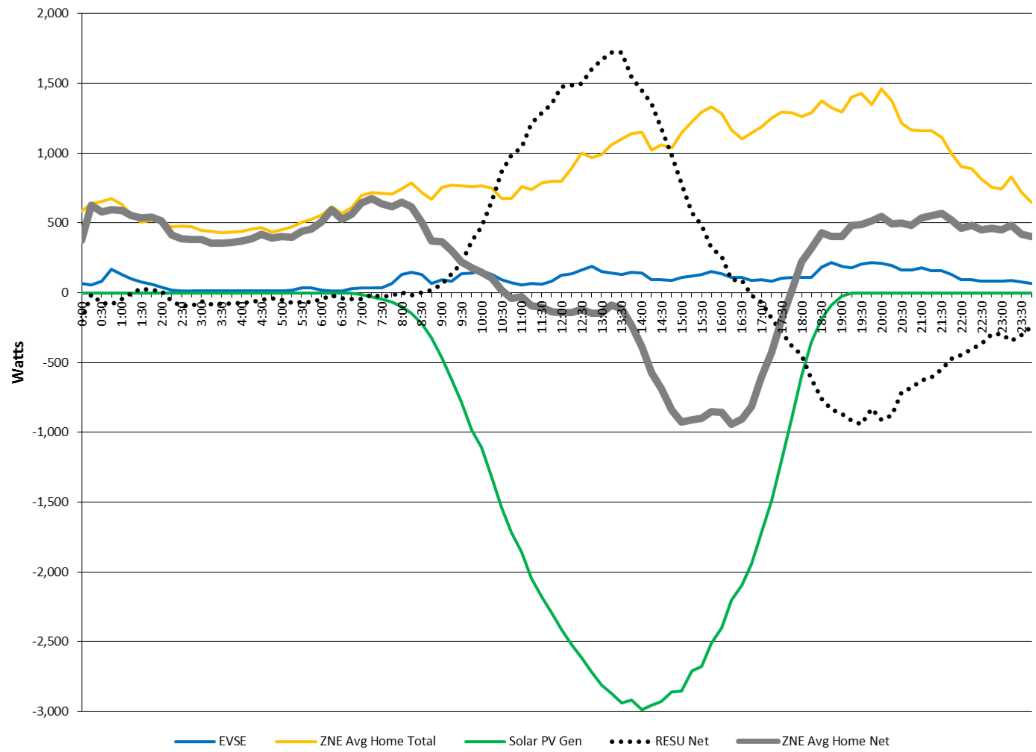


Figure 48: RESU Block Average Home Load Profile (Daily Average for September 2014)

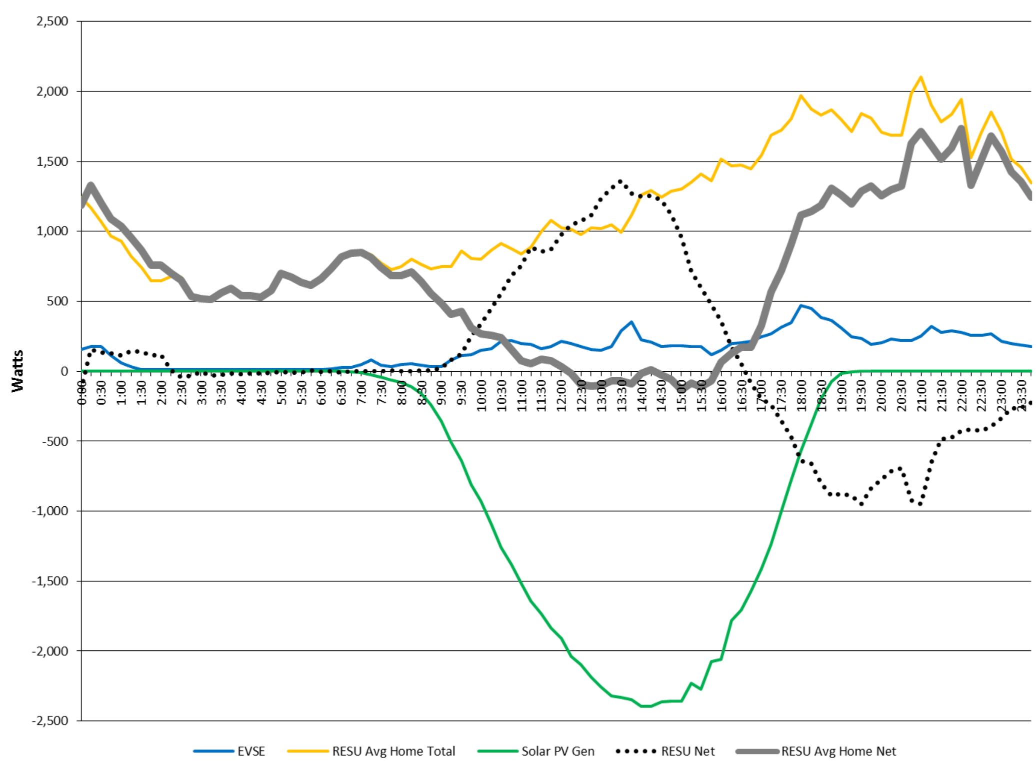
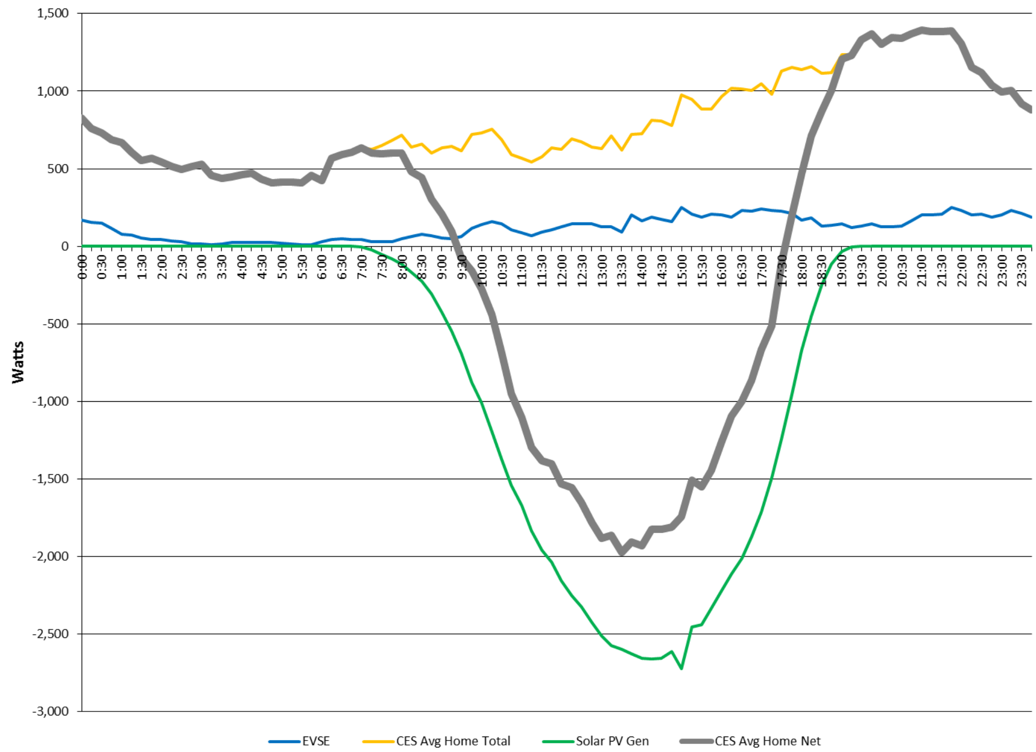
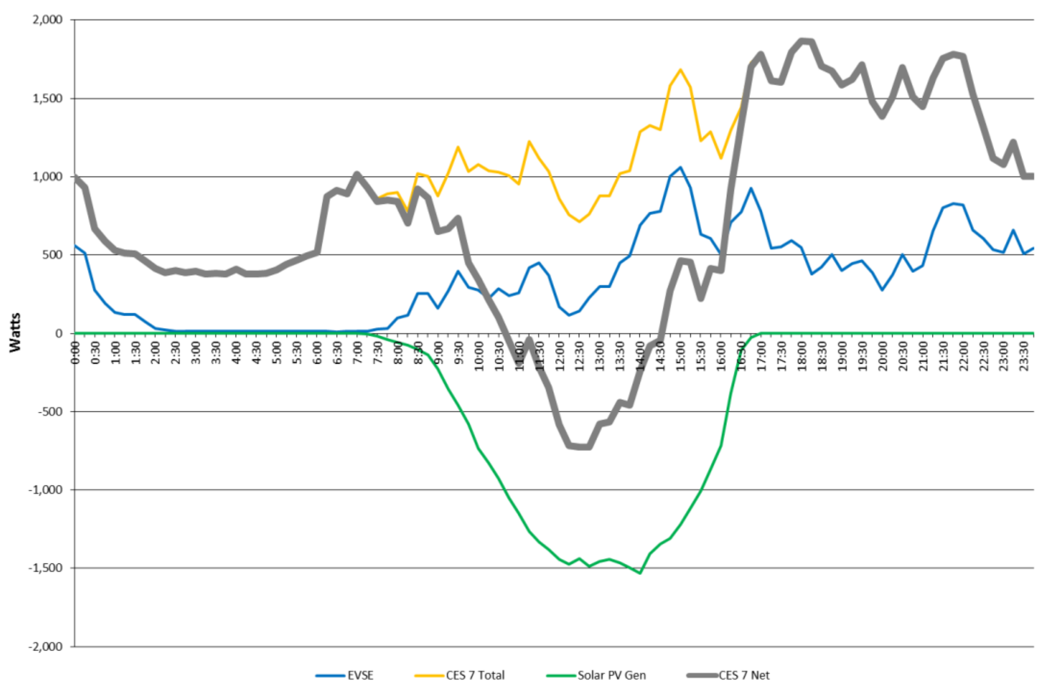


Figure 49: CES Block Average Home Load Profile (Daily Average for September 2014)



To illustrate the effect of the EVSEs on the total load and net demand profiles of the project homes, **Figure 50** presents the load profile of CES 7 for December 2013. The impact of PEV charging is evident throughout the day.

Figure 50: CES 7 Load Profiles (Daily Average for December 2013)



Test 3: Reaching the ZNE Goal

Another key objective of sub-project 1 is to assess a suite of energy efficiency measures to help homes reach ZNE status. ZNE is defined as "the energy consumed by a home (building), over the course of a year, is less than or equal to the onsite renewable energy generated." A project developer is required to show that the design of the proposed development subject to ZNE requirements achieves ZNE when models of the proposed structures are analyzed.

There are four commonly used ZNE metrics employed within the industry to evaluate a home's ZNE status: site energy, source energy, costs, and emissions. These metrics result in four possible approaches to determining ZNE: ZNE Site Energy, ZNE Source Energy, ZNE Costs, and ZNE Emissions.

In California, two regulatory agencies, the California Energy Commission (CEC) and the CPUC, have adopted a new metric to evaluate ZNE homes and buildings. This new metric is named ZNE Time Dependent Valuation (TDV) energy. The CEC developed the TDV methodology for the 2005 California Building Energy Efficiency Standards (Title 24). The concept behind TDV is that energy efficiency measure savings should be valued differently depending on which hours of the year the savings occur, to better reflect the actual costs of energy to consumers, to the utility system, and to society.

Concise descriptions of these five ZNE definitions are provided below. Each of these definitions assumes that a home is connected to the electrical grid and that all surplus energy can be sold. A home's ZNE status is highly dependent on the ZNE metric used. Different metrics may be used for different purposes, depending on stakeholder objectives. For example, building owners typically care about energy costs. Regulatory agencies, such as the DOE, may prioritize national energy policies, and are frequently interested in source energy, as is the case of California in TDV energy. A building designer may be interested in site energy use for tradeoffs between features and cost. Finally, stakeholders that are primarily concerned with pollution from power plants and the burning of fossil fuels may be interested in emissions.

ZNE Site Energy: A *ZNE site energy* home produces as much onsite renewable energy as it uses annually. Site energy does not differentiate fuel types by the amount of energy used to generate, transmit, and distribute energy to the home. It is therefore only necessary to perform a unit conversion so electricity and natural gas can be compared directly. In this report, the team has converted all energy sources to British thermal units (Btu) using a unit conversion factor of 3.412 kBtu/kWh. This means that one kWh consumed or produced at a ZNE home is equivalent to 3,412 Btu. Under ZNE site energy, it is possible to consider offsetting only the electricity use at the home with onsite renewables, instead of electricity and natural gas (or other fuel) use. When only offsetting the home's electricity use, ZNE site energy is called *zero net electric energy* (ZNEE). While ZNEE can provide a measure of electric grid neutrality, it does not fully align with the zero net energy concept, unless it is an all-electric home.

ZNE Source Energy: A *ZNE source energy* home produces as much onsite renewable energy as it uses, measured at the source of energy production. Source energy distinguishes between fuel types in terms of the amount of energy used to generate, transmit, and distribute that energy to the home. The major challenge with source energy is determining the site-to-source energy conversion factors for the various fuel types and locations to account for the generation, transmission, and distribution losses. **Table 22** provides site-to-source energy conversion factors from different organizations for electricity and natural gas.

Table 22: Site-to-Source Conversion Factors for Electricity and Natural Gas

Organization	Electricity	Natural Gas
California Energy Commission (2001)	3.00	1.00
National Renewable Energy Laboratory (2007)	3.19	1.09
American Gas Association (2009)	3.13	1.09
Environmental Protection Agency (2013)	3.14	1.05

Using the 2013 EPA factor, for example, means that one kWh (3,412 Btu) of electricity consumed within a home is assumed to come from an energy source that consumed 3.14 x 3,412 Btu of natural gas. This conversion factor recognizes that it takes more units of fossil fuel (such as natural gas) to generate one unit of electrical energy and deliver it to the home. These factors include the thermal plant conversion inefficiency and losses from the electrical transmission and distribution systems. To further illustrate this point, compare an electric resistance furnace with essentially 100% efficiency and a standard natural gas furnace with a thermal efficiency of around 80%. The electric furnace is preferable using the ZNE site energy method. However, the natural gas furnace is preferable using the source energy method—since the electric furnace requires roughly three times more energy under this method.

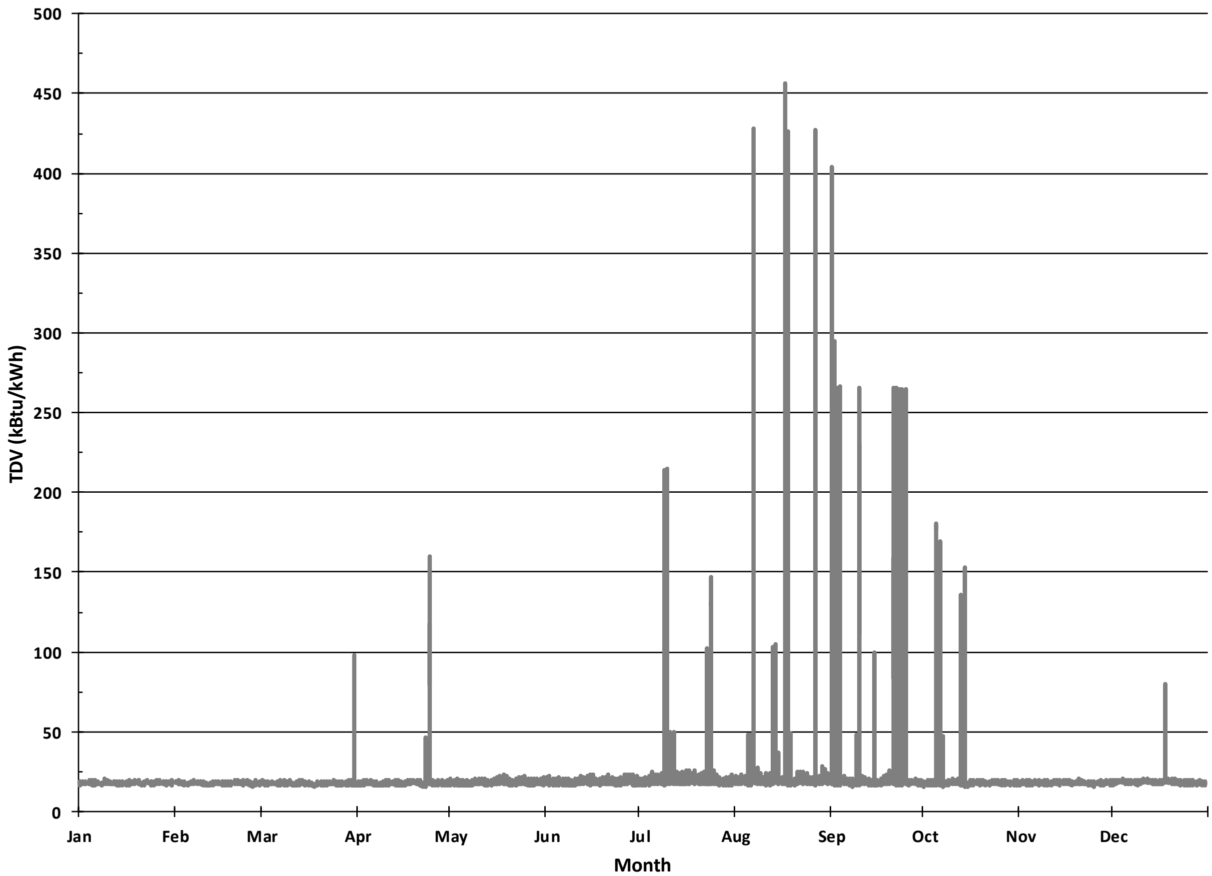
ZNE Cost: In a *ZNE cost* home, the amount the homeowner pays the utility for energy services is no more than the amount the utility pays the homeowner for energy the home exports to the grid (on an annual basis). A zero net bill for energy consumption may appeal to homeowners. However, ZNE cost may not result in lower energy use, lower costs to maintain the electric grid, or lower greenhouse gasses emissions. Furthermore, unless the home disconnects from the grid, it would likely be difficult to achieve zero net bill since the utility would still need to recover its fixed costs.

ZNE Emissions: A *ZNE emissions* home generates at least as much emissions-free renewable energy as it uses from emissions-generating energy sources. As with ZNE source energy, the challenge is to develop conversion factors to accurately reflect the emissions associated with the various sources of energy used by the home.

ZNE TDV Energy: A *ZNE TDV energy* home produces as much onsite renewable energy value as it uses annually. The value of energy used or produced in any given hour is determined by the TDV factor for that hour. The TDV factors is based on a series of annual hourly values for electricity cost (and monthly costs for natural gas and propane). TDV factors are developed for each of the sixteen CEC climate zones, for residential and for nonresidential buildings to reflect differences in costs driven by climate conditions. The TDV factors are represented in kBtu/kWh or kBtu/therms units.

The two key components of the electricity TDV factors are the marginal cost of electricity (variable cost by hour) and the *revenue neutrality adjustment* (fixed cost by hour). The marginal cost of electricity includes the source energy cost, other non-energy costs (transmission, distribution, emissions, ancillary services and peak capacity costs), the Renewables Portfolio Standard costs, and the cost of implementing other policies related to California state law (AB 32) which requires a reduction in greenhouse gas (GHG) emissions to 1990 levels by 2020. The *revenue neutrality adjustment* takes the fixed components of the total annual utility costs that go into the retail rates (taxes, metering costs, billing costs, etc.) and allocates them over all hours of the year. TDV multiplier factor for energy consumption or production are used for each hour of the year. These factors can vary by more than 20 times as shown in **Figure 51**. The TDV factors in **Figure 51** are for CEC Climate Zone 8, which is representative of climate in Irvine, California.

Figure 51: CEC TDV Factors for California Climate Zone 8



This final report evaluates the homes' ZNE status in terms of site energy, source energy, and TDV energy. As in TPR #2, the ZNE calculations exclude energy used for electric vehicle charging.

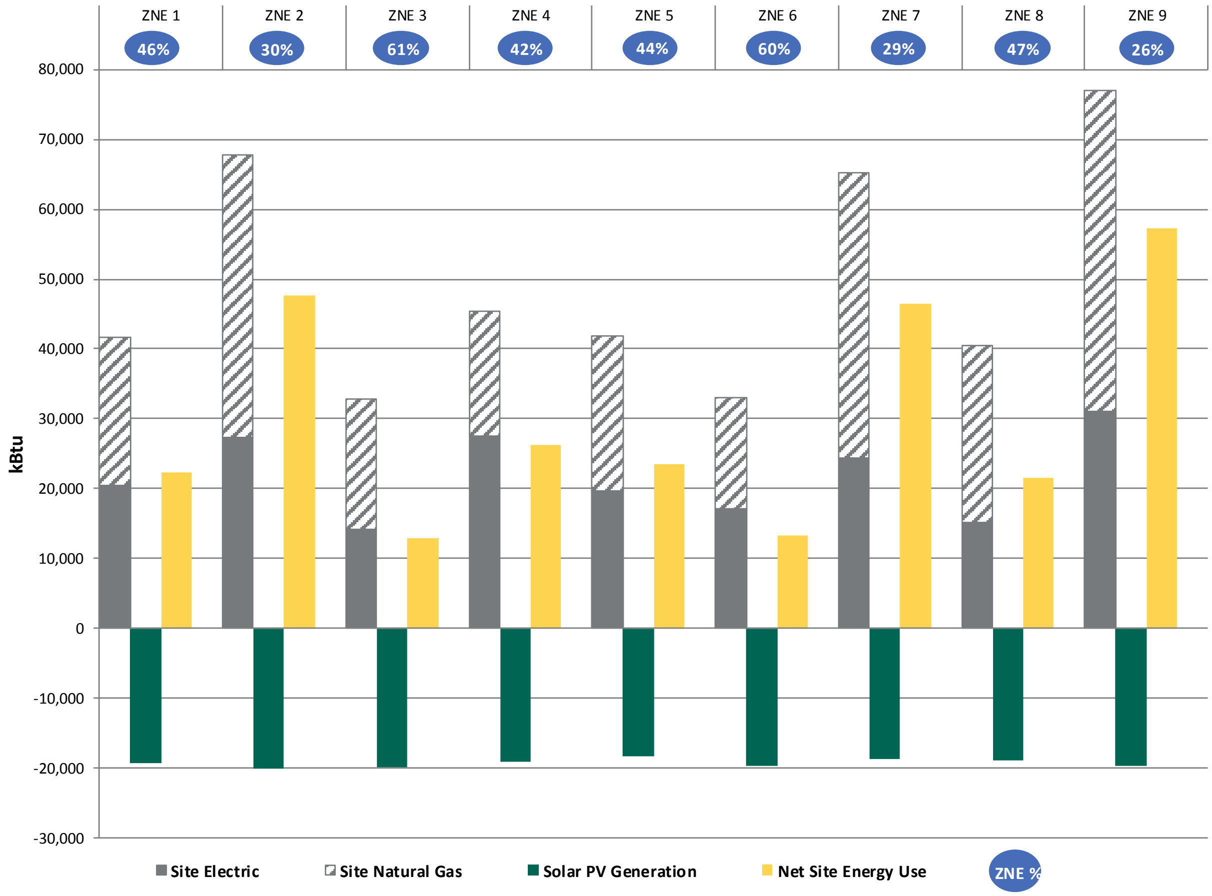
ZNE Block Homes

With California's goal of all new residential construction reaching ZNE by 2020, the team expects that the ZNE Block homes will provide insights to help California meet its ZNE goal.

<u>ZNE Site Energy Status for ZNE Homes</u>

Figure 52 shows the current ZNE status for homes in the ZNE Block based on site energy for a period of a year starting on July 1, 2014. This figure also includes the total site energy use (divided between its electricity and natural gas energy use), the solar PV generation, and the net site energy use.

Figure 52: ZNE Site Energy Status for ZNE Block Homes (July 1, 2014 to June 30, 2015)



The ZNE status represents a home's progress toward achieving ZNE. To reach the ZNE goal, a home's net energy consumption must be zero or negative. The ZNE status is equal to a home's solar PV generation divided by its total energy consumption. As an example, ZNE 1's ZNE status is 46%, which is equal to 19,283 kBtu (solar PV generation) divided by 41,696 kBtu (total energy consumption).

Figure 52 also shows that five of the nine ZNE homes (ZNE 2, 3, 7, 8, and 9) use significantly more natural gas than electricity, and one home (ZNE 4) uses more electricity than natural gas. In the remaining three homes (ZNE 1, 5 and 6), the electricity and natural gas use is similar.

Figure 52 also provides the solar PV generation for each home in the ZNE Block. All the houses in the ZNE Block have identical PV arrays with a nominal peak power direct current (DC) of 3.9 kW. To predict the solar PV generation output, the team used the National Renewable Energy Laboratory (NREL) System Advisory Model (SAM) tool. The NREL SAM is a computer model that calculates performance and financial metrics of several renewable energy systems including PV, concentrating solar power, solar water heating, wind, geothermal, and biomass. Of the PV calculation options in SAM, the team used PVWatts model. The PVWatts model is a simplified PV system model, which assumes typical module and inverter characteristics. However, it is an hour-by-hour model that produces results within 5% of a more detailed PV model in SAM for typical flat-panel PV systems.

<u>ZNE and the Use of eQUEST Simulations</u>

California bold environmental goals call for all new residential construction to be ZNE by 2020, all new commercial construction to be ZNE by 2030, and 50% of existing commercial buildings to be retrofitted to ZNE by 2030. To help achieve these goals, the CPUC and the California Energy Commission (CEC) encourage architects and designers to design more energy efficient buildings by offering financial incentives to property owners via utility energy efficiency programs and by requiring more energy efficient designs via the California Building Energy Efficiency Standards (Title 24). To capture the financial incentives and to comply with Title 24 requirements, architects and designers use whole-building energy simulation tools such as eQUEST, a Windows based tool using the DOE-2 engine. The eQUEST tool models the layout and architectural features of the home, its insulation levels, its occupancy assumptions, its energy consuming appliances, equipment, and systems, and it is driven by hourly weather data for one year. From these inputs, the tool predicts hourly and annual energy consumption of both electricity and natural gas.

A designer can use this simulation tool to try different EEMs such as more efficient equipment and better insulation in an effort to minimize energy consumption on an annual basis. Remaining energy consumption can be offset by solar generation to achieve ZNE. The solar generation is designed to meet the energy shortfall using other tools.

For Title 24 compliance, the CEC provides the weather and occupancy and equipment pattern assumptions. Since ISGD's ZNE demonstration was limited to nine existing homes,the team used measured energy consumption patterns for these homes and local weather records. In 2012, the team used monthly total natural gas and electricity utility data from 2010 to calibrate the eQUEST models. The models were then used to select the EEMs for each of the homes and to predict the degree to which the homes would be expected to achieve site energy ZNE status.

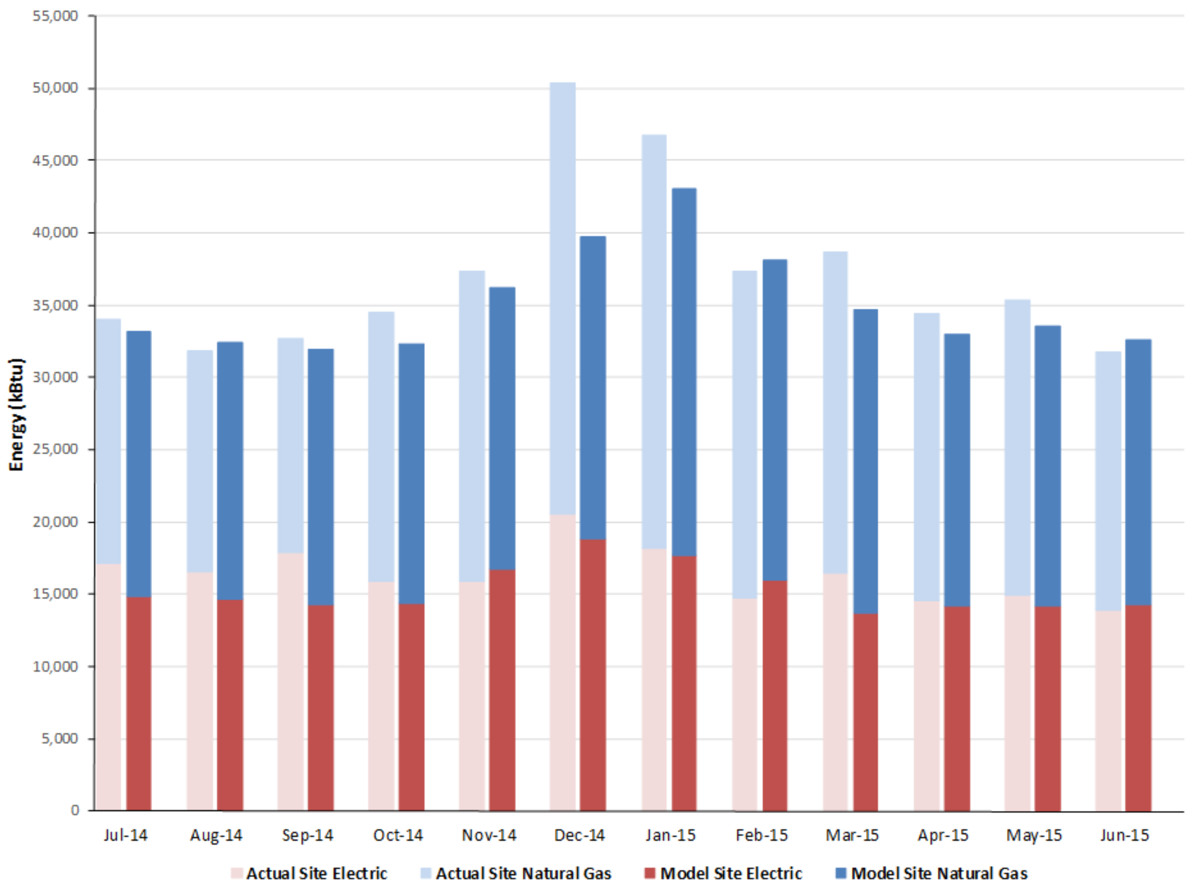
Actual consumption measured during the twelve-month period from November 1, 2013 to October 31, 2014 was compared to the 2012 eQUEST predicted consumption and reported in TPR2. Actual consumption was on the average 30% greater than predicted for homes on the ZNE Block. Part of this was due to the RESU losses, which were not included in the eQUEST simulation.

The eQuest model was then re-calibrated using the more detailed hourly energy consumption and weather data from the twelve-month period of November 1, 2013 through October 31, 2014. This input data was "scrubbed" to correct missing and erroneous data resulting from such things as lost communications with the SCE backend server. The re-calibration simulation results matched the actual monthly electric consumption of individual homes within 5% and the monthly natural gas consumption within 16% When looking at the aggregate of all homes on the ZNE Block, the re-calibrated simulations results matched the monthly electric and natural gas consumptions within 0.3% and 3.9%, respectively, indicating that the model was well tuned. RESU losses were included in the re-calibration models.

Finally, the re-calibrated eQUEST model was used to predict the site energy consumption for the July 1, 2014 through June 30, 2015 period reported in this Final Technical Report. The monthly predictions were compared to the actual monthly total energy use (natural gas and electricity[28]) for the aggregation of the nine homes in the ZNE Block as shown in **Figure 53**.

[28] EVSE energy use was excluded, since this transportation is generally excluded from ZNE definitions.

Figure 53: Actual versus Predicted ZNE Block Aggregated Site Energy Use



The eQUEST model under predicts the natural gas usage for December 2014, but for all other months there is a very good agreement. There is also very good agreement on the electricity usage predication. Overall the predication is within 5.8% of the actual total energy usage of the aggregated of all the homes in the ZNE Block from July 2014 through June 2015. **Table 23** provides a comparison of the actual energy consumption for each ZNE Block home with that predicted by the re-calibrated eQUEST model.

Table 23: Actual v. Forecasted Natural Gas and Electricity Use Percentages for ZNE Block Homes (Site Energy)

Home	Component	Actual Measurement	eQUEST Simulation	Percent Change from eQUEST
ZNE 1	Electricity Share of Energy Use	49%	48%	2.1%
	Natural Gas Share of Energy Use	51%	52%	(1.9%)
	Total Site Energy Use (kBtu)	41,696	39,214	6.3%
ZNE 2	Electricity Share of Energy Use	40%	44%	(9.1%)
	Natural Gas Share of Energy Use	60%	56%	7.1%
	Total Site Energy Use (kBtu)	67,757	56,463	20.0%
ZNE 3	Electricity Share of Energy Use	43%	34%	26.5%
	Natural Gas Share of Energy Use	57%	66%	(13.6%)
	Total Site Energy Use (kBtu)	32,887	37,541	(12.4%)
ZNE 4	Electricity Share of Energy Use	61%	60%	1.7%
	Natural Gas Share of Energy Use	39%	40%	(2.5%)
	Total Site Energy Use (kBtu)	45,351	47,642	(4.8%)
ZNE 5	Electricity Share of Energy Use	47%	52%	(9.6%)
	Natural Gas Share of Energy Use	53%	48%	10.4%
	Total Site Energy Use (kBtu)	41,864	34,262	22.2%
ZNE 6	Electricity Share of Energy Use	52%	63%	(17.5%)
	Natural Gas Share of Energy Use	48%	37%	29.7%
	Total Site Energy Use (kBtu)	32,983	26,413	24.9%
ZNE 7	Electricity Share of Energy Use	38%	34%	11.8%
	Natural Gas Share of Energy Use	62%	66%	(6.1%)
	Total Site Energy Use (kBtu)	65,136	55,626	17.1%
ZNE 8	Electricity Share of Energy Use	37%	31%	19.4%
	Natural Gas Share of Energy Use	63%	69%	(8.7%)
	Total Site Energy Use (kBtu)	40,430	54,331	(25.6%)
ZNE 9	Electricity Share of Energy Use	40%	41%	(2.4%)
	Natural Gas Share of Energy Use	60%	59%	1.7%
	Total Site Energy Use (kBtu)	77,024	69,297	11.2%
Totals	Electricity Share of Energy Use	44%	44%	0.0%
	Natural Gas Share of Energy Use	56%	56%	0.0%
	Total Site Energy Use (kBtu)	445,127	420,789	5.8%

Comparing the homes' ZNE status for the period of July 1, 2014 to June 30, 2015, with the forecast made with the re-calibrated eQUEST models reveals that the homes missed their ZNE targets by an average of 15%. **Table 24** summarizes these results.

Table 24: Actual versus Forecasted ZNE Site Energy Status for the ZNE Block Homes

ZNE Status (%)	ZNE 1	ZNE 2	ZNE 3	ZNE 4	ZNE 5	ZNE 6	ZNE 7	ZNE 8	ZNE 9
eQUEST Simulation/Forecasted	49	36	53	40	51	75	34	35	28
Field Measurement	46	30	61	42	44	60	29	47	26
Change from Forecast	(6)	(17)	15	5	(14)	(20)	(15)	(34)	(7)

The differences between the actual and forecasted ZNE site energy status of the ZNE Block homes is a result of uncertainties in the RESU losses and (at least in part) occupant behavior, which has a major impact on household energy consumption. While the energy simulation work incorporated the occupants' and energy consuming devices' schedules, both are dynamic and change over time.

The overall conclusion illustrates the sensitivity of eQUEST predictions to the validity of its input data with respect to homeowner behavior and weather.

Table 25 compares the field measurements of the solar PV generation output to the PVWatts results. Although these results indicate that the solar PV performance was below the forecast, most of the PVWatts results are in reasonable agreement with the field measurements. One exception is ZNE 3, which generated much less solar PV energy than the simulation results. This was a result of a faulty electrical connection with ZNE 3, which the team corrected. One other factor that contributed to the difference between field measurements and forecasted results is the size of the solar PV array. The solar PV arrays installed were 4% smaller than the array size used for the simulations (3.9 kW versus 4.05 kW). This is reflected in the Adjusted PVWatts Forecast row.

Table 25: Actual versus Forecasted Solar PV Site Energy Generation for the ZNE Block Homes

Solar PV Generation		ZNE 1	ZNE 2	ZNE 3	ZNE 4	ZNE 5	ZNE 6	ZNE 7	ZNE 8	ZNE 9
PVWatts Forecast	kBtu	22,793	22,881	22,813	22,793	23,005	23,251	23,385	23,005	23,285
	kWh	6,680	6,706	6,686	6,680	6,742	6,814	6,854	6,742	6,824
Adjusted PVWatts Forecast	kBtu	21,949	22,033	21,968	21,949	22,153	22,390	22,519	22,153	22,422
	kWh	6,433	6,458	6,439	6,433	6,493	6,562	6,600	6,493	6,572
Actual Solar PV Generation	kBtu	19,283	20,137	19,928	19,049	18,326	19,747	18,712	18,924	19,696
	kWh	5,652	5,902	5,840	5,593	5,371	5,788	5,484	5,546	5,773
Shortfall from Forecast (%)		15	12	13	16	20	15	20	18	15
Shortfall from Adjusted Forecast (%)		12	9	9	13	17	12	17	15	12

It is also important to note that ZNE 1 and ZNE 4 have the same roofline slope and orientation, which resulted in similar actual solar PV generation for both houses (19,283 versus 19,049, a 1.2% difference). The solar PV generation for ZNE 5 and ZNE 8 was also close to each other (18,326 versus 18,924, a 3.2% difference). These homes also have the same roofline slope and orientation. ZNE 2 and ZNE 3 have the same slope and almost the same orientation, which resulted in a similar solar PV generation. **Table 26** summarizes the ZNE Block home roofline slope and orientation. The average azimuth is 236 degrees, slightly west of due southwest. This is suboptimal in terms of total energy production but perhaps fortuitous for the TDV metric that values production during peak load hours.

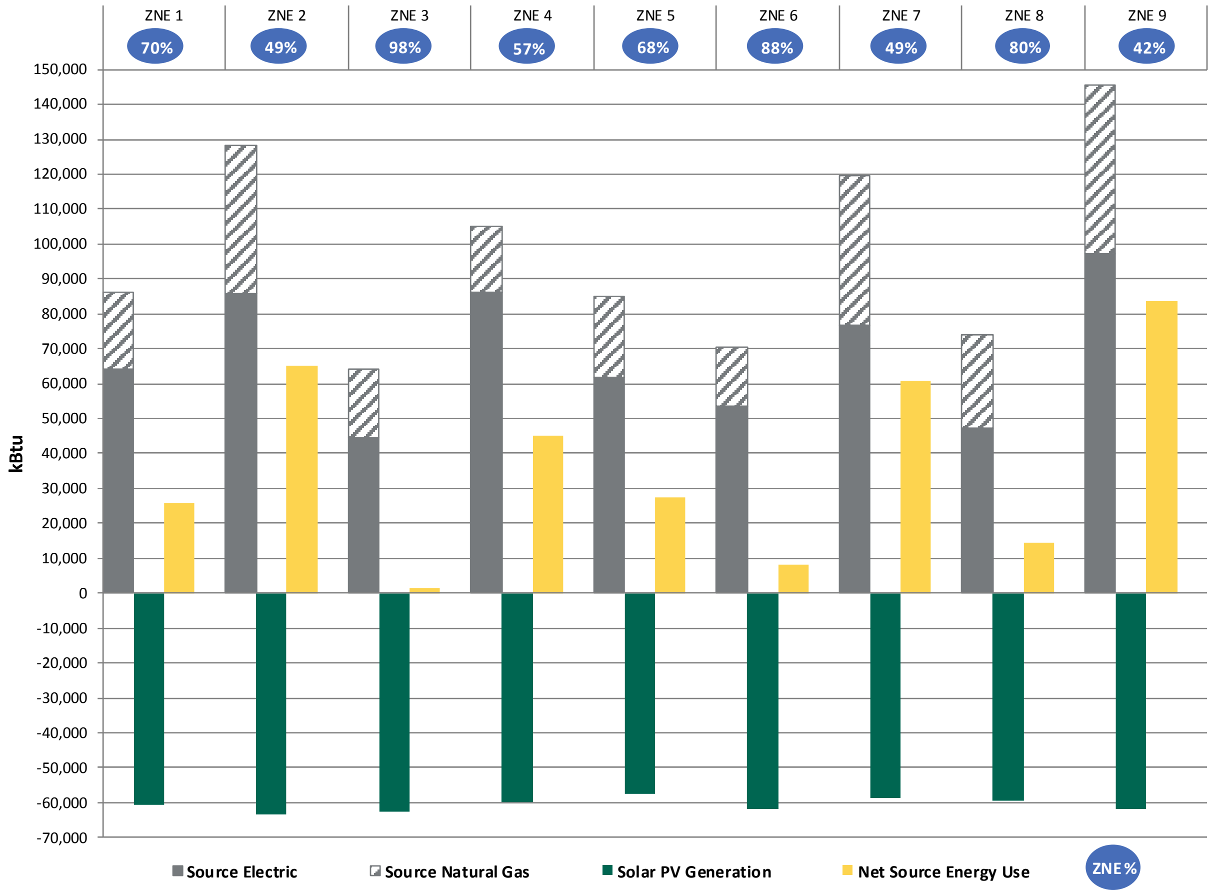
Table 26: Roofline Slope and Orientation for the ZNE Block Homes

Roofline	ZNE 1	ZNE 2	ZNE 3	ZNE 4	ZNE 5	ZNE 6	ZNE 7	ZNE 8	ZNE 9
Slope (degrees)	21	27	27	21	21	21	27	21	27
Orientation/Azimuth (degrees)	244	242	244	244	237	226	222	237	227

ZNE Source Energy Status for ZNE Homes

Figure 54 shows the current ZNE status for homes in the ZNE Block based on source energy for the twelve-month period that ended on June 30, 2015. This figure also shows each home's total source energy use (divided between its electricity and natural gas energy use), the solar PV generation, and the net source energy use.

Figure 54: ZNE Source Energy Status for ZNE Block Homes (July 1, 2014 to June 30, 2015)



As was the case with the site energy, none of the homes achieved ZNE status based on source energy. However, using source energy (rather than site energy) increased the ZNE target achievement by an average of 58% for the ZNE Block homes, as shown in **Table 27**. This increase is due to the fact that one unit of electricity from onsite solar PV generation offsets 3.14 units of natural gas when using source energy.[29] **Figure 54** also shows that all homes use more energy in the form of electricity than in the form of natural gas, after applying the site to source energy conversion factors.

Table 27: Source versus Site Energy ZNE Status for the ZNE Block Homes

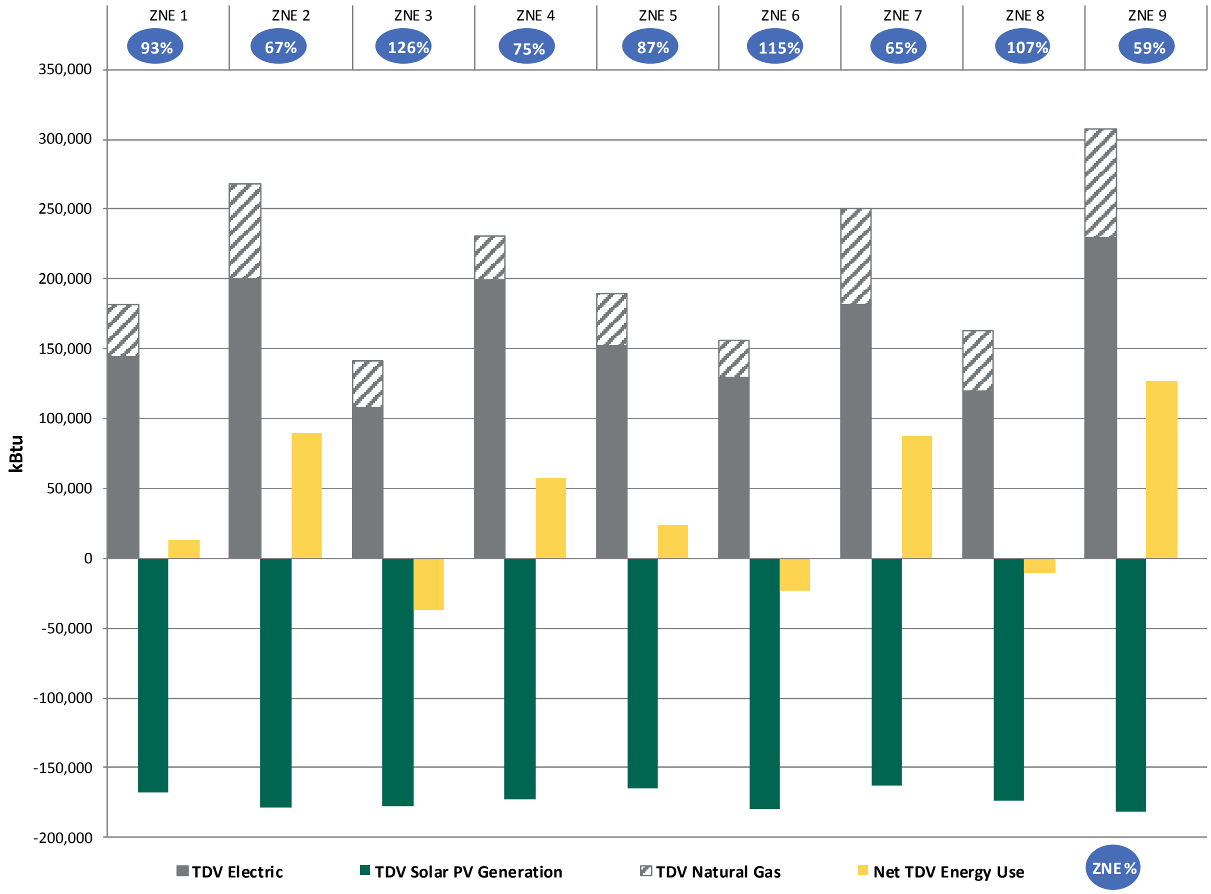
ZNE Status (%)	ZNE 1	ZNE 2	ZNE 3	ZNE 4	ZNE 5	ZNE 6	ZNE 7	ZNE 8	ZNE 9
Site Energy	46	30	61	42	44	60	29	47	26
Source Energy	70	49	98	57	68	88	47	80	42
Increase from Site Energy	52	66	61	36	54	47	71	72	66

ZNE TDV Energy Status for ZNE Homes

Figure 55 shows the current ZNE status for homes in the ZNE Block based on TDV energy for the 12-month period that ended on June 30, 2015. This figure also shows each home's total TDV energy use (divided between its electricity and natural gas energy use), the solar PV generation, and the net TDV energy use. Using the TDV energy metric, ZNE 3, ZNE 6, and ZNE 8 homes achieved ZNE, while ZNE 1 achieved 93%.

[29] This report uses the EPA site-to-source conversion factor of 3.14 for electricity.

Figure 55: ZNE TDV Energy Status for ZNE Block Homes (July 1, 2014 to June 30, 2015)



Using TDV energy (rather than site energy) increased the ZNE target achievement by an average of 109% for the ZNE Block homes. **Table 28** summarizes site energy to site electric energy percentage increase of reaching the ZNE status for the homes in the ZNE Block.

Table 28: Site Energy versus TDV Energy ZNE Status for the ZNE Block Homes

ZNE Status (%)	ZNE 1	ZNE 2	ZNE 3	ZNE 4	ZNE 5	ZNE 6	ZNE 7	ZNE 8	ZNE 9
Site Energy	46	30	61	42	44	60	29	47	26
TDV Energy	93	67	126	75	87	115	65	107	59
Increase from Site Energy to TDV Energy	102	123	107	79	98	92	124	128	127

Using the TDV Energy method instead of the source energy method resulted in an average ZNE performance improvement of 33%, as shown in **Table 29**.

Table 29: TDV Energy v. Source Energy ZNE Status for the ZNE Block Homes

ZNE Status (%)	ZNE 1	ZNE 2	ZNE 3	ZNE 4	ZNE 5	ZNE 6	ZNE 7	ZNE 8	ZNE 9
Source Energy	70	49	98	57	68	88	49	80	42
TDV Energy	93	67	126	75	87	115	65	107	59

Increase from Source Energy to TDV Energy	33	37	29	32	28	31	33	34	40

Table 30 shows the ZNE status achieved by the homes in the ZNE Block based on the three metrics used: site energy, source energy, and TDV energy. As can be seen from this table, the ZNE status increases for each home by using the TDV energy in the ZNE calculation methods (instead of the site or source energy method). This is important because it would cost less to achieve ZNE status using the TDV energy metric, since homes would require a smaller solar PV array. As mentioned, the southwesterly orientation of these solar arrays may have skewed solar production into the more highly valued afternoon and evening hours for the TDV metric.

Table 30: Site v. Source v. TDV Energy ZNE Status for ZNE Block Homes

ZNE Status (%)	ZNE 1	ZNE 2	ZNE 3	ZNE 4	ZNE 5	ZNE 6	ZNE 7	ZNE 8	ZNE 9
Site Energy	46	30	61	42	44	60	29	47	26
Source Energy	70	49	98	57	68	88	49	80	42
TDV Energy	93	67	126	75	87	115	65	107	59

CES Block Homes

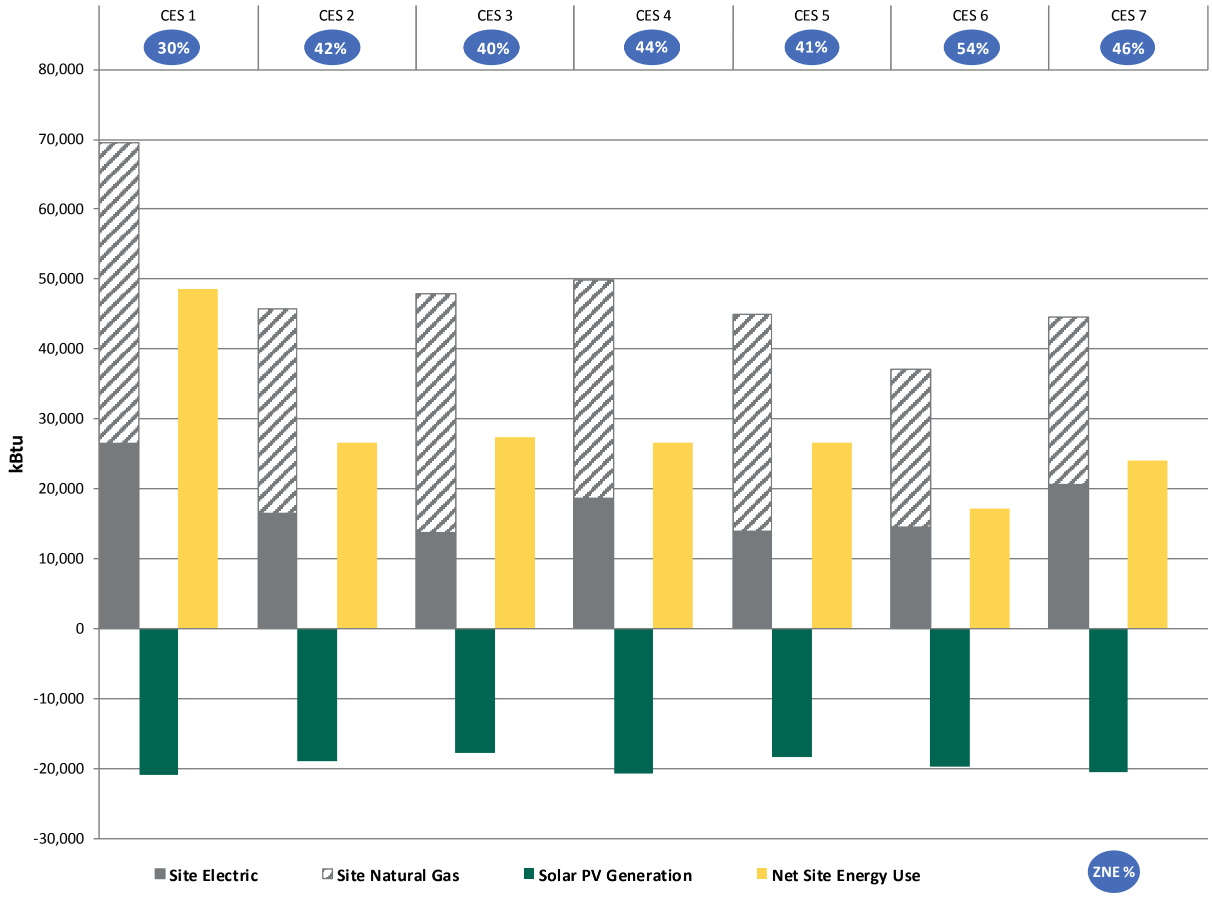
The homes in the CES Block did not receive the full suite of energy efficient measures. However, these homes received ENERGY STAR smart appliances and a solar PV array with a nominal peak power DC of 3.6 kW.[30]

ZNE Site Energy Status for CES Homes

Figure 56 shows the current ZNE status for homes in the CES Block based on site energy for the twelve-month period that ended on June 30, 2015. This figure also shows each home's total site energy use (divided between its electricity and natural gas energy use), the solar PV generation, and the net site energy use.

[30] Two exceptions are that CES 5 has 3.3 kW array and CES 4 has a 3.8 kW array.

Figure 56: ZNE Site Energy Status for CES Block Homes (July 1, 2014 to June 30, 2015)

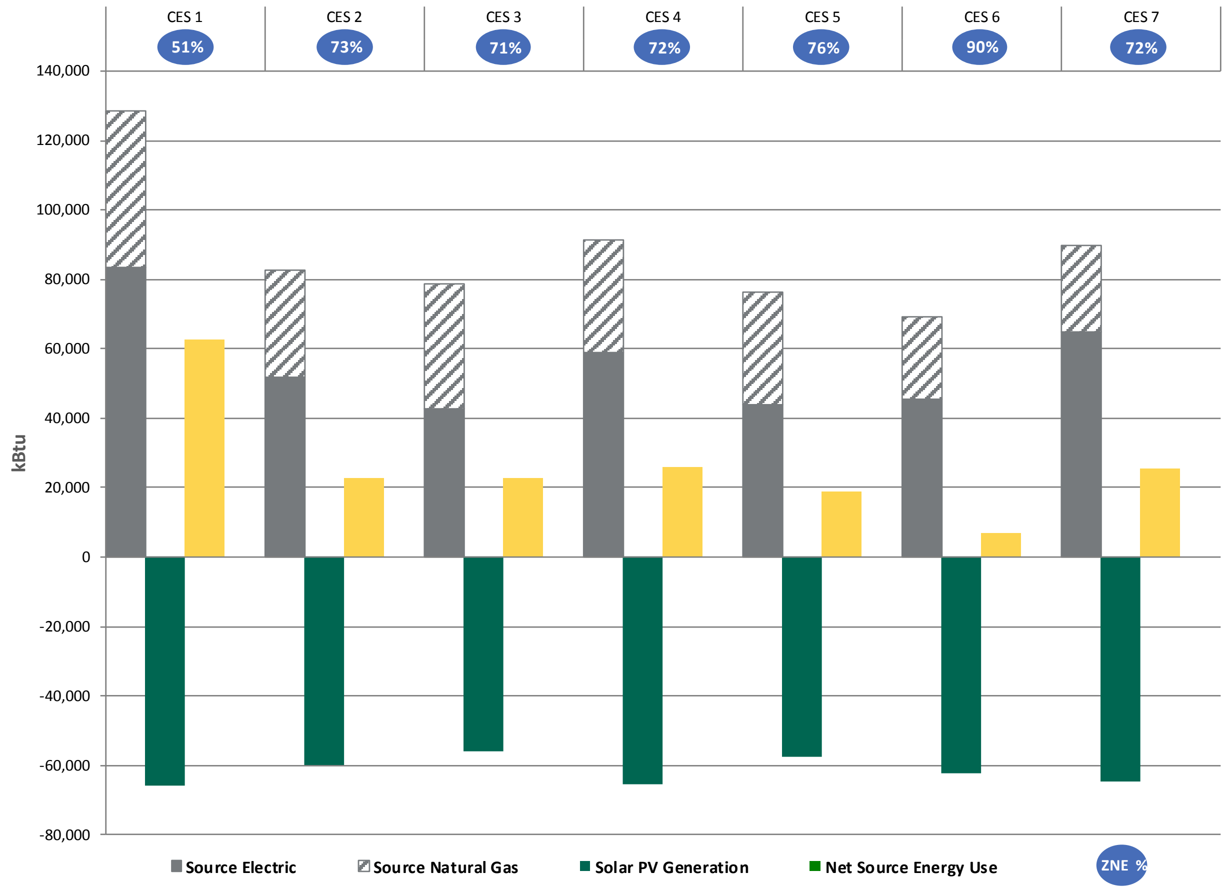


None of the homes in the CES Block achieved ZNE status based on site energy. However, it was not expected that these homes would achieve ZNE status as they did not receive a full suite of energy efficient measures. Similar to the homes in the ZNE Block, **Figure 56** shows that the CES homes have a greater consumption of natural gas than electricity when site energy metric is used.

<u>ZNE Source Energy Status for CES Homes</u>

Figure 57 shows the current ZNE status for homes in the CES Block based on source energy for a period of a year starting on July 1, 2014. This figure also shows each home's total source energy use (divided between its electricity and natural gas energy use), the solar PV generation, and the net source energy use.

Figure 57: ZNE Source Energy Status for CES Block Homes (July 1, 2014 to June 30, 2015)



As it was the case with the site energy, none of the homes reached ZNE status based on source energy. However, using source energy, instead of site energy, resulted in an average percentage increase of reaching the ZNE status of 71% for the CES Block homes as shown in **Table 31**.

Table 31: Site Energy versus Source Energy ZNE Status for the CES Block Homes

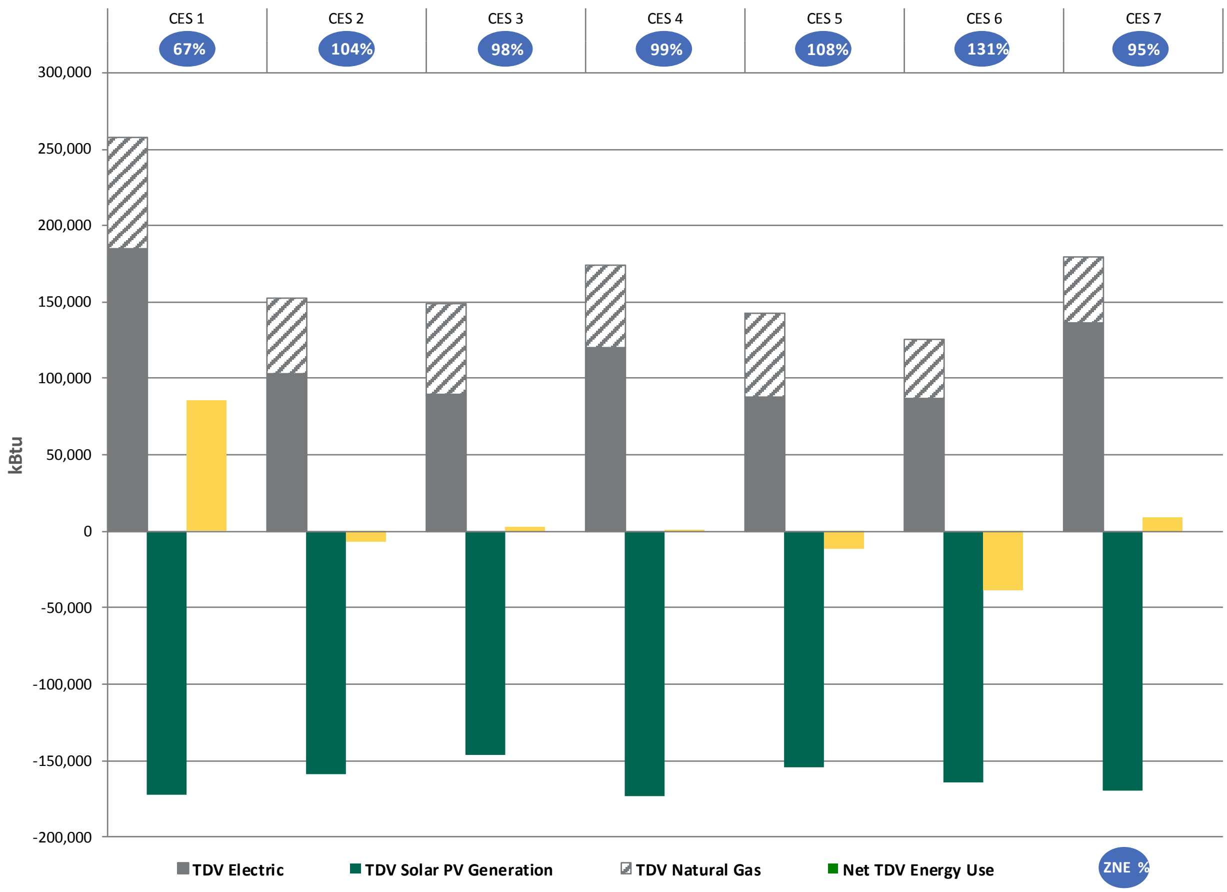
ZNE Status (%)	CES 1	CES 2	CES 3	CES 4	CES 5	CES 6	CES 7
Site Energy	30	42	40	44	41	54	46
Source Energy	51	73	71	72	76	90	72
Increase from Site Energy to Source Energy	70	74	78	64	85	67	57

Figure 57 also shows that all CES homes use more energy in the form of electricity than in the form of gas, after applying the site to source energy conversion factors.

ZNE TDV Energy Status for CES Homes

Figure 58 shows the current ZNE status for homes in the CES Block based on TDV energy for a 12-month period ending June 30, 2015. This figure also shows each home's total site electric energy use, the solar PV generation, and the net TDV electric energy use. Using the TDV energy metric, CES 2, CES 5, and CES 6 achieved ZNE status, while CES 3, CES 4, and CES 7 achieved a percentage in the mid to high 90s.

Figure 58: ZNE Status using TDV Energy for CES Block Homes (July 1, 2014 to June 30, 2015)



Using TDV energy instead of site energy as the method for assessing the home's ZNE status increased the home's ZNE status by an average of 100% for the CES Block homes. **Table 32** summarizes site energy to TDV energy average percentage increase of reaching the ZNE status for homes in the CES Block.

Table 32: TDV v. Site Energy ZNE Status for CES Block Homes

ZNE Status (%)	CES 1	CES 2	CES 3	CES 4	CES 5	CES 6	CES 7
Site Energy	30	42	40	44	41	54	46
TDV Energy	67	104	98	99	108	131	95
Increase from Site Energy to TDV Energy	123	148	145	125	163	143	107

Using the TDV method instead of the *source energy* method resulted in an average ZNE performance improvement of 38%, as shown in **Table 33**.

Table 33: TDV v. Source Energy ZNE Status for CES Block Homes

ZNE Status (%)	CES 1	CES 2	CES 3	CES 4	CES 5	CES 6	CES 7
Source Energy	51	73	71	72	76	90	72
TDV Energy	67	104	98	99	108	131	95

Increase from Source Energy to TDV Energy	31	42	38	38	42	46	32

Table 34 shows the ZNE status achieved by the homes in the CES Block based on the three metrics used: site energy, source energy, and TDV energy. This table also reveals that the homes' ZNE status improves when changing the ZNE method from site energy to source energy or to TDV energy. This is important because it would potentially cost less to achieve ZNE under these latter two methods, since it would require smaller solar PV arrays. This reduction in PV array size relates directly to the decrease in the weight given to natural gas use as site energy is replaced with either source energy or TDV energy.

Table 34: Site v. Source v. TDV Energy ZNE Status for CES Block Homes

ZNE Status (%)	CES 1	CES 2	CES 3	CES 4	CES 5	CES 6	CES 7
Site Energy	30	42	40	44	41	54	46
Source Energy	51	73	71	72	76	90	72
TDV Energy	67	104	98	99	108	131	95

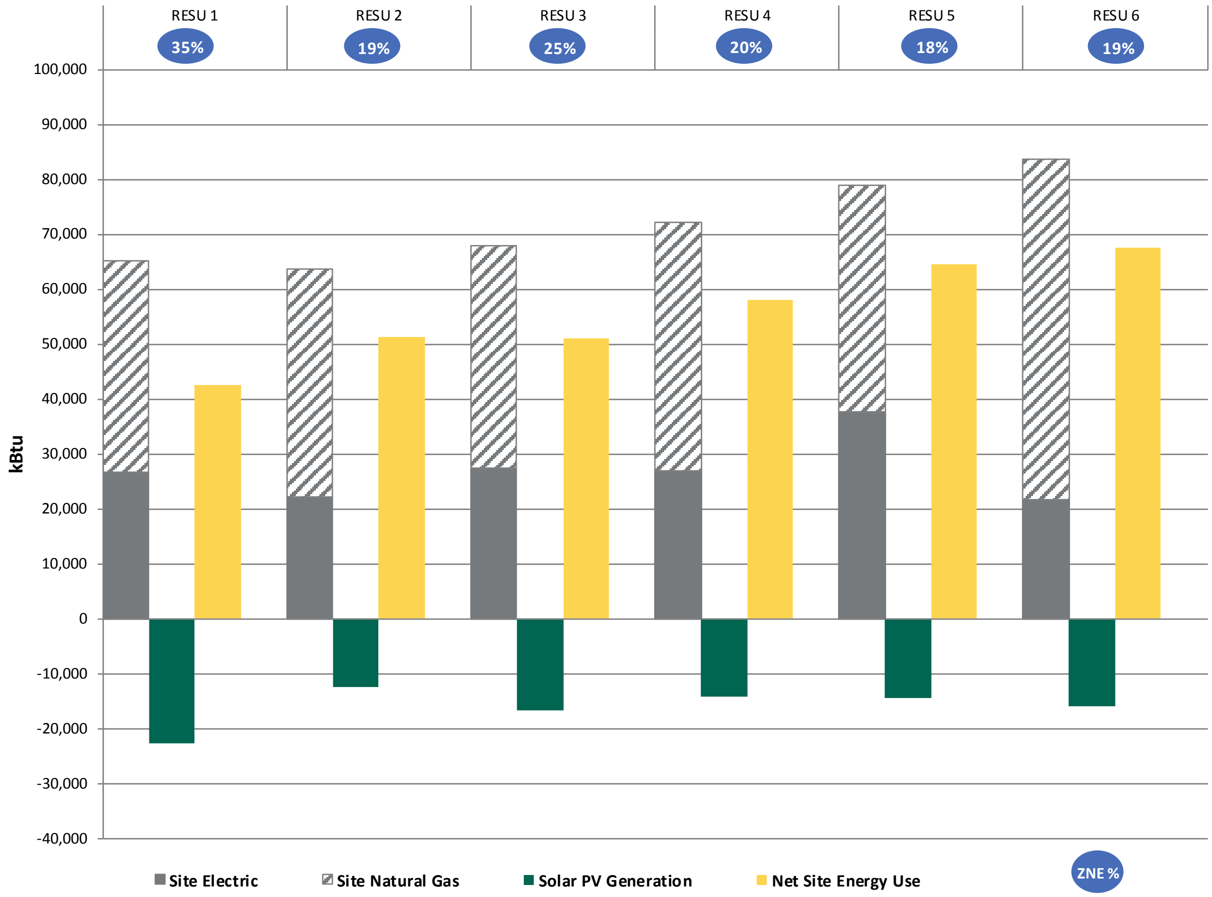
RESU Block Homes

As is with the CES Block, the homes in the RESU Block did not receive a full suite of energy efficiency measures. However, these homes received ENERGY STAR smart appliances and a solar PV array with a nominal peak DC power of 3.6 kW, except for RESU 1 home, which had nominal peak power DC of 3.8 kW.

ZNE Site Energy Status for RESU Homes

Figure 59 shows the current ZNE status for homes in the RESU Block based on site energy for a period of a year starting on July 1, 2014. This figure also shows each home's total site energy use (divided between its electricity and natural gas energy use), the solar PV generation, and the net site energy use.

Figure 59: ZNE Site Energy Status for RESU Block Homes (July 1, 2014 to June 30, 2015)

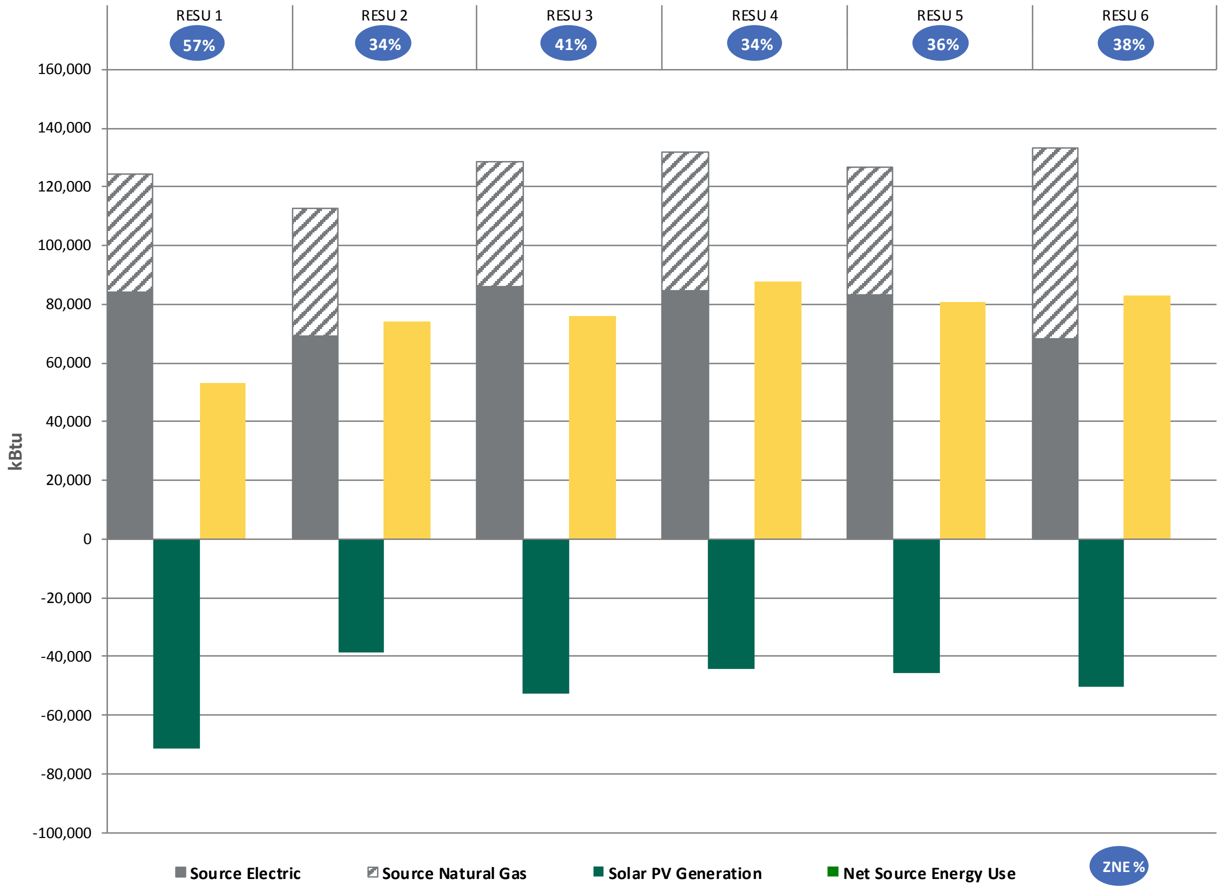


None of the homes in the RESU Block achieved ZNE status based on site energy. However, the team did not expect that these homes would achieve ZNE status since they did not receive a full suite of energy efficient measures. Consistent with the CES Block homes, using the site energy metric results in the RESU homes having higher consumption of natural gas than electricity, as shown in **Figure 59**.

<u>ZNE Source Energy Status for RESU Homes</u>

Figure 60 shows the current ZNE status for homes in the RESU Block based on source energy for a period of a year starting on July 1, 2014. This figure also shows each home's total source energy use (divided between its electricity and natural gas energy use), the solar PV generation, and the net source energy use.

Figure 60: ZNE Source Energy Status for RESU Block Homes (July 1, 2014 to June 30, 2015)



As it was the case with the site energy, none of the home reach ZNE status based on source energy. However, using source energy, instead of site energy, resulted in an average percentage increase of reaching the ZNE status of 79% for the RESU Block homes as shown in **Table 35**.

Table 35: Source versus Site Energy ZNE Status for the RESU Block Homes

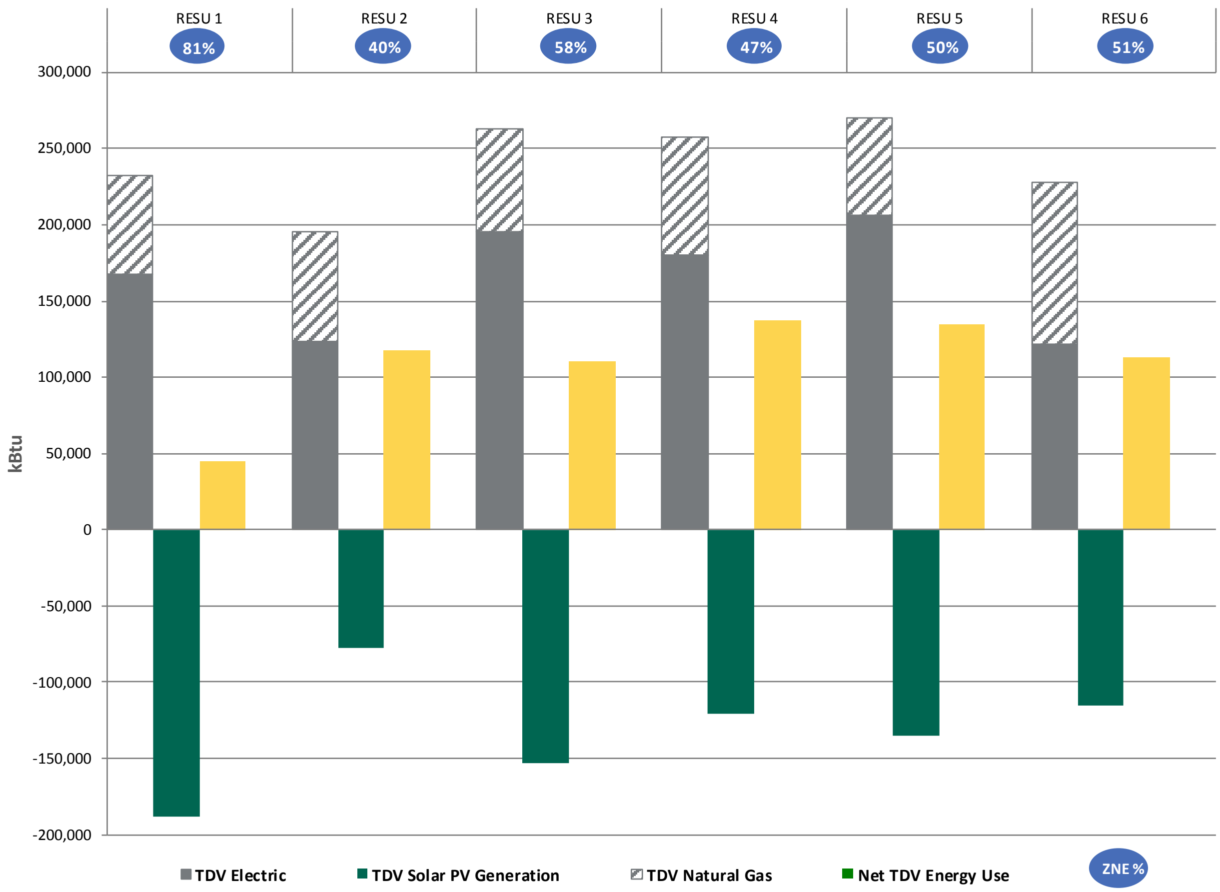
ZNE Status (%)	RESU 1	RESU 2	RESU 3	RESU 4	RESU 5	RESU 6
Site Energy	35	19	25	20	18	19
Source Energy	57	34	41	34	36	38
Increase from Site Energy to Source Energy	65	77	66	71	96	97

Figure 60 also shows that all RESU homes use more energy in the form of electricity than in the form of gas, after applying the site to source energy conversion factors.

<u>ZNE TDV Energy Status for RESU Homes</u>

Figure 61 shows the current ZNE status for homes on the RESU Block based on TDV energy for the 12 months starting on July 1, 2014. This figure also shows each home's total TDV electric energy use, the solar PV generation, and the net TDV electric energy use.

Figure 61: ZNE Status Using TDV Energy for RESU Block Homes (July 1, 2014 to June 30, 2015)



As it was the case with the site energy, none of the home reached ZNE status based on TDV energy. However, using site electric energy, instead of site energy, resulted in an average percentage increase of reaching the ZNE status of 143% for the RESU Block homes as shown in **Table 36**.

Table 36: TDV versus Site Energy ZNE Status for the RESU Block Homes

ZNE Status (%)	RESU 1	RESU 2	RESU 3	RESU 4	RESU 5	RESU 6
Site Energy	35	19	25	20	18	19
TDV Energy	81	40	58	47	50	51
Increase from Site Energy to TDV Energy	131	111	132	135	178	168

Using the TDV energy method instead of the source energy method improved the average ZNE performance by 35%, as shown in **Table 37.**

Table 37: TDV versus Source Energy ZNE Status for the RESU Block Homes

ZNE Status (%)	RESU 1	RESU 2	RESU 3	RESU 4	RESU 5	RESU 6
Source Energy	57	34	41	34	36	38
TDV Energy	81	40	58	47	50	51
Increase from Site Energy to TDV Energy	42	18	41	38	39	34

Table 39 shows the ZNE status achieved by the homes in the RESU Block based on the three metrics used: site energy, source energy, and TDV energy. This table also indicates that changing the ZNE method from site energy to source energy or to TDV energy improves the ZNE performance. This is important because it would potentially cost less to achieve ZNE status, as homes would require smaller solar PV arrays. This reduction in solar PV array size relates directly to the decrease in the weight given to natural gas use as site energy is replaced with either source energy or TDV energy.

Table 38: Site vs. Source vs. TDV Energy ZNE Status for the RESU Block Homes

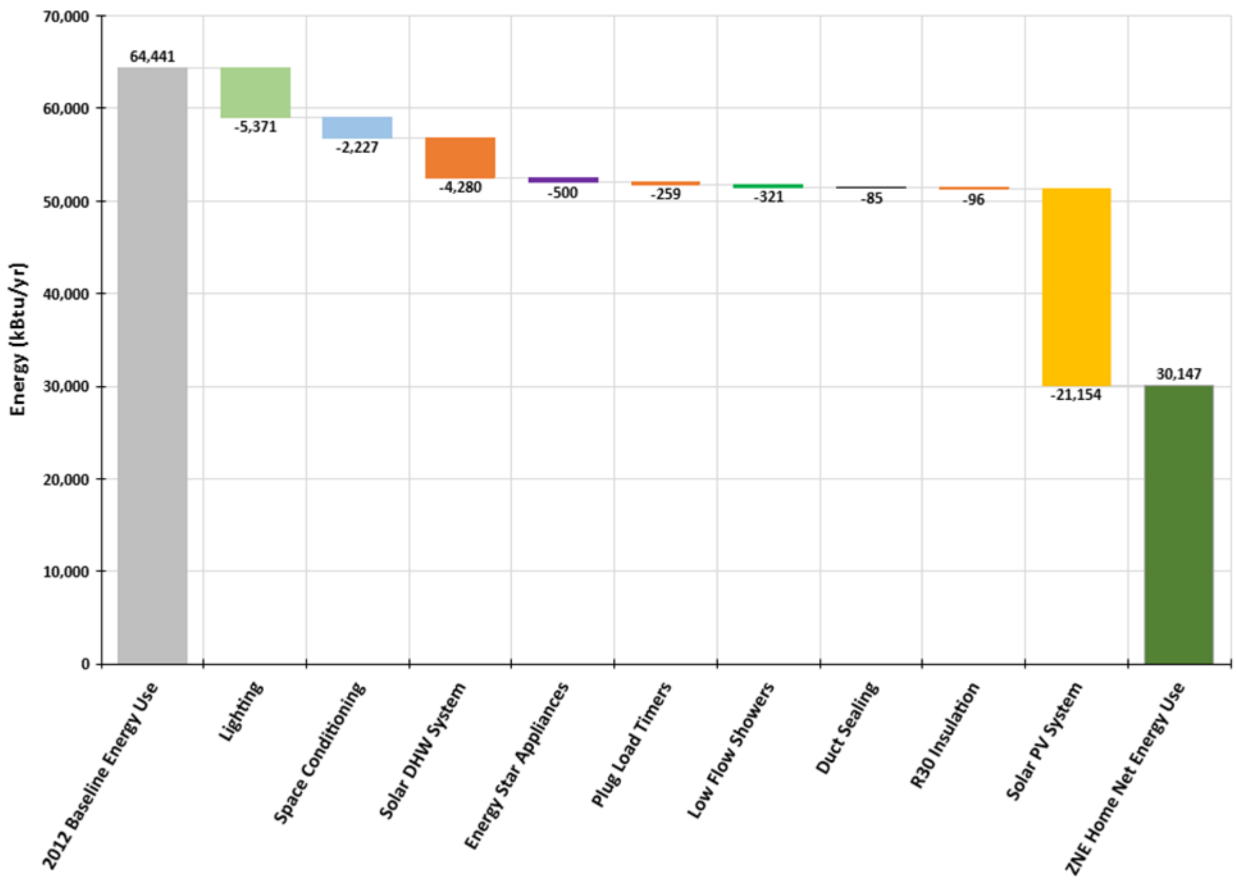
ZNE Status (%)	RESU 1	RESU 2	RESU 3	RESU 4	RESU 5	RESU 6
Site Energy	35	19	25	20	18	19
Source Energy	57	34	41	34	36	38
TDV Energy	81	40	58	47	50	51

Evaluation of Contributions to Energy Conservation

The waterfall chart in **Figure 62** compares average energy consumption for the ZNE Block homes in 2012—prior to the homes being retrofitted with EEMs and solar PV—with annual energy consumption between July 2014 and June 2015. The latter period energy consumption was adjusted for weather effects using the Control Block homes. If Site Energy ZNE had been achieved, the final column labeled ZNE Home Net Energy Use value would have been zero. The actual Site Energy ZNE performance reflects a ZNE achievement of 41%[31]. Solar PV is the largest contributor toward the ZNE goal, followed by lighting, domestic hot water (solar or high efficiency), and air conditioning. Smart appliances make a very small contribution. The ZNE Home Net Energy Use column represents the average net energy use for the ZNE Block homes. This figure excludes the EVSE load, but includes the RESU losses. Removing the RESU losses would improve the Site Energy ZNE performance.

[31] The Site Energy ZNE was calculated by dividing the solar PV system generation by the gross energy use (i.e., the solar PV generation plus ZNE Home Net Energy Use).

Figure 62: Relative Contributions of EEMs and Solar PV to Site Energy ZNE Performance



Field Experiment 1B: Impact of Demand Response Events on Smart Devices, Homes, and Grid

Test 1: In-home Display Price Signal (August 8, 2013)

The purpose of this experiment was to test the ability of the IHDs to receive a price signal from a smart meter, and to display the current price of electricity. This experiment consisted of sending a price signal from SCE's NMS to a group of 13 IHDs via the project smart meters. The IHDs would then display the current price of electricity for 24 hours. The ISGD customers were not enrolled in a dynamic pricing tariff, so the team used a simulated price of $0.50/kWh. The team also sent a text message to the IHDs requesting customers to confirm receipt of the message. This event occurred on August 8, 2013 between 4 pm and 7 pm. Upon sending the price signal and text messages to the 13 IHDs, six customers confirmed receipt of the message.

The team identified two abnormal device behaviors during this experiment. The first issue emerged during a visit to one of the project homes two days after the experiment. Upon visual inspection of the HAN devices, the team member noticed that the PCT and IHD still displayed the text message from the event, even though it should have stopped displaying after 24 hours. The team member attempted to confirm receipt of the message, but could not (i.e., the project meter did not report the event to the NMS).

The second abnormality was that one customer confirmed the same message four times on the PCT and two additional times on the IHD. The message should have stopped displaying on both devices after the customer first confirmed the message. The team replicated this experience by executing a second similar event. These types of errors could be confusing or annoying to customers, which could limit consumer adoption of these devices as well as customer participation in associated load management programs.

The team did not observe any load reduction at the customer premises because of this price signal. This was consistent with the team's expectations since the simulated price signal offered no incentive for customers to reduce their energy use.

Test 2: PCT Duty Cycle Demand Response Event during Cooling Operation (September 16, 2013)

The purpose of this experiment was to test the ability of the project's PCT to receive and respond appropriately to DR duty cycle signals. These signals should cause the air conditioning to turn off, thereby reducing electricity loads on hot days. This experiment consisted of sending a 50% duty cycle signal from the ISGD Advanced Load Control System (ALCS) via the project smart meters to all participating customer homes with air conditioning. Three homes operated their air conditioners at least once during the DR event (RESU 5, CES 4, and ZNE 7).

The DR events were scheduled for 3:30 pm, 4:00 pm, 4:30 pm, and 5:00 pm with durations of 15 minutes per event. The 50% duty cycle should have caused the PCTs to turn off for 7.5 minutes, and then turn back on for 7.5 minutes over the course of each 15-minute event. Unfortunately, the PCTs did not react as anticipated. The team learned that the PCTs ignore duty cycle commands. They simply curtail their operation for the duration of the event. Devices that responded to the events generally remained off for 15 minutes, rather than the expected 7.5 minutes.

The large number of short duration DR events made it difficult to assess their effectiveness. However, the homes with the air conditioning running during the event showed a load drop during some of the events. CES 4 turned on the air conditioner at 4:14 pm, and then turned off at the beginning of the second DR event at 4:30 pm. ZNE 7 turned on at 4:37 pm, and then turned off at 5:00 pm (the beginning of the fourth DR event). RESU 5 experienced load reductions that corresponded with the 3:30 pm and 4:30 pm events. The team could not determine why the response was limited to these two events. The other participating homes exhibited similar behavior in which load drops resulted from some of the events, but not others.

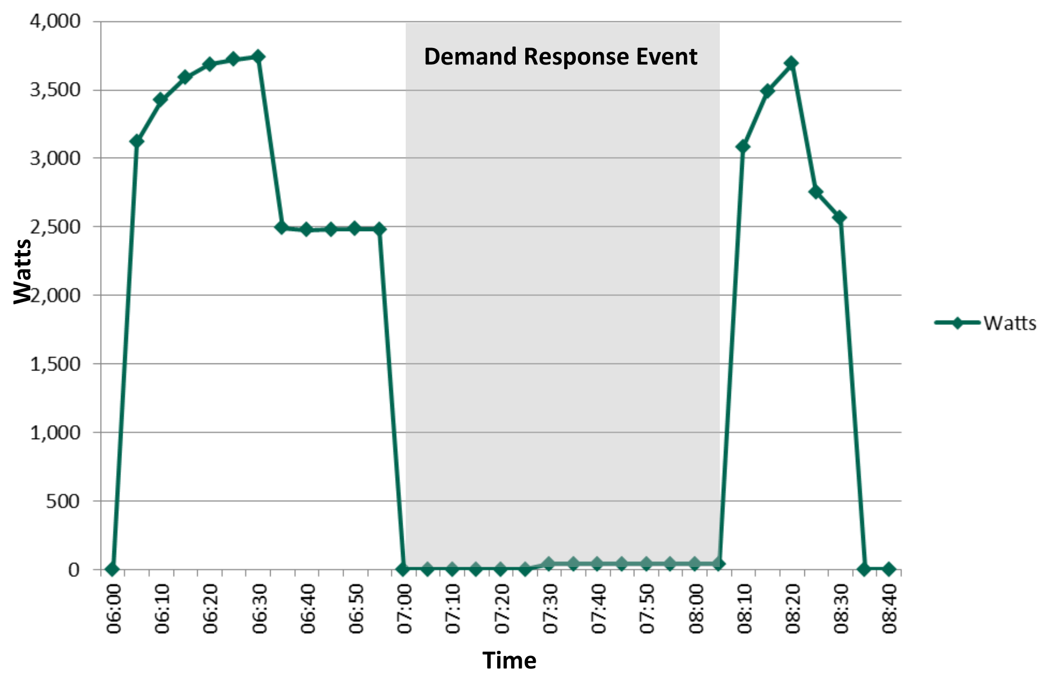
Test 3: PCT Duty Cycle Demand Response Event during Heating Operation (December 20, 2013)

The purpose of this experiment was to test the ability of PCTs to receive and respond appropriately to DR duty cycle signals. This particular test should cause the heat pump to turn off. This capability could reduce electric heating loads on cold mornings.

The experiment consisted of sending a 100% duty cycle signal from the ISGD ALCS via the project smart meters to all participating ZNE Block customer homes. Eight of the nine homes on the ZNE Block have heat pumps. One of the homes (ZNE 3) has a gas furnace, although this requires a forced air unit (FAU) which uses electricity. Each PCT was expected to cycle off 100% for the entire duration of the event, which was scheduled for 7am to 8am.

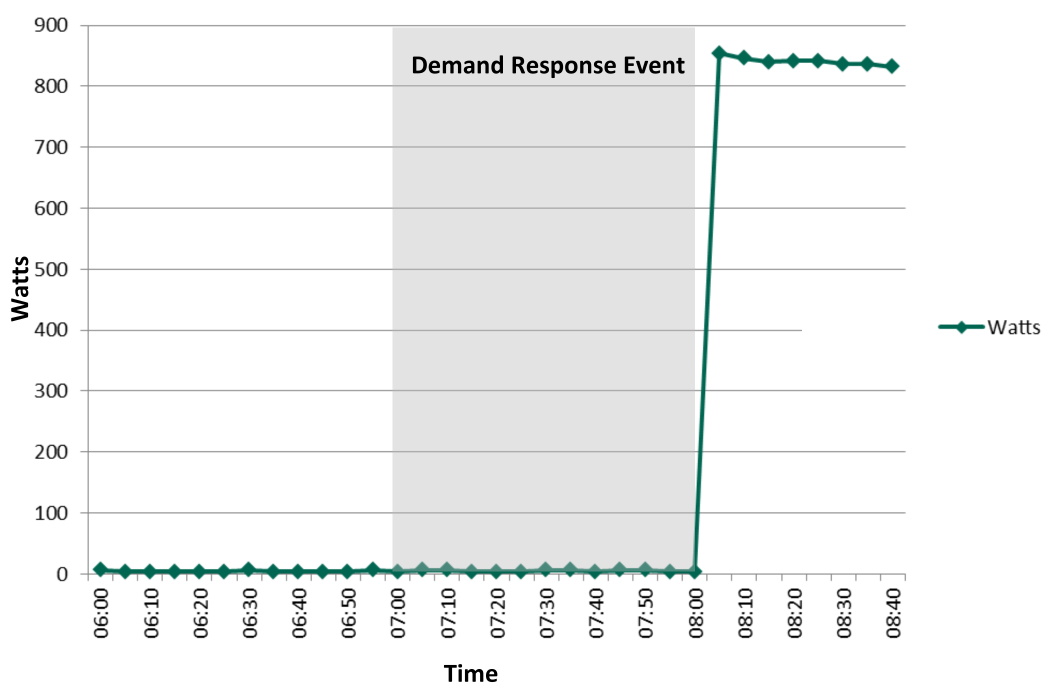
Four homes were operating their heat pumps during this event (ZNE homes 1, 4, 5, and 6). Three of the homes responded to the DR event signal by curtailing their heat pump use at 7:00 am. The fourth home (ZNE 6) continued to operate throughout the one-hour event. Either this home did not receive the DR event signal, or the homeowner overrode the event. The team's instrumentation does not have visibility of the reason for this home's response. Of the three homes that shut off their heat pumps, two resumed operation soon after the event ended at 8:00 am, while the third remained off. The third home likely remained off due to the customer's programmed set points (i.e., it was scheduled to turn off at or before 8:00 am). Each of these three homes experienced load reductions of approximately 2.5 kW throughout the experiment. **Figure 63** displays the air conditioning load of ZNE 1 during the DR event. This home shut off its heat pump at 7:00 am and resumed operation at 8:10 am.

Figure 63: ZNE 1 Air Conditioner Load



In addition to the four homes that operated their heat pumps during the experiment, it appears that ZNE 3 attempted to turn on its gas furnace during the experiment. It also appears that the DR event caused the gas heater to delay its operation until after the event ended, at 8:00 am. The gas furnace operates in conjunction with the FAU. **Figure 64** shows the FAU load of ZNE 3 during the DR event. The FAU did not operate until precisely 8:00 am. It is likely that the PCT was programmed to turn on the heater sometime between 7:00 am and 8:00 am, and that the DR event delayed its operation until 8:00 am.

Figure 64: ZNE 3 Forced Air Unit Load



Although SCE is a summer peaking utility, in the future it is likely that more flexible resources will be required on a year-round basis, during both on-peak and off-peak periods. Such resources could be useful in managing the grid impacts of increasing amounts of distributed energy resources (such as solar PV and energy storage), and new types of load (such as plug-in electric vehicles and energy storage). Heat pumps could therefore be a potentially valuable demand response resource.

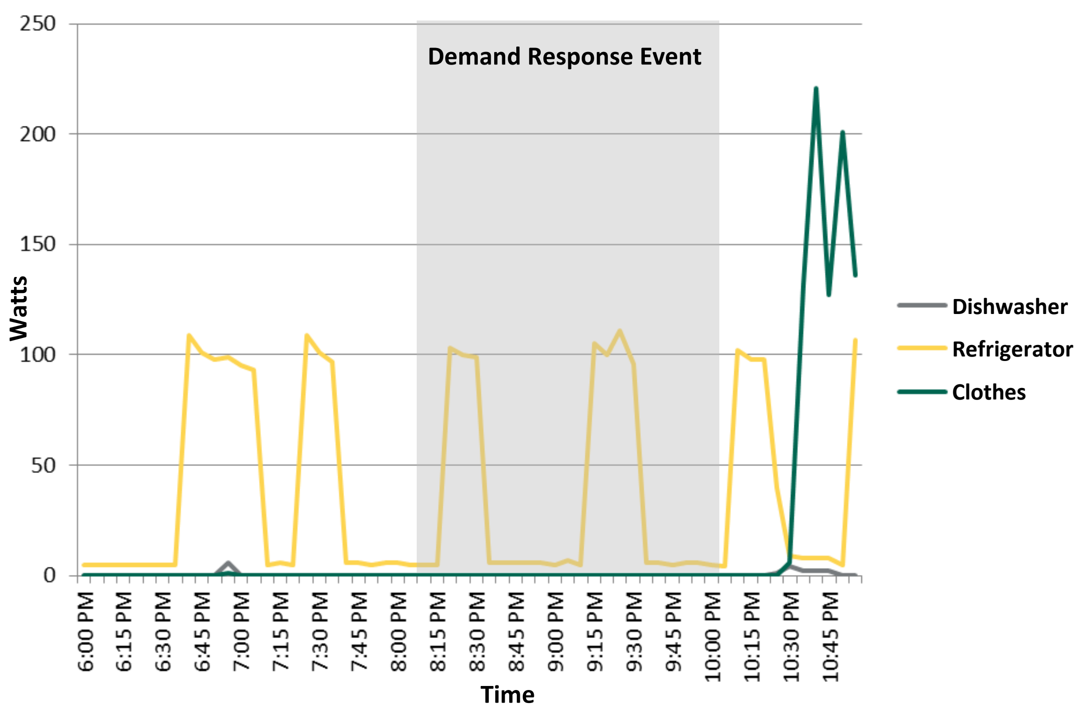
Test 4: Smart Appliance Demand Response Event (February 19, 2014)

The purpose of this experiment was to test the ability of smart appliances to receive and react appropriately to DR event signals in an attempt to reduce electricity loads. This experiment consisted of sending a DR event signal from the ISGD ALCS via the project smart meters to the 22 project homes with smart appliances. The DR event was scheduled from 8:00 pm to 10:00 pm.

If a smart appliance is operating during a DR event, the appliance is designed to switch to a "low power" mode of operation. This mode reduces the average wattage of the appliance operation by either eliminating an operation or reducing the energy use of a given operation. If the smart appliance is not operating and someone attempts to begin using it during the DR event, the smart appliance should delay its operation. The appliance should also display a message stating that a DR event is currently in process, and that the user can override the event.

Prior to initiating the test, the team notified the project homeowners of the event and asked them to run their appliances during the event. The team then compared the appliance loads to the loads on the day prior to the event in an attempt to identify noticeable load reductions. It was easy to identify energy use cycles in refrigerators and when clothes washers and dishwashers were in use. However, it was difficult to identify any load reductions or delayed loads that resulted from the DR event signal. **Figure 65** presents the smart appliance load shapes for CES 1. The clothes washer represents a typical load profile for a clothes washer operating during the evening.

Figure 65: CES 1 Smart Appliance Load



The refrigerator, identified by the yellow line, continues to cycle up to 100 watts approximately every 30 minutes throughout the event duration. The clothes washer, identified by the green line, begins operating at about 10:30 pm, but it is unclear whether this resulted from the DR event. To improve its understanding of the appliance behaviors during demand response events, the team visited one of the experiment homes on February 27, 2015. The results of this visit are summarized in Appendix 13.

Test 5a: Dual PCT-EVSE Demand Response Event (July 24, 2014)

The purpose of this experiment was to evaluate the ability of the project PCTs and EVSEs to simultaneously receive and respond to a duty cycle DR signal. This signal should cause the air conditioners (AC) and electric vehicle chargers to turn off, thereby reducing the homes' electricity loads. This experiment consisted of sending a 100% duty cycle signal from the ISGD Advanced Load Control System (ALCS) via the project smart meters to all 22 participating customer homes.[32]

The team scheduled the DR event to take place between 3:00 pm and 6:00 pm. Since this was a 100% duty cycle event, the PCTs and EVSEs should have turned off for the entire duration of the three-hour event. Prior to conducting this event, the team adjusted the data collection settings to begin retrieving and storing data for each component in one-minute intervals. The tables below identify the AC units and EVSEs that operated between 2:00 pm and 7:00 pm (within one hour of the DR event period), and describes how they behaved during the DR event.

Out of the 22 homes included within this experiment, six operated their AC units during the DR event. Of these six homes, three responded properly. The AC units in ZNE 3 and ZNE 4 were both off before and during the event, and then turned on when the internal temperature of the homes reached 84° F, which the team verified through the wireless temperature sensors.[33] ZNE 9 has two AC units. This customer verified that they overrode the DR event on their first AC unit (AC1), and that they allowed their second AC unit (AC2) to participate in the DR event. AC2 remained off throughout the DR event, and then began operating at 6:01 pm after the event ended.

Three homes had AC units that did not respond properly to the DR event. The AC unit in ZNE 7 was operating prior to the DR event and continued to run after the event began. Either the customer overrode this DR event or the PCT did not receive the event signal. The team was unable to confirm the cause, but suspects that the customer overrode the event. The AC units in the other two homes, CES 1 and RESU 5, both turned on during the DR event. The room temperatures in these two homes were below 84° F, so the AC units did not turn on due to their temperatures being above the duty cycle set point. The ISGD team later determined that these homes did not receive the DR event signals due to a loss of communications between the homes' GE Nucleus and the project meter. Since the Nucleus is used to route DR signals from each home's project meter to the home's respective smart appliances and PCTs, this loss of communications means that the team could not deliver DR signals to these devices. Appendix 12 summarizes the team's efforts to understand these communications challenges.

Table 39: PCT Behavior (July 24, 2014)

Home	Unit	On Time	Off Time	Proper Response?	Comments
CES 1	AC2	2:40 pm	3:04 pm	No	Unit ran through the event start
		3:34 pm	4:12 pm	No	Unit turned on during event
		4:35 pm	6:04 pm	No	Unit turned on during event
RESU 5	AC1	4:22 pm	5:04 pm	No	Unit turned on during event
		5:18 pm	6:57 pm	No	Unit turned on during event
ZNE 3	AC2	5:10 pm	6:01 pm	Yes	Unit turned on due to room temp.
ZNE 4	AC1	5:31 pm	6:59 pm	Yes	Unit turned on due to room temp.
ZNE 7	AC2	2:54 pm	3:49 pm	No	Unit ran through the event start
		4:16 pm	6:59 pm	No	Unit turned on during event

[32] ALCS reported an error message after the team initiated the event. The team then initiated the same event using the NMS. The team contacted the ALCS help desk the following day and determined that the error was due to a power outage that occurred at the AT Labs in July 2014.

[33] The ISGD PCTs have implemented the duty cycle DR function by adjusting the temperature setpoint to 84° F. This curtails the PCT until the room temperature rises to 84° F, when the AC unit turns on.

Home	Unit	On Time	Off Time	Proper Response?	Comments
ZNE 9	AC1	2:13 pm	2:36 pm		Pre-event
		3:02 pm	3:19 pm	Yes	Customer overrode event
		3:45 pm	4:51 pm	Yes	Customer overrode event
		5:09 pm	6:24 pm	Yes	Customer overrode event
	AC2	6:01 pm	6:49 pm	Yes	Unit turned on after event finished

The team set up this DR event as a 100% duty cycle event. The team later discovered that the EVSEs interpret and respond to duty cycle signals differently than the PCTs. Whereas the PCTs interpret a 100% duty cycle event as a request to curtail operation, the EVSEs interpret the same signal as a request to charge at 100% of their operating capacity. As a result, none of the three EVSEs that were in use during this DR event responded as the team intended. They continued to operate throughout the event, or until the PEV batteries were fully charged.

Table 40: EVSE Behavior (July 24, 2014)

Home	On Time	Off Time	Power (watts)	Proper Response?	Comments
CES 7	2:34 pm	3:50 pm	3,400	Yes	100% duty cycle allows EVSE to run at full power
	4:02 pm	4:23 pm	3,390	Yes	100% duty cycle allows EVSE to run at full power
	4:24 pm	4:46 pm	640	Yes	Normal step down charge rate
RESU 5	4:34 pm	6:04 pm	3,196	Yes	100% duty cycle allows EVSE to run at full power
ZNE 5	4:47 pm	5:06 pm	3,200	Yes	100% duty cycle allows EVSE to run at full power
	5:07 pm	5:28 pm	680	Yes	Normal step down charge rate

Test 5b: Dual PCT-EVSE Demand Response Event (July 28, 2014)

During the DR event on July 24, 2014, a number of homes did not respond as the team expected. Since the team initiated this event through the NMS, due to an error with ALCS, the team suspected that this could have contributed to the unexpected results. The team therefore conducted a similar DR event on July 28, 2014 using ALCS to verify whether the NMS contributed to the results of the previous DR event.

Consistent with the July 24, 2014 experiment, the purpose of this experiment was to evaluate the ability of the project PCTs and EVSEs to simultaneously receive and respond to a duty cycle DR signal. This signal should cause the AC and electric vehicle chargers to turn off, thereby reducing the homes' electricity loads. This experiment consisted of sending a 100% duty cycle signal from the ISGD ALCS via the project smart meters to all 22 participating customer homes.

The team scheduled the DR event to take place between 3:00 pm and 5:00 pm. Since this was a 100% duty cycle event, the PCTs and EVSEs should have turned off for the entire duration of the two-hour event. The tables below identify the AC units and EVSEs that operated between 2:00 pm and 7:00 pm (within one hour of the DR event period), and describes how they behaved during the DR event.

Out of the 22 homes included within this experiment, five operated their AC units during the demand response event. Of these five homes, three responded properly. The second AC unit in ZNE 3 turned on during the event when the room temperature reached 84° F, which the team verified through the wireless temperature sensors. The two AC units in ZNE 7 were both off before and during the event, and then turned on after the DR event was complete. ZNE 9 overrode the DR event on their first AC unit and allowed their second AC unit to participate in the DR event. ZNE 9's second AC unit remained turned off throughout the DR event, then turned on at 5:02 pm after the event concluded.

Two homes had AC units that did not respond properly to the DR event. The second AC unit in CES 1 turned on at 3:19 pm, during the DR event, and remained on throughout the event. Either the customer overrode the event or the PCT did not receive the event signal. The first AC unit in RESU 5 turned on at 2:58 pm and continued to operate after the event began at 3:00 pm. The room temperature in this home was below 84° F, so the AC unit did not turn on due to the temperature being above the duty cycle set point. Similar to the test performed on July 24, 2014, the ISGD team later determined that these two homes did not receive the DR event signals due to a loss of communications between the homes' Nucleus and the project meter. Since the Nucleus is used to route DR signals from each home's project meter to the home's respective smart appliances and PCTs, this loss of communications means that the team could not deliver DR signals to these devices.

Table 41: PCT Behavior (July 28, 2014)

Home	Unit	On Time	Off Time	Proper Response?	Comments
CES 1	AC2	3:19 pm	7:00 pm	No	Unit turned on during event
RESU 5	AC1	2:58 pm	4:05 pm	No	Unit ran through the event start
		4:49 pm	5:32 pm	No	Unit turned on during event
		5:18 pm	7:00 pm		Post-event
ZNE 3	AC1	1:21 pm	2:04 pm		Pre-event
	AC2	4:30 pm	5:22 pm	Yes	Unit turned on due to room temp.
		5:30 pm	6:00 pm		Post event
ZNE 7	AC1	2:14 pm	2:36 pm		Pre-event
		5:01 pm	5:37 pm	Yes	Unit turned on after event finished
	AC2	2:10 pm	2:41 pm		Pre-event
		5:01 pm	7:00 pm	Yes	Unit turned on after event finished
ZNE 9	AC1	3:07 pm	6:01 pm	Yes	Customer overrode event
	AC2	5:02 pm	6:01 pm	Yes	Unit turned on after event finished

The team set up this DR event as a 100% duty cycle. Similar to the test performed on July 24, 2014, the team later discovered that the EVSEs interpret and respond to duty cycle signals differently than the PCTs. Whereas the PCTs interpret a 100% duty cycle event as a request to curtail operation, the EVSEs interpret the same signal as a request to charge at 100% of their operating capacity. As a result, none of the three EVSEs that were in use during this DR event responded as the team intended. They continued to operate throughout the event, or until the PEV batteries were fully charged.

Table 42: EVSE Behavior (July 28, 2014)

Home	On Time	Off Time	Power (watts)	Proper Response?	Comments
CES 4	1:00 pm	3:19 pm	3,339	Yes	100% duty cycle allows EVSE to run at full power
	3:20 pm	3:40 pm	702	Yes	Normal step down charge rate
RESU 3	2:23 pm	3:17 pm	3,429	Yes	100% duty cycle allows EVSE to run at full power
	3:18 pm	3:39 pm	691	Yes	Normal step down charge rate
	4:37 pm	5:35 pm	3,433	Yes	100% duty cycle allows EVSE to run at full power
	5:36 pm	5:55 pm	690		Post-event
ZNE 6	6:33 pm	6:59 pm	3,389		Post-event
ZNE 8	2:43 pm	3:21 pm	3,301	Yes	100% duty cycle allows EVSE to run at full power

Home	On Time	Off Time	Power (watts)	Proper Response?	Comments
ZNE 8	5:58 pm	6:29 pm	3,300		Post-event
	6:30 pm	6:57 pm	600		Post-event

Test 5c: Dual PCT-EVSE Demand Response Event (July 29, 2014)

The DR events on July 24, 2014 and July 28, 2014 both yielded unexpected results. When attempting to diagnose the communications problem with the PCTs on the CES and RESU blocks, none of which responded to the prior two DR events, the team used the NMS tool to ping the Nucleus devices via the AMI project meters. None of the Nucleus devices on the RESU and CES blocks responded. Interestingly, all the Nucleus devices in the ZNE block homes could be pinged. Although the team has been unable to determine the cause of the loss of Nucleus communications on these two blocks, this explained why these homes' PCTs did not respond to the DR event. Since the PCTs receive DR signals via the Nucleus, the loss of Nucleus communications means that the Nucleus was unable to pass the DR signals to the PCTs.

The team also identified the cause of the unexpected EVSE behavior during the two previous events. The team had erred in assuming that the PCTs and EVSEs respond the same way to 100% duty cycle DR events. Whereas the PCTs interpret a 100% duty cycle event as a request to curtail operation, the EVSEs interpret a 100% duty cycle event as a request to charge at full power. To curtail EVSE charging, the DR event signal should have specified a 0% duty cycle.

The team initiated a duty cycle DR event to all homes on the ZNE block in order to verify that the EVSEs would respond as expected by reducing their charging levels. This test consisted of 25% duty cycle event with a one-hour duration from 4:30 pm to 5:30 pm. The purpose of the 25% duty cycle event was to "throttle" any EVSEs that operated during the event and cause them to charge at a reduced power level. AC units would interpret a 25% duty cycle event as a command to turn off completely, since the ISGD PCTs do not respond to duty cycle events. The tables below identify the AC units and EVSEs that operated between 3:30 pm and 6:30 pm (within one hour of the DR event period), and describes how they behaved during the DR event.

Out of the nine homes included within this experiment, three operated their AC units during the demand response event, and all behaved as expected. The second AC unit in ZNE 3 turned on during the event since the room temperature exceeded the DR set point. The first AC unit in ZNE 7 remained off for the duration of the event, and then turned on after the event ended, while the second AC unit turned off when the event began and turned back on when the event ended. The AC unit in ZNE 9 turned on during the event due to customer override.

Table 43: PCT Behavior (July 29, 2014)

Home	Unit	On Time	Off Time	Proper Response?	Comments
ZNE 3	AC2	4:57 pm	5:27 pm	Yes	Unit turned on due to room temp.
ZNE 7	AC1	3:23 pm	3:39 pm		Pre-event
		5:29 pm	5:55 pm	Yes	Unit turned on after event finished
	AC2	3:06 pm	3:36 pm		Pre-event
		4:19 pm	4:30 pm	Yes	Unit turned off at beginning of event
		5:29 pm	6:21 pm	Yes	Unit turned on after event finished
ZNE 9	AC1	3:25 pm	4:04 pm		Pre-event
		4:54 pm	6:01 pm	Yes	Customer overrode event

The team set up this DR event as a 25% duty cycle. When EVSEs receive DR event signals to reduce the charging level by a certain percentage (such as 25%), the EVSE reduces the charging level based on the maximum charging capacity of the

EVSE, not by the current PEV charging rate. The maximum charge rate of the ISGD EVSEs is 7.2 kW, so a 25% duty cycle should reduce the charge rate to approximately 1.8 kW.

Three of the nine ZNE block homes operated their EVSEs during this test, and each of them responded properly. ZNE6 was charging before the event began and then reduced its charging rate once the event began. ZNE 7 began charging—at the proper power level—after the event had already commenced. ZNE 8 was charging at a stepped-down power level when the DR event began, since it was near the end of its charging event. Since this reduced rate is less than 25% of the EVSE maximum charge capacity, its rate of charge did not change once the event began.

Table 44: EVSE Behavior (July 29, 2014)

Home	On Time	Off Time	Power (watts)	Proper Response?	Comments
ZNE 6	4:00 pm	4:29 pm	3,390		Pre-event
	4:30 pm	5:29 pm	1,720	Yes	Charge rate dropped to 25% of EVSE capacity
	5:30 pm	6:41 pm	3,413	Yes	Charge rate returned to full power after event completed
ZNE 7	4:48 pm	5:28 pm	1,763	Yes	Began charging at 25% of EVSE capacity
	5:29 pm	7:06 pm	3,503	Yes	Charge rate returned to full power after event completed
ZNE 8	2:30 pm	4:22 pm	3,300		Pre-event
	4:23 pm	4:48 pm	616	Yes	Normal step down charge rate, below 25% of EVSE capacity

Test 6: Aggregated Demand Response Event using All HAN Devices (September 15, 2014)

The purpose of this experiment was to evaluate the ability of the project's HAN devices to simultaneously receive and respond to DR signals. This should cause the RESU to discharge energy. It should also cause the AC units, EVSEs, and smart appliances to either turn off or reduce their energy use, depending on whether they are in use. This should result in substantial reductions in the homes' net electricity loads. Such a capability could be useful for addressing overload conditions on hot weather days. This capability could also help reduce the impacts of the "duck curve" in which low or negative afternoon loads turn sharply higher in the late afternoon as the sun sets—which reduces solar PV output—and as household energy use increases when customers arrive home. The team scheduled this experiment for September 15, 2014 between 4:00 pm and 9:00 pm, when household energy use is typically the highest.

To prepare the RESUs for the DR event, on the day preceding the event, the team scheduled the RESUs to charge to a 100% SOC, and to maintain this charge level until the event. The team specified a 20% energy reserve, leaving 80% available for the DR event. Since each RESU can store 10 kWh of energy, each RESU would have 8 kWh available for discharge. The RESUs determine their energy output level by dividing the available energy by the event duration. Since this DR event was to have a 5-hour duration and each RESU had 8 kWh of available energy, each RESU should have discharged at approximately 1.6 kW over the entire DR event.

The DR event for the AC units consisted of a "degree offset" event whereby the PCT set points are increased. This event changed the set points by 4° F. For example, if a customer had their AC set to turn on when the room temperature reaches 80° F, during the DR event the AC unit would only turn on if the room temperature reaches 84° F. In no case could the PCT be set to a temperature higher than 84° F.

The DR event for the EVSEs consisted of a 0% duty cycle between 4:00 pm and 9:00 pm, and a 25% duty cycle between 9:00 pm and 12:00 am. This should have caused the EVSEs to stop charging at 4:00 pm, or not begin charging between 4:00 pm and 9:00 pm. It should have also caused the EVSEs to charge at a reduced rate between 9:00 pm and midnight.

The DR event for smart appliances consisted of a "critical" DR event signal, which should have caused the appliances to either reduce their energy consumption—if they were already in use when the event began—or delay their start if a customer tried to use them after the event had already begun.

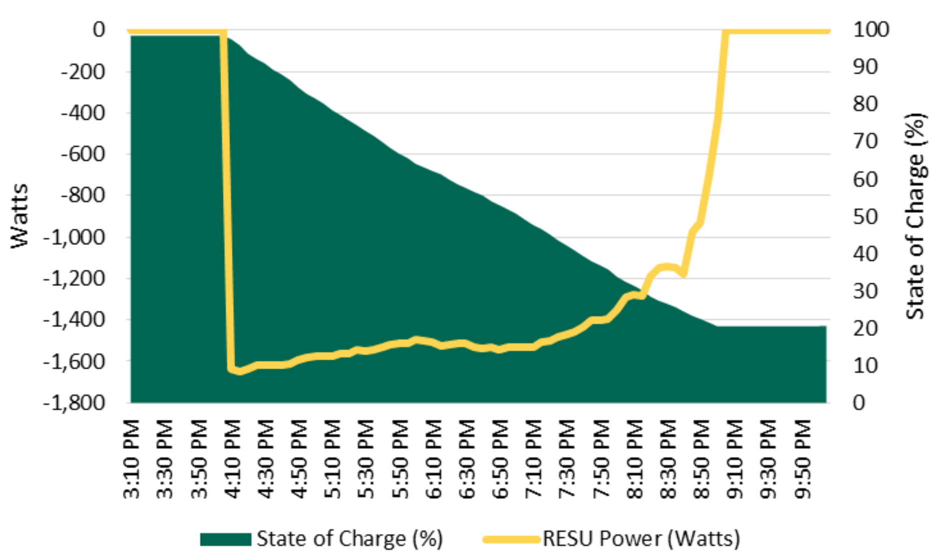
The following table summarizes the details of this DR experiment in terms of the DR resources, the number of homes, the DR event signals and the event durations.

Table 45: DR Event Details for September 15, 2014

DR Resource	Participant Homes	DR Event Type	Event Duration
RESU	ZNE Block and RESU Blocks (14 homes)	Discharge at constant rate over 5 hour period	4:00 pm to 9:00 pm
PCT	All Blocks (22 homes)	4 degree offset	4:00 pm to 9:00 pm
EVSE	All Blocks (22 homes)	1. 0% duty cycle 2. 25% duty cycle	1. 4:00 pm to 9:00 pm 2. 9:00 pm to midnight
Smart Appliances	All Blocks (22 homes)	Critical DR event	4:00 pm to 9:00 pm

At 4:00 pm, all 14 RESUs began discharging at approximately 1.6 kW, consistent with the team's expectations. At 7:20 pm, RESU4 stopped discharging, although it had approximately 2.2 kWh of stored energy available for discharge. The homeowner confirmed that they inadvertently cancelled the event manually via the RESU touchscreen. The remaining 13 RESUs continued to discharge until the end of the event at 9:00 pm. The following figure depicts the average power output and SOC of these 13 RESUs throughout the DR event.

Figure 66: Average RESU Power and State of Charge (September 15, 2014)



As the RESUs neared the end of the DR event, their rates of discharge declined more quickly than the team expected. These declines were greater than what the team observed during the initial lab testing prior to ISGD deployment, and resulted from the RESUs having less energy available than expected during the initial power calculation at the beginning of the DR event (i.e., when the RESU calculates the average rate of discharge over the course of the event). In order to continue discharging throughout the duration of the DR event, as the event progressed the RESUs' internal control systems began reducing power to extend the discharge period of the remaining available energy. This behavior was due to the RESUs' batteries having a lower capacity than during their initial lab tests, and the inability of the RESUs to adjust to the capacity degradation.

Out of the 22 homes included in this experiment, 12 operated their AC units during the DR event. Of these 12 homes, eight responded properly to the DR event signal and four did not. Of the eight homes that responded properly, five had AC units that shut down when the event began. These AC units then resumed operation later during the event when the room temperatures reached their DR event-adjusted set points. The other three homes that responded properly turned off when the event began, and then turned on during the event when the room temperatures reached their DR event-adjusted set points. The four homes that did not respond properly had a loss of communications between their project meter and Nucleus. The PCTs in these homes therefore did not receive the DR event signals.

Table 46: PCT Behavior (September 15, 2014)

Home	Unit	On Time	Off Time	Proper Response?	Comments
CES 1	AC2	3:00 pm	4:41 pm	No	Loss of communication with Nucleus
		4:49 pm	6:06 pm	No	Loss of communication with Nucleus
		6:22 pm	6:59 pm	No	Loss of communication with Nucleus
		7:06 pm	10:10 pm	No	Loss of communication with Nucleus
CES 7	AC2	4:51 pm	5:54 pm	Yes	Room temp reached 84° F
		6:01 pm	10:02 pm	Yes	Room temp reached 84° F
RESU 2	AC1	2:00 pm	6:01 pm	No	Loss of communication with Nucleus
		9:01 pm	10:01 pm	No	Unit turned on after event finished, but this was coincidental; there was no communication with the Nucleus
RESU 5	AC1	3:00 pm	4:01 pm	Yes	Unit turned off at event start
		6:45 pm	7:01 pm	Yes	Room temperature (82°F) likely exceeded set point
		7:30 pm	9:22 pm	Yes	Room temperature (82°F) likely exceeded set point
RESU 6	AC1	8:50 pm	9:16 pm	No	Loss of communication with Nucleus
	AC2	2:04 pm	3:58 pm		Pre-event
		4:15 pm	6:02 pm	No	Loss of communication with Nucleus
		6:44 pm	7:07 pm	No	Loss of communication with Nucleus
ZNE 1	AC1	2:05 pm	3:17 pm		Pre-event
		3:31 pm	4:01 pm	Yes	Unit turned off at event start
		5:28 pm	5:37 pm	Yes	Room temp reached 82° F
		5:42 pm	5:55 pm	Yes	Room temp reached 82° F
ZNE 2	AC2	2:58 pm	7:01 pm	No	Loss of communication with Nucleus
		8:46 pm	11:00 pm	No	Loss of communication with Nucleus
ZNE 3	AC1	2:00 pm	4:01 pm	Yes	Unit turned off at event start
		5:24 pm	5:41 pm	Yes	Room temp reached 82° F
		6:03 pm	6:20 pm	Yes	Room temp reached 82° F
		7:22 pm	7:36 pm	Yes	Room temp reached 82° F
		8:55 pm	9:44 pm	Yes	Room temp reached 82° F
ZNE 4	AC1	2:00 pm	4:01 pm	Yes	Unit turned off at event start
		5:27 pm	6:32 pm	Yes	Room temp reached 88° F
		8:17 pm	8:56 pm	Yes	Room temp reached 88° F
ZNE 5	AC1	6:56 pm	7:01 pm	Yes	Room temp reached 88° F

Home	Unit	On Time	Off Time	Proper Response?	Comments
ZNE 5	AC1	7:06 pm	10:53 pm	Yes	Room temp reached 88° F
ZNE 6	AC1	3:16 pm	3:37 pm		Pre-event
		3:51 pm	4:01 pm	Yes	Unit turned off at event start
		5:44 pm	6:02 pm	Yes	Room temp reached 86° F
		6:05 pm	6:17 pm	Yes	Room temp reached 86° F
		6:49 pm	7:10 pm	Yes	Room temp reached 86° F
ZNE 9	AC1	6:15 pm	9:20 pm	Yes	Room temp reached 83° F
	AC2	6:16 pm	7:57 pm	Yes	Room temp reached 83° F
		8:02 pm	8:16 pm	Yes	Customer overrode event

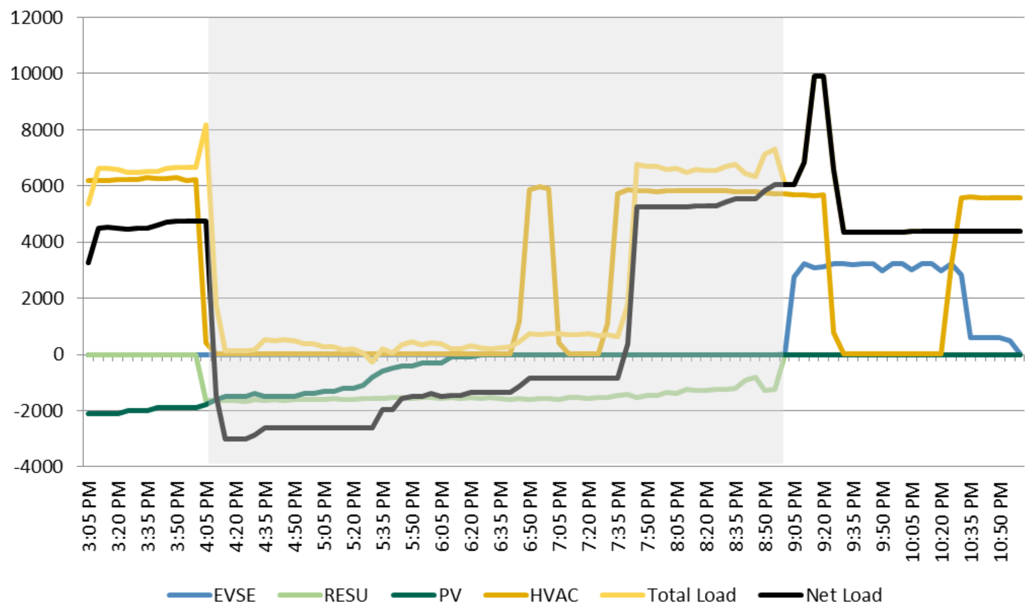
Seven of the 22 homes operated their EVSEs during this test, and each of them responded properly. Two homes, CES3 and ZNE5 were operating their EVSEs immediately prior to the event, and then curtailed their charging when the event began at 4:00 pm. The other five homes began charging immediately after the event completed at 9:00 pm. The original intent of this test event was to perform two separate DR events for the EVSEs: 0% duty cycle between 4:00 pm and 9:00 pm, and 25% duty cycle between 9:00 pm and 12:00 am. The team initiated both events using ALCS, but only the first event actually occurred. The team determined that sequential DR events require a gap of at least one minute in between. Since the second event occurred immediately after the first—with no time in between—ALCS ignored the second event. The team performed another set of sequential EVSE DR events on September 18, 2014 to verify that it could perform sequential DR events, but with a five-minute interval between the events.

Table 47: EVSE Behavior (September 15, 2014)

Home	On Time	Off Time	Power (watts)	Proper Response?	Comments
CES 3	3:00 pm	4:01 pm	730	Yes	Unit turned off at event start
	9:01 pm	9:57 pm	3,510	Yes	Unit returned to full power at event end
CES 7	9:01 pm	11:00 pm	3,386	Yes	Unit turned on at full power at event end
RESU 1	9:01 pm	11:00 pm	3,700	Yes	Unit turned on at full power at event end
RESU 5	9:00 pm	10:55 pm	3,237	Yes	Unit turned on at full power at event end
RESU 6	9:01 pm	10:57 pm	701	Yes	Unit turned on at ramp-down power at event end
ZNE 6	9:01 pm	10:11 pm	633	Yes	Unit turned on at ramp-down power at event end
ZNE 5	3:22 pm	4:01 pm	690	Yes	Unit turned off at event start

Figure 67 provides a decomposed view of RESU 5's load and generation during the DR event. At 4:00 pm the total household load dropped to and remained at nearly zero throughout the DR event. The AC was the only major source of load prior to the event. Since the RESU discharged during the event, and since the home was also generating solar PV, the net household load (indicated by the black line), was negative. The household provided approximately 3 kW of negative load (generation) back the grid when the DR event began, and maintained negative load until around 7:30 pm, when the AC turned on because the room temperature exceeded 82°F. When the DR event concluded at 9:00 pm, the RESU stopped discharging and the EVSE began operating.

Figure 67: RESU 5 Load Summary (September 15, 2014)



Although the team initiated a critical DR event for the smart appliances, only the nine homes on the ZNE Block and two homes on the RESU Block had Nucleus devices that were communicating with the project meters. The team was unable to identify any load reductions that resulted from the DR event. The team performed additional laboratory testing on the three smart appliances to assess the DR capabilities of these devices.

Test 7: Sequential EVSE Demand Response Events (September 18, 2014)

The purpose of this experiment was to verify that the team could perform sequential DR events using the ISGD EVSEs. On September 15, 2014, the team attempted to perform two sequential DR events. All the EVSEs operating during the first DR event responded properly. However, no EVSEs responded during the second event. The team determined that sequential DR events require a gap of at least one minute in between. Since the second event occurred immediately after the first—with no time in between—ALCS ignored the second event.

On September 18, 2014, the team attempted to repeat the test performed on September 15, 2014. However, rather than scheduling the second event to begin immediately after the first, the second event would now begin five minutes after the end of the first event. This test therefore consisted of a 0% duty cycle between 4:00 pm and 9:00 pm, and a 25% duty cycle between 9:05 pm and 12:05 am. This should have caused the EVSEs to stop charging at 4:00 pm, or not begin charging between 4:00 pm and 9:00 pm. It should have also caused the EVSEs to charge at a reduced rate between 9:05 pm and 12:05 am. Each of the EVSEs that attempted to operate during the test event behaved properly, with one potential exception. CES 7 stopped charging at the beginning of the second event, when it should have reduced its charging level to 25% of the EVSE capacity. The team suspects that the EVSE tripped at the beginning of the second event at 9:05 pm, and that the customer turned it back on at 10:48 pm. At 10:48 pm, the EVSE properly resumed charging at the reduced power level. The following table summarizes the EVSE activity during the test.

Table 48: EVSE Behavior (September 14, 2014)

Home	On Time	Off Time	Power (watts)	Proper Response?	Comments
CES 5	11:00 pm	0:04 am	1,730	Yes	Began charging at 25% of EVSE capacity during event 2
	0:05 am	0:32 am	3,490	Yes	Increased to full power after event #2
CES 7	3:41 pm	4:01 pm	3,310	Yes	Turned off at beginning of event #1

Home	On Time	Off Time	Power (watts)	Proper Response?	Comments
CES 7	9:01 pm	9:05 pm	3,340	Yes	Turned on at full power after event #1
	9:06 pm	10:47 pm	0	No	Turned off at beginning of event #2; should have decreased to 25% of EVSE capacity
	10:48 pm	0:05 am	1,720	Yes	Decreased to 25% of EVSE capacity during event #2
	0:06 am	1:16 am	3,434	Yes	Increased to full power after event #2
RESU 1	3:47 pm	4:00 pm	3,660	Yes	Turned off at beginning of event #1
	9:00 pm	9:04 pm	3,670	Yes	Turned on at full power after event #1
	9:05 pm	0:04 am	1,670	Yes	Decreased to 25% of EVSE capacity at beginning of event #2
	0:05 am	0:42 am	3,660	Yes	Increased to full power after event #2
RESU 3	9:01 pm	9:04 pm	3,420	Yes	Turned on at full power after event #1
	9:05 pm	10:37 pm	1,680	Yes	Decreased to 25% of EVSE capacity at beginning of event #2
	10:38 pm	10:53 pm	650	Yes	Normal step down charge rate, below 25% of EVSE capacity
RESU 5	9:00 pm	9:02 pm	3,040	Yes	Turned on at full power after event #1
	9:03 pm	9:19 pm	548	Yes	Normal step down charge rate, below 25% of EVSE capacity
	10:19 pm	0:04 am	1,506	Yes	Turned on at 25% of EVSE capacity during event #2
	0:05 am	1:12 am	3,040	Yes	Increased to full power after event #2
RESU 6	9:00 pm	9:04 pm	3,500	Yes	Turned on at full power after event #1
	9:05 pm	0:03 am	1,740	Yes	Decreased to 25% of EVSE capacity at beginning of event #2
	0:04 am	0:15 am	670		Post-event; normal ramp down rate
ZNE 6	3:27 pm	3:42 am	3,440		Pre-event
	3:43 pm	4:00 pm	650	Yes	Turned off at beginning of event #1
ZNE 8	10:40 pm	0:04 am	1,680	Yes	Turned on at 25% of EVSE capacity during event #2
	0:05 am	0:17 am	3,400	Yes	Increased to full power after event #2

Test 8: Pre-Cool Homes Using PCT Demand Response (October 3, 2014)

The purpose of this experiment was to evaluate the viability of using the project PCTs as a load source. If the team could use DR event signals to turn on AC units to pre-cool a group of homes in the morning and midday periods, then it could potentially reduce the AC energy use in the afternoon peak-period. This capability could potentially be useful for load shifting and other applications such as absorbing surplus solar generation, which could help avoid curtailing renewable generation.

The team's approach was to pre-cool the homes between 9:00 am and 2:00 pm by gradually reducing the temperature set points by one degree each hour between 9:00 am and 12:00 pm. The team would then increase the set points by performing a four-degree temperature offset DR event between 2:00 pm and 6:00 pm. The test included the following sequence of distinct DR events:

(1) 9:00 am to 10:00 am – temperature set point at 79°F
(2) 10:00 am to 11:00 am – temperature set point at 78°F
(3) 11:00 am to 12:00 pm – temperature set point at 77°F

(4) 12:00 pm to 2:00 pm – temperature set point at 76°F
(5) 2:00 pm to 6:00 pm – four-degree temperature offset

As the team executed the first DR event, they learned that the project PCTs do not allow pre-cooling. These PCTs ignore commands to reduce their temperature set point below their current temperature set point. The PCTs treat all DR events as “load shedding” events and, therefore, do not respond to DR signals that increases their energy use.

The failure of the PCTs to allow pre-cooling demonstrated the need for vendors to allow flexibility when designing DR capable devices. With changing loads in California resulting from the proliferation of renewable energy resources like rooftop solar, there may be times when the electrical grid can benefit from surplus renewable energy. Designing DR-capable equipment with the flexibility to either increase or reduce electricity use depending on the needs of the grid will best serve the future needs of the electric grid.

While the team could not execute the pre-cool part of this test, the load shedding by the AC units behaved as expected.

Test 9a: Simple EVSE Curtailment (March 16, 2015)

In December 2014, the team removed the originally installed EVSEs from each customer home and replaced them with new EVSEs from a different vendor. The purpose of the test on March 16, 2015 was to verify that the new EVSEs were capable of curtailing charging through demand response. To perform this test the team scheduled a 0% duty cycle event between 6:00 pm and 9:00 pm for the 22 EVSEs on all three ISGD experiment blocks. At 6:00 pm, any PEVs that were in the process of charging should have reduced their charge levels to 0 kW. When the event ended at 9:00 pm, any vehicles that were still plugged in should have resumed charging at full power. In addition, any additional vehicles that were plugged in between 6:00 pm and 9:00 pm should have also begun charging at full power at 9:00 pm.

The following table summarizes the behavior of the vehicles that were charging immediately before the event began, and the vehicles that began charging when the event finished.

Table 49: EVSE Behavior (March 16, 2015)

Home	On prior to 6 pm?	Off from 6 to 9 pm?	On after 9 pm?	Behave as expected?
CES 5	Yes	Yes	Yes	Yes
RESU 3	No	Yes	Yes	Yes
RESU 5	No	Yes	Yes	Yes
ZNE 6	No	Yes	Yes	Yes
ZNE 7	No	Yes	Yes	Yes

Only one home, CES 5, had a vehicle charging when the event began. This home’s EVSE behaved as expected by curtailing charging at 6:00 pm and resuming charging at 9:00 pm. There were four additional homes with EVSEs that began charging when the event concluded at 9:00 pm. This was also consistent with the teams expectations.

Test 9b: EVSE Throttling (March 17, 2015)

The purpose of this test was to verify that the EVSEs are capable of curtailing charging, resuming charging at a reduced charge rate, and then returning to the maximum charge rate after the test. To perform this test the team scheduled two discrete DR events for the 22 EVSEs on all three ISGD experiment blocks. The first DR event was a 0% duty cycle between 6:00 pm and 9:00 pm. At 6:00 pm, any PEVs that were in the process of charging should have reduced their charge levels to 0 kW. The second DR event consisted of a 20% duty cycle event between 9:00 pm and 10:00 pm. At 9:00 pm, this should have caused any vehicles that were still plugged-in (in addition to any vehicles that were plugged-in during the first event, between 6:00 pm and 9:00 pm) to begin charging at 20% of their maximum charge rate[34]. At 10:00 pm, vehicles that were still charging should have increased their charging rate to full power.

The following table summarizes the behavior of the vehicles that were charging immediately before the event began, and the vehicles that began charging after the first DR event completed at 9:00 pm.

Table 50: EVSE Behavior (March 17, 2015)

Home	On prior to 6 pm?	Off from 6 to 9 pm?	20% of max between 9 and 10 pm?	Full charge at 10 pm?	Behave as expected?
CES 7	Yes	Yes	Yes	Yes	Yes
RESU 5	Yes	Yes	Yes	Yes	Yes
RESU 4	No	Yes	Yes	No	Yes
ZNE 1	No	Yes	Yes	Yes	Yes
ZNE 7	No	Yes	Yes	Yes	Yes
ZNE 6	No	No	Yes	No	No

Two homes, CES 7 and RESU 5, were charging electric vehicles when the event began at 6:00 pm. Both homes' EVSEs behaved as expected—they curtailed charging at 6:00 pm, charged at a reduced rate between 9:00 pm and 10:00 pm, and then resumed charging at the maximum charge rate at 10:00 pm.

Three homes began charging electric vehicles when the first DR event concluded at 9:00 pm. These vehicles all charged at the reduced rate during the second DR event, between 9:00 pm and 10:00 pm. One of the vehicles (RESU 4) finished charging the second DR event, while two vehicles (ZNE 1 and ZNE 7) increased to the maximum charge rate when the event concluded at 10:00 pm.

The team observed one vehicle that did not behave as expected. ZNE 6 began charging at the maximum charge rate at 6:20 pm, continued charging at this rate until 6:40 pm, and then stopped charging. This vehicle began charging again at 9:00 pm, at the 20% of the maximum charge rate. It continued charging at this rate until it finished charging at 9:55 pm.

Test 9c: EVSE Staggered Throttling (March 18, 2015)

This test was similar to the EVSE throttling test performed on March 17, 2015 in that it involved curtailing the EVSE charging on all three project blocks and then resuming charging at a reduced rate. However, it differed in that the blocks were staggered such that they would resume charging at the reduced rate at different times. To perform this test the team scheduled three discrete DR events. The first DR event was a 0% duty cycle between 6:00 pm and 11:00 pm. The event was sent to all 22 homes on the three project blocks. At 6:00 pm, any PEVs that were in the process of charging should have reduced their charge levels to 0 kW.

The second DR event consisted of a 20% duty cycle event between 9:00 pm and 10:00 pm for the nine homes on the ZNE block. This DR event signal would supersede the first DR event signal for the ZNE block homes—although it would not impact the first DR event signal for the RESU and CES blocks (which would continue to operate at a 0% duty cycle). At 9:00 pm, this should have caused any vehicles that were still plugged-in (in addition to any vehicles that were plugged-in during the first event, between 6:00 pm and 9:00 pm) to begin charging at 20% of their maximum charge rate. At 10:00 pm, vehicles that were still charging should have increased their charging rate to full power.

The third DR event consisted of a 20% duty cycle event between 10:00 pm and 11:00 pm for the 13 homes on the RESU and CES blocks. This DR event signal would supersede the first DR event signal for the RESU and CES block homes. At

[34] The ISGD project home EVSEs have a maximum charge rate of 7.2 kW. A 20% duty cycle would cause the EVSEs to reduce their charge levels to about 1.4 kW.

10:00 pm, this should have caused any vehicles that were still plugged-in (in addition to any vehicles that were plugged-in during the first event, between 6:00 pm and 10:00 pm) to begin charging at 20% of their maximum charge rate. At 11:00 pm, vehicles that were still charging should have increased their charging rate to full power.

Table 51 summarizes the behavior of the vehicles that were charging immediately before the event began, and the vehicles that began charging after the first DR event completed at 9:00 pm.

Table 51: EVSE Behavior (March 18, 2015)

Home	Pre event	Event #1 (All blocks)	Event #2 (ZNE block)		Event #3 (RESU & CES blocks)		Behave as expected?
	Vehicle charging?	Charging curtailed?	20% of max power?	Full charge rate?	20% of max power?	Full charge rate?	
	Before 6 pm	*6 to 10 pm*	*9 to 10 pm*	*10 pm*	*10 to 11 pm*	*11 pm*	
ZNE 4	No	Yes	Yes	Yes	N/A	N/A	Yes
ZNE 6	No	Yes	Yes	Yes	N/A	N/A	Yes
ZNE 8	No	Yes	Yes	Yes	N/A	N/A	Yes
CES 2	Yes	No	N/A	N/A	No	No	No
CES 7	No	No	N/A	N/A	No	No	No
RESU 2	No	No	N/A	N/A	No	Yes	No
RESU 3	No	No	N/A	N/A	Yes	No	No
RESU 5	No	No	N/A	N/A	Yes	Yes	No

CES 2 – Vehicle began charging at 5:27 at the maximum rate (3.3 kW), and continued charging at this rate until 7:02, when it reduced the charge rate to about 600 watts. It continued charging at this rate for 30 minutes (until 7:32), and then stopped charging. It appears that this EVSE did not receive the DR event signal.

CES 7 – Vehicle was off from 5:00 pm until 9:01 pm, when it began charging at 100% (3.3 kW). It continued charging at this rate until 9:45 pm, when it reduced its charge level to about 600 watts. It then charged at this rate until 10:12, when it stopped charging. It appears that that this EVSE also did not receive the DR event signals.

RESU 2 – Vehicle was off from 5:00 pm until 9:25, when it began charging at 3.4 kW. It charged at this rate until 10:27 pm, when it reduced its charge level to 600 watts. It charged at this rate until 10:50 pm. At 10:51 pm the EVSE began charging at 2.3 kW and continued charging at this rate until past midnight. It appears that the home did not receive either of the DR signals (and that the homeowner switched vehicles at 10:51 pm – from the Scion IQ to the Prius).

RESU 3 – Vehicle was off until 9:01, when it began charging at 3.4 kW. It charged at this rate until 10:00, when it reduced its charge rate to 600 watts. It then charged at this rate until 10:29 pm, when it stopped charging. It appears that the vehicle did not receive the first DR event signal. Since the vehicle was charging at a reduced rate at 10:00 since it was completing its charging cycle, it is unclear whether the EVSE received the third DR event signal.

RESU 5 – Vehicle was off until 9:25 pm, when it began charging at 100% (3.4 kW). It continued charging at this rate until 10:00 pm, when it began charging at 20% (1.3 kW). It continued charging at this rate until the third DR event ended at 11:00 pm, when it resumed charging at maximum power. This EVSE did not respond properly to the first DR event, but it did respond properly to the third DR event.

The team verified that in each of the above cases, the meters received the DR event signals. However, the team could not verify that the EVSEs received these event signals. It is possible that due to the event involving three DR event signals, the EVSEs did not process the events properly.

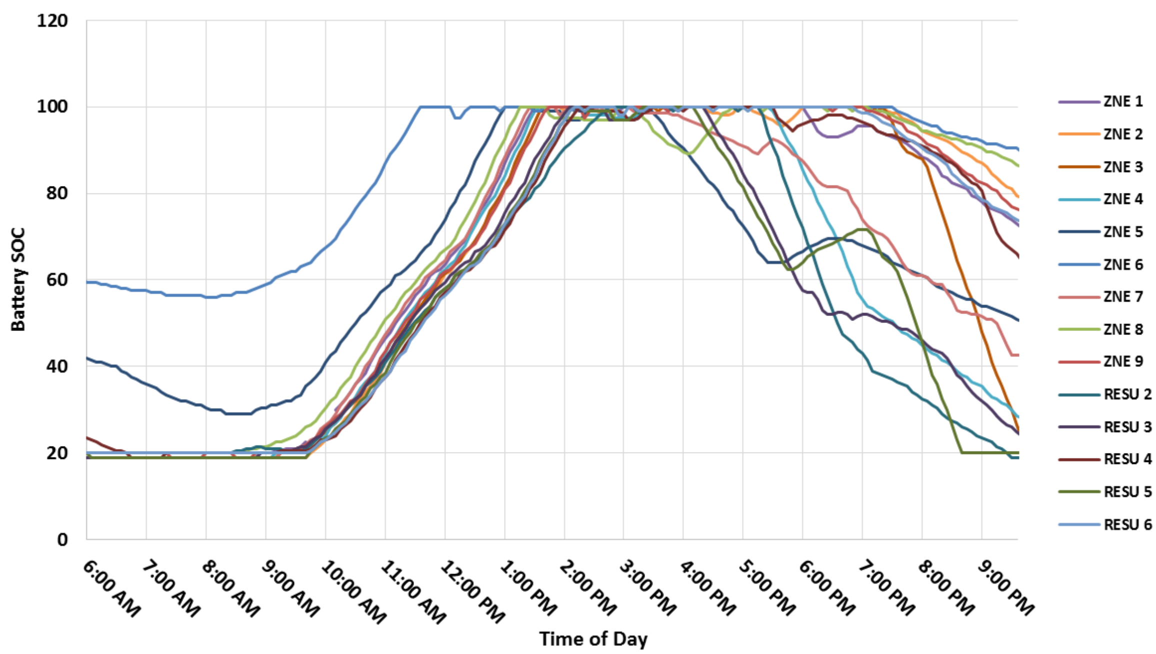
Field Experiment 1C: RESU Peak Load Shaving

Test 1: Secure Load Backup (July 8, 2014)

On July 8, 2014, a scheduled power outage occurred within the residential community where the ISGD project homes are located. This interrupted electric service between 9:40 am and 3:05 pm. Fourteen homes on the RESU and ZNE blocks are equipped with RESUs, which provided electricity to “secure loads” during the outage. The secure loads in these homes consist mainly of kitchen refrigerators and garage door openers. At least one home also has a garage refrigerator and a forced air unit on the secure load circuit. The RESUs also allowed the homes’ solar PV arrays to remain operational over much of the period. The RESUs would capture the PV energy generated over much of the period.

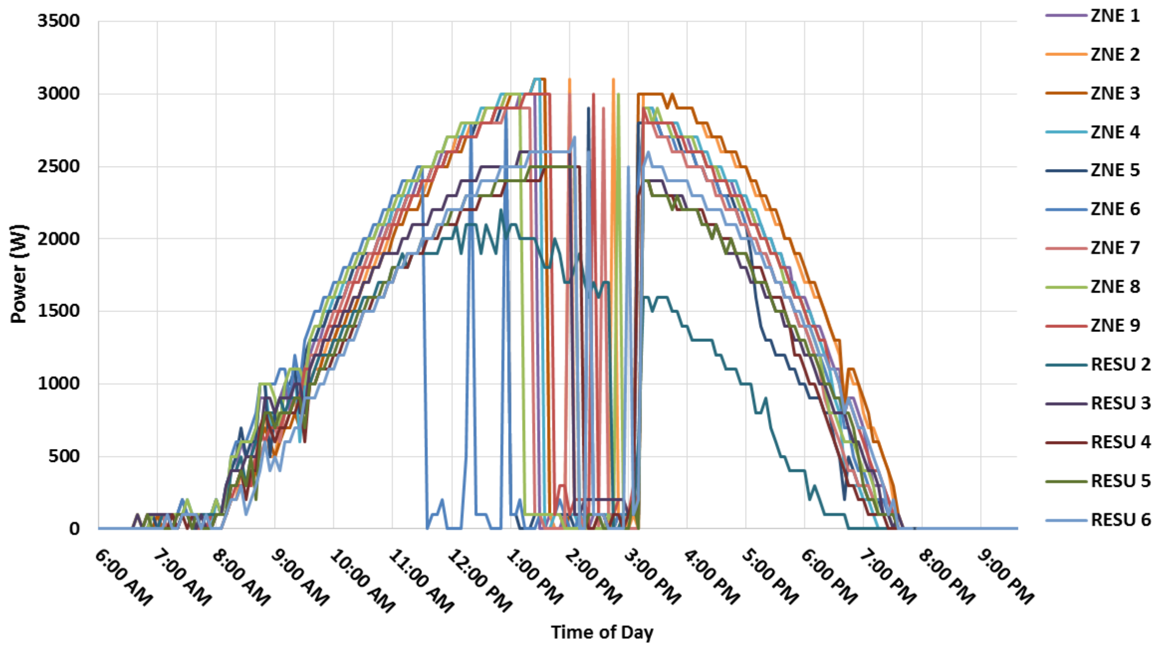
At the time of this outage, the RESUs were operating in “PV capture” mode. This mode causes the RESUs to capture the excess solar PV energy not consumed within the home and to discharge it to support the house load at night. This helps to minimize a home’s need to draw power from the electric grid. When the power outage began at 9:40 am, service was interrupted to all homes in the neighborhood. However, all 14 RESUs successfully detected this grid outage and immediately began providing backup power to the secure loads—for each respective home with a RESU. Most of the RESUs were at a 20% state of charge, the reserved capacity, since the PV Capture mode caused the RESUs to discharge to this level the prior evening. Two exceptions were ZNE 5 and ZNE 6, which were at 34% and 63%, respectively, due the homeowners’ low consumption the prior evening. Because these homes’ SOCs were higher when the outage occurred, they reached the max SOC at 1:00 pm and 11:35 am, respectively. The remaining RESUs reached a full charge between 1:20 pm and 2:45 pm. **Figure 68** summarizes the RESU SOCs throughout the day of the outage event.

Figure 68: RESU States of Charge (July 8, 2014)



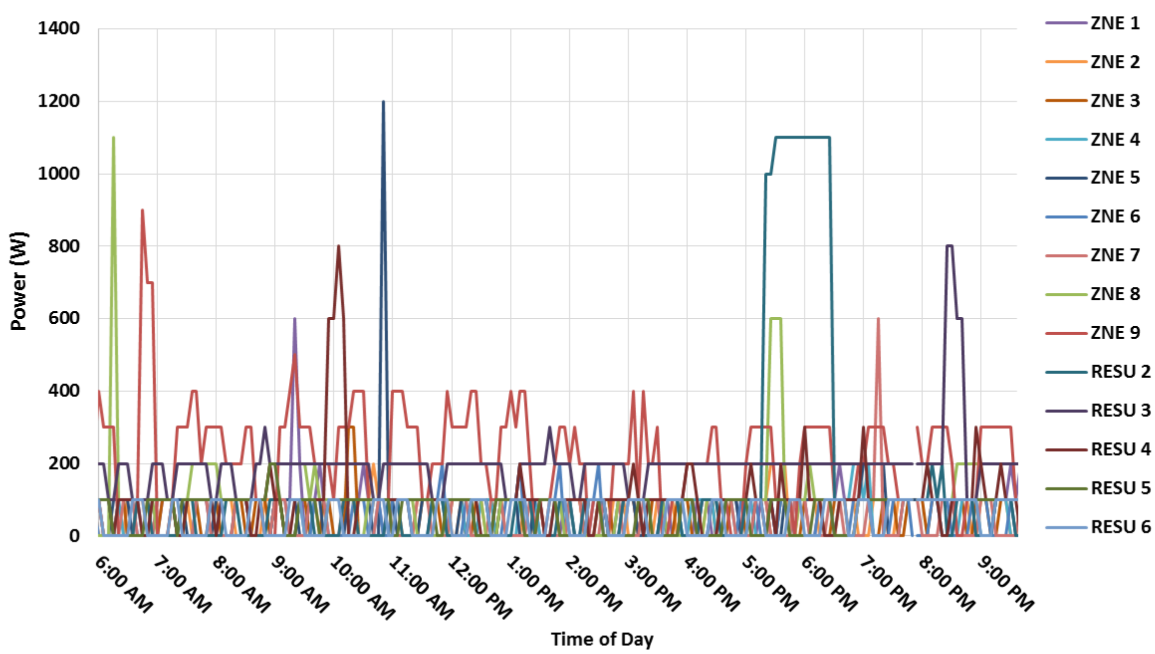
The solar PV output stopped briefly when the outage began, and then resumed operation in “backup” mode. The RESUs began charging their internal batteries with the excess solar PV generation. This excess energy equals the solar PV output less the energy required to operate the RESUs and to power the secure loads. During the outage, the 14 RESUs each stored substantial amounts of energy while also continuously powering the secure loads. As the RESUs approached their maximum SOCs, the RESU inverters reduced the solar PV generation to provide only for the RESU system and secure loads. This internal RESU control prevents battery overcharging and system trips. When a RESU reached its maximum state of charge, the charge rate would drop to zero, and then periodically increase in order to “top off” the battery. Once the outage event completed at 3:10 pm, all solar PV generation resumed within five minutes. Figure 50 summarizes the solar PV output for each RESU home on the day of the outage event.

Figure 69: Solar PV Generation Output (July 8, 2014)



The secure loads within each of the 14 RESU homes received sufficient power to operate throughout the event. Since most loads consist of an ENERGY STAR refrigerator and a garage door opener, power levels and overall energy consumption remained low throughout the event. **Figure 70** summarizes the secure load power demands for each RESU home during the power outage.

Figure 70: RESU Secure Load Power Levels During Outage (July 8, 2014)



During the outage event, the ISGD project's data acquisition system components and 4G radios turned off since they were not connected to the RESU secure load circuits. As a result, the team's only data source during the event was the

RESU internal data logs. The ISGD team recommends that data acquisition systems used for future projects should connect to a backup power source, where possible.

All 14 RESUs reached their maximum SOC during the outage due to a combination of low loading on the secure load circuits and high solar PV generation. Connecting additional loads to the secure load circuit could make additional use of solar PV generation during long-duration grid outages. However, during nighttime outages, a RESU would not receive any PV generation. The secure loads could therefore potentially consume all the RESU's stored energy.

Test 2: Time-Based Permanent Load Shifting (October 10, 2014 to June 3, 2015)

Approach

This experiment was conducted with all 14 deployed RESUs on the ZNE and RESU blocks. The purpose of this experiment was to demonstrate the RESU's ability to shift load from on-peak periods to off peak periods and to determine if there were any unexpected effects. The experiment lasted for 236 days and included both the summer and winter seasons. All RESUs were scheduled to charge at night and discharge in the afternoon to take advantage of the on-peak/off-peak TOU-price differential. This experiment was performed two times to demonstrate two different modes of PLS operation.

The first experiment consisted of operating the RESUs' discharge cycles with the "automatic power" power calculation that limits the RESU power output based on the scheduled discharge duration and available energy. This mode is used to optimize output due to the inverter being restricted to 4 kW_{AC} and having to be shared between the PV and battery. The limit on the first experiment was necessary to check if the influx of battery power in addition to existing solar PV generation would cause distribution issues. The minimum SOC of each RESU was set to 20% throughout the test period. The RESUs were scheduled to charge from 1:00 to 5:00 am, and to discharge from 12:00 to 6:00 pm.

The second experiment was performed between 11/11/14 and 6/3/15. In the second experiment, the discharge cycle was changed to a "max power" power calculation that attempts to maximize battery power output up to the 4 kW_{AC} inverter limit regardless of the duration of the scheduled discharge. The minimum SOC of each RESU was set to 20% throughout the test period. The RESUs were scheduled to charge from 1:00 to 5:00 am, and to discharge from 2:00 to 6:00 pm.

During the 236-day experiment, the 14 RESUs provided approximately 13.4 MWh of load shifting. From October to January, there were eight RESU failures but only four required direct intervention to clear while the other four resolved themselves without intervention. From January until the end of the experiment, there were no additional errors, indicating that all 14 RESUs experienced 100% uptime during that period. The experiment highlighted the RESUs' improved reliability when operated in a simple PLS mode of operation.

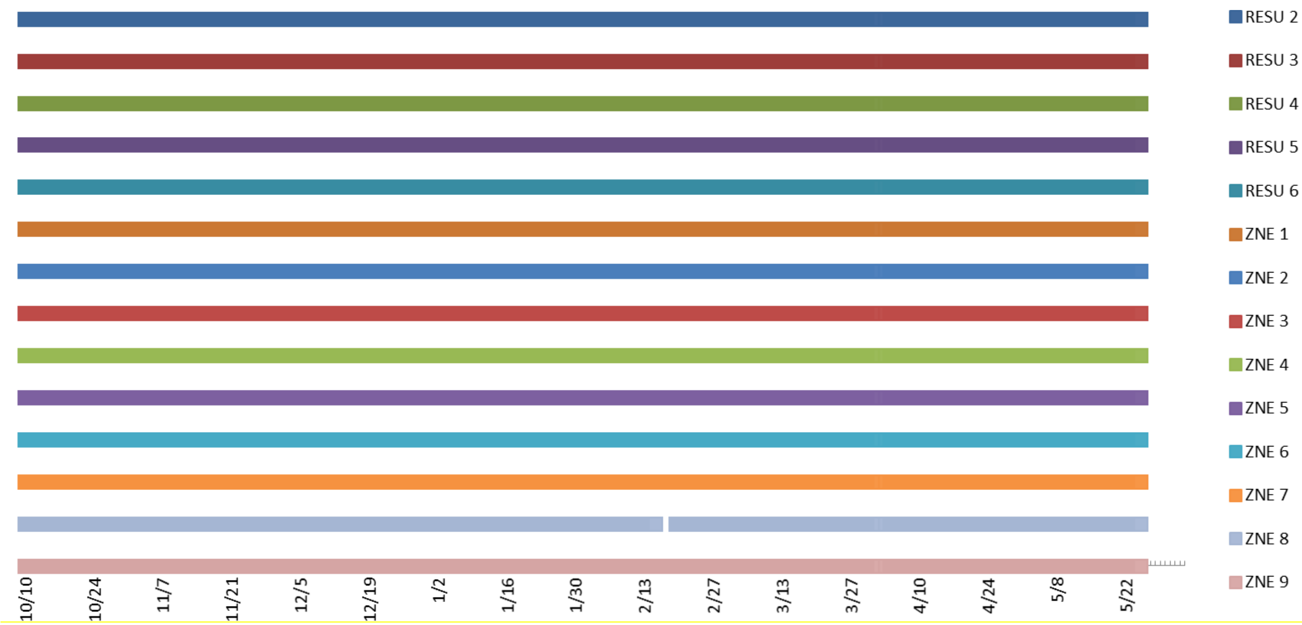
Results

The long duration of the PLS experiment provides many analysis points for learning. In particular, the team assessed RESU uptime, PV generation, energy arbitrage economics, transformer impacts, and battery usage.

RESU Uptime

During the test period, several RESUs lost functionality for various durations although overall reliability was high. Over the 236-day test period (5,650 hours), eight RESU failures resulted in 951 hours of unscheduled downtime across the 14 RESUs. Total system uptime improved to 98.8% (951 hours / 79,098 hours), which is half the amount of downtime compared to previous experiments within the ISGD project. While this is a large improvement over previous long-term experiments, it is important to note was that there was a six-month period where no RESUs required an on-site reset and a four-month period where no RESUs experienced an error. Most failures such as boot loops, freezes, and communication errors were easily resolved with a system power cycle. Only one RESU experienced a hardware failure that was resolved by replacing the RESU Control Hub (RCH) display. **Figure 71** shows an operational timeline for each RESU. Periods of normal operation are plotted in color, with the white spaces indicating data not recorded by the RESU during a failure or communications loss. Due to the duration of the experiment, only extended downtimes that lasted more than a week are visible.

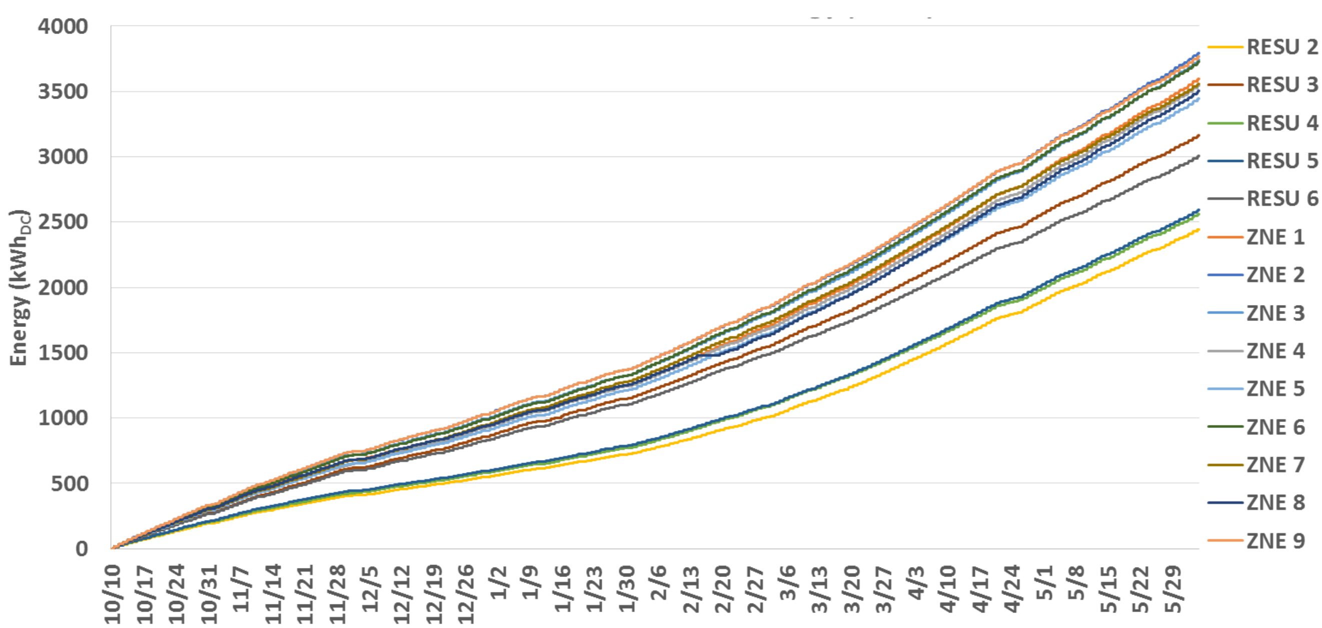
Figure 71: RESU Operational Timeline



RESU PV Generation

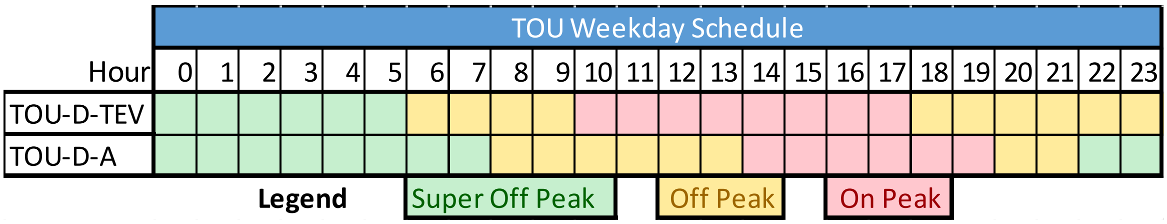
Over the test period, between 2,400 and 3,800 kWh DC were received by each RESU-equipped ISGD home, resulting in a total of 46.4 MWh of solar PV generation. The ZNE Block has nine homes with 3.9 kW PV arrays while the RESU block has five homes with 3 kW PV arrays and one additional unmonitored home with a 4 kW array. Despite each RESU Block home being configured the same way, RESU 3 and RESU 6 produced significantly more energy than their peers produced. The team suspects this is the result of tree shading. **Figure 72** plots the solar PV generated for each home over the period of this experiment.

Figure 72: Cumulative Solar PV Generation



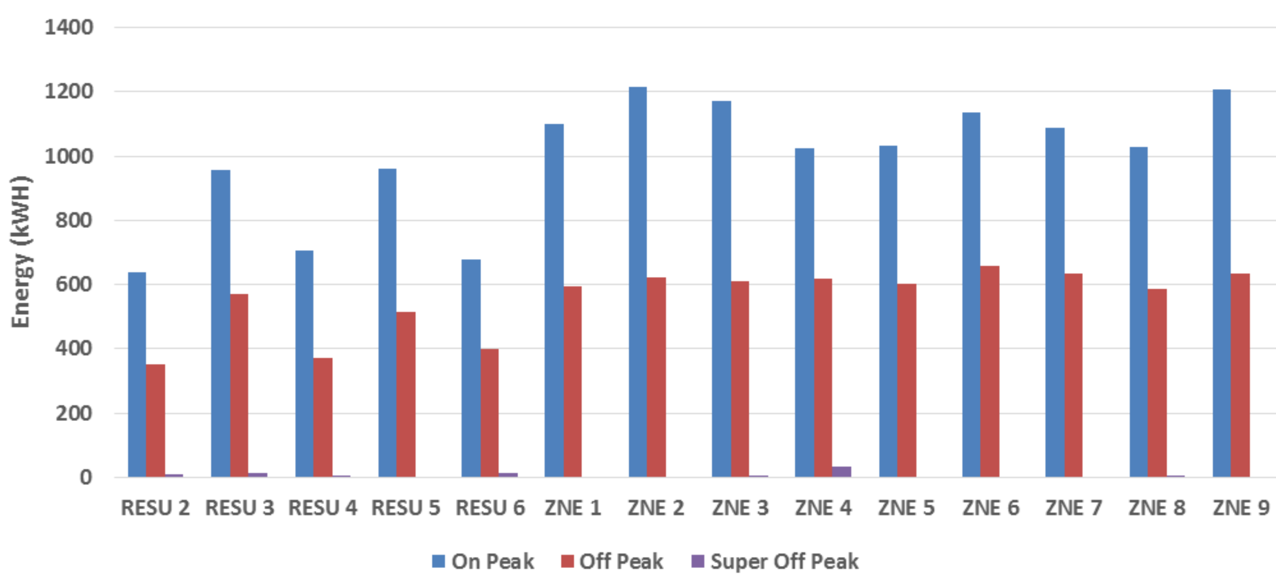
On 3/1/15, SCE's TOU-D-TEV rate was retired and replaced with the TOU-D-A rate for all the ISGD homes. The primary difference between the rates is a significantly altered time schedule for the on-peak, off-peak, and super off-peak times and some slight adjustments to pricing. **Figure 73** summarizes the time schedule of the two rates.

Figure 73: TOU Weekday Schedule



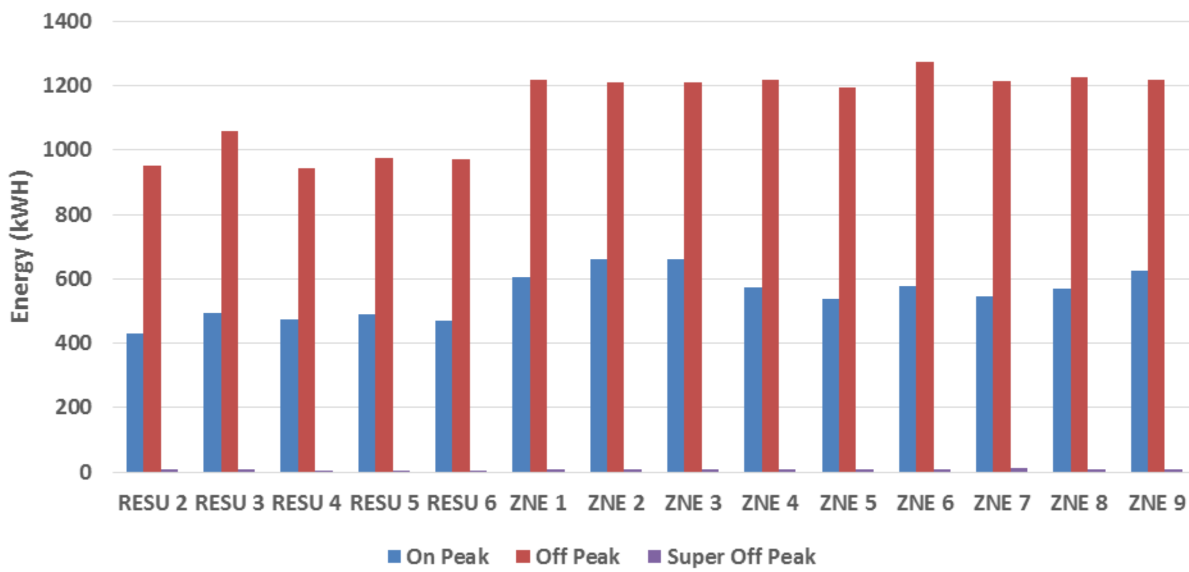
This change in time schedule resulted in a larger share of the solar PV generation falling into the off-peak period. The former TOU-D-TEV schedule had greater benefits for PV owners as the PV generation occurs primarily during the on-peak period. The new TOU-D-A time schedule shifts the off-peak time so that it now receives the majority portion of the solar PV generation. The energy analysis of the PLS operation will focus on SCE's winter schedule period from 10/10/2014 to 5/31/2015. Summer data from 6/1/2015 to 6/3/2015 is omitted since it only covers two days. **Figure 74** through **Figure 76** summarize the breakdown of solar PV generation during the winter period.

Figure 74: Solar PV Output for TOU-D-TEV



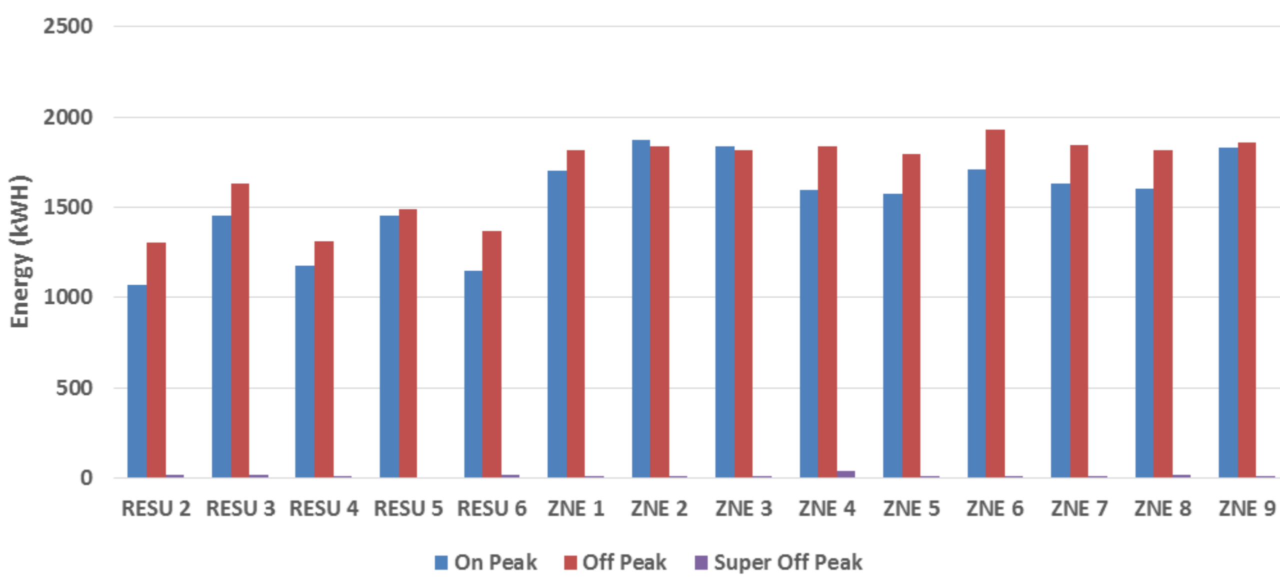
Approximately two-thirds of the PV generation occurred during on-peak periods under the TOU-D-TEV rate.

Figure 75: Solar PV Output (TOU-D-A)



When the rate schedule shifted to TOU-D-A, the share of solar PV generated on-peak dropped to approximately one-third. PV generation during super off-peak nearly doubled, but was still negligible at less than 0.2% of total generation.

Figure 76: Solar PV Generation (Entire Test Period)

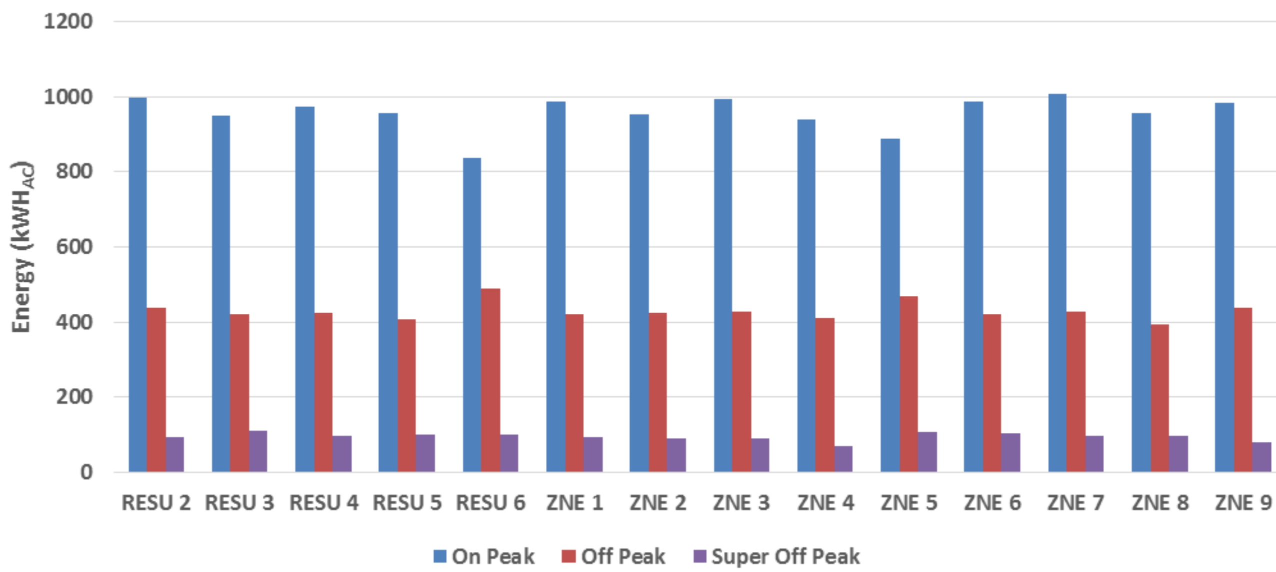


Over the entire PLS experiment period, solar PV generation was almost evenly split between the on-peak and off-peak periods, at 48% and 52%, respectively. These percentages have a significant effect on the effective arbitrage value for residential energy storage systems. Large differences in total PV generation between the ZNE and RESU homes were due to the difference in PV array sizing (3 kW vs. 3.9 kW). Variations in solar PV generation between the RESU Block homes were due to various levels of shading on individual home rooftops.

Permanent Load Shifting – Energy Arbitrage

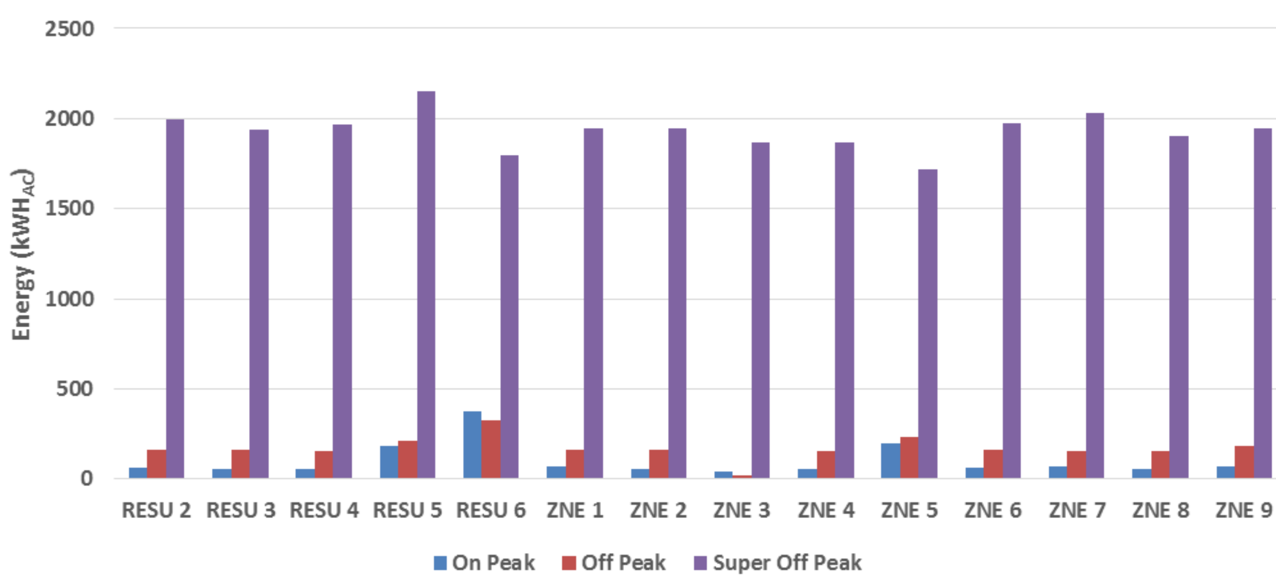
One unique aspect of this PLS experiment is its ability to conduct residential energy arbitrage by charging at super-off-peak times when prices are low and then discharging during on-peak periods when prices are significantly higher. This ability was made possible from the May 15th, 2014 CPUC ruling stipulating that grid-connected storage paired with PV systems can operate under the existing NEM tariffs. This allows for energy from fossil-fueled sources at night to be stored and exported during the day at higher rates.

Figure 77: RESU Discharge Periods



RESU discharge total among the 14 ISGD homes was generally consistent except for RESU 6 and ZNE 5, which had slightly lower on-peak to off-peak ratios due to a delay in moving them into PLS mode.

Figure 78: RESU Charge Periods



As indicated by **Figure 78**, nearly all charging occurred during the most price advantageous super-off-peak period. Measurement error was the likely cause in the on-peak and off-peak period charging. A possible but unconfirmed cause of the higher discharging error for RESU5, RESU6 and ZNE5 is greater than expected capacity degradation.

Permanent Load Shifting – Distribution Impact

Understanding the impacts of RESU behavior on the distribution system is essential for utility planning activities and for informing ratemaking activities. The ZNE and RESU blocks of homes are each connected a separate 120/240V, 50 kVA distribution transformer. The eight homes are connected to the RESU Block transformer, which serves one home with solar PV, five homes with RESUs and solar PV, and two homes with neither. The ZNE Block transformer serves nine homes all of which have RESUs and solar PV. The team measured and examined voltage, current, temperature, and relative loading impacts for both transformers over the nine-month experiment.

Figure 79 and **Figure 80** present the effects of the RESUs on the RESU and ZNE block transformers when they experienced the peak current during the Automatic Power mode experiment. The RESU operation provided the largest impacts to the transformer in both blocks. In the early morning a large and fast ramp up in current is caused by simultaneous charging of the all the RESUs. This is followed by a sharp drop once charging completes. The larger concentration of RESUs on the ZNE block resulted in a higher peak current and relative load that peaked at nearly 92% of the transformer rating during the super-off-peak period. On the RESU Block the max loading was only 69%, which occurred only once during the evening off-peak period when customers typically come home. On most other days, the RESU block homes stayed under 50% loading and the ZNE block homes stayed under 80% during the Automatic Power experiment. The relative load increase beginning at 12:00 pm indicates that the RESU discharging also adds to the transformer loading (rather than reduce it) due to simultaneous peak solar PV and battery generation.

Figure 79: ZNE Block Loading in Automatic Power PLS Mode

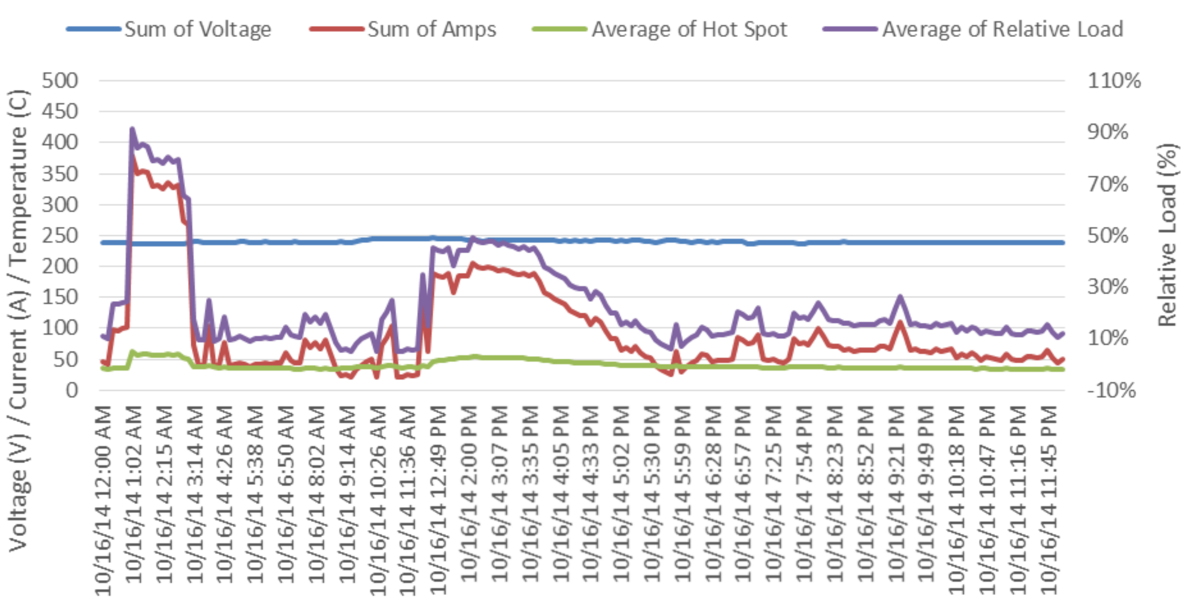
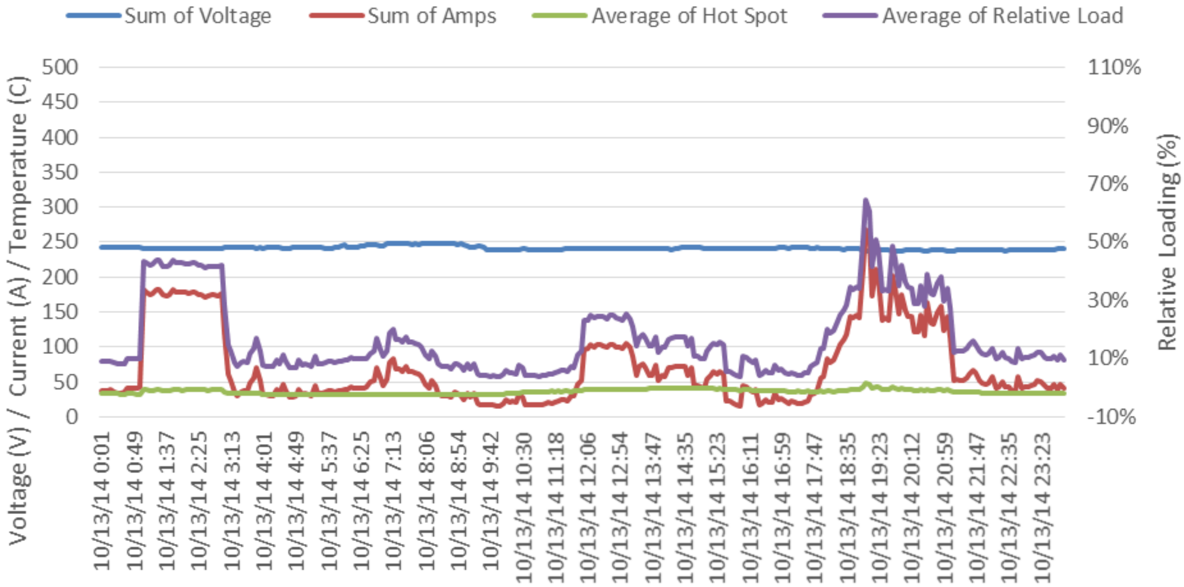


Figure 80: RESU Block Loading in Automatic Power PLS Mode



Operation of the both blocks in the Max Power mode exacerbates the issues seen in the Automatic Power mode. In this operational mode, the removal a power control increases the peak load seen during the on-peak discharge. The addition of battery power on the distribution transformer is clearly defined in the relative load increase from 2:00 pm to 5:00 pm daily. Max load still occurs during the super-off-peak period when all RESUs begin simultaneous charging. The ZNE block experienced the peak loading for the entire PLS experiment during the super-off-peak, as shown in **Figure 82**. Transformer loading reached as high as 107.5% on the ZNE block. Cause for this increased loading is attributed to customers beginning to shift their loads during the super-off-peak period, thereby increasing the super-off-peak load further. Particularly concerning was the simultaneous impact of RESU charging and EV charging which was the likely cause of the overloading on this transformer.

Figure 81: RESU Block Loading in Max Power PLS Mode

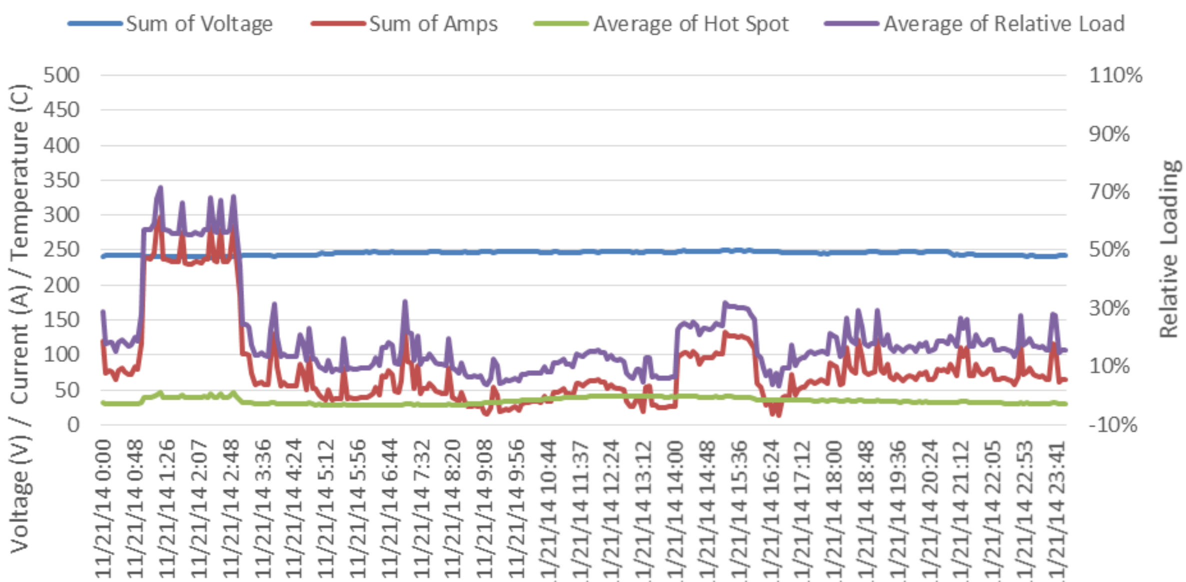


Figure 82: ZNE Block Loading in Max Power PLS Mode

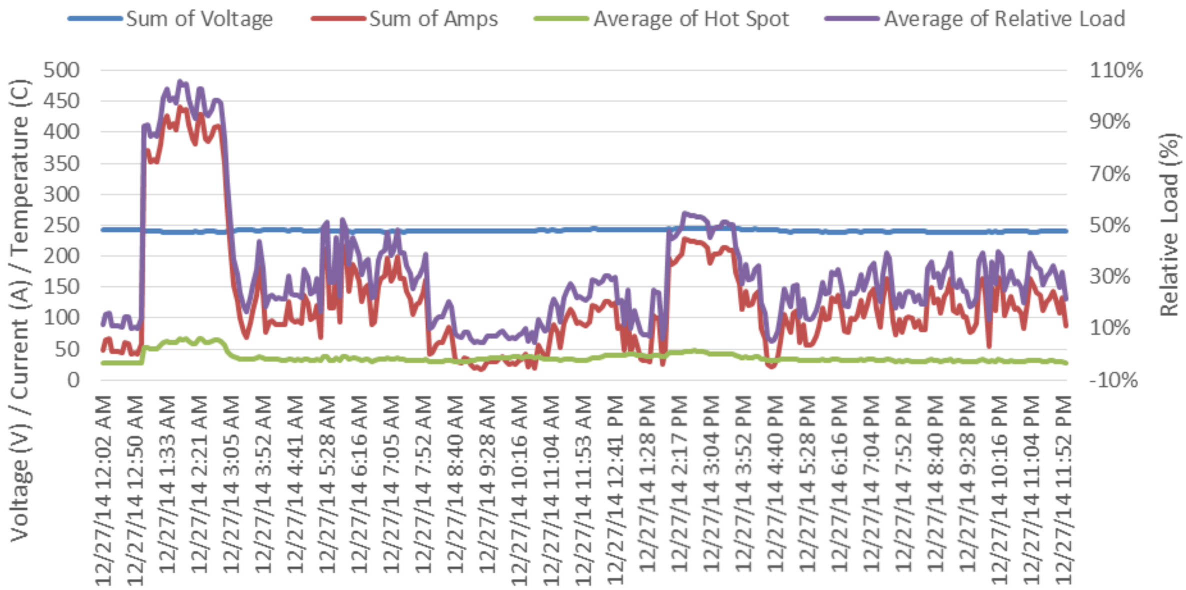
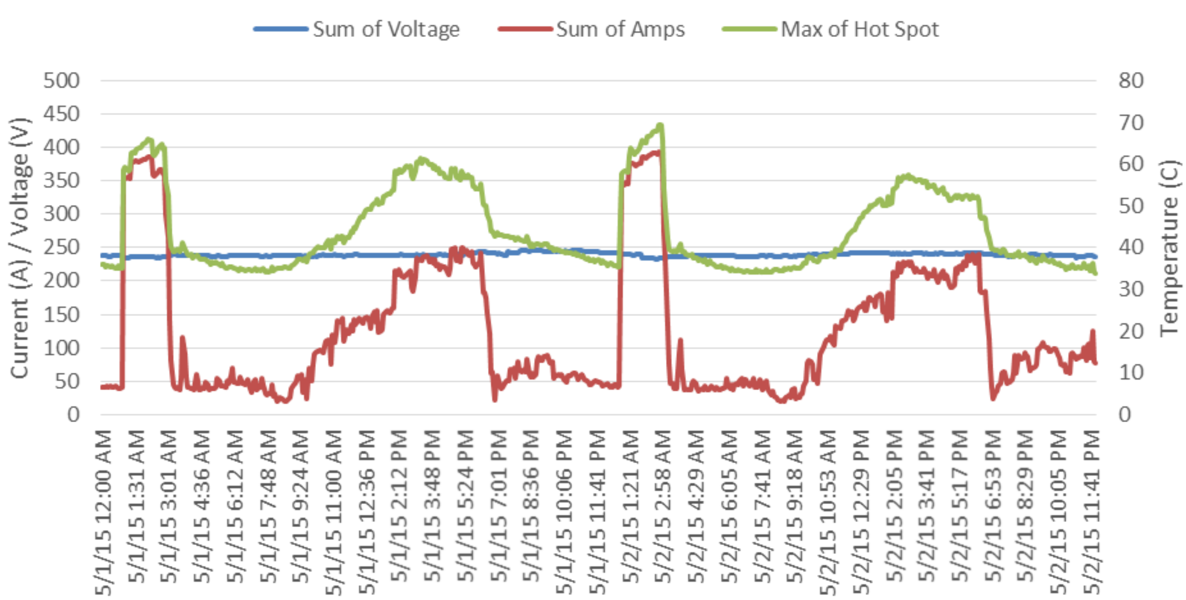


Figure 83 presents the 2-day plot of transformer load versus temperature, indicating how transformer temperatures rise and cool based on load. The spring months resulted in a more gradual warm up of the transformer temperature due to the increased PV generation and higher associated current. Transformer temperatures drop to 30 degrees Celsius around 7:00 am daily. The temperature then begins a slow rise as PV generation increases, spiking suddenly when RESU operation begins at 2:00 pm.

The biggest contributor to transformer temperatures is transformer loading/current rather than ambient temperature. This is especially true during the super-off-peak period when all RESUs begin charging simultaneously, causing an rapid increase in hotspot temperature within 5 minutes and a cool down of the hotspot to near steady state temperatures within 5 minutes of the RESUs ending their charging.

Figure 83: ZNE Block Transformer Temperature and Loading



Test 3: RESU Peak Load Shaving (Price-based Mode)

RESU peak load shaving involves using the RESU to shift on-peak loads by discharging during peak periods and recharging during off-peak times. The intent of the price-based mode is to use time-of-use (TOU) pricing obtained through the ZigBee Smart Energy Profile 1.0 available on SCE smart meters to make these charge and discharge decisions. The RESU will only construct a schedule based on available pricing from the smart meter. The price-based mode allows the RESU to construct a schedule to charge at the lowest price during the day and discharge during the highest price periods in the day. This mode was designed to operate when there are two or more prices with at least 25% difference (i.e., between the on-peak and off-peak pricing). The RESU vendor designed the control logic and graphical user interface (GUI) to receive TOU prices for a single calendar day. The RESU would then obtain updated pricing from the smart meter on each successive day for the respective day.

The ISGD team performed extensive RESU lab testing between 2011 and 2012 using the vendor's smart meter development kit (DevKit). This testing demonstrated that the RESUs were able to create a charge/discharge schedule when the smart meter provided a price schedule for the entire day. To operate in the price-based mode during field-testing, the RESUs would need to receive pricing information (via the smart meter) from the Network Management System (NMS). Unfortunately, the NMS was unavailable to SCE until late 2012, after a RESU software freeze. As a result, the team did not perform lab testing with the NMS until December 2014, just prior to the field test.

One large difference between use of the DevKit and the NMS software is that the DevKit software was unable to repeat the sending of prices. This resulted in misunderstanding how the pricing schedule would be published using the NMS system, which sends updated pricing to the meter frequently throughout the day (even when there are no actual price changes). The DevKit software programs prices directly onto the meter register with a start time and duration, which is then broadcasted for ZigBee end-devices to read (such as the RESU). Additionally, the RESU polls the registers every 5 minutes in case it fails to receive the initial broadcast. If the RESU sees any price change on the meter, it will clear its entire internal price table and attempt to reload it from the meter. Once prices are stored on the RESU, it will hold them until new prices are published or 1:00 am the following day (for the next day's pricing). While the RESU was designed to handle changes in mid-day prices, it is unable to receive prices from a smart meter that is being repeatedly updated by the NMS.

The team attempted several workarounds but all failed. It was determined that working around the issue with existing capabilities would be extremely clumsy, potentially complicated, and possibly unfeasible. The suggested workarounds could have also caused unintended side effects on other HAN devices in the homes and would likely require constant manual oversight. Changing the RESU control logic to accommodate the different control behavior from the Itron NMS price system would have been impractical. Due to the complexity of the RESU software, required changes in the base control logic and associated GUIs, difficulty in obtaining vendor support so late in the project, and required UL retesting for new software controls weighed against this option.

Test 4: VAR Support

This experiment was conducted with all 14 RESUs on both the ZNE and RESU blocks. The experiment was able to demonstrate the RESUs' ability to provide voltage support through injection or absorption of reactive power (VARs). Each of the 14 RESUs had the capability to inject or absorb 1.8 kVARs. During the experiment, the RESUs were programmed to absorb (inductive) VARs. The RESU could also inject (capacitive) VARs if the voltage exceeds a lower threshold. The latter capability was not conducted in this experiment due to grid conditions.

The experiment included four different scenarios in which voltage support was enabled for ten-minute intervals to measure and validate the impact on each neighborhood. The four scenarios included:

- High DER penetration (DVVC on)
- High DER penetration (DVVC off)
- Low DER penetration (DVVC on)
- Low DER penetration (DVVC off)

The RESU voltage support operation was closely controlled and coordinated with other experiments to prevent undesired effects. Each test scenario was repeated three times to increase confidence in the results. The intent of the scenarios was to understand the impact of VAR absorption with maximal or minimal DER penetration and local loads. The minimal DER penetration scenarios were run in the morning between 4:30 and 7:00 am, before the solar PV begins generating power and when home loads were low. During this period, the RESU provided 1.8 KVAR of reactive power, but no additional load or generation. The maximal DER penetration scenarios were run in the afternoon between 4:30 and 5:30 pm, when the RESU is providing its maximum real power output of 4 kW (PV and Battery combined), in addition to 1.8 kVAR of reactive power. An extended test was not conducted as unattended and dynamic VAR injection remains off limits due to current UL1741 rules.

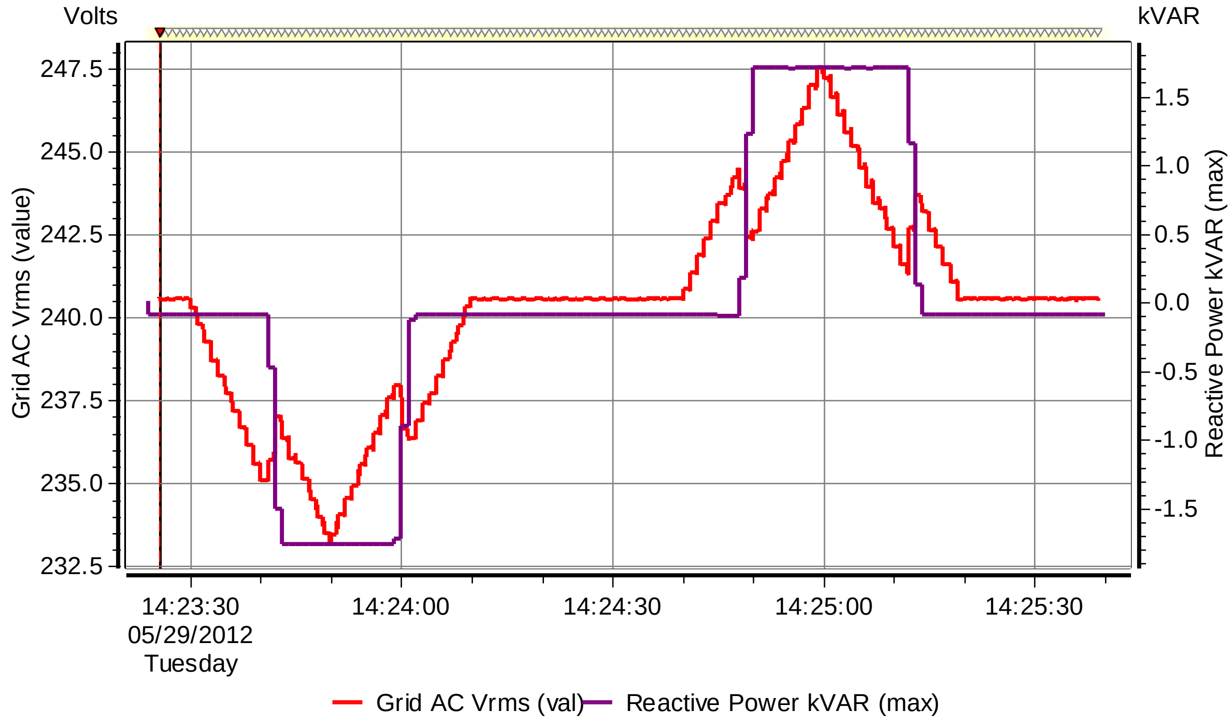
The 14 RESUs provided a maximum of 25.2 KVAR of reactive power across the two neighborhoods. A 50 kVA 120/240 volt transformer provides service to each of the two neighborhoods. The ZNE block contains nine homes with nine RESUs that provided maximum of 36 kW of DER generation and 16.2 kVAR of reactive power. The RESU block contains five homes with five RESUs that provided a maximum of 20 kW of DER generation and 9 kVAR of reactive power.

During the experiment, the 14 RESUs were able to provide the expected reactive power output during each scenario. Intermittent communication issues and varying grid voltages affected some of the results. However, each scenario was repeated three times to provide sufficient data for the analysis. The net effect of the VAR absorption was sufficient to reduce voltage at neighborhood transformers from 241.6 to 239.2 volts. The local voltage at each smart meter also recorded a drop of up to 2.4 volts from high of 244.2 to 241.8. On the downside, voltage support increased transformer loading from 6.1 amps to as much as 76 amps with an average increase of 32 amps.

RESU Issues and DVVC

During the experiment, some RESUs did not behave as expected. The RESUs were tested with DVVC on and off. When DVVC was on, the line voltage was closer to the optimal 240 volts, preventing the RESU’s voltage support from engaging. However, on certain occasions the RESU voltage support hysteresis function failed to force full power VAR injection. Under the expected voltage support operation with hysteresis, the RESU voltage support turns on full reactive power at a set voltage point, and turns off all reactive power at a lower threshold, as depicted in **Figure 84**.

Figure 84: RESU Voltage and Reactive Power Thresholds



Instead of providing an absolute 1.8 KVAR output, some RESUs varied their reactive power output between 0 and 1.8 KVAR, based on its proximity to the VAR support set point. The team observed this behavior in the lab and corrected it prior to deployment. The team suspects that the voltage variance, the proximity of the voltage to the set points, and a low hysteresis threshold of 1 volt is the cause of the issue. Due to the optimal voltage provided by DVVC, the team lowered these thresholds to ensure voltage support would be engaged. In normal practice, the set points would have been set with a higher threshold to prevent this scenario.

Transformer Impacts

The cumulative impact of the nine RESUs providing 36 KW and 16 KVAR was sufficient to impact the voltage on the ZNE Block transformer, indicating the achievability of volt/VAR support. The charts below show the impact to the local transformer with DVVC turned off and with RESUs providing their maximum output. Each time the RESU voltage support turned on can be noted as a bulge in the power factor going from -1 to -0.8. An associated increase in the transformer current and drop in voltage occurs in each case.

Figure 85: DVVC Off - High RESU Current Output (ZNE Block)

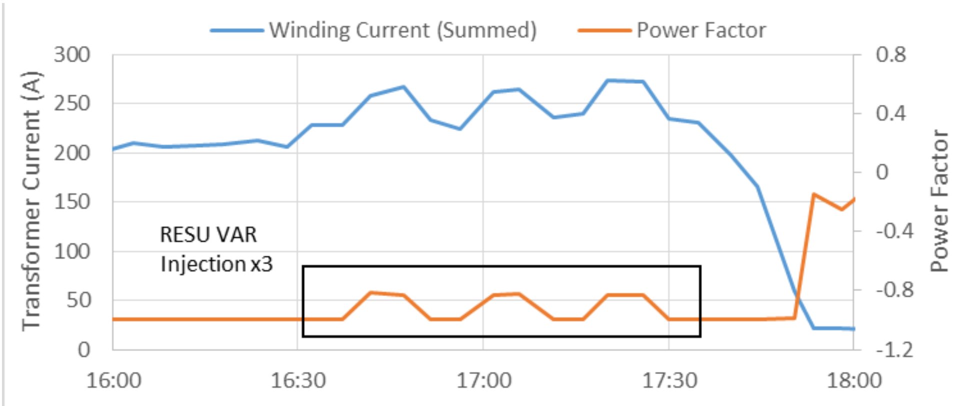


Figure 86: DVVC Off - High RESU Voltage Output (ZNE Block)

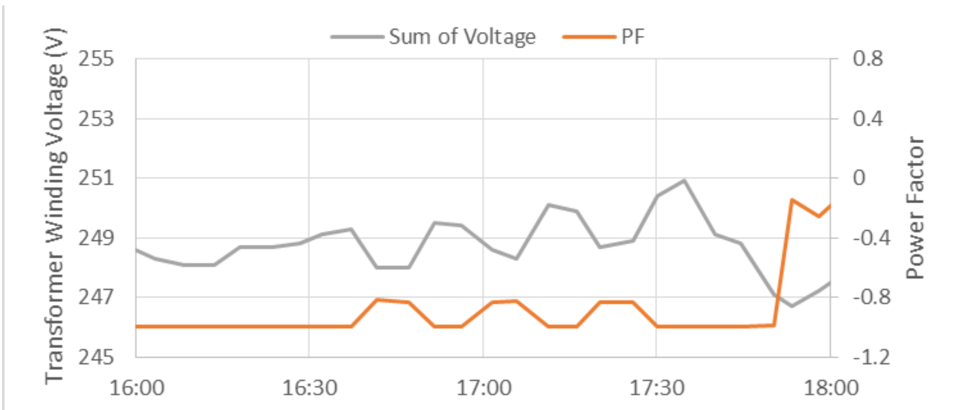


Figure 86 and **Figure 87** show the increase in transformer line current that results from VAR absorption. The large increase in line loading and in the minimum load scenario with both DVVC on and DVVC off indicates that in these scenarios, large amounts of additional VAR is detrimental to the local line loading. There were limited reactive loads to compensate for during the minimum loading condition and, as a result, the VAR injection itself added to the loading. The maximum load scenario resulted in a much smaller increase due to the presence of other reactive loads that the volt/VAR compensated for.

Figure 87 shows the impact of VAR absorption on each transformer's line voltage. Voltage support provides the greatest benefit in the maximum load scenarios. The DVVC behavior also had a noticeable impact on the RESU block where the benefit of RESU VAR support was roughly half when DVVC was turned on. The ZNE block results were more mixed, potentially due to the larger impact of VAR support having the maximally loaded nine RESUs providing 36 kW and 16.2 KVAR. The minimum load with DVVC on scenario showed the smallest benefit for both ZNE and RESU block likely due to DVVC providing all available VAR support benefits. In the minimal load, DVVC off scenario, the increase in voltage drop shows that VAR support can provide some benefits despite minimal loading.

Figure 87: Transformer Voltage Change with VAR Support Turned On

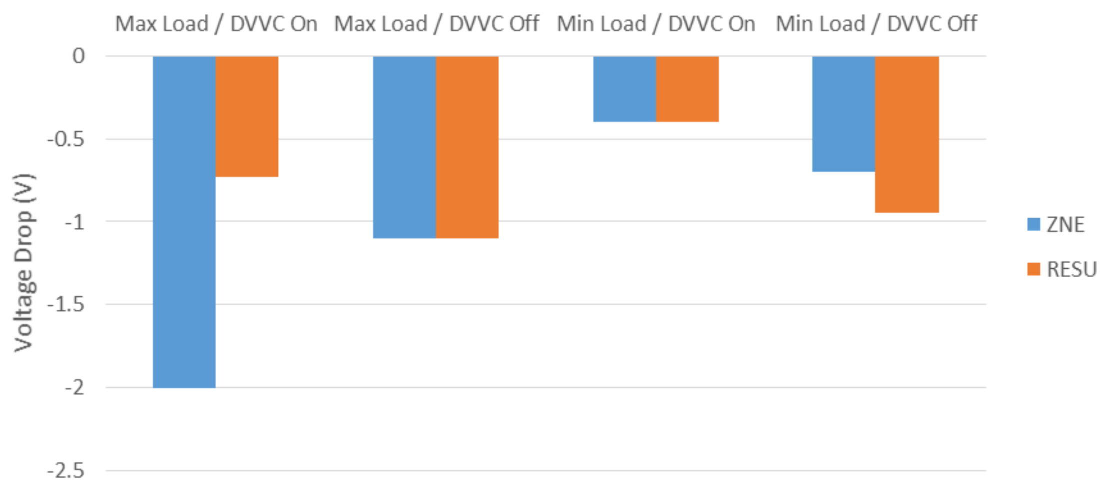
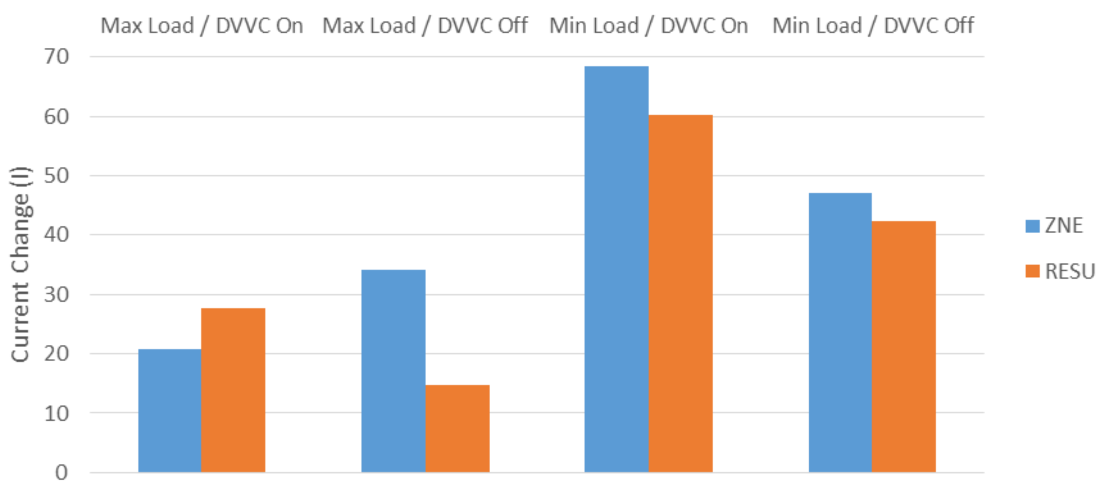


Figure 88 shows the increase in transformer line current that results from VAR absorption. The large increase in line loading in the minimum load scenario with both DVVC on and DVVC off indicates that in these scenarios, large amounts of additional VAR is detrimental to the local line loading. There were limited reactive loads to compensate for during the minimum loading condition and, as a result, the VAR injection itself added to the loading. The maximum load scenario half a much smaller increase due to the presence of other reactive loads that the volt/VAR compensated for.

Figure 88: Transformer Current Change with VAR Support Turned On

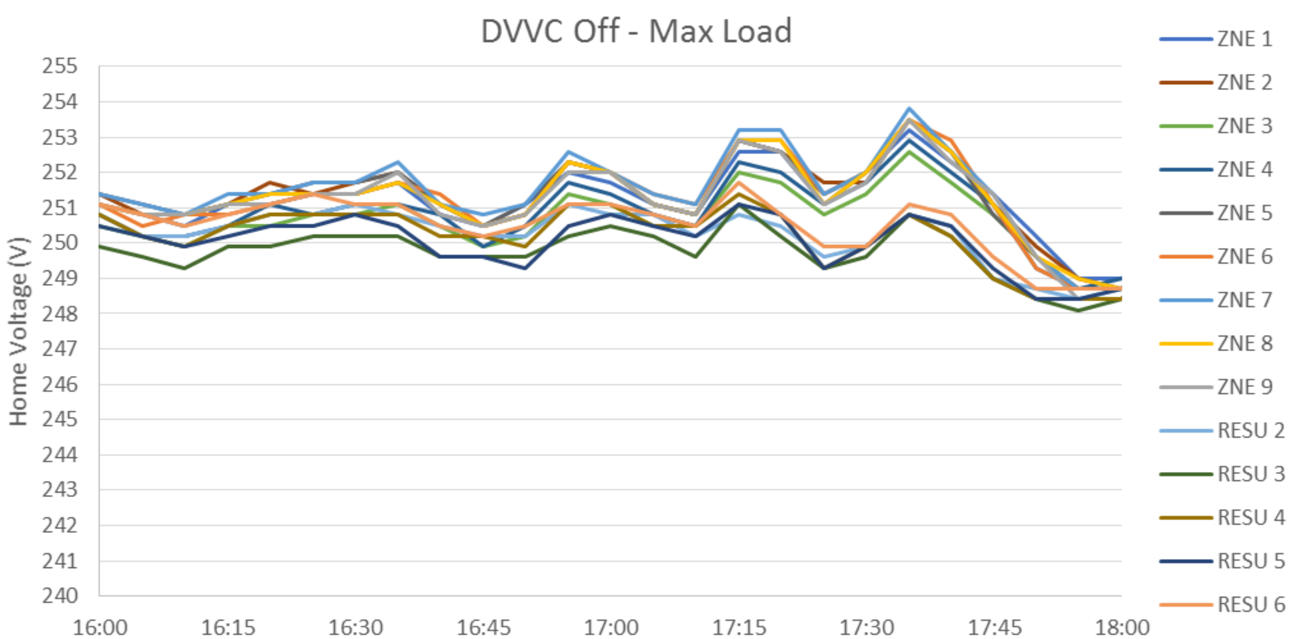


Home Voltages

The team captured smart meter voltage data to determine the impact of the RESUs on local voltages. Each graph contains 5-minute voltage data for each of the RESU and ZNE homes. **Figure 89** and **Figure 90** (high DER penetration and loading) use the same voltage scale from 240 to 255 volts, while **Figure 91** and **Figure 92** (low DER penetration and loading) are scaled from 235 to 250 volts. In all the graphs, it is readily apparent that with DVVC on, the local voltage has a lower and somewhat flatter output.

In the high load with DVVC off scenario, the local grid voltage can surpass local limits (252 volts) with all 14 RESUs injecting a total of 56 kW of power to the local grid. VAR absorption was able to reduce local voltage by approximately 2 volts on the ZNE block and to a lesser degree on the RESU block. This was especially apparently during the third VAR absorption period between 5:18 and 5:28 pm. Once the solar PV and battery power started to drop after the completion of the test by 5:50 pm, grid voltage dropped steeply. A slight spread in voltage due to the lower power capacity of the RESU block is visible between 5:15 and 6:00 pm.

Figure 89: High DER with DVVC Off



With DVVC on, high voltage was less of an issue. Adding VARs still impacted local grid voltages, as depicted in the chart below, with the 3 separate voltage dips over the test period.

Figure 90: High DER with DVVC On

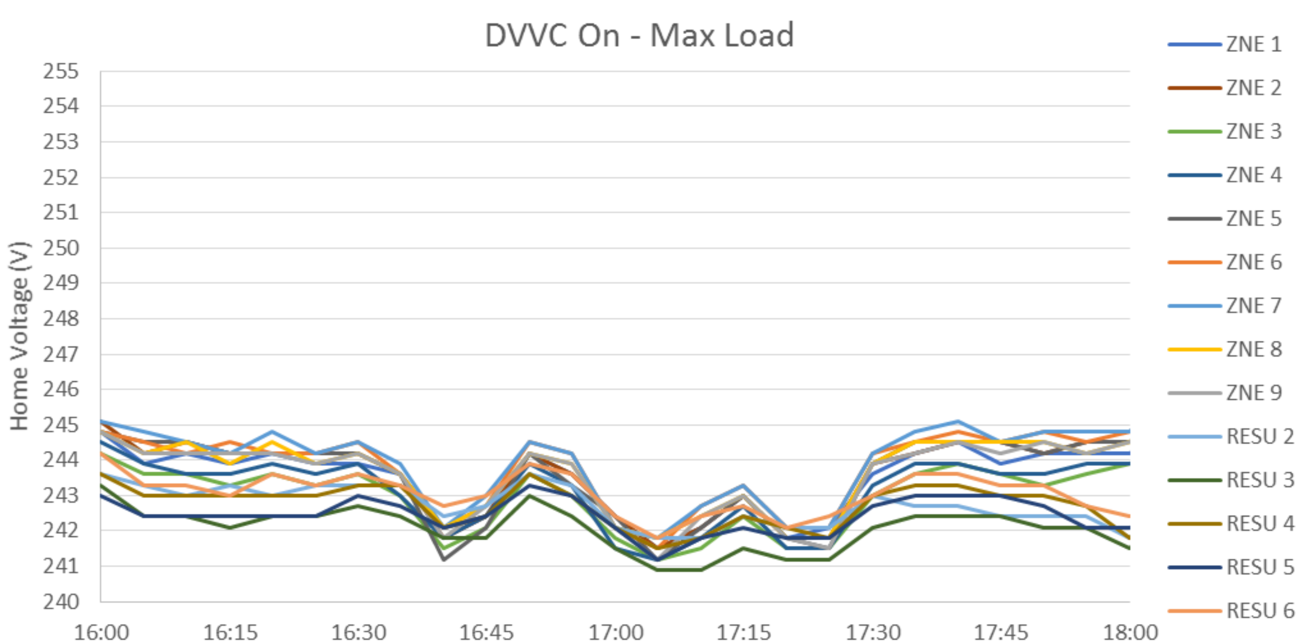
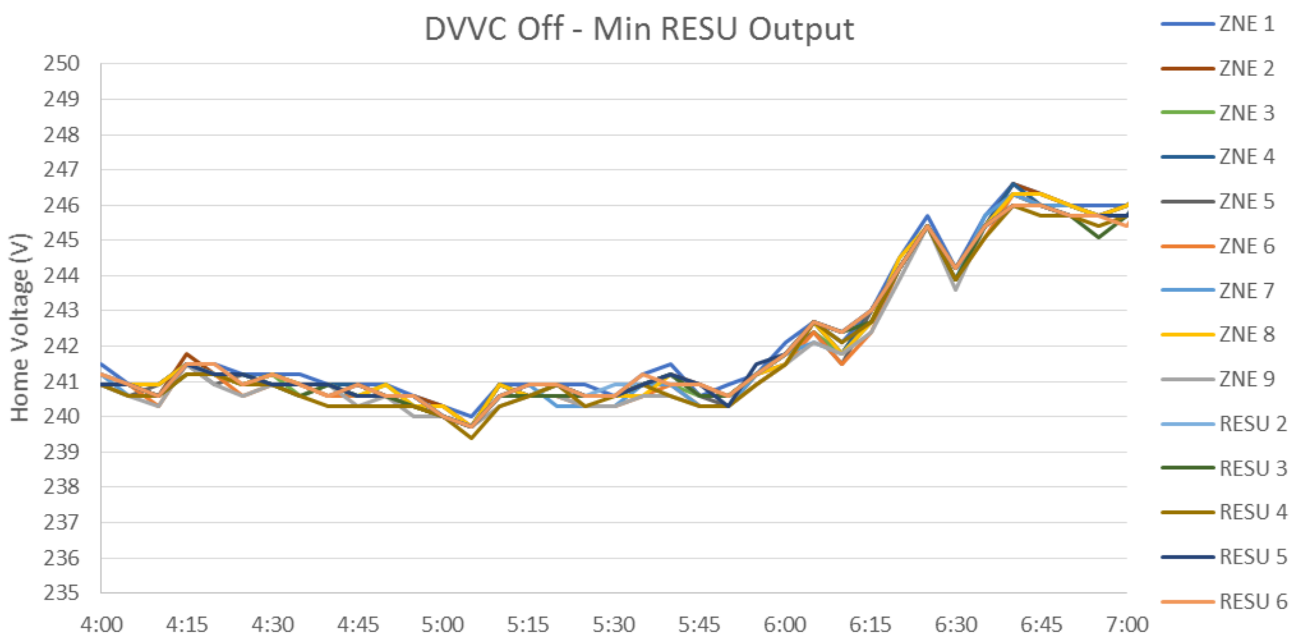


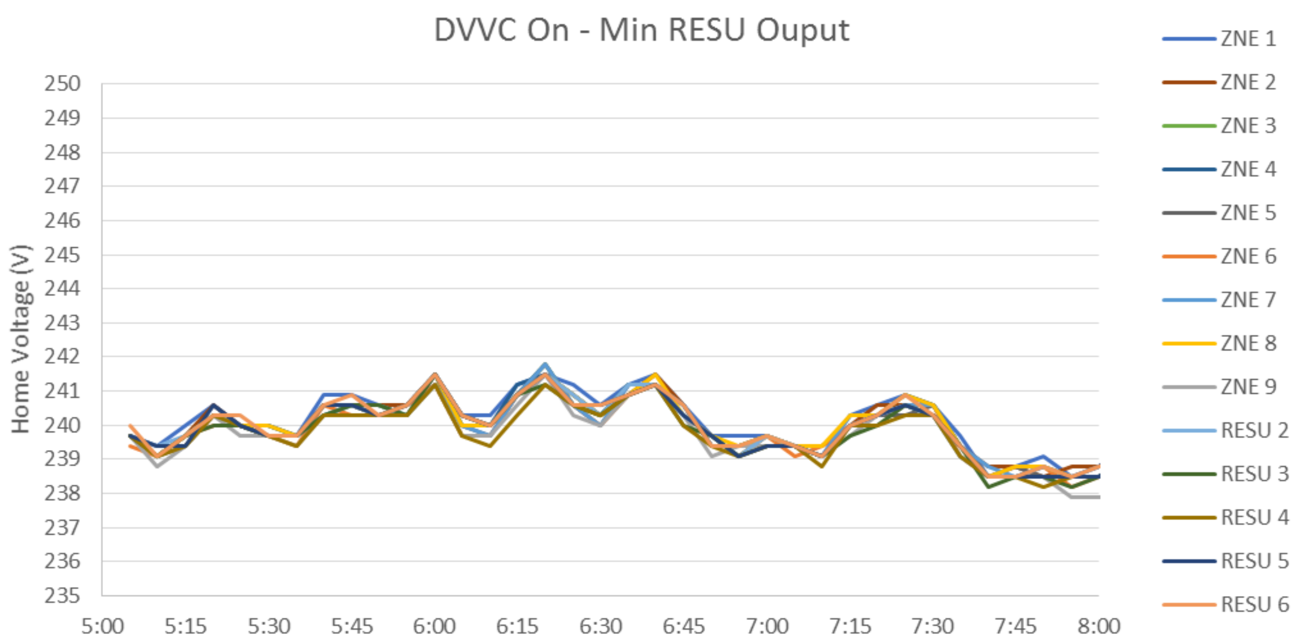
Figure 91 and **Figure 92** illustrate the local home voltages with little to no PV generation and minimal loading. With DVVC off and DVVC on, a lower overall voltage is still observable despite a lack of PV generation. On the latter portion of the DVVC off portion, local voltages rise as the sun begins to rise around 6:15 am. The impact of VARs can be seen faintly as a small dip in the general voltage trend between 5:20, and 5:41 am.

Figure 91: Low DER with DVVC Off



When DVVC was turned on, the lower voltage trend makes it difficult to observe the effects of voltage support. The first two VAR absorptions occurred at 6:00 and 6:21, while the third never occurred due to the voltage being two low engage in VAR absorption.

Figure 92: Low DER with DVVC On



The RESU volt/VAR support was strong enough to affect transformer line voltages. However, the limited benefit in voltage support comes at a cost of increased line loading from the additional reactive power and, as a result, increased current. In a minimally loaded circuit, adding unnecessary VARs can significantly increase line loading with minimal VAR support benefit. During peak demand periods, even minor increases in line loading from VAR injection/absorption might inadvertently cause circuit overloading.

Lessons for the Industry

Volt/VAR control at the residential level can potentially cause additional line loading issues due to a lack of feedback on line reactance. Feedback from the neighborhood transformer on the amount of reactive power in a line can provide the necessary information to optimize the VAR output from DER systems. Controls based on voltages measured locally could improve this, but would not eliminate the issue.

Field Experiment 1D: RESU Level Demand

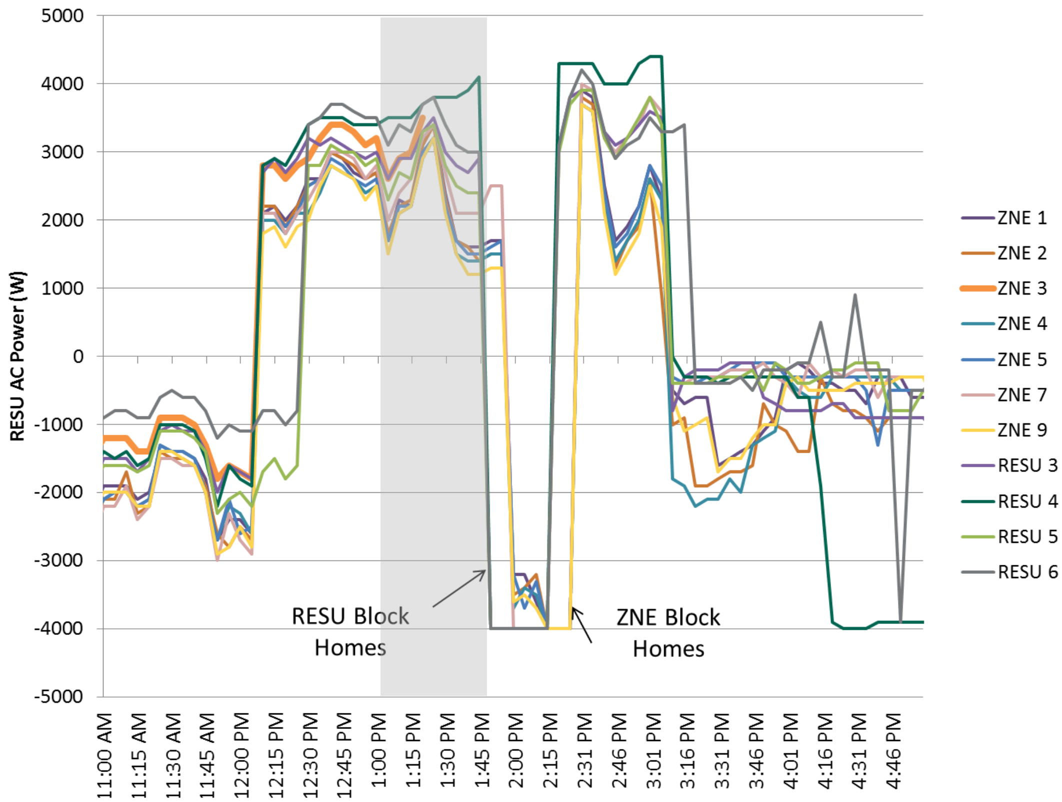
Test 1: RESU Demand Response Event (November 7, 2013)

The purpose of this experiment was to demonstrate the ability of the RESUs to receive DR event signals sent through the RESUs' ZigBee interface via a project smart meter. The test should also confirm that the RESUs automatically discharge at the appropriate time and for the appropriate duration, as defined in the DR event command. The test targeted the 14 RESUs deployed within the ZNE Block and RESU Block homes. The ISGD team conducted this experiment after the deployment as a one-time experiment.

This experiment consisted of configuring the RESUs to charge and discharge according to a predefined schedule. On November 6, 2013, the day before the demand response event, the RESUs were scheduled to charge during the peak PV generation period (12:00 pm to 4:00 pm), and to discharge during the evening peak load period (between 6:00 pm and 9:00 pm). The RESUs were configured to repeat this charge and discharge profile daily, and this schedule was expected to be interrupted by the DR event. The morning of November 7, 2013, the ISGD team published a 30-minute DR event for the RESUs to discharge at full power (4 kW) for 30 minutes. The RESU Block RESUs were scheduled to begin discharging at 1:40 pm, and the ZNE Block RESUs were schedule to begin discharging at 1:50 pm.

After completing the experiment, the team evaluated the RESUs' performance by analyzing data from multiple sources. **Figure 93** presents the RESU AC (alternating current) power recorded by the back office RESU server. This data indicates that the RESU behaved as expected during this test. Note that the negative power represents generation—power output from the RESU to the home/grid.

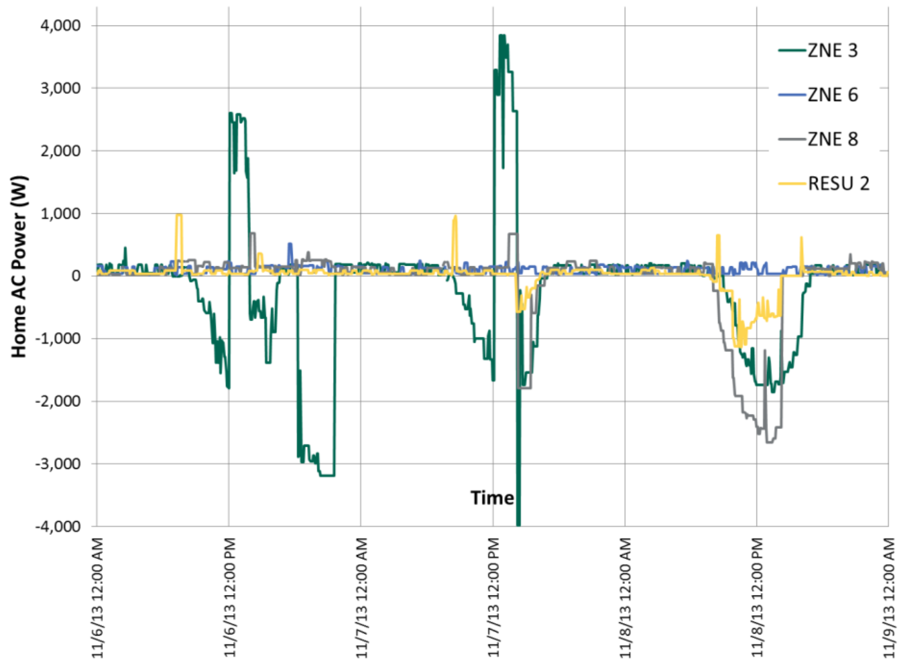
Figure 93: RESU Load (RESU Server)



The RESUs all began charging around noon, as defined by the daily schedule. The RESUs discharged during the schedule DR events, and then resumed charging after the events completed. Two notable exceptions are RESU 5 and RESU 6, which began charging closer to 12:30 pm (not 12:00 pm like the other RESUs). The team believes that these RESUs were setup with incorrect charging schedules (they were setup on the test date separately from the other RESUs). ZNE 3 is another notable exception. This RESU appears to have lost communication just before 1:30 pm. Due to a lack of communications with this RESU, the RESU server was unable to determine whether the RESU participated in the event. The behavior of ZNE 3 is discussed in more detail below.

Four out of the 13 RESUs included in this experiment were not operating during the test. These RESUs performed in three unique ways. The behaviors of these four RESUs (as measured by the RESU ION meter) are shown in **Figure 94**. Note that this meter also measures garage door opener and garage refrigerator energy use (referred to as secure loads).

Figure 94: RESU Load (TrendPoint ION Meter)



ZNE 6 stopped operating and communicating on November 6, 2013. As such, this RESU did not receive the DR event, and did not operate at all during the test. This was confirmed with the very low power recorded (between 0 and 500 W) which is attributable to this RESU's secure loads.

ZNE 3 lost communication just before the DR test occurred. The RESU database confirms that it was operating properly until approximately 1:30 pm on November 7. The TrendPoint data confirms that the RESU charged and discharged as expected until the DR Event. The loss of communication was due to local control problems. When these problems occur, a portion of the RESU becomes non-responsive, which explains why the RESU did not receive the DR event. Rather, the RESU continued charging through the event.

RESU 2 and ZNE 8 both failed due to a battery error in October 2013. This error prompted the RESU to turn off the RESU's internal battery charger and the inverter in order to protect the system. These RESUs did not charge or discharge for several weeks. However, both of these RESUs received the DR event signal on November 7, 2013. When the event began, the RESUs began outputting PV power to the grid. This was unexpected, since the team believed that the battery error would prevent the inverter from operating. **Figure 94** shows that RESU 2 and ZNE 8 provided PV power after the DR event began. Because this behavior was unexpected, the team manually shut down the RESUs. Based on discussions with the manufacturer, the team determined that the manufacturer had incorrectly programmed the RESUs to allow PV operation during the battery error. The manufacturer addressed this programming bug in a subsequent software release that was installed in all the RESUs. This experience highlights an important issue with respect to the potential future development of utility programs for managing distributed energy resources: device manufacturers must design and test their products to ensure that utility-provided signals do not lead to erroneous device behavior. The manufacturers cannot rely on certifications (including UL standards and communications protocol specifications), since these do not address device behaviors under specific internal fault conditions. Utilities cannot test every operational aspect of every device that connects to its system, and should therefore not assume this role. Device manufacturers must be responsible for the operational integrity and safety of the devices they sell to end-users.

Test 2a: RESU 30/70 Level Demand (January 13, 2014 to February 25, 2014)

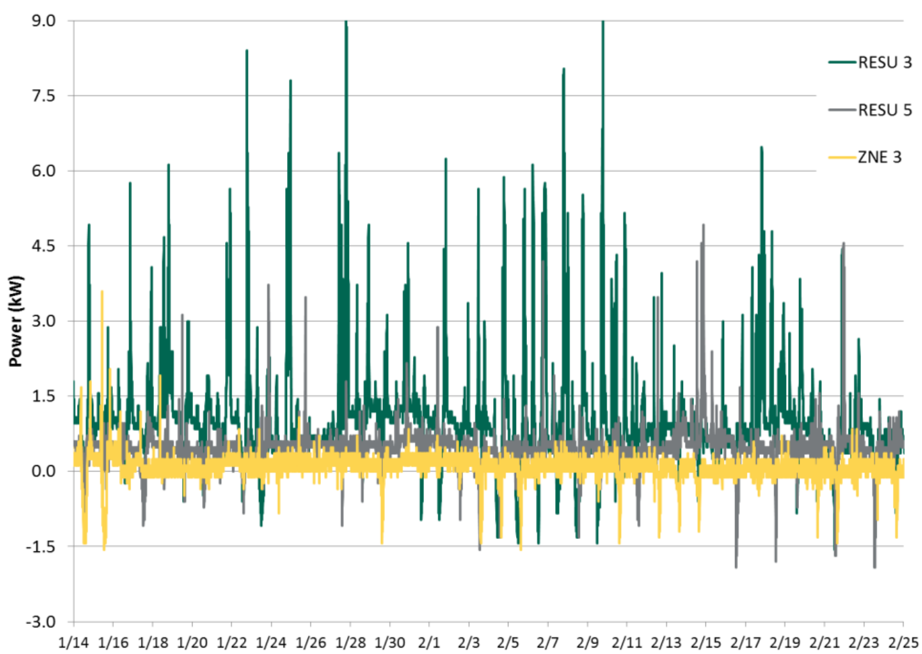
The purpose of the RESU Level Demand experiment was to demonstrate how RESUs could decrease a home's maximum demand and increase its minimum demand through charging and discharging. The goal is to "level" the home's demand throughout the day by removing peaks and valleys in the load profile. A secondary goal is to use as much of the solar PV generation as possible locally, without exporting it to the grid.

The RESU level demand algorithm uses 15-minute historical usage data to autonomously calculate maximum and minimum demand thresholds. When the household demand meets one of these thresholds, the RESU programming causes the RESU to either charge or discharge. The algorithm calculates the historical usage using a weighting parameter that determines the relative importance of prior day versus all other historical usage. For this particular experiment, the previous day's data received a 30% weighting and the historical average received a 70% weighting. The RESU updates its thresholds approximately every 15 minutes, and adjusts its charge or discharge levels approximately every 30 seconds based on the instantaneous demand received from the project smart meter. Ideally, a RESU could use this operating mode to maintain a home's demand at a constant power level throughout the test period.

This experiment included all 14 RESUs deployed on the ZNE Block and RESU Block. Each RESU operated in the level demand mode with the battery limited to operate between 20 and 100% SOC. During the 43-day test period, each PV array generated between 260 and 620 kWh DC (direct current) energy, while the homes consumed between 300 and 1,200 kWh AC. The RESUs were operational 97% of the time (on average) and autonomously charged and discharged throughout the test period.

During the test period, ZNE 3 had the lowest total load while RESU 5 had a moderate load and RESU 3 had the highest. **Figure 94** plots the demand of each home during the test period.

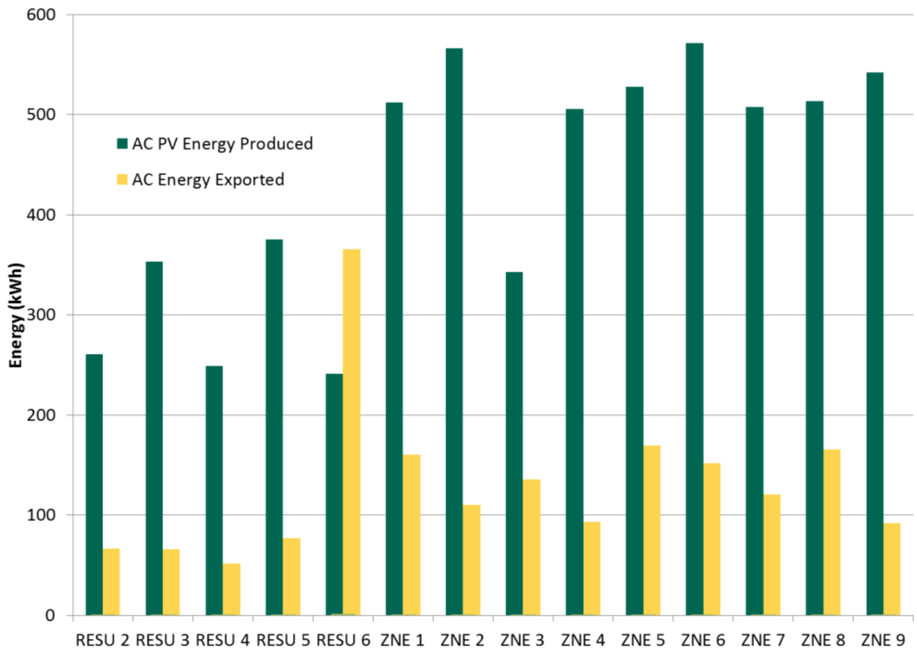
Figure 95: Household Demand during the RESU Level Demand Test Period



This plot shows that the RESU was able to maintain ZNE 3's load near 500 W throughout most of the test period. However, the RESU 3 exhibited numerous load spikes that the RESU was unable to respond to (i.e., by discharging to reduce the overall household demands from the grid). The RESU can discharge at up to 4 kW and can provide 8 kWh of energy (due to SOC restrictions) per cycle. However, due to the intermittent nature of the high-demand loads at RESU 3, it was difficult for the RESU to appropriately predict and respond to these demand spikes.

Overall, the homes used approximately 75% of the total solar PV energy generated either through instantaneous use, or through storage in the battery for later use. **Figure 96** summarizes the solar PV energy generated and the solar PV energy exported to the grid during the test period.

Figure 96: Solar PV Generation and RESU Export



This figure shows that the RESU Level Demand algorithm was able to use locally 70 to 80 % of the PV energy produced. RESU 6 was a significant exception. The energy this home exported to the grid exceeded the energy generated by its solar PV panels. This indicates that during the test period the RESU discharged energy that it received from the grid. The project data shows that this RESU's power varied frequently between full charge and full discharge. It is unknown exactly what conditions led to these large oscillations, but they may have resulted from the slow feedback loop and load averaging that the RESU uses to adjust its charge/discharge power levels. It appears that the RESU's 30-second control loop is insufficient for responding to dynamic load conditions.

The RESU Level Demand algorithm needs improvement in two areas: predicting future load, and response time. Due to the dynamic or unpredictable nature of certain loads (such as HVAC, forced air unit, and PEV charging), the RESU's historical data was unable to forecast and respond to such load variations. In addition, variations in solar PV output prevented the RESUs from fully 'leveling' demand, and the homes all experienced spikes in 5-minute demand. The RESU's load forecast calculations use historical average data that results in thresholds not flexible enough to account for daily load fluctuations. In addition, the RESU only adjusts its power every 30 to 60 seconds. These adjustments are based on moving averages of the site demand reported by project smart meters. The slow update and site demand averaging limit the accuracy of the RESU response.

The team performed this experiment again during the demonstration period. Prior to the next test, the team adjusted the level demand algorithm's weighting parameter. The current weighting of 30% and 70% (between prior day and historical average) produced consistent thresholds. However, due to the highly dynamic nature of the home loads and generation, in the next test the prior day usage received a 70% weighting and the historical average usage received a 30% weighting. This should make the calculations more dependent on the previous day's profile and reduce the impact of the previously recorded historical data.

Test 2b: RESU 70/30 Level Demand (June 3, 2015 to June 17, 2015)

As with test 2a, the purpose of the RESU Level Demand experiment was to demonstrate how RESUs could decrease a home's maximum demand and increase its minimum demand through charging and discharging. The goal is to "level" the home's demand throughout the day by removing peaks and valleys in the load profile. A secondary goal is to use as much of the solar PV generation as possible locally, without exporting it to the grid.

This experiment was conducted with all 14 RESUs on the ZNE and RESU blocks. It represents a re-test of a prior experiment conducted in early 2014, but with a change in a key variable. The level demand algorithm uses historical load patterns to generate a demand threshold that determines when to charge or discharge the RESU. A crucial aspect of calculating that threshold is based on the weighting of historical versus present load. In the previous experiment, the weighting was set to 30% present and 70% historical load. This resulted in slower responsiveness but greater smoothing. This follow up experiment was conducted with 70% present and 30% historical weighting. The intent of this change was to increase the responsiveness of the battery, while sacrificing the smoothing using the battery less. The experiment was operated over a 14-day period between 6/3/15 and 6/17/15. Each RESU was programmed to operate using the Level Demand operating mode with the battery limited to operation between 20 and 100% SOC.

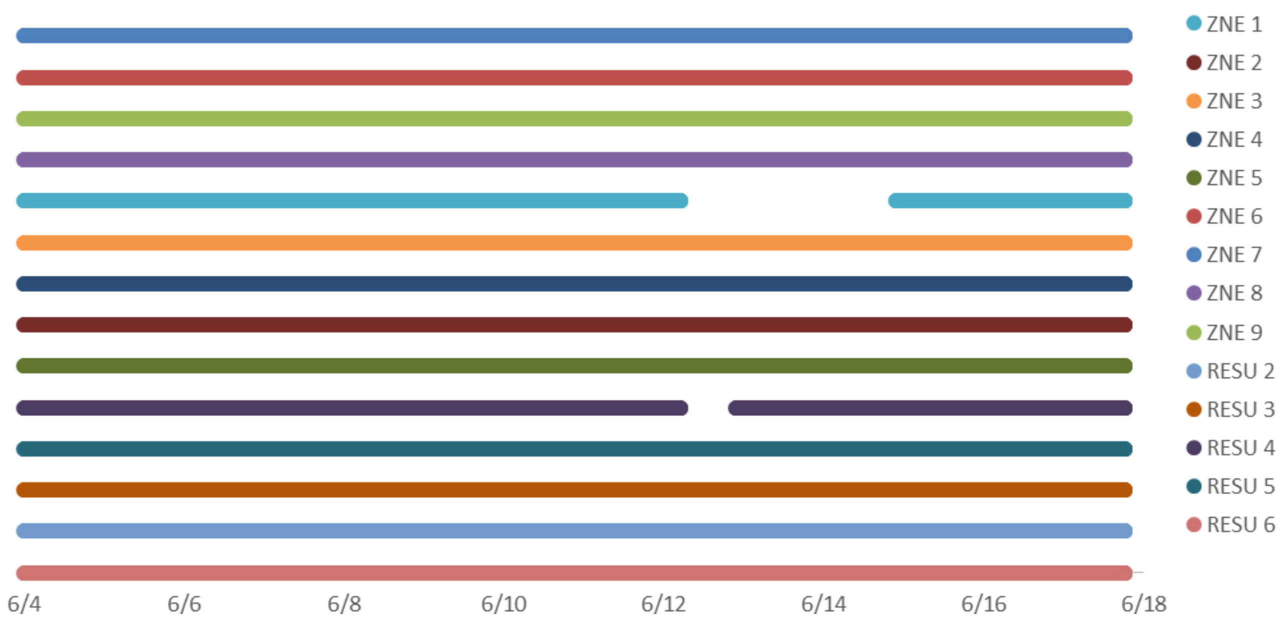
During the 14-day test period, between 215 and 290 kWh DC PV energy was generated by each solar PV array and home loads required between 160 and 460 kWh AC. Overall, the homes used approximately 64% of the total PV energy generated either by using it instantaneously or by storing it in the battery for later use.

The homes all experienced spikes in 5-minute demand throughout the test period. This was due to the dynamic and unpredictable nature of certain loads (such as PV, HVAC, FAU, and EV charging). The RESU was unable to forecast and account for such load variations using historical data. In addition, the RESU only adjusts its power every 30 seconds to one minute. The charge/discharge level adjustment is made using a moving average of the site demand reported by the smart meter. The slow update and site demand averaging limited the accuracy of the RESU response.

RESU Uptime

During the test period, two RESUs lost functionality for a short duration after their weekly automatic reboots. These errors prevented the RESU from operating with the expected behavior, although it did not impact solar PV production. These errors occurred after nearly 6 months of continuous operation in Permanent Load Shifting and came soon after switching to the Level Demand mode. The team believes that the RESU instability resulted from the high computational resource needs of the Level Demand mode. A power cycle was sufficient to clear the errors. Throughout this test period, the "uptime" of the RESUs was calculated by determining the average percentage of time all of the RESUs were operational. For the 14-day test period, the uptime of the RESUs was 98.2%. **Figure 97** shows an operational timeline for each RESU.

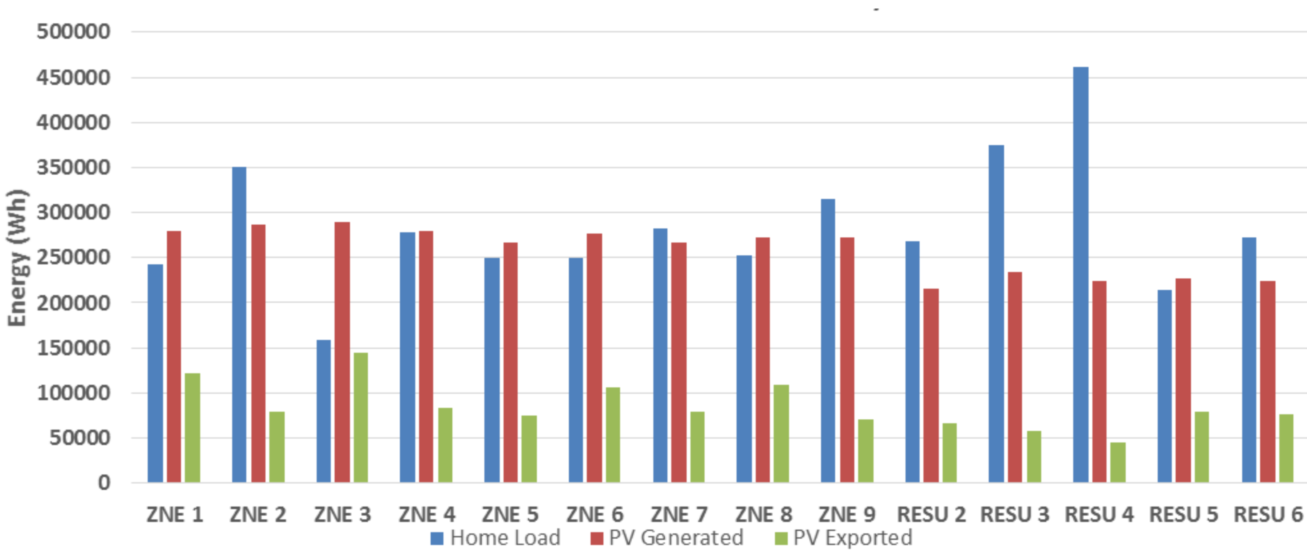
Figure 97: RESU Operational Time



Home Loads

To determine the impact of the RESU's Level Demand algorithm, the team first calculated the RESU AC grid impact. The impact of PV and RESU was subtracted from the homes' metered load to determine the real load (net of the RESU). Over the 14 days that included the Level Demand test period, the loading of each home was relatively consistent, although the consumption varied significantly between homes. The total energy produced and used by each home during the test period is provided the in the chart below.

Figure 98: RESU Total Home Load and PV Generation

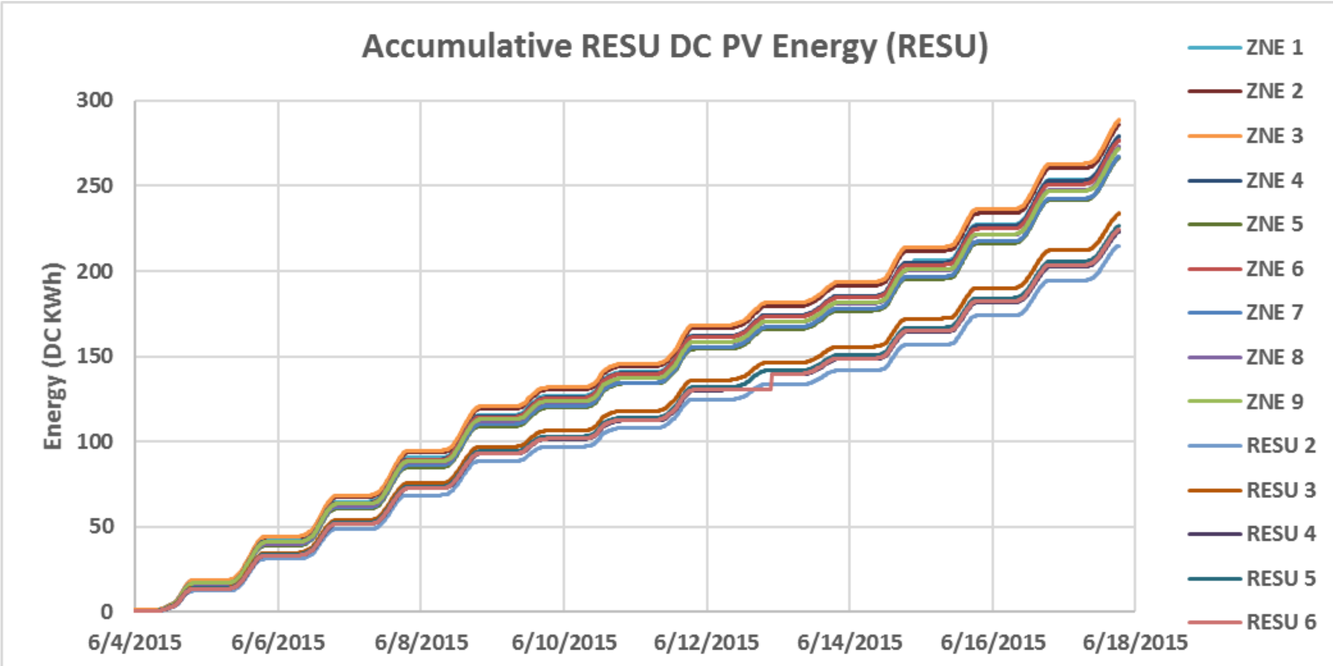


The PV exported bar represents the PV energy that was neither used by home loads nor stored by the RESU. Variability in the home loads increased due to some of the home owners having left for summer vacation. This resulted in in a decreased home load and increased in PV exported due to over generation (ZNE 1 & ZNE 3).

RESU PV Generation

PV arrays were installed with each RESU to demonstrate the RESU's ability to shift excess PV generation to periods when it is most needed. Throughout the test period, each home generated between 215 to 290 kWh. The sizes of arrays installed, 3.2 kW on the RESU block and 3.9 kW on the ZNE block, resulted in a clear separation between the blocks in terms of solar PV generation.

Figure 99: Cumulative RESU DC PV Generation



Level Demand Results

The objective of the RESU Level Demand algorithm is to decrease the maximum demand of the home and increase the minimum demand by removing peaks and valleys in the load profile. This operation aims to "level" the home's demand throughout the day. The algorithm uses 15-minute historical data captured from the smart meter and calculates maximum and minimum demand thresholds for controlling its charge and discharge activities. A weighting parameter is used to control how the historical data is averaged. For the June 2015 Level Demand test, the weight parameter was set to 70%, which weighted the previous day's data at 70% and the historical average at 30%. The RESU updates its threshold approximately every 15 minutes, but adjusts its charge or discharge power approximately every 30 seconds based on the instantaneous demand received from the smart meter. Ideally, the RESU could use the algorithm to maintain the home's demand at a constant power level throughout the test period, provided battery capacity exceeds the home loads.

Primary differences between the January 2014 test and the June 2015 June test include a weighting factor increase from 30% to 70% for faster response, lower battery capacity due to 1.5 years of operation in a hot garage, and an increase in PV generation due to summer operation versus winter operation.

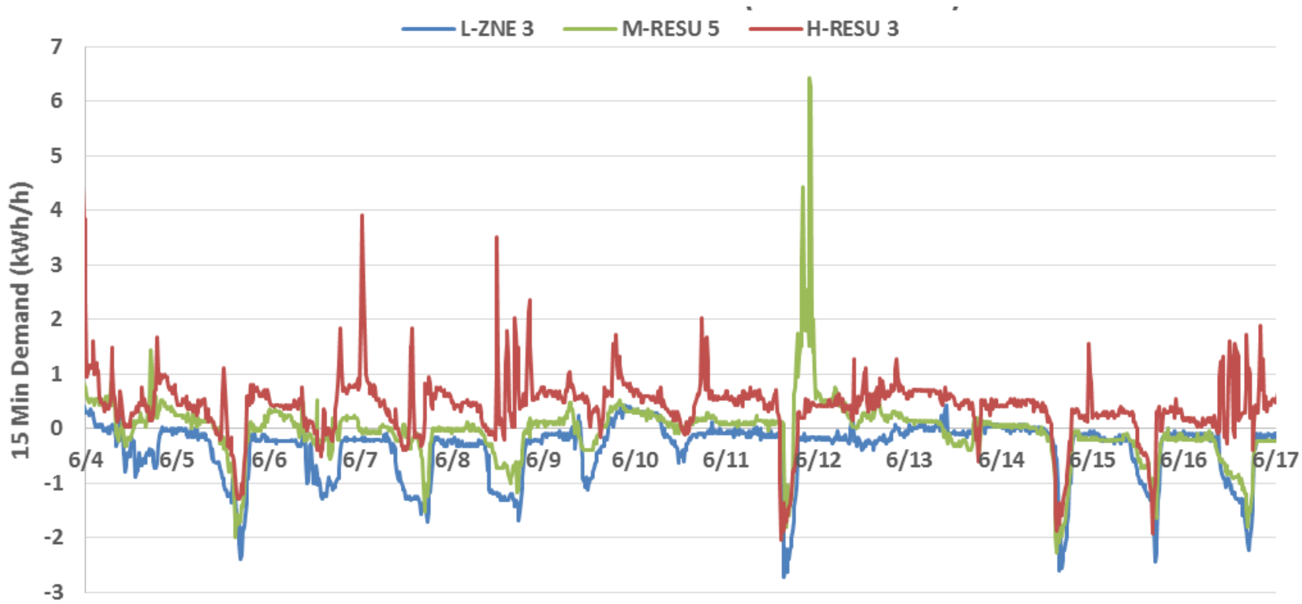
The low PV generation impact to the Level Demand performance was minimal as all homes were able to maintain demand within its demand thresholds. Demand in most homes were reduced to approximately 1 kW with the exception of ZNE 6 and RESU 5 who high demands quickly used up the RESU battery capacity as shown in the SOC graph below. These high demands were likely from EV charging that resulted in a steep drop in battery SOC.

Compared to the previous January 2014 experiment, the results were not significantly different for most homes. Batteries ended up fully charged by 12:00 pm in both 2014 and 2015 experiments, although some demand-spikes occurred due to early battery exhaustion. Primary issues with performance remain in the control algorithm inability to anticipate EV charging and battery capacity.

Weighting Factor Impacts

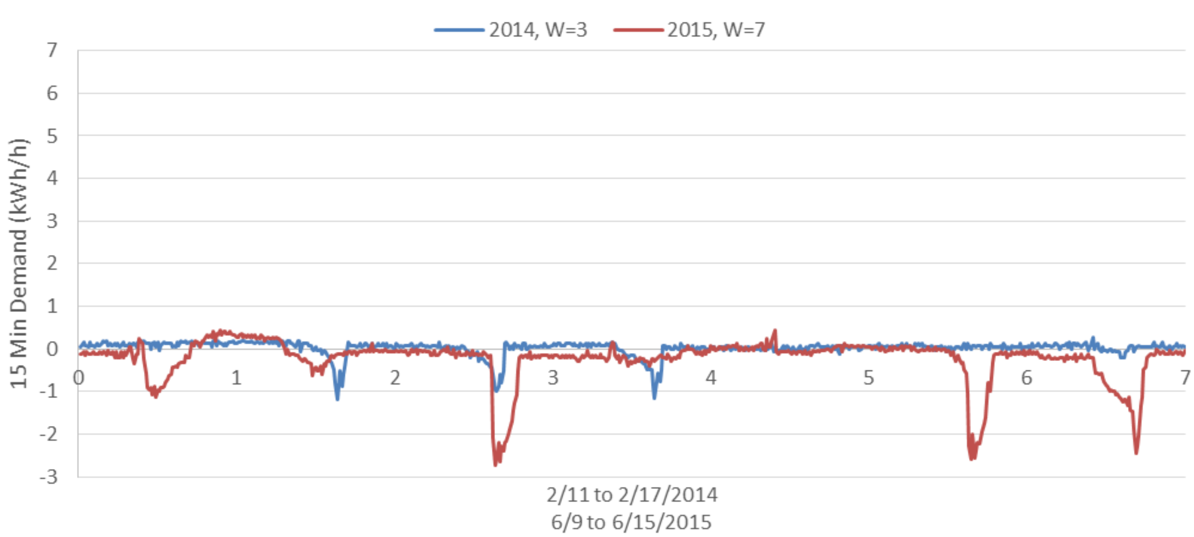
The team conducted an analysis of the weighting factor's impact on three home loads. The three chosen homes represented different levels of home load: ZNE 3 represented a low usage home (345 kWh/month), RESU 5 represented a medium usage home (470 kWh/month), and RESU 3 represented a high usage home (815 kWh/month). **Figure 100** presents the demand profiles for these homes over the two-week level demand test period.

Figure 100: Home Demand per Smart Meter over Test Time



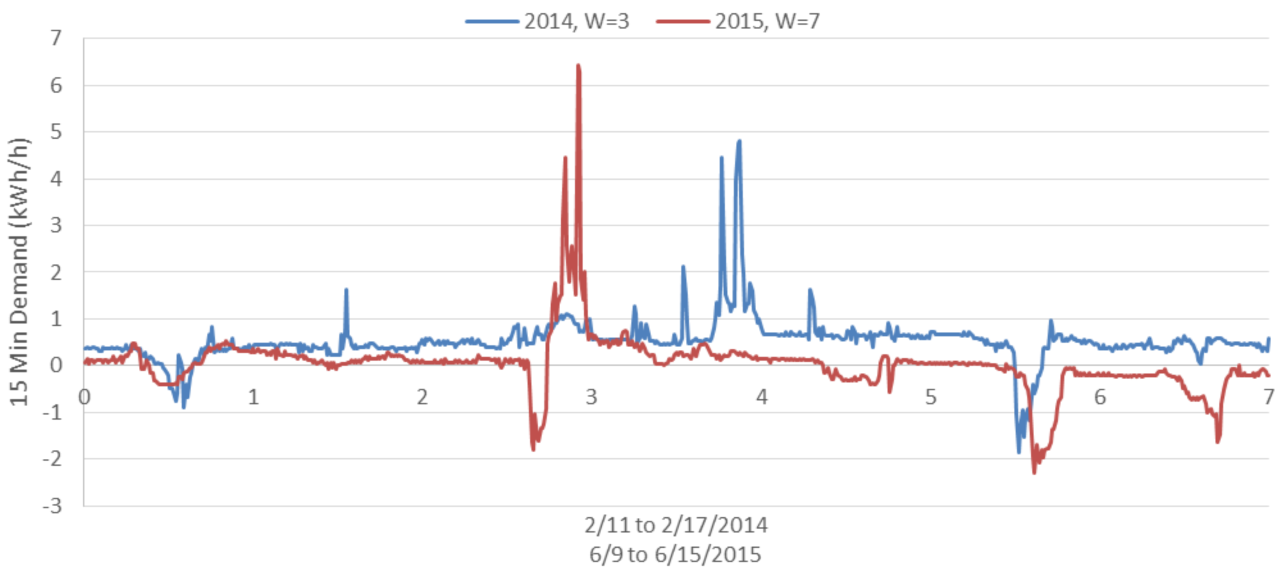
The team selected a one-week period in the middle of the experiment to represent each weighting factor's impact. For 2014, the one-week period extended from 2/11/14 to 2/17/14. In 2015, the one-week period was from 6/9/15 to 6/15/15.

Figure 101: Low ZNE 3 Weighting Factor



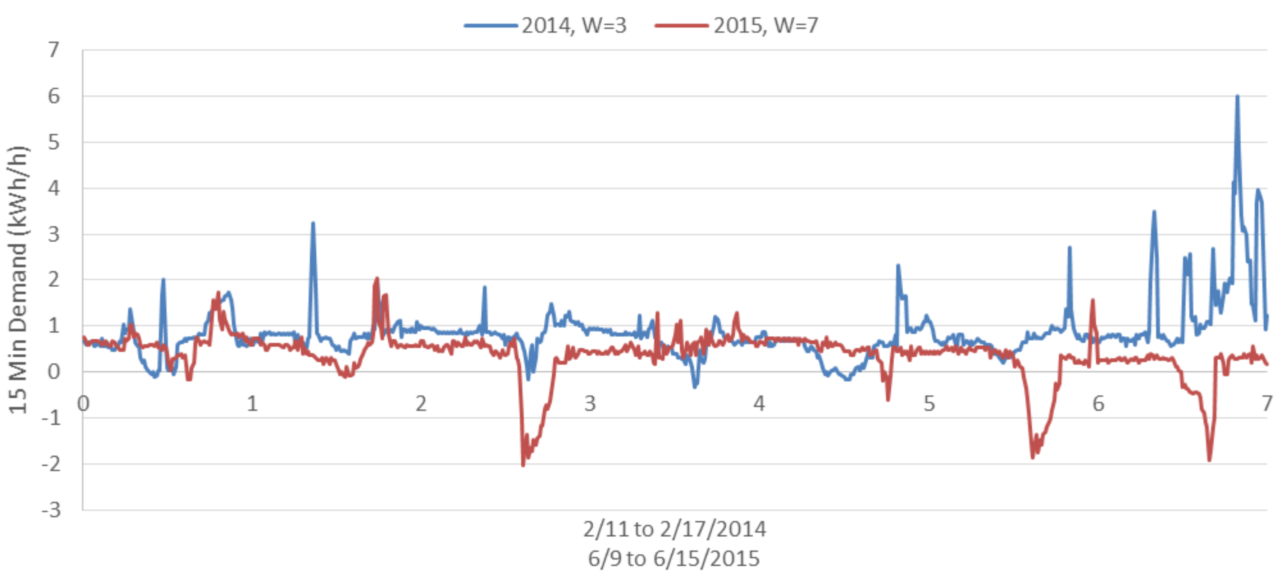
The low energy use home (ZNE 3) exhibited better performance under the higher smoothing slower response settings in the 2014 experiment than the less smoothing, faster response settings in the 2015 test.

Figure 102: Medium RESU 5 Weighting Factor



The medium energy use home (RESU 5) experienced spikes in demand that the RESU could not mitigate in both tests. Unexpectedly, the faster response and less smoothing actually produced lower overall demand over the one-week period although its peak demand was also significantly higher.

Figure 103: High RESU 3 Weighting Factor

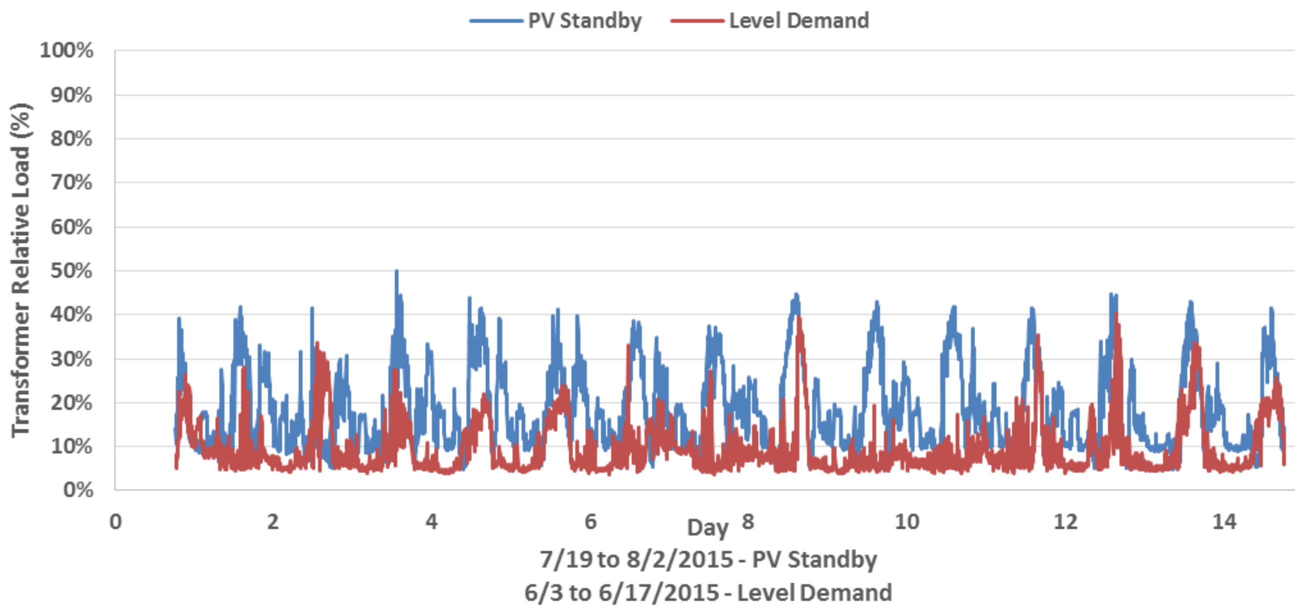


The high energy-use home (RESU 3) experienced the greatest impact from using the faster response, lower smoothing mode. There were fewer peak demand spikes, likely due to a higher reserve battery capacity from the faster response, lower smoothing. More summer solar PV generation may have also played a role in the improved performance.

Transformer Impact

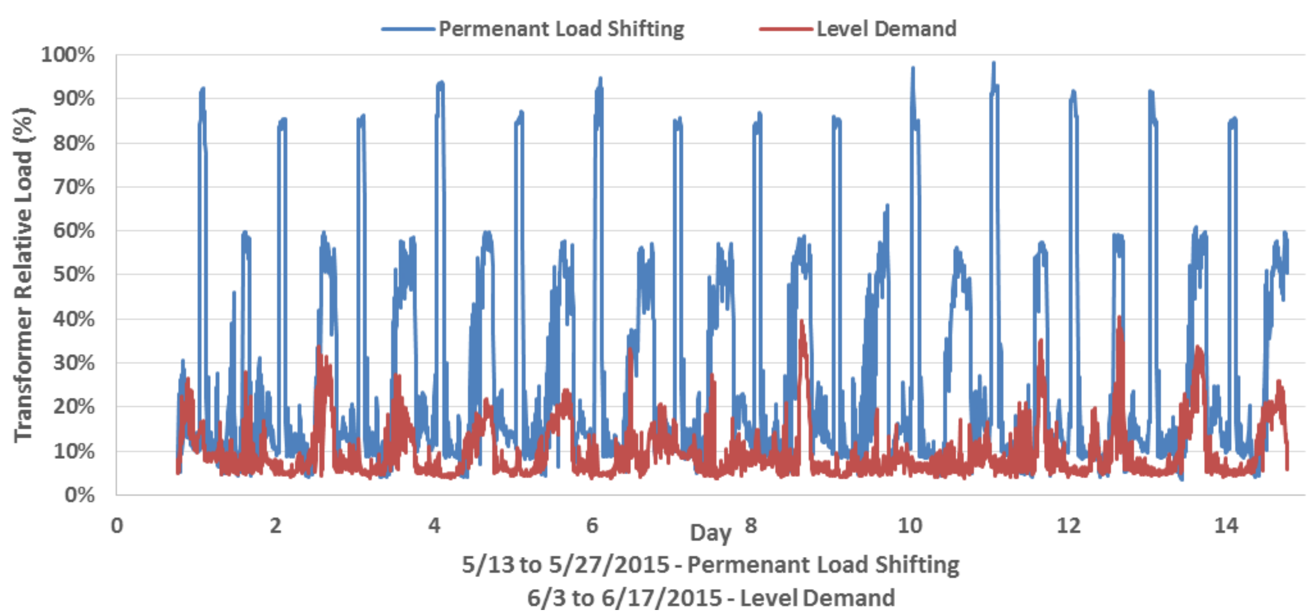
The level demand algorithm had a positive impact on the neighborhood transformer as **Figure 104** illustrates. Overall loading was significantly reduced compared to PV-only operation.

Figure 104: ZNE Home Transformer Loading



The impact of the level demand mode was even more pronounced when compared to the PLS mode, as depicted in **Figure 105**.

Figure 105: ZNE Home Transformer Loading - PLS



The development of adaptive, intelligent, and autonomous algorithms for energy storage is crucial to obtain maximum value from energy storage systems. In this case, we observe that better performance can result in some cases from fine-tuning the algorithm parameters.

Test 3a: RESU PV Capture (February 25, 2014 to October 9, 2014)

The purpose of the RESU PV Capture experiment was to demonstrate how RESUs could help customers store surplus solar PV generation for later use. Such a mismatch occurs when solar PV generation exceeds a home's current electricity demand. For example, solar PV output is highest during the midday hours, when customers are often not at home and electricity use is low. Operating the RESU in PV Capture mode would store this energy for later use, potentially during the evening. Customers participating in utility net energy metering (NEM) programs would not benefit from this RESU mode, since they receive credit for the surplus solar PV they feed back to the grid. By storing excess solar generation for later use rather than exporting it to the grid at full retail price, NEM customers would bear the cost of storage losses.

To operate the RESUs in PV Capture mode, the team first configured each of the 14 project RESUs to operate in the Cap Demand mode. The Cap Demand mode causes a RESU to either charge or discharge based on current household demand (measured by each respective RESU). Since the intent of this experiment was to store excess solar PV generation, the team configured the Cap Demand set point to 0 kW. If household demand exceeds 0 kW (meaning the household demand is greater than the current solar PV generation), then the RESU discharges. If household demand is below 0 kW (meaning there is surplus PV feeding back to the grid), then the RESU charges. Each battery was allowed to operate between 20% and 100% state of charge.

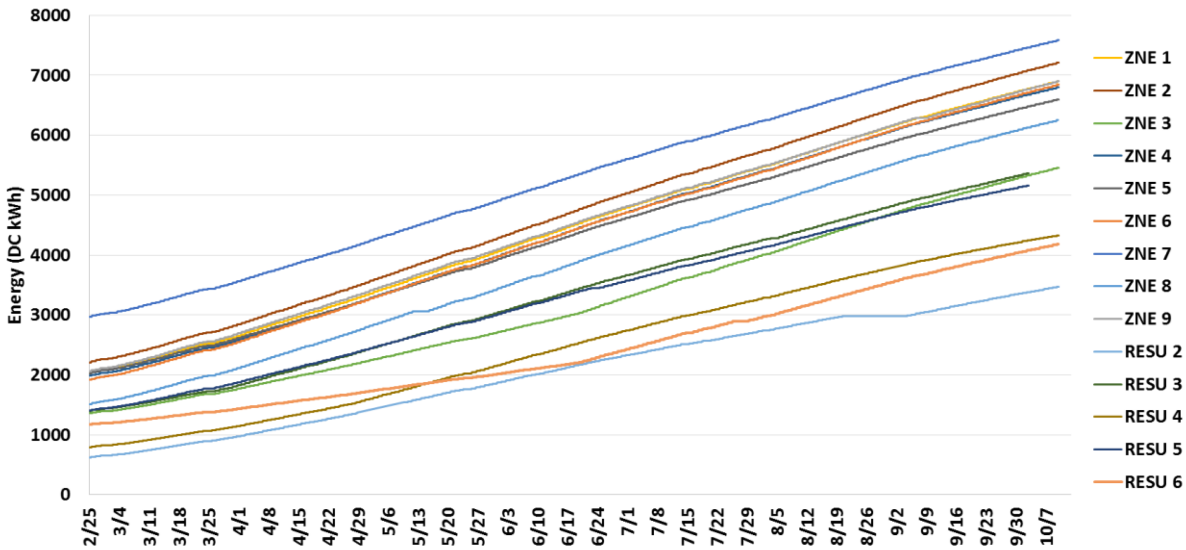
During the experiment, which lasted 226 days, the solar PV arrays of the 14 RESU homes generated approximately 59.8 megawatt-hours (MWh) DC of solar PV energy. Of this amount, approximately 27% was exported to the grid immediately, 36% was used by the homes immediately, and 37% was stored in the RESUs for later use (either by home loads or by exporting to the grid).

The long duration of this experiment highlighted multiple RESU issues. While most homes were able to generate full solar PV power, two RESU homes had faulty solar PV electrical connections that resulted in lower solar PV output. Another home had shading issues that resulted in the home generating approximately 27% less solar PV energy than adjacent homes.

During the test period, several RESUs experienced operational failures of various durations. The team replaced two RESUs with spares. During the 226-day test period (5,424 hours), 16 RESU failures resulted in 2,191 hours of unscheduled downtime across the 14 RESUs. This equates to system uptime of approximately 97%. These RESU issues are described in more detail below.

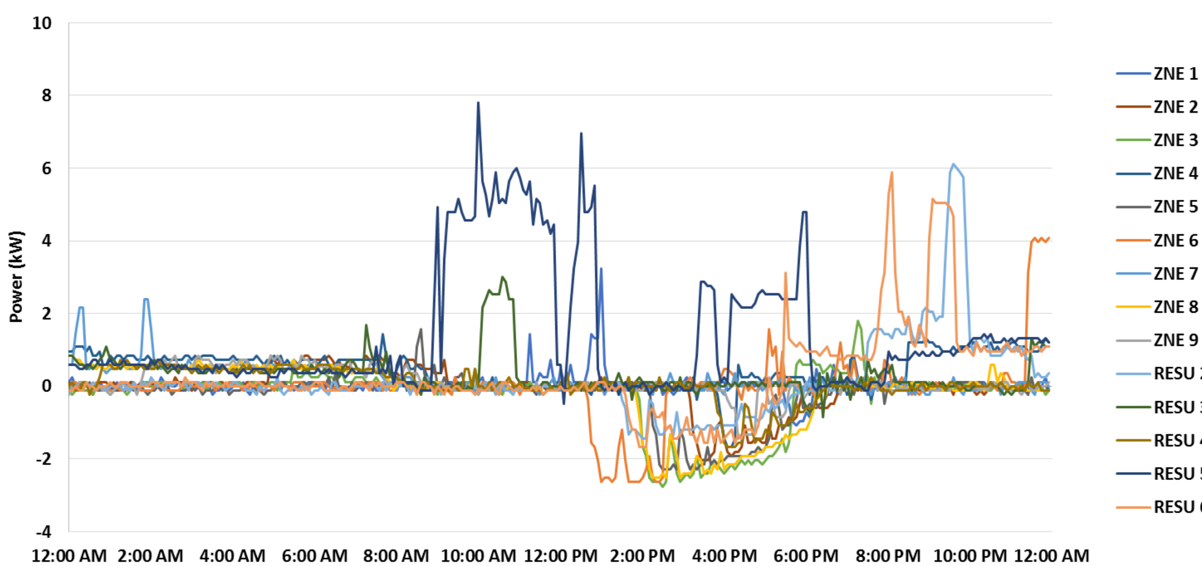
Throughout the test period, each RESU received between 2,800 and 5,000 kWh DC. RESU 2 experienced significant shading, which affected its power production, while RESU 6 had a problem with its solar PV electrical connection, which the team resolved on June 20, 2014. **Figure 106** summarizes the cumulative solar PV generation for each RESU home over the course of this experiment. The slope for RESU 6 increases after the team fixed the electrical connection.

Figure 106: Cumulative Solar PV Generation



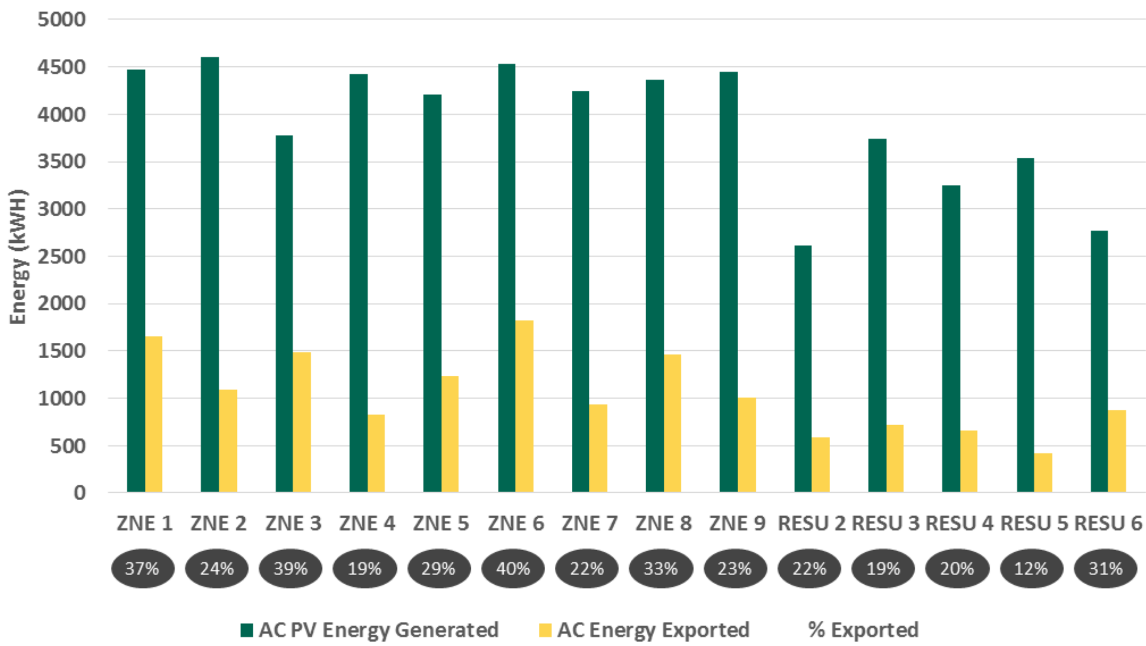
The intent of the PV Capture experiment is to use the RESU to absorb surplus solar PV energy and then discharge this energy when household electricity demand exceeds the solar PV output. **Figure 107** plots the household demand for each RESU home on July 4, 2014. Each of the homes' RESUs absorbed the surplus solar PV up until approximately 1:00 pm, as indicated by the relatively flat and positive demand levels. Beginning at approximately 1:00 pm the RESUs began to reach 100% state of charge and the RESUs started exporting the surplus solar PV to the grid. The RESUs continued to export the surplus solar PV to the grid until about 6:00 pm. Near the end of the solar PV generation period, the RESUs began discharging to make up for the solar PV shortfall to maintain household demand at 0 kW (for most homes).

Figure 107: RESU Home Demand (July 4, 2014)



Since the objective of this experiment is to evaluate a method for limiting the amount of solar PV generation exported to the grid, a useful metric for evaluating the experiment's effectiveness is the percentage of solar PV generation exported. **Figure 108** summarizes the solar PV energy generated for each RESU home, the solar PV energy exported the grid, and the percentage of solar PV energy exported to the grid. The team adjusted the solar PV energy DC (measured by the RESUs) based on their 92% DC/AC efficiency metric to determine the AC energy amounts. This figure reveals that operating the RESUs in the PV Capture configuration allows the homes to consume between 60% and 88% of their solar PV energy. Interestingly, the ZNE Block homes exported approximately 9% more solar PV energy than the RESU Block homes. This is likely due to the ZNE Block homes generating more solar PV energy. These homes also received a series of energy efficiency upgrades, which help them to consume less energy.

Figure 108: Solar PV Generation and Export



Between March 1, 2013 and October 31, 2015, the team identified five operational issues with the RESUs, four of which caused the RESUs not to operate in their intended mode. These five issues are described below. The team has worked closely with the vendor to identify the root causes and develop solutions. The first two issues have been resolved, and the ISGD team is working to identify solutions for the remaining three. The team continues to monitor the RESUs closely to identify and resolve any potential issues that arise in the future. The total downtime for the 14 RESUs over this eight-month period was approximately 2,000 hours, which means the RESUs were operational more than 97% of the time.

Battery Discharge Level: While operating the in the Cap Demand mode as part of the PV Capture experiment, three RESUs discharged below their minimum state of charge set points. This error prevents further battery charging and discharging. The team sent a remote reboot signal to each RESU to clear the error. The RESU vendor determined that this error resulted from an error with the program logic for the Cap Demand mode. The vendor provided a software update to fix this problem.

Electrical Noise: Random electrical noise on the internal communication wiring caused faults on two RESUs. On-site RESU reboots were required to clear the errors. The team has received, tested, and installed a software upgrade to improve system stability. The team updated all 14 RESUs with this software over a three-day period that ended on September 24, 2014. If a noise-induced communication fault occurs, the software upgrade would cause the RESU to log the fault, reset the system, and resume normal operation. Since the software upgrade, several RESUs have experience this error. The software upgrade functioned appropriately and the RESU cleared the error without any downtime.

Battery Charge Level: There was one incident where the battery charged beyond its operating limits. RESUs are designed to stop charging based on the average voltage of all the battery modules. Differences between the modules' SOC can result in a higher or lower voltage between modules, as the BMS programming allows some variation. One module's voltage significantly exceeded the average voltage, resulting in it being charged over its operating limits. The

BMS ultimately protected the system by stopping RESU operation. The BMS should have "balanced" the module voltages to prevent this type of issue. However, the BMS for this particular RESU did not function as intended in late February 2014. A failed battery module may have also caused this issue. The team replaced this RESU with a spare unit. The RESU vendor is continuing to investigate the root cause of this failure.

Weekly Automatic Reboot Failure: The RESUs reboot on a weekly basis in order to clear the memory of the Windows CE operating system used for the RESU touchscreen. Three RESU failed to reboot after a weekly automatic reboot. This RESU required an on-site power cycle to clear the error. The RESU vendor determined that the cause of this error is due to the operating system that controls the touchscreen. The RESU vendor could not obtain support from the software vendor, and would thus not provide a solution to this problem. Any future product release for consumer use would likely require a software redesign. The ISGD team continues to monitor the RESUs and plans to manually reboot any RESUs that experience this error again.

BMS Fault: One RESU indicated a BMS fault on its battery pack, which immediately caused the RESU to stop all battery and inverter operations. The team was unsuccessful in rebooting the RESU remotely. The team replaced this RESU with a spare unit.

Test 3b: RESU PV Capture (June 17, 2015 to June 30, 2015)

This experiment was conducted with all 14 deployed RESUs on the ZNE and RESU blocks. The experiment is a retest of the earlier PV Capture experiment conducted in 2014, modified to extend the operating capacity of the battery. The experiment was conducted to test the means of effectively storing and using solar PV energy generated locally, reducing the need to draw energy from the grid when solar PV is not being generated. Ideally, the RESU would use daytime PV generation to completely offset the home's electrical loads, and use remaining PV capacity to fully charge the RESU's battery. Then, as PV generation stops, the RESU would begin discharging the battery to offset the home's electrical loads until solar PV generation resumes the next day.

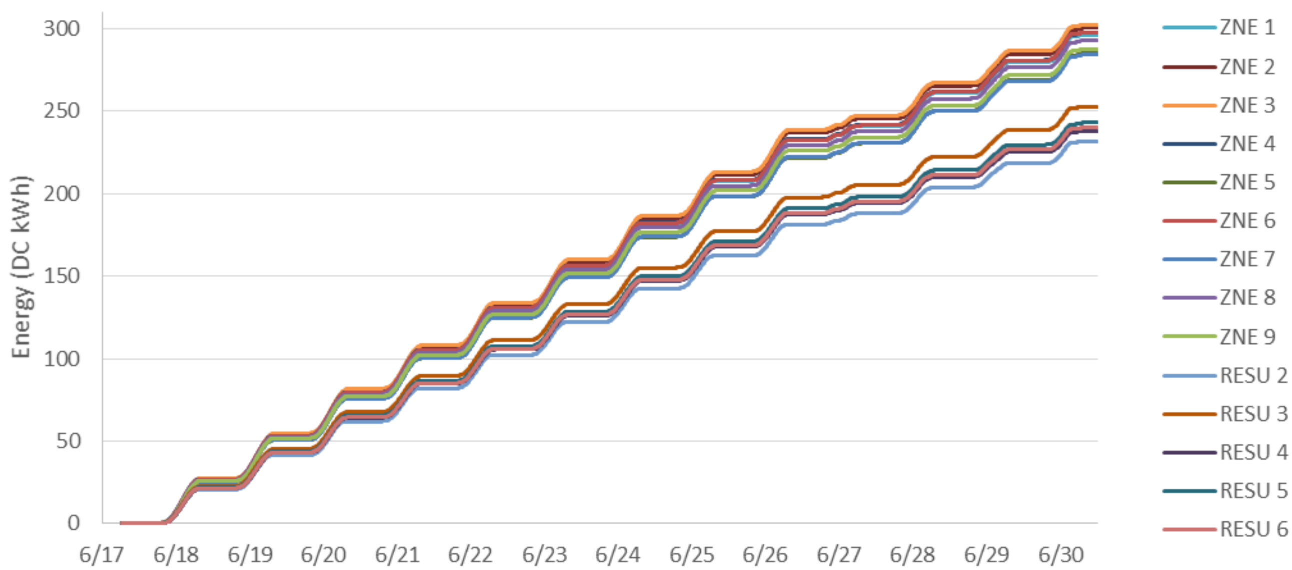
Since battery capacity is a major limiting factor for PV capture performance, the battery operating range was increased compared to the 2014 experiment. In 2014, the operating range was set to 20–100% SOC, while in this 2015 experiment, the operating range widened to 10–100% SOC. This reduced the RESU's reserve backup capacity by the same amount (i.e., in the event of a grid power failure, the battery may already be as low as 10% SOC, compared to the previous 20% SOC reserve). Like the 2014 experiment, the Maximum Site Demand Limit (MSDL) parameter remained at 0 kW, which meant the RESU attempted to keep the home from drawing any power from the grid unless the battery was completely discharged to the 10% SOC reserve.

While the 2014 and 2015 PV capture experiments used the same RESUs at the same time of year, they were also conducted one year apart. Over this time the RESU battery capacity degraded approximately 7.5%. Therefore, even though the battery operating range was increased by 10%, the net increase in battery capacity was only about 2.5%. In addition, the relative amount of PV energy stored in the RESU batteries was less than the 2014 experiment, since the average home loads went up between 2014 and 2015

Results

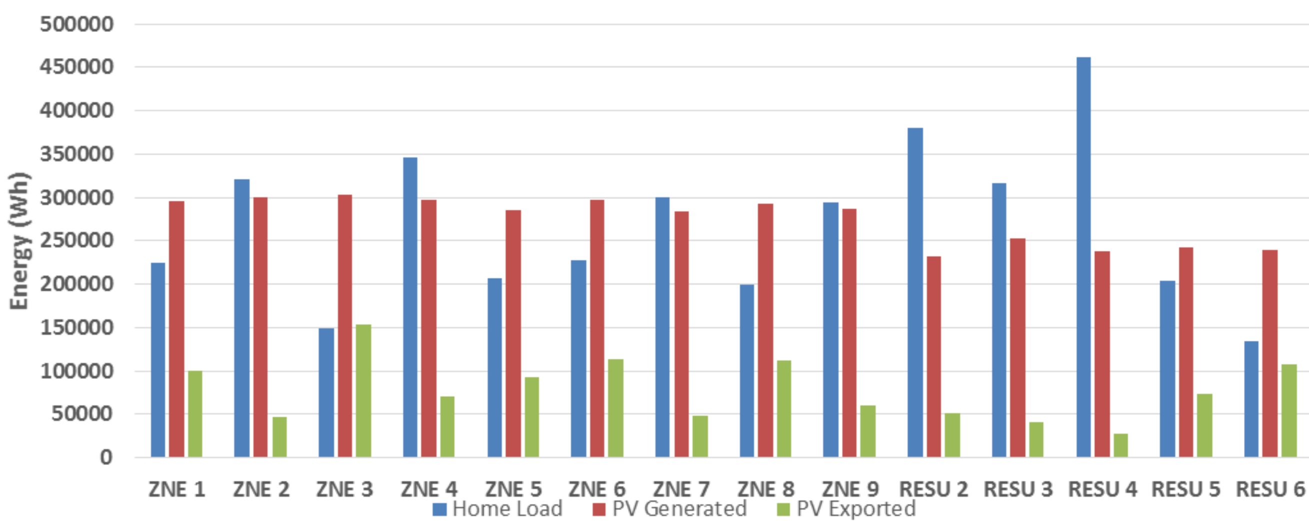
All 14 RESUs operated normally for the duration of the experiment, which extended from 6/17/15 to 6/30/15, for a total of 293.5 hours of operation and 100 % uptime. Each home generated between 232 and 303 kWh of solar PV energy over the experiment period, as shown below. Total solar PV generation for all 14 homes was 3.85 MWh.

Figure 109: Cumulative Solar PV Generation (June 17 to June 30, 2015)



Seven of the 14 homes generated more PV energy than they used, while the remaining seven homes used more energy than they generated. This is different from the 2014 experiment, where all of the homes generated more energy than they used over the course of the test. Nevertheless, the sum of all 14 homes was still a net generation of 19 kWh. Each home also exported PV energy to the grid when the RESU battery was fully charged and available PV power exceeded the home's current load. **Figure 110** summarizes the load, solar PV generation, and solar PV exports for each home. Similar to the 2014 experiment, the ZNE homes generally exported more energy than the RESU homes, likely due to the energy efficiency measures and lower loads.

Figure 110: RESU Total Home Load & Solar PV Generation



Overall Trends

In the 2014 experiment, many homes had higher demand during the day (7–8 kW peaks), while in 2015 these homes had reduced demand with peaks up to 5 kW. While this may be due in part to the marginally increased battery capacity, it is also likely due to a general reduction in midday energy usage, possibly influenced by a switch to time of use (TOU) rates between the two experiment periods. Home occupants may have modified their behavior and learned to reduce afternoon and evening on-peak energy usage. In both 2014 and 2015, a majority of the RESU batteries reached a 100% SOC between 1:00 pm and 4:00 pm, coinciding with the mid-to-late peak of the daily solar PV generation curve.

Single Day Comparison

Figure 111 and **Figure 112** show the 15-minute demand for each of the 14 homes over the course of a representative day from the 2014 and 2015 experiments. The Normal Capacity chart shows results from the 2014 experiment with a 20–100% SOC operating range, while the Extended Capacity chart shows results from the 2015 experiment with a 10–100% SOC operating range.

Figure 111: RESU Home Demand (2014 Test)

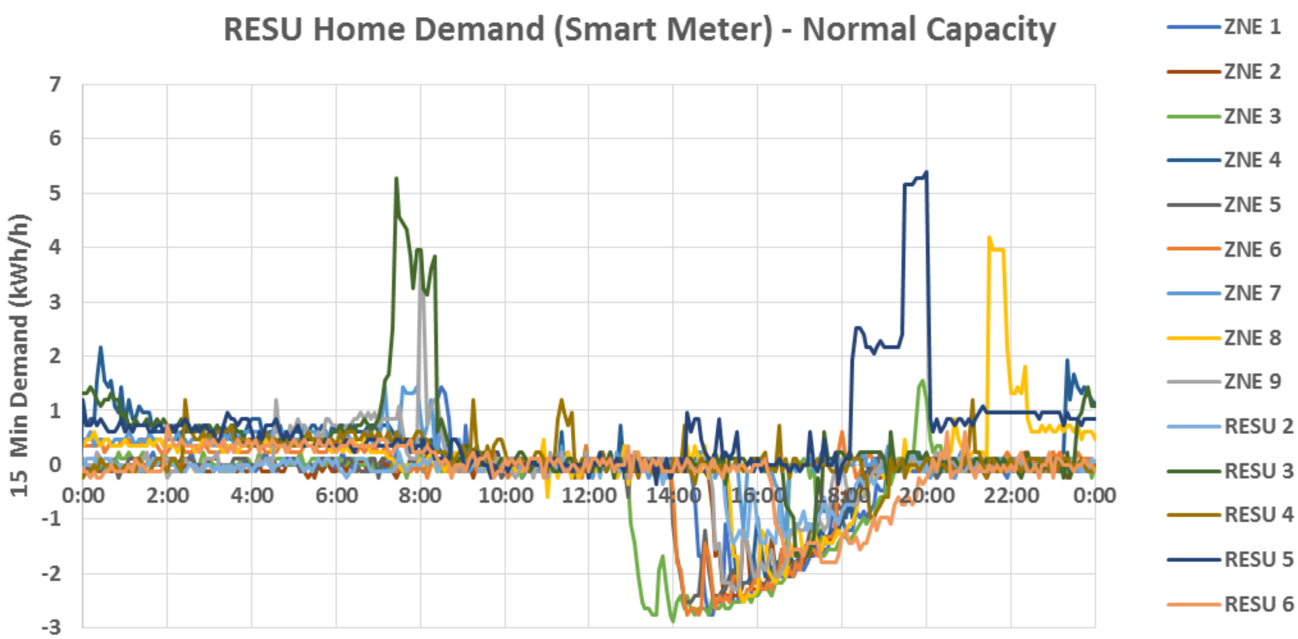
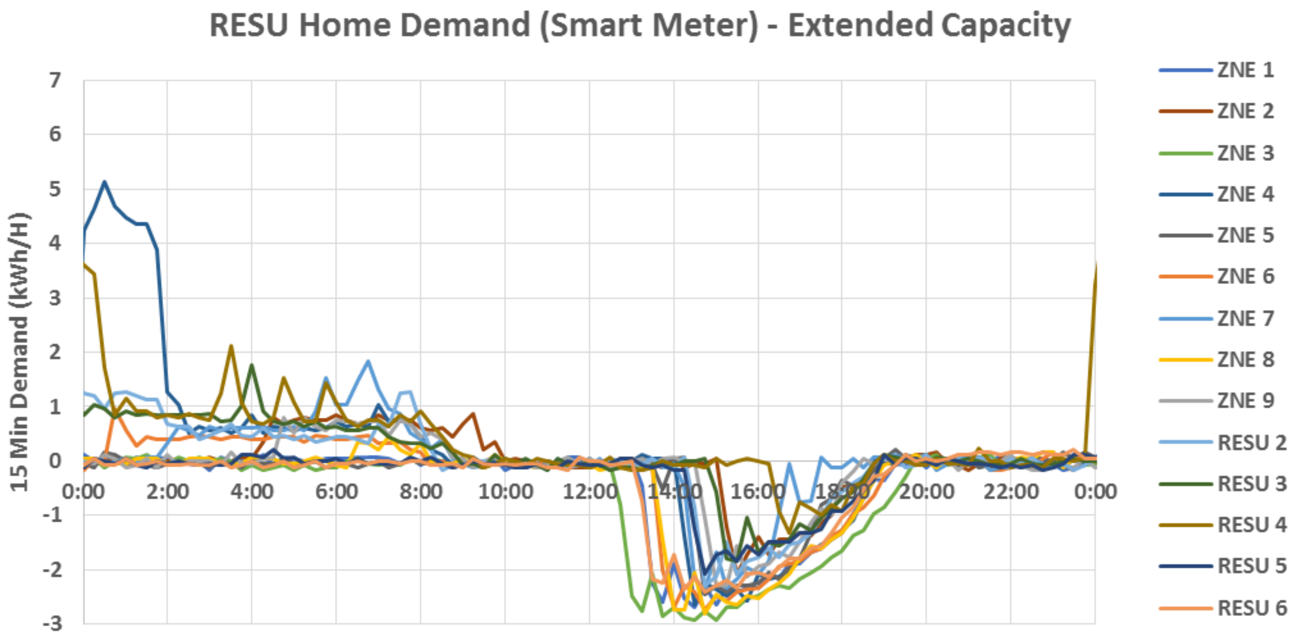


Figure 112: RESU Home Demand (2015 Test)



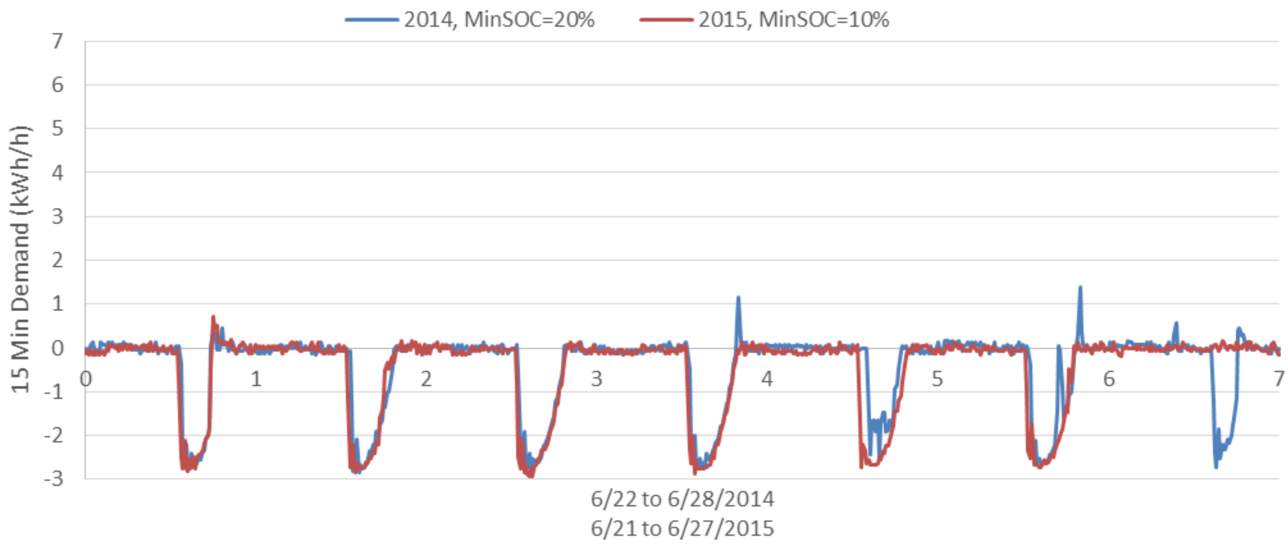
As seen in **Figure 111**, several of the homes have noticeable demand during the latter half of the day, due to the RESU battery being depleted and the home drawing power from the grid. Some of the homes also have a morning spike in demand, indicating the battery was able to provide for the home's electricity needs throughout the night and partway through the morning. By comparison, in **Figure 112**, many of the homes are drawing a noticeable amount of power from the grid during the morning hours, but not during the evening hours. This may be a result of the switch to TOU rates, where lower afternoon and evening on-peak energy usage allows the RESU battery to discharge throughout the evening, but then run out of energy sometime in the morning.

Specific Home Comparisons

Results from three homes (one ZNE and two RESU) representing low, medium, and high load cases are compared between the 2014 and 2015 experiments.

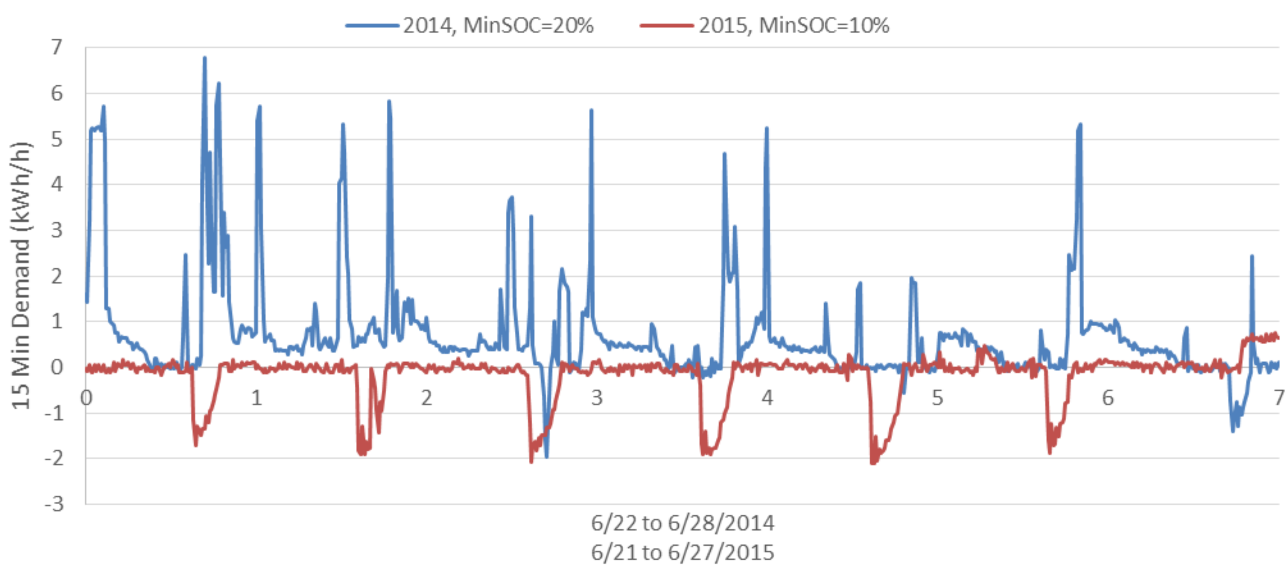
In the case of ZNE 3, which represents a low load home, the 2014 and 2015 results were similar. The home rarely drew power from the grid during either test. While there were a few demand spikes in 2014, there were no noticeable demand spikes in 2015. This home is characterized by low energy usage, high PV generation, and relatively high PV export. The homeowner's behavior, energy efficiency measures, and RESU performance combine to minimize the home's need to from draw power from the grid.

Figure 113: ZNE 3 Demand Comparison under Two PV Capture Tests



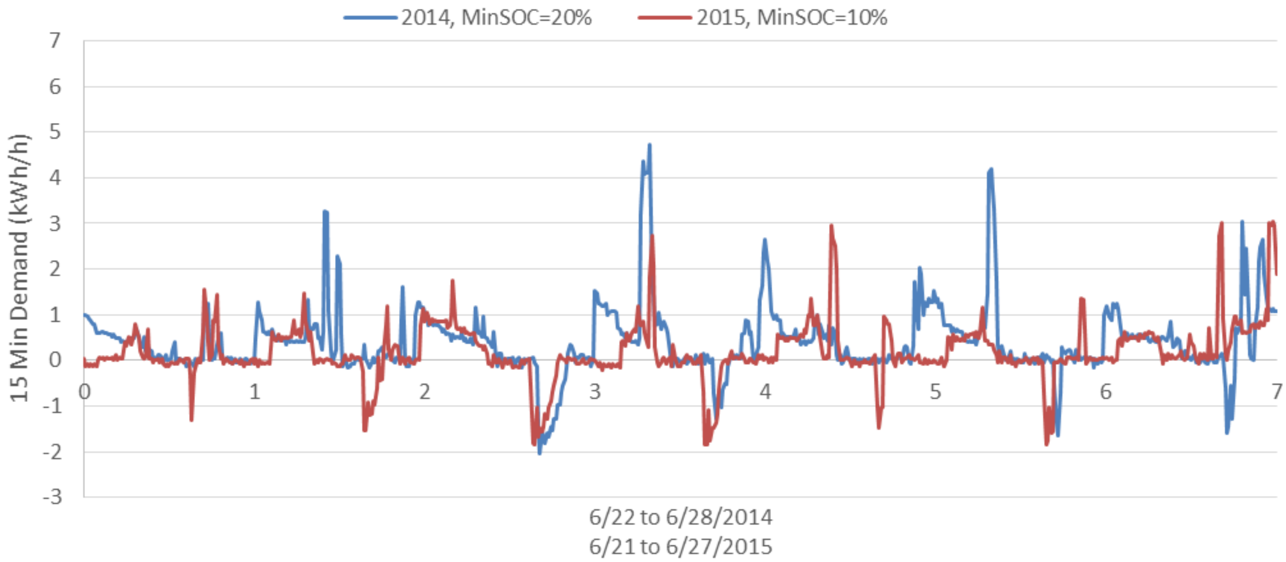
RESU 5, which represents a medium load home, experienced significant demand spikes in 2014 and periods of grid power usage throughout the experiment period. In contrast, in 2015 this home experienced no demand spikes and almost no grid power use. In 2014, the home nearly always drew power from the grid. While the RESU had marginally greater operating capacity in the 2015 experiment, most of this difference was likely also due to behavioral changes of the home's occupants. As it was the beginning of summer, it is possible that some of the occupants had left for vacation.

Figure 114: RESU 5 Demand Comparison under Two PV Capture Tests



RESU 3, which represents a high load home, experienced a marked difference between the 2014 and 2015. In 2014, this home experienced significant daily spikes in demand and long periods of grid power usage. By comparison, 2015 had a similar demand profile but the spikes were noticeably lower.

Figure 115: RESU 3 Demand Comparison under Two PV Capture Tests



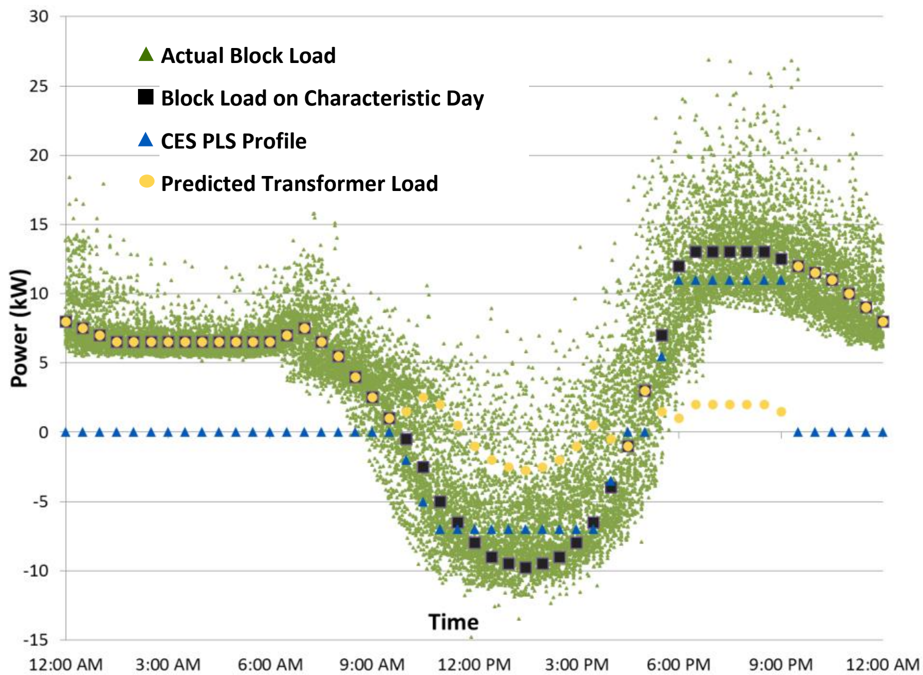
Field Experiment 1E: CES Permanent Load Shifting

Test 1: CES Custom (PV) Permanent Load Shifting (November 18, 2013 to January 13, 2014)

The purpose of this test was to evaluate the ability of the CES to shave demand on the distribution transformer by charging during periods of excess local PV generation and discharging during periods of maximum home electricity use.

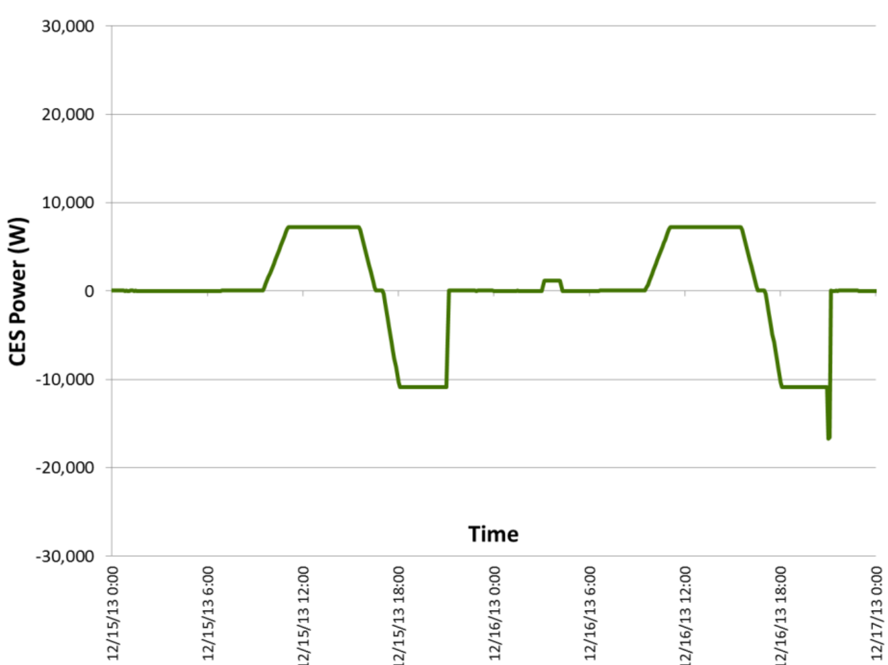
To construct the CES charge/discharge schedule, the team analyzed the load on the CES Block between September 1, 2013 and November 15, 2013. The hourly load for each day within this period is plotted in **Figure 116** below (identified by the green triangles). The team used this hourly load data to create a characteristic load curve for this block (identified by the black squares). The team then designed a CES charge/discharge profile (CES PLS profile) with the goal of reducing the variation in load on the transformer by minimizing both PV export and peak evening demand. The blue triangles identify the CES PLS profile, and the yellow circles identify the resulting predicted transformer load profile. By charging the CES during periods of excess solar PV generation and discharging when energy use peaks in the early evening, the CES should reduce the peak transformer load during the early evening.

Figure 116: PV CES PLS Profile



The CES charged and discharged daily throughout the test period, following the CES PLS profile as expected. **Figure 94** shows the actual CES charge/discharge behavior for December 15 and 16, 2013. While the CES behaved ideally on December 15, 2013, the team observed two abnormalities on December 16, 2013: a small charge period at approximately 3:00 am and a spike in discharge at the end of the discharge period. These abnormalities occurred many times throughout the test period. The project team is still evaluating the cause of this behavior. The team is also assessing the impact on the residential transformer.

Figure 117: CES PLS Power Profile



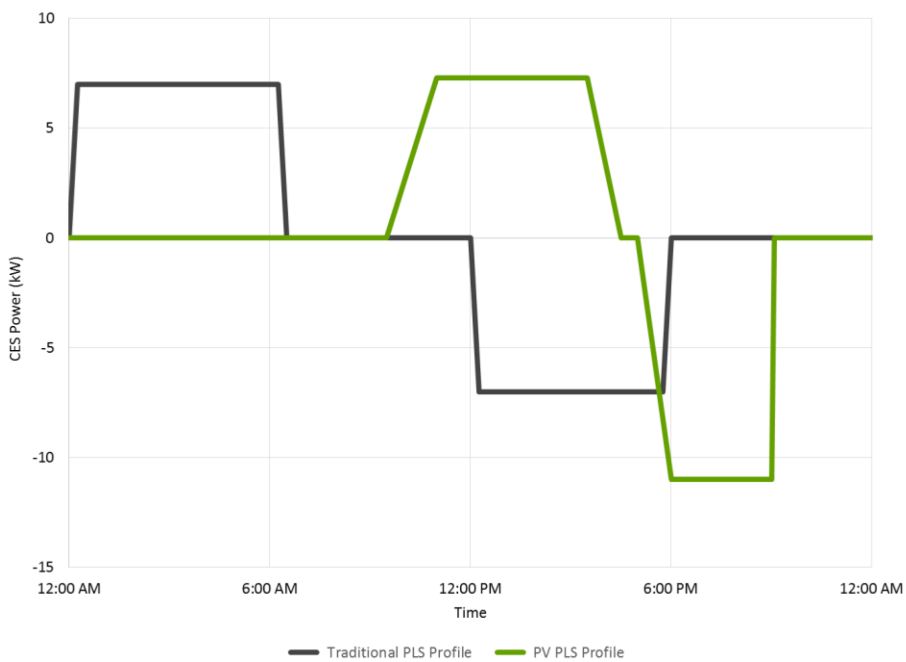
Test 2a: CES Traditional Permanent Load Shifting (January 13, 2014 to September 20, 2014)

The purpose of this test was to evaluate the ability of the CES to operate in a Traditional Permanent Load Shifting (PLS) capacity over an 8-month test period. The CES was programmed to follow a consistent schedule, charging during traditionally off-peak nighttime hours (between 12:15 am and 6:15 am) and discharging during traditionally on-peak afternoon hours (between 12:15 pm and 5:45 pm). This differed from the initial PLS test summarized in the first TPR. The initial PLS test was custom designed to charge the CES during periods when solar PV output was highest, and then discharge during periods of maximum home electricity use—typically in the late afternoon and early evening. Operating the CES using the Traditional PLS schedule should also impact the load profile of the CES Block transformer.

The team performed this test between January 13, 2014 and September 20, 2014. The load shifting profile was programmed into the Distributed Energy Manager (DEM), which controls the CES device via DNP3 using a 4G radio connection. Once the team programmed the profile in the DEM, the DEM automatically controlled the CES throughout the duration of the test.

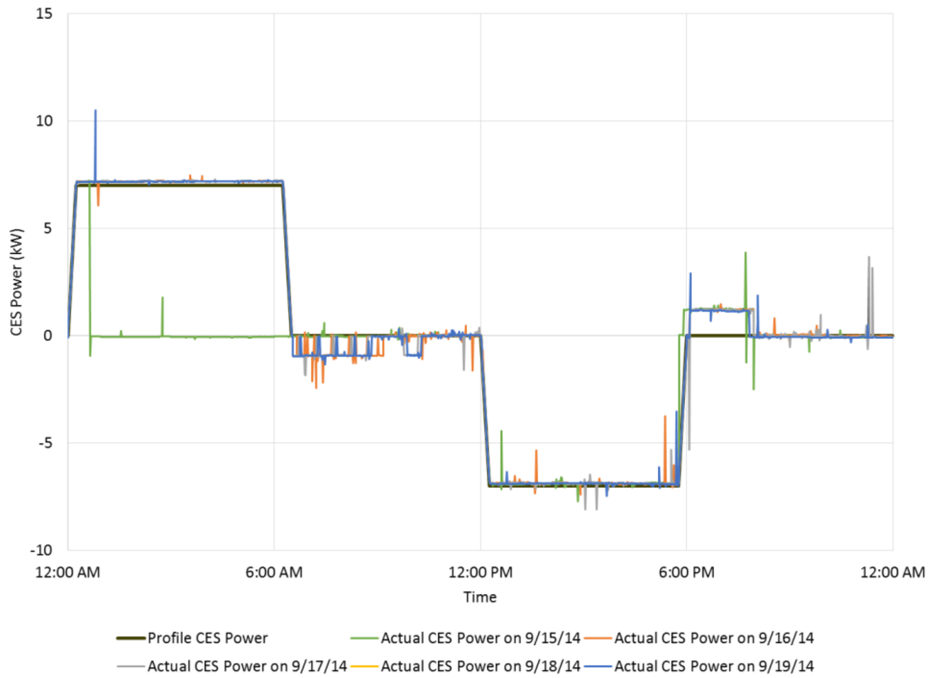
Figure 118 summarizes the PLS profiles that the team designed and used for both PV PLS test (performed for the first TPR) and the Traditional PLS test.

Figure 118: CES Permanent Load Shifting Profiles



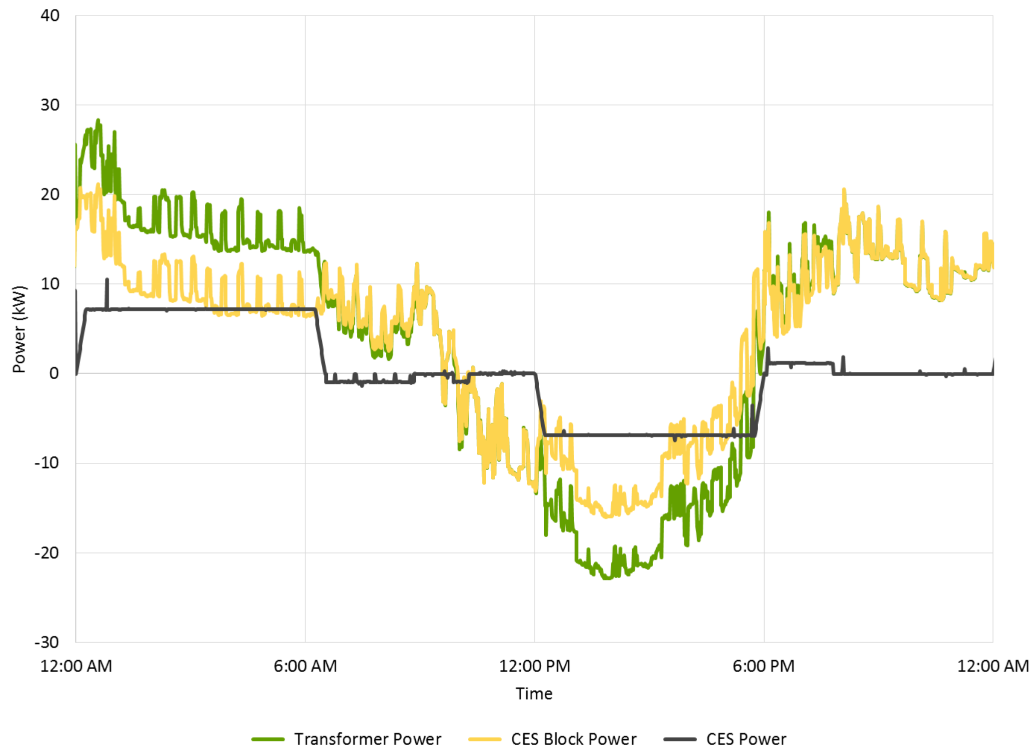
The CES charged and discharged in a manner consistent with the Traditional PLS schedule throughout the entire experiment period. The CES performed maintenance charges whenever it finished a discharge, and it performed maintenance discharges whenever it finished a charge. The purpose of the maintenance charges is to bring the CES SOC to within the thresholds configured within the CES. **Figure 119** summarizes the Traditional PLS schedule and the charge and discharge profiles for the week of September 15, 2014.

Figure 119: Measured CES Power Versus PLS Profile



The Traditional PLS profile actually added to the transformer loading both when the CES charged and when it discharged. By charging during the early morning hours, the CES added to the transformer loading, and by discharging in the afternoon hours, it added to the solar PV generation that was flowing back through the transformer. The Traditional PLS profile, therefore, caused the CES to place more strain on the distribution transformer. **Figure 120** summarizes the measured load of the CES, the CES Block transformer and CES Block load profiles for September 19, 2014. The first PLS test that the ISGD team performed (summarized in TPR #1) had the opposite impact on the distribution transformer. In that test, the CES charged when solar PV output was highest, which reduced the back feeding through the transformer. Likewise, the CES discharged when household energy use was highest, which also reduced transformer loading.

Figure 120: Load Profiles of CES, CES Block Transformer, and CES Block Load (September 19, 2014)



Test 2b: CES Traditional Permanent Load Shifting (September 21, 2014 to January 27, 2015)

Overview

The purpose of this test was to evaluate the effectiveness of using a time-based traditional PLS profile on the CES.

Experiment Steps

The experiment was conducted as specified in the ISGD CES Load Shifting Tailboard. This test was still in progress when TPR 2 was written. TPR 2 covered the PLS testing up until 9/20/14. This document covers the PLS testing conducted between 9/21/14 and 1/27/15. The minimum SOC of the CES was set to 20% throughout the test period.

Results

The CES performed the schedule as expected. Monday through Friday, the CES charged between 12:00 am and 6:30, and discharged between 12:00 and 6:00. **Figure 121** shows the Profile CES Power that was programmed on the same axis as the CES Power measured on 1/6/15. The CES charged at a slightly higher power than what the profile called for (7.2 kW rather than 7 kW). The CES also performed several maintenance charges and discharges in between the scheduled charges and discharges to maintain its SOC.

The CES neighborhood load profile is unique because the peak load occurs in the evening and there is an abundance of generation during the day. The Traditional PLS profile was designed with the assumption that peak load would occur during the afternoon, and the load would be at its lowest in the evening. As a result, the CES discharges while there is excess generation from the neighborhood's PV generation, and the CES charges in the evening, when the neighborhood's load is at its highest. Instead of relieving the transformer during peak times, enabling Traditional PLS in the CES actually exposed the neighborhood transformer to higher power levels (and as a result, higher currents) that it would have been exposed to without Traditional PLS enabled. **Figure 122** shows the Grid Power, Load Power, and CES

Power for the week of 1/5/15. Notice that the Grid Power increased while the CES charged. The power being pushed back to the grid also increased whenever the CES discharged.

Figure 121: The Profile CES Power and the Measured CES Power on January 1, 2015

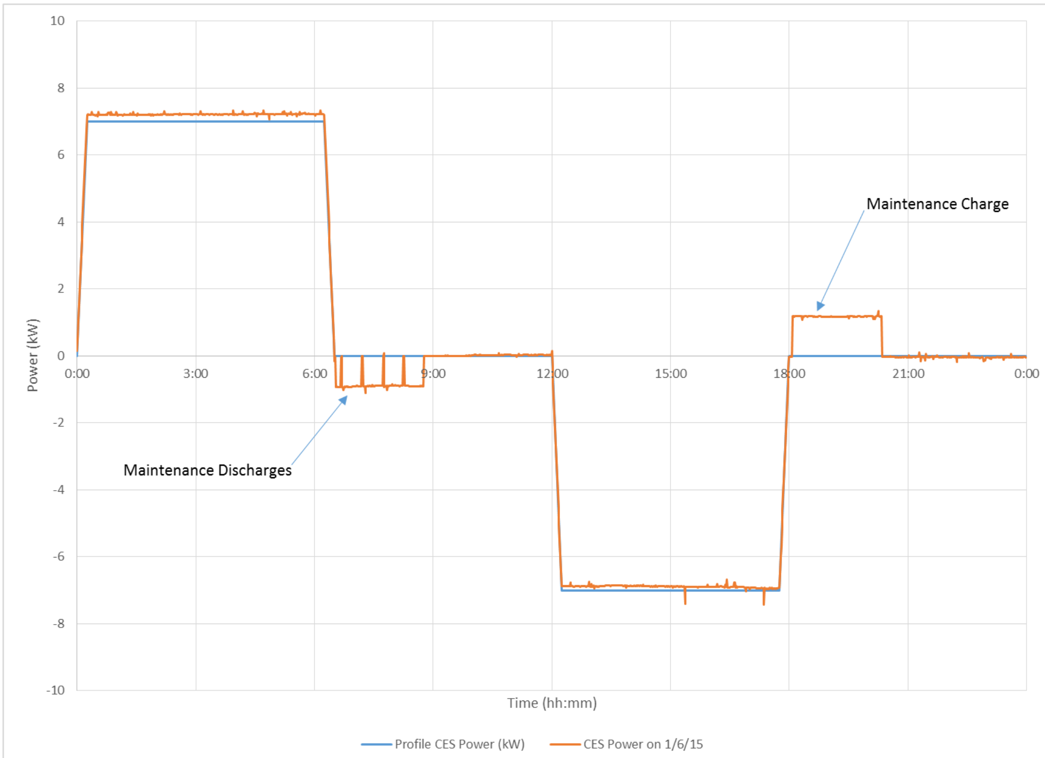
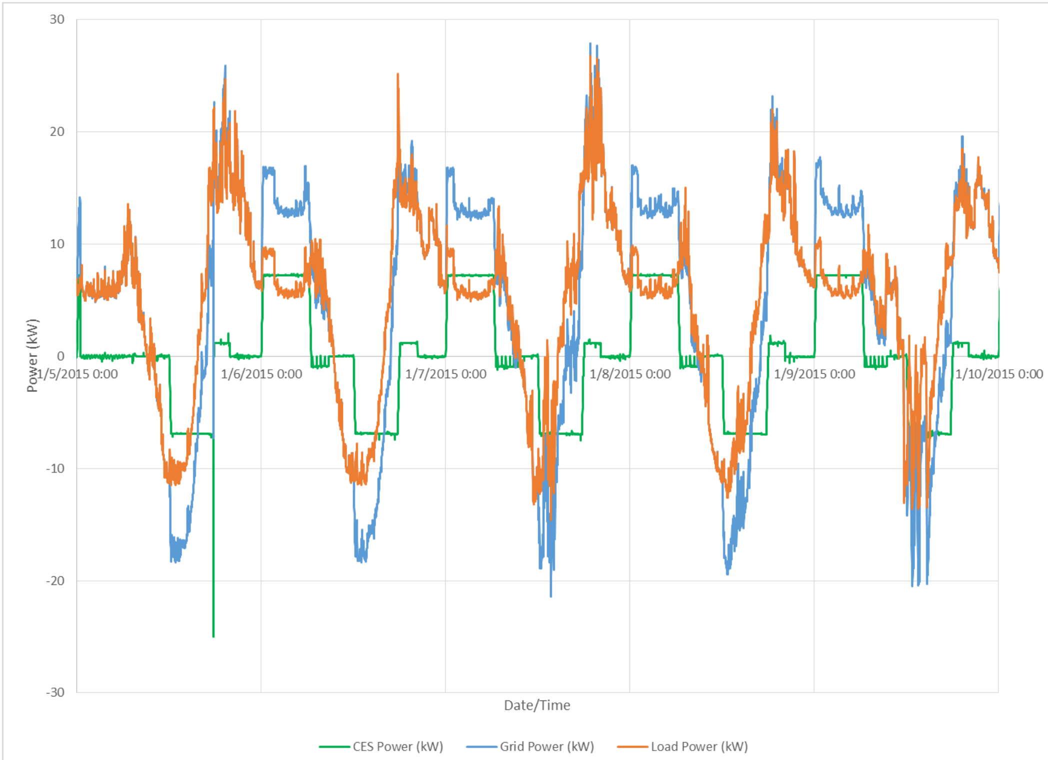


Figure 122: CES Power, Grid Power, and Load Power for the week of January 5, 2015

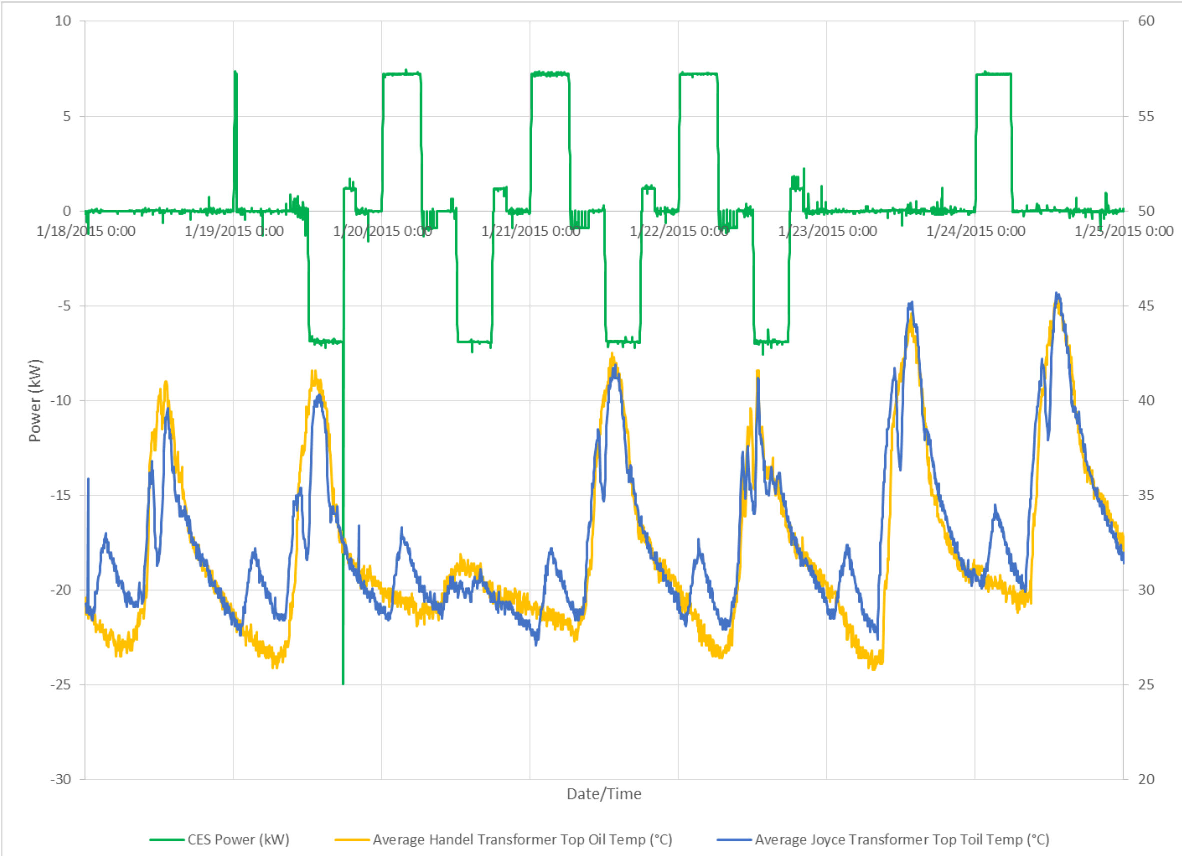


**Note: For this report, a positive grid power indicates that the grid is providing power to the CES and the loads while a negative power indicates that the CES and loads are a net generator. A positive CES Power indicates that the CES is charging while a negative CES power indicates that the CES is discharging. A positive Load Power indicates that neighborhood is consuming power while a negative Load Power indicates that the neighborhood is generating power.

The higher currents that the transformer is exposed to as a result of traditional PLS would normally be a concern because they have the potential to load the transformer and increase its temperature. However, the transformer in the CES neighborhood was upgraded from a 50 kVA transformer to a 100 kVA transformer. The CES is also programmed so that it does not add any additional load or generation that would cause the Grid Power to go over 25 kVA (load or generation), regardless of the schedule that it is running. That means that unless the neighborhood load goes above 25 kVA, the loading on the transformer would not go above 25%.

Figure 123 shows the CES power, and the average oil temperature for the CES transformer, and the ZNE Block transformer for the week of 1/18/15. In general, the average CES and ZNE transformer temperatures are similar to one another when the loading on both transformers is low. However, the ZNE transformer services a neighborhood with several RESUs performing Traditional PLS as well. The RESU PLS profiles are not exactly the same as the CES PLS profile, but they have the same effect: they load the transformer more than if the PLS was disabled. Unlike the CES Block transformer, the ZNE transformer is only rated at 50 kVA. The loading on the ZNE transformer while the RESUs were performing PLS got as high as 70% the transformer rating. **Figure 123** shows that the ZNE transformer temperatures increased because of the additional loading while the CES did not. If the CES Transformer was not upgraded, and remained at 50 kVA, the loading on the transformer could potentially have reached 50%, and the CES Block transformer temperature could have exhibited characteristics similar to the ZNE transformer temperature.

Figure 123: CES Power, and Average Oil Temperature of Both Windings for the CES and ZNE Transformers the Week of January 18, 2015



Impacts & Lessons Learned

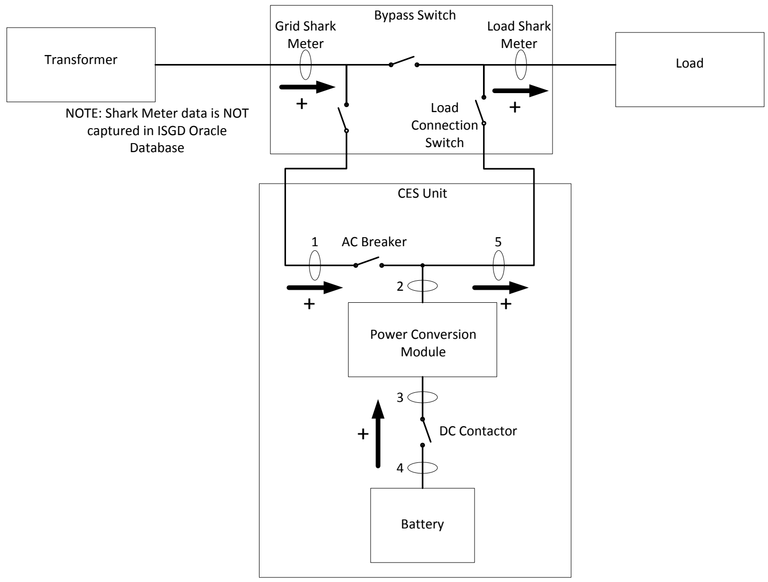
Traditional PLS was supposed to decrease the load on the transformer. In this particular case, implementing Traditional PLS did the opposite. Since the transformer in the CES neighborhood was upgraded, the extra loading on the transformer did not significantly impact the transformer temperature. Implementing PLS would be better suited for a neighborhood that does not have excess solar generation throughout the day. If the CES had enough capacity, it could potentially defer a transformer upgrade. If the CES is installed in a neighborhood with a high capacity transformer (like the neighborhood that the CES is currently installed in), it can potentially load-shift upstream – meaning that even though it increases load on its own transformer, it decreases the load somewhere upstream.

Test 3: CES Islanding Test

Part I: Preparation for CES Islanding Test

When the ISGD team commissioned the CES in June 2013, they configured it to operate in parallel with the distribution transformer by closing the bypass switch for the CES. In this configuration, the distribution transformer would provide service to the customers residing on the CES block. In the event of an outage, these customers would experience a service interruption since the bypassed CES could not isolate the loads from the grid by opening its ac breaker. In this configuration, the CES would see and respond to grid outages by ceasing to charge or discharge, but it could not provide power to the homes in the neighborhood.

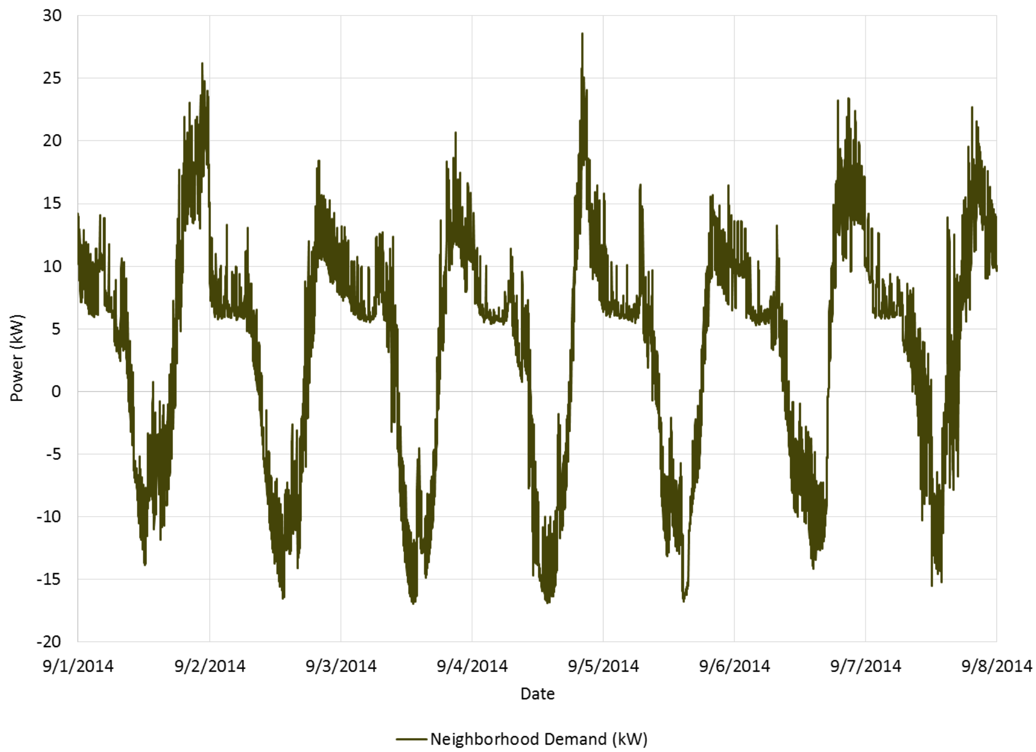
Figure 124: CES One Line Diagram



To allow the CES to service the neighborhood, the CES's load connection switch would need to be closed and the bypass switch opened. **Figure 124** shows the electrical configuration of the CES. The CES would then be able to supply power to the homes in the neighborhood in the event of a grid outage. To avoid any unexpected issues that would arise in the actual islanding test, the ISGD team monitored the load characteristics of the neighborhood and the CES's behavior during grid events.

The CES Block load profile follows the same basic trend every week. In general, the neighborhood experiences loading that exceeds 10 kW between 4:00 pm and 1:00 am, and solar PV generation that exceeds 10 kW between 9:00 am and 4:00 pm. **Figure 125** summarizes this profile over a typical week.

Figure 125: CES Block Load Profile (Week of September 1, 2014)



The utility transformer can support loads as high as 100 kVA while connected. The neighborhood's demand has never exceeded 50 kVA, so the design has sufficient load throughput capacity to serve this block when grid-connected. If a grid outage causes the CES to initiate islanding, the CES can only support the neighborhood until the battery has discharged its available energy. There are three conditions that would cause the CES to trip when operating in islanded mode: (1) when the load exceeds 62.5 kVA, (2) when the load is between 25 kVA and 62.5 kVA for longer than three seconds, and (3) when the CES battery becomes fully discharged. The daily peak load of the CES Block is usually less than 25 kW, but it exceeds 25 kW at least twice a month. If the CES islands and one of these trip conditions are met, the CES would trip. It is therefore important that the CES islanding test occur when loads are likely to be within these limits.

Over a period of several months of bypassed operation, the ISGD team observed the CES's grid connection behavior to verify that it only islanded during appropriate grid events. Prior to September 10, 2014, the CES islanded at least twice a month. According to the logs generated by the CES, in all but one of those islanding events the reason the CES islanded was short (less than 160 ms) voltage sags. The ISGD team performed experiments using a replicate CES at EVTC to refine the CES's islanding settings. The new settings made the CES less sensitive to normal grid disturbances, while still maintaining compliance with SCE's Rule 21.[35]

On September 10, 2014, the team performed a firmware update on the CES and applied the new islanding condition settings. Since applying these new settings, the team detected two voltage sag events that would have caused the CES to island if the team had not updated the settings. Instead of islanding, the CES rode through these short voltage sag events. However, the CES has also islanded unnecessarily on one occasion. This improvement was judged sufficient for islanding tests of modest duration.

Part II: Actual Islanding Tests

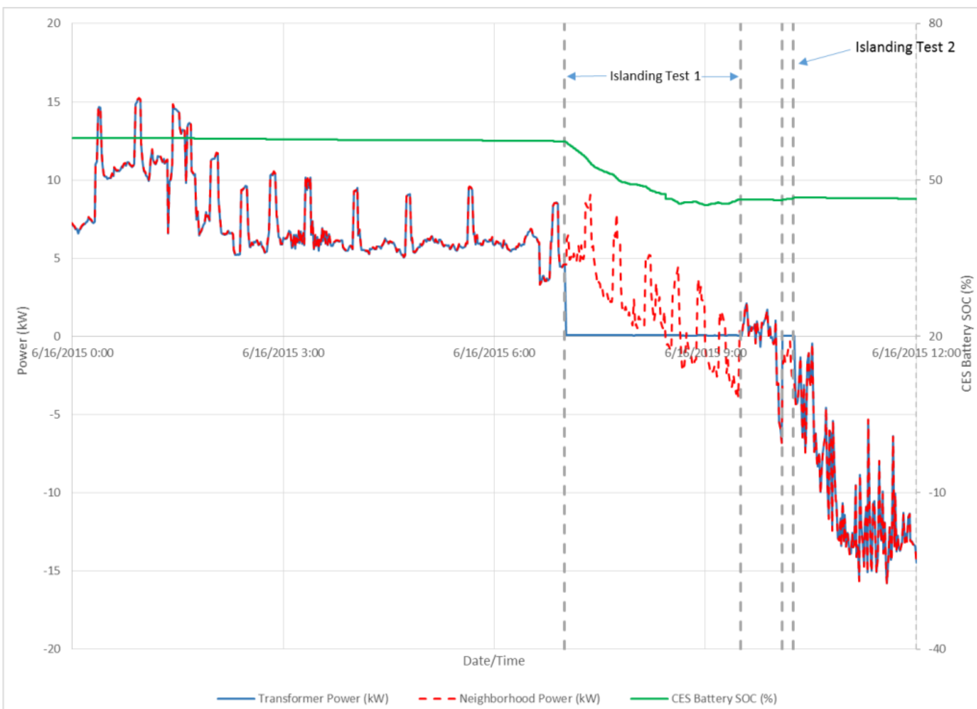
[35] Rule 21 specifies the disconnection time requirements for grid events such as under/over voltages and frequency excursions for generating facility interconnections to SCE's distribution system.

The objective of this experiment was to validate the CES's ability to island, and support the neighborhood that it was servicing. The test validated the transition to islanding under two different scenarios: when the neighborhood was consuming power, and when the neighborhood was generating power. The CES was also tested to verify that it was able to handle the neighborhood transitioning from net load to net generator (and vice versa) in the islanded mode.

Results

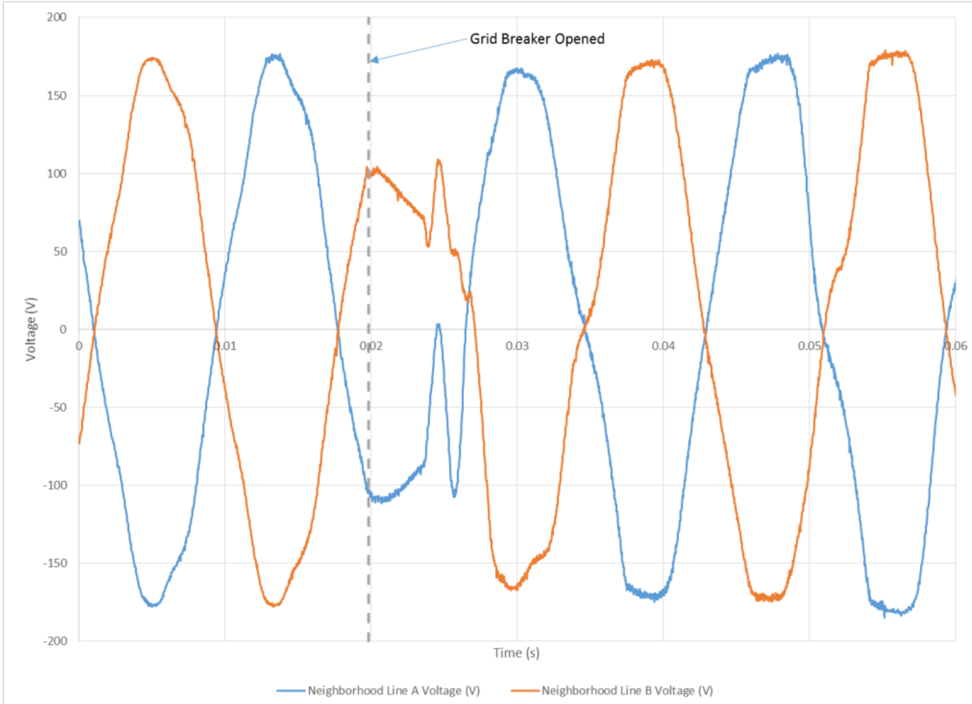
On 6/16/15, the experiment commanded the CES to initiate islanding from 7:00 a.m. to 9:30 a.m., and from 10:05 a.m. to 10:15 a.m. Both times the CES was commanded to island, it successfully opened its Grid AC Breaker and supported the neighborhood by itself. **Figure 126** shows the Transformer Power, Neighborhood Power, and CES Battery SOC from 12:00 a.m. to 12:00 p.m. on the day of the test. At 7:00 a.m., the CES initiated islanding. Transformer Power dropped to 0 kW while the CES supported all the neighborhood load. The CES supported the neighborhood until islanding was commanded to end at 9:30 a.m. For the first islanding test, the CES initiated islanding while the neighborhood was a net load. The neighborhood power switched from positive to negative (consuming power to generating power) and vice versa several times during this time period. The CES did not have any issues with the transitions. At 10:05, the CES was commanded to initiate islanding while the neighborhood was generating power. The CES initiated islanding successfully, and was allowed to remain in islanded mode for ten minutes. The CES Battery SOC throughout the day indicates that the CES could have supported the neighborhood for longer than the duration of the test.

Figure 126: Transformer Power, Neighborhood Power, and CES Battery SOC for June 16, 2015



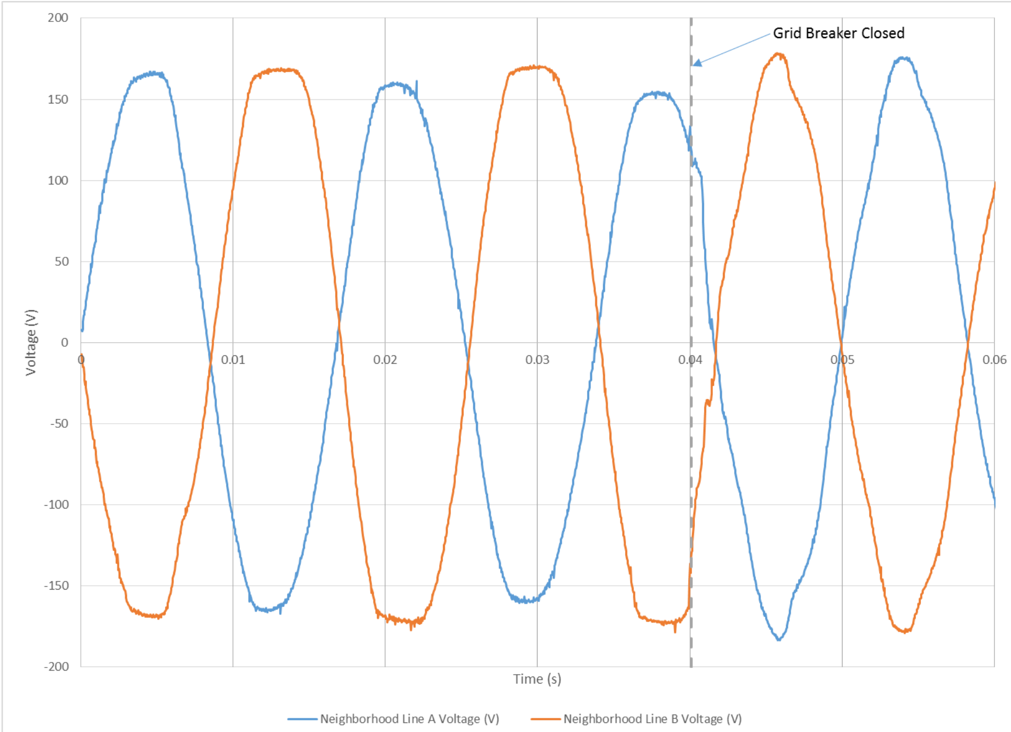
When the CES initiates islanding, it disconnects itself (and the neighborhood) from the transformer by opening its Grid AC Breaker. At the same time, the CES inverter begins supporting the neighborhood. The transition is not completely seamless. There was a voltage transient for about ½ cycle in the CES output voltage when the CES initiated islanding. **Figure 127** shows the Neighborhood Line Voltages when the CES first initiated islanding at 7:00 a.m.

Figure 127: Neighborhood Line Voltages when CES Islanded at 7:00 am on June 16, 2015



When the CES stops islanding, it closes its Grid Breaker and transfers the neighborhood load to the grid. For both Islanding Tests, the voltage transients when the CES closed its grid circuit breaker were smaller than when the CES opened its grid circuit breaker. **Figure 128** shows the Neighborhood Line Voltages when the CES exited Islanding Mode at the end of the first islanding test.

Figure 128: Neighborhood Line Voltages when the CES Disabled Islanding Mode after the First Islanding Test



The Voltage Total Harmonic Distortion (THD) in the neighborhood significantly increased while the CES was in Islanded Mode. **Figure 129** shows the THD measured at CES 8 between 6/15/15 and 6/17/15. The Voltage THD did not exceed 4% the day before or after the test. On the day of the test (6/16/15), the THD significantly increased, and almost reached 10% at one point. **Figure 130** shows the Voltage THD for CES 8 on the day of the Islanding Test from midnight to 12:00 pm.

Figure 129: THD at CES 8 from June 15 to June 17, 2015

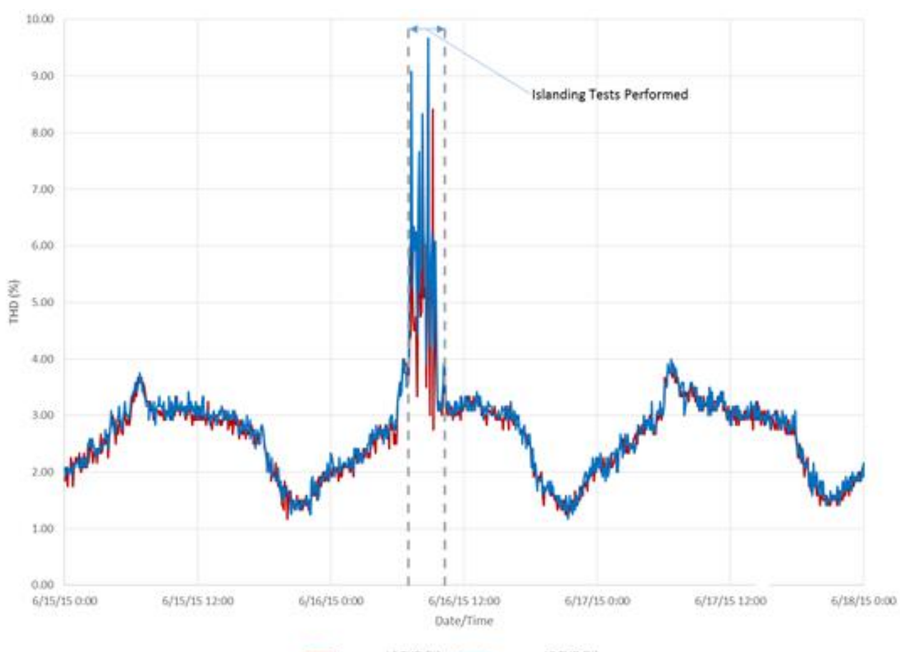


Figure 130: THD at CES 8 from midnight to 12:00 pm on June 16, 2015

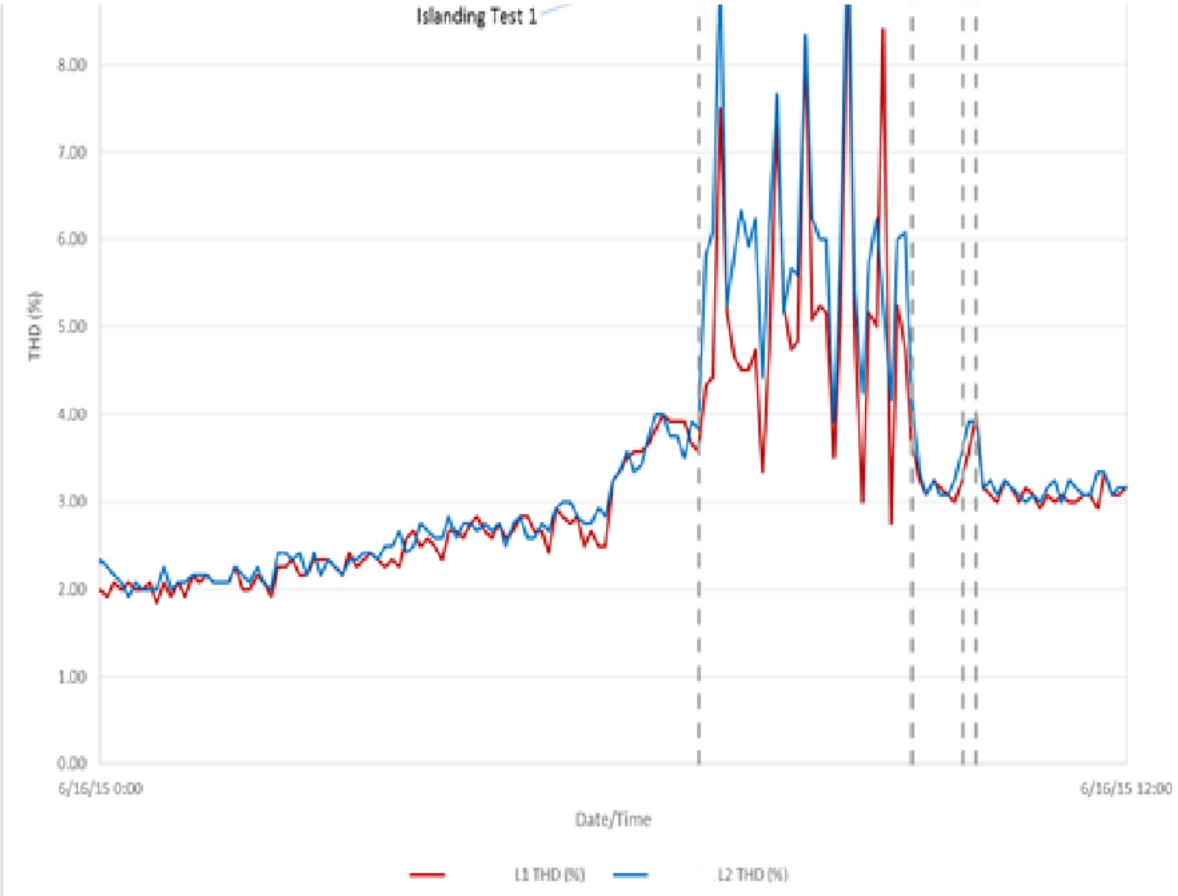


Table 52 shows the maximum THD measured at each monitored house while the CES was in Islanded Mode. CES 2 experienced the largest THD out of all the houses. Line 2 of CES 2 experienced a maximum THD of 15.67% while the CES was in islanded mode.

Table 52: Maximum THD while CES in Islanding Mode

House	Line 1 Max Voltage THD (%)	Line 2 Max Voltage THD (%)
CES 1	9.92	9.17
CES 2	12.25	15.67
CES 3	8.25	10.08
CES 4	9.25	11.7
CES 5	10.08	7.92
CES 6	10.33	8.75
CES 7	9.25	11.6

Because the CES uses its power electronics to provide the “grid” to the neighborhood, it is not as stiff as an actual grid, and the THD is impacted by the power quality of the actual load. In addition, the timeframe in which the Islanding Test was performed coincides with a time period in which the THD is normally high. **Figure 129** shows that CES 8 THD normally peaks at around 6:45 am, but remains relatively high until around 6:00 pm. This trend is true for all houses. Not only was the CES grid weaker than a real grid, but the test was performed during a timeslot in which the characteristic THD of the neighborhood even when connected to the real grid, was at its highest (when compared to the rest of the day).

Impacts & Lessons Learned

Although devices such as the CES have the capability to act as a backup for a neighborhood, if the resulting THD as seen by the neighborhood is too high, the CES has the potential to damage customer equipment.

The limitations due to battery size can potentially be an issue if a CES device is forced to island for longer than a few hours. Due to the large amount of solar generation in the neighborhood, the CES's batteries could have reached 100% SOC if the test was extended for the whole day. To maintain maximum ability to supply a neighborhood with power, a solution would be to develop a control scheme that would allow the CES to shave load or generation in the neighborhood.

Test 4: Load Limiting

Objectives

The objective of this experiment was to validate the CES's ability to limit the load and generation at the secondary of the distribution transformer that is servicing the neighborhood.

Experiment Steps

The experiment was conducted as specified in the Load Limiting ISGD Field Experiment Tailboard. The CES was commanded to enable load limiting between March 3 and April 6, 2015. The maximum load was set at 10 kW, and the maximum generation was set to 4 kW.

Results

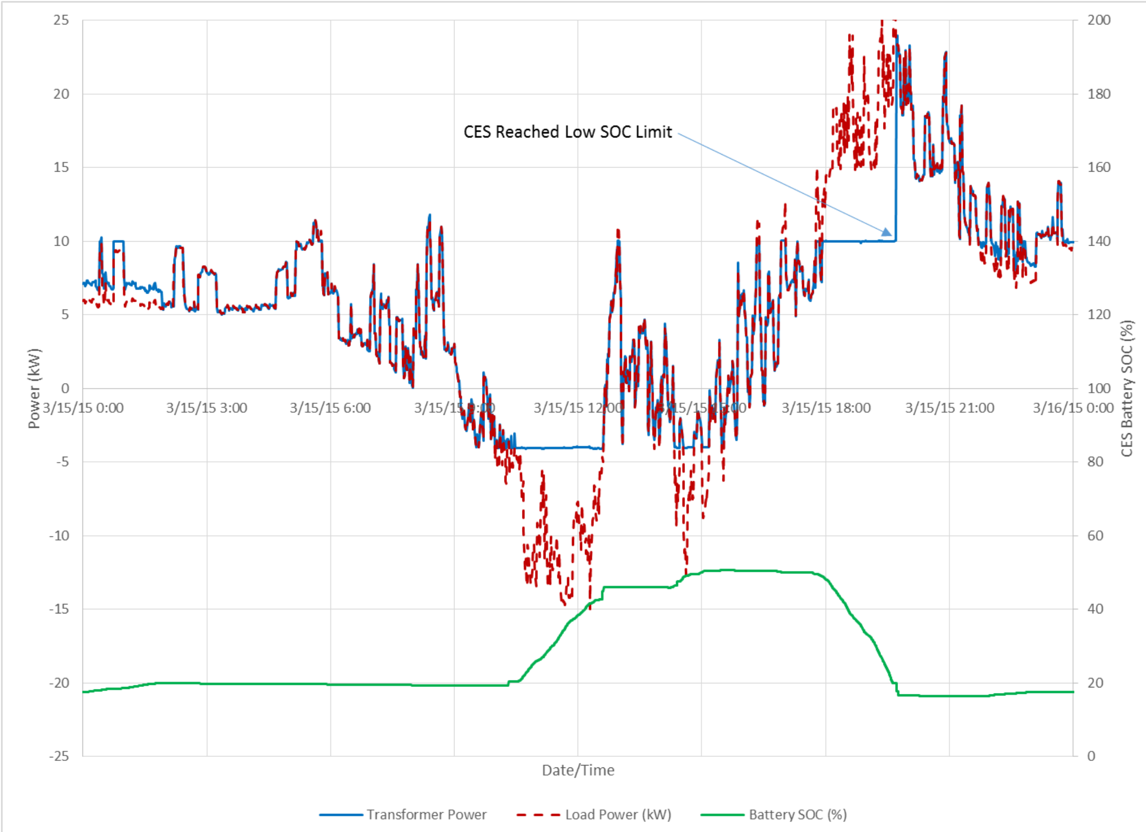
The CES was effective at limiting the transformer load as long as its battery had enough capacity. When the neighborhood load exceeded 10 kW, the CES discharged its battery and provided enough power to keep the transformer load at 10 kW. When the neighborhood generation exceeded 4 kW, the CES charged its battery so that the transformer did not see more than 4 kW of generation.

Figure 131: Transformer Power, Load Power, and CES Power on March 8, 2015

*Note: For this document, a positive CES power indicates that the CES is charging, and a negative CES power indicates that the CES is discharging. A positive transformer power indicates that the transformer is providing power, while a negative transformer power indicates that the transformer is receiving power. Finally, a positive load power indicates that the neighborhood is acting as a load, while a negative load power indicates that the neighborhood is generating power.

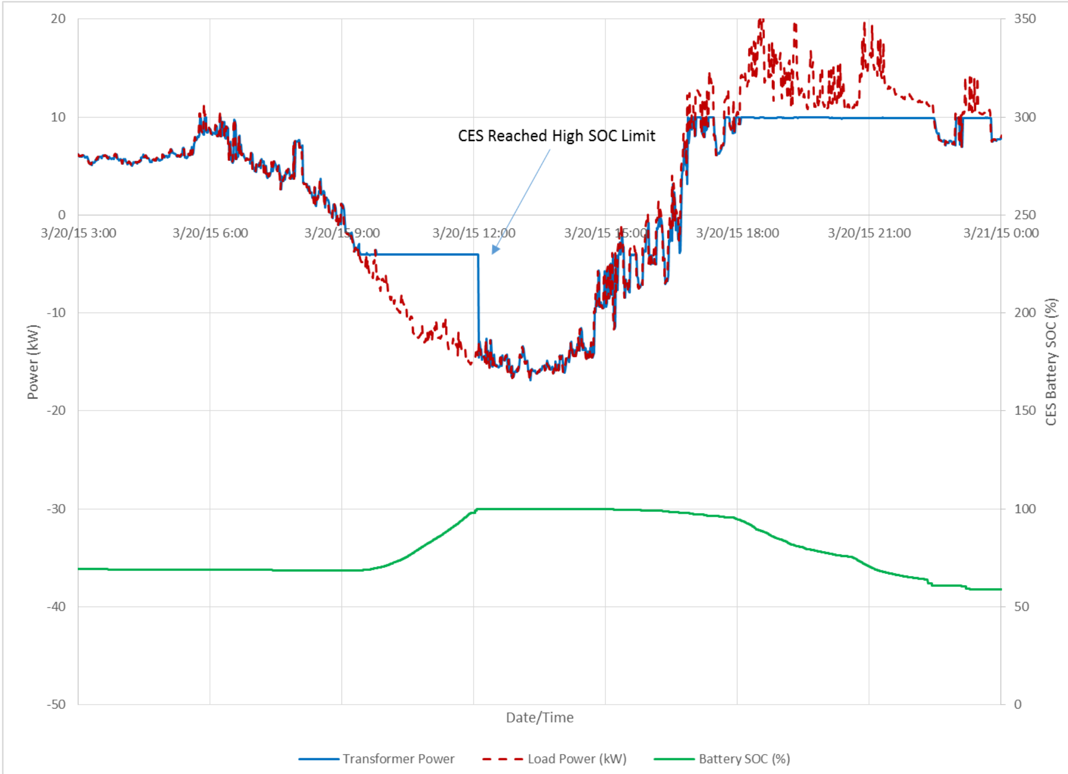
The CES kept the transformer load within the programmed limits for as long as the CES's battery had enough capacity. Because the programmed power limits were static and the neighborhood load changed from day to day, the CES did not always have enough capacity to support the excess load or generation throughout the day. Figure 109 shows the Transformer Power, Load Power, and Battery SOC on 3/15/15. The generation throughout the day was not enough to charge the battery back to 100% SOC. In the evening, the CES limited the Transformer Load to 10 kW until it reached its Low SOC limit of 20%. Once the CES reached its Low SOC Limit, the CES was no longer able to offset the load in excess of 10 kW; the transformer had to support all the load in the neighborhood without any assistance from the CES.

Figure 132: Transformer Power, Load Power, and Battery SOC on March 15, 2015



On March 20, 2015, the excess load during the evening did not discharge the CES battery enough to accommodate the excess generation during the day. The CES battery SOC was already almost 70% before the neighborhood started generating power. Once the CES Battery reached its High SOC Limit of 98% SOC, it stopped limiting the generation to 4 kW, and all of the power produced by the neighborhood was transferred to the transformer.

Figure 133: Transformer Power, Load Power, and Battery SOC on March 20, 2015



Load limiting is an active process and causes the CES battery to charge and discharge daily. The Weekly CES Charge Energy is defined as the amount of AC Energy absorbed by the CES every time it charges over a one-week period. The Weekly CES Discharge Energy is defined as the amount of AC Energy provided by the CES every time it discharges over a one-week period. Due to the daily variability of the neighborhood load and generation, the Weekly CES Charge and Discharge Energy varied from week to week. **Table 53** shows the Weekly CES Charge and Discharge Energy for every week that Load Limiting was enabled.

Table 53: Weekly CES Charge and Discharge Energy

Week	Weekly CES Charge Energy (kWh)	Weekly CES Discharge Energy (kWh)
3/1/2015	82.94	63.32
3/8/2015	120.49	122.74
3/15/2015	154.94	112.72
3/22/2015	170.38	142.02
3/29/2015	87.11	65.06
Total	615.86	505.86

**Note: Load Limiting was enabled on 3/3/15 and not active the whole week of 3/1/15.

Because the CES limits the transformer load, a potential benefit of the CES's load limiting feature is the ability to reduce the temperature increase due to high loads. The oil temperature in all the transformers in the neighborhood had a higher temperature than the ambient temperature. However, their temperature profiles throughout the day maintained the same general shape as the ambient temperature. (The ZNE Block transformer oil temperature has a small exception to this observation, but it will be discussed later.) **Figure 134** shows the transformer oil temperatures between February 22 and March 1, 2015 – before the CES's Load Limiting feature was enabled. **Figure 135** shows the transformer oil temperature between March 1 and March 8, 2015. Load Limiting was enabled on March 3, 2015, but the

CES Block transformer (the transformer servicing the neighborhood the CES is installed in) Oil Temperature curve maintained a shape that resembled the ambient temperature even after Load Limiting was enabled.

Figure 134: Transformer Oil Temperatures between February 22 and March 1, 2015

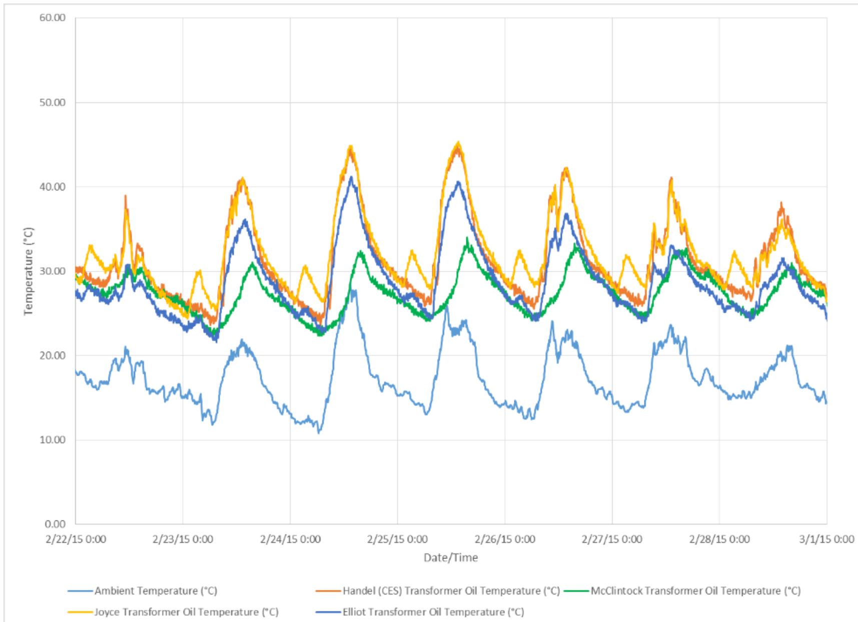
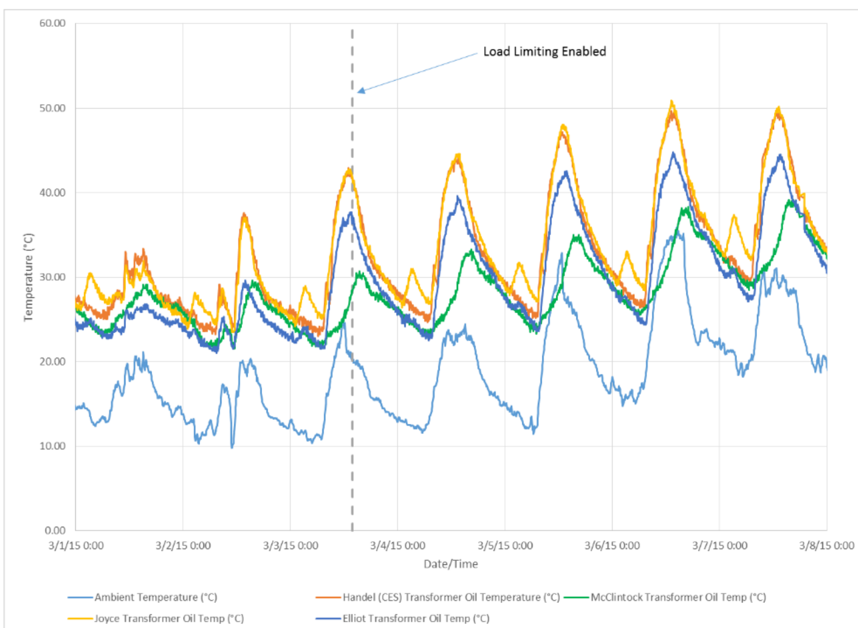


Figure 135: Transformer Oil Temperatures between March 1 and March 8, 2015



Based on **Figure 134** and **Figure 135**, the oil temperatures of the ZNE and CES Block transformers are generally within 2°C of each other. The only exception occurs between 1:00 am and 3:00 am. The RESUs in the homes serviced by the ZNE Block transformer were running a load shifting profile and the ZNE Block Transformer was at more than 70% its capacity during those hours. As a result, a temperature spike could be observed during those hours. Other than the temperature spike observed between 1:00 and 3:00 pm, the transformer oil temperature for the ZNE Block transformer was normally close to the CES Block transformer oil Temperature. **Figure 136** shows the average ambient and transformer oil temperatures for each day from February 2 and April 20, 2015. In that timeframe, the CES was in three different modes: Idle, Power Smoothing, and Load Limiting. No matter which mode the CES was in, the average daily temperature of the CES and ZNE Block transformer oil was within 2°C of each other.

Figure 136: Daily Average Transformer Oil Temperatures

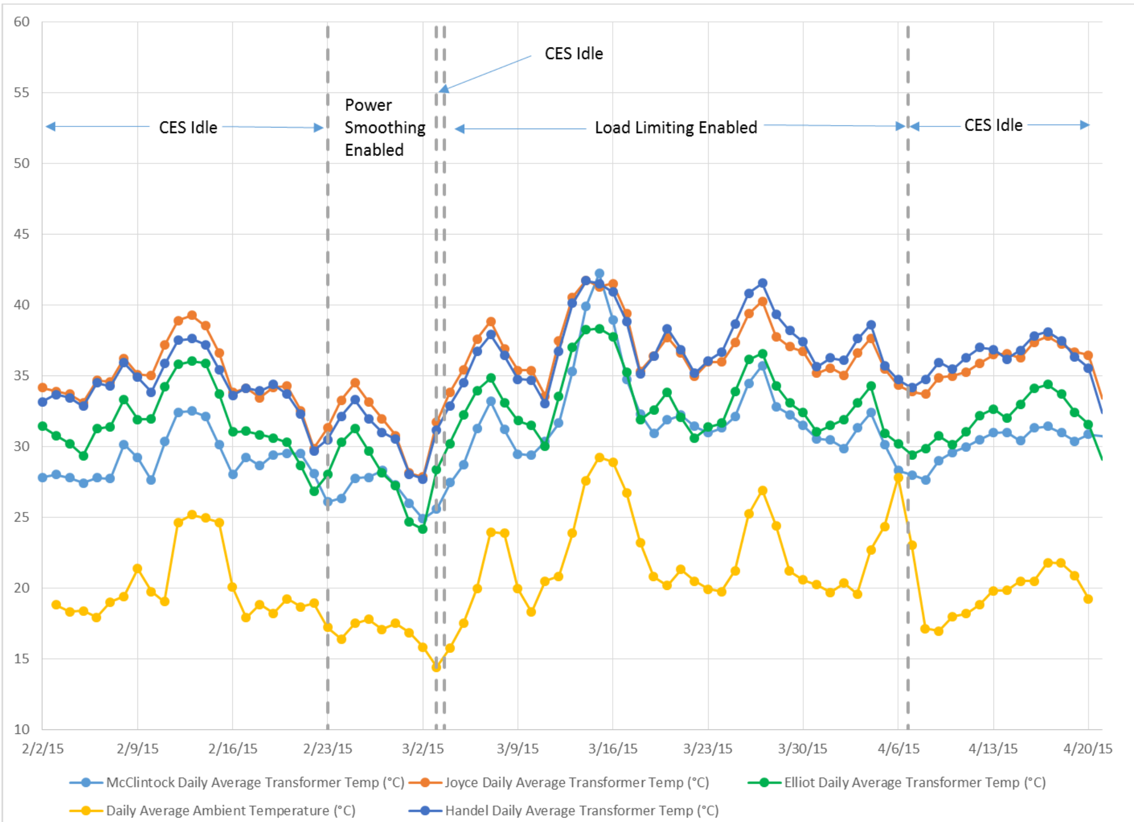


Figure 137 shows the transformer oil temperature and the loading on the ZNE and CES Block transformers as a function of their capacity. The loading is given as a percentage of full capacity because the ZNE and CES Block transformers have different ratings. The ZNE Block transformer is rated at 50 kVA, and the CES Block transformer is rated at 100 kVA. The ZNE Block transformer oil temperature increased significantly compared to the CES Block transformer oil temperature when its loading increased to greater than 70%. Once the high loading stopped, the ZNE Block transformer oil temperature plot gradually approached the CES Block oil temperature plot. The CES Block transformer did not see loading larger than 20% of its full capacity, and the overall shape of its oil temperature plot resembled the ambient temperature plot.

Figure 137: Transformer Oil Temperature and Loading of the ZNE and CES Block Transformers from March 10 to March 12, 2015

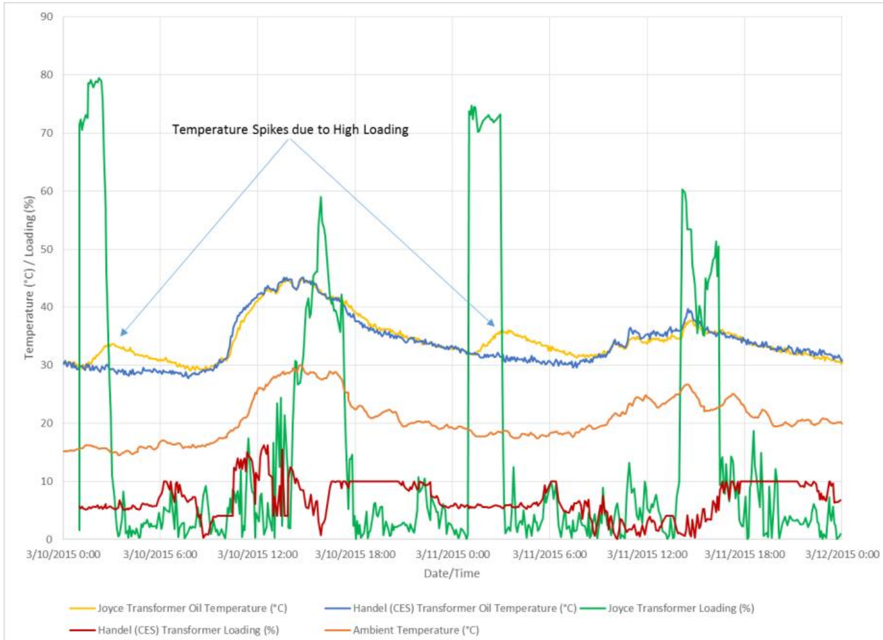


Figure 134 through **Figure 137**, indicate that unless their loading is significantly different, the CES and ZNE Block transformer oil Temperatures exhibit similar temperatures throughout the day. When the loading on the ZNE Block transformer was more than 70%, there was a measureable difference between the ZNE Block transformer oil plot and the CES Block transformer oil temperature plots. The load on the CES Block transformer has never been observed to exceed 30 kVA (30% of its full capacity.) Since the CES Block transformer is so large (100 kVA), and the loading on this transformer is relatively small compared to its full rating, there is no benefit to enabling load limiting in a neighborhood with such a high transformer rating. If the CES was installed in the same neighborhood that the ZNE Block transformer was servicing, it could have limited the loading on the transformer and potentially prevented the temperature spikes between 1:00 am and 3:00 am.

Impacts & Lessons Learned

This experiment validated the functionality of the CES's Load Limiting feature. The CES Load Limiting Feature can be used to limit the load and generation seen by a transformer. If a transformer's load regularly reaches its capacity, a CES may be used to keep the transformer from increasing its oil temperature due to the high load. This can not only extend the life of the transformer, but can also eliminate the need to upgrade a transformer. Care must be taken to ensure that the Load Limiting feature is indeed providing a benefit, such as preventing an increase in temperature due to high loading.

Test 5: Power Smoothing

Overview

The objective of the Power Smoothing Test was to validate the CES's Power Smoothing feature. The Power Smoothing feature is meant to smooth out variations in grid power due to intermittent renewable generation and unpredictable loads. Three parameters affect the Power Smoothing algorithm: The Target SOC, the KpSOC, and the Time Constant. The Target SOC is the SOC that the CES would attempt to maintain while in Power Smoothing Mode. If the CES's SOC deviates from the Target SOC, it would charge or discharge appropriately so that the CES's SOC returns to the programmed Target SOC. The KpSOC determines how aggressively the CES attempts to maintain the SOC. The Time Constant is the target time for the Grid Power to equal the Load Power when the Load Power changes. Since the Load Power is dynamic, it is not likely that the Grid Power would equal the Load Power for any length of time. The overall effect is that the Grid Power lags behind the Load Power, and short power fluctuations in the Load Power are filtered and not passed on to the Grid Power profile.

Experiment Steps

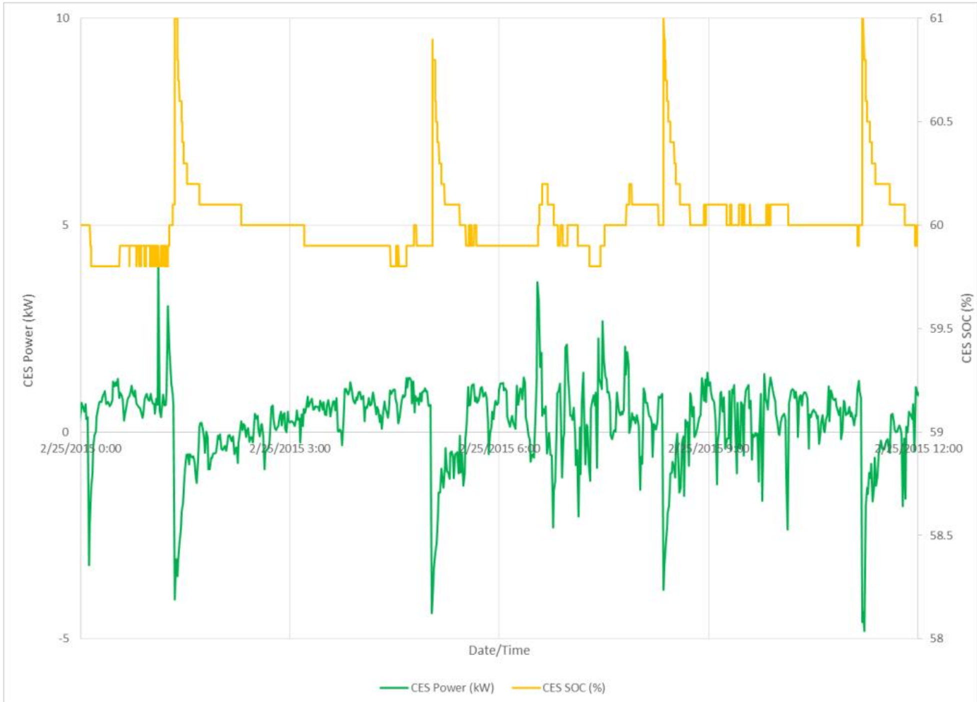
The experiment was initially performed between February 24 to March 3, 2015. A five minute time constant was used, the Target SOC was set at 60%, and the KpSOC was kept at its default value of 20 (maximum setting). The test was repeated between June 1 and June 10, 2015, because the weather forecast for the week of June 1, 2015 indicated cloudy weather and thus variable solar output such that the benefits of the Power Smoothing feature could be better studied.

Results

On a typical non-cloudy day, (when PV generation was relatively stable), the CES smoothed out most of the small power variations from the neighborhood and the Grid Power took more time to ramp up and ramp down than if Power Smoothing was not active. However, there were times in which the CES caused the Grid Power to spike. **Figure 138** shows the Grid and Load Power for a sunny day (February 2, 2015). **Figure 138** shows the Grid and Load Power between 12:00 am and 12:00 pm on February 25, 2015. The magnitude of the grid power spikes were around 5 kW in addition to the base load. The spikes were generally larger than the variations in the load power that were being smoothed out. The reason the power spikes occurred was because the CES was trying to maintain the 60% Target SOC and because KpSOC was left at its default maximum value. As the CES charged and discharged to smooth out the Grid Power, the CES SOC changed. Once the SOC deviated too much from 60%, the CES charged or discharged to maintain the 60% SOC. **Figure 139** shows the CES Power and SOC for the same time period shown in **Figure 138**.

Figure 138: Grid Power and Load Power on February 25, 2015 from 12:00 am to 12:00 pm

Figure 139: CES Power and CES SOC on February 25, 2015 between 12:00 am and 12:00 pm

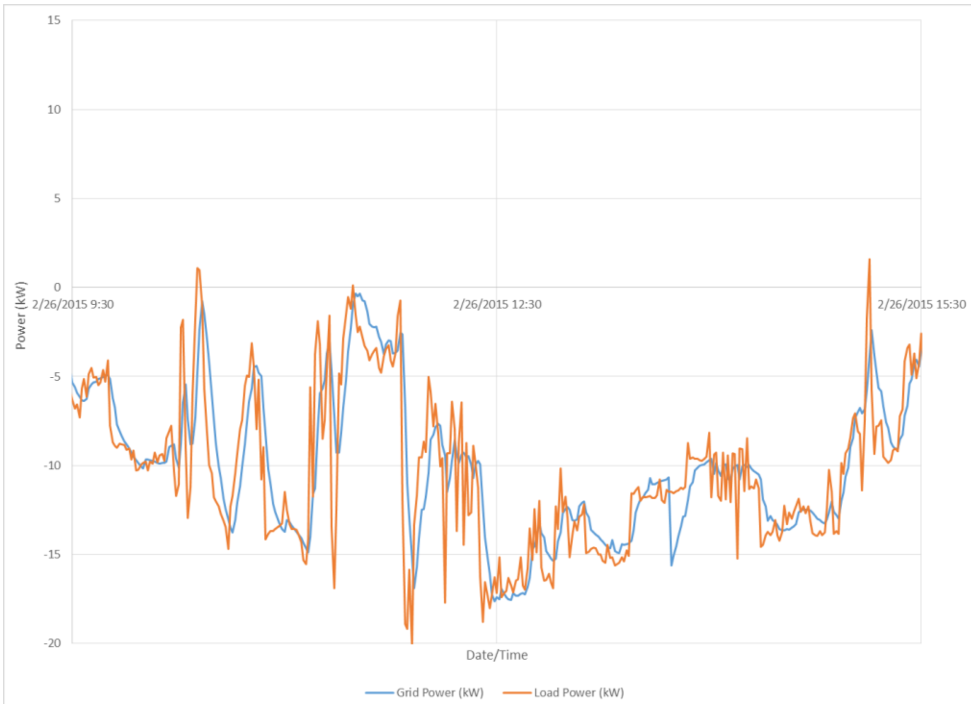


On cloudy days, when the PV generation was more intermittent, Power Smoothing reduced the impact of power fluctuations that were less than five minutes. This is expected because the five-minute time constant programmed in the CES ensures that it will take five minutes for the Grid Power to reach the same level as the Load Power. **Figure 140** is a zoomed in view of February 26, 2015 between 12:00 pm and 3:30 pm. Between 12:00 pm and 3:30 pm, there were several instances in which the Load Power changed by more than 5 kW for less than five minutes. In those cases, the power fluctuations did not transfer over to the Grid Power. During this time period, the CES did contribute to the power fluctuations by performing a discharge to maintain its SOC.

Figure 140: Grid and Load Power on February 26, 2015 between 12:00 pm and 3:30 pm

Figure 141 shows the Grid and Load Power from 9:30 am to 3:30 pm on February 26, 2015. Between 9:30 am and 3:30 pm, there were several load power fluctuations larger than 10 kW that lasted more than five minutes. In these instances, the CES did smooth out the power transitions, but the five-minute time constant was too short to keep them from transferring over to the Grid Power.

Figure 141: Grid and Load Power on February 26, 2015 between 9:30 pm and 3:30 pm



**Note: For this report, a positive CES Power indicates that the CES is charging. A negative CES Power indicates that it is discharging.

Impacts & Lessons Learned

The CES's Power Smoothing feature was shown to be able to smooth out the Grid Power compared to the Load Power. However, the CES created Grid power fluctuations of its own when it charged and discharged to maintain its SOC. On sunny days, the SOC maintenance charges and discharges were actually larger than the regular Load Power fluctuations. The KpSOC value could be optimized so that the CES does not cause power fluctuations greater than the power fluctuations that it is supposed to prevent. However, due to the unpredictable nature of the neighborhood loads and PV generation, there may not be a setting that works for every situation. Enabling Power Smoothing also caused the CES battery to cycle. If Power Smoothing is enabled for a significant amount of time, it would affect battery life.

Test 6 VAR Support

Overview

The objective of the VAR Support Test was to validate the CES's VAR Support feature. When the VAR Support feature is enabled, the CES monitors the grid voltage and attempts to modify the voltage if it exceeds a maximum or minimum voltage as specified by the user. The CES does this by absorbing or injecting reactive power.

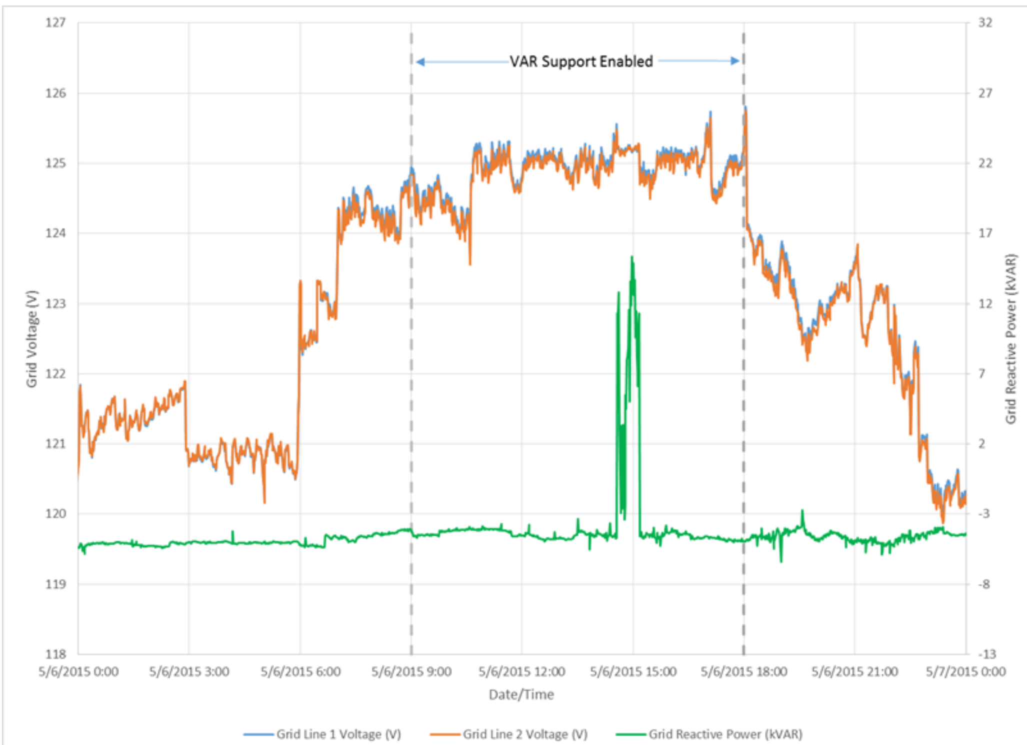
Experiment Steps

The experiment was conducted as outlined in the ISGD SP1 Community Energy Storage (CES) VAR Support Tests Tailboard. Test 1 validated the Over Voltage Setting while Test 2 validated the Under Voltage Setting. Test 1 and Test 2 had to be performed multiple times. The Over Voltage Multiplier, Under Voltage Multiplier, and test times were adjusted for reasons outlined in the Results section of this document.

Results

The first attempt of Test 1 was performed on May 6, 2015 because distribution volt/VAR control (DVVC) was disabled. Grid voltages are generally higher when DVVC is disabled, so the Over Voltage Multiplier was adjusted to 104%. An Over Voltage Multiplier of 104% was used because based on previous data and laboratory tests, the CES VAR Support feature would be triggered several times during the course of the day, but the grid voltage would not be so high that VAR Support would turn on and remain at full power for the duration of the test. VAR Support was enabled between 9:00 am and 6:00 pm. **Figure 142** shows that the CES only initiated VAR Support between 2:30 pm and 3:15 pm. If VAR Support was not enabled, Grid L1 and Grid L2 Voltage probably would have exceeded 125.2V for longer periods of time. Instead, VAR Support initiated and kept the grid voltages from exceeding 125.2 for extended periods of time.

Figure 142: VAR Support Test 1 Performed on May 6, 2015 and Using an Over Voltage Multiplier of 104.0%



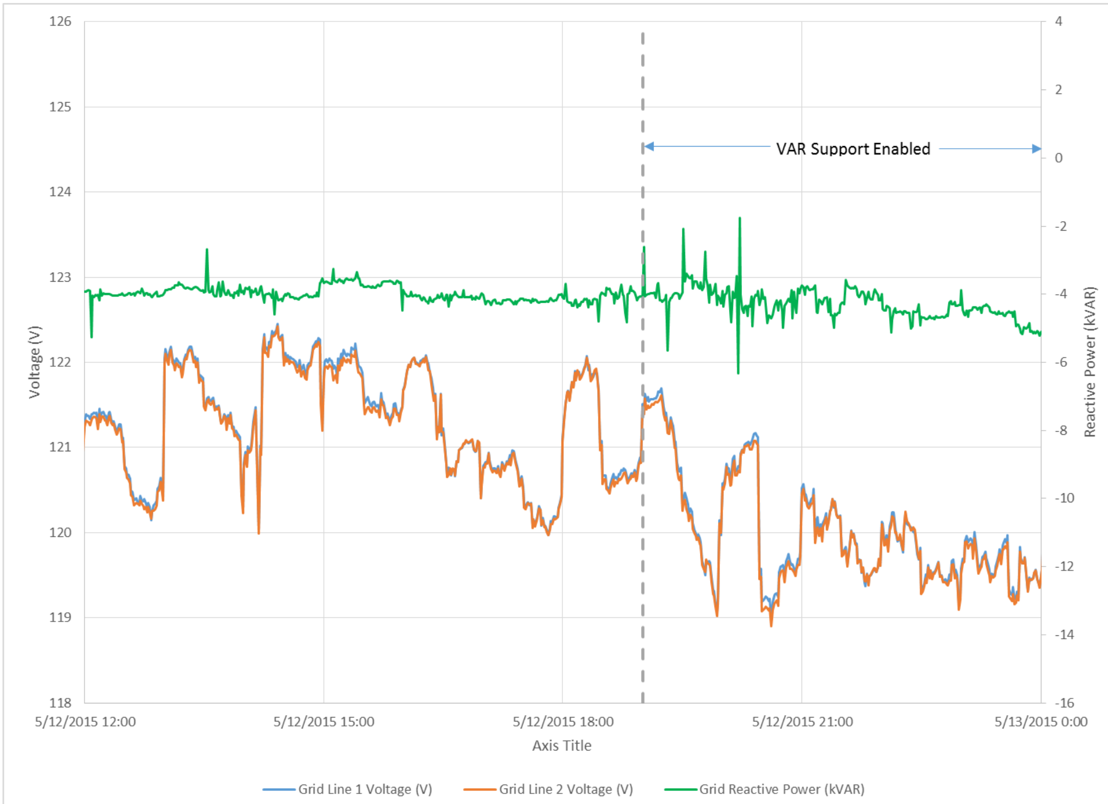
The maximum CES Reactive Power while VAR Support was initiated was only 14.9 kVAR, indicating that the CES could have maintained a lower voltage if desired. On May 7, 2015, VAR Support Test 1 was repeated with an Over Voltage Multiplier of 103.0%, as depicted in **Figure 143**.

Figure 143: VAR Support Test 1 Performed on May 7, 2015, Using an Over Voltage Multiplier of 103.0%

VAR Support was enabled at 9:00 am, but the CES did not initiate VAR support until 9:26 am. The CES initiated VAR support until it was disabled at 12:00 pm. The CES was able to maintain a grid voltage at 124V until 11:30 pm. At that point the CES reached its power limit and was unable to maintain the voltage any longer. VAR Support was disabled at 12:00 pm. Once VAR Support was disabled, the grid line voltages jumped to 125.8.

Test 2 was first attempted on May 12, 2015. The Under Voltage Setting was adjusted to 99.5% because the grid voltage, even with DVVC enabled, only dropped to just below 119 V at its lowest point. VAR Support was enabled at 7:00 pm. As **Figure 144** shows, VAR Support was not triggered, and the Grid Reactive Power did not change much. The Grid Reactive Power did show some small spikes, but they did not coincide with when the grid voltages dropped.

Figure 144: VAR Support Test 2 Performed on May 12, 2015, Using an Under Voltage Multiplier of 99.5%



Test 2 was repeated on May 27, 2015, but from 12:00 am to 11:59 pm. As **Figure 145** shows, reactive power decreased from -5 kVAR to -4 kVAR as the Grid L1 and Grid L2 Voltages dropped below 119.4V. The grid voltages did not remain below the threshold for an extended period of time. However, the reactive power drop was small enough that it could have been caused by other factors. It is not clear like it was in Test 1, whether or not the CES's VAR Support feature did anything at all. During both tests, the natural voltage profile in the CES's neighborhood was too high for the CES's VAR Support feature to make any clear difference when it comes to the Under Voltage Multiplier settings.

Figure 145: VAR Support Test 2 Performed from 12:00 am to 11:59 pm on May 27, 2015, Using an Under Voltage Setting of 99.5%

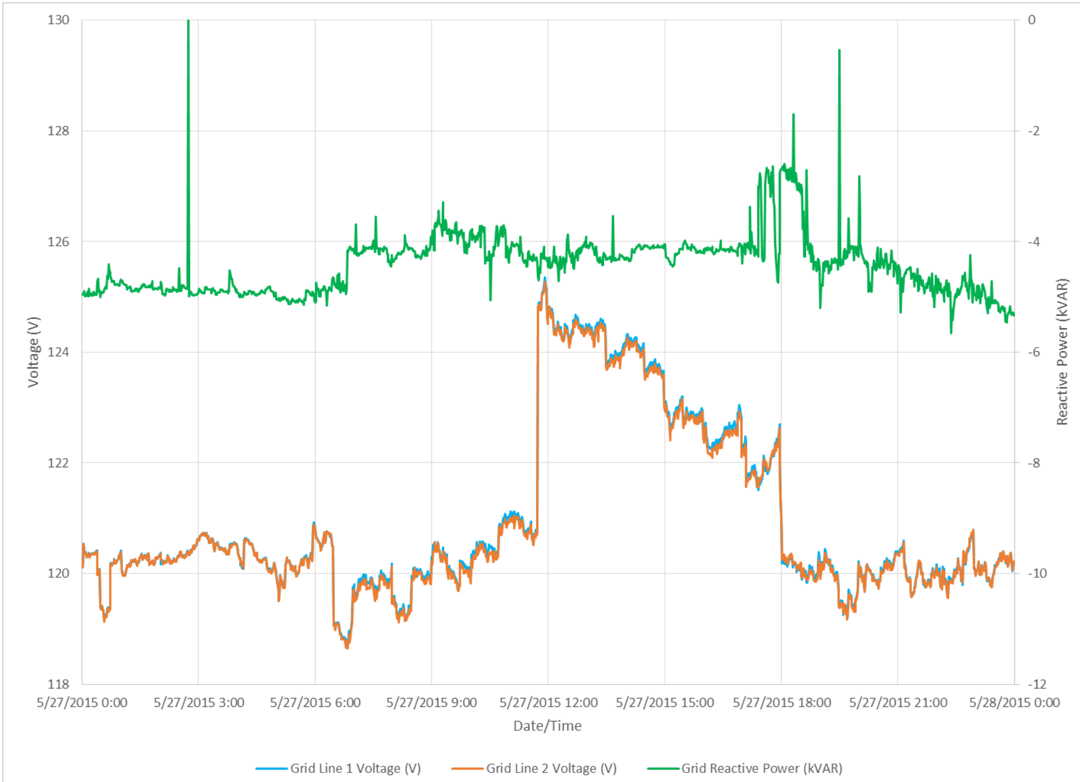


Figure 146 shows the Grid Real Power during the VAR Support test performed on May 27, 2015. Grid L1 and Grid L2 Voltages increased at around the same timeframe that more than 6 kW of generation from the neighborhood was observed. If the Grid Power was capped to keep generation as seen by the grid less than 6 kW, this voltage increase may have been prevented. If local voltage is easily affected by load or generation, a better way to regulate local voltage may be to cap the load and generation using Load Limiting, rather than injecting or absorbing reactive power. Another drawback of injecting and absorbing reactive power to affect the local voltage is that it increases the transformer current. **Figure 147** shows the grid (or transformer) current, transformer temperature, and reactive power during the VAR Support Test on May 7, 2015. Triggering VAR Support caused higher Grid Reactive Power, and as a result, higher currents. This higher current increased the loading on the transformer and caused the transformer to heat up more than if VAR Support was not enabled. Figure 6 shows that the transformer oil temperature started increasing at around 7:00 am, but the slope of the temperature increase was higher starting at around 9:30 am, when the CES caused the Grid Reactive Power to increase.

Figure 146: Grid Real Power during VAR Support Test Performed on May 27, 2015

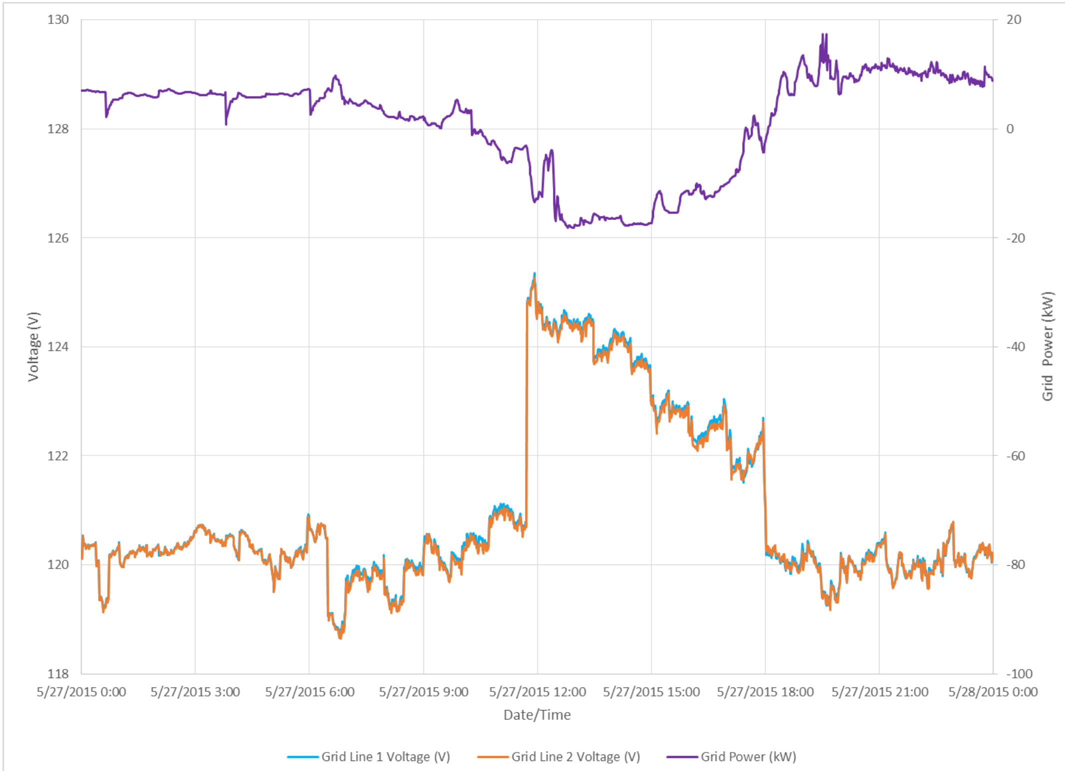
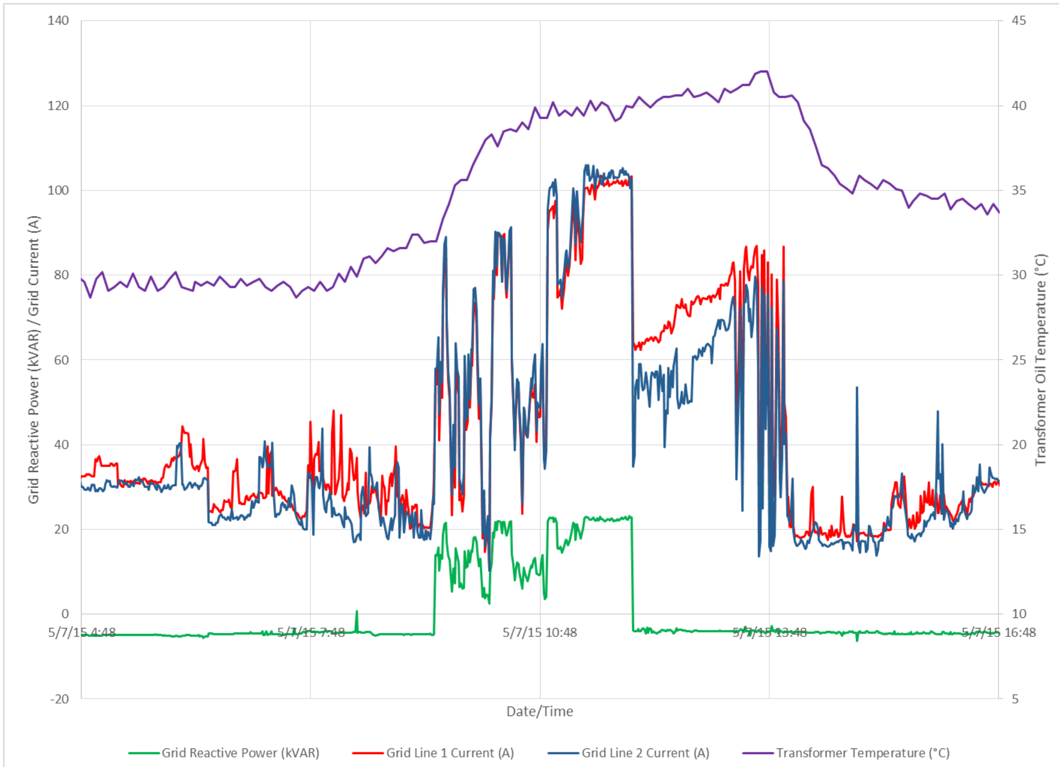


Figure 147: Grid Reactive Power and Line Currents during VAR Support Test Performed on May 7, 2015



Impacts & Lessons Learned

VAR Support has limited usefulness if the voltage profile is biased. With or without DVVC enabled, the grid voltage was high, making the Under Voltage Multiplier setting of limited value. VAR Support could be triggered by the Over Voltage Multiplier setting. However, because of the CES's power limitations, it could only maintain voltages as long as the voltages did not deviate too much from the programmed limits (as seen when the Over Voltage Multiplier was set to 104%). Once the Over Voltage Multiplier setting was changed to 103%, the CES reached its maximum power capabilities, and grid voltage still increased above the defined limit. Relying on the voltage to determine whether or not reactive power should be absorbed or injected also increases the transformer current. Adding current load to the transformer is not an effective method of maintaining a local voltage range. Load limiting may be a better way to keep the voltage at specific limits. VAR support may provide value when there is low voltage caused by high line inductance.

Test 7 Capacity Test

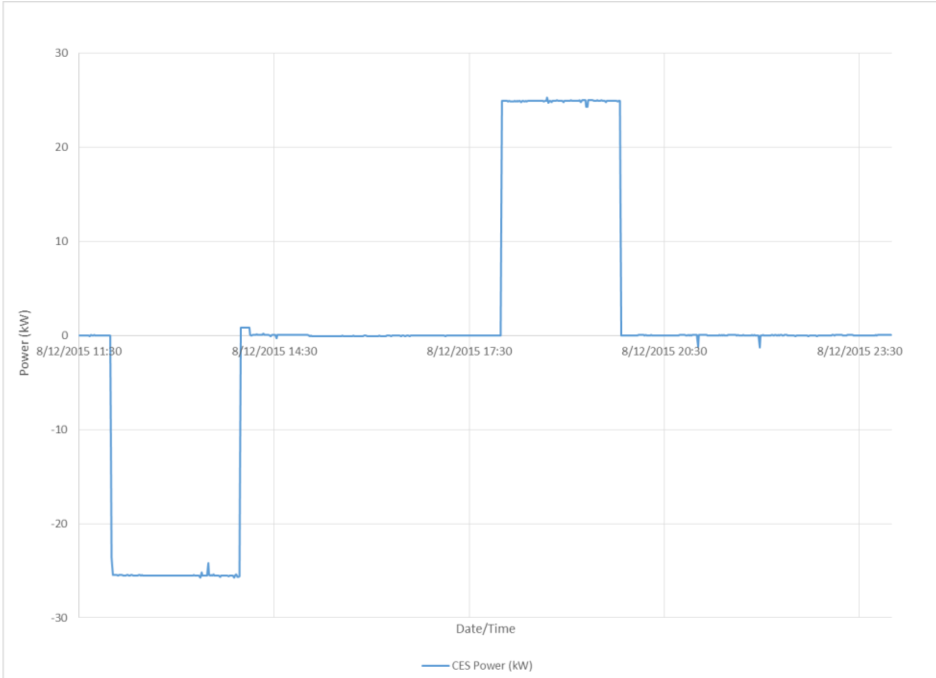
Overview

The objective of this experiment was to determine the CES's capacity at the conclusion of testing. Before being deployed in the field, the CES was tested in a laboratory setting. The results of the field capacity test will be compared to the results of the lab testing.

Results

The CES carried out the charge and discharge commands without any issues. The CES performed a short maintenance discharge once it finished charging. The energy discharged from the battery during the maintenance discharge was added to the energy discharged by the battery during the discharge command when calculating Round Trip Efficiency. Figure 1 shows the CES Power during the capacity test.

Figure 148: CES Power During the Capacity Test Performed on August 12, 2015



The results of the Round Trip Efficiency Test are summarized in **Table 54**. When the CES charged, it consumed 50.55 kWh of energy. When the CES discharged, it provided 45.76 kWh of energy. The energy discharged during the maintenance discharge was 0.12 kWh. The round trip efficiency achieved by the CES was 90.76%.

Table 54: Round Trip Efficiency Results

Charge Energy (kWh)	Discharge Energy (kWh)	Maintenance Discharge Energy (kWh)	Efficiency (%)
50.55	45.76	0.12	90.76

Table 55 summarizes the capacity degradation that the CES experienced while deployed. As per the CES Laboratory Test Plan, three capacity tests were performed on the CES while it was in the lab. The average CES capacity during the laboratory tests that occurred in July of 2013 was 50.81 kWh. The capacity degradation that occurred between when the CES was tested in the lab and when the Capacity Test was performed out in the field was 9.94%.

Table 55: Capacity Degradation

July 2013 Average Discharge (kWh)	August 2015 Discharge Energy (kWh)	Capacity Degradation (%)	Capacity as a Percentage of Original Capacity (%)
50.81	45.76	9.94	90.06

Although the Capacity Test was designed to emulate the original capacity tests performed in the lab as close as practically possible, various factors which cannot be controlled in a field environment (such as ambient temperature) could have altered the results of the test.

Lessons for the Industry

If the CES continues to degrade at the same rate, it would lose almost 20% of its capacity after four years of deployment. The capacity degradation of any deployed CES varies depending on the load characteristics, the CES operational mode, and the resulting battery usage profile. If a CES is deployed for a specific application, it must be sized properly so that it would still have the necessary capacity to fulfill its function despite the expected degradation.

Field Experiment 1F: Impact of Solar PV on the Grid

Test 1: RESU PV Grid Impact (October 11, 2013 to November 6, 2013)

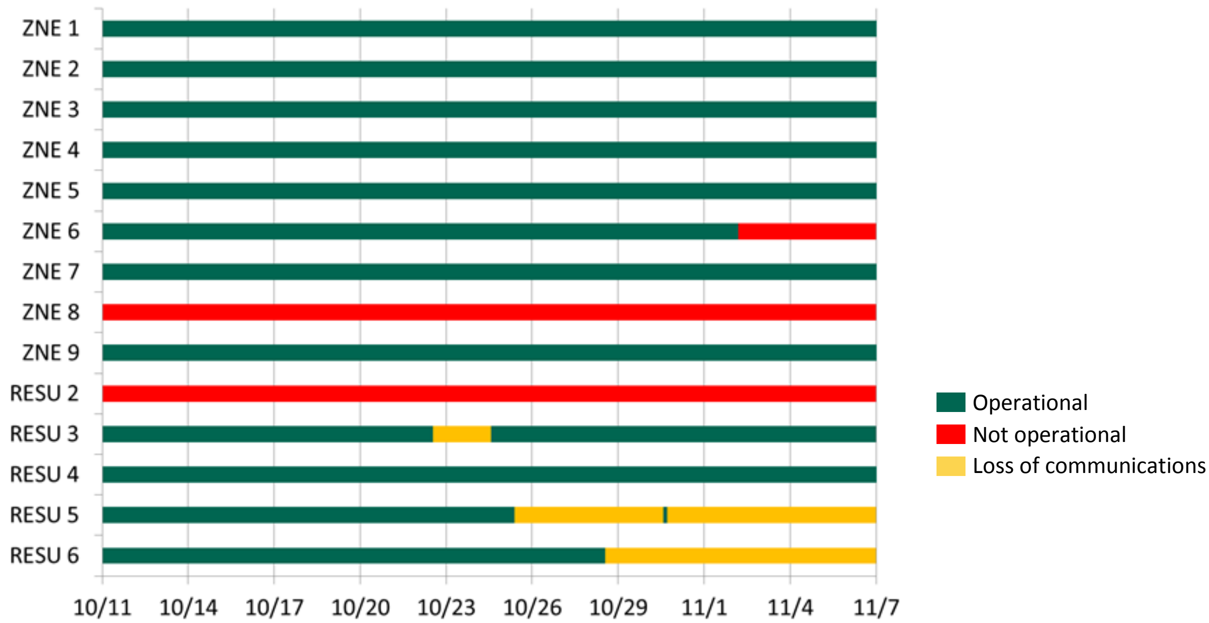
This experiment used all 14 RESUs deployed on the ZNE Block and the RESU Block. Two RESUs were not functioning throughout the test, and another RESU encountered a functional problem that limited its PV output. Each RESU was programmed to act as a standard PV inverter throughout the test period, with the batteries disabled. Over the 26-day test period, each of the homes with operational RESUs generated between 150 and 400 kWh AC.

This test confirmed that the PV arrays on each of the RESU homes could significantly affect the home's load profile. Each of the arrays exported power to the grid during most sunny periods since the electricity produced was typically greater than the electricity consumed by the homes during the daytime. The significant PV penetration in these test locations (particularly the ZNE Block), led to higher average current on the transformers. Because the PV generation is not coincident with most customer load, the power exported through the transformer increased the current through the transformer during the formerly low-load periods.

In addition to investigating the grid impact of these arrays, the team validated the performance and characteristics of the PV arrays when coupled with the RESUs. Test results indicate that several PV arrays are shaded in the afternoon, while two other arrays may not be performing as expected. The team validated the RESU data collection and gathered approximate "calibrated" efficiencies in order to translate RESU-recorded DC PV power and energy to approximate AC power and energy. The team estimates that converting the recorded DC PV energy to AC PV energy has 92% efficiency, while converting DC PV power to AC PV power is 95%. These calibrated efficiencies differ significantly since energy is an accumulative value while the recorded power is an instantaneous value.

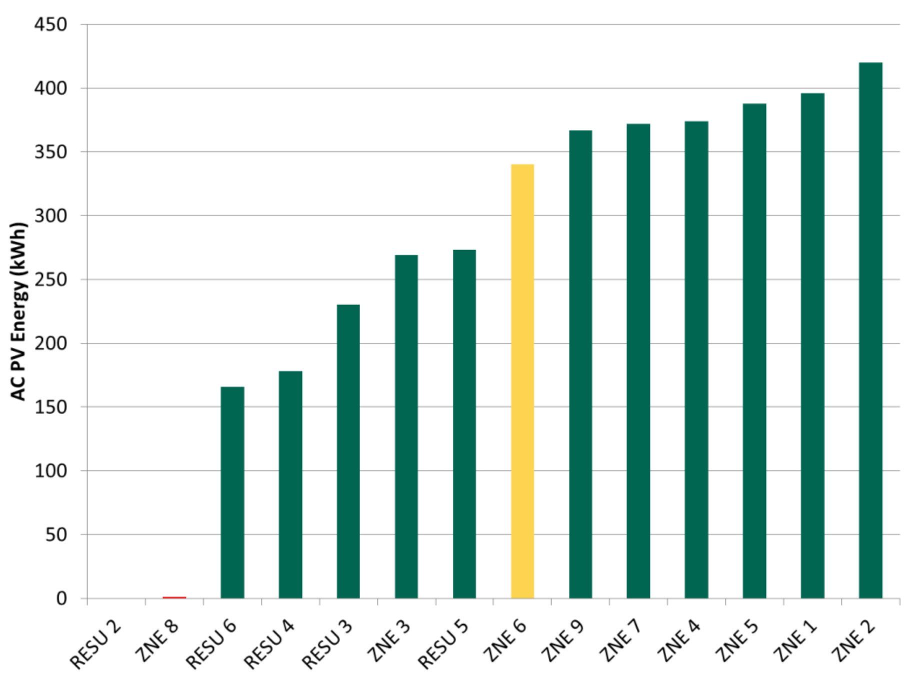
Several RESUs reported errors during the test period. These errors prevented operation of the systems, including the PV generation. Throughout this test period, the team calculated the RESU "uptime" by determining the average percentage of time that all RESUs were operational. The RESU uptime was only 78% over the 26-day test period. Two RESUs did not function at all, while four additional RESUs experienced performance issues in the second half of the test period. **Figure 149** presents a timeline with failure time (in red) for each of the RESUs. This figure also indicates periods where the RESUs lost communication (in yellow). The TrendPoint meters functioned as expected throughout the experiment. The TrendPoint data indicates that the RESUs provided PV power despite the communication errors. The RESU uptime, including periods when the RESUs lost communication but the PV was still operational, is approximately 85%. The errors are described under Field Experiment 1D, Test 3.

Figure 149: RESU Operational State Summary



During the 26-day experiment, the RESUs output between 150 and 450 kWh AC to the home. **Figure 150** shows the total energy produced by the PV arrays.

Figure 150: RESU AC PV Energy Delivered

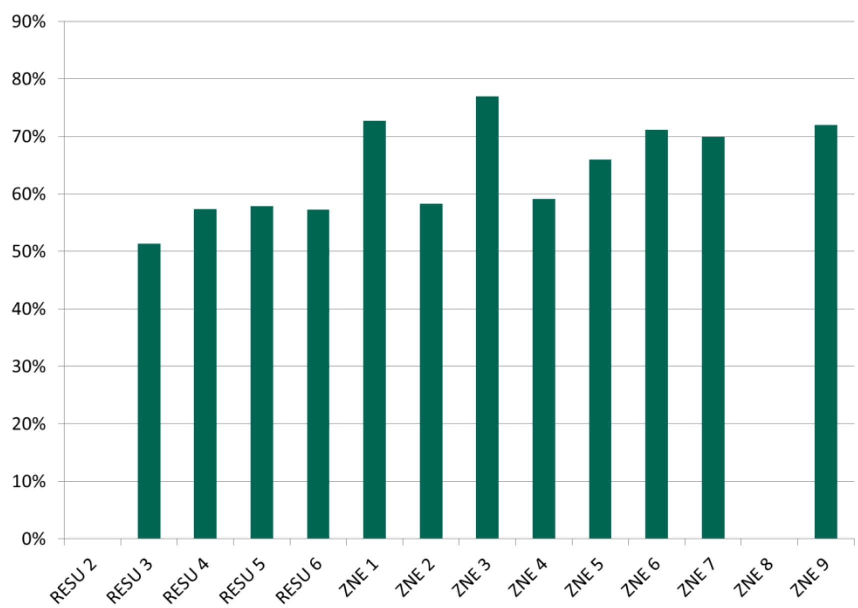


The ZNE Block had nine homes with solar PV arrays, each identically sized at 3.9 kW. Six of these produced over 350 kWh during the test period. The array at ZNE 6 produced less than 350 kWh, probably because it stopped operating late in the test. The RESU at ZNE 8 was never operational during the test period, and the array therefore produced no energy due to software issues. The array at ZNE 3 produced just 270 kWh. This is approximately 75% of the generation by the other arrays.

The RESU Block has five homes with solar PV arrays, each identically sized at 3 kW. Two of these (RESU 2 and RESU 3) produced approximately 250 kWh over the test period. The other two operational arrays (RESU 1 and RESU 5) produced approximately 175 kWh during the test period, about 70% of the production of the other PV arrays. This large variation in PV generation may be due to the physical orientation, shading, environmental factors, or hardware issues.

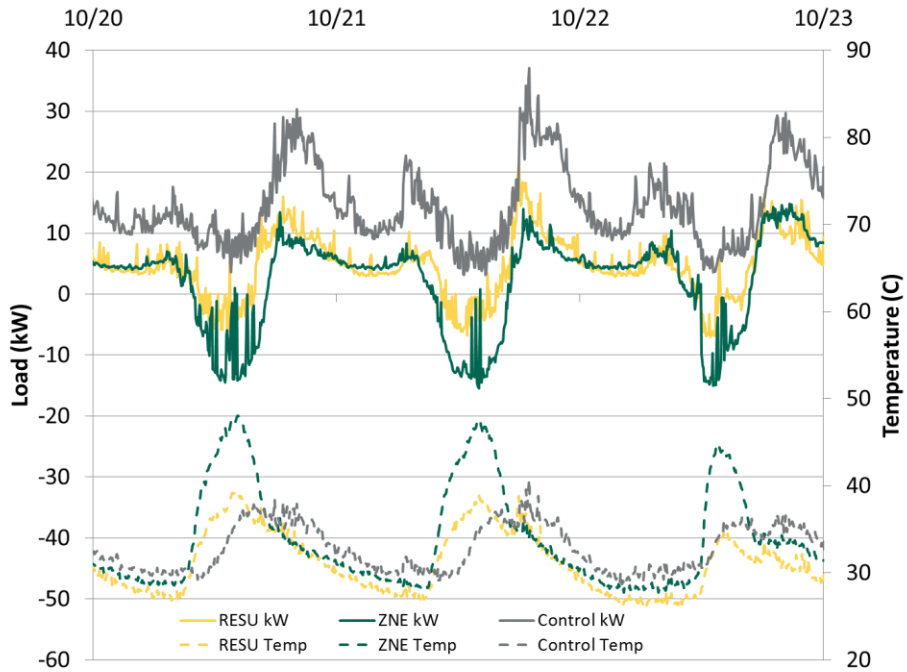
While operating as a standard inverter, the homes exported much of the PV generation to the grid. Residential electricity consumption is typically highest during the evening. To maximize the financial benefit of PV arrays, customers enroll in the net energy metering (NEM) tariff. However, due to the energy storage capabilities of the RESUs (not used during this experiment), these homes are not eligible for NEM. These customers therefore received no credit for any exported energy. The amount of energy exported to the grid for each home varied based on both the PV production of the specific array and the electricity consumed by each respective home. **Figure 151** summarizes the share of solar PV energy exported to the grid.

Figure 151: Share of Solar PV Generation Exported to Grid



During this experiment, the homes exported more than 50% of the energy produced by the solar PV arrays to the grid, which affected the load profiles of the ZNE and RESU Block transformers. Although the customers' energy consumption peaked during the evenings, solar PV generation was exported to the grid during the day. This means that the distribution transformers had high currents during both the evenings and daytime. All nine homes on the ZNE Block have 3.9 kW PV arrays, while the RESU Block has five homes (out of eight homes on the block) with 3 kW PV arrays, and one additional home with a 4 kW array (but no RESU). The Control Block has two homes (out of 20 homes on the block) with PV arrays, totaling less than 8 kW of PV capacity. **Figure 152** shows the loading and hot spot temperature of the ISGD transformers for a three-day period with high PV output.

Figure 152: Transformer Loading and Temperature



Both the ZNE and RESU Block transformers fed power back into the grid during peak solar periods. The Control Block transformer (10% PV penetration) showed reduced load during the day while the RESU Block (75% PV penetration) exported to the circuit during peak periods. The additional generation on the ZNE Block—which has 100% PV penetration—was readily apparent on the transformer, as the power output by the entire block during the test period was over 15 kW.

The changes in the transformer load profiles also seem to have noticeable impacts on the transformer temperatures. The RESU Block and ZNE Block transformers reached peak temperature at approximately 2:00 pm, while the Control Block peaked between 6:00 pm and 8:00 pm. In addition, the large amount of generation on the ZNE Block significantly increased the average current through the transformer. The large amount of current from PV generation flowing through the transformer during the solar peak period, coupled with direct sunlight heating of the transformers at the same time results in a significant temperature excursion. The heating effect of this current is proportional to the square of its magnitude.

Test 2: RESU PV Grid Impact (March 1, 2014 to October 31, 2014)

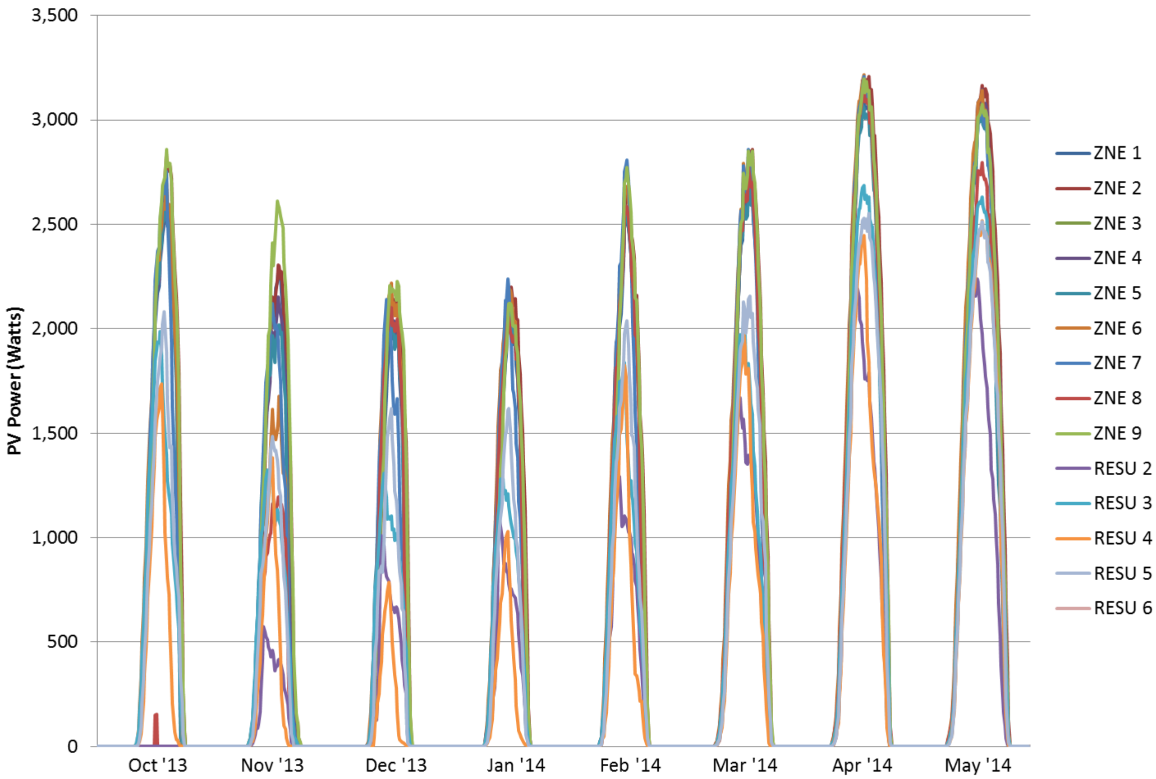
Table 55 and **Table 56** summarizes the solar output for each ISGD home over the eight-month period between March 1, 2014 and October 31, 2014. The solar output showed considerable variation throughout the year, with lower amounts during the spring and fall months, and higher output during the summer. Variations also exist between the various project homes. The section below this table explores the potential sources of this variation.

Table 56: Solar PV Generation by Month (March 2014 through October 2014)

Project Home	Solar PV Generation by Month (kWh)								
	Mar. '14	Apr. '14	May '14	Jun. '14	Jul. '14	Aug. '14	Sep. '14	Oct. '14	Total
ZNE 1	561	683	729	727	667	694	572	472	5,105
ZNE 2	577	701	743	746	688	712	596	503	5,266
ZNE 3	376	460	488	581	685	710	587	488	4,375
ZNE 4	545	677	729	730	666	688	558	458	5,051
ZNE 5	535	639	681	688	601	648	540	447	4,779
ZNE 6	577	697	737	726	661	706	585	489	5,178
ZNE 7	540	657	695	688	625	650	542	347	4,744
ZNE 8	550	680	651	711	664	694	568	465	4,983
ZNE 9	574	692	718	710	655	674	554	505	5,082
RESU 1	585	713	762	770	699	725	612	496	5,362
RESU 2	326	438	579	577	525	493	361	312	3,611
RESU 3	389	593	625	619	572	584	498	417	4,297
RESU 4	326	438	579	577	525	493	361	312	3,611
RESU 5	431	550	589	556	542	539	447	331	3,985
RESU 6	238	286	298	410	525	597	484	406	3,244
CES 1	489	630	673	666	608	652	570	479	4,767
CES 2	424	553	616	620	567	639	537	430	4,386
CES 3	482	581	623	600	537	568	482	395	4,268
CES 4	550	640	669	651	599	655	580	481	4,825
CES 5	493	623	674	666	609	647	518	355	4,585
CES 6	469	630	674	673	611	649	548	435	4,689
CES 7	527	632	664	666	609	646	560	468	4,772
Totals	10,564	13,193	14,196	14,358	13,440	14,063	11,660	9,491	100,965

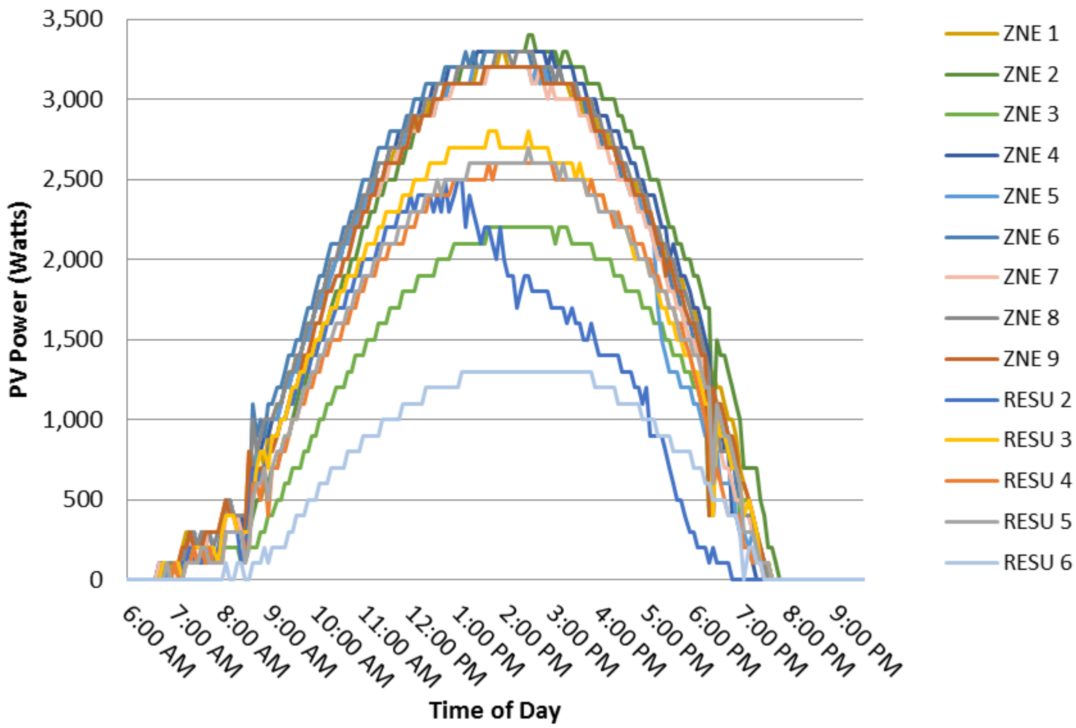
In June 2013, the ISGD team performed an analysis of the solar PV output of on the ZNE and RESU blocks. The solar PV on these two blocks share an inverter with the RESUs at each respective home. The purpose of this analysis was to assess the homes' solar PV output over time and across all the project homes. **Figure 153** summarizes the solar PV output for each home between October 2013 and May 2014. The chart reveals considerable variation in output between the homes, and between the months—with lower output during the winter months.

Figure 153: Average Solar PV Output (October 2013 to May 2014)



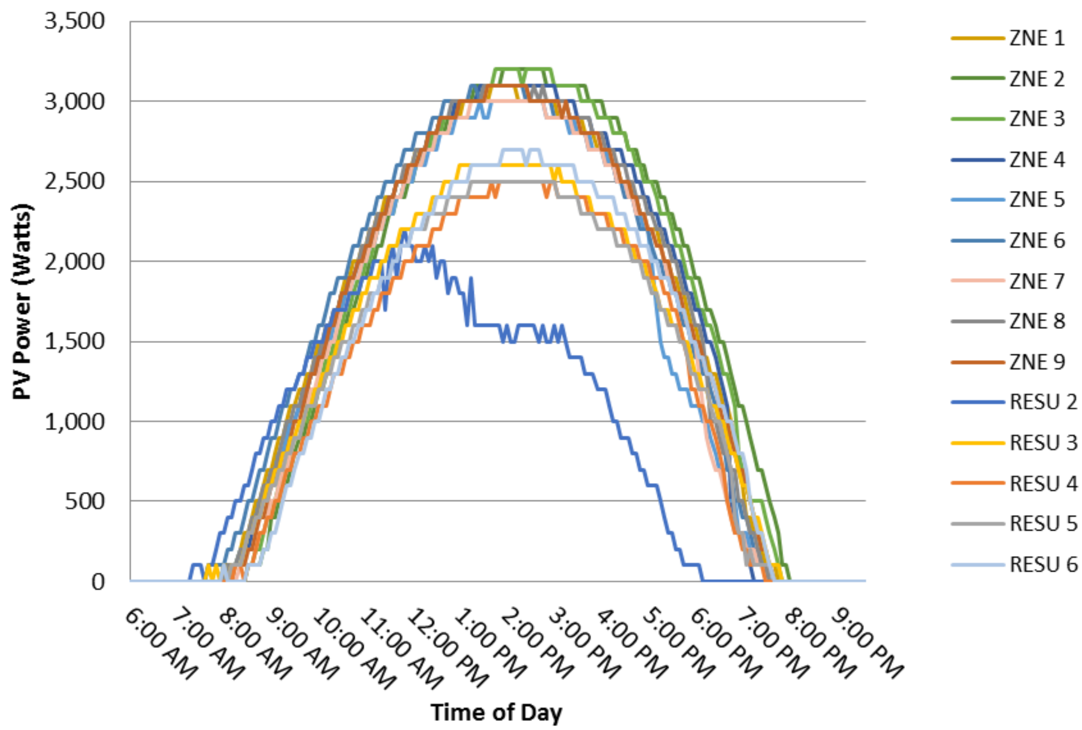
While performing this analysis of the PV output, the team discovered that three of the solar installations were generating less than their peak design capacities. By May 2014, shading that had limited the solar PV output in the winter months had disappeared. However, the output of ZNE 3, RESU 2, and RESU 6 remained well below their expected production levels. **Figure 154** summarizes the output of each homes on June 17, 2014. The output of these three homes is well below the other homes. The team suspected that the reduced RESU 2 output was due to afternoon shading. Its output peaked at around noon and then declined more sharply than the other homes in the afternoon. This suggested that perhaps the problem with RESU 2 was not due to wiring or other technical issues. The team suspected there might be technical issues with the other two homes, ZNE 3 and RESU 6.

Figure 154: Solar PV Generation (June 17, 2014)



The team conducted an on-site visit to ZNE 3 and RESU 6 on June 20, 2014, and discovered problems with the electrical connections of the homes' PV equipment. ZNE 3 had a bad electrical connector, which the team replaced. At RESU 6, the team discovered fuses inside the PV combiner box were not properly placed in service during the installation process. The solar PV output of both of these homes immediately improved after fixing these two installations. **Figure 155** shows that the output of these two homes was consistent with the other homes following the repairs.

Figure 155: Solar PV Generation (July 22, 2014)



The solar output of RESU 2 remained poor in the summer season. The ISGD team verified that this was due to shading of the solar array. This home had been producing 20-30% less energy than its neighboring systems before this issue was resolved.

Field Experiment 1G: EVSE Demand Response Applications

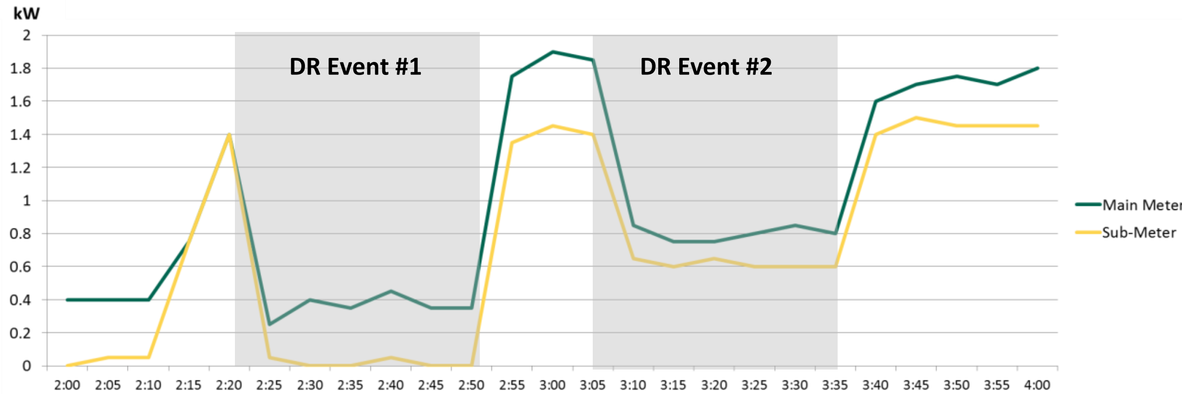
Test 1: EVSE Demand Response Event (November 20, 2013)

The purpose of this experiment was to demonstrate the ability of the EVSEs to receive DR event signals sent through the homes' project smart meters. The intent of this test was also to confirm that the EVSEs respond to the DR event signals properly. This includes automatically reducing the EVSE charging level by the proper amount, at the correct time, and for the correct duration, and returning to the normal charge level once the DR event is complete.

This test consisted of two DR duty cycle events. Both events targeted one home on the CES Block of customer homes (CES 7). The first was a 50% duty cycle event, scheduled for 30 minutes (from 2:20 pm to 2:50 pm). The second event was a 20% duty cycle event, scheduled for an additional 30 minutes (from 3:05 pm to 3:35 pm). The events were initiated in the ISGD ALCS, which then delivered the event signals to the EVSE through the home's project smart meter.

The EVSE response to both DR event signals was consistent with the ISGD team's expectations. The EVSE reduced charging from 1.4 kW to zero at 2:20 pm, and continued in this state until 2:50 pm, when the EVSE resumed charging at 1.4 kW. At 3:05 pm, the EVSE reduced its charging level from 1.4 kW to 0.6 kW, consistent with the team's expectations for a 20% duty cycle event. At 3:35 pm, the EVSE resumed charging at 1.4 kW. **Figure 156** presents the total household demand and sub-metered EVSE demand for the period covered by these DR events.

Figure 156: CES 7 Demand During EVSE Demand Response Event



Test 2: EVSE Demand Response

The team performed five DR events using EVSEs during the timeframe covered by this report. Each of these DR events used multiple HAN devices including the PCTs, RESUs, and smart appliances. The results of these tests are summarized under Field Experiment 1B.

Over the prior several months, the ISGD team had worked with original EVSE vendor to resolve more than 20 software and hardware problems with the units used in both sub-project 1 and sub-project 2. Although most of these issues related to EVSE operation, in three instances the EVSEs posed an electrical hazard by demonstrating excessive heat buildup that resulted in heat damage on both wires and terminal blocks. These three cases occurred with three different EVSEs, all located within the parking structure. These events occurred on June 2, 2014, October 14, 2014, and October 21, 2014. The team determined the cause of the first event and resolved it within a few days. Following the third event, the manufacturer performed a root cause analysis and determined that the cause was likely due to over-torqueing the wires (i.e., tightening the wires too tightly). The manufacturer stated that this over-torqueing was due to a discrepancy between the torqueing specification listed on the contactor specification sheet and the specification printed on the contactor device.

Based on the continued problems with these devices, and the fact that three of these incidents had the potential to impact safety, the ISGD team decided to disable all the ISGD EVSEs and to replace them with different EVSEs. The team selected two new replacement models, one for the ISGD homes (sub-project 1) and another for the parking structure (sub-project 2). The team completed all the EVSE replacements in December 2014.

Field Experiment 1H: EVSE Sub-metering

The project team monitored and collected PEV charging activity through separately metered EVSE usage. **Table 57** summarizes the aggregate PEV charging activity for the final twelve months of the demonstration period. November 2014 is omitted because the EVSEs were replaced during that month.

Table 57: Sub-metered EVSE Charging Activity by Month (kWh)

Month	Average Home	High Home	Low Home	All Homes
Mar. ‘14	85.6	324.9	10.8	1,882.8
Apr. ‘14	86.0	385.7	11.2	1,891.5
May ‘14	87.9	383.7	11.0	1,934.5
Jun. ‘14	89.7	288.4	10.8	1,973.2
Jul. ‘14	85.4	339.6	11.4	1,878.9
Aug. ‘14	80.1	317.4	11.3	1,762.5
Sep. ‘14	91.0	307.8	10.9	2,003.0

Month	Average Home	High Home	Low Home	All Homes
Oct. ‘14	94.8	365.6	11.0	2,084.6
Nov. ‘14				
Dec. ‘14	37.9	158.9	3.2	834.0
Jan. ‘15	99.6	377.1	7.8	2,190.7
Feb. ‘15	104.6	356.9	7.0	2,300.7
Mar. ‘15	112.2	398.4	7.7	2,468.8
Apr. ‘15	93.8	329.9	7.5	2063.2
May ‘15	101.6	415.6	7.7	2234.6
Jun. ‘15	74.8	247.5	7.4	1,645.7

7.1.2 Sub-project 2: Solar Car Shade

The solar car shade consists of an array of solar panels on the roof of a parking structure on the UCI campus, a BESS, and 20 electric vehicle chargers. The various system components were deployed between July and November 2013, and field experimentation began in December 2013. This section summarizes the lab testing, commissioning tests and field experiments used to assess this system.

7.1.2.1 Laboratory Tests

Battery Energy Storage System

Prior to installing the BESS in the field, SCE performed lab testing to validate the behavior of the system under simulated duty cycles and operating modes. The results helped the team determine the system’s reaction to grid events, limits, and efficiencies (including standby power consumption, inverter efficiency, and PV maximum power point tracking). Since the inverter is UL listed, the team only performed functional and performance testing to verify the overall integration of the system components. The laboratory testing allowed the team to verify the BESS’ technical capabilities and its readiness for field deployment.

Electric Vehicle Supply Equipment

Refer to sub-project 1 (7.1.2.2) for a summary of the laboratory testing performed on the EVSEs prior to field deployment.

7.1.2.2 Commissioning Tests

Battery Energy Storage System

Following the field deployment of the BESS in August 2013, the ISGD team demonstrated the BESS’ PLS capability over approximately eight weeks, between September 10, 2013 and November 7, 2013. The first day of this experiment constituted the BESS commissioning wherein the team verified its ability to remotely control the BESS and confirmed the device’s ability to cycle at constant charge/discharge rates. The Field Experiment 2C discussion below describes this experiment in more detail.

7.1.2.3 Field Experiments

Figure 157 depicts the configuration of the various solar car shade components. The 20 EVSEs are at the lower right, while the converter, battery, and PV systems are at the lower left (collectively referred to as the BESS). The EVSEs and BESS components connect to the grid at the top. Dedicated 480 V 3-phase meters measure each of these three connections (indicated by the red dots).

Figure 157: Solar Car Shade System Overview

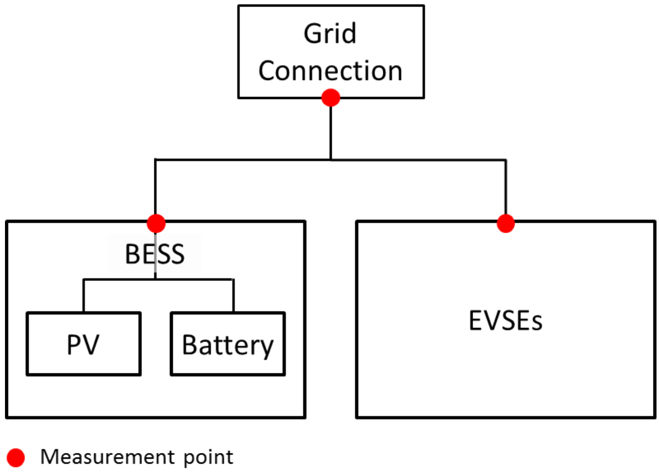


Table 58 summarizes the measurement points and sign conventions.

Table 58: Solar Car Shade System Measurement Points

Measurement Point	Measurement Source	Sign Convention
Grid Connection	Dedicated 480 V 3-phase meter (1 for each measurement point)	(-) generation (+) load
BESS		
EVSE		
Battery	Inverter internal dc (one for each measurement point)	(-) discharging (+) charging
PV		

The field experiments are discussed below. In addition to those experiments, the team is also monitoring the overall performance of the entire Solar Car Shade system in terms of the energy used for electric vehicle charging and the electricity production of the solar PV arrays. **Table 59** summarizes the Solar Car Shade performance from deployment through August 31, 2015.

The battery system was installed and operational in September 2013, the PV was installed in early November 2013, and the EVSEs were made available to the public for PEV charging in December 2013. Electric vehicle charging varied depending on the school schedule (summer session versus fall, winter, and spring quarters), and it increased noticeably at the beginning of the fall 2014 quarter. The EVSEs were turned off in late October 2014, and replaced with EVSEs from a new vendor in December, which is why the EVSE load drops significantly for November and December of that year. Similarly, the values measured at the BESS connection to the grid changed with the season due to the effects of sun angles and weather on the solar PV generation. Finally, the values in all three columns of **Table 59** were measured by three separate meters, so the sum of the first two columns does not precisely equal the third column.

The total row indicates that from September 2013 through August 2015, electric vehicle charging consumed 109 MWh, while the BESS supplied 70 MWh from PV energy, for a net consumption of 39 MWh from the UCI grid. It is interesting to note that from September 2013 through October 2014, the Solar Car Shade system was a net generator, with surplus of 45 MWh supplied back to the UCI grid. However, with an increase in electric vehicle charging and the effect of seasons different and BESS operating modes on PV generation, the Solar Car Shade system became a net consumer by the end of the project. Even though the system was a net consumer, the BESS was still successful in generating 70 MWh of PV energy to offset the impact of workplace electric vehicle charging, equivalent to 64 percent of the energy used to charge electric vehicles. This was in addition to operating in three different modes that intelligently reduced this impact, including: 1) shifting load from on peak to off peak hours, 2) minimizing the peak period impact of electric vehicle charging, and 3) capping the demand of electric vehicle charging. These operating modes are further discussed below.

Table 59: Solar Car Shade System Performance

• Values are in ac kWh • Negative values indicate generation, positive values load		EVSE	BESS	Solar Car Shade Grid Connection
2013	September	0	1,398	1,382
	October	0	1,669	1,690
	November	289	(424)	(116)
	December	1,539	(1,023)	571
2014	January	2,977	(1,356)	1,662
	February	2,893	(2,973)	(45)
	March	3,164	(3,405)	(306)
	April	4,363	(4,464)	12
	May	3,946	(5,935)	(1,964)
	June	3,779	(6,731)	(2,994)
	July	3,624	(6,234)	(2,572)
	August	4,237	(6,711)	(2,414)
	September	4,942	(5,232)	(397)
	October	7,097	(3,805)	3,520
	November	492	(2,701)	(2,190)
	December	1,432	(1,959)	(565)
2015	January	7,216	(1,762)	5,492
	February	7,699	(2,158)	5,693
	March	7,880	(2,486)	5,141
	April	9,108	(3,642)	5,796
	May	9,687	(2,264)	7,519
	June	7,941	(1,109)	6,771
Totals		94,305	(63,307)	31,686

As discussed above, the team disconnected these EVSEs in October and replaced them with EVSEs from a different manufacturer by December 2014.

Field Experiment 2A: Minimize Peak Period Impact of PEV Charging

March 1, 2015 to April 20, 2015

To perform this experiment, the team operated the Solar Car Shade system in a power regulating mode and evaluated the ability of the system to minimize (or even eliminate) the impact of electric vehicle charging during peak periods. The team configured the system to charge at night and regulate the demand of the Solar Car Shade system at zero kW during the day. This schedule attempted to prevent the UCI grid from seeing any load from daytime electric vehicle charging, within the limits of the BESS power and energy capacity. This operation also addressed the dynamic nature of EV charging by adjusting the rate of battery discharge and PV generation to match load in real time, and it reduced overall energy consumption of the charging station from the grid (through PV generation). The BESS was operational and the EVSEs were available for use by the UCI general population throughout the experiment period, excluding occasional maintenance, troubleshooting, and tour activities. These troubleshooting issues are described in more detail below.

The team programmed the BESS' Site Controller with the following schedule to carry out this experiment:

- Daily starting at 12:00 am, charge the BESS from the grid at a power level of approximately 20 kW. This includes 2 kW to operate the BESS, so the net power used to charge the battery is 18 kW. Charge the battery until the charge tapers back and reaches 100% SOC, then continue to draw grid power to operate the BESS.

- Daily from 9:00 am until 12:00 am, regulate Solar Car Shade system demand at 0 kW, unless EVSE demand exceeds 75 kW or the sum of available PV generation and battery power, in which case Solar Car Shade system demand increases in the amount of the EVSE demand excess. The BESS also charges the battery with available PV generation that exceeds EVSE demand, and decreases PV generation if the battery is fully charged and available PV generation exceeds EVSE demand.

Unlike the load shifting experiment described below, both EVSE load and solar PV generation affect the BESS discharge rate. So, the BESS discharge rate changes based on dynamic electric vehicle charging activity, as well as solar incidence (sun angles and weather) and the efficiency of the solar PV array (temperature and dirt buildup). Greater levels of solar PV generation decreases the battery's discharge rate after 9:00 am, or may even cause the BESS to charge if it is great enough, since solar PV generation is used to power the EVSEs before battery energy. Similarly, higher EVSE demand increases the battery's discharge rate, and may even completely discharge the battery on a day with high EVSE usage and low PV generation. In this case, the system is not able to regulate overall demand at 0 kW, and would add load to the UCI grid.

Figure 158 presents the BESS power profile on March 18, 2015. This represents the typical weekday power profile as measured at the Solar Car Shade, main BESS (including battery and PV), and EVSE ac connections. This profile includes the 20 kW load/charge starting at 12:00 am, and the BESS regulating Solar Car Shade system load at 0kW starting at 9:00 am. This figure also includes solar PV generation (dc) and battery SOC.

Figure 158: BESS Weekday Power Profile (March 18, 2015)

In general, the Solar Car Shade system is the sum of the BESS and EVSE. However, since the actual values come from three separate meters, this relationship is approximate. **Figure 158** demonstrates the system's ability to minimize peak period impact by charging the battery during an off-peak period (from 12:00 am to approximately 6:00 am at 20 kW), and regulating the Solar Car Shade system demand at 0 kW during an on-peak period (from 9:00 am to 12:00 am). The PV generation during the regulation period has the effect of extending the amount of time the BESS can maintain overall demand at 0 kW. In this example, the solar car shade's solar PV generation is able to provide power for the majority of the EVSE load during the on-peak period. As a result, the BESS battery does not discharge completely and is even able to charge twice during the regulation period, when the PV generation exceeds the EVSE load.

At least two limitations to this mode of operation can be seen in: 1) the PV generation profile, and 2) the battery SOC profile. In the PV generation profile, the BESS does not start using the PV array until the 9:00 am regulation start time. Between 6:00 am and 9:00 am, the system is essentially idle, even though the PV array could be generating a small amount of energy using early morning light. The 9:00 am regulation start time was chosen over 6:00 am to make sure the battery didn't start discharging too early, and then reach a fully discharged state earlier in the day. This is especially apparent on days with less PV generation and/or heavier EVSE usage, where the battery rate of discharge is higher (see second point below). Under a more ideal operational schedule, the system would use PV generation, without battery discharge, between 6:00 am and 9:00 am, to take advantage of the available PV generation capacity. However, this more ideal schedule was not implemented due to concerns with making the necessary changes to the BESS inverter settings on a daily basis, which had been shown under observational operation to make the inverter less stable and more prone to trips.

The other limitation can be seen in the battery SOC profile. At the beginning of the day, the battery starts at slightly less than 10 percent SOC, which was the battery's minimum SOC operating setting. This indicates the battery was fully discharged the previous day, due to heavy EVSE usage and/or lower PV generation. However, for the day illustrated in the chart above, the battery only discharges to approximately 23 percent SOC by the end of the day, meaning it still had 13 percent of its normal operating capacity left. The differences between these two days shows the difficulty in predicting EVSE usage and PV generation, and setting appropriate start/stop times and thresholds for a given mode of operation.

An additional consideration not illustrated in the chart above is the regulation point at 0 kW. If the Solar Car Shade system were operated in a *cap* demand mode, the system would attempt to keep overall load from *exceeding* a specific threshold (ex.: 0 kW), while still allowing the system to discharge any excess PV generation back to the UCI grid in the event the battery is fully charged and EVSE load is less than available PV generation capacity. However, with the Solar Car Shade system operating in a *regulation* mode, the system attempts to keep overall load at 0 kW, regardless of whether or not excess PV generation capacity is available. In the event the battery is fully charged and EVSE load is less than available PV generation, the PV generation is actually curtailed to make sure the system doesn't discharge back into the UCI grid. This behavior may or may not be desirable, depending on the tariff and associated export/non-export rules. For example, the tariff may not allow an energy storage system to act as a generator on the grid, in which case the regulation mode is appropriate. Likewise, other tariffs may provide compensation for any energy delivered to the grid, in which case the cap demand mode is appropriate.

During this experiment, the BESS experienced three failures, and had 107.5 hours of down time and no maintenance time. Two of the failures were related to internal safety faults designed to protect the system when the inverter or battery exceeds operational thresholds. In both cases, the fault conditions were transient and the team had seen them before. Based on experience operating the system and recommendations from the integrator, the team reset the inverter and battery, which then resumed operation. Together, these failures resulted in 107.5 hours of down time, reflecting the time it took an engineer to schedule a visit to the BESS, confirm the issue, and restart the system. These types of failures relate to the integration of the various system components, and highlight the importance of ensuring subsystem compatibility and safety through integrator experience and extensive pre-deployment testing.

The final failure was a loss of communication with the BESS, preventing remote status checks, control, or data transfer. Throughout the communication loss, the BESS continued to operate as programmed, so this failure did not contribute to the hours of down time metric. This communication loss was due to an issue with the 4G radio back office security certificates expiring. This issue affected all ISGD components with 4G radios. The team resolved this issue by updating the security certificates; the 4G radios then resumed operation, and data that had been recorded internally by the BESS during the communication outage was automatically transferred to the back office databases with no data loss.

Field Experiment 2B: Cap Demand of PEV Charging System

April 24, 2015 to July 9, 2015

To perform this experiment, the team operated the Solar Car Shade in a power limiting mode and evaluated the ability of the system to prevent demand from exceeding a constant threshold. The team configured the system to generate PV power and discharge the battery as needed to prevent EVSE load from exceeding the threshold, as well as charge the battery using PV generation and/or grid power coming from any margin between lower EVSE load and the threshold. This mode attempted to prevent the UCI grid from seeing any BESS or EVSE load above the threshold at all times of the day, within the limits of the BESS power and energy capacity. This operation also addressed the dynamic nature of EV charging by adjusting the rate of battery discharge to match load in real time, and it reduced overall energy consumption of the charging station from the grid (through PV generation). The BESS was operational and the EVSEs were available for use by the UCI general population throughout the experiment period, excluding occasional maintenance, troubleshooting, and tour activities. These troubleshooting issues are described in more detail below.

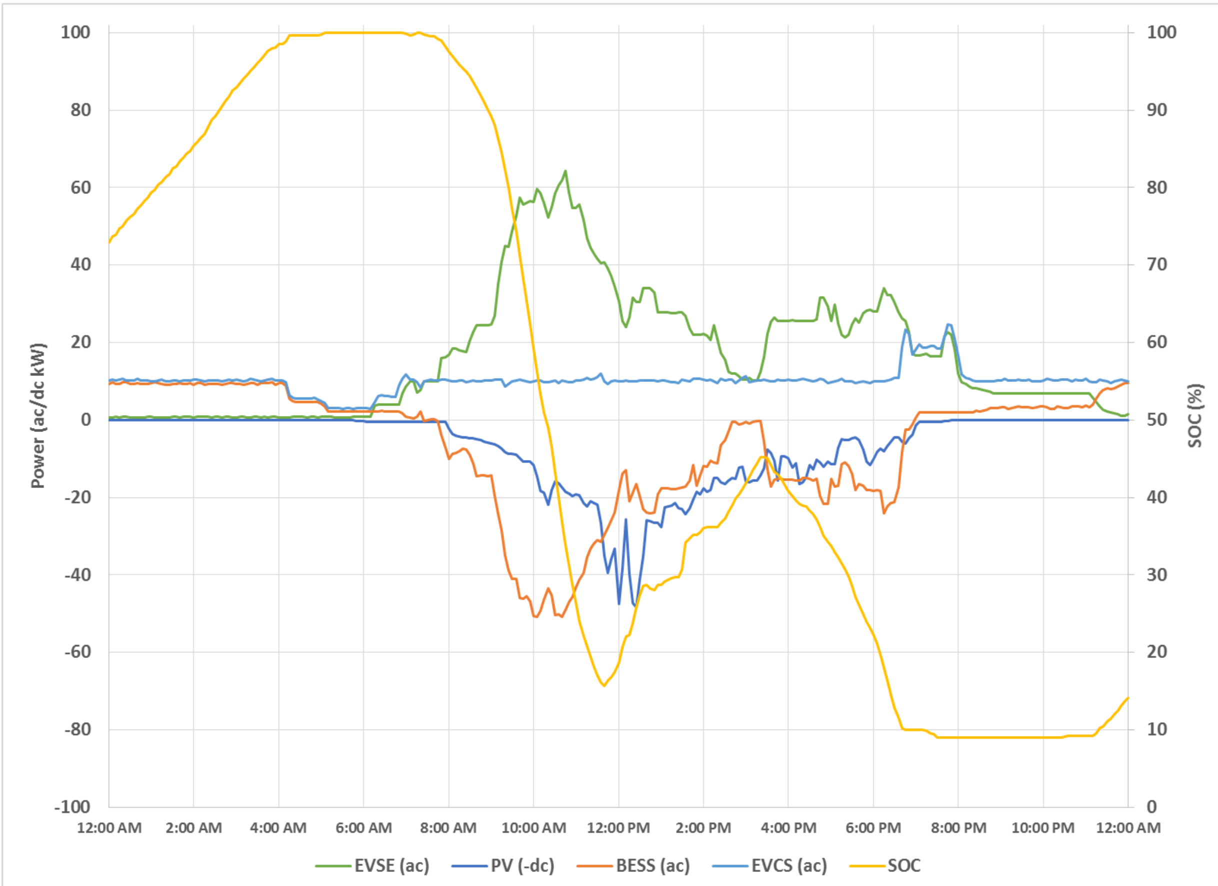
The team programmed the BESS' Site Controller with the following to carry out this experiment:

- Twenty-four hours per day, the BESS limited Solar Car Shade system demand to the set threshold, unless EVSE demand exceeds 75 kW (the 100 kW converter was limited to 75 kW to prevent nuisance trips) or the sum of available PV generation if the battery depleted. If the battery were to become depleted, the Solar Car Shade system demand would increase by the amount of the excess EVSE demand. The BESS charges the battery with any PV generation that is greater than EVSE demand, and curtails PV generation if the battery is fully charged and available PV generation exceeds EVSE demand. The BESS also charges the battery with grid power when EVSE demand is less than the threshold.
- In an attempt to optimize the daily charging and discharging of the battery, the threshold was changed as follows:
    - April 24 to May 4: 20 kW
    - May 4 to May 12: 10 kW
    - May 12 to July 9: 15 kW

Unlike the load shifting experiment described below, both EVSE load and solar PV generation affect the BESS charge and discharge rates. So, the BESS charge and discharge rates change based on dynamic electric vehicle charging activity, as well as solar incidence (sun angles and weather) and the efficiency of the solar PV array (temperature and dirt buildup). Greater levels of solar PV generation decreases the BESS' discharge rate, or may even cause the BESS to charge if it is great enough, since solar PV generation is used to power the EVSEs before battery energy. Similarly, higher EVSE demand and a lower threshold increases the battery's discharge rate, and may even completely discharge the battery on a day with high EVSE usage, low PV generation, and/or an initially low battery state of charge (SOC). In this case, the system is not able to prevent overall demand from exceeding the threshold.

Figure 159 presents the BESS power profile on May 5, 2015 with a 10 kW Solar Car Shade system threshold. This represents a weekday power profile as measured at the Solar Car Shade, main BESS (including battery and PV), and EVSE ac connections. This profile also includes solar PV generation (dc) and battery SOC.

Figure 159: BESS Weekday Power Profile (May 5, 2015)



In general, the Solar Car Shade is the sum of the BESS and EVSE. However, since the actual values come from three separate meters, this relationship is approximate. **Figure 159** demonstrates the system's ability to limit overall Solar Car Shade system demand to the threshold by dynamically charging and discharging the battery with PV generation and grid power.

Figure 159 also demonstrates the effect of limited battery capacity on the system's ability to limit demand to the threshold. On this particular day, between approximately 6:30 p.m. and 8:00 p.m., the Solar Car Shade system demand exceeded the 10 kW threshold as the battery was depleted, PV generation ceased, and EVSE load continued. If the battery had more capacity, the system would have been able to maintain the threshold for the entire day. Similarly, between approximately 4:00 a.m. and 6:30 a.m., overall system demand was noticeably less than the threshold, as the battery was fully charged and EVSE load was low. While system demand was still below the threshold, this is another example of the effect of limited battery capacity, but in the opposite direction. Interestingly, if the battery had approximately enough capacity to continue the morning charge and hold overall system demand at the threshold, it would have also had enough capacity to prevent overall system demand from exceeding the threshold later that evening.

This behavior also shows the effect of preexisting battery state of charge from the prior day, and its potential effect on the next day. In this case, the battery started at approximately 75 percent SOC from the previous day, which allowed it to continue charging in the early morning hours to a fully charged condition. However, over the course of the day, the battery reached a fully discharged state (ten percent SOC is considered fully discharged), and due to ongoing EVSE load late into the night, wasn't able to start recharging until approximately 11:30 p.m. By the end of the day, it was at only 15 percent SOC. This low state of charge is carried into the next day, and even with low EVSE load, would result in the battery not being fully charged before the next day's heavy EVSE usage begins. In turn, this would result in the battery fully discharging well before the end of the day, likely sometime during the peak of EVSE usage. This results in underutilization of the battery's capacity, since it would likely wind up cycling between a fully discharged condition and a moderately low SOC for the rest of the week, never reaching a full state of charge again until the weekend when there is lower EVSE usage.

In order to better use the battery's full capacity, it needs to be able to recharge each night. In order to accomplish this, the threshold needs to be increased, so the battery can use grid power to recharge overnight (an alternative may be to pair the battery with a larger PV array that could better keep the battery charged during the day). This is why the project team tried three different thresholds, first at 20 kW, then at 10 kW, and finally at 15 kW. The 20 kW threshold resulted in the opposite behavior from the 10 kW threshold, where the battery always fully recharged, and almost never reached a fully discharged state. This is because of the tradeoff where a higher threshold, while allowing the battery to full charge, also allows EVSE usage to be served more by the grid than the BESS, resulting in less BESS discharge. After the 20 and 10 kW thresholds demonstrated less-than-ideal behavior over multiple days of operation, the project team settled on 15 kW to optimize battery usage with respect to EVSE load.

Finally, **Figure 159** shows an interesting period of time between approximately 12:00 p.m. and 3:30 p.m., when the battery was being recharged with PV energy. During this period, PV generation was great enough that the BESS was able to continue providing power to maintain the 10 kW threshold, while also recharging the battery. Essentially, the battery was charging from PV, while the PV was also outputting power through the BESS main ac connection. When this contribution was combined with the 10 kW of grid power, the EVSE load was met.

During this experiment, the BESS experienced three failures and had 142 hours of down time and two hours of maintenance time. The first of the failures was related to internal safety faults designed to protect the system when the inverter or battery exceeds operational thresholds. In this case, the fault conditions were transient and the team had seen them before. Based on experience operating the system and recommendations from the integrator, the team reset the inverter and battery, which then resumed operation. This failure resulted in 25 hours of down time, reflecting the time it took an engineer to schedule a visit to the BESS, confirm the issue, and restart the system. This failure was due to integration issues with the various system components, and highlights the importance of ensuring subsystem compatibility and safety through integrator experience and extensive pre-deployment testing.

The second failure was related to incorrect minimum SOC settings on the BESS Site Controller. After restoring the system to operation following the previous trip, the minimum SOC setting was inadvertently left at zero percent, when it should have been set to ten percent. The BESS attempted to discharge the battery to zero percent SOC, which triggered the inverter's battery under voltage fault (as a preventative measure; the battery itself was not actually in an under voltage condition), causing a trip. This failure resulted in 109 hours of down time, reflecting the time it took an engineer to schedule a visit to the BESS, confirm the issue, and restart the system. The system was recovered by recharging the battery and confirming all set points were correct in the Site Controller. This failure demonstrates the importance of confirming system set points, especially after the system is operated outside of its normal range as part of restoration efforts or investigating other issues. This failure also points to the importance of clear, well-structured, user-friendly interfaces. One of the reasons the minimum SOC setting was inadvertently left at zero percent was due to the overall complexity of the user interface, making it easy to mistakenly change the incorrect set points or leave set points with incorrect values.

The final failure was caused by a battery voltage imbalance while the system was at 100 percent SOC. This imbalance was likely caused by the battery relaxing after completing a full charge, and different modules within the battery experiencing a drop in voltage at different rates. These different rates eventually caused a great enough imbalance that it caused the battery management system to trip the battery as a preventative measure. This failure resulted in 8 hours of down time, reflecting the time it took an engineer to schedule a visit to the BESS, confirm the issue, and restart the system. Once the system was restarted, the battery was discharged to relax the modules and remove the imbalance. The battery was then cycled over its normal operating range to better balance the modules and confirm the imbalance did not reoccur. Since all battery packs are comprised of multiple cells in parallel and series arrangements, they are prone to internal imbalances. Battery management systems monitor these imbalances as an indicator of potential battery problems. Different battery chemistries and cell configurations are susceptible to different levels of imbalance, and the battery management system is designed accordingly. In this case, the battery manufacturer established conservative imbalance limits that were triggered as the battery relaxed from a full charge. This highlights an operating characteristic of lithium-ion chemistries, where the battery is under maximum stress when close to full charge or full discharge. Therefore, most lithium-ion battery manufacturers recommend storing the battery at a moderate state of charge if inactive for extended periods of time. Also, the life of the battery can be extended by limiting the operating range.

Finally, the two hours of maintenance time were due to: 1) removing a power quality meter that was previously installed in support of investigating the EVSE pilot signal noise issue, and 2) replacing the inverter air filters.

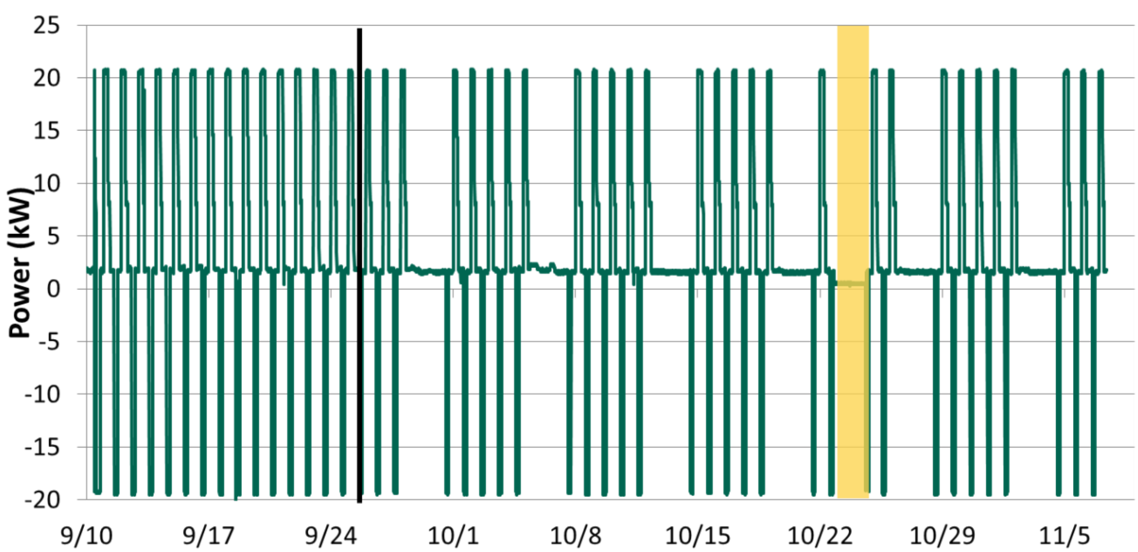
Field Experiment 2C: BESS Load Shifting

Test 1: Battery Only, September 10, 2013 to November 7, 2013

This experiment was a demonstration of the BESS' internal control mechanisms and long-term (approximately 8 weeks) performance using a scheduled constant power control algorithm. The test occurred between September 10 and November 7, 2013. During the test period, neither the solar PV nor the EVSEs were operational, so no other devices affected the BESS' performance. The team scheduled the BESS to charge at 12:00 am at a rate of 20 kW, and discharge at 2:00 pm (also at 20 kW) on a daily basis. The team altered the BESS' charge and discharge schedule once during the test period, and at one point, a system trip interrupted testing for about two days. The BESS operated with a time-based schedule that the team configured in the BESS site controller.

Testing confirmed that the BESS controls operated as expected throughout the test period. The BESS charged and discharged per the defined schedule. Below is a plot of the power of the BESS throughout the test period. As noted above, the initial schedule included a daily charge and discharge. However, on September 25 (identified by the black line), the schedule was modified to operate only on weekdays.

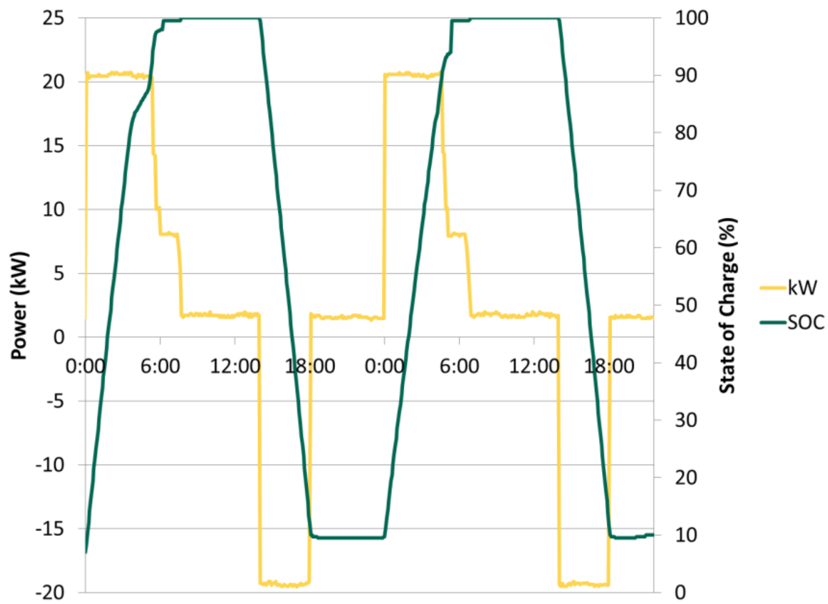
Figure 160: BESS Rate of Charge and Discharge



During the eight-week test period, the BESS tripped once on October 22, 2013 (identified by the yellow shaded region in **Figure 160**). The trip caused the system to safely shut itself down utilizing protections built into the system. The team immediately downloaded diagnostic data collected by the BESS and investigated the issue with the manufacturer. The manufacturer was unable to find the cause of the trip. This produced a lesson learned that is described further in chapter 3. The team successfully restarted the BESS manually during a visit on October 24, 2013. After the restart, the BESS resumed normal operation.

The BESS charged and discharged at 20 kW, until limited by the battery. The BESS began discharging at 2:00 pm and began charging at midnight. The system provided constant power during the discharge but saw a reduction in charging power as the battery neared a full SOC. **Figure 161** shows a typical daily 90 percent discharge. The charge tapers to just 8 kW when the battery's SOC exceeds approximately 90 percent. This plot also shows that the base load of the BESS is approximately 2 kW and that over 7.5 hours is required to fully charge the BESS when limited to 20 kW initially (the charge tapering increases the charge time).

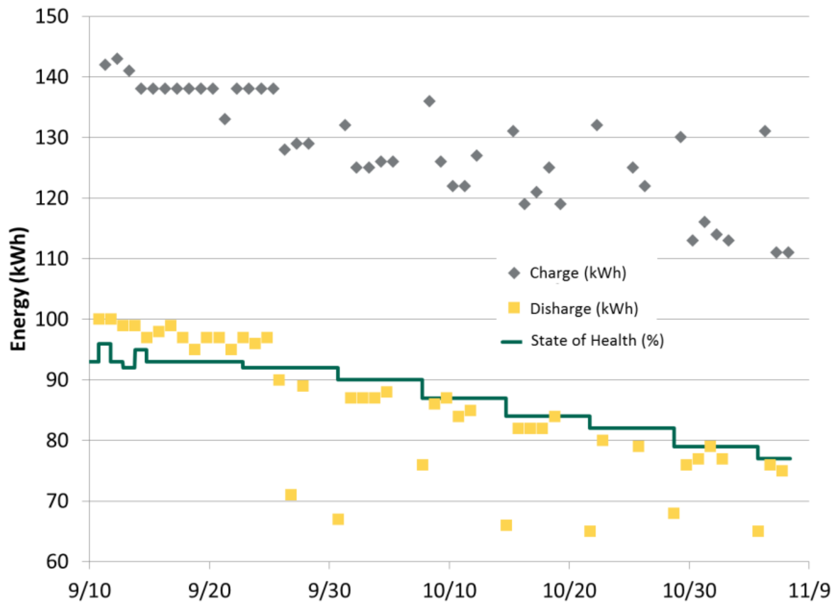
Figure 161: Daily Power Cycle Schedule for PLS



The second issue identified during testing was an artificially accelerated degradation in available battery capacity. Initial cycles discharged approximately 100 kWh AC as expected. However, after the eight-week test period, the available discharged energy was just 75 kWh AC. This performance degradation was realized by significant reduction in the "state of health" (SOH) measured by the battery management system (BMS)[36]. After discovering this issue, the team downloaded the diagnostic data and provided it to the BESS integrator and the battery manufacturer.

[36] The SOH is a manufacturer-specific algorithm that measures the battery's capacity degradation over time. The BMS uses the SOH to determine the BESS' amount of dischargeable energy. As the SOH decreases, the BMS limits the system's dischargeable energy. The BMS calculates the SOH by measuring the energy discharged by the battery once it discharges from a 100% SOC to an 8% SOC. Once the battery reaches an 8% SOC, the BMS compares the discharged energy measurement with the amount measured during previous cycle, and then adjusts the SOH (by up to 3% per cycle). If the amount of energy discharged is less than the amount discharged during the previous cycle, the algorithm adjusts the SOH downward.

Figure 162: BESS State of Health Degradation



SCE addressed this issue with the manufacturers. This behavior was due to a combination of unusual software calculation methods and the inverter using energy from the battery to operate. Several calculations act as inputs to determine the health and current state of the battery (including the SOC). These calculations erroneously indicated the battery was rapidly degrading and, thus, the BMS was artificially limiting the battery's discharge capacity. The manufacturer provided a firmware upgrade to fix this issue, and the BESS has now resumed operation at its expected capacity. Chapter 3 describes the lessons learned from this field experiment in more detail.

Test 2: Full System April 23, 2014 to October 31, 2014

To perform this experiment the team operated the BESS in a permanent load shift mode in conjunction with PV generation, and quantified the ability of the system to shift energy between on and off-peak periods. The team configured the system to charge at night and discharge during the day using constant power charge/discharge set points. This schedule effectively offset on-peak load with off-peak energy. This operation did not address the dynamic nature of EV charging, but it reduced the overall energy consumption of the charging station from the grid (through PV generation) and it also reduced on-peak demand. The BESS was operational and the EVSEs were available for use by the UCI general population throughout the experiment period, excluding occasional maintenance, troubleshooting, and tour activities. These troubleshooting issues are described in more detail below.

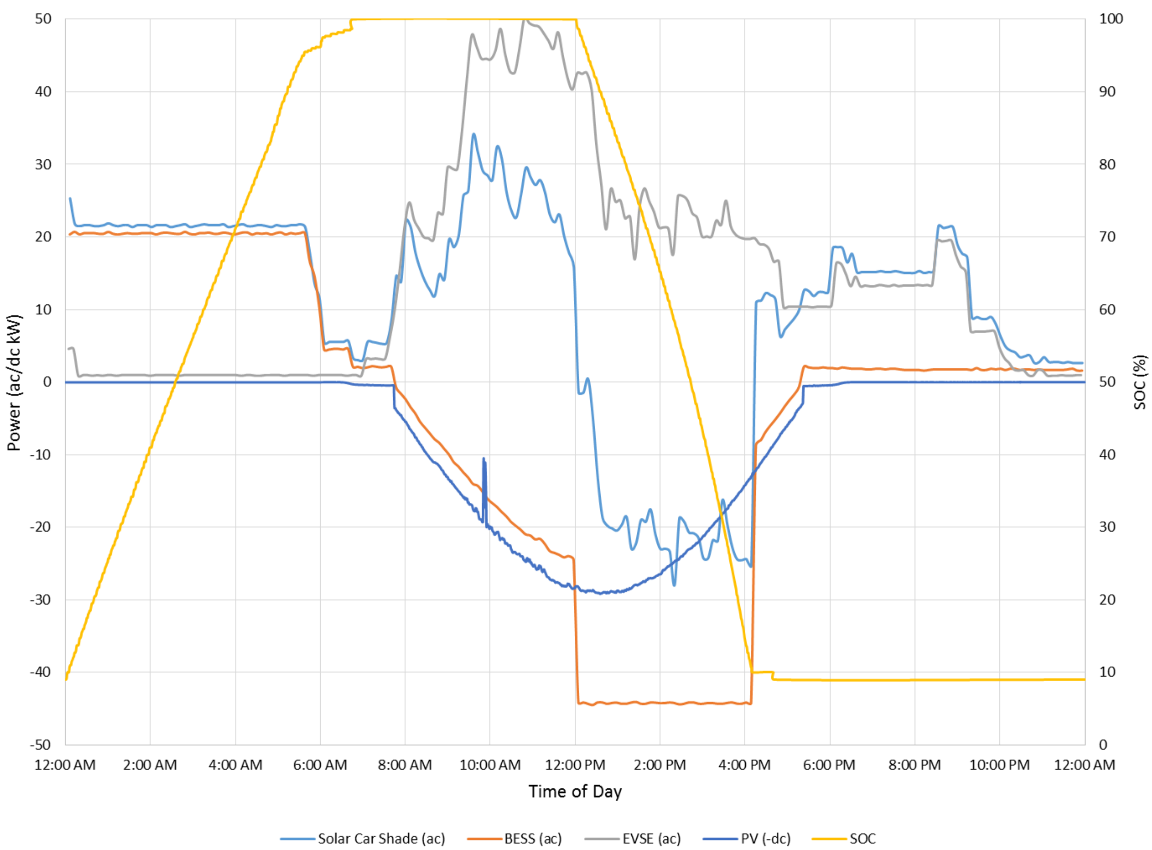
The team programmed the BESS's Site Controller with the following schedule to carry out this experiment:

- Monday through Saturday starting at 12:00 am, charge the BESS from the grid at a power level of approximately 20 kW. This includes 2 kW to operate the BESS, so the net power used to charge the battery is 18 kW. Charge the battery until the charge tapers back and reaches 100% SOC, then continue to draw grid power to operate the BESS.
- Every day starting at 6:00 am, supply all available solar PV output to the main BESS connection, where the power would either power the EVSEs (if there are electric vehicles charging), or feed back to the grid. This solar PV output would also power the BESS (2 kW). If the solar PV is insufficient, the BESS would operate using grid power.
- Monday through Friday starting at 12:00 pm, provide approximately 45 kW of combined power from the solar PV and BESS to power the EVSEs. If the EVSE load is less than 45 kW, the excess power would feed back to the grid. The BESS would modulate its discharge rate based on the solar PV output in order to maintain a combined power level of 45 kW between the BESS and solar PV.

EVSE loads do not affect the BESS discharge rate. However, solar PV generation does affect the BESS discharge rate. The BESS discharge rate changes based on solar incidence (sun angles and weather) and the efficiency of the solar PV array (temperature and dirt buildup). Greater levels of solar PV generation decreases the BESS's discharge rate after 6:00 am, and extends the discharge time of the battery past 12:00 pm on weekdays—since more solar PV generation reduces the battery rate of discharge in order to maintain 45 kW of combined solar PV and BESS power.

Figure 141 presents the BESS power profile on October 28, 2014. This represents the typical weekday power profile as measured at the Solar Car Shade, main BESS (including battery and PV), and EVSE ac connections. This profile includes the 20 kW load/charge starting at 12:00 am, PV generation starting at 6:00 am, and the constant 45 kW output starting at 12:00 pm. This figure also includes solar PV generation (measured in DC) and battery SOC.

Figure 163: BESS Weekday Power Profile (October 28, 2014)



In general, the Solar Car Shade is the sum of the BESS and EVSE. However, since the actual values come from three separate meters, this relationship is approximate. **Figure 163** demonstrates the system's ability to shift energy by charging the battery during an off-peak period (from 12:00 am to approximately 6:00 am at 20 kW), and discharging during an on-peak period (from 12:00 pm to approximately 4:00 pm). The solar PV generation during the discharge period has the effect of extending the discharge time. At 45 kW, the 100 kWh battery takes a little over two hours to discharge. However, the solar PV generation causes the battery's rate of discharge to decrease, which extends the discharge duration. In this example, the solar car shade's solar PV generation varies from 12 kW to 29 kW during the discharge, and extends the battery by approximately two hours.

This figure also demonstrates the system's ability to decrease on-peak demand. Without the BESS (including the solar PV), the Solar Car Shade's net load on the grid would have the same load profile as the EVSE. However, the BESS's daytime solar PV generation reduces the morning peak of the Solar Car Shade, while the afternoon solar PV generation and battery discharge creates a net surplus of generation, which feeds back to the grid. Only after the battery is discharged does the constant 45 kW generation stop. Once the battery stops discharging, the solar PV generation continues for approximately one more hour, helping to offset the Solar Car Shade load. Once the PV generation stops, the Solar Car Shade load profile matches the EVSE plus BESS auxiliary loads.

Figure 163 demonstrates the limitations of a constant power-based schedule, which does not address the dynamic nature of EVSE load. Even though the system reduced peak demand and shifted energy from on to off-peak periods, the overall Solar Car Shade load profile continued to vary with EVSE load. Similarly, the constant power, time-based discharge, in addition to the finite battery capacity, resulted in the Solar Car Shade generating power between 12:00 pm and 4:00 pm, but then consuming power for the rest of the evening and night. If the battery capacity was larger or the schedule was adjusted to decrease the afternoon discharge power to more closely match EVSE load, the discharge period would have been longer and further reduced the demand of the Solar Car Shade on the grid. More sophisticated control strategies such as load smoothing or cap demand or more intelligent algorithms capable of adjusting timing and thresholds based on past behavior—would help to improve the overall performance and value of the BESS in supporting the Solar Car Shade.

Over the course of this experiment, which lasted more than six months, the BESS experienced four failures and had 244 hours of down time and nine hours of maintenance time. Two of the failures related to internal safety faults designed to protect the system when inverter/battery exceeds operational thresholds. In both cases, the fault conditions were transient and the team had seen them before. Based on experience operating the system and recommendations from the integrator, the team reset the inverter and battery, which then resumed operation. Together, these failures resulted in 108 hours of down time, reflecting the time it took an engineer to schedule a visit to the BESS, confirm the issue, and restart the system. These types of failures relate to the integration of the various system components, and highlight the importance of ensuring subsystem compatibility and safety through integrator experience and extensive pre-deployment testing.

Another failure related to incorrect instantaneous trip settings on the main AC circuit breaker feeding the BESS. The team was aware of this issue before the start of the experiment, as it had previously caused multiple nuisance trips. However, the team believed they could perform the experiment with the existing trip settings due to the specific operating schedule of the BESS and associated current inrush during daily inverter startup. This allowed the experiment to proceed while the team performed a coordination study to determine new trip settings. Once the new trip settings are in-place, this type of failure should not reoccur. This failure resulted in 50 hours of down time, reflecting the time it took an engineer to schedule a visit to the BESS, confirm the issue, and restart the system. This failure demonstrates the importance of ensuring all protective devices (e.g., circuit breakers) are coordinated and adjusted appropriately for the load during installation, rather than retaining their manufacturer default settings.

The final failure was a loss of communication with the BESS, preventing remote status checks, control, or data transfer. Throughout the communication loss, the BESS continued to operate as programmed, so this failure did not contribute to the hours of down time metric. The team resolved this issue by visiting the BESS and restarting the system's internal 4G cellular radio and router.

The remaining down time was due to an engineer incorrectly logging off from the BESS's Site Controller computer during a routine status check. This caused the control software to close, and a subsequent BESS trip. The system remained in this state over the weekend, and then another engineer remotely reset and restarted the system 66 hours later. This issue demonstrates a disadvantage of using a consumer/commercial-off-the-shelf approach to system integration. In this case, the manufacturer chose to run their system control software on an embedded computer running a standard version of Windows 7. This approach makes it simple to inadvertently log off from the embedded computer rather than disconnecting from remote desktop sessions. If the system integrator had customized Windows to prevent logging off, or had used an always-on industrial embedded control system to operate the BESS, this type of issue would be less likely to occur.

The nine hours of maintenance time was due to safety tours and checks of the BESS, as well as short pauses in the experiment to manually operate the BESS as part of power quality testing. The power quality testing resulted from issues with the EVSEs, where certain PEV makes/models were unable to charge. This behavior was due to electrical noise on the EVSE pilot signal (a form of communication between the PEV and EVSE), originally thought to originate from the BESS inverter's power electronics. This issue was investigated over multiple trips to the site, including engineers, power quality experts, and the EVSE manufacturer. Finally, the power quality expert discovered that the two transformers feeding the EVSEs from the Solar Car Shade System's main panel had been grounded incorrectly during installation. This resulted in high levels of electrical noise on the secondary side of the transformers, which was carrying over to the EVSE pilot signal. While most PEVs could charge with the noise present, some PEVs were more sensitive and refused to charge. Once the team properly grounded the transformers, the electrical noise diminished and all PEVs could charge normally.

7.2 Next-Generation Distribution System

7.2.1 Sub-project 3: Distribution Circuit Constraint Management Using Energy Storage

This sub-project demonstrated a mobile, containerized DBESS that could be used to help prevent load on the distribution circuits from exceeding a set limit and to mitigate overheating of the substation getaway. The team moved the DBESS from its original location at one of SCE's energy storage laboratories to the field in March 2014, and first connected it to the grid on April 15, 2014. This section summarizes the laboratory testing performed on the DBESS prior to field deployment, as well as the commissioning activities after its move to the field. This Final Technical Report summarizes the results of the field experiment activities for sub-project 3. Since the DBESS's commissioning, the team has operated it to support Sub-project 6: Deep Grid Situational Awareness (see section 4.2.4).

7.2.1.1 Laboratory Testing

In December 2009, SCE acquired two 2-MW/0.5 MWh grid battery systems to gain firsthand experience with the operation and performance of large containerized energy storage devices. One of these battery systems was later relocated to Irvine to be used for the ISGD DBESS experiments.

SCE performed an extensive evaluation under a tightly controlled environment at its facilities in Westminster, California. Based on these evaluations, the system was effective in reducing circuit overloads by automatically and continuously injecting or absorbing energy. The monitoring equipment and control algorithm used to implement the feeder relief function performed as expected.

7.2.1.2 Commissioning Tests

The team relocated the DBESS to the field in March 2014. Between March and April, the DBESS's battery and battery management system trays were inspected and reinstalled in the battery racks (originally removed for transportation), and the mechanical and electrical connections between the auxiliary equipment skid and battery/inverter container were reconnected. The auxiliary skid was also connected to the new interconnection equipment installed at the site, which serves as the interface between the utility distribution circuit and the DBESS.

The team first connected the system's auxiliary skid to the grid on April 15, 2014. Project engineers then energized the DBESS's auxiliary power circuits and verified the operation of all supporting systems throughout the auxiliary skid and battery/power conversion system (PCS) container, including the chiller, in-row air conditioners, dehumidifier, control system HMI, control system PLC, battery management system, control system uninterruptible power supplies, fire suppression system, primary lighting system, and emergency lighting system. After checking all auxiliary systems against manufacturer installation, operation, and maintenance manuals, the team closed the DBESS's primary power circuit disconnects and circuit breakers. The team then started the DBESS, including closing the battery rack contactors and synchronizing the PCS with the grid.

Over the following several weeks, the team operated the system manually through several charge/discharge cycles to help balance the battery racks and verify the overall operation of the system. During this time, the team installed a power quality monitoring (PQM) system between the interconnection equipment and auxiliary skid to locally record the system's actual real and reactive power dispatches in support of sub-projects 3 and 6. The team also installed an industrial 4G cellular radio to connect the PQM with the project's pilot production network and allow for remote data access.

Other commissioning activities included the installation of a mobile office for local operation and maintenance visits, development of a site-specific safety policy, and a PCS output calibration by the manufacturer (which increased the real power dispatch accuracy of the control system). The DBESS was ready for experimentation by September 18, 2014.

7.2.1.3 Field Experiments

Field Experiment 3A: Peak Load Shaving/Feeder Relief

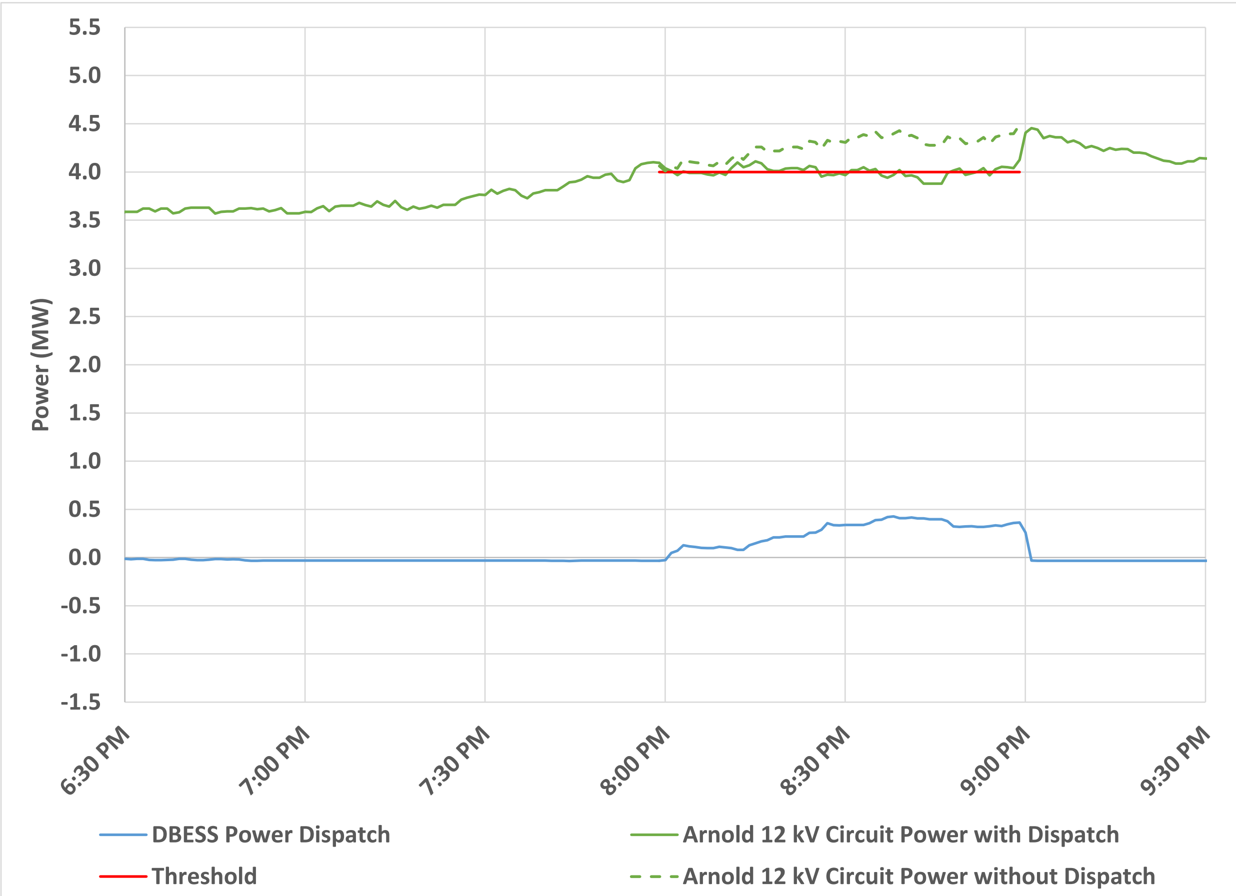
The purpose of this experiment was to demonstrate the ability of the DBESS to provide peak load shaving/feeder relief in support of distribution circuit operations. Normally, BESSs are installed on distribution circuits to address actual operational constraints, such as high line loading, intermittency in load and/or generation, or overheating of the substation getaway. In this case, the DBESS was connected to the Arnold 12 kV circuit out of MacArthur Substation, which was a relatively lightly loaded residential distribution circuit. Therefore, the circuit did not have any operational constraints throughout the project duration, and the DBESS wasn't dispatched in a realistic circuit relief scenario.

However, the team still demonstrated the ability of the DBESS to affect the loading of the circuit through various charges and discharges as part of operation in support of Subproject 6. On an average summer day, load on the Arnold 12 kV circuit varied between 2.5 and 6.5 MW. With the DBESS performing a full power charge or discharge, these values could be changed by up to 2 MW in either direction. In cases with low circuit load and a full power discharge, the circuit could have almost no load, and in other cases with high circuit load and a full power charge, the circuit could have up to 8.5 MW of load. Due to the amount of load on the circuit relative to the size of the DBESS, all DBESS dispatches at full power (especially step changes with no ramp) were very noticeable at the 12 kV circuit level. However, due to the circuit's light loading, none of these dispatches created operational concerns or constraints that limited the DBESS' operation.

The team performed a peak load shaving/feeder relief experiment specifically for Field Experiment 3A during summer 2015. The Arnold 12 kV circuit is a mainly residential distribution circuit with a predictable evening peak between 8:00 and 9:00 p.m., and a corresponding morning trough between 4:00 and 5:00 a.m. To demonstrate the ability of the DBESS to provide feeder relief during a peak period, the team scheduled this experiment to correspond with a typical summertime evening peak.

In preparation for the experiment, the team charged the DBESS several hours prior to the evening peak. Then, at 8:00 p.m. (the typical start of the evening peak), circuit load was 4 MW. The team used this value as a threshold to dynamically dispatch the DBESS to keep net circuit load from exceeding 4 MW. **Figure 164** shows the circuit load and DBESS dispatch.

Figure 164: DBESS Peak Load Shaving/Feeder Relief



The red line in **Figure 164** represents the 4 MW power threshold used to dispatch the DBESS. The blue line is the measured dynamic power dispatch of the DBESS, and the solid greed line is the measured power of the Arnold 12 kV distribution circuit. The dashed green line is the projected loading of the circuit without the DBESS dispatch, calculated by adding the measured DBESS dispatch to the measured circuit load. As shown above, the DBESS successfully held circuit power at the 4 MW threshold between 8:00 and approximately 9:00 p.m. However, by 9:00 p.m., the DBESS' 500 kWh battery was completely discharged, and was unable to continue holding the circuit at 4 MW.

This demonstrates the importance of sizing battery energy storage systems for their intended application. While the DBESS has an appropriate power rating of 2 MW (well suited for a typical 12 kV distribution circuit on SCE's system), its energy storage capacity of 500 kWh is fairly small. This system was originally intended to provide short duration, high power dispatches for frequency regulation and ramping services on the open market. It is not well suited to performing distribution or grid operation functions, which typically require much longer charge/discharge durations at similar power levels. Since this system was purchased prior to the ISGD project, its power and energy ratings were already chosen for other, more appropriate applications. However, the basic ability of a BESS to perform peak load shaving or feeder relief functions is still demonstrated above.

Figure 164 also shows that the instantaneous circuit peak for the day occurred around 9:00 p.m., rather than around 8:30 p.m. as originally expected. Therefore, the circuit peaked at around the same time the DBESS was fully discharged and unable to continue keeping the circuit from exceeding 4 MW. Again, this shows the importance of sizing battery energy storage systems. A higher capacity system could have continued discharging through the peak. A higher capacity system also could have started earlier and ended later, at a lower threshold, to "shave" a greater amount of peak energy or provide feeder relief for a longer duration.

7.2.2 Sub-project 4: Distribution Volt/VAR Control

During the period covered by TPR 1, the team completed the simulations, laboratory testing and system integration activities, leading to the successful implementation of DVVC on the ISGD DMS in January 2014.

During the period covered by TPR #2—March 1, 2014 through October 31, 2014—the team successfully operated the system. A number of issues involving the electric system under DVVC control arose during this period. For example, without the ISGD team's knowledge, SCE Grid Operations transferred some circuits to a different substation operating bus, and some circuit capacitors were temporarily out of service. These issues brought the early field experiment results into question. The last of these issues was not resolved until early October 2014. Nevertheless, the qualitative performance of the DVVC met the team's expectations, with the system producing lower overall voltages of approximately 1.5 to 2 volts (on a 120 volt base) while operating in CVR mode. An average reduction of 1.75 volts (or 1.45%) and a CVR factor of 1.0 translates into energy savings of approximately 1.45%.

During the final portion of the demonstration period – November 1, 2014 through June 30, 2015, the system continued to operate normally.

7.2.2.1 Simulations

In January 2012, the vendor's technical team that supported sub-project visited SCE to begin discussions regarding the software and hardware requirements for DVVC. The ISGD team presented the methodology that the DVVC algorithm should follow by demonstrating it with an in-house Microsoft Excel-based software solution. The vendor team then documented the DVVC algorithm definition, which it would use to implement the software solution for ISGD.

In April 2012, SCE obtained a very early version of the vendor software. SCE tested the DVVC algorithm under various scenarios to check the algorithm logic, and provided feedback to the vendor to further refine the software. A few months later, SCE tested the algorithm logic of the DMS DVVC software on a server utilizing GE's XA21 platform. SCE performed side-by-side test scenarios using SCE's Microsoft Excel model as a baseline for evaluating the DMS DVVC test results. These scenarios were designed to demonstrate the ability of the DVVC application to reduce or raise average system voltage using field capacitors, substation capacitors, or combinations of both. Likewise, these tests were designed to demonstrate "pushing" or "pulling" VARs between distribution and sub-transmission systems. Both of these sets of simulations also demonstrated the ability of the DVVC algorithm to limit the number of capacitor switching operations. These tests relied solely on the vendor software, and did not use any field devices.

The team performed simulations of the substation operating bus and seven circuits under DVVC control using a representative set of circuit loading conditions. The simulation results confirmed the DVVC design.

7.2.2.2 Laboratory Testing

Between August 2012 and December 2012, SCE developed tests for evaluating DVVC during factory acceptance testing(FAT) and site acceptance testing (SAT). The purpose of these tests was to evaluate the DVVC algorithm by using actual field devices (i.e., programmable capacitor controllers or PCCs). This consisted of evaluating the DVVC algorithm by performing end-to-end testing from the software to the field devices. The purpose of this testing was to demonstrate the ability of the DVVC algorithm to receive telemetered inputs from the PCCs, derive an optimal PCC switching solution, and either raise or reduce voltage, or provide reactive power to the sub-transmission system. Acceptance test procedures (ATP) were aligned with the DVVC business requirements to ensure that the FAT and SAT testing would demonstrate that DVVC met SCE's requirements.

To facilitate end-to-end testing in a laboratory, the DVVC vendor set up a test environment in their product testing facility, to emulate SCE's Advanced Technology Labs in Westminster, California. This laboratory included four S&C Electric IntelliCAP Plus PCCs and four Netcomm radios. Variable transformers provided distribution circuit primary voltage inputs and provided a power sources to the PCCs. The vendor server housing the DVVC algorithm was configured to the PCCs via the radio network. This system was used throughout the various FAT cycles in 2013, including a round of Pre-FAT testing, and two rounds of FAT testing. SCE personnel witnessed and approved all vendor ATPs, ensuring that the application satisfied ISGD's DVVC application requirements.

SCE conducted the first round of SAT testing in September 2013. This testing used the same test scenarios and ATPs as FAT. During the second round in October 2013, SCE verified that the DVVC application satisfied all of SCE's business requirements.

The team performed both factory and site acceptance testing, as reported in the first TPR, confirming the successful integration of DVVC, ISGD Distribution Management System, and all field components.

7.2.2.3 Commissioning Tests

The ISGD team performed field testing of the DVVC algorithm in December 2013 for approximately two weeks. This testing verified that DVVC could communicate with the field PCCs and the PCC at MacArthur Substation. The algorithm made the correct selections for switching PCCs. During field-testing, the team encountered a connectivity problem with SCE's Netcomm radio network. A firmware upgrade to this network disabled some of the radios, which limited the DVVC algorithm's ability to deliver switching commands to all the PCCs.

The DVVC application became operational at MacArthur Substation in January 2014 for the team to experiment with the volt/VAR control set points. The team monitored the distribution system's behavior closely, and adjusted the set points when appropriate. To assess the reliability of radio communications for the DVVC algorithm's control signals, the team also monitored the Netcomm Radio system. The DVVC application's logic was determined to be successful during these field tests. The overall impact on average system voltage was also consistent with the team's expectations.

7.2.2.4 Field Experiments

The ISGD team began operating the DVVC algorithm in January 2014. The first TPR stated that the preliminary results indicated that it was performing as expected.

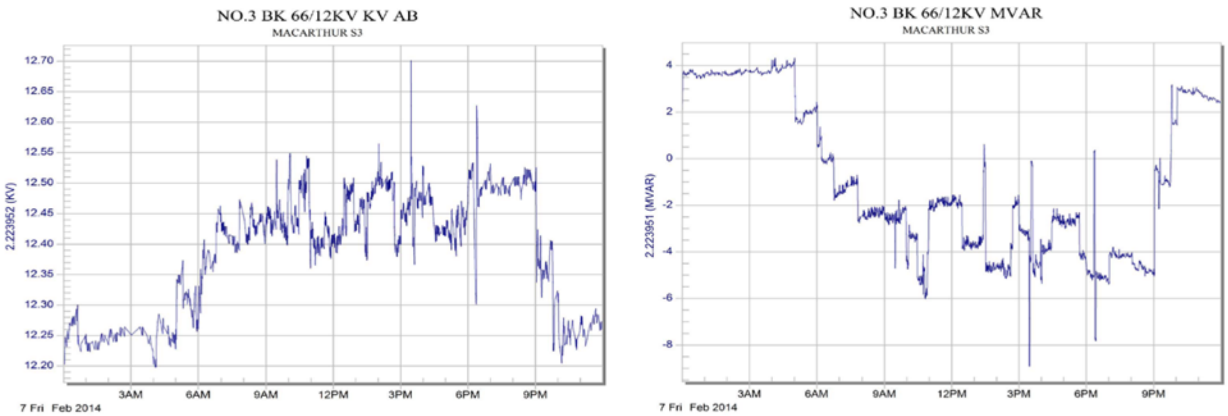
The second TPR covered the period from March 1, 2014 through October 31, 2014. The team operated the DVVC application throughout this period and it performed as expected. However, a number of unexpected issues arose that affected the testing. These issues included the loss of the substation current transformer (CT) from March 21 through May 30, the unavailability of the substation and some field capacitors for much of the period, and periods in which one or more of the circuits under DVVC control where mistakenly transferred to the bus not under DVVC control. As a result, the system operated in its intended configuration for only four weeks, between October 3 and October 31, 2014.

Despite these difficulties, the system performed largely as expected. The DVVC application was turned on and off for alternate weeks throughout the eight month period, always in the CVR mode. Voltages both at the substation bus and on a sample of customer AMI meters were approximately two volts lower on a 120 volt base (and with fewer fluctuations) when DVVC was operating.

Field Experiment 4A: DVVC VAR Support

The VAR support mode of operation is an abnormal mode that would only be useful under limited circumstances. The team would only operate DVVC in this mode if the sub-transmission system's reactive power needs were urgent enough to have the distribution system supply VARs to it. This would require having more capacitors on line, which would in turn require operating the distribution system near the upper range of ANSI C84.1 voltages. **Figure 165** shows the VAR and voltage levels on one of the MacArthur Substation busses on February 7, 2014, when DVVC operated in the VAR support mode. For this test, the maximum voltage was set at 125 volts on a 120 volt nominal basis. As voltage is raised from 122.5 to 125 volts, the reactive power flow changed from 4 megavolt-amperes reactive (MVAR) flowing into the substation to 5 MVAR flowing out of the substation into the sub-transmission system.

Figure 165: VAR Support Mode (February 7, 2014)



Field Experiment 4B: DVVC Conservation Voltage Reduction

DVVC began operating in CVR mode on alternate weeks beginning in January 2014. During the weeks when DVVC was off, the individual capacitors were set to operate autonomously with appropriate settings. When DVVC was on, the individual capacitor voltage settings were set to not interfere with DVVC operation, but to act as backups if voltage became too high or low. **Figure 166** shows the voltage on a MacArthur Substation bus over approximately four weeks. DVVC operated in CVR mode on periods between February 17, 2014 and March 21, 2014, resulting in a clear voltage reduction compared with the weeks immediately before and after (when DVVC did not operate). The SCADA system used for this graph takes data at four-second intervals. Fluctuations also seem to decline when DVVC is on.

Figure 166: Substation Bus Voltages with DVVC in CVR Mode (February 15, 2014 to March 15, 2014)

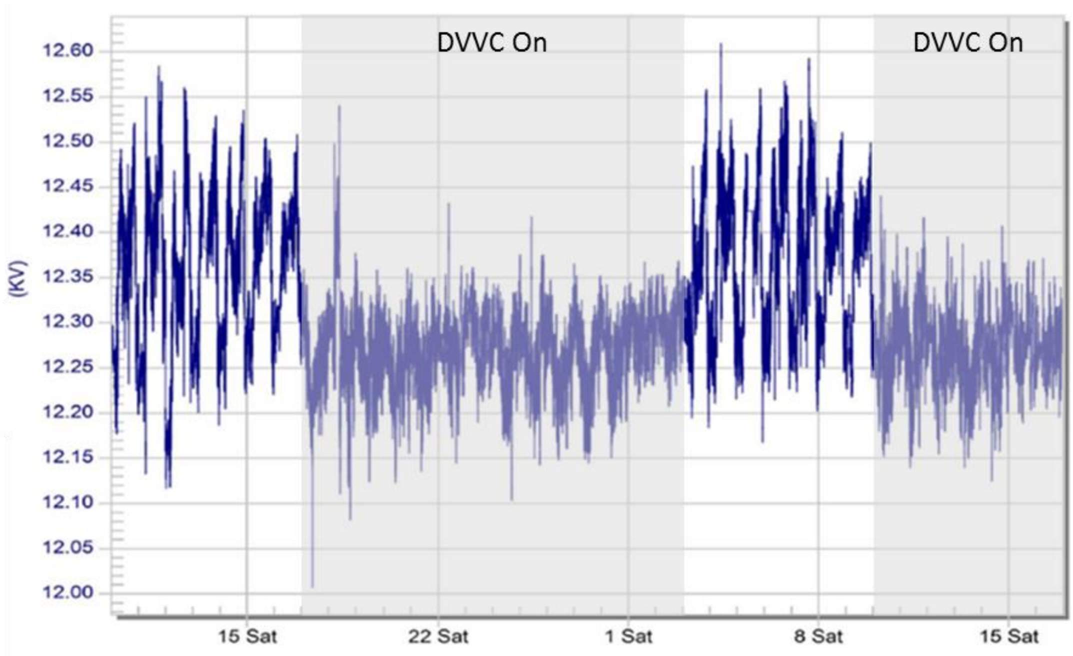
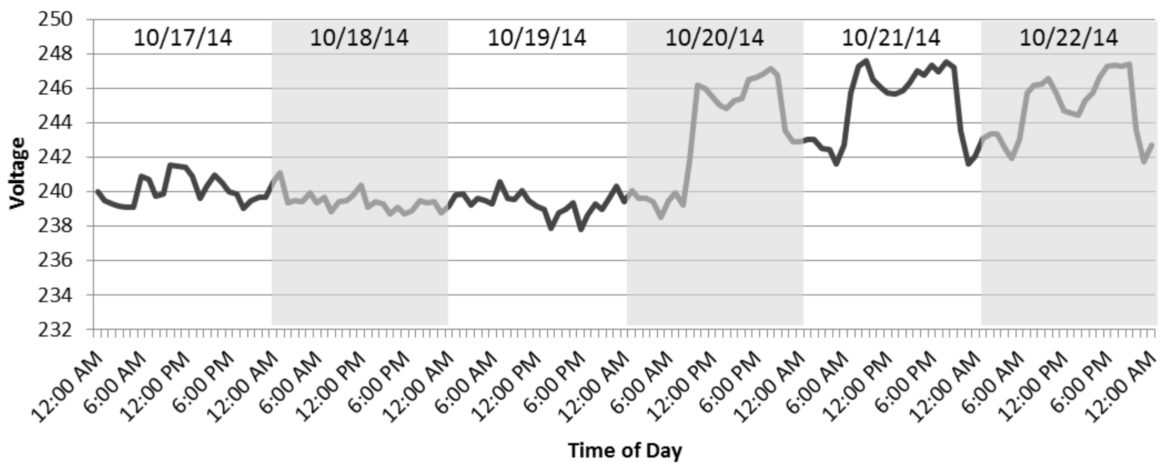


Figure 167 provides the voltages from an AMI meter over a six-day period. DVVC was turned on for three days (October 17, 2014 to October 19, 2014), and turned off for three days (October 20, 2014 to October 22, 2014). These meters are capable of capturing the average voltage value for each hour. This figure reveals material reductions in both the absolute voltage levels and voltage variability.

Figure 167: Customer Voltages with and without DVVC (October 17, 2014 to October 22, 2014)



Once the circuit anomalies mentioned in section 4.2.2 were rectified in early October 2014, the team obtained voltage and energy consumption data for two sets of alternate on-off weeks. For each week, the team averaged all of the voltage readings from the 14 field capacitors (one capacitor was out of service) and the substation bus. **Table 60** summarizes the results of these on/off periods.

Table 60: DVVC CVR Results (October 6, 2014 to November 10, 2014)

Time Period	DVVC	Average Voltage	Energy kWh	CVR (ΔkWh%/ΔV%)
Oct 6 – Oct 13	Off	121.8	4,009,010	5.7/1.5=3.6
Oct 13 – Oct 20	On	120.0	3,780,000	
Oct 28 – Nov 3	On	119.8	3,068,990	3.2/1.96=1.6
Nov 4 – Nov 10	Off	122.2	3,172,990	

The average CVR factor for these two test periods is 2.6, which is much higher than the team's expected 1.0 (based on SCE's results with DCAP), as well as the 0.4 to 1.0 range mentioned in the EPRI survey of 52 utilities[37]. The team did not perform weather adjustments for the weekly comparisons, and two periods on only seven circuits is a small sample compared to the 172 circuits measured in the DCAP program. The team has not reached any conclusions about the impacts of DVVC. The above information for information purposes only.

The team made a few observations during this initial period of operating DVVC. A system such as DVVC operates on a substation bus and all of the circuits connected to that bus. If one circuit has chronically low voltage near its end, that low voltage point acts as a constraint on what the DVVC can do for the rest of the system. Actions to correct such weak spots could free the DVVC to achieve greater overall results. For example, siting a line regulator or smaller capacitor bank closer to the end of the line could increase end-of-line voltages without increasing voltage levels on the rest of the circuit.

The configuration of circuits in the MacArthur Substation in support of the ISGD project is maintained manually. There is no automatic updating of the DVVC when operators switch a circuit from one bus to another. Inevitably, required notifications sometimes fail when human action is required. A full implementation should link the DVVC to the

[37] Volt-VAR Optimization Survey Summary presentation, March 15, 2012.

substation EMS-SCADA system and the field OMS system such that DVVC is aware of configuration changes when they occur.

VVO schemes such as DVVC can result in significant energy savings. They work best when careful attention has been given to establishing proper voltage schedules, transformer tap settings, and circuit design.

Final Demonstration Period Supplement

During the final eight months of the demonstration period (November 2014 through June 2015) the DVVC system continued to operate as before. The team identified no subsequent periods of incorrect circuit alignments and focused its efforts on developing a better estimate of the CVR factor.

From October of 2014 through August of 2015 the team observed energy consumption over sixteen two-week periods, each with DVVC on one week and off the next, in an effort to estimate the CVR. The energy consumption for the week with higher average peak temperatures was adjusted downward to compensate for the known temperature sensitivity of load. The calculated CVR was 1.56. This is higher than generally observed in industry. The method of adjusting weekly load based on weekly average high temperatures is less rigorous than one using the daily three-day weighted training average of peak temperature for load adjustment. The more rigorous approach yielded a CVR of about 1.0 during the DCAP project and even lower figures reported by other utilities. The team considers the current results to simply confirm the continuing validity of the DCAP measurement.

Table 61: CVR Measurements

DVVC Off Week	Temperature Adjusted Load	DVVC On Week	Temperature Adjusted Load	Voltage Decrease
Oct. 6-12, 2014	3,665.4	Oct. 13-19, 2014	3,780.0	1.5%
Nov. 4-10, 2014	2,852.1	Oct. 28 - Nov. 3, ‘14	3,069.0	2.0%
Nov. 17-23, 2014	3,071.0	Nov. 24-30, 2014	2,716.4	1.9%
Jan. 23-25, 2015	1,117.5	Jan. 30 – Feb. 1, ‘15	1,179.0	1.6%
Feb. 2-8, 2015	3,441.0	Feb. 9-15, 2015	3,218.7	1.3%
Feb. 16-22, 2015	3,227.3	Feb. 23–Mar. 1, ‘15	3,290.0	1.4%
Mar. 2-8, 2015	3,398.0	Mar. 9-15, 2015	3,254.9	1.4%
Apr. 6-12, 2015	3,285.0	Apr. 13-19, 2015	3,085.4	1.8%
Apr. 20-26, 2015	3,326.0	Apr. 27-May 3, ‘15	2,847.4	1.7%
May 4-10, 2015	3,356.0	May 11-17, 2015	3,192.9	1.8%
May 19-24, 2015	2,864.0	May 26-31, 2015	2,736.7	1.5%
Jun. 1-7, 2015	3,502.0	Jun. 8-14, 2015	3,529.7	2.1%
Jun. 15-21, 2015	3,748.0	Jun. 22-28, 2015	3,733.9	1.4%
Jul. 6-12, 2015	3,554.0	Jul. 13-19, 2015	3,444.2	1.3%
Aug. 3-9, 2015	4,096.0	Aug. 10-16, 2015	4,045.0	1.2%
Aug. 17-23, 2015	4,294.0	Aug. 24-30, 2015	4,337.5	1.3%
Total MWh	**52,797.3**		**51,460.7**	
Delta MWh and Volts (%)			**2.53%**	**1.58%**
CVR Ratio				**1.61**

7.2.3 Sub-project 5: Self-healing Distribution Circuits

This project is demonstrating a self-healing, looped distribution circuit that uses low-latency radio communications to locate and isolate a fault on a specific circuit segment, and then restore service once the fault is removed. This protection scheme is designed to isolate the faulted circuit section before the substation breaker opens (typically 670 milliseconds after a fault). This functionality should lead to improved distribution circuit reliability by reducing the number of customers exposed to momentary outages and easing the circuit restoration burden on system operators.

7.2.3.1 Simulations

The team performed simulations to determine the maximum load levels for which looped operation is appropriate. Additional simulations helped to verify the fault isolation logic and timing for a wide range of operating conditions. The simulations included various fault scenarios at different locations on the Arnold and Rommel 12 kV distribution circuits. They also included different types of faults at each location (all combinations of phase to ground, phase to phase, double phase to ground, and a three-phase fault). Faults were simulated at each section of load between the protection relays to verify that they operate correctly. The team performed these simulations using SCE's RTDS with the actual protective relay inputs and outputs attached to the simulator for closed loop testing. Outputs from the RTDS were physically connected to four Schweitzer Engineering Laboratories (SEL) 651Rs and two GE F60 relays.

The team reviewed all event files and oscillography files when the simulations produced an undesired outcome. These files helped the team to troubleshoot the protection logic. When changes were required for the protection settings, the team repeated all the testing.

The simulation testing was successful in validating the system protection scheme, and helped the team identify the need for a few modifications to the protection settings. The biggest issues were false tripping under heavy-load conditions, box loops around URCIs (which effectively bypass the URCI), and clearing end-of-line faults. To address the heavy-load issue, the team decided that if the circuit loading exceeds 600 amps (i.e., the combined loading of the two looped circuits), then the Arnold and Rommel circuits would be de-looped to prevent both circuits from tripping. In the event that a box loop[38] forms around a URCI, the two circuits would be de-looped to minimize the number of customers affected by the fault. The last issue related to end-of-line faults. The protection scheme required six seconds to clear a three-phase fault at the end of the line. To resolve this issue the team reduced the trip settings on two of the URCIs.

7.2.3.2 Laboratory Testing

The team assembled and tested the relays and radios as a system prior to field installation to verify that they function and perform properly. They imposed actual circuit fault conditions (derived from simulation tests) on the assembled laboratory test setup, and recorded the protection scheme responses. High-speed communications system performance was also verified in the laboratory. The team also evaluated the SA-3 system's ability to coordinate with the URCI protection scheme.

Since the scheme could not be tested by inducing actual faults on live circuits without impacting customers, the team conducted laboratory testing in lieu of such field testing. However, the team installed instrumentation in the field to record actual faults that might occur during the demonstration period. Any such faults would provide additional information about the design and performance of this advanced protection system.

The team performed laboratory testing to verify that the ISGD DMS could monitor and control the URCIs. For SCADA data messages, the URCI relays communicate using IEC 61850 MMS protocol, while the ISGD DMS communicates using DNP 3.0 protocol. ISGD DMS receives DNP 3.0 messages via the substation gateway, which translates the messages from IEC 61850 to DNP 3.0. Laboratory testing validated that this translation works effectively and that the ISGD DMS is capable of receiving and responding to the URCI communications appropriately.

7.2.3.3 Commissioning Tests

Commissioning tests consisted of verifying the effectiveness of the radio network communications. The two critical factors that the team evaluated were reliability and latency. The commissioning tests took longer than the team originally expected due to multiple communications challenges with the field radios and substation gateway.

A number of repeater radios were necessary to allow the URCI radios to communicate with each other and with the substation gateway at MacArthur Substation. The first step for commissioning the URCIs was to confirm that the URCI radio repeater locations would be sufficient for the URCI radio communications. When selecting the radio repeater locations, the team had to limit the number of repeaters, since adding repeaters increases the communications latency.

[38] A box loop forms when circuit switching creates a bypass around a series element such as a URCI.

Where possible, the team tried to use streetlights for repeater locations since they are higher off the ground. Licenses were required for all repeater locations since there are located on UCI property. The repeater locations also required reliable 120 VAC to power the radios.

There are multiple ways to assess the health of the URCI radio communications. The first and most rudimentary method is to watch the LED lights on the front of the radios. These LEDs indicate whether the unit is powered on, its health status, whether it is able to communicate, whether it is communicating with its neighbors, and whether it has a valid Ethernet cable connection. The mesh LED light remains on if it has a valid communication link. An LED that turns on and off sporadically means that the communications link is unreliable.

Another method for evaluating communications reliability and latency is to use software from the radio vendor that can generate statistics on communications link strength. One of these statistics is RSSI. RSSI measures the power received in a radio signal. The software can also ping the other radios that it is communicating with in order to evaluate latency. Pinging another radio provides an indication of how reliable the link is and how fast the radios can communicate with each other. The ISGD team used these two tools to identify valid radio repeater locations.

The team used the following acceptance criteria for evaluating the URCI radio communications.

- Reliable communications links with RSSI readings greater than -80 dBm and an 80% ping success rate
- URCI to URCI communications latency of less than 100 ms
- Constant 120 VAC power supply availability

The team encountered a number of challenges when performing the URCI radio commissioning tests that required troubleshooting of the radio equipment and the substation gateway. These challenges involved both the communications reliability and latency.

The team completed the URCI radio and radio repeater installations in April 2014, which allowed the team to begin thoroughly testing all the communications links. The team immediately determined that the original installation plans were not sufficient to achieve effective and reliable communication. For example, the MacArthur Substation head-end radio required two sectional antennae to communicate with two adjacent radio repeaters (rather than a single omnidirectional antenna). Each of these antennae required two 40-foot cable and connectors, which negatively impacted the RSSI. The following table lists the various challenges the team encountered while commissioning the URCI system as well as the resolution of these challenges.

Table 62: URCI Commissioning Challenges

Challenge	Resolution
1. Challenges obtaining licenses for repeater radio locations limited the team's options for repeater radio siting	a. Radios were installed on the UCI campus (private property), eliminating the need for city licenses, but still required licenses from the university
2. Unreliable communication from MacArthur Substation to adjacent repeater radios	a. Increased antenna heights at MacArthur Substation and Repeater 1 b. Improved the antenna alignment
3. Unreliable communications between URCIs and omni-directional antenna due to tree growth	a. Switched from omni-directional antenna to panel antenna, which improved the radio signal transmission strength b. Moved the antenna location to inside a fake vent pipe, which improved the line of sight with the repeater radio
4. Unreliable communications at a number of radio installation sites	a. Changed to antennas with greater gain b. Changed to different radio channels

	c. Improved the antenna alignment d. Removed physical obstacles (e.g., a temporary construction fence)
5. Different voltages for streetlights and UPS equipment	a. Installed instrument transformers for locations with 240 VAC (since all UPS equipment was rated up to 130 VDC)
6. Streetlights were not always on due to the use of photocells to only turn the lights on after dark	a. Worked with the Irvine Campus Housing Authority (ICHA) to bypass the street light photocell controllers
7. Universal protection settings are not realistic in the field environment	a. Used different protection settings for each URCI based on protection criteria and circuit configuration
8. Substation gateway latency was too long, increasing the chance that, during a fault, the substation circuit breaker would trip when it should not	a. Worked with the substation gateway vendor to reduce the latency to an acceptable level

The team concluded all initial field testing of the radio network communications. In January 2015, the team verified that the ISGD DMS is able to monitor and control the URCIs. The team also performed an "end point test" to test all the functionalities of the URCI protection scheme. Once these two tests were complete, the team verified that the URCIs performed the correct operations when a fault occured. While the URCIs were in a bypass condition, the team used Doble Simulators to inject voltage and current into the relays. This testing relied on COMTRADE files created from the RTDS simulations, which the team replayed through the Doble Test sets to simulate fault conditions. The team simulated faults on each section of load between each protection device and verified that the correct devices operated. Difficulties with the low-latency radios prevented the URCIs from being placed into service.

7.2.3.4 Field Experiments

Field Experiment 5A: Self-healing Circuit

This consisted of a passive experiment whereby the team would verify self-healing circuit capability on an energized circuit only if a fault occurs on the circuit. Although the team will not induce a fault to test this capability, it has been tested using lab simulations. It will also be tested by isolating the URCI from the circuit using the bypass switches, and then injecting fault currents into the field devices. This testing will not interrupt any customers' service. Difficulties with the low-latency radios prevented the URCIs from being placed into service.

Field Experiment 5B: De-looped Circuits

The team also plans to evaluate the effectiveness of the URCI capability when the two circuits are de-looped. There are a number of scenarios where the two circuits cannot operate in a looped configuration, including when the circuit loading exceeds 600 A, when additional circuits need to be tied to Arnold or Rommel (to deal with a temporary issue), or if box loops occur. Since the URCIs were never placed into service, the two circuits were never operated in the looped configuration.

7.2.4 Sub-project 6: Deep Grid Situational Awareness

The objective of this sub-project was to demonstrate how high-resolution power monitoring data captured at a substation could detect changes in circuit load from a DER such as demand response resources, energy storage, or renewables. Phasor measurement units (PMUs) were used to capture this data. Such a capability could help enable aggregators of such resources to participate in energy markets by providing a means of verifying resource performance. The 2 MW DBESS from sub-project 3 supported this testing. The team operated the DBESS to produce load changes of various magnitudes and durations, and at various ramp rates, to simulate the behaviors of DERs. The team relocated the

DBESS to the field in March 2014, and first connected it to the grid on April 15, 2014. The team completed various commissioning activities between April 15 and September 18, 2014 (see section 4.2.1.2). Testing in support of sub-project 6 commenced on September 19, 2014, and concluded in August of 2015.

7.2.4.1 Pre-deployment Testing

Section 4.2.1.2 summarizes the pre-deployment testing that the team performed on the DBESS to support the sub-project 6 testing. In addition, Appendix 7 provides a detailed explanation of how the UCI team designed the filter and ANN to support the PMU data analysis.

7.2.4.2 Field Experiments

Field Experiment 6A: Verification of Distributed Energy Resources

The lead UCI researchers for this sub-project divided the field experiment into two phases. Phase 1 consists of dispatching the DBESS to follow a variety of different real power charge/discharge profiles, including step, ramp, impulse, and saw tooth functions at magnitudes covering the extent of the system's capabilities (-2 to 2 MW), and at different on- and off-peak periods throughout the day. The purpose of phase 1 testing is to determine the characteristics of the system (DBESS and grid) and refine the algorithms for PMU data analysis. Phase 2 consists of dispatching the DBESS to follow additional charge/discharge profiles developed based on the phase 1 results. Phase 2 includes the actual PMU data analysis and results of this field experiment.

Phase 1: Phase 1 Testing

Phase 1 testing began on September 19, 2014, and consisted of a simple charge/discharge step profile with a +/- 2 MW amplitude. The charge/discharge sequence was as follows:

1. Maintenance charge(s) prior to 8:00 am
2. Discharge at 2 MW at 8:00 am until the battery is discharged and the system output reduces to 0 MW, then go to idle mode
3. Charge at 2 MW at 10:30 am until the battery is fully charged and the system input reduces to less than 500 kW, then perform a maintenance charge(s), then go to idle mode
4. Discharge at 2 MW at 12:00 pm until the battery is discharged and the system output reduces to 0 MW, then go to idle mode
5. Charge at 2 MW at 2:00 pm until the battery is fully charged and the system input reduces to less than 500 kW, then perform a maintenance charge(s), then go to idle mode
6. Discharge at 2 MW at 5:00 pm until the battery is fully discharged and the system output reduces to 0 MW, then go to idle mode
7. Charge at 2 MW at 7:00 pm until the battery is fully charged and the system input reduces to less than 500 kW, then perform a maintenance charge(s), then go to idle mode
8. Discharge at 2 MW at 9:00 pm until the battery is fully discharged and the system output reduces to 0 MW, then go to idle mode
9. Perform maintenance charge(s) after completion of item 8

The DBESS operator was able to perform the 8:00 am, 10:30 am, and 12:00 pm charges and discharges per the sequence above, but had to stop testing due to several related issues, including chiller alert, inverter temperature climb, and rack temperature differential error messages in the control system. The inverter temperature climb also caused the operator to manually reduce the 10:30 am charge power from 2 MW to 1 MW approximately 13 minutes into the charge in order to keep the inverter from overheating and tripping. All of these issues were cooling-related and indicative of a problem with the chiller. The DBESS operator shut down the device and paused testing until the chiller could be serviced.

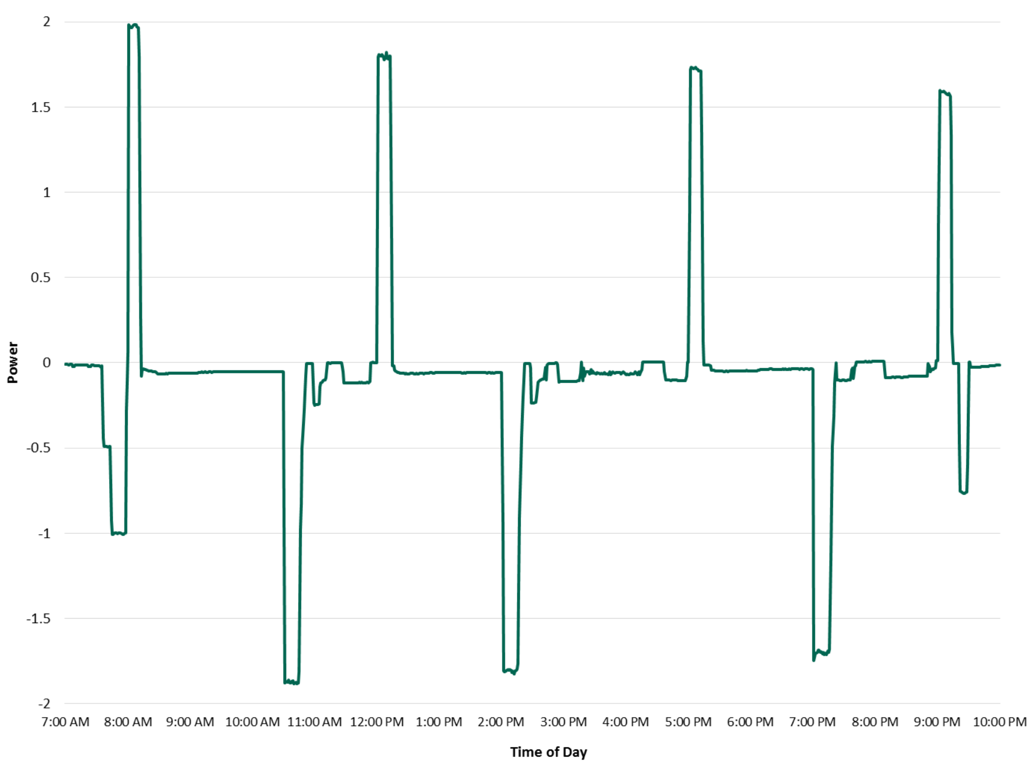
On September 26, the chiller experienced a mechanical failure before it could be serviced, resulting in a complete cooling system failure for the battery/PCS container. Since the system was already shut down when this happened, it did not pose an immediate safety or integrity concern. However, without cooling, the auxiliary systems in the container (including controls and fan motors) increased the interior temperature of the container to nearly 100 degrees Fahrenheit during the day.

On September 29, the chiller was inspected by an HVAC contractor, who found a faulty cold water flow sensor which prevented the chiller's water circulation pumps from turning on. The contractor ordered a replacement part and then installed it on October 9, restoring the cooling system to full functionality.

On October 24, 2014, the original 2 MW step profile test was successfully repeated in its entirety. The system was capable of following the test sequence, but still exhibited some minor failures. One of the in-row air conditioners had an intermittent temperature and humidity sensor fault, which resulted in that unit running at full air volume capacity. This behavior did not decrease the performance the battery system, and only had the effect of locally decreasing the container's interior temperature a few degrees below normal. Also, one of the container's 18 battery racks reported a "module cell voltage sum error," which indicated a battery module was out-of-balance with the rest of the rack. The team observed this type of error during lab testing and commissioning. It is more prevalent as the system ages and/or operates at maximum power for an entire charge/discharge cycle (which increases cell/module imbalance). Again, this error did not significantly affect the performance of the system.

Figure 168 summarizes the complete charge/discharge profile as recorded by the local PQM at the point of interconnection. The UCI research team used this data in conjunction with PMU data to support system characterization and refinement of algorithms for future PMU data analysis.

Figure 168: DBESS Charge/Discharge Profile (October 24, 2014)



The gradual tapering of the maximum charge/discharge amplitude over the course of the day is representative of the system's normal output degradation due to heat buildup in the batteries and PCS, which affects the capabilities of the system. Also, the current control system is open-loop and uses calibration constants to achieve a particular power output for a given set point. The team replaced the control system in early 2015 to include closed-loop monitoring of the PCS output, which decreased reliance on calibration constants and more tightly regulates the output. Other charges and discharges (significantly less than 2 MW) relate to auxiliary loads (such as the chiller turning on and off to regulate temperature) and maintenance charges to balance and top off the batteries after a full charge.

Test 2: Phase 2 Testing

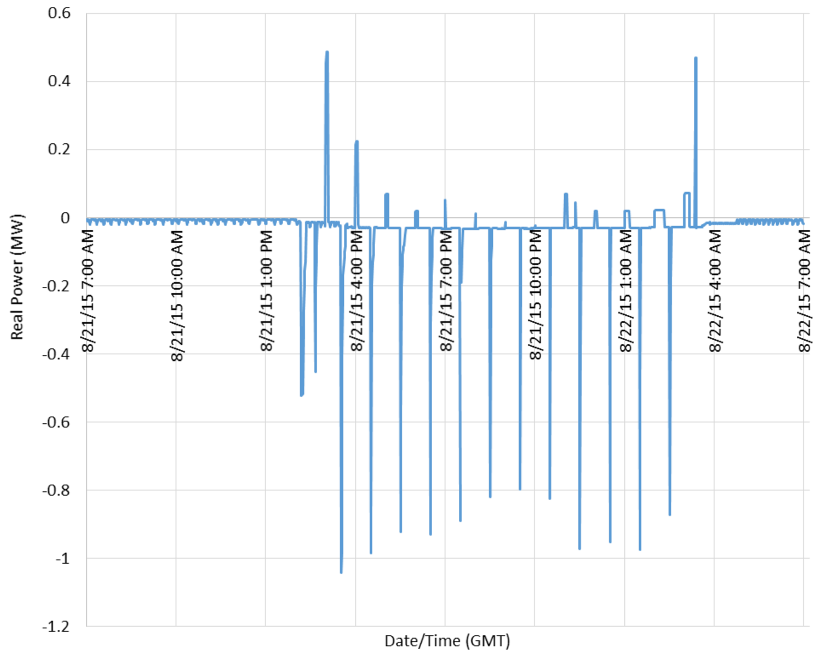
During the week of August 17, 2015, several tests were attempted and some were unfinished due to unforeseen issues. A complete and successful test was done on August 21, 2015 corresponding to test day 18 in the test plan Phase II as shown in **Table 63**.

Table 63: Test Day 18 Test Sequence (August 21, 2015)

Time (PST)	Action	Profile	Power(kW)	Duration(minutes)
8:00 am	Discharge	step function	500	5
8:30 am	Fully charge	step function	1000	
9:00 am	Discharge	step function	250	5
9:30 am	Fully charge	step function	1000	
10:00 am	Discharge	step function	100	5
10:30 am	Fully charge	step function	1000	
11:00 am	Discharge	step function	50	5
11:30 am	Fully charge	step function	1000	
12:00 pm	Discharge	Impulse	500	NA
12:30 pm	Fully charge	step function	1000	
1:00 pm	Discharge	Impulse	250	NA
1:30 pm	Fully charge	step function	1000	
2:00 pm	Discharge	Impulse	100	NA
2:30 pm	Fully charge	step function	1000	
3:00 pm	Discharge	Impulse	50	NA
3:30 pm	Fully charge	step function	1000	
4:00 pm	Discharge	step function	100	5
4:30 pm	Fully charge	step function	1000	
5:00 pm	Discharge	step function	50	5
5:30 pm	Fully charge	step function	1000	
6:00 pm	Discharge	step function	50	10
6:30 pm	Fully charge	step function	1000	
7:00 pm	Discharge	step function	50	20
7:30 pm	Fully charge	step function	1000	
8:00 pm	Discharge	step function	100	10

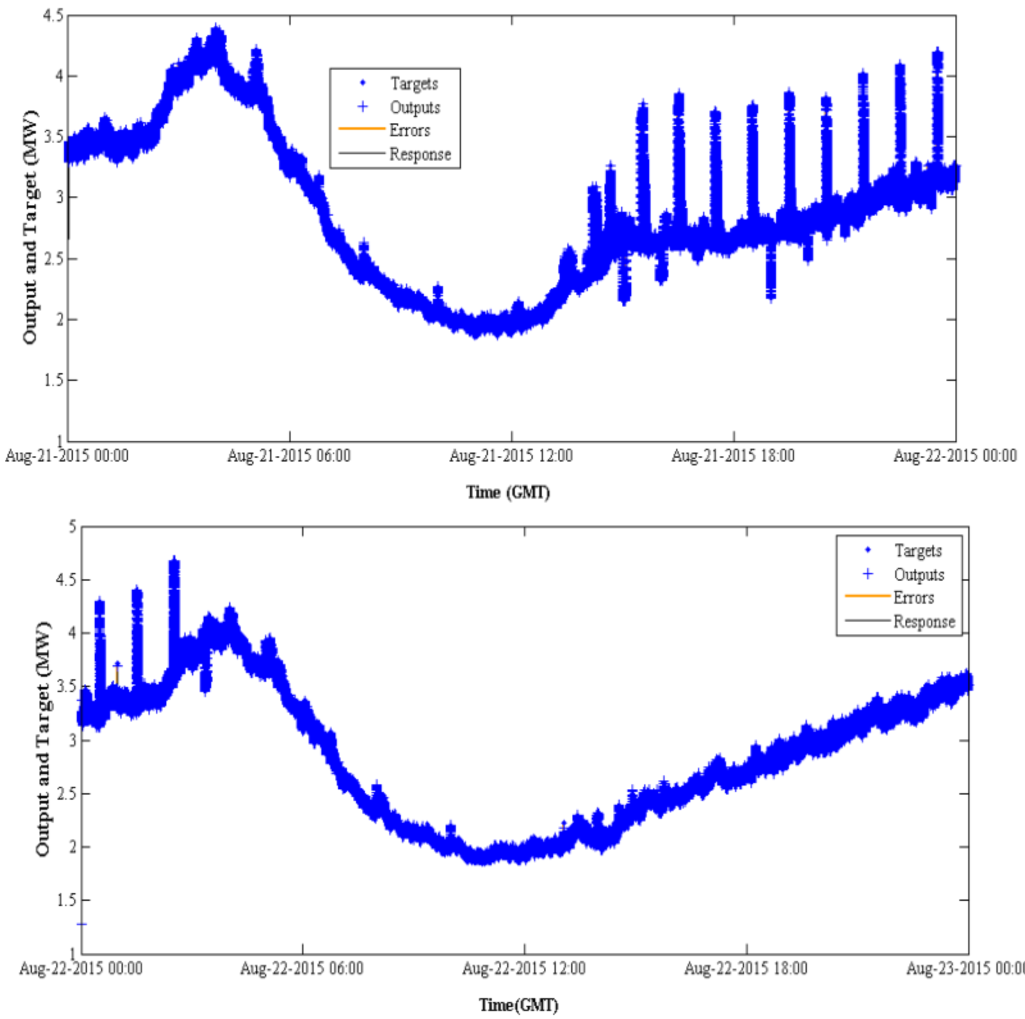
The locally recorded real power is shown in **Figure 169**. The time is expressed in GMT since the timestamp of the data collected by the PMU is in GMT.

Figure 169: Real Power Recorded On-site (August 21, 2015, Test Day 18)



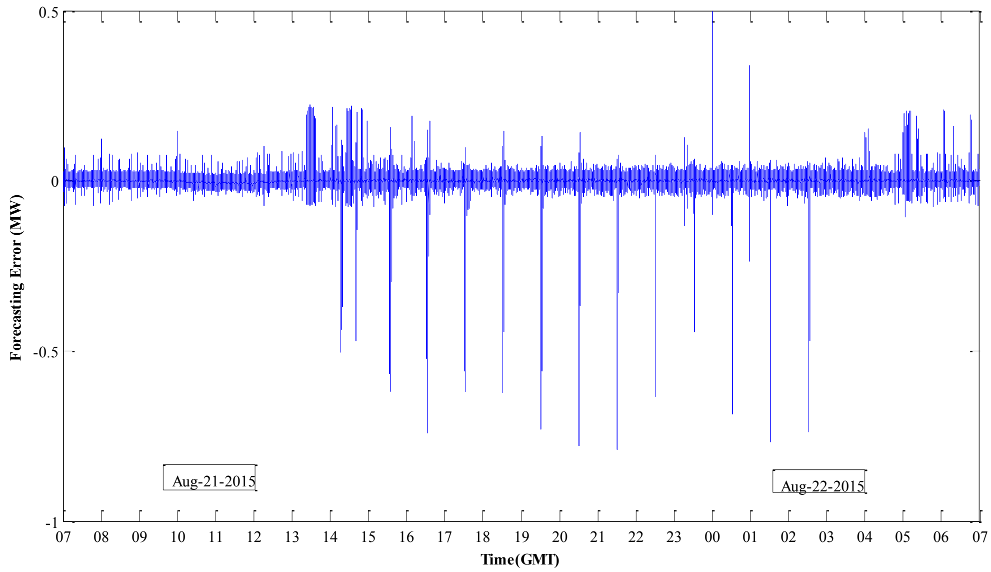
The real power data collected at the substation for this day are shown in **Figure 169**. The result of using the trained network for this day is shown in **Figure 170**. It is evident that the errors are significantly higher when the battery is being used whether charging or discharging.

Figure 170: Result of ANN for Test Day 18



The errors in forecasting the power using neural network are then used to determine the power profile of the battery. Previously a post-processing method was developed that used the error signal, filtered it and removed the "false alarms." This method includes a minimum time for an "event" to be registered, therefore an isolated high error does not mean that the DER has been dispatched, and also very small error are inherent to the forecasting and neural networks. The parameters of this algorithm are based on the data collected during the tests (mostly impulse and step function tests). The results are then calibrated to represent actual operation of the battery based on the data collected on-site (adjust for time and size). Applying the methodology to test day 18 error which is shown in **Figure 171**, the charging of the battery at ~1MW is detected correctly along with discharging at or higher than 500 kW.

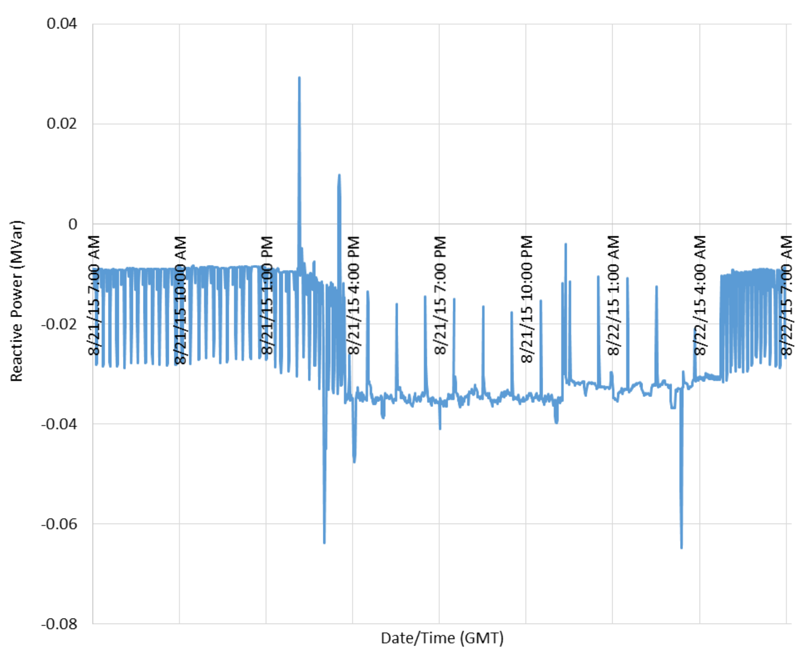
Figure 171: Forecasting Error (Test Day 18)



The methodology is recalibrated again and 250kW can also be detected. 100 kW and 50 kW levels still cannot be detected. The test at 50 kW lasting 20 minutes, however might be detectable with further calibration. As a result, a combination of DER size and duration of dispatch determines whether it is detectable using PMU data or not.

The signal to be analyzed has been the real power so far. In what follows, other signals are also examined. In **Figure 172**, the reactive power recorded on-site during test Day 18 is shown.

Figure 172: Reactive power recoded on-site (August 21, 2015, test day 18)



In **Figure 173**, current, voltage frequency, phase angle and reactive power recorded at the substation are shown (after ore-processing the data). It is evident from the figure that voltage, frequency and reactive power are not impacted by dispatch of the battery. However, it seems that the current does change with the DER charge/discharge. The current associated with the test day 18 is shown in **Figure 173**. A simple step detection methodology using wavelet transform coefficients is performed on the current corresponding to the test day.

Figure 173: Parameters Recorded at the Substation (Week of August 17, 2015)

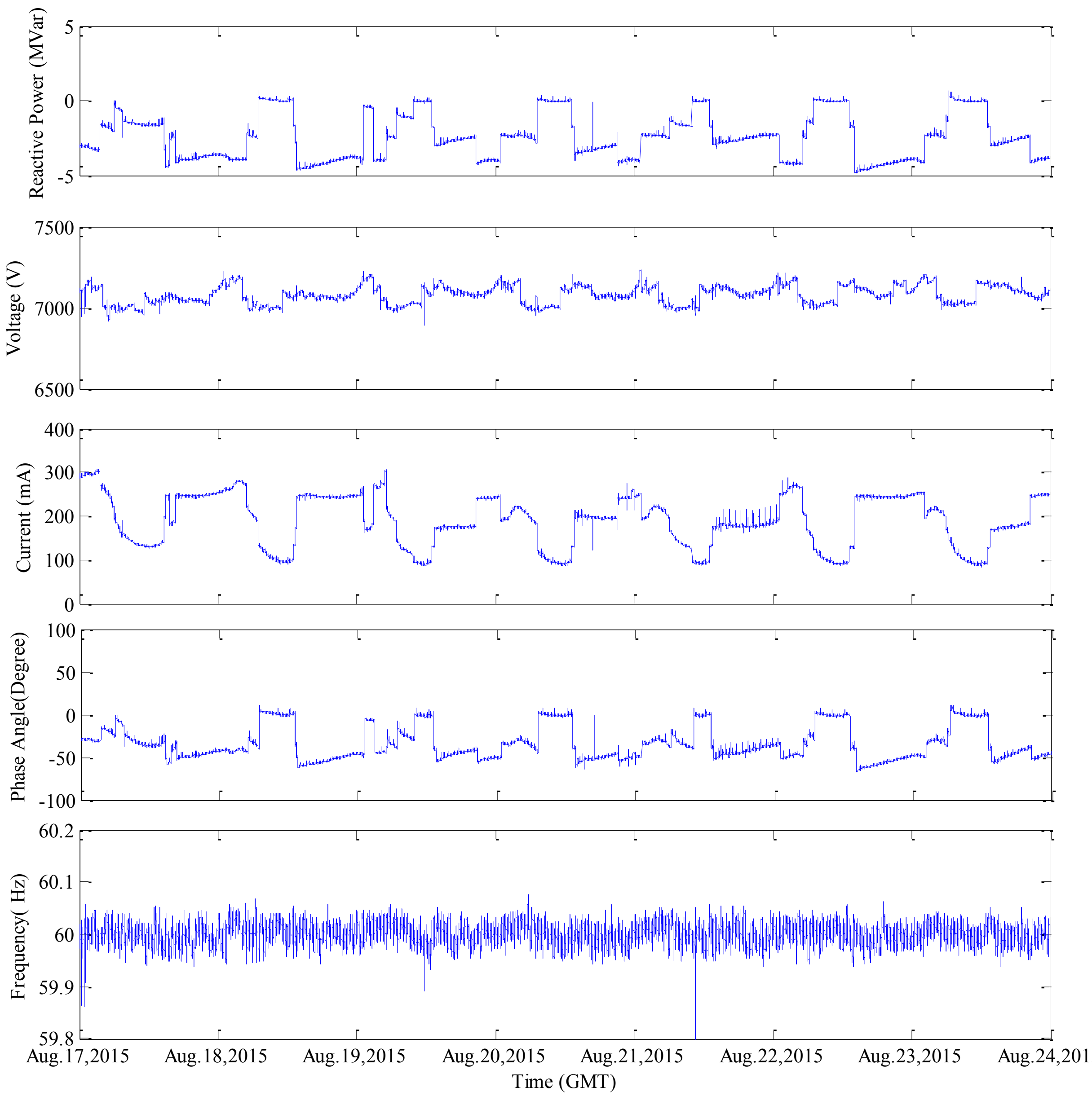


Figure 174: Wavelet Decomposition of the Current Signal

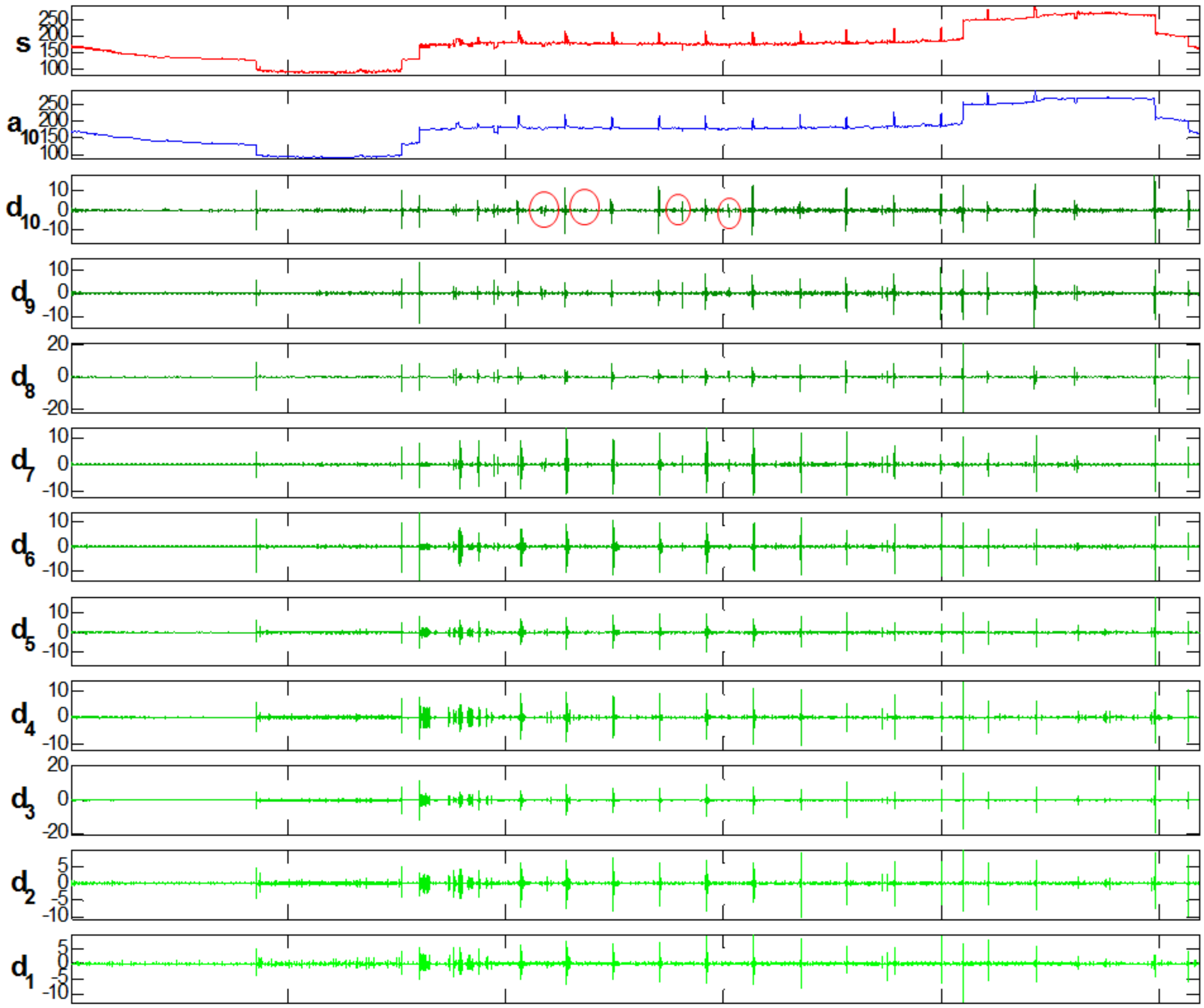


Figure 174 shows the results of the wavelet decomposition and coefficients for step detection. As can be seen from this figure, the 250 kW level can be detected as well as 100 kW. However, it must be noted that this simple methodology only applies to impulse or step profiles and cannot be used to determine which DER resulted in the change.

Discussion and Conclusions

The data collected at a substation using a PMU were used to develop a strategy to detect DER operations in a distribution system. Following are the major conclusions and lessons learned from this effort.

- Overall the synchrophasor data are quite reliable; however calibration tests are required.
    - Data should be collected before a DER is installed in a circuit and after installation, several tests should be performed to calibrate the parameters of the filter and neural network for that specific DER and its physical characteristics.
    - Operation of the battery at 250 kW and higher was detectable.
    - A combination of DER size and the duration of its operation determines whether it can be detected or not.
    - DER detection has lowest accuracy during the times in the day when the gradient of power is high (before the afternoon peak)
    - DER operation with very slow ramp rate cannot be detected
- PMU data collected at 30 samples per second were used in detecting a DER; however, whether high resolution of data is necessary or higher resolution results in better outcome has not been established in this research.

- The current method could establish a criteria for the utility or the ISO to accept these resources to participate in the market or be compensated for the services they provide to the grid without additional measurement. More tests and analysis on other circuits, however, are required to verify the results. This ANN method is computationally intensive so it is recommended that a simpler method such as step detection algorithms be used in real time with ANN used to “verify” the dispatch.
- As the number of DERs increase on a circuit, it is necessary to add a pattern detection component to the algorithm to distinguish different DERs.
  - This can be done by identifying the “footprint” of DERs on various components of the circuit. As was shown here, the battery also impacts the reactive power at the substation in a specific way that “might” be unique to technology type.
  - If there are two or more similar DERs on the same circuit, a statistical approach needs to be added to the methodology to determine the probability of each of these DERs contributing to the change in the signal observed.
- This method is an alternative to metering the DER at their location. Synchrophasors in general are used for system reliability and using them for DER detection can be an added bonus; however, synchrophasors only record and keep the data associated with an “event”, using them in the manner specified here requires keeping the data and analyzing it. This cost should be compared with the cost of direct metering to weigh pros and cons.

7.3 Interoperability & Cybersecurity

7.3.1 Sub-project 7: Secure Energy Net

Smart grid capabilities typically require electronic communications between field devices and utility back office systems. Creating SENet was one of ISGD’s most technically demanding and resource intensive sub-projects. Its development had to address diverse communications and security requirements for back office services, including data collection and control functions for a variety of applications involving field equipment. Although the SENet design was mindful of interoperability and cybersecurity needs, it also had to accommodate legacy SCE systems. Using a rigorous systems engineering approach, SCE designed, developed, integrated, and tested several communication networks and back office software systems. SENet operated as planned since deployment. It represents a solid baseline for future SCE distribution system back office automation.

7.3.2 Sub-project 7: Substation Automation 3

The goal of SA-3 is to transition substations to standards-based, automated configuration of communications, interfaces, control, and an enhanced protection design. Achieving these goals will provide enhanced system interoperability and enable advanced functionalities such as automatic device configuration while introducing integration compatibility with legacy systems.

7.4 Workforce of the Future

This project area does not include any field experimentation or performance testing.

Appendices

Appendix 1: Abbreviations

AC	Air Conditioner or Alternating Current
ACM	Appliance Control Module
ALCS	Advanced Load Control System
AMI	Advanced Metering Infrastructure
ANN	Artificial Neural Network
ANSI	American National Standards Institute
API	Application Programming Interface
ATP	Acceptance Test Procedures
BESS	Battery Energy Storage System
BMS	Battery Management System
BTC	Broadband TelCom Power, Inc.
Btu	British thermal unit
CAD	Computer Aided Drafting
CCS	Common Cybersecurity Services
CES	Community Energy Storage
CIM	Common Information Model
CLT	Contingency Load Transfer
CMS	Central Management Services
CPUC	California Public Utilities Commission
CT	Current Transformer
CVR	Conservation Voltage Reduction
DBESS	Distribution-level Battery Energy Storage System
DC	Direct Current
DCAP	Distribution Capacitor Automation Project
DEM	Distributed Energy Manager
DER	Distributed Energy Resource
DHCP	Dynamic Host Configuration Protocol
DHW	Domestic Hot Water
DMS	Distribution Management System
DMZ	Demilitarized Zone
DNP3	Distributed Network Protocol
DOE	Department of Energy
DR	Demand Response
DVVC	Distribution Volt/VAR Control
eDNA	Enterprise Distributed Network Architecture
EEM	Energy Efficiency Measure
EMS	Energy Management System
EPRI	Electric Power Research Institute
ESB	Enterprise Service Bus
ESP	Encapsulating Secure Payload
EVCS	Electric Vehicle Charging Station
EVSE	Electric Vehicle Supply Equipment
EVTC	Electric Vehicle Technical Center
FAN	Field Area Network
FAU	Forced Air Unit
FDIR	Fault Detection, Isolation and Restoration

FLISR	Fault Location, Isolation, and Service Restoration
GBS	Grid Battery System
GE	General Electric
GHz	Gigahertz
HAN	Home Area Network
HMI	Human-Machine Interface
HVAC	Heating, Ventilation and Air Conditioning
ICHA	Irvine Campus Housing Authority
IDSM	Integrated Demand Side Management
IEC	International Electrotechnical Commission
IED	Intelligent Electronic Device
IEEE	Institute of Electrical and Electronics Engineers
IETF RFC	Internet Engineering Task Force Request for Comment
IHD	In-home Display
IKE	Internet Key Exchange
IPSec	Internet Protocol Security
ISGD	Irvine Smart Grid Demonstration
IVVC	Integrated Volt/VAR Control
kBtu	Thousand British thermal units
kVA	Kilovolt-amps
kW	Kilowatt
kWh	Kilowatt-hour
LAN	Local Area Network
LED	Light Emitting Diode
LL	Low-latency
LMS	Least Mean Square
LTC	Load Tap Changer
LTE	Long Term Evolution
MBRP	Metric and Benefits Reporting Plan
MHz	Megahertz
MPLS	Multiprotocol Label Switching
ms	Millisecond
MVAR	Megavolt-ampere Reactive
MW	Megawatt
MWh	Megawatt-hours
NEM	Net Energy Metering
NERC CIP	North American Electric Reliability Corporation Critical Infrastructure Protection
NETL	National Energy Technology Laboratory
NIST	National Institute of Standards and Technology
NMS	Network Management System
PCC	Programmable Capacitor Controller
PCT	Programmable Communicating Thermostat
PDC	Phasor Data Concentrator
PEV	Plug-in Electric Vehicle
PLC	Programmable Logic Controller
PLM	Plug Load Monitor
PLS	Permanent Load Shifting
PQM	Power Quality Monitoring
PSLF	Positive Sequence Load Flow
PV	Photovoltaic

QA/UAT	Quality Assurance/User Acceptance Test
RDP	Remote Desktop Protocol
RESU	Residential Energy Storage Unit
RF	Radio Frequency
RLS	Recursive Least Square
RSSI	Received Signal Strength Indicator
RTDS	Real Time Digital Simulator
SAE	Society of Automotive Engineers
SAN	Storage Area Network
SA-3	Substation Automation 3
SCE	Southern California Edison
SCEP	Simple Certificate Enrollment Protocol
SDO	Standards Developing Organization
SEL	Schweitzer Engineering Laboratories
SEMT	Substation Engineering Modeling Tool
SENet	Secure Energy Network
SEP	Smart Energy Profile
SME	Subject Matter Expert
SNMP	Simple Network Management Protocol
SOAP	Simple Object Access Protocol
SOC	State of Charge
SOH	State of Health
SQL	Structured Query Language
SSI	Smart Grid Software Services Infrastructure
STI	Space-Time Insight
TLS	Transport Layer Security
TPR	Technology Performance Report
T&D	Transmission and Distribution
UCA	Utility Communications Architecture
UCI	University of California, Irvine
UL	Underwriters Laboratories
URCI	Universal Remote Circuit Interrupter
VAR	Volt-ampere Reactive
VRT	Voltage Rise Table
WAN	Wide Area Network
XML	Extensible Markup Language
ZNE	Zero Net Energy
ZNEE	Zero Net Electric Energy

Appendix 2: Build Metrics

Over the course of the project, the ISGD team filed "build metrics" with NETL on a quarterly basis. These metrics summarize project investments in terms of quantities and costs for AMI and customer systems, and electric distribution system assets. The tables in this appendix summarize the final ISGD build metrics as of June 30, 2015.

AMI smart meters installed and operational	Quantity	Cost
Total	38	$59,559
Residential	38	
Commercial	0	
Industrial	0	
AMI smart meter features operational	**Feature enabled**	**# of meters with feature**
Interval reads	Yes	38
Remote connection/disconnection	Yes	38
Outage detection/reporting	Yes	38
Tamper detection	Yes	38
AMI communication networks and data systems	**Description**	**Cost**
Backhaul communications	The backhaul from the collector meters (cell relays) to SCE back office uses 4G cellular services employing the CDMA protocol.	$0
Meter communications network	Meter to meter and meter to collector (cell relays) use 900 MHz communications in the ISM band and uses Itron's RF Mesh protocol.	
Head end server	The head end system consists of Itron's OpenWay system. The primary component is the Network Management System (NMS). The function of the NMS is to pass through meter data (e.g., consumption), events, and two-way communications between the meters and MDMS. Other tasks performed by the NMS include managing meter configurations, managing groups of meters, and supporting reads of individual meters for diagnostics.	$1,275,691
Meter data analysis system	All meter data is collected through the Network Management System and stored in an Oracle relational database.	
Other IT systems and applications	Not applicable to project.	
Web portal deployed and operational	**Quantity**	**Description**
Customers with access to web portal	0	
Customers enrolled in web portal	0	The gateway that each home has received is capable of displaying a web portal.

Customer systems installed and operational	Quantity	Description	Cost
Communication networks and home area networks	N/A	A HAN is a network established in the home to enable access, control, and operation of devices such as appliances and air conditioners. ISGD uses the Zigbee Smart Energy Profile 1.X protocol for the HAN network.	N/A
In home displays	22	Most IHDs provide consumers with comprehensive information about their energy consumption, including: current household energy use in both kilowatts and dollars per hour, daily energy cost, including a comparison to the prior day's cost, the real time cost of electricity, monthly bill tracking with up-to-date billing information and an estimated end – of-month bill, and demand response event messages.	$7,020
Energy management devices	22	Energy management systems control loads in the home and centralize operation and control of other HAN devices. They typically function as a gateway or hub and can be accessed locally in the HAN or remotely through the meter of the internet.	$0
Direct load control devices	0	Not applicable	$0
Programmable communicating thermostats	31	PCTs are capable of communicating wirelessly with the HAN and enable customers to take advantage of AC DR pricing programs.	$9,610
Heat pump	11	This is an electric HVAC system controlled by the PCT.	$333,839

Customer systems installed and operational	Quantity	Description	Cost
Water heaters	16	The project used two types of water heaters: (1) The GDHE-50 Vertex™ Power Direct Vent gas water heater delivered a 96% thermal efficiency rating and is designed specifically to generate a constant flow of 4 gallons per minute, featuring a 50-gallon tank and a 100,000 BTU gas burner. (2) The solar domestic hot water (SDHW) systems collect and store the sun’s radiant energy to produce and store hot water for use in the kitchen, bath and laundry. SDHW systems utilize a roof-mounted flat plate collector panel. Fluid in the collector, heated by the sun, is circulated into the house where it transfers its heat into the domestic water in an insulated tank.	$124,636
Lighting	700	Approximately 700 lights ranging from 5 to 44 watts were installed in 8 homes.	$357,912
Smart appliances	64	Smart appliances are capable of receiving signals from the AMI HAN and can react to DR commands from an AMI load control system. The smart appliances being evaluated on ISGD include refrigerators, dishwashers and clothes washers.	$137,428
Customer system communication networks			**Description**
Network characteristics within the customer premises			A HAN is a network established in the home to enable access, control and operation devices such as appliances and air conditioners. ISGD uses the Zigbee Smart Energy Profile 1.X protocol for the HAN network.

Distributed energy resources	Quantity	Capacity	Description	Cost
Distributed generation	23	108 kW	All distributed generation is solar PV. The sizes vary by project block.	$843,530
Energy storage	16	181 kW		$1,850,130
Plug-in electric vehicle charging points	44	328 kW		$234,022
Distributed energy resource interface	Not applicable	Not applicable		$0

Electric distribution system	%	Description
Portion of distribution system with SCADA due to SGIG/SGD program	0%	Not applicable to project
Portion of distribution system with DA due to SGIG/SGD program	0%	Not applicable to project

DA devices installed and operational	Quantity	Description	Cost
Automated feeder switches	0	Not applicable to project	$0
Automated capacitors	15		$0
Automated regulators	0		$0
Feeder monitors	0		$0
Remote fault indicators	0		$0
Transformer monitors (line)	0		$0
Smart relays	0		$0
Fault current limiter	0		$0
Other devices	0		$0

SCADA and DA communications network	Cost
Communications equipment and SCADA	$0

Distribution management systems integration	Integrated	Description
AMI	No	DMS is used by system operators to monitor and control the distribution system. DMS will also be used to monitor and display to the system operator the status of the URCIs and provide manual override capabilities. DMS is also being used to control distribution capacitors and provide capacitor readings to DVVC.
Outage management system	No	Not applicable to project
Distributed energy resource interface	No	Not applicable to project
Other	No	Not applicable to project

Distribution automation features/functionality	Function enabled	Description
Fault location, isolation and service restoration (FLISR)	No	Not applicable to project
Voltage optimization	Yes	DMS used to control distribution capacitors and to provide voltage readings to DVVC.
Feeder peak load management	No	Not applicable to project
Microgrids	No	Not applicable to project
Other functions	No	Not applicable to project

Appendix 3: Instrumentation for Home Data Collection

A3.1 Requirements

During the ISGD design phase, the team needed to identify a method for monitoring the electricity usage in the project homes. This includes 38 homes (16 control homes and 22 homes with modifications). These homes are located on four blocks in the University Hills housing area of UCI. This monitoring system has to help the team measure the electricity savings stemming from energy efficiency upgrades. It also has to measure the impacts of the ISGD field experiments. The data acquisition system needs to monitor up to 21 individual circuits in each home (watts, amps, voltage, and watt-hours) as well as loads plugged into the wall (watts, watt-hours), ambient temperatures on each floor, and temperature in the air conditioning duct system. Data should also be recorded at down to one-minute intervals. The monitoring system also needs a method to communicate data back to SCE's back office where it is stored, validated, and made available to users. After researching several systems, the team selected a package assembled by TrendPoint for implementation in the homes. In addition to this system, the team installed two additional Smart Connect® meters in each home to avoid disturbing the existing billing meter.

A3.2 Design Overview

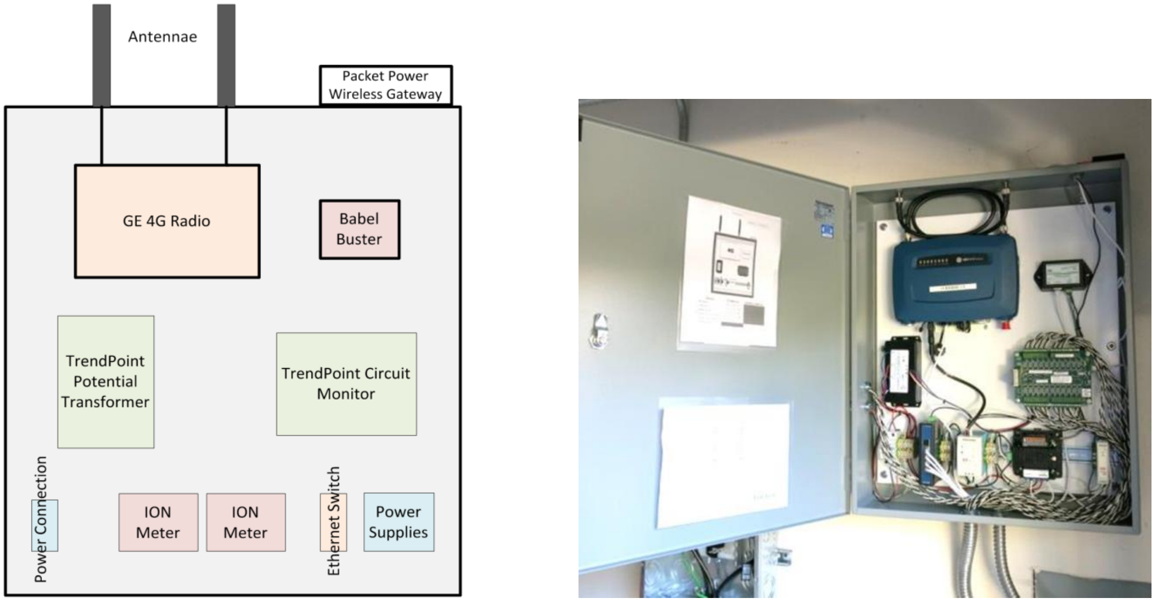
The TrendPoint monitoring system is composed of a data collection and communications cabinet installed in the garage as well as sensors located throughout each home. In addition to the monitoring equipment, a HAN supports communications between the project's Smart Connect meter and the smart appliances, thermostat, in-home display, EVSE, and RESU.

A3.3 Data Collection Cabinet

The TrendPoint data collection cabinet houses a number of monitoring and communications components, which are depicted in **Figure 175**. These components include:

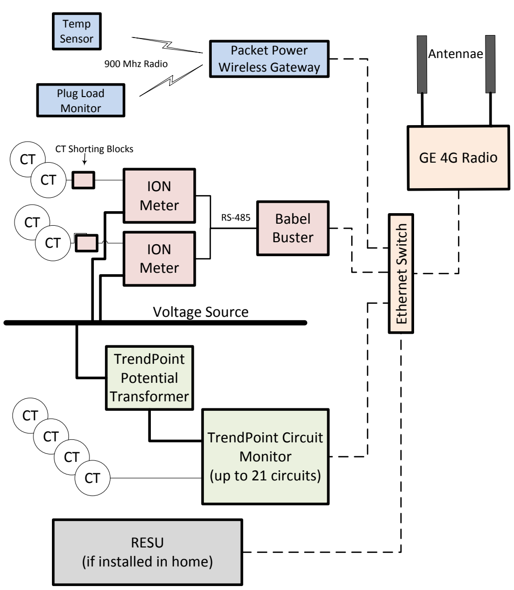
- TrendPoint Enersure circuit monitoring board (with its potential transformer)
- Schneider ION meter(s) and Babel Buster (converts metered readings to Simple Network Management Protocol (SNMP)/Ethernet)
- Packet Power wireless gateway (receive signals from wireless plug load monitors and temperature sensors)
- GE 4G radio with externally mounted antennae
- Current transformer shorting blocks, Ethernet switch, and power supplies

Figure 175: Home Data Collection Cabinet Arrangement



Due to the limited modifications in the control homes, these homes only received a data collection cabinet with a wireless gateway, 4G radio, and required power supplies. **Figure 176** depicts how these components are connected. All data collected in the cabinet is converted to Ethernet, which is pooled in an Ethernet switch and connected to the 4G radio for transmission to the TrendPoint server located in the SCE back office in Alhambra. This path uses the public cell system to the public carrier back office where the data is placed on a leased circuit going directly to SCE's Alhambra facility. All data is converted to SNMP for transmission to the back office. The project also uses this 4G link to communicate directly with the RESU.

Figure 176: Home Data Collection Cabinet Block Diagram



A3.4 TrendPoint Enersure System

The TrendPoint Enersure system is composed of a stack of circuit boards located in the home data collection cabinet that is connected to current transformers installed in the home electrical panel and subpanel. This system is capable of monitoring up to 21 separate 120 VAC circuits (ranging from 20 to 200 amps). There is also a potential transformer installed in the data collection cabinet that converts the 120 VAC signals to low voltage for use by the TrendPoint measurement boards. The CTs used for each circuit have internal resistors in them so low voltage signals are delivered to the TrendPoint boards and they do not require shorting blocks for safety. The Enersure system is capable of measuring amps, watts, watt-hours, volts, and power factor for each home circuit. Proper installation of the CTs and voltage selector jumpers is necessary to correctly measure power; this system is not capable of measuring reverse power. Data is sent to the 4G radio through Ethernet using the SNMP protocol.

A3.5 Schneider ION Metering System

The team installed up to two Schneider ION meters at each home. These meters allow measurement of two-way power flow and provide more detail than is possible with the TrendPoint Enersure system. The CES Block homes have one ION meter that measures the total home load. The ZNE Block and RESU Block homes have two ION meters to measure the total home load and RESU operations. The Control Block homes did not receive ION meters. The ION metering system is composed of the ION meter, CTs with shorting blocks, and the Babel Buster module that converted the ION meter's RS-485/Modbus connection to Ethernet/SNMP. The Babel Buster polls the ION meters and stores the results in a buffer. When the Babel Buster is polled by the TrendPoint back office server, it returns the latest value in its buffer. This system is capable of measuring a full range of two-way electrical values including amps, volts, watts, VARs, power factor, watt-hours, VAR-hours, harmonics, and frequency.

A3.6 Packet Power Wireless Sensor System

A Packet Power wireless sensor system is installed in each project home. This system is composed of a wireless gateway located on the exterior of the data collection cabinet, plug load monitors (PLMs) and temperature sensors. The wireless gateway is connected by Ethernet cable to the 4G radio through an Ethernet switch. The wireless sensors communicate with the wireless gateway through a 900 MHz radio network and are located throughout the home. The wireless sensors report to the wireless gateway to store the latest reading on a regular basis. The wireless gateway is then polled by the TrendPoint back office server and the latest value in the gateway buffer is retrieved. The PLMs report watt-hours, watts, frequency, amps, volt-amps, power factor, and volts. The temperature sensors only report temperature.

A3.7 General Electric 4G Radio Gateway

Each home data collection cabinet contains a 4G radio that communicates data from the local Ethernet network and makes a connection to the public carrier back office through the public 3/4G cell network. This radio gateway contains a 4G radio and has inputs for Ethernet, RS-232, and Wi-Fi. The radio also contains software that provides a connection to SCE's centralized cybersecurity system. Once the communications makes its way to the public carrier back office, it passes through a lease-line link to SCE's project back office servers in Alhambra.

A3.8 Back Office Systems

SCE houses a number of servers at its back office facility in Alhambra, California. These servers include:

- RESU SQL database (directly accessed for data)
- TrendPoint Smart Grid Management Console (data transferred to Oracle server)
- DEM for the CES (data transferred to Oracle server)
- BESS local server (data transferred to Oracle server)
- NMS for project smart meters (data transferred to Oracle server)
- Oracle (stores validated data from TrendPoint, DEM, BESS, and NMS servers)

All data is consolidated in SCE's back office, checked for errors, and transferred to an Oracle database for use by the ISGD team. Data from the RESU server is accessed directly. These servers are routinely backed-up and maintained by SCE's Information Technology department.

A3.9 Lessons Learned

Over the course of design, installation, commissioning, and operation of the data acquisition system, the team learned a number of lessons. The following is a listing of the major lessons and a description of what the project team learned.

A3.9.1 Local Data Storage Would Improve Data Retention

Wireless communications for retrieving data from the project homes has been unreliable, leading to lost data. This challenge has manifested itself in two ways: retrieving data from the wireless plug load monitors and temperature sensors within the project homes, and retrieving the data from the homes through the 4G radio system.

Since the plug load monitors and temperature sensors needed to be installed in existing homes on a retrofit basis, the team chose to retrieve the sensor data on a wireless basis. Unfortunately, some of the locations in the homes have poor connections to the wireless gateway in the garage. This has led to lost data from these sensors. Although some temperature data was lost, enough was recovered to determine the temperature trends in the homes for analysis. Temporary loss of communications with the plug load monitors led to some minor losses of kW data. However, the plug load monitors contain a running counter for kWh, which allows the team to calculate usage data after restoring communications. A better design would have used local data storage at each sensor so data lost due to communications problems could be recovered later when the communications channel was working better. The instrumentation manufacturer has been to the sites and made suggestions on how SCE might improve data recovery through relocating the wireless gateway.

The team has encountered a similar problem retrieving data from the customer homes. All home data is retrieved through the 4G radio system. The cell coverage at some of the homes is weak, causing loss of communications at times. Because of how the home data collection package was designed, there is no local storage of data. This leads to the loss of data when the 4G cell communications fails. A better system design would have been to require some local storage so data lost during communications dropouts could be recovered later when the communications channel was working better. Changes have been made to the configuration of these radios to reduce the duration of the dropouts. With these changes, sufficient data is recovered to allow the required analyses to be performed.

A3.9.2 Retrofitting Current Transformers into the Customers' Electrical Panels Was Difficult Due to Space Constraints

The team is monitoring the circuits in each home using small clamp-on CTs. These CTs are placed in the customer's electrical panel and the leads routed back to the TrendPoint Enersure circuit monitor boards. Because of space constraints, these CTs are hard to fit in the panel and routing of sensor wires is difficult. This leads to a very crowded panel and misidentification of some of the leads as well as installation of the CTs in a reversed direction. Since the TrendPoint measurement board only measures power flow in one direction, any CT installed backwards or misidentified as to which leg of the panel it was connected to causes zero values for power and energy. Because of this, each panel needs to be verified and CTs or potential jumpers corrected to ensure proper recording of the data. This is very time consuming. A measuring system with either smaller CTs or the ability to switch potential settings or CT orientation remotely would have made installation easier. A system that would have measured power in either direction would also have made installation easier and obviated the need for the installation of the Schneider ION meters to observe two-way power flow.

A3.9.3 Installing Instrumentation in Existing Homes Is Difficult

Retrofitting instrumentation into homes is difficult and takes significant amounts of time. Once instrumentation is installed, it may take several more visits to the home to work out all of the bugs. This is difficult since it requires appointments with the homeowners to gain access. This slows the progress of correcting installation problems and makes it difficult to fix problems as they occur during the monitoring period.

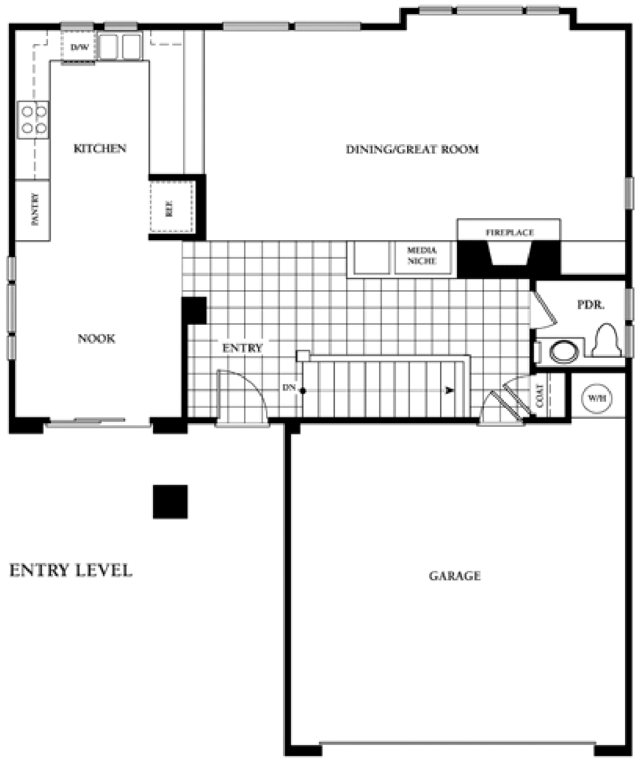
A3.9.4 Understand How Instruments Can Fail and Use This to Help Validate Data

Understanding how the various communications paths can fail (and how this affects the data), can provide insights for identifying bad data or failed sensors. For example, a reading of zero might be caused by zero current flow, or it could be caused by a wireless sensor not reporting as expected. With an understanding of the failure mechanisms for each measurement system, data can be validated more easily.

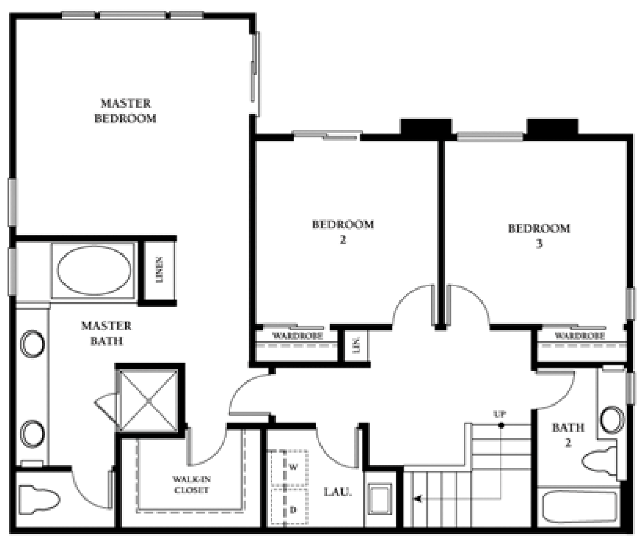
Appendix 4: Project Home Floor Plans

Plan 751

- Two Story Hillside Home
- Approximately 1,900 Square Feet
- Three Bedrooms
- Two and a Half Bathrooms
- Great Room/Dining Room with Wood-Burning Fireplace
- Kitchen with Breakfast Nook
- Attached Two-Car Garage



ENTRY LEVEL



LOWER LEVEL

Plan 752

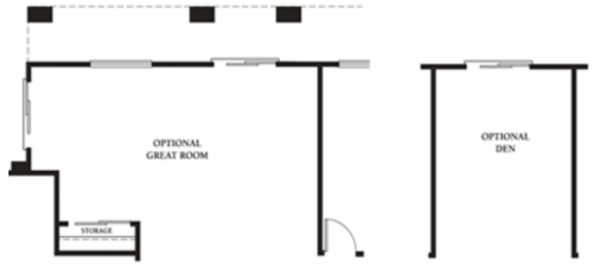
- Two Story Hillside Home
- Approximately 2,200 Square Feet
- Three Bedrooms plus Den
- Three Bathrooms
- Great Room/Dining Room with Wood-Burning Fireplace
- Kitchen with Breakfast Nook
- Inside Laundry Room with Sink
- Attached Two-Car Garage

ENTRY LEVEL

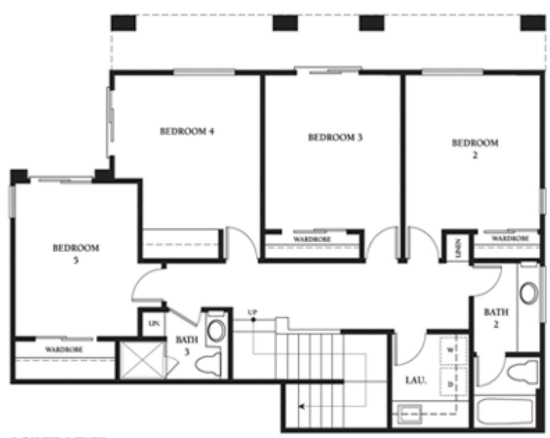
LOWER LEVEL

Plan 753

- Two Story Hillside Home
- Approximately 2,500 Square Feet
- Five Bedrooms
- Three and a Half Bathrooms
- Family Room with
  Wood-Burning Fireplace
- Dining Area and Kitchen with Breakfast Nook
- Inside Laundry Room with Sink
- Attached Two-Car Garage



ENTRY LEVEL



LOWER LEVEL

Plan 754

- Three Story Hillside Home
- Approximately 2,900 Square Feet
- Four Bedrooms plus Loft
- Three and a Half Bathrooms
- Wood-Burning Fireplace
- Dining Area and Kitchen with Island and Breakfast Nook
- Inside Laundry Room with Sink
- Attached Two-Car Garage

Appendix 5: ZNE Flyer Sample

ISGD PROJECT

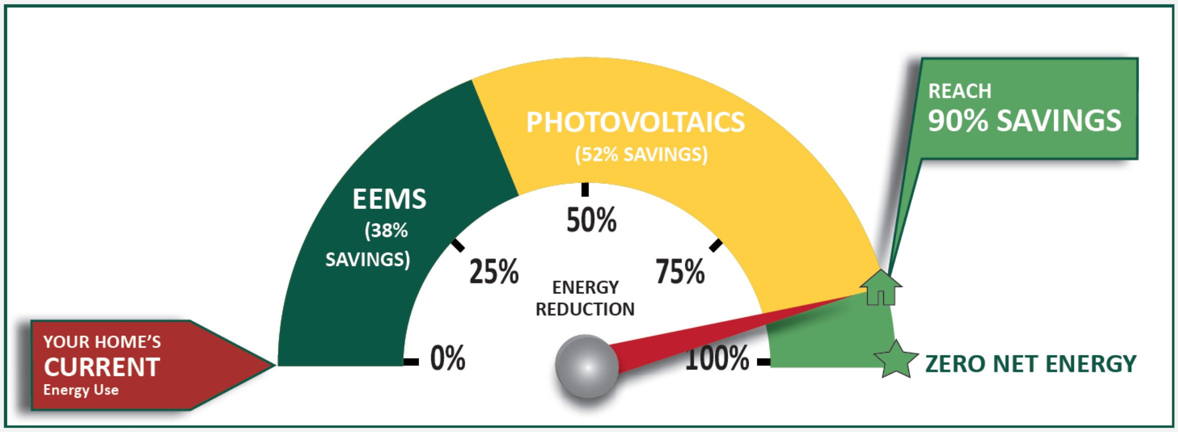
The Path to Zero Net Energy

Implement these energy efficiency measures (EEMs) with photovoltaics and see how close your house can get to generating as much energy as it consumes!

SOUTHERN CALIFORNIA EDISON
An EDISON INTERNATIONAL® Company

ZNE 3

Irvine, California



ENERGY EFFICIENCY MEASURES

CUSTOM

EEM 1 — LED lighting
Hard wired and stand up lamps will be replaced with the top of the line LED bulbs reducing energy consumption while maintaining excellent light quality.

EEM 2 — Heat pump
The furnace and AC (if the house has cooling) will be replaced with a 19 SEER/9 HSPF heat pump with electric resistance backup heat.

EEM 3 — 96% domestic hot water heater
The existing hot water heater will be replaced with a 96% efficient condensing gas water heater along with improved insulation.

EEM 4 — Solar hot water heater
Solar panels will be installed to provide domestic hot water heating.

EEM 5 — Plug load timers
Smart strips and timers will be installed to turn equipment off when you are away reducing energy consumed in low-power modes while you are not using it.

EEM 6 — Low flow showers
Your shower head will be changed from a 2.5 to 1.5 gallon per minute fixture to conserve water and decrease the amount of water you will need to heat.

EEM 7 — Duct sealing
Ducts will be sealed to increase the efficiency of your heating and cooling systems while also increasing the comfort in your home.

EEM 8 — Add R30 to the attic
Insulation will be added to the attic to reduce air leakage and infiltration, saving energy costs related to heating and cooling.

STANDARD

EEM 9 — ENERGY STAR® appliances
Full-time use appliances will be replaced with ENERGY STAR appliances reducing energy consumption and offering significant savings.

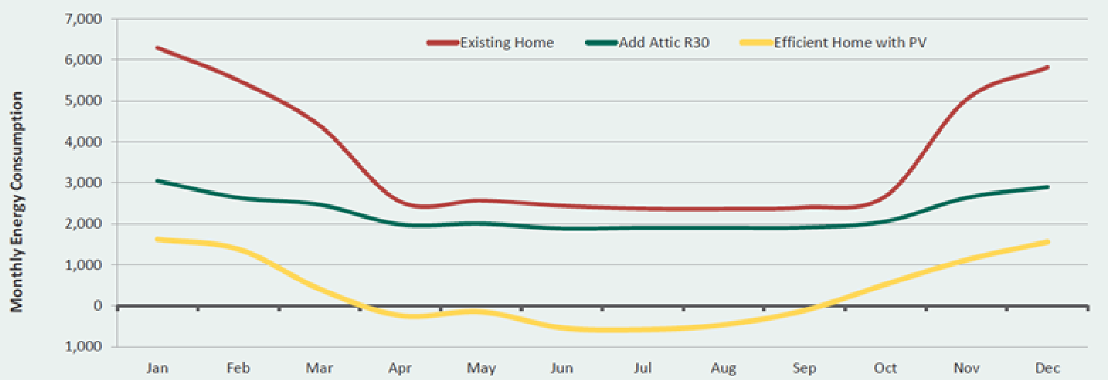
EEM 10 — Photovoltaic array
Photovoltaics will be installed.

ZNE 3
Irvine, California

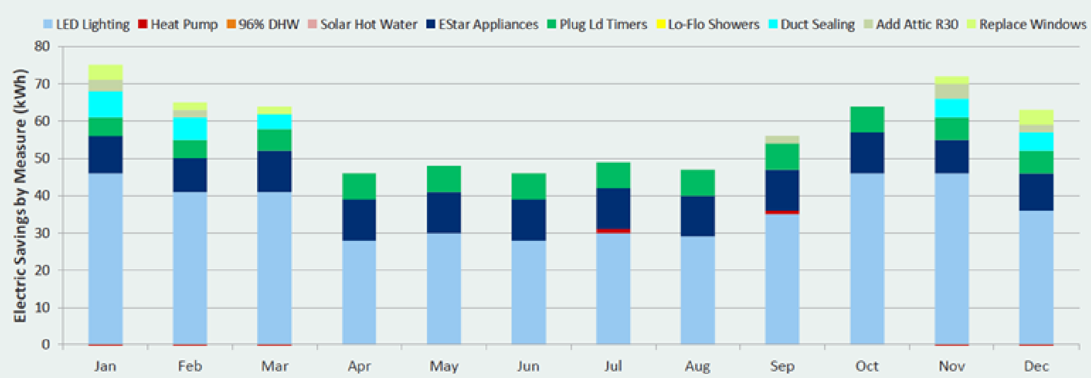
YOUR HOME'S PERCENT SAVINGS
(compared to your current energy consumption)

90%
PER YEAR

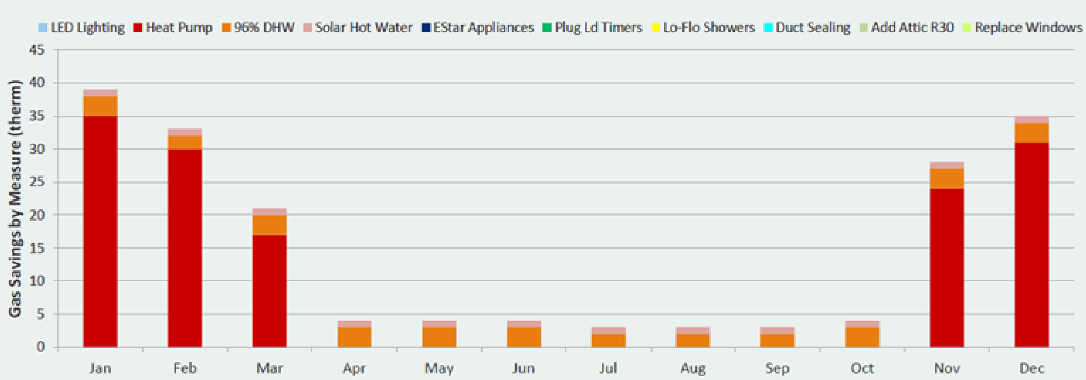
Annual Energy Consumption/Generation Comparison



ELECTRIC — Monthly Energy Savings by Measure



GAS — Monthly Energy Savings by Measure



Appendix 6: Data Storage Requirements

A6.1 Introduction

This section contains findings and discussion related to the amount of storage required for operation of the ISGD systems.

The amount of storage required for systems like those used in ISGD varies greatly, depending on the number and frequency of readings or other parameters being collected and recorded, how many devices are deployed, what internal representation formats are used to persist the readings, and how many copies are made of that data. Furthermore, some data may need to be retained for several years, while some might be kept only for a few hours. Therefore, it is not a simple answer, but a simple example of a single measurement at one minute frequency could take over 100 megabytes (MB) per year. This equates to approximately 400 TB per year for SCE's 4 million meters. Therefore, large systems with multiple devices—and multiple data points per device—can quickly get into terabyte (1,000 GB) and even petabyte (1,000 TB) scales.

A6.2 Schema

Each system has a schema, which consists of a set of files and tables used to store configuration data, including which devices are in use, where they are located, and what functions are enabled. The systems also have tables to store measurement readings taken by those devices, as well as status, configuration, and command parameters that can be recorded.

The largest amount of storage required for these types of systems will be in the data that is recorded on an ongoing basis. Configuration and reference data may be quite extensive and complex, but there will only be a few records per device. Recordings of measurements may occur at frequencies from every hour to sub-second, so this is the area on which to focus.

Through analysis of the various interfaces and internal structures on ISGD, it is clear there are many ways to store time-series data (values over time). All schemas used to record readings will need to have timestamps and values somewhere in the table structure. They will also require references to what each value means—namely, which device recorded the readings, and what do the readings mean? These attributes are called "location" and "reading type" in the discussion below. The main differences in schemas relates to where these references are located. In general, attributes can be distinguished using any of the structural elements of the storage platform, namely database instances, table names, column names, or values.

Reading Types in Columns

This type of schema stores one row per timestamp per device or internal component, along with all of the readings taken at that time, one value per reading type, with each reading type in a different column. **Table 64** provides an example.

Table 64: Readings Types in Columns Example

DEVICE_ID	TIMESTAMP	POWER_W	ACC_ENERGY_KWH	VOLTAGE_V
123	2014/11/07 14:37	23.6	28764.2467	124.3

Storing multiple values with a single timestamp does save space, since timestamps and device references are reused. However, this schema may not be as flexible as the alternative below, since the reading types are in the structure and therefore must also be in the associated code.

Reading Types in Values

This schema pattern stores one row per individual reading value, so the structure must contain references to the device taking the readings as well as the reading type that describes what the value means. It is possible to combine these and use an internally generated unique number (surrogate key) to identify the type, but the example below uses simple names for flexibility. **Table 65** provides an example.

Table 65: Reading Types in Values Example

DEVICE_ID	TIMESTAMP	READING_TYPE	VALUE
123	2014/11/07 14:37	POWER_W	23.6
123	2014/11/07 14:37	ACC_ENERGY_KWH	28764.2467
123	2014/11/07 14:37	VOLTAGE_V	124.3

One aspect about this arrangement is that all of the values must use the same data type, typically a decimal number. However, a system could have a few structures very similar to this, one for each value type, to allow for parameters that require a different data type, such as alpha-numeric character strings.

Regarding references to physical devices and installed locations, it is best to relate readings to the physical device that took the reading, and then relate physical devices to locations with effective dates. This way, it is possible to replace the device at a location and retain the ability to retrieve all readings at that location regardless of which device took those readings. For example, one device location association record might relate device D1 with location L1 from 1/1/2014 through 10/1/2014, and another record could link device D2 with location L1 after 10/1/2014. An important aspect of this is that the location does not change when the device changes, only the associated device per the effective dates.

A6.3 Time-Series Data Storage Sizes

The amount of storage required for a time-series type of system can be roughly estimated using the size of each record, number of devices, reading types per device, and frequency of readings. This section describes typical attribute storage sizes, and the following section provides a method to compute storage requirements.

Timestamp

There are two common internal storage formats for timestamps: one with a time zone, and one without a time zone. Inclusion of time zone is required for a system that is to be configured across multiple time zones, as well as for accurate reporting on days when the time zone offset changes due to daylight savings time.

- Decimal days / fractional seconds / no time zone (8 bytes)
- Timestamp with time zone (13 bytes)

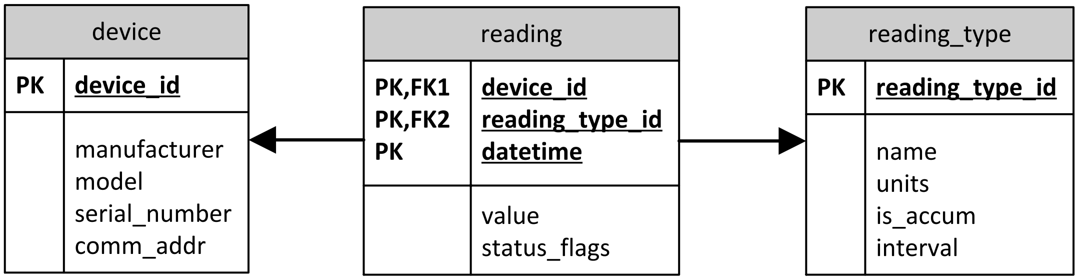
References

The amount of storage required for the references to a specific device and reading type can vary greatly across systems, depending on how the references are modeled in the schema. This list provides a few examples for comparison purposes. For example, a system might store unique device and reading type identification keys along with the timestamps and values, or it could store a character string that uniquely describes the measurement point.

- Unique key(s) (4-8 bytes)
- Character field(s) for descriptive names (50-250 bytes)

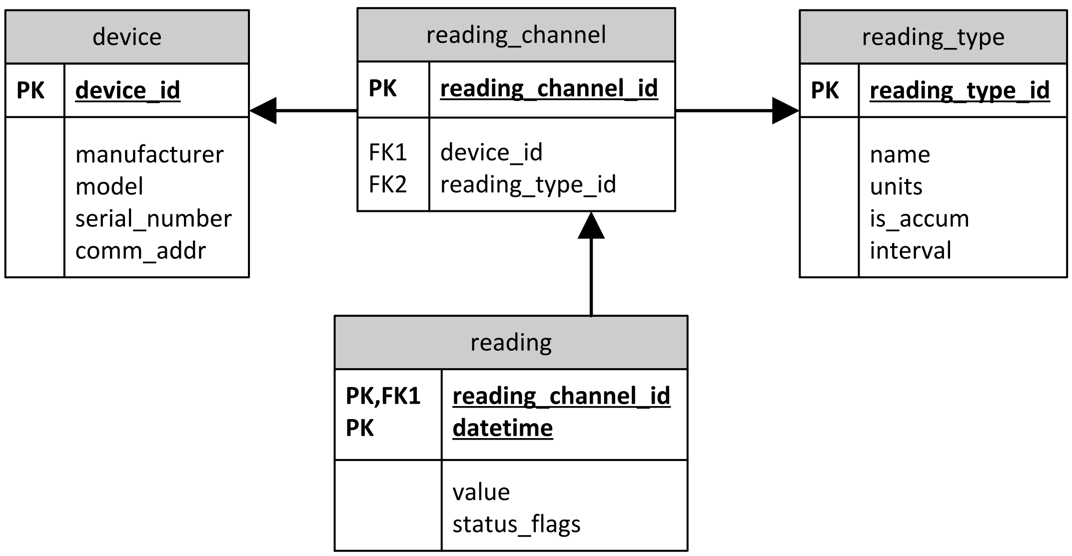
The minimal representation would keep key references to other structures containing more descriptive names. An example of these references from the schema examples is "POWER_W measured by Device 123." **Figure 177** shows one possibility, such that the descriptive character string names and attributes about the devices and reading types are kept separately so they do not have to be stored with each reading. The "id" fields can be short, 4-byte integers, whereas the attributes such as device manufacturer can be hundreds of bytes.

Figure 177: Reference Model Example



There are many ways to model this relationship. Another way is to have an intermediate table between reading values and devices and reading types called a *reading channel*, for example, that uses a single key to link back to the additional device and reading type information, as in **Figure 178**.

Figure 178: Reference Model Example Using an Intermediate Table



Value

- Typical size for a precise, decimal number is 8 bytes

Status

A few bytes can be useful to denote various qualities, such as whether the data is raw, estimated, calculated, valid, or invalid (whatever status qualities are desired can be defined).

- Reading value quality status (2 bytes)

A6.4 Storage Estimation

The minimum amount of storage per reading (without adding multiple types to the structure) is around 20 bytes. A large size would be 200 bytes or more. The general formula for estimating the storage requirements of a system is shown below.

*Number of points across all devices * Size per point * Frequency of readings = Storage estimate*

For example, a million points (e.g. 10 reading types at each of 100,000 locations) at five minute intervals would give 288 million readings per day, times 365 days is 105,120,000,000 readings per year, and then multiplied by a "typical" size of 120 bytes per reading is 12,614,400,000,000 bytes per year, or 12.6 TB/year. Also, storage will be required for indexes, which are used to speed up retrieval queries, adding up to around half of the size of the data itself.

An example from the ISGD project is the meter data storage database, which is recording 5-minute data for 394 points, and hourly data for another 122 points, and is using around 22 MB per day of primary storage, including indexes. Dividing 22 MB by the 116,400 readings per day shows that it is using around 189 bytes per reading. This number could then be used to estimate storage for a different number of devices, readings, or frequencies.

It would be necessary to store each reading multiple times. A backup copy would be needed, in case the primary storage fails. This could be done using disk arrays and mirroring, database backups, or both. Additionally, any new system that will provide functionality using the readings as input would usually require a separate copy, since that application code would require a specific schema structure for processing that is tailored to the needs of that application.

A6.5 Storage Reduction

Some systems have methods for minimizing storage requirements. A typical feature of "time-series" data historians is that they will only store readings that differ from a function that uses historical point values to determine future ones, such as simply following the slope of a line. Depending on the sophistication of this process, and the complexity of the readings, it may be possible to save a large percentage of this estimated storage requirement.

Another strategy is to selectively collect and/or store "interesting" time periods with greater frequency. For example, one second or even faster samples could be saved locally in the device for some period of time, but be discarded unless requested within some time frame, for example if there is an event of some type in the area.

A common scenario is that the most accurate representation of the system is needed for only a short time, and by the fewest functions and people. As the measurements age, more people might want them, but they might only need a summary of the data—maybe a representative sample at full resolution along with aggregate totals at a longer interval resolution.

Appendix 7: Deep Grid Situational Awareness Adaptive Filter and ANN Algorithm Design

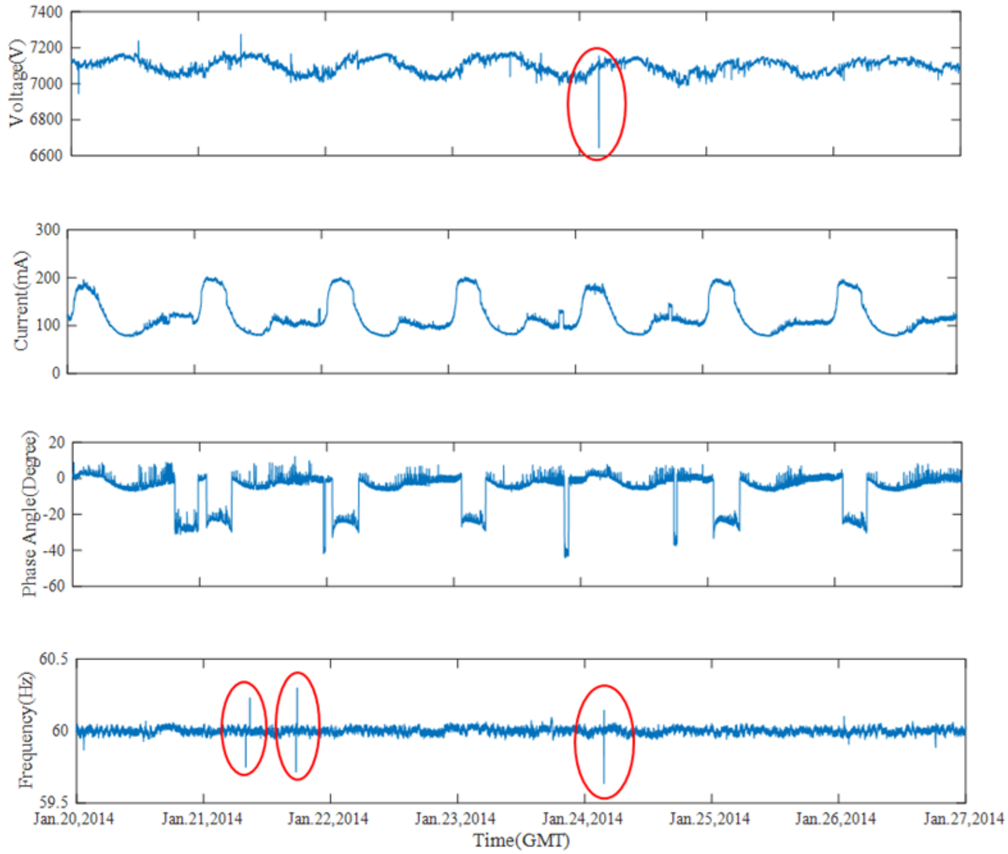
A7.1 Objective

The objective of this sub-project is to determine whether the operation of DERs can be detected or verified using data collected by synchrophasor equipment at the substation serving the circuit that the DER is connected to. Synchrophasor equipment consists of PMU equipped with a GPS clock and PDC for handling the large volume of data involved. Synchrophasors have been used mainly in the transmission system for fault detection and prevention of cascading blackouts.

A7.2 Summary of Methodology

To achieve the goal of this sub-project, a 2 MW/500 kWh Li-Ion battery energy storage was deployed on the Arnold circuit, in addition to PMUs being installed at the MacArthur substation. A detailed test plan was developed including a variety of tests to assess the impact of various factors on the successful detection/verification of DER operation. These factors include the size of the DER, the ramp rate, and the time and duration of the operation. For each test, the data including current, voltage, real, and reactive power were recorded at the site of the installation (referred to as on-site or locally-recorded data) with a resolution of one minute. PMU data including current, voltage, angle, and frequency were also collected at the substation with a resolution of 30 samples per second. Data collection at the substation started on January 20, 2014. The data collected at the substation for the week of January 20, 2014 is shown in **Figure 179**. Analyzing the data for business as usual operations (i.e. without the battery being charged or discharged), it was evident that the data collected at the substation requires processing before the detection algorithm can be applied. In the preprocessing, the null (zero) data points are replaced with moving averages, also sudden changes in the data (such as the one shown in the **Figure 179** voltage and frequency) are replaced with moving averages in order to smooth out the signal. The real and reactive powers are then calculated using the voltage, current, and the phase angle. The real power signal is used for DER verification and detection.

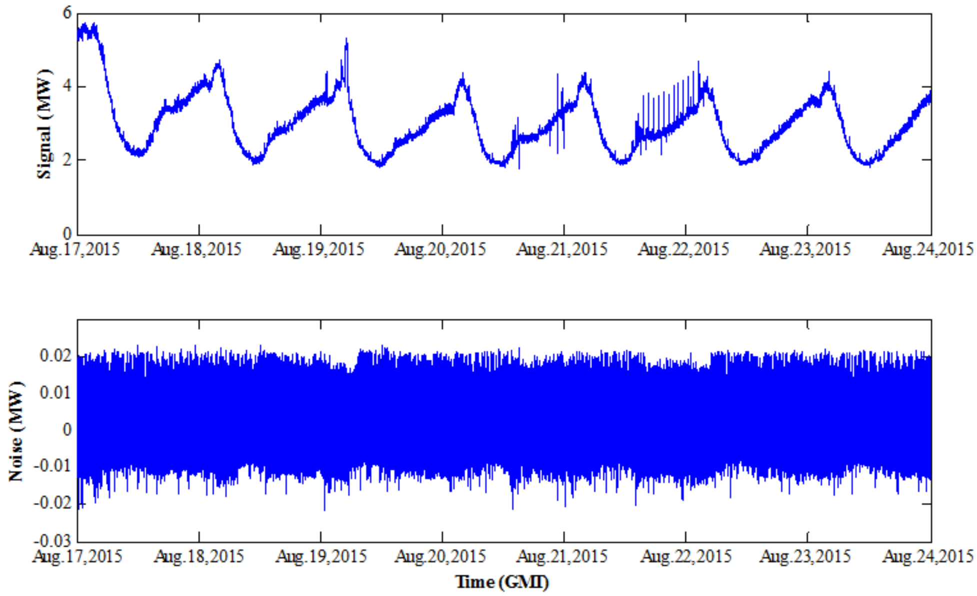
Figure 179: Data Recorded at the Substation (week of January 20, 2014)



After removing the null data points and smoothing out the data when required, the real power is calculated and the signal is de-noised. Various methods including adaptive filter (Kalman as well as Wiener filters) [1, 2] were studied before making the decision to use Wavelet Transform. Unlike Fourier transform, wavelet transform is capable of capturing local features of a signal and has been used widely in the literature for signal processing and de-noising [3-6]. To use the wavelet transform for de-noising it is necessary to first select a wavelet to apply to the noisy signal to produce the noisy signal wavelet coefficients, and then a thresholding method and threshold limits need to be selected. For more details on de-noising using wavelet transform see [7].

Unfortunately, white noise measurements were not taken in this project. As a result, the outcome of various de-noising methods cannot be verified. It was, however, determined that de-noising the data (especially without any measurements to verify) has very little to no impact on the overall analysis of this subproject. The level of white noise can be adjusted if measured data are available. Various thresholding methods were also examined and it was determined that they also have little impact on the final results. Examining the data collected and implementing various de-noising method, it was determined the noise level (assuming scaled white noise) is around 20 kW. This noise level could be adjusted more accurately once white noise data became available. In **Figure 180**, the de-noised real power associated with the Arnold circuit collected at the substation is shown along with the noise signal for the week of August 17th, 2015.

Figure 180: Real Power and Noise Signal



Next, the de-noised signal is used in an artificial neural network. The idea is to use the trained network to forecast short-term loads, and compare the forecasted signal to the actual signal (recorded at the substation by the PMU). If the error in forecasting is high, then it is concluded that something in the circuit has changed which can be the charge or discharge of the DER (battery). ANN is a machine learning method which is based on the biological neural network (it is called "artificial" because the number of neurons are orders of magnitude lower than the number of neurons in the nervous system). The use of ANN in forecasting short-term electricity demand has been established in the literature [8-30]. MATLAB's ANN toolbox is used to train a network based on a business as usual day (**Figure 181**). Then the trained network is used to forecast the real power. The input of this forecast is the observed (actual) real power at the previous time step to adjust for changes due to temperature and other factors. When the error in forecast is high, this feedback is removed and the forecast is only based on the trained network in order to isolate the DER impact. In summary, the approach combines two MATLAB ANN algorithms dynamically and switch between the two in the middle of forecasting when a DER is detected.

The error in forecasting for Test Day 18 is shown in **Figure 182**. This error is then compared to the real power data collected on-site of the installation and the results are calibrated to match actual charge/discharge. The overall approach is successful in detecting the battery at full power, and it can detect the battery at lower power levels (250 kW and higher) but the accuracy in determining the power and energy decreases. Other methods (e.g. step detection) were also examined which work pretty well for step profiles but not successful with other charge/discharge profiles.

Figure 181: Using he ANN to Forecast Real Power at the Substation

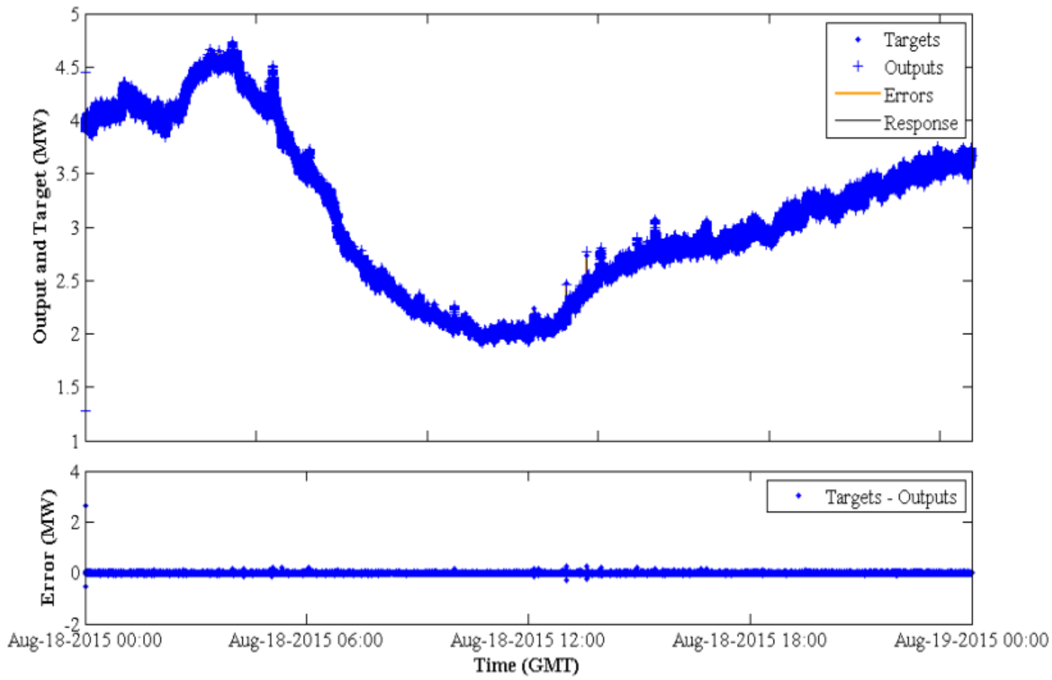
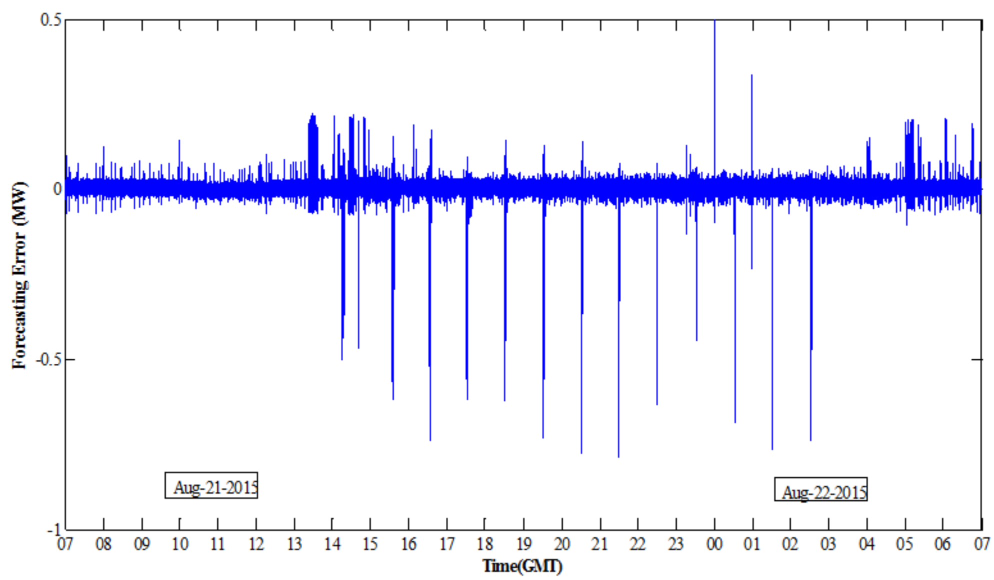


Figure 182: Error in Forecasting (Test Day 18)



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Appendix 8: Job Competency Assessment

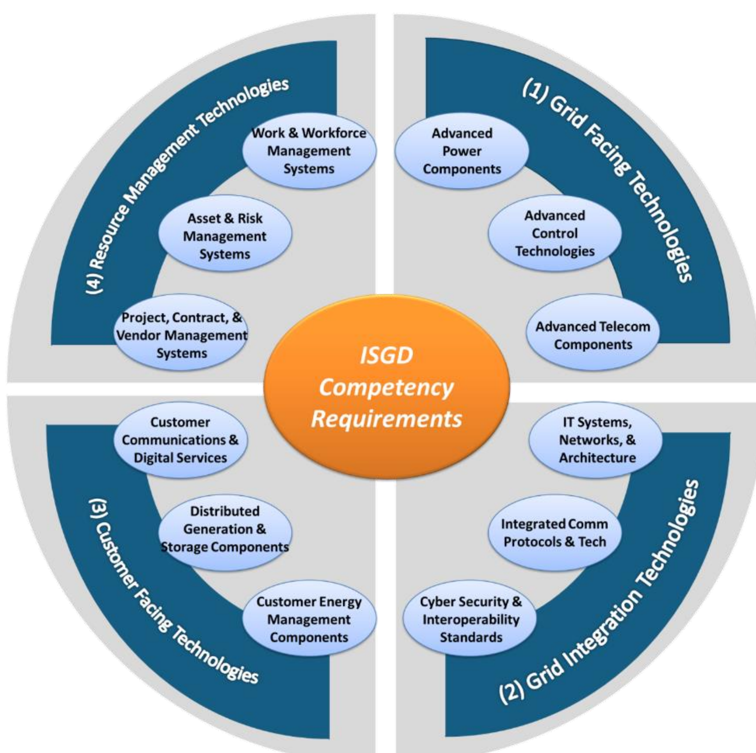
This document offers an integrated model of employee competencies required to plan, build, and run a modern distribution network that contains a mix of legacy and new intelligent components and systems.

- Section A8.1 - The ISGD Competency Requirements Model defines the skills required to plan, build, and run ISGD technologies and relevant industry smart grid technologies and applications.
- Section A8.2 - The model is applied to eight existing job classifications selected by SCE to produce individual Job Competency Profiles.
- Section A8.3 – Job competency gaps are identified using a "heat map," which summarizes these gaps by job classification, comparing the future state Job Competency Profiles to a range of current state job information.
- Section A8.4 – Discusses workforce impacts beyond the eight job classifications selected by SCE, including three potential new job classifications.
- Section A8.5 - Develops a potential training curriculum framework to guide the development and delivery of key knowledge, skills, and abilities (KSAs) to fill the workforce competency gaps.

A8.1 ISGD Competency Requirements Model

The ISGD project contains a group of smart grid technologies that impact key elements of the electric grid – from the transmission level through the distribution system and into the customer premises. Figure 1 depicts the ISGD Competency Requirements Model, which pulls from previous work done by the Illinois Institute of Technology (ITT), results from the DOE Smart Grid Workforce Development Programs, and utility industry projects underway over the past four years. The model captures the skills and experience necessary to operate the various technologies used in the ISGD project. This model also addresses the business and management issues that arise due to smart grid technologies. This model includes four technology quadrants: Grid Facing Technologies, Grid Integration Technologies, Customer Facing Technologies, and Resource Management Technologies.

Figure 183: IGSD Competency Requirements Model



Each quadrant contains key competency areas, included within the blue ovals in the figure above. SCE employees working on the ISGD project acquired key knowledge and skillsets for these various sets of technologies and components. Training channels included classroom sessions, on-line training, and hands-on equipment review sessions. In the future, depending on the deployment of ISGD technologies and components, a wider population of SCE employees will likely require some subset of these competencies.

Quadrant 1: Grid Facing Technologies

Grid-facing technologies include the components, systems, and applications operated by the distribution utility, including advanced power components, advanced telecom components, and advanced control technologies.

Advanced Power Components

Advanced power components include technologies connected electrically to the distribution grid. Examples of such technologies include the following:

- Programmable capacitor controllers
- Universal remote-controlled circuit interrupters
- Smart meters
- Phasor measurement units
- Distribution-connected energy storage

To the extent such technologies are deployed in a production environment, employees will require the skills and knowledge to plan, build, and run the distribution system components. Resources planners should also understand costs and benefits derived from these grid components. This applies to all grid technologies.

Utilities and customers are experimenting with energy storage technologies to provide various operational uses, including power smoothing, peak load shaving, and backup power. The ISGD Competency Requirements Model assumes both utilities and customers will deploy storage technologies in the future. Therefore storage components are included in the grid-facing quadrant and the customer-facing quadrant.

Advanced Control Technologies

Advanced control technologies include the various components that help to monitor and control the various grid components, often in real-time. Recent increases in the communications and computing capabilities of grid components, and increased adoption of distributed energy resources is creating opportunities to monitor and manage the grid with more precision. Examples of advanced control technologies include the following:

- Automatically locate and isolate faults to reduce outages
- Dynamically optimize voltage and reactive power for more efficient power use
- Monitor asset health to guide maintenance and emergency response
- Distributed energy resource management
- Power flow optimization

Advanced Telecom Components

The design and architecture of utility smart grid networks requires advanced communications capabilities. Historically, utilities connected and controlled remote equipment via land-line, microwave, and radio systems through the SCADA (System Control and Data Acquisition) network. Advanced telecom components now include fiber optic cables, wireless radio systems, broadband systems, radio repeaters, internet protocol routers, and Ethernet switches and converters. These new telecom networks collect and transmit data from numerous intelligent devices in the field, on customer property, and inside the substation fence. These communications capabilities support:

- Grid visualization
- Real-time load monitoring

- Automated demand response
- Automated voltage control
- Self-healing networks
- Asset condition monitoring
- Advanced system protection
- Customer premise information

Quadrant 2: Grid Integration Technologies

This quadrant addresses the applications and networks required to design, integrate, and operate the grid-facing technologies in quadrant 1.

<u>IT Systems, Networks, & Architecture</u>

The smart grid is increasing the complexity of data flow and data manipulation as compared to legacy systems. Integrating the data flow from multiple interfaces requires broader and more flexible approaches. For example, utilities are installing Enterprise Service Buses rather than creating point-to-point interfaces between applications. In addition, the convergence of Information Technologies (IT) and Field Technologies (FT) increases data flow and database management issues. This convergence is creating new jobs that require new skills.

<u>Integrated Communication Protocols and Technology</u>

Modern utility telecommunications systems have moved beyond the era of the Public Switched Telecommunications Network (PSTN) and analog voice and data flow. Utility telecommunications systems today transfer data digitally across wireless and fiber optic networks with controls and protocols based on the seven-layer OSI model. Equipment sensors and monitoring systems provide on-board intelligence, data storage, and deliver real-time data flow to operators and decision makers. LANs and other types of networks are interconnected and share data based on industry standard protocols. Telecommunications and IT data flows utilize common Ethernet and IP designs for routing and switching. Transporting data among layers utilizes Transmission Control Protocols (TCP) and User Datagram Protocols (UDP). Strategic applications sit on top of the data flow and integrate, filter, and interpret the outputs. Key employees working in this sector of the smart grid network need to master both the technologies and the protocols of the interconnected telecommunications and data network. This relates to standards associated both on the utility- and customer-sides of the meter.

<u>Cybersecurity and Interoperability Standards</u>

Cybersecurity threats exploit the increased complexity and connectivity of critical infrastructure systems, placing the United States security, economy, and public safety at risk. A critical aspect of the smart grid is protecting the information that passes through utility communication systems. Emerging cyber-threats targeting the grid highlight the need to integrate advanced cybersecurity to protect these critical assets.

Quadrant 3: Customer Facing Technologies

Customer-facing technologies include the components, systems, and applications that are used by utility customers, and that can impact the operation and maintenance of the grid.

<u>**Customer Energy Management Systems**</u>

Over the past 10 years electric utility customers have been encouraged to adopt a wide range of energy management programs and technologies. Incentives in the form of utility subsidies, state tax breaks, and industry rebates have reduced the economic barriers for consumers eager to adopt these types of systems. SCE has offered numerous energy efficiency programs, demand response alternatives, and demand-side management technologies, including:

- Energy Solutions for Your Home
    - Energy saving rebates and incentives
    - SCE Home Energy Guide
    - Save Power Days
    - Summer discounts and bill credits
    - Energy Saving Assistance Program
- Energy Solutions for Your Business
    - Energy efficiency tips
    - Business Energy Advisor
    - Specific industry sector programs
    - Time-of-use rates

Distributed Generation and Energy Storage Components

DG refers to power produced at the point of consumption. DG resources are small-scale energy resources that typically range in size from 3 kW to 10 MW. A typical household's peak demand is about 3.5 kW, so the smaller resources are used by residential customers, while the larger systems are typically used by commercial and industrial customers. In addition to PV systems, other forms of DG include small wind turbines, and combined heat and power (CHP).

Distributed generation is not a new phenomenon. The early electric industry served all local energy requirements at or near their point of use. Large industrial clients have traditionally invested in on-site generation related to combined heat process treatment or for back-up generation.

Customer Communications and Digital Services

Utilities' methods for interacting and communicating with customers continues to evolve, driven by regulatory, market, and customer activities. Although more relevant to the Customer Service Business Unit, there are skills and competencies T&D employees will use from this sector. These include a wide range of relationship management, customer communication technologies, and information sharing platforms.

Smart grid technologies provide more information and options to customers. Utilities should develop strategies and communication channels that communicate essential information to the customer regarding program offerings, event occurrences and other energy conservation initiatives. Utilities will also need more skilled customer and marketing resources to maximize the value of new grid technologies.

Quadrant 4: Resource Management Technologies

This quadrant includes the key resource management tools and knowledge the future workforce will need to successfully plan, build, and run the new smart grid systems. The ISGD project team was effective in managing an overlapping set of stakeholder, technology, asset, and risk management concerns by leveraging a highly skilled and integrated team of experts. Large scale deployment of smart grid technologies would increase the complexity and operational risk beyond the limited impact of the ISGD demonstration.

Project, Contract, and Vendor Management Systems

Utilities have developed standard project management tools which track the scope, schedule, and budget of project activities. Utilities have also established effective processes for procuring and managing vendors and equipment.

Procurement and vendor management activities are challenged by the dynamic landscape of evolving smart grid technologies and applications. As SCE experienced in the ISGD project, standardized contract terms and conditions needed modifications due to the nature of governmental and third party procurement. The integration of numerous internal engineering and technician resources with external vendors and customers also created new project management challenges. Experience with and functional knowledge of valuable resource management systems typically resides in a few concentrated sources of expertise inside specialized utility departments. This traditional approach enables the easy standardization and risk management of project and procurement processes, but also causes delays and barriers in the process when the pipeline gets too large or complicated.

Project, vendor, and contract management systems will need to evolve to become more adaptive and efficient for deploying new technologies across multiple organizations. These processes will become more integrated and projects will be better managed in a transformational Project Management Office (PMO) structure. This type of structure will share data, develop performance metrics, and integrate business analyses across all technology projects. Performance metrics will ensure the organizational transformation is proceeding and that common objectives and responsibilities are aligned.

Asset and Risk Management Systems

Evolving smart grid technologies are adding complexity and granularity to asset management. Asset management processes focus on the core activities of: (1) long-range planning, (2) building new infrastructure/tools, and (3) daily operations.

Risk management involves identifying actions and activities that guard against known and unknown threats. Most utilities have adopted some form of Enterprise Risk Management along with standardized processes for risk ownership and identification, risk measurement and assessment, and risk response and mitigation. The Enterprise Rick Management Framework (ERMC) applies across an organization to three types of risks:

- Strategic-level risks that can impede the achievement of an organization's primary mission and key objectives. These are broad strategic risk areas and include financial, business continuity, performance, stakeholder (including customers, investors, and employees), reputation, legal and compliance, and health & safety.
- Business-line risks identified by business-line departments or groups, which can impede the organization's ability to deliver products and services, meet performance targets and accomplish business objectives.
- T&D project-level risks that can threaten the scope, schedule, cost or quality of key projects and profitability – depending on the scope and complexity of the project, these risks can have strategic or business-line consequences.

For the T&D workforce, certain job classifications would benefit from more exposure and involvement in asset management and risk management at the project and business line levels. Asset management systems are typically well integrated at most utilities with key FT systems such as the Geographical Information System (GIS), Work Management System (WMS), Customer Information System (CIS), and Outage Management System (OMS). Engineers and supervisors typically populate and access these databases. As smart grid technologies become widespread, the integration of intelligence and monitoring data into these FT systems will improve the ability to manage asset risk.

Work and Workforce Management Systems

Utilities and other asset-intensive organizations need to manage labor, material and equipment, and record the time and cost associated with planning, building, and operating their assets. These activities generate information that is used to plan and complete key construction, maintenance, and repair activities. This type of work, including planned and unplanned maintenance, drives the majority of the T&D activities. A Work Management System (WMS) typically contains functionality that includes:

- Work planning and tracking
- Resource planning and utilization
- Task and activity cost and duration estimates
- Job scheduling and dispatch
- Work order generation, management, and closeout
- Data collection and integration
- Analytics to improve estimates and drive new work

More sophisticated WMS products track equipment and inventory data, are integrated with the supply-chain system, and offer mobile applications. Workforce management (WFM) is an integrated set of processes that an institution uses to optimize the productivity of its employees on individual, departmental, and enterprise-wide bases.

Work planners, designers, and supervisors typically are involved in these processes on a daily basis. The ISGD project generated work activity during the normal course of daily events, yet only three dozen work orders were actually entered over the last 3 years. The majority of these work orders deal with the work on sub-project 7, the substation upgrade work at MacArthur Substation. New technology projects can impact the WMS tools and these impacts can be captured by front-line and project employees on a regular basis. As new technology is deployed system-wide and new resources are used to plan and complete the work, the functionality and efficiency of the WMS process can be improved and made available to a broader set of employees.

Conclusion

This section has discussed the ISGD Competency Model by considering twelve unique smart grid competency areas. The knowledge and skills required in each area stem from the lessons learned in the ISGD project as well as ongoing workforce of the future developments throughout the country. These efforts include the Illinois Institute of Technology (IIT), the Center for Energy Workforce Development, (CEWD) and the Pacific Northwest Smart Energy Center of Excellence. The next section applies this model to specific job classifications.

A8.2 Competency Requirements Assessment

This section uses the ISGD Competency Requirements Model developed in Section A8.1 to evaluate the potential impacts of ISGD technologies on various employee types. The team selected eight specific job classifications for analysis and review:

1. Engineers (based on a broad and generic job description)
2. Linemen
3. Distribution Apparatus Test Technicians
4. Troublemen
5. Substation Operators
6. Substation Test Technicians
7. System Operators
8. Supervisors/Managers (based on a broad and generic job description)

SCE Workforce

These job classifications are representative of employee roles and responsibilities spread across the entire Transmission & Distribution (T&D) organization. These job classifications currently include over 1,200 craft employees and hundreds of engineers, supervisors, and managers. SCE employs several thousand individuals who are divided into craft, management and professional positions.

Most of the SCE employees who interacted with the ISGD project work in T&D. This group is comprised of over 10,000 employees in six areas with over half of these in the Distribution Business Line. This assessment evaluates the impact of ISGD technologies on employees primarily in the Distribution Business Line.

The ISGD project touched multiple organizational units supporting various job skills and competencies. SCE selected six of those craft level job classifications to evaluate in more depth: Lineman, Troubleman, Apparatus Technician, Substation Operator, Test Technician, and System Operator. There are another another 75 job classifications of management and professional employees. The Assessment selected two additional job classifications to evaluate from these groups: Engineers from the professional group and Supervisors from the management group.

The selected T&D job classifications fall into six job categories and capture the full range of plan, build, and run activities for the distribution system. These include:

Engineering – Includes jobs associated with the planning, design, and architecture of new technologies, systems, and projects.

Front-line System Construction and Installation – This consists primarily linemen, substation technicians and electricians in job categories associated with the actual installation of various ISGD grid-facing technologies.

Front-line System Maintenance and Repair – Includes jobs associated with testing, maintaining and operating the ISGD grid-facing technologies. Grid Operations also provides maintenance & repair oversight and involvement through the Switching Centers for planned and unplanned work.

Emergency Responders – These jobs include responsibilities for responding to and managing unplanned and emergency conditions on the distribution system and in distribution substations. Grid Operations dispatches Troublemen and Substation Operators from the Grid Operations Centers.

System Operations – Employees in these jobs monitor the condition of the electrical grid and coordinate planned and unplanned work with other areas. At SCE these jobs include System Operators and Process Control Technicians from Grid Operations.

Supervisors/managers – SCE maintains several job families of foremen, supervisors, and managers who lead and direct front-line employees. Supervisors are involved and should be knowledgeable in every aspect of the distribution system plan, build, and run model.

IT, Telecom, and Network – Includes employees involved in the planning, building, running of the communications and computing infrastructure.

The ISGD project team embedded IT and Customer Service functions inside the project itself. From an IT perspective this offered the opportunity for a small group of IT architects supported by sub-contractors to focus on key issues raised by ISGD technologies. These issues include: complex cyber security concerns, interoperability of multiple new technologies, and testing and design activities to integrate new communications and data networks into legacy SCE systems. The ISGD project also benefited from a separate project developing SCE's Common Cybersecurity Services (CCS) platform. ISGD is using CCS to provide high-assurance cybersecurity for substation devices and communications between the various field devices and ISGD back office systems.

Customer Service – Includes employees focused on serving the end-customer through the meter-to-cash process and affiliated communication and outreach activities.

From a customer service perspective, sub-project 1: Zero Net Energy Homes impacted a very small number of customer premises (fewer than 40 customers). The ISGD team created a direct 800 line for any customer issues that connected the customer with the third-party vendors and with the ISGD project leaders. As a result, impact to customer service jobs and roles was negligible.

Job Competency Profile Methodology

The assessment used the ISGD Competency Requirements Model to develop the job competency profiles for each of the eight job classifications. These profiles define the expected job proficiencies within each of the 12 ISGD Competency Requirements areas identified in [Figure 1]. These profiles establish the foundation for Knowledge, Skills and Abilities (KSAs) and training courses needed to build awareness, proficiency, and mastery levels of knowledge and skills.

The competency profile identifies the level of competency required for each area—Table 2 below provides an example competency profile for a Lineman. Each concentric ring indicates an escalating level of competency required, moving outward from the center of the model. For example:

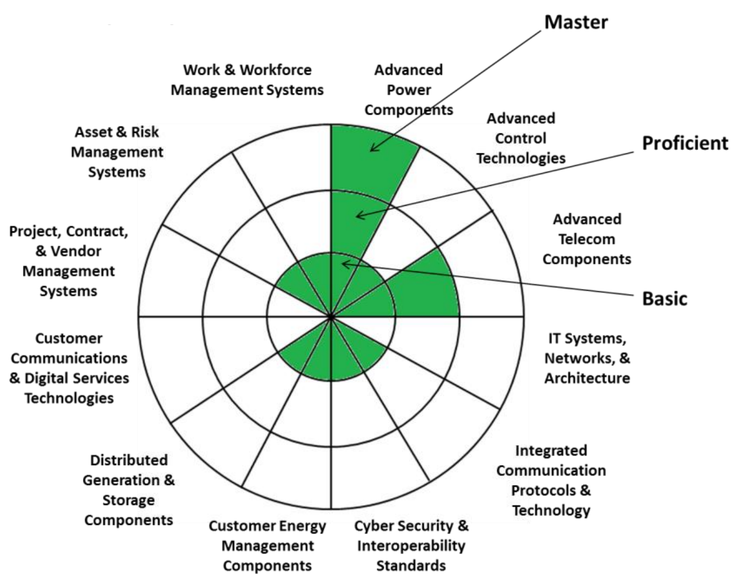
- **Basic** (inner-most ring) level of competency equates to a familiarity and awareness of technologies and processes. At this level, an employee would be able to identify the types of equipment or information related to a specific component or application and able to address basic questions including relationships with other smart grid sectors.

- **Proficient** (middle ring) level of competency equates to a full knowledge and understanding of technologies and processes. At this level, an employee will understand how to install, operate, troubleshoot, test, maintain, and repair equipment. The employee will also understand and be comfortable in applying required process management steps and solutions. This level of competency will allow the employee to accomplish a majority of the job's duties and responsibilities and will also build an understanding of the interaction and dependencies of various technologies and processes.
- **Master** (outer-most ring) level of competency equates to a mastery of technologies and processes. At this level the employee will be able to apply advanced concepts about the specific equipment or management process. The employee would be able to instruct and lead others in the performance of work and would be seen as a subject matter expert.

These competency profiles are pathways for employees to add knowledge and skills required to perform job duties driven by the introduction of new technologies and systems. They represent a taxonomy that moves employees through three levels of capabilities. The first level allows the employee to "know" the component or application. The second level allows the employee to "do" necessary activities affecting the status and condition of the component or application. The third level enables the employee to "design" current and future activities. This *know-do-design* structure is the foundation for the competency models and learning frameworks included in this assessment.

Individual job classification profiles are built to represent the highest level of mastery for a particular classification. For example, the Lineman competency profile represents a Mastery level of smart grid skills that would be appropriate for a foreman or very senior lineman. Therefore the Lineman skill level shows a high level of competency in areas related to day-to-day construction and maintenance of the electric distribution system (primarily the Advanced Power Components sector).

Figure 184: Job Competency Profile - Lineman

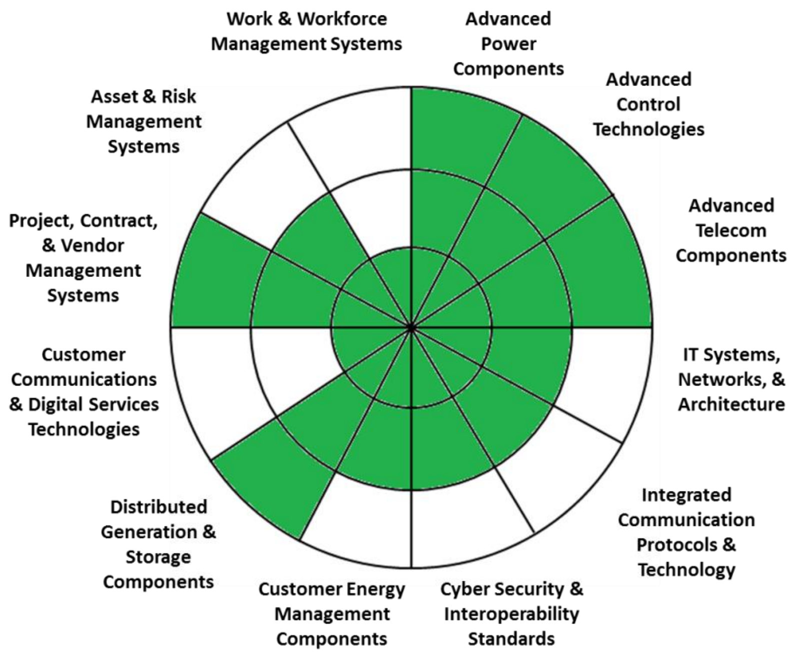


In addition to building knowledge through ascending levels of competency, the job competency profiles also recognize that the smart grid environment requires employees to develop and apply cross-functional and integrated sets of skills across multiple areas of the ISGD Competency Requirements Model. For instance, the Lineman profile contains competencies in areas such as advanced telecommunications, smart grid control and integration systems, and customer-facing technologies. The combination of cross-area and ascending level of competencies defines a certain combination of knowledge at a Basic level, a different combination at a Proficient level and yet a third combination at a Master level. This approach complements SCE's development of progressive Job Task Analyses (JTAs). The JTA development process considers all of the tasks performed by employees in a defined job classification including equipment, tools, and environmental conditions. This analysis allows each classification to be tailored to the specific needs of the organization.

Job Competency Profiles

Engineers

Table 66: Job Competency Profile - Engineer



Design of ISGD technologies and systems required a high level of integrated distribution system experience and technical knowledge. The convergence of IT and FT systems, power networks and data networks, and grid and customer facing applications challenges the traditional design approach of narrowly focused subject matter expertise. Interviews with key employees on the ISGD project highlighted the importance of individual cross-functional knowledge and integrated team structures for performing this project.

It can be expensive and inefficient to continually bring together multiple experts to address key integration and boundary issues. The project approach can work well for laboratory and demonstration projects, yet even this integrated team encountered gaps and barriers when resolving third-party vendor equipment design and non-performance. SCE has an industry-leading standards approach for new technology that is also used for piloting new components and systems. Yet even this highly experienced team of technical and operating employees acknowledged difficulties crossing boundaries and establishing new designs.

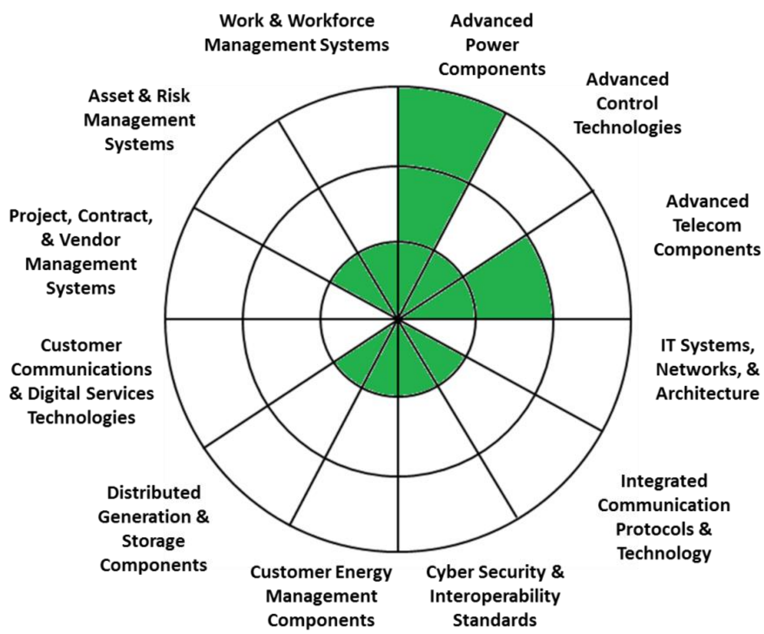
A new cross-functional approach for smart grid engineers would require the highest level of competencies for smart grid skill areas across the board, specifically in Grid Facing Technologies (Advanced Components, Advanced Control Technologies, Sensing & Measure), Integration Technologies (IT Systems, Networks, & Architecture, Integrated Communication Protocols & Technology, Cyber Security & Interoperability Standards), and Customer Facing Technologies (especially Distributed Generation and Energy Storage Systems). Engineers would also benefit from deeper skills sets in the Resource Management quadrant (especially the Project, Vendor, and Contract Management sector). These skills allow engineers to manage evolving smart grid applications and standards and the continuing evolution of vendor solutions. If the utility is to fill a role of system integrator, then the engineer position must encompass a blended set of technical and resource management skills.

ISGD has also highlighted a potential need for new engineering role. Section 5.1.4.2 states that utilities should prepared to take on the role of system integrator. This requires a commitment to develop the necessary project management and software development lifecycle skills. These skills would need to be paired with a detailed understanding of the electric grid in order to deploy sophisticated, integrated smart grid capabilities. These requirements and the potential for a utility to act as a system integrator in the future indicate a need for a Software Project Manager job classification. The requirements for such a job would require education and experience in both power operations and software engineering.

Engineers will need to be the most educated SCE resources in regards to all smart grid skill areas and should be a key audience for smart grid education and workforce training. The competency profile documents these needs. This profile is representative of a generic Smart Grid Engineering position and components of this profile could be used to model and extend key job descriptions for Distribution Engineers, Protection Engineers, and Apparatus Engineers. In addition there are also engineering positions in the Telecommunications and Information Technology domains that would benefit from similar cross-functional knowledge of the advanced power components and distribution network impacts, such as the Software Project Manager described above.

Lineman

Figure 185: Job Competency Profile - Lineman



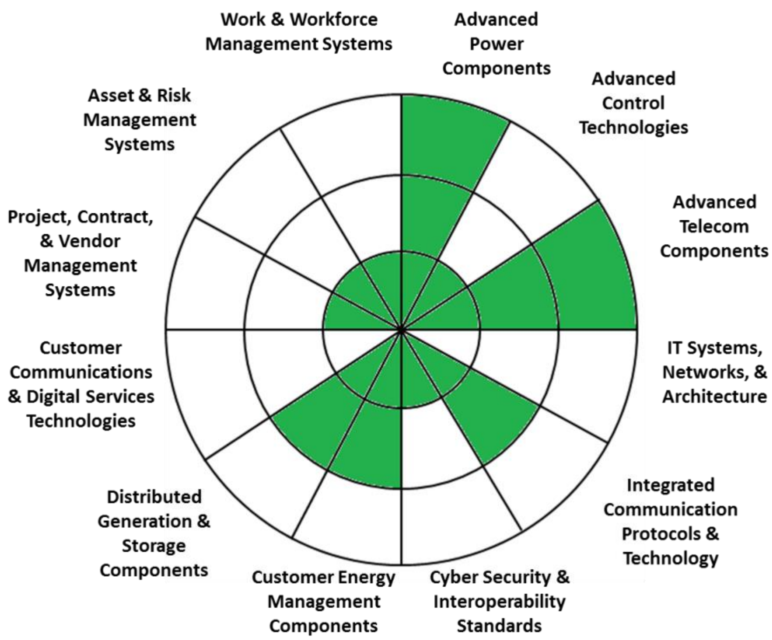
Linemen build, maintain, and repair the power lines that carry electricity through the SCE distribution and transmission networks. This assessment focused on the distribution responsibility including work on lines and apparatus from the distribution substation to the customer premises. The work includes overhead structures and conductors (primary and secondary service), underground cables and vaults, and associated components and apparatus that are attached to the lines and poles. The work occurs during planned and unplanned system conditions.

At SCE there are different classes of Linemen, including Groundman, Apprentice (Step 1 – 6), Journeyman, and Foreman. As they perform "hands-on" responsibilities with physical smart grid components, Lineman resources require varying levels of competencies with smart grid technology. The focused nature of the Lineman position at SCE results in the need for deep knowledge about Advanced Power Components, with general awareness of other key apparatus that will need to be installed, replaced, or removed from the system. In addition, it would be beneficial if Linemen were also exposed to deeper knowledge of Advanced Telecommunications Components, especially as they repair and maintain systems during emergency and storm response conditions. Similarly, deeper awareness of certain Grid Integration

Technologies and Customer Facing Technologies will broaden their understanding of the interactive and expanding nature of the power grid. Finally, Foremen also have responsibilities for managing work, teams, and assets and should be familiar with these systems. As noted earlier, this job competency profile can be expanded or limited for various steps in the employee development process (e.g. Apprentice or Groundman). The current profile represents the highest level of skills required in this job classification (Foreman).

Troubleman

Figure 186: Job Competency Profile - Troubleman

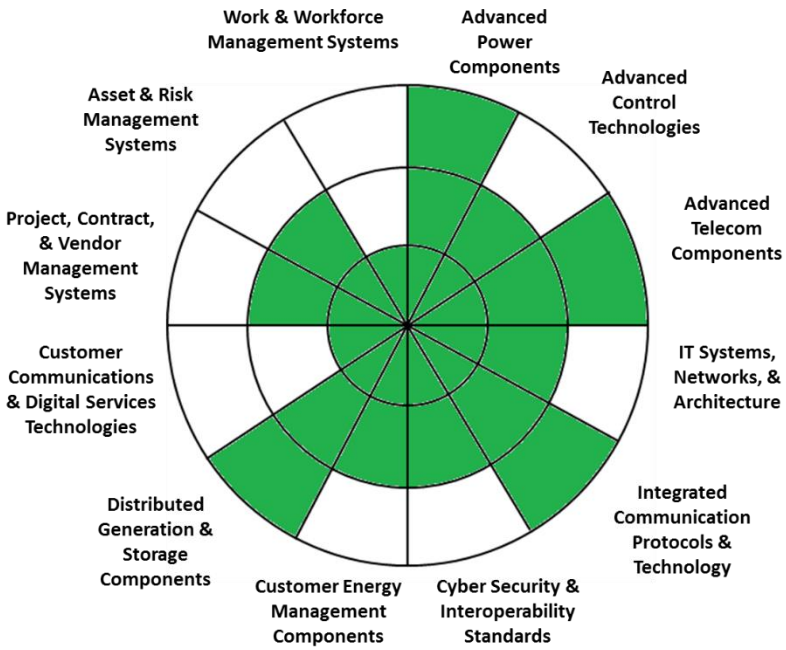


A Troubleman has all the experience and knowledge of a Lineman and works independently and with others on a variety of activities impacting the distribution network and associated apparatus. The primary role of the Troubleman is to be ready to respond to abnormal operating conditions on a 24/7 schedule. Troublemen are dispatched by the Grid Operations System Operator. They arrive first on the scene of an emergency or trouble call, and are trained to evaluate the condition and make it safe. Primary activities include repairing faults, clearing unsafe conditions, and calling for additional resources.

The Troubleman job competency profile therefore is an extended version of the Lineman profile, with an increased emphasis on the interconnected nature of power, telecom, and IT systems. The Troubleman smart grid profile also includes more knowledge of certain Customer Facing Technologies such as Distributed Generation and Energy Storage Technologies. Finally, the Troubleman will also face more opportunities to interface with third-party equipment and vendors, especially in unplanned situations.

Distribution Apparatus Technician

Figure 187: Job Competency Profile - Distribution Apparatus Technician



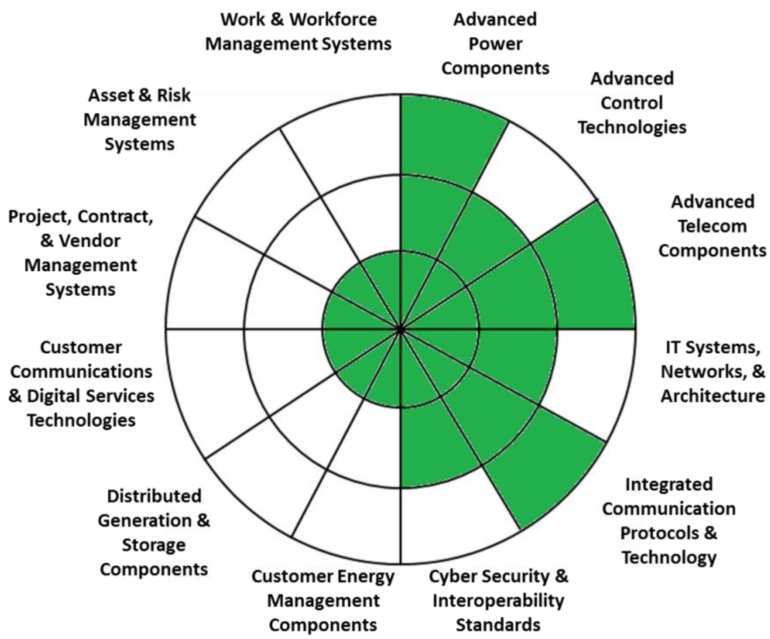
Distribution Apparatus Technicians represent the highest skilled craft employees working on the distribution network. They often move up from the Journeyman Lineman or Troubleman positions and according to a 2013 JTA, the position typically has more than 20 years of experience.

In both the ISGD project and day-to-day operations system-wide, the Distribution Apparatus Technician requires a deep set of knowledge and competencies on all the advanced components attached to the system. This classification also needs to understand the interfaces, integration, and information technologies used to connect and communicate with this equipment.

Many of the Customer Facing ISGD technologies will also impact the operating condition of the distribution system and knowledge of these systems will prove valuable. As more technology is added to the system, there will be more frequent interactions with vendors and third-party team members so knowledge of Resource Management Technologies will also provide confidence and control for the Distribution Apparatus Technicians. The profile represents the Foremen level.

Substation Operator

Figure 188: Job Competency Profile - Substation Operator



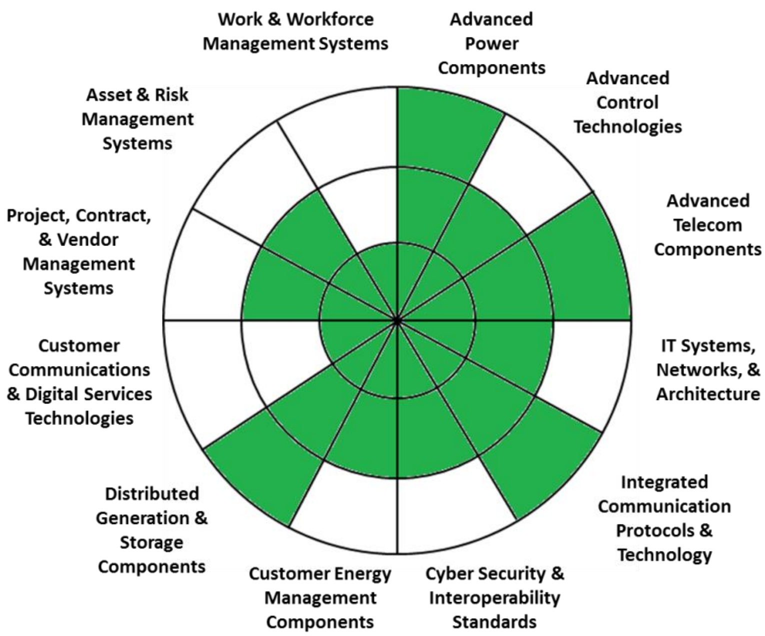
The Substation Operators are responsible for the monitoring, controlling, and operating SCE's substation systems. They inspect, troubleshoot, repair, and operate substation equipment. They implement switching orders affecting the substation and maintain the instruments, facilities, and general condition of the substation on a day-to-day basis. They are the first responder to trouble calls at the substation and possess a similar set of skills as the Troubleman on the distribution system.

The role of the distribution substation is to transfer energy from the bulk power transmission network to the distribution system that delivers energy to the customer premises. These facilities include power transformers, relays, switches, network protection equipment, and other instrumentation and monitoring apparatus. The Substation Operator must understand the function and integration of new types of energy resources, telecommunications, and information technology components and networks. Since the substation is isolated and protected from Customer Facing Technologies, the Substation Operator is focused on Grid Facing and Integration Technologies. The Substation Operator will also be expected to understand and utilize many of the Resource Management Technologies and tools as the operator interfaces with vendors, databases, and other SCE T&D crews and specialists.

ISGD sub-project 7 requires the Substation Operator to be knowledgeable of the new SA-3 Human Machine Interface (HMI), the function of substation capacitors for volt/VAR control, and upgrades to cybersecurity and telecommunication protocols of SENet. Continued automation and upgrades at substations will challenge the legacy role and duties of the Substation Operator as the convergence of power, communications, and data networks continues.

Substation Test Technician

Figure 189: Job Competency Profile - Substation Test Technician

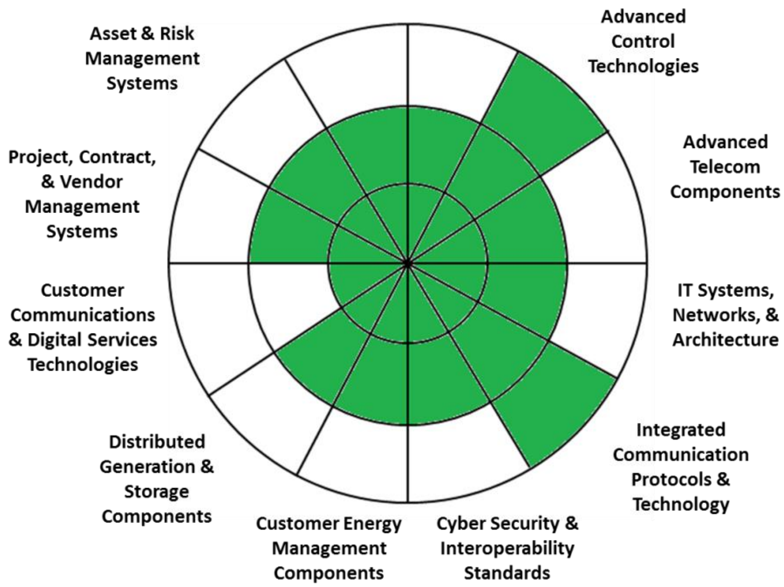


Similar to the Distribution Apparatus Technician role on the distribution network, the Substation Test Technician represents the highest level of craft skills and knowledge focused on the distribution substation. Employees in this classification are responsible for maintaining relays and other types of substation equipment. They perform initial testing and commissioning of new apparatus such as transformers, protective relays and control system automation, as well as periodic routine testing of this equipment. They also perform system restoration activities during outages and other emergencies.

Substation Test Technicians must have all the knowledge of the Substation Operator as well as more formal training in electrical engineering, or experience in jobs requiring extensive comprehension of electrical theory and use of principles of electrical theory in actual performance. They will interact with all of the power, telecommunications, and data networks in the substation and will have applied technical knowledge of many of the systems. They will be mostly concerned with the Grid Facing and Grid Integration Technologies. Continued deployment of Customer Facing Technologies such as distributed generation and battery systems will begin to impact substation operations and protection.

System Operator

Figure 190: Job Competency Profile - System Operator



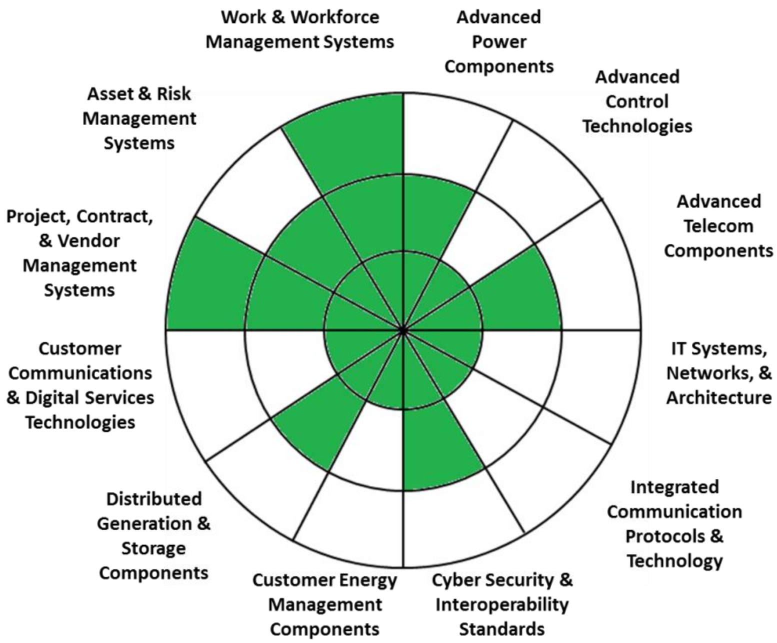
System Operators are responsible for the monitoring, control, and operation of SCE's transmission, distribution, and substation systems, during normal conditions and while restoring service to customers during emergency conditions. Located in Switching Centers and Grid Management Centers, System Operators coordinate the activities of the field crews responding to circuit interruptions, isolating trouble, and switching circuits to restore service. They also direct switching activities for routine maintenance and construction of lines and equipment and direct Substation Operators in the operation of station equipment.

System Operators focus on the current status of the distribution system and utilize an array of information technologies to inform and monitor their operating decisions. They are typically long-tenured employees with all of the knowledge and competencies of the Substation Operator. They dispatch trouble calls to Troublemen for the distribution network and Substation Operators for substation work to return lines and equipment to normal operating condition.

As new technologies are deployed on the electric grid, System Operators should be knowledgeable of the increasing convergence of power, telecommunications, and data networks. System Operators will also be leveraging various Power System Control applications and receiving and filtering information from a variety of smart grid intelligent devices and systems. System Operators will benefit more from a broader exposure to both Grid Facing and Customer Facing technologies, with a deeper understanding of controls, integration, and interoperability. As work resourcing moves towards more diverse and cross-functional teams, System Operators may become a focal point for more dynamic team response and work planning. Therefore a deeper understanding of key Resource Management technologies may also be appropriate.

Supervisor

Figure 191: Job Competency Profile - Supervisor



As smart grid technologies continue to evolve and advance, utilities will be challenged to plan, build, and run assets in an integrated fashion while also hiring, training, and managing a diverse set of resources and people. With the proliferation and access of real-time, granular information, decision-making can be pushed towards the organizational level closest to the problem. Inside the T&D organization, this responsibility will impact foremen and supervisors. Typically a supervisor is responsible for providing direction, coaching, and monitoring of specific or multiple tasks involved with assigned work. Supervisors are involved in all three plan, build, and run activities.

Supervisors direct and support Linemen, Technicians, Troublemen, Operators, and Engineers. The depth of technical knowledge differs for each of these groups. Supervisor success depends more on managing resources and decisions based on information from various sources. It is important for supervisors to understand the day-to-day issues and barriers of the employees they are supervising.

The profile focuses on the resource management nature of the typical craft employee supervisor. The depth of technology orientation or specialization is de-emphasized in this profile, and would need to be modified depending on the particular job area. For instance, Engineering Supervisors might require more technology focus in power systems, telecommunication systems, information systems, etc. An Apparatus Technician Supervisor may be required to bring a deep understanding of advanced power system components and technologies, etc.

In the new cross-functional, dynamic team environment of the future, the supervisors will benefit from a broad understanding of new technologies, integrated control and communication systems, and improved ways of leveraging the information provided by these sources. The greatest supervisor value will be found in allocating and coaching resources and teams to be productive and adaptive. The successful smart grid supervisor will master the differences between:

- Information flow versus component functionality
- Proactive work planning versus legacy approaches to work
- Adaptive and integrated resource management versus static and siloed work processes

A8.3 Job Competency Gaps

The Job Competency Profiles developed in Section A8.2 represent the desired future state of workforce competencies for eight job classifications. Not all employees will achieve the desired levels at the same time since new employees are hired, experienced employees transfer, and technology requirements change. The gaps between current state and future state are defined in this section through three different lenses. First, the assessment reviews the way T&D employees interacted with ISGD technologies. Second, the assessment reviews and summarizes current job classification information. Third, the assessment reviews the results of a specific survey issued to front-line employees associated with the ISGD project.

The design of interviews and surveys was intended to evaluate employee impacts through the lenses of people, processes and technology. People impacts were evaluated through changes in job roles, job duties, and job knowledge. Key processes in the plan, build, and run stages of ISGD were evaluated for changes and modifications. The specific ISGD technologies were the basis of this assessment – and job impacts were analyzed for any requirements or changes in tools, techniques, and equipment.

The results of the gap analysis are captured in Table 15, which summarizes the ranking of job classifications for each of the 12 ISGD Competency Requirements areas:

- **Green** – recommended additional smart grid technology competecy development is minimal
- **Yellow** – recommended additional smart grid technology competecy development is moderate
- **Red** – recommended additional smart grid technology comoetency development is significant

Table 67: ISGD Job Impacts - Heat Map

	Grid Facing Technology			Grid Integration Technology			Customer Facing Technology			Resource Management		
Job Categories	Advanced Power Components	Advanced Control Technologies	Advanced Telecom Components	Integrated Communication Protocols & Technology	Cyber Security & Interoperability Standards	IT Systems, Networks & Architecture	Customer Communications & Digital Services	Distributed Generation & Storage Components	Customer Energy Management Components	Project, Contract, & Vendor Management Systems	Work & Workforce Management Systems	Risk and Asset Management Systems
Distribution Engineer	Yellow	Red	Red	Red	Yellow	Yellow	Green	Red	Yellow	Yellow	Yellow	Green
Lineman	Yellow	Green	Yellow	Green	Green	Green	Green	Yellow	Yellow	Green	Yellow	Green
Troubleman	Red	Yellow	Red	Red	Yellow	Green	Green	Yellow	Yellow	Green	Green	Green
Apparatus Technician	Yellow	Yellow	Red	Red	Yellow	Yellow	Green	Yellow	Yellow	Yellow	Yellow	Yellow
Substation Operator	Yellow	Yellow	Yellow	Yellow	Yellow	Green	Green	Yellow	Green	Green	Green	Green
Substation Technician	Green	Yellow	Green	Yellow	Yellow	Yellow	Green	Yellow	Yellow	Yellow	Yellow	Yellow
System Operator	Yellow	Red	Yellow	Red	Yellow	Red	Green	Yellow	Yellow	Green	Green	Green
Supervisors	Green	Green	Yellow	Yellow	Yellow	Green	Yellow	Yellow	Yellow	Red	Red	Red

Interaction with ISGD technologies

The ISGD project involved a wide spectrum of customer-facing and grid-facing technologies. While SCE employees were generally aware of the customer-facing technologies located on premises beyond the meter, the installation of these technologies was performed by third-party vendors. Similarly the grid-facing technologies used in sub-Project 2: Solar Car Shade and sub-Project 3: Distribution Circuit Constraint Management Using Energy Storage, were also installed by third-party contractors. The technologies that impacted SCE employees the most were those involved in planning, building, and running of sub-Project 4: Distribution Volt/Var Control, sub-Project 5: Self-healing Distribution Circuits and sub-Project 7: SENet and SA-3 work at MacArthur Substation and Alhambra System Control.

The primary conclusions of this review show that the ISGD team planned the project with a focused group of highly skilled engineers, field engineers, and standards engineers supported by an embedded team of IT and FT architects. Most of the ISGD customer-facing technologies in Sub-projects 1, 2, and 3 were built with the assistance of third-party vendors and sub-contractors, with minimal impact on SCE employees.

Sub-project 7 activities required advanced and complex design, architecture, and integration of emerging technologies and standards. There were impacts from the work at MacArthur Substation on Grid Operations and Power Systems Control employees, with the embedded IT experts in the ISGD team stepping in to manage most of the interfaces and activities. The SCE workforce on Sub-project 7 included a significant group of sub-contractors to develop and analyze new requirements and to leverage SCE's Common Cyber Security (CSS) platform.

Current job classification information

The information for this gap analysis was derived from a review of available SCE job data, as summarized in **Table 68**.

Table 68: Job Information by Job Classification

Job Classification	IBEW Job Specification	SCE Job Description	JTA Report & Hierarchy
Engineer		√	
Lineman	√		√
Troubleman	√		
Distribution Apparatus Technician	√		√
Substation Operator	√		√
Substation Test Technician	√		√
System Operator	√		√
Supervisor		√	

Engineer Job Duties

An employee with the Engineering job classification typically performs the following duties:

- Develops studies, plans, criteria, specifications, calculations, evaluations, design documents, and performance Assessments associated with the planning, design, licensing, construction, operation, and maintenance of Edison's generation, transmission, distribution, and telecommunication facilities/systems.
- Provides consultation and recommendations to the Company within and to other business units and/or customers as a result of studying Company or customer-owned systems, processes, equipment, vehicles, or facilities.

The Engineering job family (Job Codes ENG1 – ENG5) describes a tiered and progressive set of responsibility, decision making/impact, education, and knowledge and experience requirements. The requirements in this classification are broad and generic and embrace engineering expertise in most engineering disciplines, without definition of specific knowledge of and experience with smart grid technologies. For instance, job responsibility requirements for the ENG1 – ENG3 classifications move from well-defined, routine engineering assignments with team participation to specialized and unique assignments, critical engineering and capital projects, and leadership and direction of teams. The advanced levels of Senior Engineer and Consulting Engineer expand the specialized and technical nature of the engineering role, broaden the independent and innovative aspects of the role, and add administrative and expert witness duties as well as training duties to other staff. Similarly, the decision making and impact of the engineering role advances through all five steps in the family expanding the breadth, depth, and impact of recommendations and decisions.

Generic education and licensing for Engineers range from a Bachelor's degree in engineering and no license to a doctorate degree in engineering with required licensing preferred. Knowledge and experience range from limited and general knowledge gained from 3 – 5 years of experience, to broad, thorough, and advanced knowledge with 8 – 18 years of experience. Within the Engineering job family there are no specific smart grid technology or systems, IT, telecommunications, or controls requirements.

SCE has developed a job family for Telecommunciations Engineers (ENT1 – ENT5). The duties for this role include:

- Develops studies, plans, criteria, specifications, calculations, evaluations, design documents, and performance assessments associated with the designing, documenting, and installation of telecommunication network/facilities/systems.
- Provides consultation and recommendations to the Company within and to other business units and/or customers as a result of studying Company or customer-owned systems, processes, equipment, or facilities.

The duties, education, and knowledge of the Telecommunications Engineer family exactly parallel the Engineering job family, with the noted addition of "telecommunication network, facilities, and systems" added to the description. Again, the expectations do not include any specific elements of smart grid telecommunications, networks, integration, or cybersecurity.

SCE has also developed a job family for Information Technology Specialist/Engineer (IT Sepcialist 1 – 4, IT Specialist/Engineer 5 – 6) with the following duties:

- Designs, analyzes, evaluates, tests, debugs and implements systems, programs and solutions in support of various functional areas.
- Analyzes, installs, acquires, modifies and supports operating systems, databases or utilities software.
- Plans, conducts and directs the analysis of business problems to be solved with automated systems.
- Establishes database management systems, standards, structure, documentation, guidelines, upgrades, security protection, and quality assurance.

Although there are no specific smart grid requirements in this job family, the higher levels do include "leading edge and/or future technologies" in the responsibility and decision making areas.

Engineer Competency Gap

Based on these three engineering job families, there are gaps in the specificity, granularity, and integrated nature of engineering skills required to design, test, implement, and develop smart grid technologies such as those in the ISGD pilot. Conversations with engineering supervisors and project leaders validated that new technology and more specific engineering skills are often discussed and developed when job positions are opened and posted during recruitment. For instance, the preferred requirements and experience of a Protection Engineer or Apparatus Engineer would be different from those of a Distribution Engineer and could be captured and screened during a job posting or recruitment interview process. This approach may allow the addition of smart grid skills and experience on an ad-hoc basis. It may be beneficial to develop a more focused and updated Engineering job family that would integrate various aspects of the above three job families and be focused on a Smart Grid Engineering job family. A Job Competency profile for this new engineer role is included in Section [A8.4].

For the purpose of the gap analysis, the assessment attempts to capture the requirements applicable to the ISGD Competency Requirements Model based on moving from a generic Distribution Engineering position to a broader and more integrated level of smart grid systems and technologies. The pathway for Apparatus, Protection, Telecommunications, and IT Engineers may be different but would result in a similar level of integrated knowledge and skills.

Linemen Job Duties

Journeyman Lineman work includes distribution construction and maintenance of overhead structures and conductors (primary and secondary service), underground cables and vaults, and associated components and apparatus that are attached to the lines and poles. SCE has developed a very robust JTA to enhance the Apprentice and Lineman job functions, duties, knowledge, and skills. This intensive effort reviewed over 50 tasks that Linemen perform and evaluated each task for its difficulty, importance, and frequency. In addition to the job tasks, KSAs were also reviewed, revised and validated. The results are very specific KSAs required for each task performed by each progressive job and training level in the Apprentice job development (Steps 1 – 6). Finally, the JTA recommended specific training and learning objectives and modules.

The KSAs required for the Distribution Lineman's job are grouped into the following nine categories:

- Fundamentals
- Communication Skills
- Safety
- Environmental
- Documentation
- Tools and Equipment
- OH Apparatus, Materials and Associated Techniques
- UG Apparatus, Materials and Associated Techniques
- Work Methods and Processes

This extensive and recent effort captures a large share of the duties, experience, and knowledge required by SCE Linemen in their day-to-day work. Comparison of these areas to the ISGD Competency Requirements Model results in a recommended moderate additional amount of familiarity with certain smart grid technologies.

Lineman Competency Gap

Overall the technical training approach and development of knowledge and experience by the SCE Lineman is impressive and directly related to "build" and "run" work activities. Exposure to new smart grid components and their safe installation and operation are easily added to the job expectations, training, and KSA list as these new technologies become standardized on the SCE grid. Until then, the Lineman position has the necessary underlying skills and knowledge to understand and integrate new vendor and operating requirements involved with installing and maintaining new smart grid components.

Troublemen Job Duties

The SCE Troubleman must have the same knowledge, skills, and abilities as the Lineman, so in terms of construction and installation experience levels, the Troubleman is qualified to work on smart grid apparatus. However, the Troubelman is primarily responsible as a first responder to sites where unplanned and emergency conditions are prevalent. Therefore the KSAs for the Troubleman are broader than those of the Lineman and require the ability to understand the operations, connectivity, relationship, and importance of new technology components.

The current IBEW Job Specifications are somewhat limited in defining specific smart grid related KSAs.

- Fundamental principles of electrical theory, methods and techniques employed in the construction and maintenance of the overhead and underground electrical system; mechanical principles; General Orders 95, 128, and applicable laws and Company standards.
- Applicable Injury and Illness Prevention Rules and fire Prevention Rules and Information.
- Proper use of tools and equipment; operating procedures; function and operation of personal computer, and appropriate administrative and clerical procedures.

In addition to responding to trouble calls, the Troubleman also:

- Patrols, inspects, maintains and operates overhead and underground electrical distribution circuits and associated equipment.
- Prioritizes and assigns work when acting in a lead or supervisory capacity.
- Performs activities such as investigating service interruptions, making permanent or temporary repairs, establishing and/or disconnecting service, installing and removing meters, performing volt/amp checks, replacing fuses, restoring service on customer calls, operating switching equipment, operating substations, reporting fire status, and patrolling and servicing street light systems.
- Trains, evaluates and assists other employees as required.

As new Troublemen are added from the Linemen ranks, they will bring the deeper knowledge and experience summarized earlier – yet this may not be as focused on the integrated nature of the various smart grid technologies.

Troubleman Competency Gap

The list of KSAs for the Troubleman classification demonstrates that the Troubleman has some appreciation of and contact with both Grid Facing and Customer Facing Technologies. The Troubleman also uses various types of data and analytics to diagnose and repair conditions. However, the lack of granularity around specific smart grid technologies and the lack of experience with the new integrated grid networks of power, data, and telecommunications could be improved. Comparing these current KSAs to the ISGD Competency Requirements Model for Troublemen suggests moderate gaps in dealing with some of the advanced Grid Facing and Customer Facing Technologies, and more significant gaps in the integration and control systems for these technologies.

Distribution Apparatus Test Technicians Job Duties

Apparatus Technicians have the highest level of KSAs on the distribution network apparatus and equipment since they calibrate, test, install, maintain, repair, and adjust a wide range of equipment. Similar to the Apprentice Lineman position, SCE has developed a JTA for the Distribution Apparatus Technician. Completed in 2010, this study ultimately defined 168 separate tasks for the Apparatus Technician, separated into 17 task categories and examined for 120 competencies in 10 categories.

Employees in this job classification work with a variety of distribution system components to test, monitor, repair, troubleshoot, and maintain equipment. The JTA also listed 122 skills for this job classification, separated into the 10 following categories:

- Basic Cognitive Skills
- Communication Skills
- Computer and Technology Skills
- Interpersonal and Teamwork
- Personal Work Ethic
- Physical and Environmental Demands
- Planning and Organizing Skills
- Problem Solving and Decision Making Skills
- Vision and Leadership
- Technical Knowledge Skills

This position is designed to work in multiple physical and work group environments, and to contribute to developing technical solutions and work plans. The competency categories are also insightful in building necessary knowledge and experience working in an integrated, team-based, cross-functional environment.

Distribution Apparatus Technician Competency Gap

The Apparatus Technician is expected to work with a wide range of grid technologies. The new smart grid technologies are familiar to this work group in their function. New skills and competencies regarding operational grid changes as a result of these new components will require a broader understanding and knowledge of the integrated networks, controls, and communications devices as well as the associated interfaces, data, and system used to collect and analyze the data. The mapping of these gaps for the Apparatus Technician focuses on this broader functionality as well as increased exposure to some critical Customer Facing Technologies.

Substation Operators

The Substation Operator plays a front-line role similar to the combined roles of Lineman and Troubleman, supporting the maintenance and operations of key substation activities and called as the first responder during emergency conditions. The primary role is to implement switching orders and operate other substation equipment necessary to safely complete planned and unplanned outages. The knowledge required in the IBEW Job Specification is focused on day-to-day operation of legacy substations and requires knowledge of:

- The fundamentals of electricity and the elementary principles of physics.
- Function and operation of electrical and mechanical station equipment.
- Line capacities and protection settings.
- Operating methods, practices, procedures and techniques, and general layout, line capacities, operating instructions and emergency orders of assigned substation(s).
- Principles of distribution systems.

SCE has also completed an extensive Analysis Hierarchy of key tasks for this position which guides the training of new operators. This list includes both applied and learned knowledge for each of the tasks. The list of KSAs includes complex and interrelated functions and types of knowledge relevant to the smart grid technologies deployed by the ISGD project.

Substation Operator Competency Gap

The KSAs discussed above provide a solid foundation for the Substation Operator under current conditions. Recommendations to fill potential gaps focus on moderate expansions of current knowledge critical to the safe and reliable operations of the substations. These moderate upgrades recognize the SCE and industry trend towards the ISGD SA-3 designs, integrated power, data, and telecommunications networks and incorporation of CSS. They also recognize the need to be somewhat familiar with certain Customer Facing Technologies.

Substation Test Technicians

Substation Test Technicians are similar in skill, experience, and responsibility for substation assets as the Distribution Apparatus Test Technicians are for the line assets and equipment. They have all the KSAs of the Substation Operator as a foundation. They also bring a higher and broader set of skills associated with the installation, adjustment, testing, and inspection of complex, interacting devices and networks.

The duties of the Substation Test Technician are varied, technology-oriented and include the following:

- Set up and operate test instruments and equipment to perform operational testing, adjustment and calibration of substation protection, measuring, controlling, and recording systems and equipment.
- Install, test, repair, and maintain electrical, electronic, and digital instrumentation and protective equipment.
- Determine, diagnose, and isolate electrical trouble and detect electrical faults in equipment and make necessary repairs.
- Interpret and work from complex substation plans, drawings, prints, and manufacturers' documentation.

In addition to this foundation, SCE has also produced an extensive and detailed set of KSAs. The primary categories include areas relevant to the ISGD smart grid technologies. This list is similar to the Substation Operator with more knowledge around the planning, set-up, and testing of interconnected devices and networks.

Substation Test Technician Competency Gap

All of the KSAs for the Substation Test Technician provide a valuable and relevant basis for working on the ISGD substation technologies deployed in Sub-project 7. The recommended increases in knowledge are moderate for this category and focus on the integrated nature of power, data, and telecommunications systems and the sophistication and complexity of next generation substation automation. In addition, while the Substation Operator can stay focused on equipment inside the fence, the Test Technician will begin to see more impacts from the Customer Facing Technologies as they impact feeder operations and protection schemes.

System Operators

The System Operator must have the Substation Operator background, and has broad responsibilities to cover an area or region of the electrical grid. Therefore the KSAs in this job specification resemble the Substation Operator KSAs:

- Fundamentals of electricity and the elementary principles of physics.

- Function and operation of electrical and mechanical substation equipment.
- Overall electrical system and circuits under switching center jurisdiction, including line capacities and protection settings.
- Operating methods, practices, procedures and techniques.

However, the System Operator needs a broader range of knowledge about the electric grid than the Substation Operator, but not as deep a knowledge level of individual apparatus as the Substation Test Technician. Given the changing functionality of the grid and the critical importance of the system operator role and the switching center functions, SCE has developed an extensive Job Task Hierarchy with a robust set of Job Tasks and KSAs for this position. These activities include the same KSAs for completing switching orders as in the Substation Operator Hierarchy and are increased for broader network responsibilities. In the System Operator Hierarchy, the KSAs have expanded significantly to include a deep technical understanding of the connected network (more than one substation) and the planning and tools required to determine the impacts on the network. This also includes working with many of the Field Technologies and Information Technologies impacted by ISGD. The System Operator KSAs also include an array of skills and competencies required to plan, integrate, and oversee complex operations requiring coordination with numerous internal and external stakeholders.

System Operator Competency Gap

The System Operator list of KSAs describes an integrated, network-focused role that is concerned with the entire spectrum of Grid Facing, Customer Facing, Grid Integration, and Resource Management skills and competencies. While there is a solid foundation in the current job documentation, the recommended increases in knowledge are moderate for this category and focus on the integrated nature of power, data, and telecommunications systems.

Supervisors

Similar to the Engineering job family, SCE has developed a tiered Supervisor job family (SUP1 – SUP 4). The responsibilities increase from activities with minor or moderate financial or operational impact on the organization to those with major impact. SUP1 and SUP2 have identical KSA requirements:

- Broad knowledge of department policies, objectives, strategies, and goals; applicable governmental and regulatory laws and requirements. Typically possesses five or more years' combined experience performing or supervising function.
- Associate Degree in applicable profession, business, or technical discipline or an equivalent combination of education, training, and experience.

The KSAs for SUP3 and SUP4 are similar except they require a "thorough knowledge," and SUP4 requires 10 or more years of experience.

Decision-making and impact are very similar among the family, moving from minor, to moderate, to major impact, while supervisor responsibilities increase with additional administrative, risk management, and asset management duties. Should SCE change the nature of the organization towards more team-based, cross-functional, and integrated plan, build, and run structures, the KSAs for the supervisor may need to change accordingly.

Supervisor Competency Gap

One of the areas discussed in Section A8.4 is the idea of a potential new position called "Smart Grid Supervisor." This role could combine aspects of project management, team leadership, and technology integration allowing a wide range of flexibility and adaptability for supervisors and their teams. In the current model, the T&D supervisor role will be challenged to manage the new information, tools, and dynamics of ISGD technologies and information flows. While the Job Profile does not represent all of the capabilities of the future Smart Grid Supervisor, it does allow SCE to begin to build new competencies and expectations into the current role.

Recommendations for increased knowledge for this position range from moderate to significant in areas that leverage the new interconnected platforms and networks.

Survey Results

Table 69: Job Survey Sample Size

Job Classification	Survey Invitee	Survey Participants
Engineer	30	**20**
Lineman	28	**0**
Troubleman	1	**1**
Distribution Apparatus Technician	5	**2**
Substation Operator	0	**0**
Substation Test Technician	4	**1**
System Operator	7	**2**
Supervisor	3	**1**
Manager	23	8
IT employee	17	8
Customer service	4	4
Communication Technician	5	2
Other	38	9
Total	**165**	**58**

The assessment included issuing a survey to 165 employees who logged time on the ISGD project over the past few years. The survey was designed to capture information on the eight job classifications listed above over the entire cycle of "plan, build, and run" work activities. Limited operational experience with several of the key sub-projects (either due to third party installation and operations, or in-service delays) resulted in a majority of the lessons learned from the survey on "plan and build" activities, versus the day-to-day "run" activities involved with new smart grid technologies. As shown in Table 16, the survey was sent to employees in the eight job classifications included in this assessment as well as employees in other classifications.

The eight primary classifications represented 47% of the surveys invitees and 47% of the survey respondents. Classifications with the largest representation in both categories were engineers and linemen. Given the nature of advanced technology pilot programs and the current status of the ISGD project, it is reasonable to believe that employees associated with the "plan" and "build" phases of the pilot are those that logged the most time against the project. Engineers, Project Managers, Project Leads, Technical Specialists, Scientists, and Managers deal with both the plan and build functions for ISGD.

Employees in critical areas responsible for the "run" activities have not yet had enough exposure to log time or to provide feedback. At a front-line craft level, the physical ISGD equipment and components were either installed by vendors or attached by Linemen to poles, not requiring even moderate changes in the Lineman work processes or duties. Apparatus and Test Technicians installed and tested the protection and isolation equipment and schemes associated with in-line apparatus. In addition, engineers, specialists, and project leads also advised and supervised the installation of many new components.

Although the majority of work on the project was completed through Engineering and T&D field employees, customer service was represented by Meter Technicians setting new meters for the Customer Facing Technologies, and the "Other" category represented a scattering of field construction and laboratory testing positions busy during the plan and build stages.

As expected with a new technology pilot, most of the employees (60%) are well experienced and have been with the company longer than 7 years. More than 73% of the participants self-ranked their experience as Intermediate (45%) or Expert (28%) levels. The pilot project to date has impacted employees with significant work experience and well-developed competencies for their role, typical of a leading-edge technology pilot, but probably not representative of the larger T&D field population.

Detailed results of the survey are summarized as follows:

1. The respondents gained experience and exposure on all seven sub-projects with the most participants involved in Sub-Project 3 – Energy Storage and Sub-project 1 – Zero Net Energy Homes
2. The Phasor Monitoring Units (Sub-project 6) required the most acquisition of new knowledge and skills, but in general the participants did not agree that the technologies in all sub-projects required new skills.
3. Highly experienced employees were able to learn new knowledge and understand the impact of the ISGD equipment on the network, but required a lot of work to acquire the new knowledge.
4. The introduction of two-way power flows on distribution system, feedback from intelligent devices on the grid, and advanced control systems operations and integration have raised the complexity and relationship of legacy grid operations observed by these employees.
5. As a group, most of the employees felt that a minimal amount of new information, learning about new systems, and using new tools was required to perform their duties.
6. Respondents felt that ISGD technologies moderately changed the way they work today and that future changes would be similar.
7. New knowledge or skills that are better shared among more than one job category:
    - More training on network protocols
    - Increased knowledge of wireless communications
    - Increased collaboration between engineering and IT
    - Increased collaboration between field staff and IT
    - Expanded sharing of data from systems
    - Wider distribution of equipment use and purpose
8. There is room to improve the training approach for smart grid technologies, with job aids the most productive and on-the-job training the least effective
9. Training gaps revealed some key insights
    - More communication and networking technology training required
    - Operational issues arise on a regular basis
    - Comprehensive nature of project creates a big learning curve
    - Expanded training for Test, Operational, and Protection Automation personnel would also be required
    - Electronic access to information, and aids on how to operate under given circumstances are needed

The numerical results of the survey are somewhat limited from those job classifications with hands-on operational experience. The engineers and project leaders who had the most experience with the plan and build activities were the most responsive on the survey. Their rankings indicate some gaps in training and some concern over new technologies, but not as great as the concerns expressed by the small number of front-line craft respondents. The sample size for seven of the eight key job classifications is too small to draw any substantial conclusions.

Conclusions

The Heat Map presents a snapshot of perceived opportunities for increased knowledge and competencies in the eight primary job classifications. As developed above, the potential impacts on the eight primary job classifications range from moderate to significant, and most of the more challenging competency needs are in the Advanced Control, Advanced Telecommunications, and Integrated Communications Protocols and Technology sectors. These gaps represent the pace and acceleration of new telecommunications systems and the integration of data and power networks. SCE has a small group of highly skilled and deeply knowledgeable professionals who have been working in these areas and have been embedded in the ISGD project. As SCE deploys new power, IT, and FT components and systems, it will be necessary to expand this interconnected systems view down to the front-line specialists.

A8.4 Potential Future Job Classifications

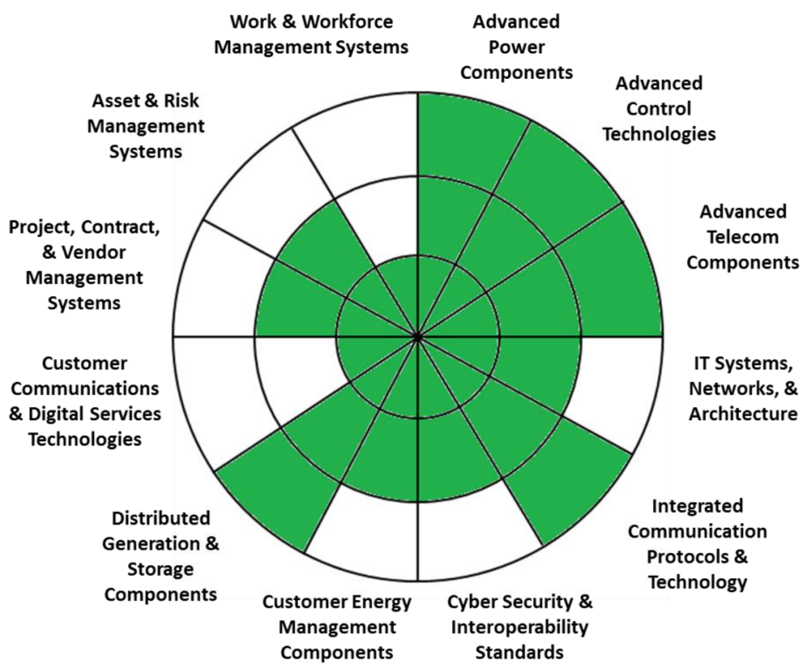
Section [A8.3] presented a gap analysis of smart grid job competencies for T&D employees. The results were the Heat Map described above focused on the eight primary job categories. There are a number of other T&D job classifications that would also be impacted by the system-wide deployment of ISGD technologies. These jobs should also be evaluated for competency gaps and learning pathways.

The evaluation of current job classifications can help inform the design and nature of jobs required to plan, build, and run the future SCE smart grid network. This section provides insights and competency profiles for three potential new job classifications:

- Smart Grid Technician
- Smart Grid Systems Director
- Smart Grid Operations Manager

Smart Grid Technician

Figure 192: Job Competency Profile - Smart Grid Technician



As electrical and telecommunication systems become integrated through intelligent devices and digital components, the need for multi-skilled and self-directed journeymen and technicians will continue to increase. As the ISGD project has demonstrated, the key positions of Distribution Apparatus Technician and Substation Test Technician—along with the Communications Technicians from the IT group—will be the primary owners of the "build" and "run" activities in the substation and outside the fence. The job competency profiles of the two T&D technician jobs indicate the highest level of KSAs within the T&D organization—outside of the Engineering Group. Within T&D, the percentage of Apparatus and Test Technicians is 4% of the workforce.

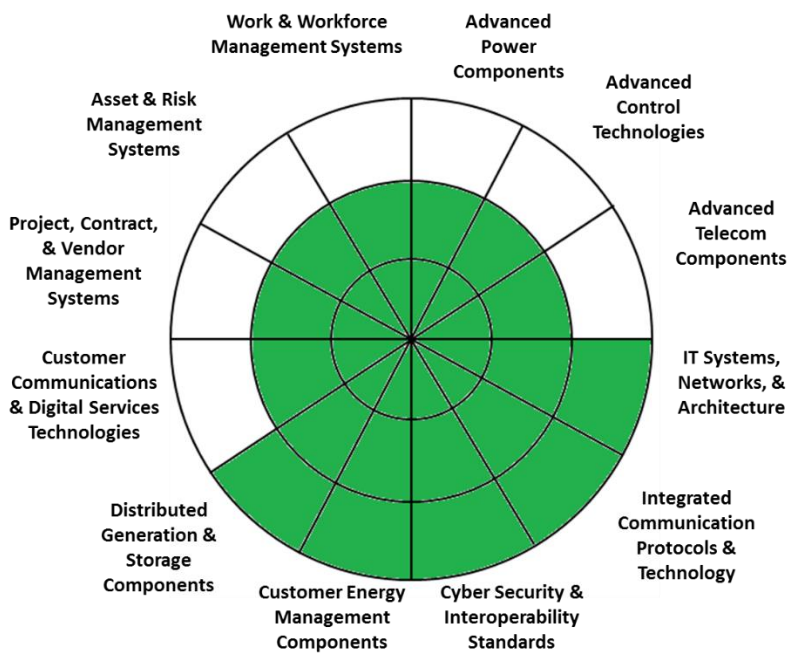
SCE might consider developing a new job classification, Smart Grid Technician, which could combine roles that currently span several classifications and multiple organizations. This classification could also include the most senior experienced and highest skilled employees in digital and communications technologies. The massive industry investment in smart grid networks, upgrades, and components, integrated through new wireless systems and information technologies will require building a new skill-set on top of the current system knowledge base. While this new classification could impact job duty classifications, it could also spawn new types of integrated field and service crew structures and present new opportunities for career growth and personal advancement.

With the help of a smart grid training curriculum leveraged through the SCE BlueBox Technical Training model, a portion of this integrated systems perspective could ultimately be built into every front-line role, including grid, service, substation, and line responsibilities. Mobile platforms, new electronic tools, improved processes, and increased communication requirements will increase the capability and autonomy of the grid technician, and will require ongoing education and skills development.

The Job Competency Profile is constructed for a Master level Grid Technician, combining the aspects of deep component knowledge, broad telecom and data networks integration experience, and a high level of understanding smart grid controls and cybersecurity. The role also combines a competency with Grid Facing technologies (substations and line apparatus) and Customer Facing technologies. Some utilities are starting to develop this integrated skill set and make it available in a consultant/advisory role.

Smart Grid System Director

Figure 193: Job Competency Profile - Smart Grid System Director



The smart grid of the future will require new approaches to energy management, system operations, outage response, customer engagement, workforce management, and risk management. The evolution of the technologies and information flow will arm systems operators with a broader and deeper set of information and insights. At the same time, the expansion of customer-facing technologies, and the increasing concerns over system vulnerability and protection will complicate the operations role. Finally, the addition of new customer, employee, contractor, and Independent System Operator (ISO) expectations add complexity and nuance to stakeholder communication and resource management.

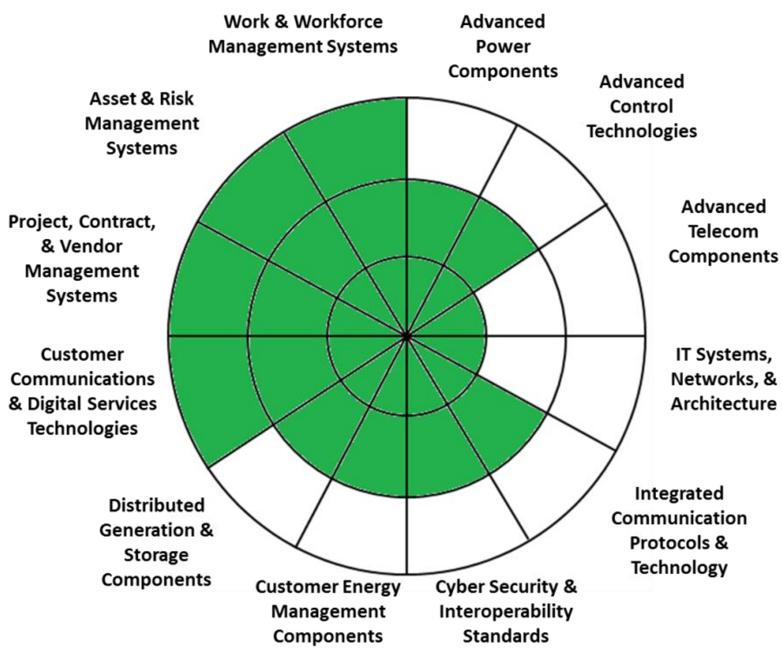
The roles of system operator, substation operator, and operations engineer could be integrated into a Smart Grid System Director role. This job would have the authority and decision-support tools to conduct real-time analysis and manage customer resources as well as system resources. The Smart Grid System Director knowledge base would include smart grid components and technologies, communication system operations, and information system security and risk management profiles. The Smart Grid System Director would be able to monitor and direct all of these resources through new interfaces and mobile platforms, review and modify performance objectives and results, and respond to and interact with numerous stakeholders throughout the day. Responsibilities could expand to include day-to-day operations, planning, and priority setting for all grid resources, both on and off the system.

Within the current job environment, the System Operator role comes closest to this position. The complexity of this job will be increase over time, and the candidates for this role will be developed with a combination of internal and industry training. Expansion and development of current system operators, grid operations personnel, and power system control employees is a favored path for developing the skills and experience required.

The Job Competency Profile is constructed to allow development and evolution of both engineers and system operators to migrate to this new role and functionality. The new job could sit in the Grid Control Center and have access and input over a wide range of resources. This role is focused more on the integrated capabilities and functionality of the system, as well as the coordination and response to external stakeholders.

Smart Grid Operations Manager

Figure 194: Job Competency Profile - Smart Grid Operations Manager



ISGD technologies offer increased information flow and automation to future grid operators. As utilities add new information technologies, new telecommunication systems, and new power equipment, the functionality and operations of the grid are changing. As customers add distributed generation, battery storage, and energy management systems, their relationship with and expectations of the utility are changing. As the aging workforce is replaced by technology-savvy, diverse, and team oriented employees, the nature of leadership is changing. Front-line supervisors will have new planning and decision-support tools to predict and plan work and emergency response.

The Grid Operations Manager role would be responsible for directing and integrating all of these people, process, and technology activities and managing a complicated mix of internal and external resources. This employee would use technology and real-time information to respond more quickly and efficiently. The Grid Operations Manager would lead new dynamic team structures, perform innovative work planning, and provide adaptive resource mobilization. As employees grow more skilled and comfortable with technology and group direction, utility supervisors of the future must bring new motivational and communication skills, and be more comfortable with change.

Utilities could develop new Grid Operations Managers by teaching today's supervisors to become the champions of cross-functional and integrated work flows. Supervisors should be encouraged to seek out and design projects that cross boundaries and create synergies. They should be developed as models for continuous learning and motivated to stay ahead of the evolving technology changes within the utility landscape. These employees will bring diverse backgrounds from numerous roles both within and from outside the utility, with an appreciation for a wide spectrum of jobs and responsibilities. Their skills will be a mix of engineering, operations, IT, and customer service – focused on accomplishing clear objectives.

Conclusions

This section addressed potential workforce impacts beyond the eight specified job classifications, including future job classifications and profiles SCE should consider as the workforce evolves. The next section presents a framework for developing and delivering the required competency training.

A8.5 Training Curriculum Framework and Delivery

This section discusses the potential development of new training modules that leverage SCE training resources and systems. This section first reviews the current SCE approach to technical training as well as the process used to develop and deliver ISGD training, and then proposes a next generation training framework that expands current efforts. This proposed approach uses the Job Competency Profiles and builds discrete learning modules that can be bundled for each job classification.

SCE Technical Training Model

SCE is utilizing a well-organized and structured process to drive updates to job descriptions, roles, and KSAs, which are then used to design new training, known as the "BlueBox" model. This process takes a systematic approach to Job and Task Analysis and Technical Training Design (including new hire training and refresher training), along with a feedback loop of assessment, documentation, and evaluation for continuous improvement.

Applied across the entire spectrum of SCE job positions, this approach provides SCE a robust methodology that has produced extensive job task and KSA requirements for many of the job classifications within T&D. These requirements are being used to drive new training material and delivery of that material. The BlueBox model provides a leading-edge technical training model for these jobs and offers an adaptable framework for updating skills and competencies through new training.

ISGD Technical Training Development

Training developed for the ISGD technologies was based more on the specific vendor technologies and systems utilized in the project versus a formal update of key job descriptions and training requirements. This approach is appropriate for new technologies, especially in the pilot stage. Technical training is one output of SCE's well-developed and leading edge T&D Standard Design process that creates, reviews, and updates new equipment standards in advance of full-scale deployment:

- The Standards Design process includes detailed scrutiny through a five step process: Initiate, Analysis, Review & Approval, Training, and Publish.
- A very robust interactive set of workshops and discussions occurs during the Analysis and Review & Approval steps.
- The process requires the consideration, development, and approval of a high quality set of training programs, job aids, and other tools; for ISGD this included instructor-led training, hands-on training, and an impressive interactive on-line training tool.
- The Standards design process also includes a modified version for demonstration projects, although the scaled version may need further improvements in future applications.

In addition to the Standards process input on training for ISGD technologies, SCE also invested in a separate technical training development approach for employees impacted by ISGD technologies. This approach resulted in the development of ISGD-specific training and support documentation including:

- Instructor guides, which included program objectives, scripted lesson plans, activities, questions sections, case studies, demonstrations, etc.
- PowerPoint decks, which included key content, diagrams, photographs, equipment specific data, etc.
- Job Aids, Installation Procedures, Operating Procedures.
- Participant Handouts, which included copies of PowerPoint decks, instructions for activities and exercises, references and resources, etc.
- One of the more useful and integrated sources of this information is an on-line, integrated, and interactive version of most if this material. The internally-developed application provides a flexible and accessible approach to provide update and refresher training for ISGD and other smart grid technologies.

Next Generation of Smart Grid Training

This assessment recommends leveraging both the BlueBox model for training development and delivery, and the Standards Process training development for new technologies. Due to the timing and dynamics of the ISGD project, the merging of these two activities actually occurred in a one-off fashion through the development of the ISGD training described earlier. SCE could begin to modify current job descriptions (based on the Smart Grid Job Competency Profiles developed in Section A8.2) and supplement the training developed in the ISGD project.

The supplemental training could be built and sustained based on the current ISGD mix of technologies and regularly reviewed and coordinated with other advanced technology initiatives underway at SCE. In order to develop, deliver, and update new and refresher training material, the current information from the ISGD project could be considered as a set of learning modules. These modules, and others, could be integrated into the training outcomes of the BlueBox model. For example, as new technologies move up the maturity curve within SCE, the BlueBox system would regularly review and update specific job descriptions driving new KSA requirements. These new KSA requirements would be compared to existing training curriculum and material to identify gaps and needed updates. New training modules would be developed and offered to existing employees ahead of system deployment. New training modules would be added to new hire and apprentice training as appropriate.

Appendix 9: Solar Car Shade Harmonics

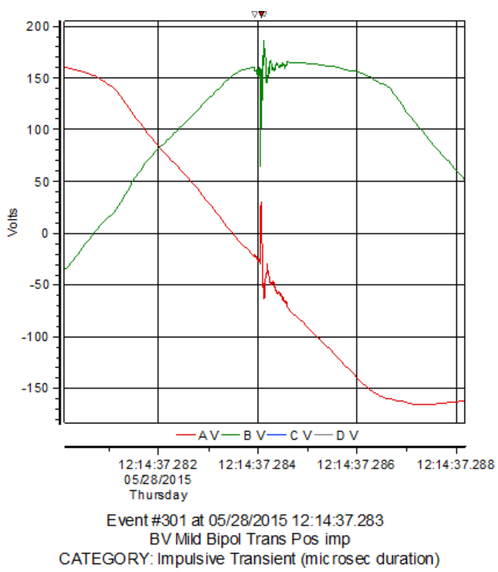
Car Shade Power Quality Survey

During two weeks in May 2015, the Car Shade system was monitored using two Dranetz™ PowerXplorer PX5 (256 samples/cycle). The meters were installed to monitor two EVSE individually and also the secondary of transformer T1, which feeds 10 EVSEs.

Power Quality Events

Transients in the phase voltage waveforms were the most significant power quality event. These transients were both impulsive and oscillatory in the low and mid-frequency range. The events could be precisely associated with PVs plugging-in into the system. Such transients are caused by the power electronics (switching and capacitor charging) on the on-board charger of the vehicles.

Figure 195: Impulsive transient event at EVSE 8

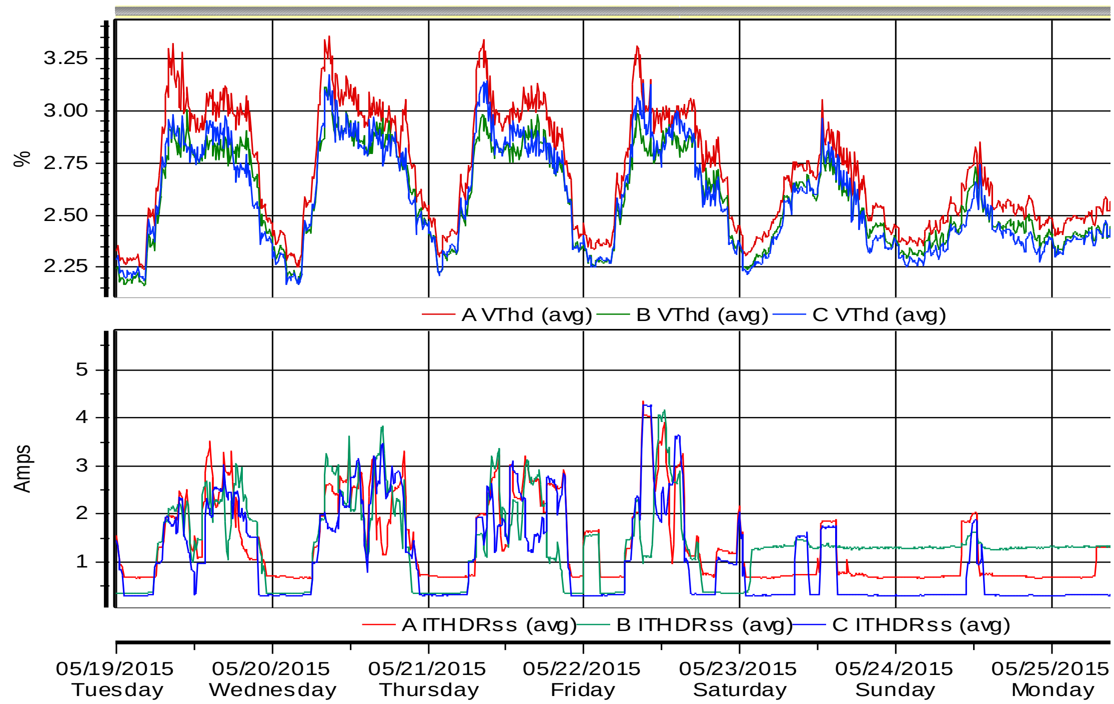


ChargePoint Portal Data	
STATION NAME	SCE-UCI / STATION 10
START DATE	5/28/2015 12:14
END DATE	5/28/2015 17:41
TOTAL DURATION (HH:MM:SS)	5:27:24
CHARGING TIME (HH:MM:SS)	4:07:51
ENERGY (KWH)	20.67
ENDED BY	Vehicle BMS
EV MODEL	BMW i3

For impulsive transients, the average rise time was 5.66 microseconds (μsec), and the worst peak-to-peak was 119 p.u. For oscillatory transients the average frequency was 14.7 kHz. These types of transients are in the voltage tolerance envelope applicable to single-phase 120V equipment, the ”no interruption in function” region of the ITIC CBMA curve (ITI, 1997), thus, such transients don’t pose a threat to sensitive electronic equipment operation. Moreover, they don’t pose a threat to equipment degradation or insulation failure, as higher magnitudes and faster rise time transients would (IEEE 1159-2009).

Voltage Total Harmonic Distortion ($\boldsymbol{THD_v}$) and Individual Harmonic Distortion ($\boldsymbol{IHD_v}$)

The THD_v (% FUND) was monitored at phases A, B and C of the secondary of T1, Figure 196. The THD_v is directly proportional to the system current distortion, THD_i, which is in turn proportional to the system’s EV charging load. Thus, the THD_v is observed to be higher during the weekdays and lower during weekends.



	Min	Avg	Max	95%
A VThd	2.24	2.70	3.35	**3.21**
B VThd	2.16	2.57	3.11	2.91
C VThd	2.17	2.57	3.17	2.94

	Min	Avg	Max	95%
A ITHD	0.67	1.75	4.34	3.26
B ITHD	0.34	1.55	4.15	3.18
C ITHD	0.30	1.49	4.28	3.09

Figure 196: T1-SEC Phase A, B, and C THD_v (top) THD_v and THD_i correlation (bottom)

The worse 95% THD_v (3.21%) occurred in Phase A (unbalanced system). According to IEEE 519-1992 (standard Table 11.1) systems up to 69KV should not exceed 5%. Thus, as the main conclusion of the PQ survey, the THD_v is not a concern at the secondary of T1 bus.

PEV Charging Profiles Characterization

The highly dynamic current profile of PEV charging power is a function of many factors such as the charger-battery system topology, charging strategy, battery initial SOC, battery temperature, ambient temperature, and others.

Taking as an example a Nissan Leaf charging profile (Figure 197), the charging event can be divided in 3 clearly distinct regions: Region 1, where the fundamental current magnitude is at its maximum. Region 2, where the fundamental current progressively drops as the battery reaches its full SOC, and a simultaneous increase in the 3rd harmonic exacerbates the ITHD (Amps). Region 3, where both fundamental and harmonic currents drop with time. The maximum

THD_i(Amps) occurs at Region 2, however the maximum THD_i (%) occurs at Region 3 due to reduced fundamental magnitude.

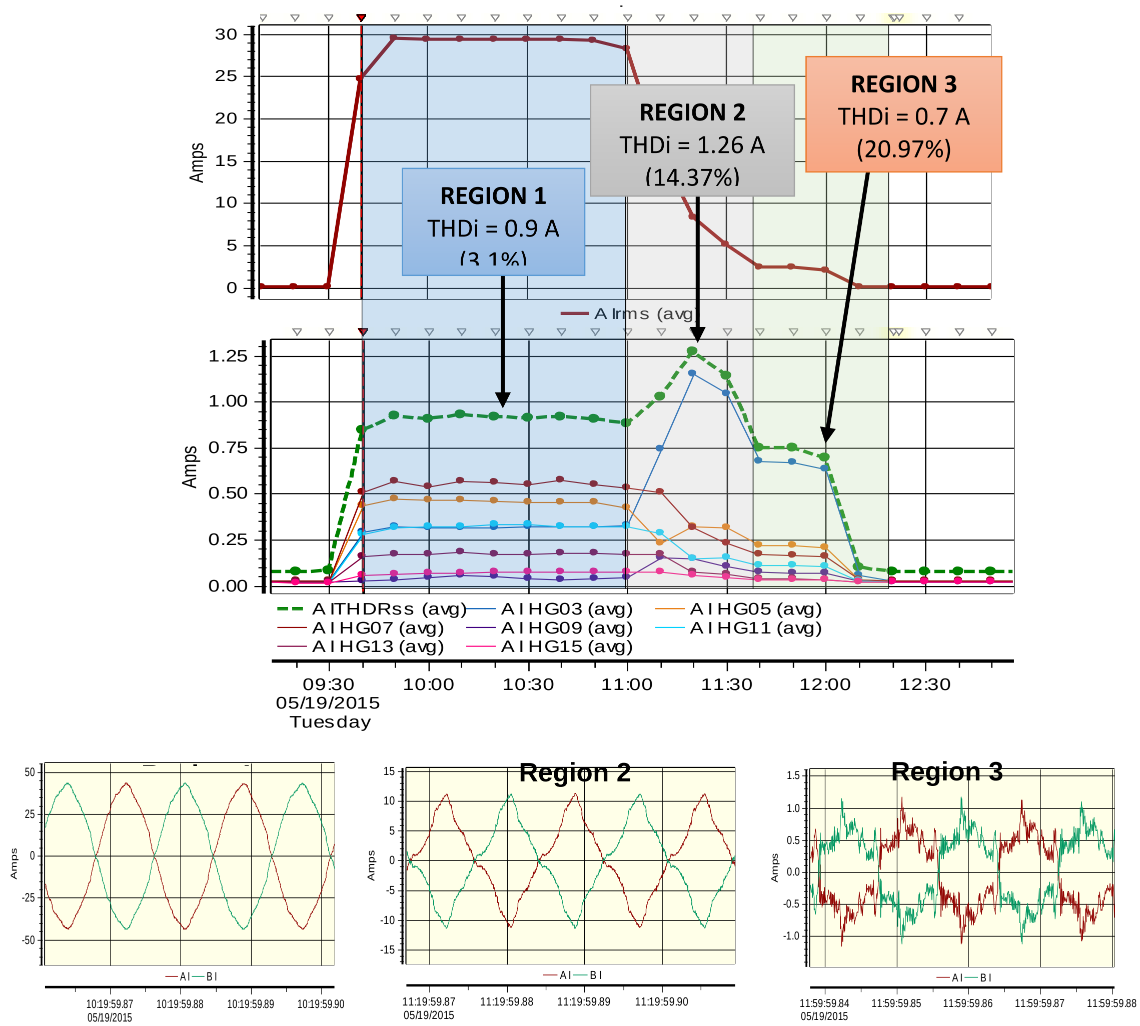
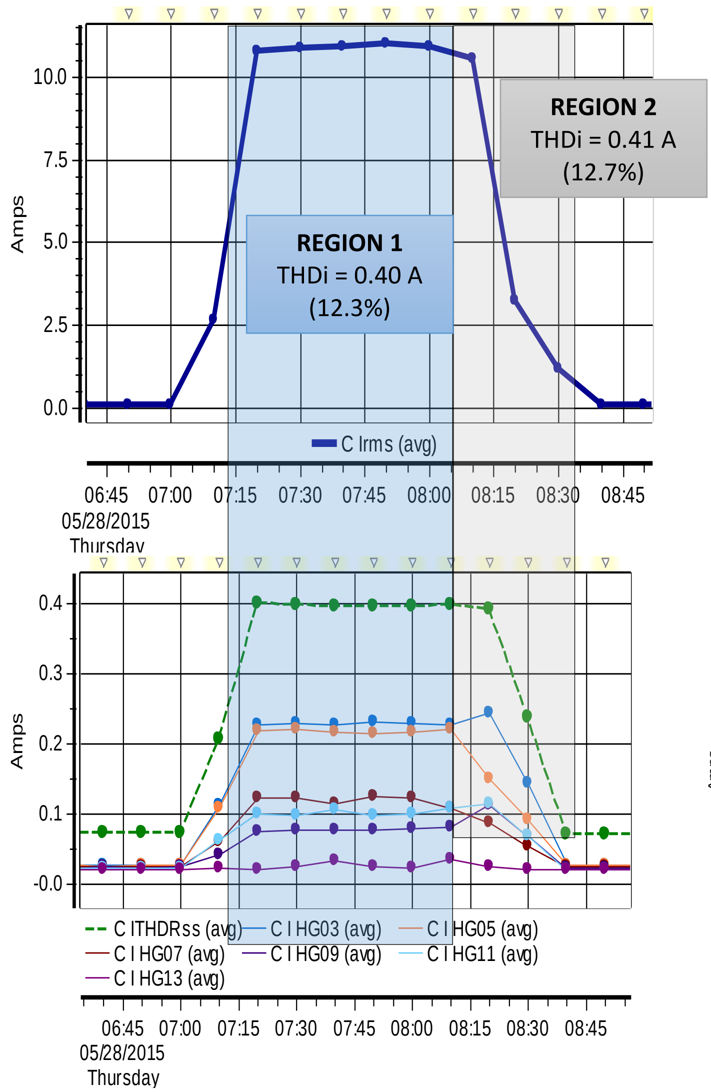
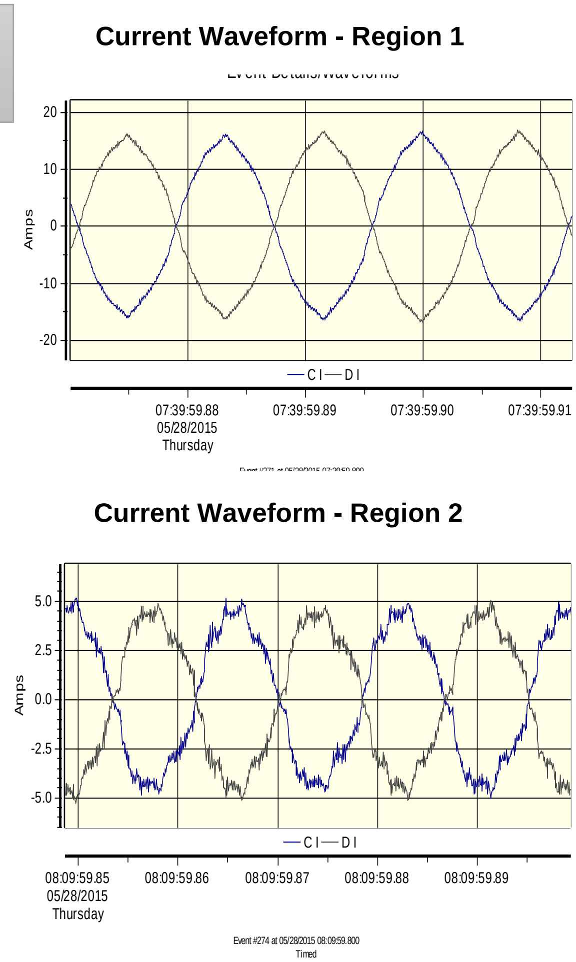


Figure 197: Nissan Leaf charging current profile (top) and charging Current Waveforms (bottom)

A similar profile can be observed for the Toyota Prius and BMW i3.



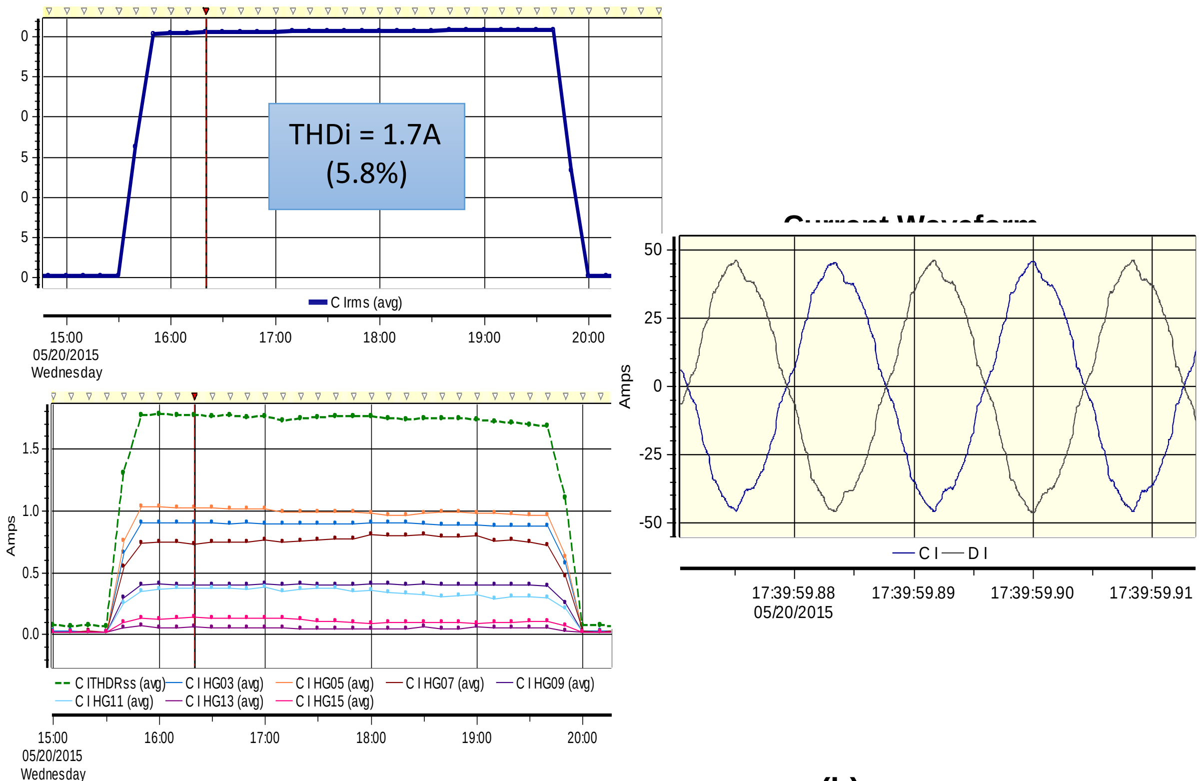
(a)



(b)

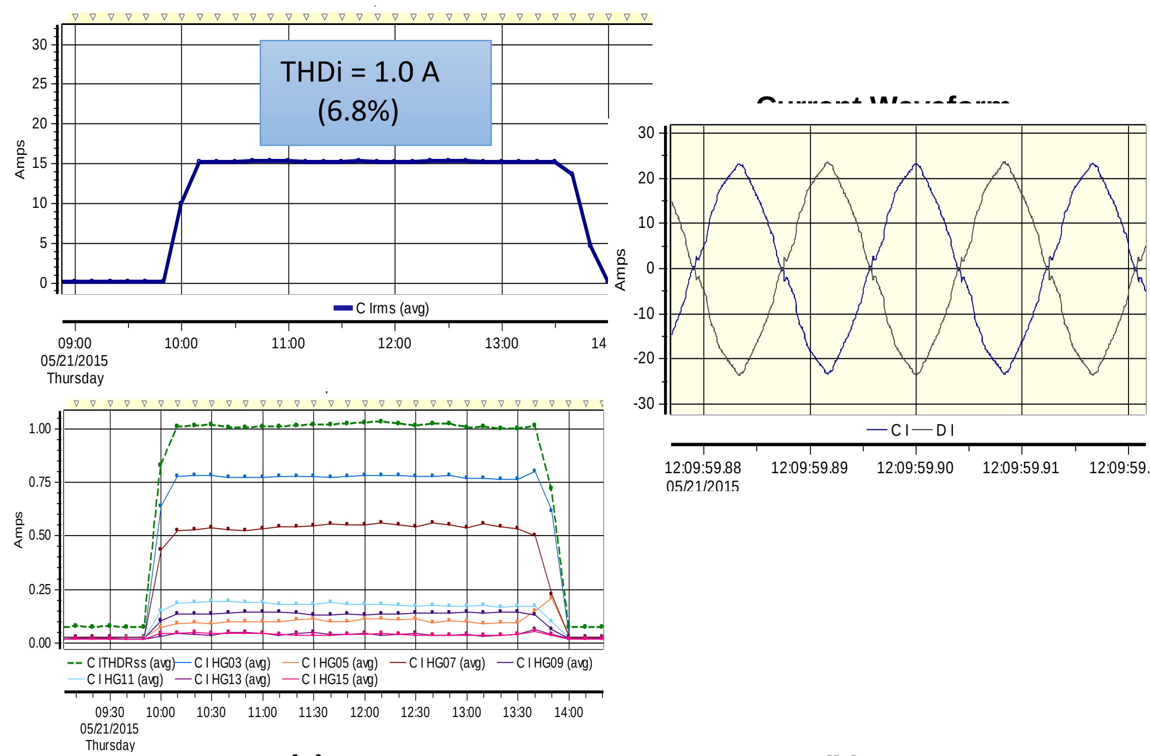
Figure 198: (a) Toyota Prius charging current profile (b) Current Waveforms

For most other PEV models, however, the charging currents (fundamental and harmonic) remain fairly constant during the entire charging event. That is the case of the Tesla model S (**Figure 199**) and the Chevy Volt (**Figure 200**), Kia Soul and Mercedes EV



(a) **(b)**

Figure 199: (a) Tesla Model S charging current profile (b) Current Waveform



(a) **(b)**

Figure 200: (a) Chevy Volt charging current profile (b) Current Waveform

Considering worst case IHD_i inputs, a signature charging harmonic profile can be defined for each PEV model in amps and as a percentage of the fundamental (considering the fundamental is the maximum registered load current during the charging event). The results are shown in **Table 70** and graphed in **Figure 201**.

Table 70: Characteristic IHD_i inputs for each EV % FUND

Harmonic Order	Volt	Leaf	Tesla	Soul	BMW	Mercedes	Prius	Spark
FUND	100	100	100	100	100	100	100	100
3rd	6.34	2.85	2.93	4.27	2.11	4.27	2.19	4.80
5th	1.13	1.76	3.26	3.05	0.77	3.47	2.18	0.66
7th	3.19	2.19	2.51	3.17	2.82	2.69	1.32	3.83
9th	0.74	0.35	1.32	0.97	1.18	1.26	0.73	1.05
11th	1.21	1.34	1.13	2.06	1.73	1.50	0.98	1.48
13th	0.37	0.62	0.18	0.38	1.19	0.39	0.31	0.27
15th	0.38	0.29	0.38	0.36	0.68	0.41	0.52	0.35

The values marked in red in Table 70 represent IHD_i inputs higher than what is recommended by IEEE 519-1992. Any sensitive loads connected in the same bus as an EVSE could suffer from poor local power quality impacts.

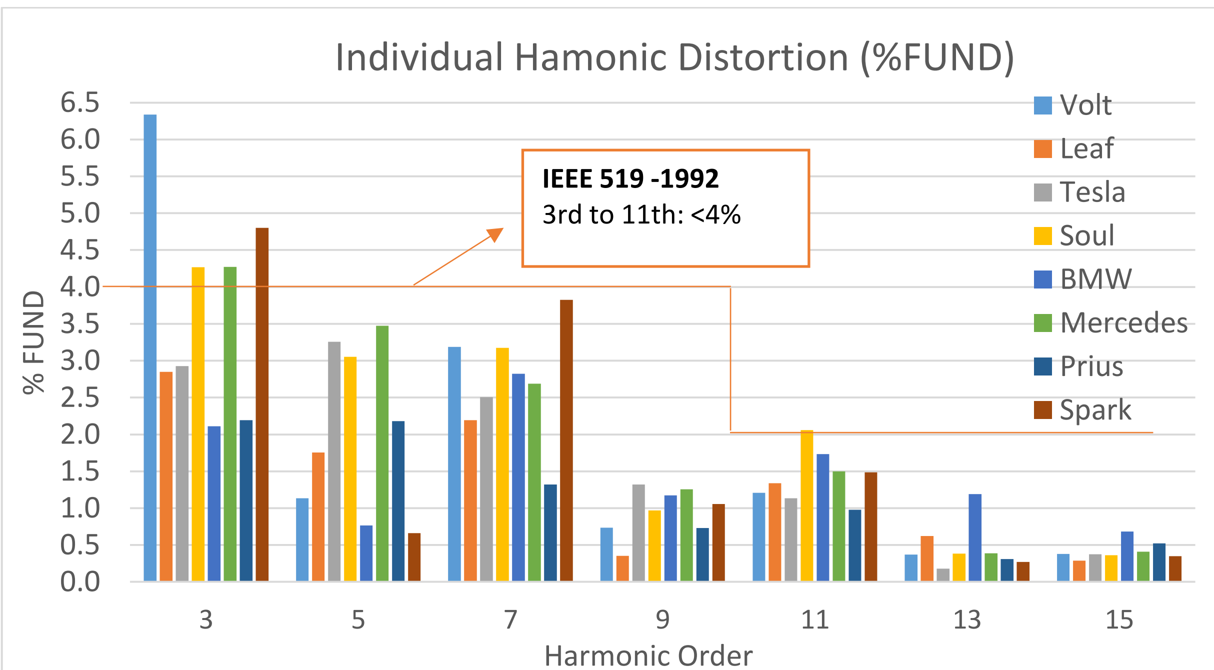


Figure 201: Comparison: Individual Harmonic Input (% FUND) for different EV models

Harmonic Flow Model Results

As power quality at the Car shade was only monitored in 2 locations, a computational power flow model was develop in *ETAP©*, to calculate harmonic individual distortion (IHD_i *and* IHD_v), as well as total harmonic distortions (THD_i *and* THD_v) throughout the system buses and cables.

Once the model was validated with survey data, the THD values for 6 points in the system: buses T1-SEC, T1-PRIM, DL-3, BESS, AIRB, MSE (the actual Car Shade PCC) were calculated and. These values are illustrated in Figure 202.

As expected, the THD is highly dependent on non-linear load location, since stronger distortion effects are observed closer to the non-linear loads (EVSEs and Inverter). The THD also depends on the system voltage levels. Here, the majority of non-linear loads are located in the 208 V (low voltage) part of the system, the distortion levels will gradually drop as voltage is increased. Moreover, the delta/wye transformer connection prevents the triplen harmonics from flowing through T1 and T2, reducing the THD in the buses upstream.

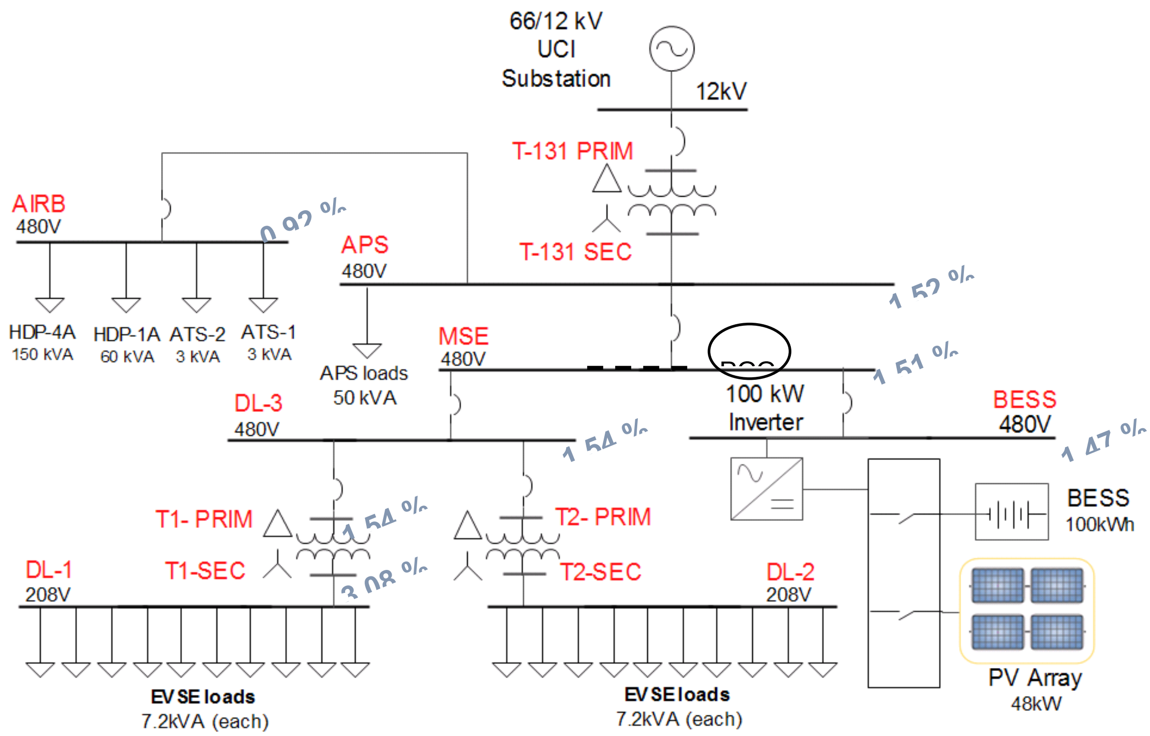


Figure 202: ETAP model Results

The model results are a good representation of the actual system's harmonic distortion characteristics. Recalling the limits proposed by IEEE 519-1992 (standard tables 10.1 and 10.3) that the Car Shade is subjected to (**Table 71**).

Table 71: IEEE 519-1992 Power Quality thresholds Car Shade is subjected to

Voltage Distortion	**Current Distortion**
Category: 69 kV and below	**Category:** General Distribution Systems 120V Through 69 kV and $\frac{I_L}{I_{sc}} < 20$
• THD_v < 5% (General Systems) • IHD_v < 2.5% (Dedicated systems: Short Circuit Impedance (SCR) at PCC=10)	• $IHD_i < 4\%$ for 3rd to 11th • $IHD_i < 2\%$ for 11th to 17th • TDD_i < 5%

The relevant observations can be made about the ETAP simulation results:

- The 5th harmonic IHD_i = 4.3% at bus MSE (PCC) goes above the 4% limit, However it does not cause excessive THD_v problems.

- At the PCC, no THD_v or IHD_v values go above the limits.
- Since T-1 is connected in Delta/Wye grounding configuration, the triples harmonics are trapped, preventing them from propagating upstream.
- An office building (AIRB) connected to the same transformer as the Car Shade did not show excessive THD. This appears to be due to the fact that it is separated by a length of cable, and that a non-linear load was modeled at the APS bus to account for the THD observed when no PEVs were charging.

Harmonic Cancellation

Charging of PEVs is expected to bring a beneficial diversity of harmonic current phase angles. Harmonic Cancellation analysis was performed at the Car shade and the main inclusions were drawn:

1. Charging events at <u>same EVSE</u> and <u>same PEV model</u> charging current phase angles were fairly close to a mean value.
2. Charging events at <u>different EVSEs</u>, however, showed different phase angles for the <u>same PEV model</u>.
3. <u>Different PEV models</u> present different phase angles

Figure 203 illustrates harmonic cancellation at the Car Shade. The 3rd and 5th orders of phase A were reduced as a consequence of a Nissan Leaf being plugged in. Which leads to the conclusion that an increased number of diverse PEVs is beneficial for harmonic cancellation, since it increases phase angle diversity in the system.

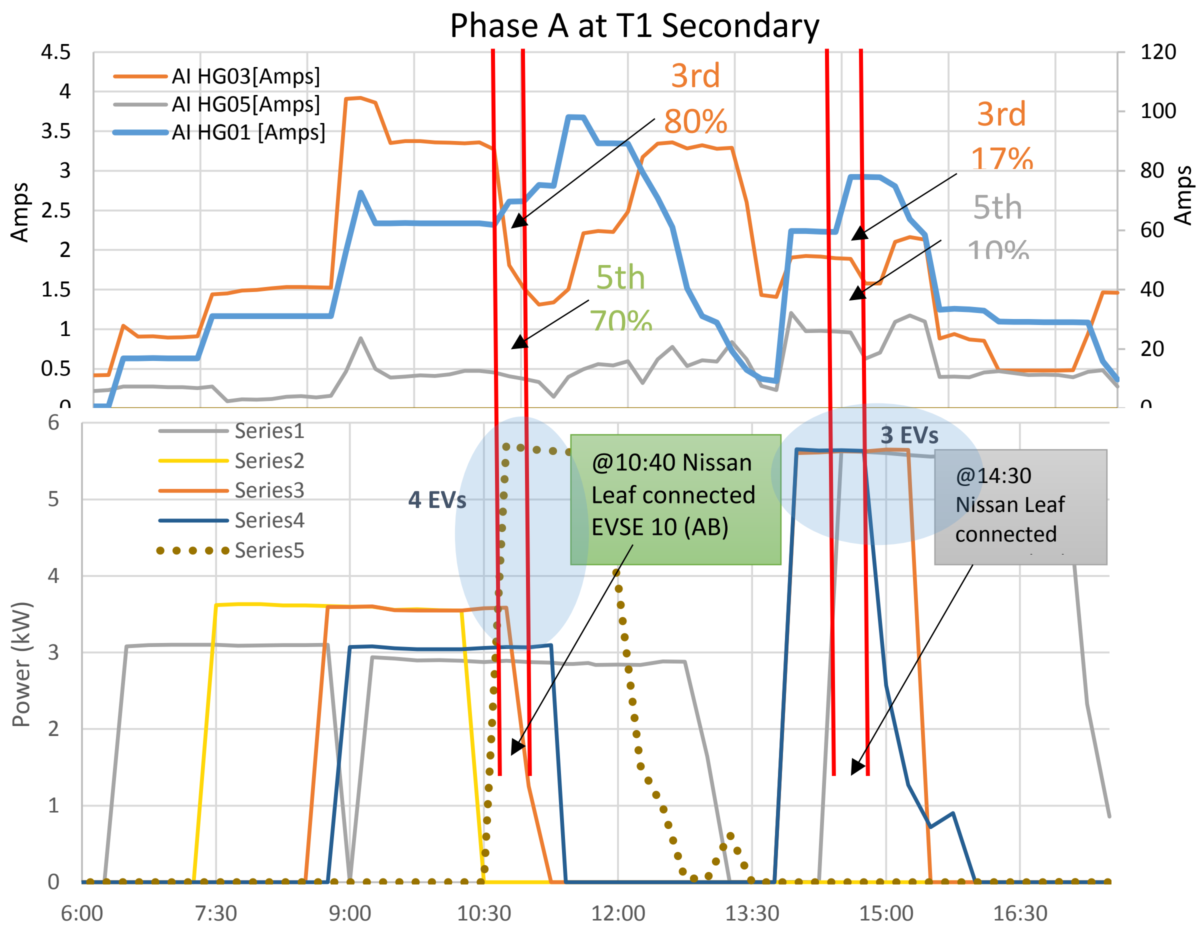


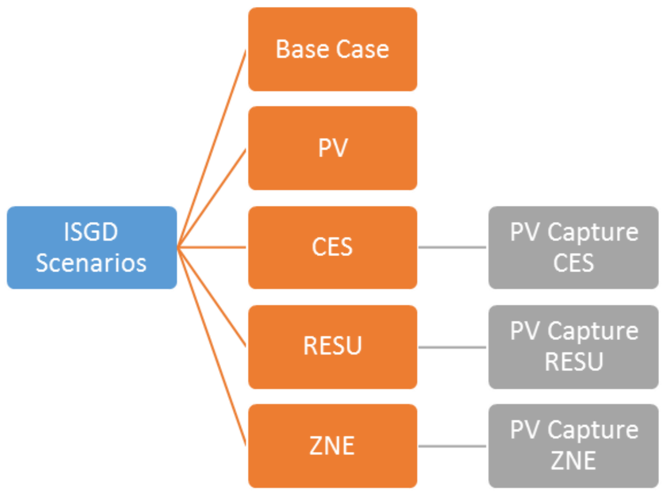
Figure 203: Harmonic Cancellation Phase A @ T1 secondary

Appendix 10: Power Grid Load-Balancing and Emissions Impacts of Smart Grid Deployment

Methodology

In this section, the power grid load-balancing and emissions impacts of smart grid deployment in California's residential sector is presented. The smart grid implementation scenarios are developed for year 2030 based on the set of smart grid technologies utilized in ISGD project. The scenarios considered in this study are presented in **Figure 204**. The Base Case scenario is used as the reference for comparing the smart grid implementation scenarios. This scenario is based on the assumption that no sort of smart-grid technologies will be deployed in California residential sector by 2030. In contrast, in the PV scenario, rooftop solar panels, sized similar to those installed in ISGD project, are implemented in 30% of California residential buildings by 2030. The CES, RESU, and ZNE scenarios are based on implementing a specific set of smart-grid technologies in 30% of California homes by 2030. In these scenarios, the original residential demand profile (Base Case) is replaced by the net load profile of the corresponding residential blocks, measured in ISGD project.

Figure 204: Scenarios Included in Study



Similar to the previous implementation scenarios, the PV Capture scenarios are expected to deploy smart technologies in 30% of California residential buildings. However, in these scenarios, the batteries are dispatched only in PV capture mode such that the battery is charged only if excess renewable power is available and discharged only if the local power generation is insufficient to meet the local demand. In this set of scenarios, the batteries are sized similar to those installed in the ISGD project.

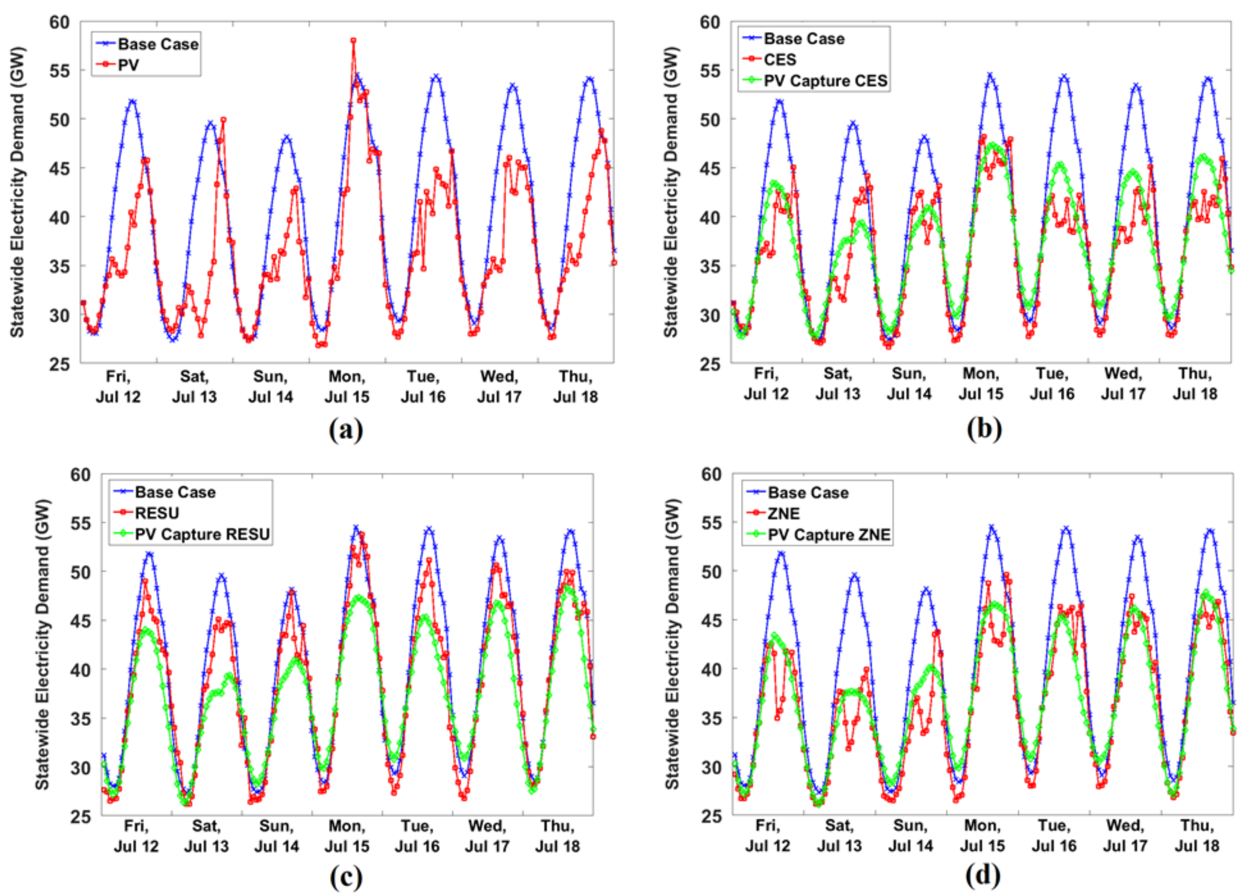
Deploying smart grid technologies in California residential buildings not only reduces the total electricity demand on the power grid due to solar PV installation, but also changes the grid dynamics. Hence, the projected statewide electricity demand profile for 2030 is modified based on the data measured in ISGD project, including solar power generation profile, residential demand profile, and net load profile.

HiGRID, which is an economic optimization model developed at UCI, is then used for dispatching power grid's renewable resources and complementary technologies. The complementary technology module of HiGRID determine the temporal power profiles of the demand response and utility-procured energy storage, which are required technologies for balancing the intermittency of renewable energy resources. In order to determine the power plants dispatch profile, PLEXOS, which is an electric grid simulation model, is used due to its advanced transmission analysis capabilities as well as its holistic resource portfolio. Finally, the temporal distribution of GHG emissions and criteria pollutants from power plants are determined by using the temporal power generation profiles and emission factors

Results

Figure 205 shows the statewide electricity demand profile during a summer week of 2030 for the smart grid implementation scenarios. As can be seen, in all scenarios, the electricity demand profile is significantly lower during the day compared to the Base Case scenario, which is due to the fact that a great portion of residential energy demand is met by local solar energy. **Figure 205(a)** indicates that the daily peak is shaved as a result of installing solar PVs, and accordingly the new peak occurs in the evening when local solar power is unavailable. An anomaly can be seen on July 15, when the statewide demand of PV scenario is greater than that of the Base Case scenario. This anomaly can be due to malfunctions in the solar panels or in the measurement devices. Although residential solar power in the PV scenario lowers the overall reliance on the power grid, it results in higher ramping rates i.e. faster dynamics of the power grid, which can cause serious challenges such as unprecedented ramping requirements for the power plants and greater dynamic emissions. In addition, the statewide electricity demand is more dynamic compared to the Base Case primarily due to the diurnal variation in solar radiation, which clearly depends on weather conditions.

Figure 205: Statewide electricity demand profile during a summer week of 2030 for (a) PV scenario (b) CES and PV Capture scenarios (c) RESU and PV Capture scenarios (d) ZNE and PV Capture scenarios



As illustrated in **Figure 205(b)**, the dynamics of CES scenario is smoother compared to the PV scenario because of utilizing community energy storage for hourly and daily load shifting, which results in enhanced overall load balancing. In the PV Capture CES scenario, a near-optimal control strategy is used for dispatching the batteries, which leads to smoother grid dynamics and accordingly lower ramping rates. **Figure 205(c)** shows that the RESU scenario has a greater overall demand compared to the CES scenario, implying that a smaller percentage of residential solar power is captured and used locally, which could be the result of improper battery dispatch strategy deployed. Similar to the PV Capture CES scenario, optimal dispatch of the battery in the PV Capture RESU scenario increases the amount of solar energy captured leading to smoother dynamics. As can be seen in **Figure 205(d)**, compared to the CES scenario, the grid dynamics of ZNE scenario is worse causing a huge valley in the middle of the day. This is due to the improper dispatch of the batteries that export the excess solar power generation to the grid instead of storing it for meeting the evening peak, which is the case in the PV Capture ZNE scenario.

Figure 206 shows the breakdown of annual solar energy generation in smart residential buildings in year 2030. The percentages above each bar indicates the overall renewable penetration of smart residential buildings. As can be seen, nearly 42% of total solar energy generation is captured and used locally in the PV scenario, while about 50% is exported to the grid and the rest is curtailed due to efficiency losses. This figure shows if solar panels are implemented in smart residential buildings without energy storage, only 35% of the annual demand of smart residential buildings is met by solar energy, while the rest is powered by the electric grid. Although the renewable penetration reduces to 17.8% in RESU scenario due to improper dispatch of the batteries, it is clear that integrating battery energy storage with solar PV using a proper dispatch strategy increases the amount of solar energy captured as the renewable penetration of CES (38.2%), and ZNE (58.8%) scenarios is greater than that of PV scenario. Furthermore, implementing near-optimal battery dispatch strategies such as PV Capture enhances solar absorption and accordingly renewable penetration through better management of local power and demand. This results show superior performance of PV Capture ZNE scenario compared to PV Capture CES scenario, while both being outperformed by PV Capture RESU scenario.

Figure 206: Breakdown of annual energy generated by solar PV installed in smart residential buildings

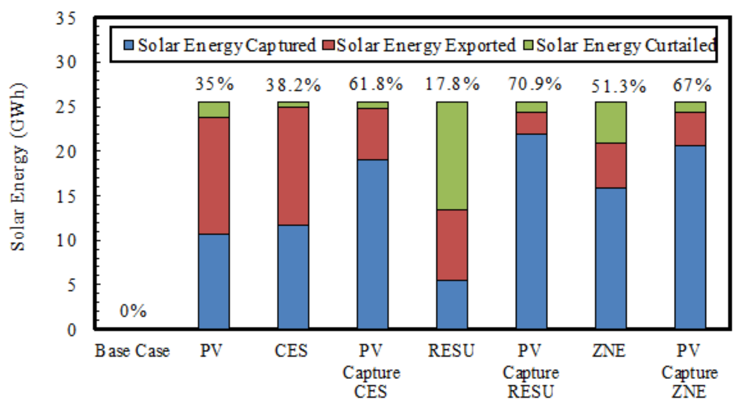
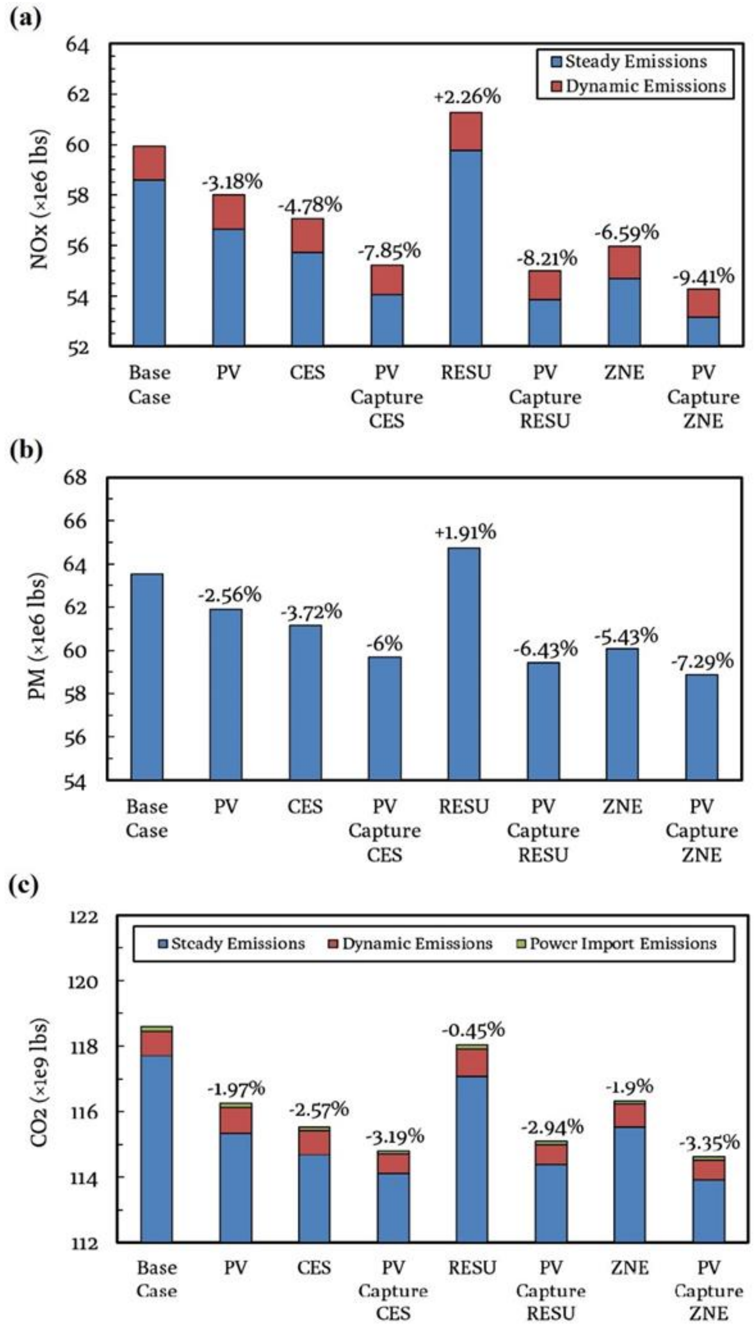


Figure 207 presents the annual emissions from power generation sector for different scenarios. In the Base Case scenario, nearly 60×10^6 pounds of Nitrogen Oxides (NOx), 63×10^6 pounds of Particulate Matter (PM), and 118.6×10^9 pounds of Carbon Dioxide (CO_2) are emitted from California power plants in 2030. The percentages above each bar indicate the change in the annual emissions compared to the Base Case scenario. Overall, compared to the Base Case, the emissions are significantly lower in all scenarios except the RESU scenario. In the RESU scenario, the NOx and PM emissions are 2.26% and 1.91% higher, respectively, than the Base Case emissions due to highly dynamic demand profile while the CO_2 emission is slightly lower. This is due to the fact that criteria pollutant emissions including NOx and PM are more susceptible to grid dynamics such as part-load operation, startup/shutdown events, and high ramping rates, while greenhouse gases including CO_2 are more dependent on steady characteristics and less susceptible to grid dynamics. Emissions reduction as much as 9.41% in NOx, 7.29% in PM, and 3.35% in CO_2 can be observed for the PV Capture ZNE scenario. This figure illustrate that the PV Capture RESU scenario leads to lower annual criterial pollutant emissions compared to the PV Capture CES scenario primarily due to smoother dynamics, while PV Capture CES scenario has superior GHG emission characteristics as a result of lower total electricity demand.

Figure 207: Annual Nitrogen Oxides emissions, Particulate Matter emissions, and Carbon Dioxide emissions from power generation sector under different scenarios



Appendix 11: Towards uniform benefit-cost analysis for smart grid projects: an example using the Smart Grid Computational Tool

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Abstract

Smart grid technology is being rolled out around the world, with the United States nearing completion of a Federal program exceeding $4 billion, funded under the American Recovery and Reinvestment Act of 2009 (ARRA). Under the Climate Change Working Group Implementation Plan, comparative analyses of benefits estimation methods for Smart Grid technologies are being conducted using four smart grid case study projects, two in each country. In this first study, three of eight Southern California Edison's Irvine Smart Grid Demonstration Project sub-projects have been analyzed over the period 2010-2035. The analysis uses the Smart Grid Computational Tool (SGCT) developed by Navigant Consulting Inc. for the U.S. Department of Energy based on Electric Power Research Institute methods. Results show significant benefits potential for technologies such as distribution voltage and VAR control and utility-scale batteries, while a 22-residence zero net energy home demonstration inspired by California's anticipated 2020 residential energy efficiency standard falls far short of economic breakeven at the current stage of costs and technology performance. This assessment indicates that the SGCT intended for widespread U.S. smart grid technology evaluation is necessarily simple, and consequently has limited applicability for international applications or comparisons.

Keywords

smart grid, benefit-cost analysis, zero net energy homes, Smart Grid Computational Tool, EPRI method, American Recovery and Reinvestment Act

1. Introduction

This work has been conducted under the auspices of a joint U.S.-China research effort. Sharing research capabilities and results in the smart grid area between the two countries forms the overarching objective of the activity. Early discussions in 2014 between the research teams led to two focuses, advanced technology (not discussed further in this paper), and on the analysis of demonstration project benefits. Researchers in both the U.S. and China have developed formal methods for benefits assessment, so demonstrating them with example analyses was the logical approach. This paper reports on the first analysis conducted on the U.S. side using the Smart Grid Computational Tool (SGCT), which was developed specifically for the American Recovery and Reinvestment Act of 2009 (ARRA) program. This demonstration is primarily intended to show the capabilities of the tool. Additionally, its applicability internationally is of interest, especially in China. As in many technical demonstrations, the purpose of the ARRA smart grid projects is multi-faceted, not least in this case, for economic stimulus.

Electrification of the economy is often cited as the crowning achievement of the last century, most notably by the United States (U.S.) National Academy of Engineering (Constable and Somerville, 2003). Nonetheless, during the latter quarter of the last century, interest in the transmission grid decayed in several ways, including a general lack of research activity, investment, and policy attention. In the U.S., this era was closed by a series of devastating hurricanes beginning with Hugo in 1989, then Andrew in 1992, followed by several others, notably Katrina in 2005 and, ultimately, Sandy in 2012. The paralyzing effect of power loss following these disasters, and the reminder that other infrastructures on which developed economies critically depend, communications, transport, sewage treatment, etc., are also lost when the grid goes black, sparked renewed interest in *the grid*. The Great East Japan Earthquake of 2011 has had a similar dramatic impact on that country's understanding of power supply resilience, and indeed worldwide (Ton et al., 2011; Marnay et al., 2015; Panteli and Mancarella, 2015). While other countries have not experienced quite such a sobering series of events, blackouts in many other places during recent times have similarly affected thinking elsewhere, e.g. the blackouts in London and Italy in 2003, Germany and Tokyo in 2006, and India in 2012. And of course, the U.S. also experienced a major non-weather-related blackout in 2003. In addition to reliability, there was growing concern that other threats to the grid are emerging too. A major one was fear that a high fraction of uncontrollable variable renewable generation in the supply mix would undermine established operating procedures based on dispatchable thermal and hydroelectric generators creating new stresses on power systems, an evolution generally known in California as *The Duck Curve* (CAISO, 2013). The name comes from its shape. With increasing solar generation during afternoon hours, the residual load to be met by traditional load-following generation gets hollowed out, the breast of the duck, while the evening ramp to evening operations becomes increasingly steep, the duck's neck, and nighttime operations remain little changed, the tail. California's immediate goal for renewable supply penetration is 33 % of retail electricity from renewables by 2020, which is driving rapid growth in solar, of which 4 GW was installed in 2014 alone. The failure of California's reformed electricity market in 2000 also raises concerns that market manipulation or other consequences of power sector reform would threaten grid performance. During the 2000 crisis, astronomical price spikes failed to evoke much demand response because very few customers were actually directly exposed to prices, rather the State struggled to keep them stable. Meanwhile on the supply side, generators were withdrawing capacity. Controlled *rolling* blackouts were required to balance supply and demand providing further stark evidence of the economic disruption that can result from market dynamics, while the financial damage inflicted on distribution companies further threated reliability. It is now recognized that if markets are to be so volatile, prices seen by customers need to reflect the resulting price variations.

Early in this century, it became clear that the technology embedded in the developed world's electricity supply system had become seriously inadequate to cope with the challenges described above, and to generally meet rising expectations for grid performance, often assumed necessary to support the emerging *digital economy* (Tapscott, 1995). *Smart Grid* emerged as an umbrella term to describe a number of technologies that had mostly already been proposed or actually developed separately, but which had failed to gain broad deployment. The notable example is advanced metering infrastructure (AMI), whose capabilities had been recognized as necessary for several decades. Other technologies too were brought under the smart grid umbrella. These can be boxed into three types. The first, already mentioned, involves establishing an appropriate AMI infrastructure to enable price-sensitive demand, and hence an efficient market. The second concerns improved operation of the legacy centralized grid. Many new applicable technologies have emerged, such as synchrophasers and better visualization tools (SEL). The third, and perhaps most radical leg of the smart grid stool is decentralized control of the power system, i.e. microgrids and community power (Marnay and Lai, 2012). This innovation has been rapidly gaining momentum since Sandy, largely driven by the exceptional performance of several microgrids during the disaster (Panora et al., 2011, Marnay et al., 2015).

The U.S. is unusual in that a definition of smart grid appears in legislation. The Energy Independence and Security Act (2007) established that U.S. Federal policy is to promote development of the smart grid. Title XIII covers the smart grid, and the list of its elements as shown in the bill has stood up well and has provided a solid definition that covers technologies in all the three areas listed above. This legislative basis made smart grid an attractive target for ARRA stimulus spending. A significant body of smart grid policy analysis had been established (TheCapitolNet, 2009). ARRA was the major U.S. macroeconomic stimulus package passed during the great recession by Congress and signed by President Obama on 17 February 2009. About $4.5B or 0.6 % of all ARRA spending was dedicated to smart grid development within the U.S. Department of Energy (DOE). Two types of grants were established. By far the larger is the Smart Grid Investment Grant (SGIG) Program, which includes 99 projects and accounts for most of the DOE funds committed. Together with private matching contributions the SGIG totals about $8B of investment, dominated by AMI deployment of an expected 65 million smart meters (DOE, 2014). The second much smaller ($650M of DOE funds) Smart

Grid Demonstration Projects (SGDP) includes 32 more technically innovative projects of which the $80M Irvine Smart Grid Project (ISGD) covered in this paper is one (Irwin and Yinger, 2014; Irwin and Yinger, 2015).

Although ARRA was an economic stimulus program, from the beginning, the SGIG and SGDP programs were intended to be open demonstrations that would serve as catalysts for development and deployment of smart grid technology. One aspect of this perspective was an explicit intention to evaluate and disseminate the results of the projects, including their societal benefits (DOE, 2009). Consequently, during the first year of the programs, DOE's Office of Electricity Delivery and Energy Reliability made a substantial effort to develop a standard benefits method that could be applied to all projects in a consistent manner. An analytic approach was developed by the Electric Power Research Institute (EPRI), and on this foundation, the SGCT used in this study was built by Navigant Consulting, Inc. (EPRI, 2010; Navigant, 2011). All projects receiving DOE ARRA funds are required to provide benefits results but not necessarily using the EPRI approach or the SGCT. An effort was also made to harmonize approaches with Europe, and the EPRI approach has been applied outside the U.S. in at least one study, and incorporated in other tools (Giordano and Bossart, 2012; Giordano et al., 2012; Vitiello et al., 2015).

The work described in this paper has been conducted as part of a collaborative research effort between the U.S. and China under the Climate Change Working Group Smart Grid (CCWG) effort, which has identified smart grid as one of five areas of promising research collaboration (CCWG, 2014). Four notable smart grid demonstrations in the U.S. and China will be studied and compared during this three-year analysis for both technical and economic-social merit. ISGD is one of the showcase U.S. projects and the first one to be scrutinized in detail. It has eight sub-projects, but the analysis described here focuses on just 3. The first involves installation of multiple sophisticated residential technologies in a group of 22 pre-existing faculty homes on the University of California, Irvine (UCI) campus. The installed equipment includes smart appliances and equipment, photovoltaic arrays (PV), solar water heating, heat pumps, and battery storage. Some of the homes are intended to achieve the California Zero Net Energy (ZNE) standard, which is California's goal for all new residential construction by 2020 (CEC-CPUC, 2015). The other two sub-projects covered are distribution network technologies involving utility-scale storage and distribution voltage and volt-ampere reactive (VAR) control intended to conserve energy.

2. Methodology

2.1 EPRI Method

Benefit-cost (B-C) analysis is a commonly used tool in public policy discussion and decisions (Mishan and Quah, 2007). While the smart grid has now been around for some time, estimating its B/C ratios is still a new area of study (Bossart and Bean, 2011). Nonetheless, as smart grid projects are being demonstrated globally, the demand for analysis of project cost effectiveness is growing rapidly, with analysis developments and related tools in both the U.S. and Europe filling this gap. EPRI with the support of DOE researched methods for estimating the benefits of individual smart grid demonstration projects (EPRI, 2011). In this study, we discuss the EPRI B-C analysis method for assessing the economic, environmental, reliability, safety, and security benefits of involved project stakeholders.

The EPRI Method defines *benefit* as a monetized value of the impact of a smart grid project to a firm, a household, or society in general. The B-C analysis in the EPRI method is based on the difference between the benefits and costs associated with a baseline scenario (Formula 1), which represents the system state without the smart grid demonstration project, and a contrasting project scenario. The benefits are usually aggregated from deferred capacity investment, reduced electricity purchases, reduced or deferred transmission and distribution (T&D) investment, lower operation and maintenance, reduced transmission congestion, improved power quality, reduced environmental insults, and so on (see Table 1 for a complete list). Net benefits are the total reductions in costs and damages as compared to the baseline, accruing to firms, customers, and society at large, excluding transfer payments between these beneficiary groups. All future benefits and costs are reduced to a net present value (NPV) using a discount rate, and an inflation rate, over the project lifetime.

Formula 1:

$$B_{net} = NPV\{C_{baseline} - C_{project}\}$$

To learn more about the cost effectiveness of a smart grid project, the EPRI Method was extended to calculate the B/C ratio, and the breakeven time of the project. The B/C ratio is calculated from Formula 2, and the higher the ratio, the more attractive the project:

Formula 2:

$$B/C = \frac{Annualized\ \sum(B_{econ} + B_{reli} + B_{env} + B_{sec})}{Annualized\ Cost}$$

where, B/C ratio is the cost effectiveness of the project. B_{econ} represents the economic benefits, B_{reli} the reliability benefits, B_{env} the environmental benefits, and B_{sec} the security benefits. Both the benefits and costs are annualized. Benefits are categorized into four groups: economic, reliability, environmental, and security. Each group has a number of benefits generated by assets and their functions, as Table 1 summarizes.

There are multiple stakeholders involved in smart grid development, *consumer*, *utility*, and *society* as a whole. It needs to be noted that different stakeholders might have different focuses and shares of those benefits. The *consumer* and *utility* would share the economic benefits, the *utility* captures most of the reliability benefits, while environmental and security benefits accrue to *society* at large.

2.2 Smart Grid Computational Tool

User friendly tools should be able to scale up applications of smart grid B-C analysis, so DOE developed the SGCT[39] to facilitate monetary benefits evaluation based on the framework EPRI developed. The SGCT is an Excel-based model that allows the user to identify the functions to be demonstrated by a smart grid project's technologies, to calculate its benefits and costs, and to estimate the project's overall value (Navigant, 2011). The SGCT is currently locked for further revision, so it cannot be used on any other platform, such as Analytica, for uncertainty analysis, nor is it open for user enhancement.[40]

The logic of the SGCT starts from a listing of smart grid assets, then identifies the functions of those assets, and ultimately monetizes project benefits, as shown in Figure 1. The first step is to list all the smart grid assets deployed in the project for evaluation, for example, *Distribution Automation*, *Smart Appliances and Equipment (Customer)*, etc. Step 2 is to identify the functions of each asset, for example, *Distribution Automation* can provide *Power Flow Control*, *Automated Feeder and Line Switching*, *Automated Islanding and Reconnection*, *Automated Voltage and VAR Control*, and so on. Step 3 is to map the benefits of each of those functions. Step 4, the last step, is to monetize all the benefits. One function might have multiple benefits, therefore, all should be summed up to estimate the project's total monetized value.

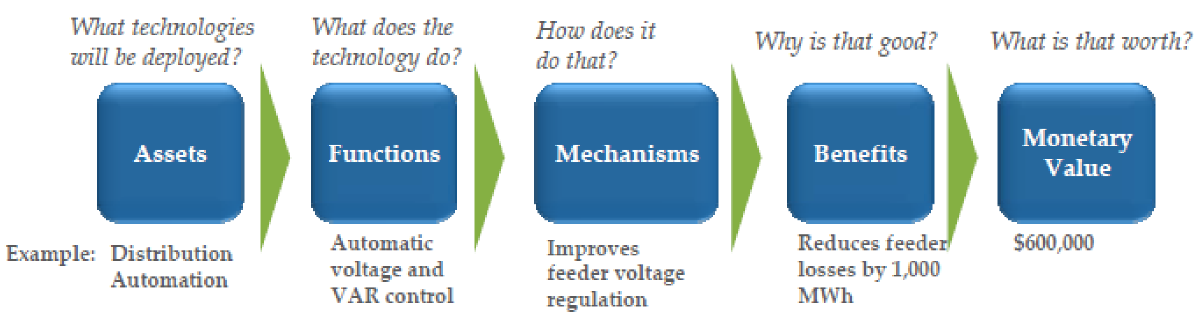
Table 72: Itemized benefits of SGCT

Benefits
Economic: Optimized Generator Operation Deferred Generation Capacity Investments Reduced Ancillary Service Cost Reduced Congestion Cost Deferred Transmission Capacity Investments Deferred Distribution Capacity Investments Reduced Equipment Failures

[39] More information at https://www.smartgrid.gov/recovery_act/publications/analytical_tools (accessed 5 March 2015)
[40] www.lumina.com

Benefits
Reduced T&D Equipment Maintenance Cost Reduced T&D Operations Cost Reduced Meter Reading Cost Reduced Electricity Theft Reduced Electricity Losses Reduced Electricity Cost
Reliability: Reduced Sustained Outages Reduced Major Outages Reduced Restoration Cost Reduced Momentary Outages Reduced Sags and Swells
Environmental: Reduced Carbon Dioxide (CO_2)Emissions Reduced Sulfur Oxide (SO_X), Nitrogen Oxide (NO_X) and Particulate Matter (PM)-2.5 Emissions
Security: Reduced Oil Usage Reduced Wide-scale Blackouts

(Source: This benefits table is adapted from Navigant (2011))



(Source: EPRI, 2010)

Figure 208: The logic flow of SGCT

In this paper, the SGCT tool is applied to analyze the cost effectiveness of the ISGD sub-projects. Data were collected for the key SGCT inputs and are used to conduct B-C analysis on selected ISGD sub-projects independently; a sensitivity analysis on discount rate was also conducted.

Clearly, uncertainty is a central issue that needs to be addressed in any analysis attempting to evaluate an evolving technology over a multi-decade horizon. All inputs should be questioned, but those regarding performance and cost of the technology generate the most discomfort and call most convincingly for attention. The SGCT provides only rudimentary uncertainty capability in the form of automated sensitivity analysis on roughly 110 input variables used in benefits calculation such as annual generation cost, price of capacity at annual peak, ancillary services cost, congestion cost, distribution investment time deferred, total T&D maintenance cost, T&D losses, CO_2 emission, CO_2 prices, and so on. However, there is no sensitivity analysis on some key variables, such as project capital cost, and some project costs are not included at all, e.g. installed equipment maintenance and operational costs. Possible price reduction due to future technological change is also uncertain and not considered in the EPRI method or the SGCT. In addition, modeling of technology capital costs could be enhanced if they included failure probability and/or equipment lifetime. Unfortunately, since the SGCT is available only in a locked version, omitted variables cannot be added, and using stochastic variables for Monte Carlo or other simple uncertainty analysis is not possible.

3. Case Study - Irvine Smart Grid Demonstration Project

3.1. Project Overview

Southern California Edison (SCE) operates the ISGD project primarily in California's Orange County City of Irvine. Many of the project components are located on or near the UCI campus, which is 60 km southeast of the Los Angeles airport (LAX). Key project participants include UCI, General Electric Energy, SunPower Corporation, LG Chem, Space-Time Insight, and EPRI. The primary objective of ISGD is to verify and evaluate the ability of smart grid technologies to operate effectively and securely when deployed in an integrated framework (Irwin and Yinger, 2015). ISGD is a comprehensive demonstration that spans the electricity delivery system and extends into customer homes. ISGD's evaluation approach includes four distinct types of testing: simulations, laboratory tests, commissioning tests, and field experiments. The ISGD project uses simulations and laboratory testing to validate a technology's performance capabilities prior to field installation. The purpose of the field experiments is to evaluate the physical impacts of the various technologies on the electric grid and to quantify the associated benefits for different types of stakeholders.

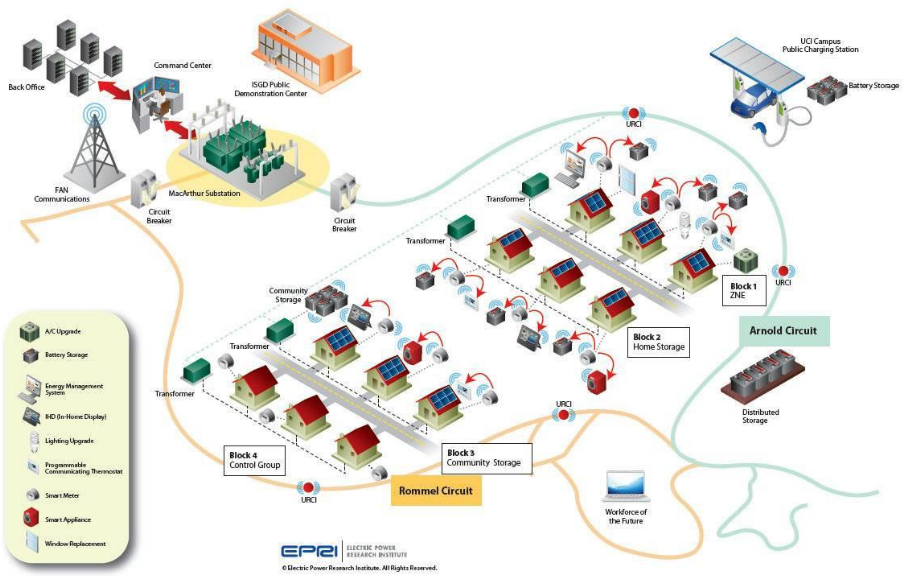


Figure 209: Irvine Smart Grid Demonstration (ISGD) project

The project includes four *domains*. Each domain includes one or more with distinct objectives, technical approaches, and research plans. There are 8 sub-projects within these 4 domains, only 3 of which, shown *italics* below, are included in the analysis in this paper, as shown below:

- Smart Energy Customer Solutions (Sub-Projects 1 & 2)
  - *Sub-project 1: Zero Net Energy Homes*
  - Sub-project 2: Solar Car Shade
- Next-Generation Distribution System (Sub-Projects 3, 4, 5 & 6)
  - *Sub-project 3: Distribution Circuit Constraint Management Using Energy Storage*
  - *Sub-project 4: Distribution Volt/VAR Control*
  - Sub-project 5: Self-healing Distribution Circuits
  - Sub-project 6: Deep Grid Situational Awareness
- Interoperability & Cybersecurity (Sub-Project 7 only)
- Workforce of the Future (Sub-Project 8 only)

3.2. Sub-project 1: Zero Net Energy Homes

In sub-project 1, ISGD is evaluating a variety of technologies designed to help empower customers to make informed decisions about how and when they consume (or produce) energy. Such technologies have the potential to better enable customers to manage their energy costs, while also improving grid reliability and stability (Irwin and Yinger, 2015). This project domain includes a variety of technologies designed to help empower customers to make informed decisions about their energy use. The project extends into a residential neighborhood on the UCI campus used for faculty housing. ISGD has equipped three blocks of homes with an assortment of advanced energy technologies, including energy efficiency upgrades, energy storage, rooftop solar photovoltaic (PV) panels, thermostats and smart appliances capable of demand response, and in-home displays.[41] The project is using one block of homes to evaluate strategies and technologies for achieving zero net energy (ZNE) or near-ZNE. Energy efficiency upgrades are only included in this block of homes. A building achieves ZNE when it produces at least as much (usually renewable) on-site energy as it consumes over a given period, including both natural gas and electricity, typically on an annual basis. The concept of ZNE buildings is widespread and has been incorporated into California's next Title 24 building code, effective in 2017 (CEC-CPUC, 2015). From this point of view, the objectives of this sub-project are to evaluate the impact of advanced demand side measures to better understand their impacts on the electric grid, as well as their contributions toward enabling homes to achieve ZNE. Three levels of home retrofits and details are as follows:

1. Zero Net Energy (ZNE) block (9 homes)
    a) Demand response devices
    b) Energy efficiency upgrades
    c) Residential energy storage units (4 kW/10 kWh)
    d) Solar PV arrays (~3.9 kW)
2. Residential Energy Storage (RESU) block (6 homes)
    a) Demand response devices
    b) Residential energy storage units (4 kW/10 kWh)
    c) Solar PV arrays (3.2-3.6 kW)
3. Community Energy Storage (CES) block (7 homes)
    a) Demand response devices
    b) Community energy storage unit (25 kW/50 kWh)
    c) Solar PV arrays (3.2-3.6 kW)

Table 73: Demand response capable devices deployed in Sub-Project 1

Energy Star Smart Refrigerator
Energy Star Smart Clothes Washer
Energy Star Smart Dishwasher
Programmable Communicating Thermostat
Home Energy Management System
In-Home Display

Table 74: Energy efficiency upgrades and onsite renewable technologies deployed in Sub-Project 1

Central Air Conditioning Replacement (Heat Pump)
LED Lighting Upgrades
Insulation
Efficient Hot Water Heater
Domestic Solar Hot Water and Storage Tank
Solar Panels for Water heaters
Low Flow Shower Heads
Plug Load Timers
Solar PV Panels

[41] Additionally, there is a fourth block of homes, which is aimed to provide baseline data in B-C analysis, although in this work a time series comparison is used.

ISGD is evaluating two types of residential-scale batteries in this neighborhood; additionally, a utility-scale battery was demonstrated in Sub-Project 3, as described in more detailed below. All batteries used in ISGD are Li-ion, but from 3 separate vendors. Individual residential energy storage units have been installed in 14 homes as mentioned above, and they are being evaluated using a variety of control modes. In addition, 7 homes share a community battery, which is also being evaluated using a variety of control modes. Both devices can provide load leveling, storage of daytime PV output for later use, and a limited amount of backup power during electricity outages. These batteries underwent extensive testing prior to commissioning. ISGD performed various field experiments over a one-year period to evaluate the impacts of the Sub-project 1 capabilities.

Field Experiment A: The objective of this experiment is to quantify the impact of energy efficiency upgrades and other IDSM measures on the home and transformer load profiles. This experiment helped the team determine how the homes, particularly on the ZNE block, but also on the RESU and CES blocks, perform against the goal of achieving zero net energy, and assess the impact on the distribution transformer temperature and load profile.

Field Experiment B: The objective of this experiment is to quantify the impacts of demand response devices on the load profiles of smart devices, the homes, and the secondary transformers.

Field Experiment C: The objective of this experiment is to quantify the ability of the RESU to shift coincident peak load to the off-peak period by discharging during the peak period.

Field Experiment D: The objective of this test is to quantify the ability of the RESU to automatically level demand over a 24-hour period. RESUs operate in the Level Demand mode, which directs the RESU to discharge during periods of high demand and charge during periods with little load, thereby flattening the home's demand curve.

Field Experiment E: The objective of this experiment is to quantify the CES's ability to shave demand on the secondary transformer. The CES automatically adjusts its discharge power level based on real-time load provided from a locally installed power quality meter. This control reduces the demand on the transformer.

Field Experiment F: The objective of this experiment is to quantify the impacts of rooftop solar PV generation on the load profile of the secondary transformer.

3.3. Sub-Project 3: Distribution Circuit Constraint Management Using Energy Storage

The electric grid is evolving into an increasingly dynamic system with new types of distributed and variable generation resources and changing customer demands. This project domain includes a distribution-level battery energy storage system (DBESS) to help prevent a distribution circuit load from exceeding a set limit, to mitigate overheating of the substation getaway, and reduce peak load on the circuit. The DBESS, which has a rating of 2 MW of real power and 500 kWh of energy storage, connected to the Arnold 12 kV distribution circuit. This circuit receives power from MacArthur Substation and is the same circuit where the project test homes in sub-project 1 are located.

This battery is also being used along with phasor measurement technology installed within the Substation and at a transmission-level substation upstream to detect changes in distribution circuit load from distributed energy resources, such as demand response resources or energy storage.

3.4. Sub-Project 4: Distribution Volt/VAR Control

Also included in this study is Distribution Volt/VAR Control (DVVC), which optimizes the customer voltage profiles in pursuit of conservation voltage reduction. A 1 % voltage reduction potentially yields an approximate 1 % reduction in customer energy consumption, in most cases. This often proposed measure is required in California where the voltage should be maintained as close as possible to the minimum acceptable level, nominal voltage minus 5 %, and nominal, i.e. between 114-120 V, at the customer connection. While maintaining the voltage closer to its minimum acceptable level is simple and attractive in principle, it proves quite difficult to implement accurately in the field. DVVC technology significantly improves capability and can also provide VAR support to the transmission system, i.e. control high voltages to maximize capacity. The DVVC application underwent multiple rounds of factory testing and site acceptance testing, and is now operating on seven distribution circuits out of MacArthur Substation. Field experiments showed an average 2.6 % energy savings, making this demonstration a major success. SCE intends to gradually roll the technology out system wide, although it may not be applicable to all distribution networks, depending on pre-existing equipment.

3.5. General Assumptions

This study contains B-C analyses of Sub-Projects 1, 3, and 4 of ISGD, for which the following assumptions were made.

- Homes on each block have different levels of retrofits, as mentioned earlier in Section 3.1. The retrofits differ from even home-to-home in the same block. The average cost associated with each upgrade is detailed in **Table 75**. In calculation of project costs, it is considered that upgrades of white goods in homes, namely smart refrigerators, smart dish washers, smart clothes washers, and efficient hot water heater, would be more expensive varieties of common models. Thus, for those technologies, only incremental cost, via comparison with similar model prices in the market, was included in the analysis. On the other hand, for the new technologies such as home EMS display, RESU, CES, and PV panels, the total cost of the equipment is used. Table A1 summarizes the key inputs and parameters used in the study. In addition, details of the technology costs and assumptions on incremental costs are also presented in tables A2 and A3.
- Since the EPRI method and the SGCT tool do not consider equipment lifetime or model survival of technologies, survival probability of each technology was calculated exogenously and implemented in the SGCT as input costs. Survival probabilities are assumed normally distributed with a mean average lifetime (see Table A3) and variance of 3 years for each technology.
- Discounting costs and benefits at a societal discount rate provides the value of the project to society, regardless of actual project costs. International practices recommend real discount rates varying from 1 to 15 % with the highest rates used in developing countries (Harrison, 2010). The U.S. Office of Management and Budget uses a discount rate of 7 % and recommends 3 % as a sensitivity, while the U.S. Environmental Protection Agency uses 2-3 % with a sensitivity rate of 7 %. The European Commission suggests 5 %, while the United Kingdom Treasury uses 3.5 %. Given this range of views, a societal discount rate of 5 % was assumed and sensitivities performed for 2.5, 7.5, and 10 %.
- Project input parameters are employed for 2014 because ISGD was activated around mid-2013, making 2014 a full representative test year, while baseline parameters are based on historical 2012.
- A time horizon of 25 years from the beginning of the project is chosen.
- The value of T&D capacity is based on projected total cost to add capacity system-wide over a 5-10 year horizon, although actual benefits will depend on the location of peak reductions. In addition, T&D losses of 4.8 % and 2.7 %, respectively, were used.

Table 75: Average cost of retrofit by project blocks in Sub-project 1

Blocks	Average Cost per home ('000 2010$)
ZNE Block	$164.0
Demand Response	$12.2
Energy Efficiency Measures	$65.7
Residential Energy Storage Unit	$66.7
Solar PV Panels	$19.5
RESU Block	$115.6
Demand Response	$12.2
Residential Energy Storage Unit	$66.7
Solar PV Panels	$36.7
CES Block	$60.7
Demand Response	$12.2
Community Energy Storage Unit	$22.3
Solar PV Panels	$26.2

The analysis and results reported here should be regarded as preliminary and intended to be illustrative for the purpose of demonstrating and assessing the SGCT. Broader conclusions regarding the relative efficacy of the demonstrated technologies in ISGD sub-projects should not be made based on this work. SCE will file its official benefits report at project completion.

4. Results

The main structure of the EPRI method declares assets provide a set of functions that can, in turn, generate Smart Grid benefits to be monetized (EPRI, 2010). The analysis begins therefore by identifying the assets deployed in each of the sub-projects included in this study, and then mapping them to functions that generate benefits.

4.1. Mapping

Figure 210 illustrates the assets identified for each Sub-project, listed in blue boxes, and mappings to functions activated by the assets. Once the functions are identified, the tool in turn maps them on to a standardized set of benefits.

Figure 211 summarizes the functions to benefits mapping provided by the SGCT for each test case Sub-project. The green cells with *YES* mark the benefits of each Sub-project identified through the mapping exercise; however, this second mapping shows that functions to benefits links are not accurate in every case. Some identified functions do not appear to be linked as expected to benefits, and one function is linked to an unexpected benefit. *Optimized Generator Operation* is a benefit not directly realized from the *Distributed Production of Electricity* function in Sub-project 1. It is certainly credible that coordination between output from distributed sources and operation of centralized assets might improve overall fuel efficiency, but such coordination implies a detailed level of operational control. In this study, no input was made for this benefit to eliminate it from calculations. Likewise, *Automated Voltage and VAR Control* function in Sub-project 4 is only linked to the benefits *Reduced Electricity Losses*, *Reduced CO_2 Emissions*, and *Reduced SO_x, NO_x, and PM-2.5 Emissions*; however, field experiments have shown DVVC produces an average customer energy savings of 2.6 %, ranging between 1.6 % and 3.6 % (Irwin and Yinger, 2015) [42]. Figure 5 illustrates customer voltages realized in field experiments with and without DVVC. The technology also delivers benefits from deferred generation and T&D capacity investments, and the cost of distribution equipment maintenance is reduced. These benefits not identified in the tool for DVVC are marked in red (with *+YES*) in Figure 4. To overcome this limitation, a phantom asset was added to

[42] In early October 2014, the SCE research team obtained voltage and energy consumption data for two sets of alternate on-off weeks. For each week, all of the voltage readings from 14 instrumented field capacitors and the substation bus were averaged. The Conservation Voltage Reduction (CVR) factor, which for these two test periods averages 2.6, measures the decrease in energy consumption associated with a 1 % voltage decrease (i.e., % average power reduction/1 % voltage reduction). Normally, the CVR factor is expected to be close to unity, and no explanation for this disparity is known. For more detail, see Irwin and Yinger (2015).

generate the missing benefits at no cost.

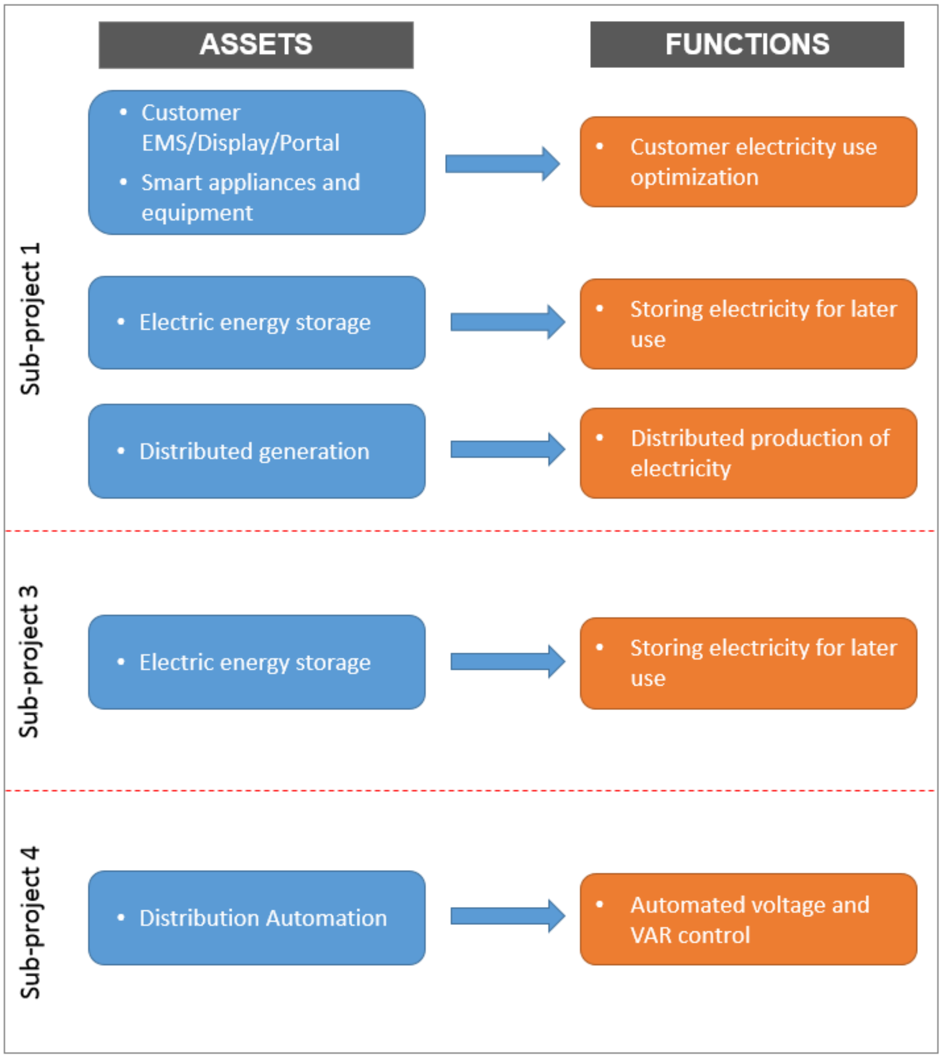
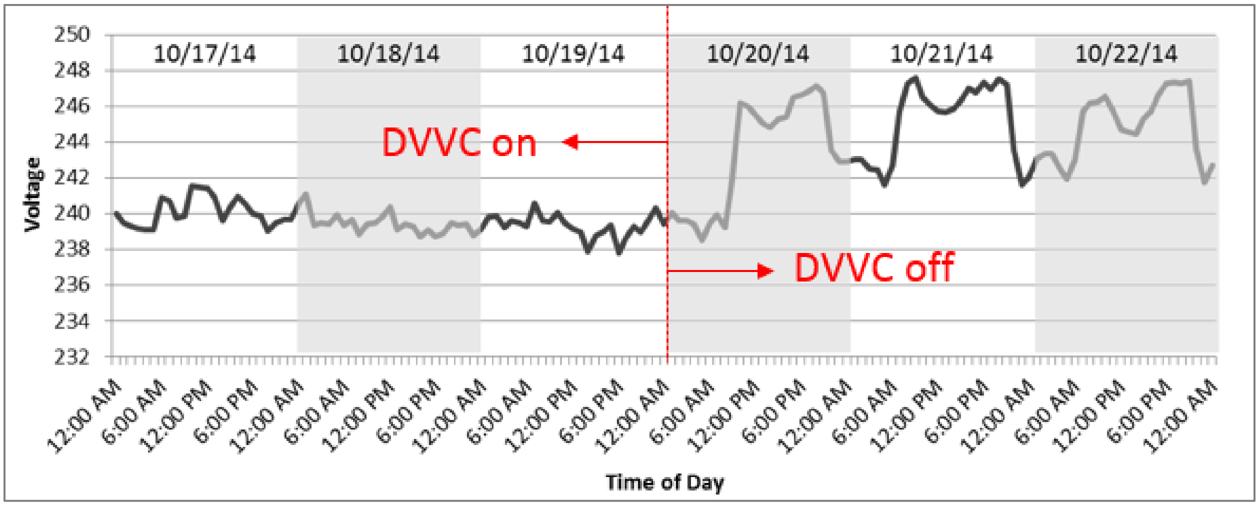


Figure 210: Assets to functions mapping of each case Sub-project

Benefits			Sub-project 1 Functions			Sub-project 3 Functions	Sub-project 4 Functions
			Customer Electricity Use Optimization	Storing Electricity for Later Use	Distributed Production of Electricity	Storing Electricity for Later Use	Automated Voltage and VAR Control
Economic	Improved Asset Utilization	Optimized Generator Operation			YES		
		Deferred Generation Capacity Investments	YES	YES	YES	YES	+YES
		Reduced Ancillary Service Cost	YES	YES	YES	YES	
	T&D Capital Savings	Reduced Congestion Cost	YES	YES	YES	YES	
		Deferred Transmission Capacity Investments	YES	YES	YES	YES	+YES
		Deferred Distribution Capacity Investments	YES	YES	YES	YES	+YES
	T&D O&M Savings	Reduced Equipment Failures					
		Reduced T&D Equipment Maintenance Cost					+YES
		Reduced T&D Operations Cost					
	Theft Reduction	Reduced Meter Reading Cost					
	Energy Efficiency	Reduced Electricity Theft					
	Electricity Cost Savings	Reduced Electricity Losses		YES	YES	YES	YES
Reliability	Power Interruptions	Reduced Electricity Cost	YES		+YES		+YES
		Reduced Sustained Outages					
		Reduced Major Outages					
	Power Quality	Reduced Restoration Cost					
		Reduced Momentary Outages					
Environmental	Air Emissions	Reduced Sags and Swells					
		Reduced CO2 Emissions	YES	YES	YES	YES	YES
Security	Energy Security	Reduced SOx, NOx, and PM-2.5 Emissions	YES	YES	YES	YES	YES
		Reduced Oil Usage (not monetized)					

(Note: green cells are identified by the SGCT, red cells are additional)

Figure 211: Functions to benefit mapping of each case Sub-project



(Source: Irwin and Yinger, 2015)

Figure 212: Customer voltages with and without DVVC (October 17, 2014 to October 22, 2014)

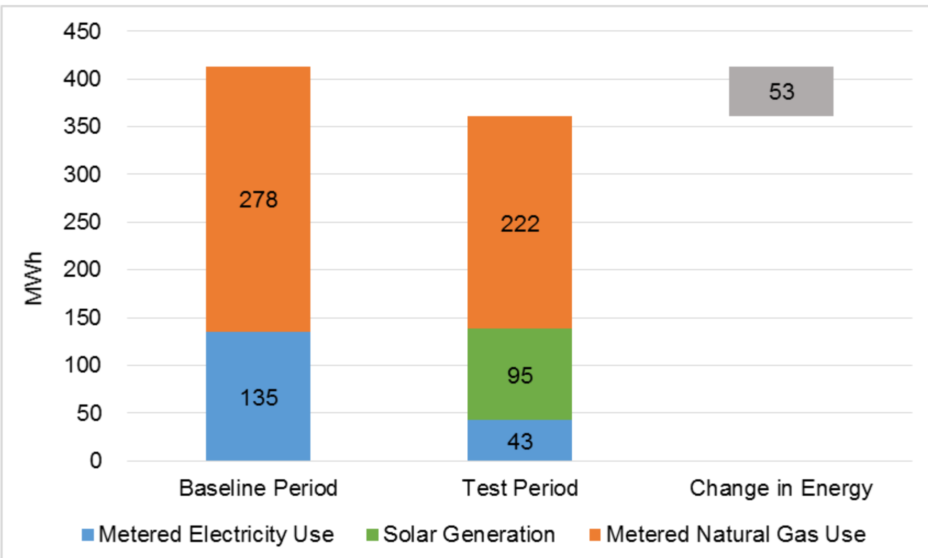
4.2. Benefits and Costs

Table 76 summarizes the estimated benefits for the three stakeholder groups shown. *Utility* benefits are reductions in the cost of providing service. This relates to any cost changes in generation or T&D. Showing benefits in this way is controversial because a regulated utility is unlikely to retain all of them, as some will be ultimately returned to customers via reduced future rates. In the case of California, deviations from expected revenues and fuel costs are explicitly tracked and mostly incorporated into future rates, although changes in other costs, as listed in Table 5, are less clear-cut. Nonetheless, since this exercise is intended to be a trial application of the SGCT, its usage is followed.

Table 76: Overview of stakeholders and impacted benefits in case sub-projects

	Utility	Consumer	Society
Economic	Deferred Generation Capacity Investments Reduced Ancillary Service Cost Reduced Congestion Cost Deferred Transmission Capacity Investments Deferred Distribution Capacity Investments Reduced T&D Equipment Maintenance Cost Reduced Electricity Losses	Reduced Electricity Cost	
Environment			Reduced CO_2 Emissions Reduced SO_x, NO_x, and PM-2.5 Emissions

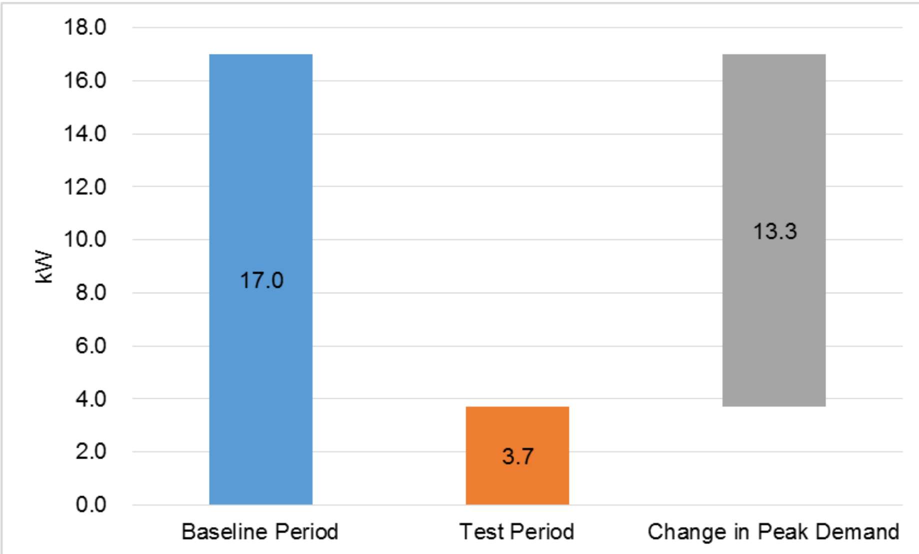
Consumers are mainly affected through changes in electricity and natural gas consumption due to efficient and/or smart equipment, feedback on electricity usage, substitution of grid electricity by on-site PV generation, energy storage, and DVVC. The SGCT evaluation method for *Consumer* benefits relies on the decrease in annual total electricity cost. For the 22 project homes, Sub-project 1 reduces the total electricity bill by 68 %, as shown in Figure 6. In addition, 69 % of total electricity consumption is met by PV generation, i.e. 95 MWh of 138 MWh. These effects result in a large reduction of coincident peak load, as shown in Figure 7. The total peak load of the 22 project homes drops from 17 kW in the Baseline period to 3.7 kW during the test period. However, electricity requirements grow by 3.4 MWh. The substitution of heat pump heating in the ZNE block homes and behavioral changes tend to increase electricity consumption, while PV and other measures reduce it. [43] As shown in **Figure 213**, energy savings are in largely in the form of reduced natural gas consumption, not electricity. In the baseline, 67% of the total energy consumed in three blocks of homes of the Sub-project 1 comes from natural gas energy usage, valuing electricity at its site equivalent. In the test period, natural gas consumption is decreased 20%, and total saving, after subtracting additional electricity, is equivalent to 53 MWh. A reduction in natural gas consumption results from energy efficiency measures affecting usage, especially the solar hot water systems and heat pumps, but also the ENERGY STAR clothes washers, which are one of the demand response devices used. Natural gas consumption was not reduced as much as these investments would suggest, a result that remains largely unexplained; however, warmer weather during the test period, compared to the baseline, did decrease space and water heating demand somewhat.



(Source: Irwin and Yinger, 2015)

Figure 213: Combined 22-home annual energy consumption (MWh)

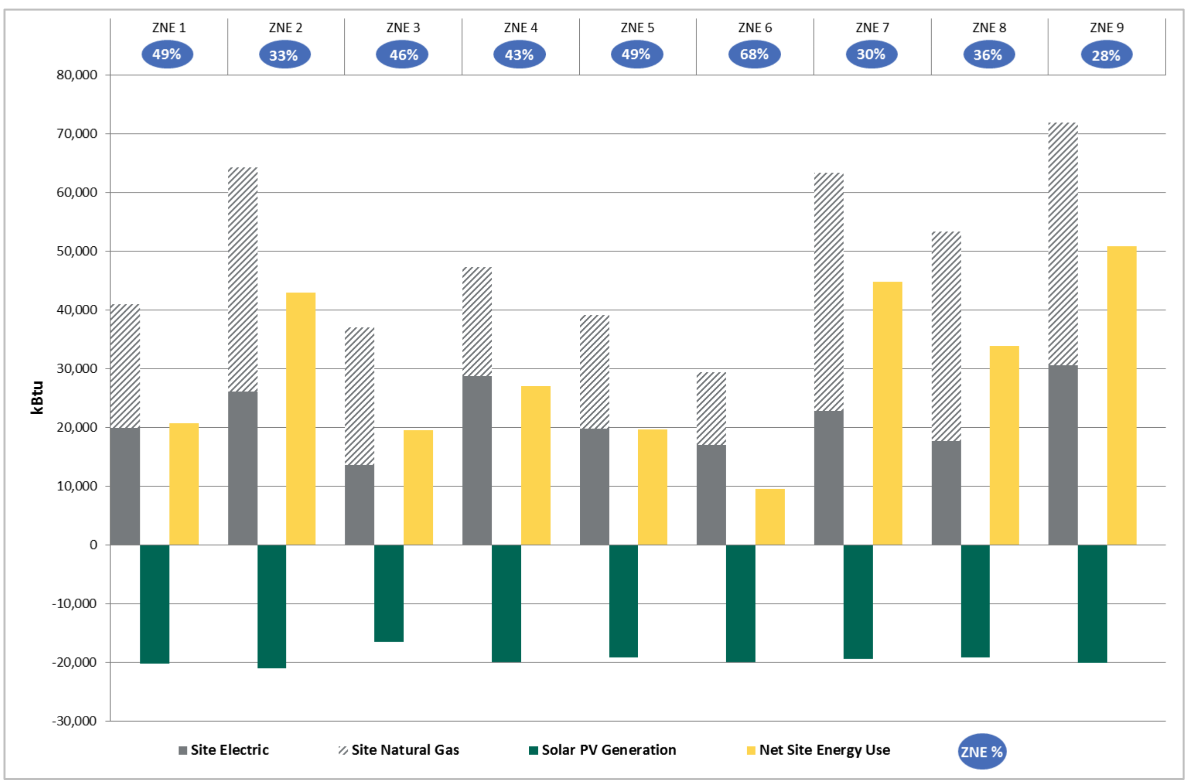
[43] In the calculation of energy saving, the following heat pump adjustment approach was used: (1) If there is no air conditioning use in the baseline (i.e., 2012), remove all heat pump use; (2) if there is air conditioning, remove November to February heat pump usage only. In addition, charging station usage and losses due to RESU are not included. To calculate source energy equivalent, EPA suggests one kWh of electricity from onsite solar PV generation offsets 3.14 kWh of natural gas source equivalent energy (Irwin and Yinger, 2015).



(Source: Irwin and Yinger, 2015)

Figure 214: Combined 22-home coincident peak (kW)

Figure 215 shows the ZNE status for homes in the ZNE Block based on site energy for a period of a year starting on November 1, 2013. The ZNE status represents a home's progress toward achieving ZNE. The ZNE status is equal to a home's solar PV generation divided by its total energy consumption (i.e., electricity and natural gas energy use). As an example, ZNE 1's ZNE status is 49%, which is equal to 20,153 kBtu (solar PV generation) divided by 40,882 kBtu (total energy consumption).



(Source: Irwin and Yinger, 2015)

Figure 215: ZNE Site Energy Status for ZNE Block Homes (November 1, 2013 to October 31, 2014)

SCE reported that the actual ZNE status of homes, measured in the test period, is nearly 50% below what the SCE team originally forecasted by using eQUEST simulation model[44] (see Figure 8). The difference is believed to result from technical assumptions in the calculations, such as using higher PV arrays and solar hot water capacities than installed, not including RESU and possible related efficiency losses in the analysis, and behavioral changes. In its prospective analysis, the SCE team assumed that the energy efficiency improvements and DR measures applied in each of three blocks are cost-effective, and the team sized the solar PV array to offset the remaining customer load. Using a RESU to store energy was not included in the original plan.

For Sub-Project 4, the 2.6 % energy savings rate demonstrated in these field experiments were applied to the seven circuits, which serve roughly 8300 customers, served from MacArthur substation.

Shaving of peak load would postpone, reduce, or even eliminate the need to install expensive generation and T&D capacity. In addition, peak load tends to drive delivery losses more than average load; thus, managing the peak, i.e., reducing maximum demand and flattening the load curve, leads to improvements in electricity delivery efficiency. All sub-projects investigated in this paper help decrease peak load. The technologies implemented in Sub-project 1 reduces the peak based on efficient appliance usage, demand shift, PV generation, and battery discharge at peak times. The 2 MW battery can be discharged at peak hours in Sub-project 3, and optimizing voltage/VAR control in Sub-project 4 also reduces the peak demand and the amount of T&D losses.

Benefits for the environment relate to CO_2 emissions' and other pollutants' damage costs. Estimation relies on physical quantification of the emissions and subsequently on their conversion to monetary costs, using California carbon and pollutant costs.[45] Increased consumer awareness of electricity use and decrease in electricity consumption achieved through improved efficiency of smart appliances reduces both the electricity generation required and the associated emissions. PV panels provide electricity without CO_2 emissions, contributing to the reduction of overall CO_2 emissions of Sub-project 1. Electricity reductions based on improved efficiency and energy conservation voltage reduction in Sub-project 4 reduce generation and associated emissions. There is also potential for emissions reductions by decreasing peak, although calculation of emission reductions in the EPRI method is based only on consumption reduction and excludes peak reduction.

NPVs for total costs and benefits of each Sub-project are summarized in **Table 77**. Results appear to be significantly different among the sub-projects analyzed here. The overall B/C ratio of Sub-project 1 is 0.1 (with -$3.6M annual net benefits), while Sub-Projects 3 and 4 have B/C ratios of 2.5 (with $1.3M annual net benefits) and 12.9 (with $6.8M annual net benefits), respectively. Moreover, Figure 7 shows present net benefits cumulatively over time, i.e., the cost of each year is the sum of that year's value plus all previous years. As can be seen, net benefits are far from turning positive in the investigation period for Sub-project 1, i.e. the blue line is always strongly and increasingly negative, Sub-project 3 turns to positive starting from 2019, and Sub-project 4 turns positive starting in 2013, i.e. even before project deployment is completed.

These SGCT results indicate that Sub-project 1 is not economically attractive at current project performance and expenditures. The cost of Sub-project 1 needs to be about 91 % lower to achieve a B/C ratio greater than 1, i.e. breakeven. Nonetheless, a low B/C ratio is acceptable for a purely technology demonstration project, as Sub-project 1, in which most of the equipment installed is at an emerging stage requiring a steep learning curve. The ZNE Homes are very much a technology demonstration, and were not intended to reach breakeven. Recent announcements of residential battery cost reductions underscore the early vintages of the equipment installed in the 22 homes (Tesla, 2015). Nonetheless, B/C ratio results are still valuable for providing suggestive estimates of the cost-performance gap between current generation technology and breakeven, or viable commercialization. The EPRI method does not include uncertainty on cost reductions over time, which would be a welcome extension

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[44] For more information on eQUEST model, http://www.doe2.com/equest/

[45] We used $12/t$CO_2$ based on the average California carbon price in 2014 (http://calcarbondash.org/), $3000/tNOx and $250/tSOx, based on SGCT default data for Western Electricity Coordinating Council (Navigant, 2011).

of these results. In addition, performing a separate B-C analysis for each technology group (i.e., demand response, energy efficiency measures, energy storage, and PV panels) could provide a better understanding on B/C ratio. Cost of some of the technologies such as energy storage dominates the overall cost of Sub-project 1 and prevents some other technologies from showing their benefit performances. For example, even though the demand response technologies could generate much higher B/C ratio when evaluated separately, it becomes invisible when combined with other group of technologies in the analysis. However, such analysis requires more detailed and disaggregated data, which were not available in this part of study.

On the other hand, Sub-Projects 3 and 4 appear to be economic, the latter strongly so. The result for Sub-project 4 parallels SCE's experience, and the company is already moving to widespread deployment. Sub-project 3 results suffer from some methodological limitations. For example, factors like charging-discharging inefficiencies and auxiliary energy use are not available. Importantly, the analysis excludes the energy capacity and considers only storage power. This causes overestimates of utility capacity deferrals from batteries because any storage system may not have sufficient energy capacity to sustain its maximum power level long enough to achieve an equivalent lower peak.

Table 77: Total costs and benefits of each Sub-project (in NPV)

	Sub-project 1	Sub-project 3	Sub-project 4
NPV (of annual cost)	$(3.92M)	$(0.85M)	$(0.59M)
NPV (of annual benefit)	$0.34M	$2.14M	$7.58M
NPV (of annual net benefit)	$(3.59)M	$1.30M	$6.99M
B/C Ratio	0.1	2.5	12.9

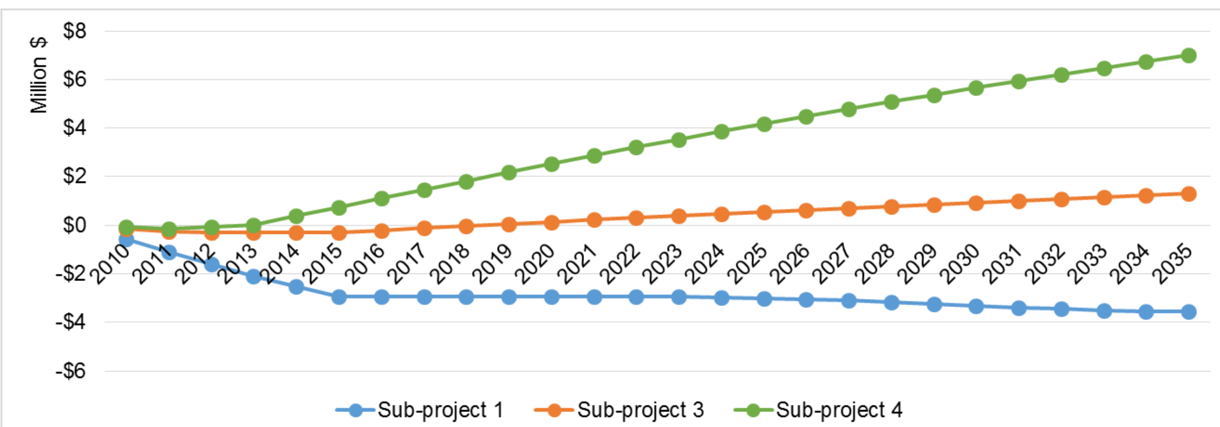

Figure 216: Cumulative net present benefits of each Sub-project

Figure 216 and **Figure 217** provide the breakdown of benefits. In both Sub-Projects 1 and 4 more than 80 % of the benefits are from reduction of electricity cost, which is a *Consumer* benefit,. For Sub-project 3, almost 70 % of the benefits come from deferral in generation capacity investments, while 25 % derives from reduction in losses, with the remaining benefit from T&D deferral. There is no beneficial stakeholder other than *Utility* in this Sub-project (see Figure 9); however, many would argue the EPRI method treats some of the *Consumer* benefits as *Utility* benefits, as explained above. For example, if energy procurement cost and operating cost are reduced, or capital investment is deferred, this saving may ultimately accrue to customers through subsequent reduced rates.

In addition, energy storage technologies (i.e., RESU and CES) in Sub-project 1 do not contribute reduction in electricity cost benefit, and they are responsible for 57% of the total project cost. Thus, it is beneficial to perform a separate sensitivity analysis and calculate B/C ratio by excluding energy storage. Since the benefits are highly dominated by reduction of electricity cost, the error margin in benefit calculation would be very small.

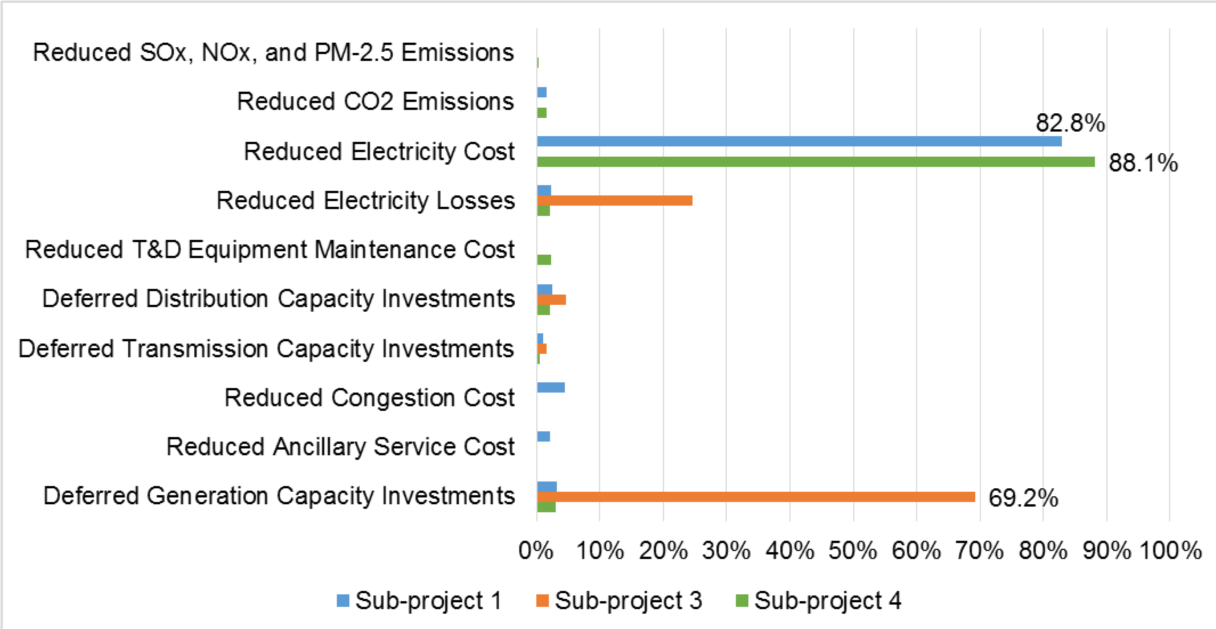

Figure 217: Distribution of benefits in each Sub-project

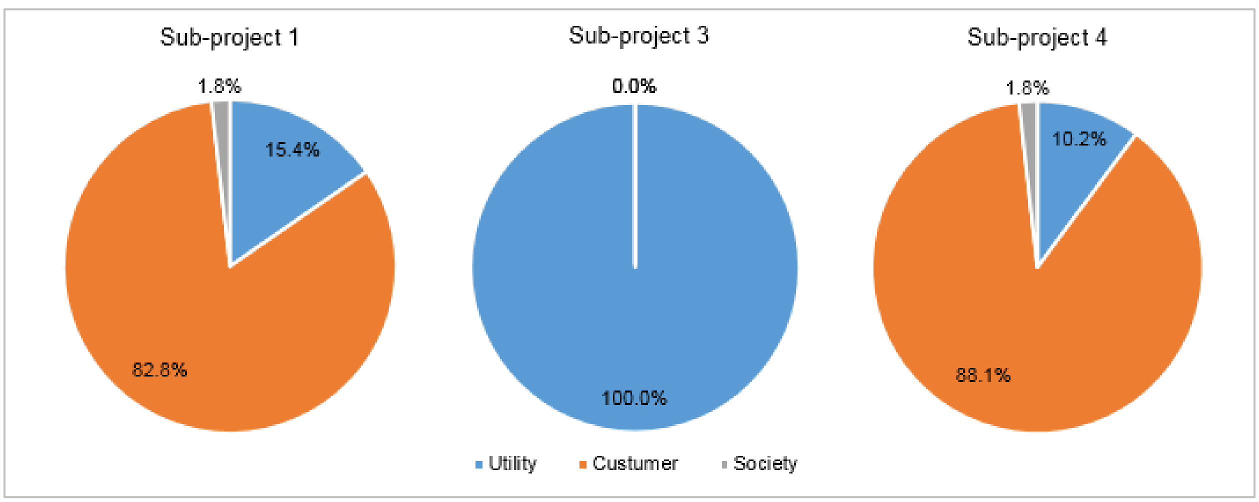

Figure 218: Distribution of benefits to stakeholders in each Sub-project

4.3. Sensitivity Analysis

Figure 219 compares the cumulative net present benefits of sub-project 1 with and without energy storage technologies and also heat pumps. Heat pump is the second expensive technology in the project, listed after energy storage technologies. As can be seen, net benefits are improved when the energy storage technologies are excluded from the analysis with or without heat pump. However, they are still negative throughout the computation horizon. In addition, the results showed that the B/C ratio increased to 0.2 when only energy storage technologies are excluded, and 0.3 when energy storage technologies and a heat pump are together excluded, which are still very low to be an economically positive demonstration project.

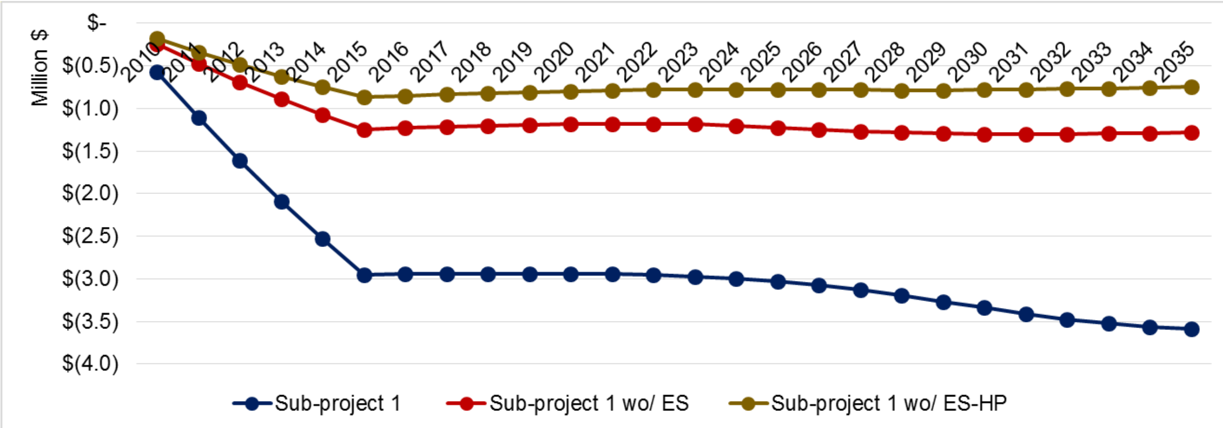

Figure 219: Cumulative net present benefits of Sub-Project 1 compared to the scenarios 'without Energy Storage Technologies' and 'without Energy Storage Technologies and Heat Pump'
(Sub-Project 1 wo/ ES represents sensitivity run without including Energy Storage Technologies in the analysis, Sub-Project 1 wo/ ES-HP represents sensitivity run without including Energy Storage Technologies and Heat Pumps in the analysis

The sensitivity of B-C analysis outcomes to variations in key variables and parameters is critical to any economic analysis involving uncertain variables. The discount rate, for example, typically has a significant impact on the assessment of smart grid projects, since costs are incurred predominantly at the beginning of the scenario while benefits may be sustained over the long-term. **Figure 220** and **Table 78** illustrate the sensitivity of each case Sub-project to discount rate. Naturally, the results show that the higher the discount rate, the lower the NPV. Nonetheless, note that results are fairly robust and all NPVs are negative and all Sub-project 1 B/C ratios are close to zero regardless of the discount rate, while Sub-Projects 3 and 4 always generate positive NPVs and B/C ratios above breakeven.

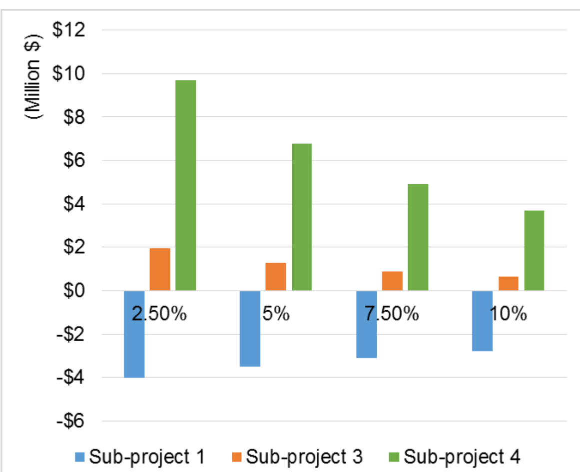

Figure 220: Sub-project NPVs with varying discount rates

Table 78: B/C ratios with varying discount rates

	2.5%	5%	7.5%	10%
Sub-Project 1	0.11	0.09	0.07	0.06
Sub-Project 3	3.07	2.53	2.16	1.92
Sub-Project 4	14.42	12.94	11.00	9.61

5. Discussion

This example case analysis and the other international work summarized below show the SGCT has only limited ability to effectively compare B-C analysis results of international smart grid demonstration projects.

5.1. General limitations of the SGCT

Some of the functions identified are not necessarily mapped to the benefits listed in the SGCT as mentioned earlier. For example, the tool lists *Optimized Generator Operation* as a benefit from the *Distributed Production of Electricity* function for Sub-project 1. While distributed generation assets such as PV panels might allow utilities to remotely operate distributed generation systems to dispatch a more efficient mix of generation (Navigant, 2011), this seems unlikely in practice. Similarly, the *Automated Voltage and VAR Control* function is never linked to *Reduced Electricity Cost* benefit, while field experiments show a notable potential decrease in electricity bills, and the results in Section 5 reflect this large benefit. The NPV of Sub-project 4 is about $7M, and 88 % of it comes from *Reduced Electricity Cos*t. Similarly, there may be some other benefits that are not listed but should be included in a thorough B-C analysis. For example, batteries are not allowed to generate a reliability benefit, when their provision of emergency power is clearly one of their desirable features. In other words, that the set of available benefits incorporated in the SGCT is necessarily limited causes a *de facto* bias, that is, the set is likely to be incomplete.

The SGCT is intended to be generally applicable to highly diverse projects, and consequently it is inevitably too generic to address the subtleties of any particular one. Variations in the nature and the scope of the ISGD project are not well considered, and indeed all projects are effectively evaluated on the same criteria set. Because the tool is locked and considered proprietary, no customization specific to a particular project is possible. This limitation places a heavy burden on the user to design exogenous analysis of any benefits and mechanisms whose exclusion is suspected to be a significant limitation, particularly so for international applications.

Among the other analysis limitations that emerged in the analysis of the ISGD project are the following:

- By including only the kW capacity of energy storage, the model overstates the value of capital deferrals for energy storage. Battery discharge cannot necessarily lower peak by the full discharge power because it may not store enough energy to sustain this reduction throughout high load periods. In other words, models should consider both the power and energy constraints of storage.
- Efficiency parameters for energy storage systems are not included in the model. Thus, the SGCT is not capable of tracking these losses.
- Tariff representation is basic, without time differentiation of energy or demand charges. This limitation can have a significant effect on the attractiveness of technologies. Customer benefits could be greater by including time-based rates.
- Treatment of uncertainty is limited, and notably does not allow sensitivity analysis on some key variables, such as project capital cost, and some project costs are not included at all, e.g. installed equipment maintenance and operational costs. Possible price reduction due to future technological change is also uncertain and not considered in the EPRI method or the SGCT.
- Modeling of costs is inadequate because no failure probability or equipment lifetime is possible.
- Nothing on scaling up of projects is provided; in other words, the project can be analyzed only in isolation without consideration of its likely merits in wider scale deployment.
- Categorization of benefits under stakeholders is not necessarily correct, although a correct allocation is a non-trivial task. The EPRI method treats some of the *Consumer* benefits as *Utility* benefits, since they accrue initially to the distribution company. All cost reductions in operational, maintenance and capital investments are considered *Utility* benefits. Over time, as rates are adjusted to match the changing cost structure, customers may ultimately benefit, whether or not they are project participants.

- Nothing on possible reduction of benefits due to aging of physical infrastructure or software, or unexpected damage, is available.
- Calculation of emission reduction is based only on consumption reduction; however, there is also potential for emissions reductions by decreasing peak.
- The discount rate is constant. Some studies in the literature suggest using a lower rate to discount costs and benefits that accrue decades in the future.

Finally, it should be repeated that the balance between consistency and wide applicability is not easily struck, and any tool intended for such a wide range of projects included in the SGIG Program and the SGCP will necessarily not satisfy the detailed needs of any individual project.

5.2. Application of the SGCT to the Tianjin Eco-City

Smart Grid projects are being demonstrated worldwide, and this study has been conducted in the context of U.S.-China cooperation on energy and climate change. The U.S.-China Joint Announcement on Climate Change released on 21 November 2014 specifically mentions smart grid among the additional measures planned to strengthen and expand cooperation. Existing research vehicles, in particular the CCWG, the U.S.-China Clean Energy Research Center, and the U.S.-China Strategic and Economic Dialogue will be utilized to foster coordination and cooperation between the countries (White House, 2014).

> "**Demonstrating Clean Energy on the Ground**: Additional pilot programs, feasibility studies and other collaborative projects in the areas of building efficiency, boiler efficiency, solar energy and smart grids."

The 31 km^2 Tianjin Eco-city project, which is planned to ultimately accommodate 350,000 residents, was selected as one of the two demonstration projects from China to be part of the CCWG smart grid B-C analysis demonstration projects. The Sino-Singapore Eco-city is located in Binhai New Area, close to the Economic-Technological Development Area and the Port of Tianjin.

This project integrates renewable energy, automatic control, microgrid and energy storage systems, intelligent building, combined heating, cooling and power, geothermal heating, cool storage, and other smart grid technologies to achieve efficient use of energy. The CCWG Benefit Subgroup is collecting data to complete a B-C analysis of the Tianjin Eco-city project and compare benefits approaches and results for projects in China and the U.S. However, the SGCT is designed for assessing U.S. smart grid projects, and the assumptions are mainly based on the U.S. situation. International application of this approach will likely focus on using the EPRI method embodied in other modes, as the example below shows.

5.3. Application the EPRI Method by the Joint Research Center

The European Commission's Joint Research Centre (JRC) has more than 450 active smart grid projects with more than 3 billion EUR invested since 2002. In Europe, JRC proposed an assessment framework for smart grid projects which includes defining boundary conditions, identifying costs and benefits, and performing sensitivity analysis (Giordano et al., 2012). This guidance also includes the costs and benefits derived from broader social impacts such as security of supply, consumer participation, and improvements to market performance, etc. JRC adapted the EPRI method to the European context and made it more relevant by using project specific factors such as geography, typology of consumers, and regulations. A new report discussing the first application of B-C analysis to the City of Rome has recently been released (Vitiello et al., 2015).

Other international applications and comparisons would enable further in-depth discussion of the methods and tools for B-C analysis of smart grid projects, and approaches to result dissemination. The findings from doing such analysis and comparison will help to identify the best practices and industrial trends for implementing smart grid technologies and facilitate policy making to scale up smart grid deployment.

6. Conclusion

This exercise was conducted within a broader bilateral effort to compare the benefits of a two U.S. microgrid projects to Chinese cohorts, and to demonstrate the methods developed and applied in both countries. This first U.S. analysis is intended to demonstrate the capabilities of the SCGT via an example analysis of three ISGD subprojects, which are the type of ARRA project for which the tool was developed Initial results show significant benefits potential for two technologies, distribution voltage and VAR control and utility-scale batteries, while the third 22-residence ZNE home demonstration inspired by California's 2020 residential energy efficiency standard falls far short of economic breakeven at the current stage of costs and technology performance. It should be emphasized that the ZNE homes subproject was not based on economic objectives but was rather intended to be a technology demonstration. Consequently, the cost of the installed equipment was very high, and the energy savings, especially of natural gas use, are disappointingly small. Based on this limited experience, the strengths of the SGCT are its simplicity and explicit and transparent mappings, its clear definitions of technologies, and access to the formulas behind them in the literature. Its weaknesses are actually the other side of the same coin, namely its inflexibility and poor applicability to projects outside straightforward technology deployment or outside U.S. conditions. The model is locked and considered partially proprietary by Navigant Consulting Inc., which is a major impediment to its broad application, especially internationally.

Acknowledgements

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Smart Grid Assets	Functions														
	Delivery												Use	Other	
	Fault Current Limiting	Wide Area Monitoring, Visualization, and Control	Dynamic Capability Rating	Power Flow Control	Adaptive Protection	Automated Feeder and Line Switching	Automated Islanding and Reconnection	Automated Voltage and VAR Control	Diagnosis & Notification of Equipment Condition	Enhanced Fault Protection	Real-Time Load Measurement & Management	Real-time Load Transfer	Customer Electricity Use Optimization	Storing Electricity for Later Use	Distributed Production of Electricity
Advanced Interrupting Switch										•					
AMI/Smart Meters								•			•		•		
Controllable/regulating Inverter							•	•							
Customer EMS/Display/Portal													•		
Distribution Automation					•	•	•	•				•			
Distribution Management System			•		•	•	•	•			•	•			
Enhanced Fault Detection Technology										•					
Equipment Health Sensor			•						•						
FACTS Device				•											
Fault Current Limiter	•														
Loading Monitor			•						•			•			
Microgrid Controller							•								
Phase Angle Regulating Transformer				•											
Phasor Measurement Technology		•	•	•	•		•	•		•					
Smart Appliances and Equipment (Customer)													•		
Software - Advanced Analysis/Visualization		•	•												
Two-way Communications (high bandwidth)		•			•	•	•	•			•	•			
Vehicle to Grid Charging Station													•		
Very Low Impedance (High Temperature Superconducing) cables				•											
Distributed Generator (diesel, PV, wind)								•							•
Electricity Storage device (e.g., battery, flywheel, PEV etc)								•						•	

Figure A 1 Smart grid assets and functions considered in the EPRI methodology and listed in the SGCT

Benefits			Functions														
			Fault Current Limiting	Wide Area Monitoring, Visualization, and Control	Dynamic Capability Rating	Power Flow Control	Adaptive Protection	Automated Feeder and Line Switching	Automated Islanding and Reconnection	Automated Voltage and VAR Control	Diagnosis & Notification of Equipment Condition	Enhanced Fault Protection	Real-Time Load Measurement & Management	Real-time Load Transfer	Customer Electricity Use Optimization	Storing Electricity for Later Use	Distributed Production of Electricity
Economic	Improved Asset Utilization	Optimized Generator Operation		•												•	•
		Deferred Generation Capacity Investments													•	•	•
		Reduced Ancillary Service Cost		•						•			•		•	•	•
		Reduced Congestion Cost		•	•	•									•	•	•
	T&D Capital Savings	Deferred Transmission Capacity Investments	•	•	•	•									•	•	•
		Deferred Distribution Capacity Investments			•								•	•	•	•	•
		Reduced Equipment Failures	•		•						•	•					
	T&D O&M Savings	Reduced T&D Equipment Maintenance Cost									•						
		Reduced T&D Operations Cost						•		•							
		Reduced Meter Reading Cost											•				
	Theft Reduction	Reduced Electricity Theft											•				
	Energy Efficiency	Reduced Electricity Losses				•				•			•	•	•	•	•
	Electricty Cost Savings	Reduced Electricity Cost													•	•	•
Reliability	Power Interruptions	Reduced Sustained Outages					•	•	•		•	•	•			•	•
		Reduced Major Outages		•					•				•	•			
		Reduced Restoration Cost					•	•	•		•	•	•				
	Power Quality	Reduced Momentary Outages										•				•	
		Reduced Sags and Swells										•				•	
Environmental	Air Emissions	Reduced CO_2 Emissions				•		•		•	•		•	•	•	•	•
		Reduced SO_x, NO_x, and PM-10 Emissions				•		•		•	•		•	•	•	•	•
Security	Energy Security	Reduced Oil Usage (not monetized)						•			•		•			•	
		Reduced Widescale Blackouts		•	•												

Figure A 2 Smart grid functions and benefits considered in the EPRI method and listed in the SGCT

Table A 1 Inputs used in SGCT calculations

Input Name	Value	Source
Price of Capacity at Annual Peak	\$50.17/kW-year	SCE, 2014
Ancillary Services Cost	\$5/MWh	LBNL Assumption
Congestion Cost	\$10/MWh	LBNL Assumption
Capital Carrying Charge of Transmission Upgrade	\$310-370K/MVA	SCE expert opinion
Capital Carrying Charge of Distribution Upgrade	~\$2.1M over 3 years/Distribution circuit	SCE expert opinion
Transmission Investment Time Deferred	1.5 (in baseline); 6 (in Test period)	LBNL Assumption
Distribution Investment Time Deferred	1.5 (in baseline); 6 (in Test period)	LBNL Assumption
Total Distribution Equipment Maintenance Cost	~\$130K/year/new circuit ~\$120K/year/new circuit	LBNL Assumption
Distribution Losses	4.8%	SCE expert opinion
Transmission Losses	2.7%	SCE expert opinion
Average Price of Wholesale Energy	\$52.22/MWh	SCE expert opinion
Average Residential Electricity Cost	\$0.17/kWh	SCE expert opinion
CO2 factor	0.28tCO2/MWh	2010 Carbon dioxide for WECC California (from eGRID; total output emissions rate)
SOx factor	0.000077tSOx/MWh	2010 Sulfur dioxide for WECC California (from eGRID; total output emissions rate)
NOx factor	0.000184tNOx/MWh	2010 Nitrogen dioxide for WECC California (from eGRID; total output emissions rate)
Value of CO2	\$12/tCO2	California carbon price in 2014 (http://calcarbondash.org/)
Value of SOx	\$520/tSOx	SGCT default data for Western Electricity Coordinating Council (Navigant, 2011)
Value of NOx	\$3000/tNOx	SGCT default data for Western Electricity Coordinating Council (Navigant, 2011)
Efficiency of DBESS	90%	Based on SCE experts
Energy savings from DVVC	2.6%	Irwin and Yinger, 2015

Table A 2 Technology cost structure

Technology	Unit Investment Cost ($/unit)	Unit installation Cost ($/unit)	Incremental Cost Assumption	# of Assets Acquired	# of assets in the project
Energy Star Smart Refrigerator	$ 2,229.0	$ 706.4	40% of total cost* is used	23	21
Energy Star Smart Clothes Washer	$ 1,288.0	$ 706.4	40% of total cost* is used	22	20
Energy Star Smart Dishwasher	$ 1,357.0	$ 706.4	40% of total cost* is used	24	22
Programmable Communicating Thermostat	$ 118.0	$ 131.2		36	31
Home Energy Management System (home EMS)	$ 118.0	$ 808.6		27	22
In-Home Display	$ 118.0	$ 8,083.6		22	22
Central Air Conditioning Replacement (Heat Pump)	$ 4,200.0	$ 26,314.9		11	9
Lighting Upgrades	$ 1,262.5	$ 518.2	50% of the investment cost is used	700	700
Insulation	$ -	$ 1,666.7		9	9
Efficient Hot Water Heater	$ 2,000.0	$ 33,252.0	40% of total cost* is used	2	2
Domestic Solar Hot Water and Storage Tank	$ 2,000.0	$ 4,101.0		7	7
Solar Panels for Water heaters	$ 2,312.0	$ 5,591.0		7	7
Low Flow Shower Heads**	$ 118.0	$ 808.6		9	9
Plug Load Timers**	$ 118.0	$ 808.6		22	22
Community Energy Storage Unit	$ 22,865.1	$ 3,061.6		1	1
Residential Energy Storage Unit with Smart Inverter	$ 61,300.0	$ 5,358.8		18	14
CES By Pass Switch	$ 2,237.1	$ 3,061.6		1	1
CES - Intelliteam DEM Controller	$ 10,207.1	$ 3,061.6		1	1
3.2 – 3.6 kW Solar PV Panels	$ 18,486.8	$ 18,253.3		113	113
3.9 kW Solar PV Panels	$ 9,816.0	$ 9,692.0		108	108
DBESS and equipment	$ 642,477.0 (total unit cost)			1	1
DVVC license and equipment	$ 359,266.0 (total unit cost)			1	1

Source: SCE experts, *total cost = unit investment cost + unit installation cost, ** There was no available cost data. Costs of Home Energy Management System (home EMS) are repeated for Low Flow Shower Heads and Plug Load Timers

Table A 3 Technology lifetime

Measure Name	Lifetime (years)	Source
Energy Star Smart Refrigerator	14	Demesne, 2010
Energy Star Smart Clothes Washer	14	Demesne, 2010
Energy Star Smart Dishwasher	10	Demesne, 2010
Programmable Communicating Thermostat (PCT)	30	InterNachi, 2015
Home Energy Management System (home EMS)	10	LBNL Assumption
In-Home Display	10	LBNL Assumption
Central Air Conditioning Replacement (Heat Pump)	12	Zogg, 2014
Lighting Upgrades	13	BTP DOE, 2015
Insulation	whole project assessment time (i.e., 25 years)	Diez, 2014
Efficient Hot Water Heater	12	Lowe’s, 2015
Domestic Solar Hot Water and Storage Tank (SHW)	30	Home Energy Saver, 2015
Solar Panels for Water heaters	20	Energy Star, 2015
Low Flow Shower Heads	30	InterNachi, 2015
Plug Load Timers	10	Mallery, 2013
Community Energy Storage Unit	10	Schoenung, 2011
Residential Energy Storage Unit with Smart Inverter	15	Schoenung, 2011
CES By Pass Switch (CES_b)	30	Mallery, 2013
CES - Intelliteam DEM Controller	15	InterNachi, 2015
3.2 – 3.6 kW Solar PV Panels	30	Strecker, 2011
3.9 kW Solar PV Panels	30	Strecker, 2011
DBESS and equipment	15	LBNL Assumption, based on Schoenung, 2011
DVVC license and equipment	15	SCE expert opinion

Appendix 12: HAN Communications Study

During the ISGD project's M&V period, the team observed a number of anomalies in the communications between the various HAN devices and the AMI meters. One of the primary curiosities was that the HAN component performance was inconsistent from home to home and from street to street. The components worked well in some homes and failed consistently in others. To better understand these observations, a few members of the project team went into the field to gather relevant information that could help to explain these issues.

This field-work was performed by the engineers from SCE's Grid Edge Solutions lab. The team visited 13 of the 22 project homes to measure the radio frequency (RF) link quality between the respective homes' meter and HAN devices. The team also collected ZigBee communication diagnostic data to observe communication between all the devices, including mesh routing among ZigBee devices and the measured distances between the meter and HAN devices within each respective home. Using a variety of signal strength measuring devices, the team collected signal information from various HAN components and from the AMI meters in all 13 of the 22 homes visited.

The team prepared a report that provides details on the performance of the HAN devices, specific results from each of the components at each of the homes, and information about how, in some homes, the engineering team changed or added components and re-measured signal characteristics and strength in the new component architecture. The results of the study show:

1. ZigBee SEP 1.x communications from the meter to EVSE, RESU and Aztech in all 22 homes had stable communications during the M&V period (July 2013 to June 2015).
2. There was a meter firmware over-the-air upgrade (SR 3.7 to SR 3.9) that occurred between 4/3/14 and 4/14/14 across all 22 homes. The upgrade did not affect the meter communications to EVSE, RESU or Aztech. However, the upgrade affected the meter-to-GE nucleus communications. Homes on two streets, the CES and RESU blocks (totaling 12 project homes) dropped communications between the meter and the GE nucleus. The nine homes on the ZNE block were not affected and the meter-to-GE nucleus communications continued without issue.
3. Based on lab measurements and measurements within the customer homes, Wi-Fi did not appear to be a major source of disruption for the homes' ZigBee communications.
4. When the nucleus disconnected from the meter, the loss of communication typically took place at the ZigBee Application Layer. However, the Nucleus maintained its communication with the meter at the network layer.
5. This 13-home study indicates that power cycling the Nucleus in the homes on the RESU and CES Blocks caused the Nucleus to rejoin to the meter. However, within approximately three days the Nucleus dropped from meter.
6. GE reported that there were memory leakage issues with the Nucleus firmware that could result in Nucleus application layer problems. This could result in the Nucleus dropping from meter that the team observed.
7. The study was unable to identify conclusively the root cause of the Nucleus-meter communications issues.

The team identified three categories of recommendations for future improvements:

1. Test tools and testing procedures
2. HAN device selection
3. Communication Technologies.

Test tools and Testing Procedures

Based on test and experiment results, the following testing functionality is desirable:

- Add built-in function to ping HAN devices periodically using the Itron Collection Engine. For example, automate Collection Engine to ping a HAN device every 15 minutes over the following 72 hours.
- Store RSSI from Collection Engine pings of HAN devices as a parameter in the meter event log.

- Add capability to meter configuration to report HAN join and rejoin in meter event log.
- Create robust remote monitoring system and storage to sniff ZigBee packets inside the home (upgraded Wesbox).
- Perform a pre-deployment test in the lab with the HAN devices to ensure ZigBee mesh routing is working properly.
- Perform a detailed lab regression test for meter firmware upgrade. This should include single HAN device functionality tests as well as an interoperability test with all HAN devices connected to the meter.

HAN device selection

ZigBee technology is used in all current Itron SmartConnect meters. HAN devices selected were based on ZigBee SEP 1.x to be compatible with Itron meters in the ISGD project. Here are some recommendations:

- Work with products that are supported and upgraded through the entire project.
- Use latest firmware version. In the case of the Nucleus, firmware 3.9 was preferable as the newest version and should have been updated in all homes earlier in the project.

Communication Technologies

RF transmit power of a wireless device dictates how far the signal can travel - ZigBee HAN devices used in ISGD as well as the Itron meter have a transmit power of about 20 dBm (100 mW). Based on previous SCE studies inside single-family homes, a distance of 30 ft. from the meter to a ZigBee HAN device produces 90% or better message success rate. Beyond 30 ft. and up to 60 ft., some devices, depending on their locations, will have less than 90% message success rate.

HAN devices are allowed to have up to 30 dBm (1 W) power output, which is the maximum allowable power in the free license 2.4 GHz band. In this case, a meter with 30 dBm power output can penetrate longer distances with high fidelity signal inside the home, resulting in better signal coverage in the homes.

The other factor known to effect signal reception for ZigBee is Antenna diversity. Based on Packet Success Rate (PSR) tests done inside the home as well as outside near the meter, it was evident that very small spatial variation could result in PSR differences. This means a small change of location- as much as 2.5 inches- of HAN device could produce very different signal quality. Devices that have multiple antennae can potentially obtain better reception inside the home independent of placement location.

Summary Recommendation

- To obtain better signal coverage inside the home, use devices, especially the meter, with transceiver output power close to the allowable 30 dBm.
- Use devices with antenna diversity that can improve signal reception inside the home.

Appendix 13: Smart Appliance Demand Response Field Test

To improve the team's understanding of how the various smart appliances in the field respond to DR signals, a few members of the team performed a series of tests on the refrigerator, clothes washer, and dishwasher at the RESU 5 project home on February 27, 2015. The team was present during the entire testing period and developed findings from measurements from the TrendPoint monitor and direct observations of each appliance's performance. The team was able to access the TrendPoint measurements while in the field, allowing them to observe how the appliances responded as they issued the DR commands.

Table 79 summarizes the responses of each smart appliance to the DR events using the four price levels. For each of the three appliances, the lab testing process recorded the energy use during normal operations and during a DR event with price-level 3 and price-level 4 commands.

Table 79: Smart Appliance Responses to Demand Response Event Signals

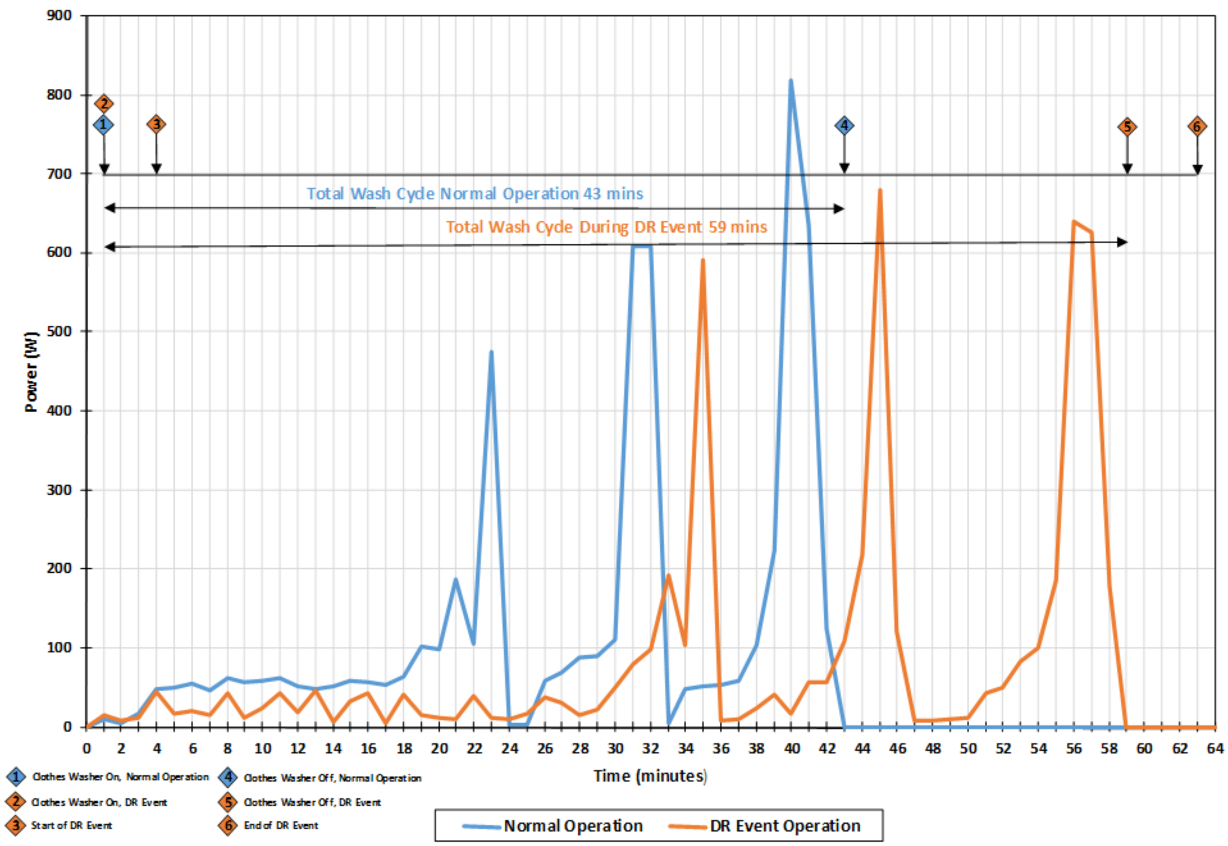
	DR Price Level			
	Low (Level 1)	Normal (Level 2)	High (Level 3)	Critical (Level 4)
GE Appliances	Appliance Response			
Refrigerator			Freezer setpoint temperature raises to 5°F causing the refrigeration components to turn off for a time	Freezer setpoint temperature raises to 5°F causing the refrigeration components to turn off for a time
			Defrosts are delayed	Defrosts are delayed
			Anti-sweat heaters (ASH) are disabled	Anti-sweat heaters (ASH) are disabled
			Special cooling functions are disallowed (fast freeze, quick ice, turbo cool, energy saver, beverage center fan, and special ice mode)	Special cooling functions are disallowed (fast freeze, quick ice, turbo cool, energy saver, beverage center fan, and special ice mode)
				Mandatory 10 minute off time for compressor and fans
Clothes Washer			Delay the start of a wash cycle until the event has cleared (does not affect a wash in progress	Delay the start of a wash cycle until the event has cleared (does not affect a wash in progress
				Reduce duty cycle of wash motor and heater to 50%
Dishwasher			Delay the start of a wash cycle until the event has cleared (does not affect a wash in progress)	Delay the start of a wash cycle until the event has cleared (does not affect a wash in progress)
				Turn heated dry off

All of the appliances were connected to the GE Nucleus using their respective ACM. The team conducted the tests by issuing commands through the meter, which then routed the signal through the Nucleus to the appliances. The team also performed the DR tests with the appliances directly connected to the meter ZigBee network, thereby bypassing the Nucleus. The appliances acted the same regardless of the path of the DR command.

Clothes Washer Tests

The clothes washer behaved as expected, similar to the price-level 4 lab tests. The team measured a power level decrease of approximately 100 watts and observed an increase in wash time of about 50% due to the motor operating at 50% duty cycle as shown in **Figure 221**.

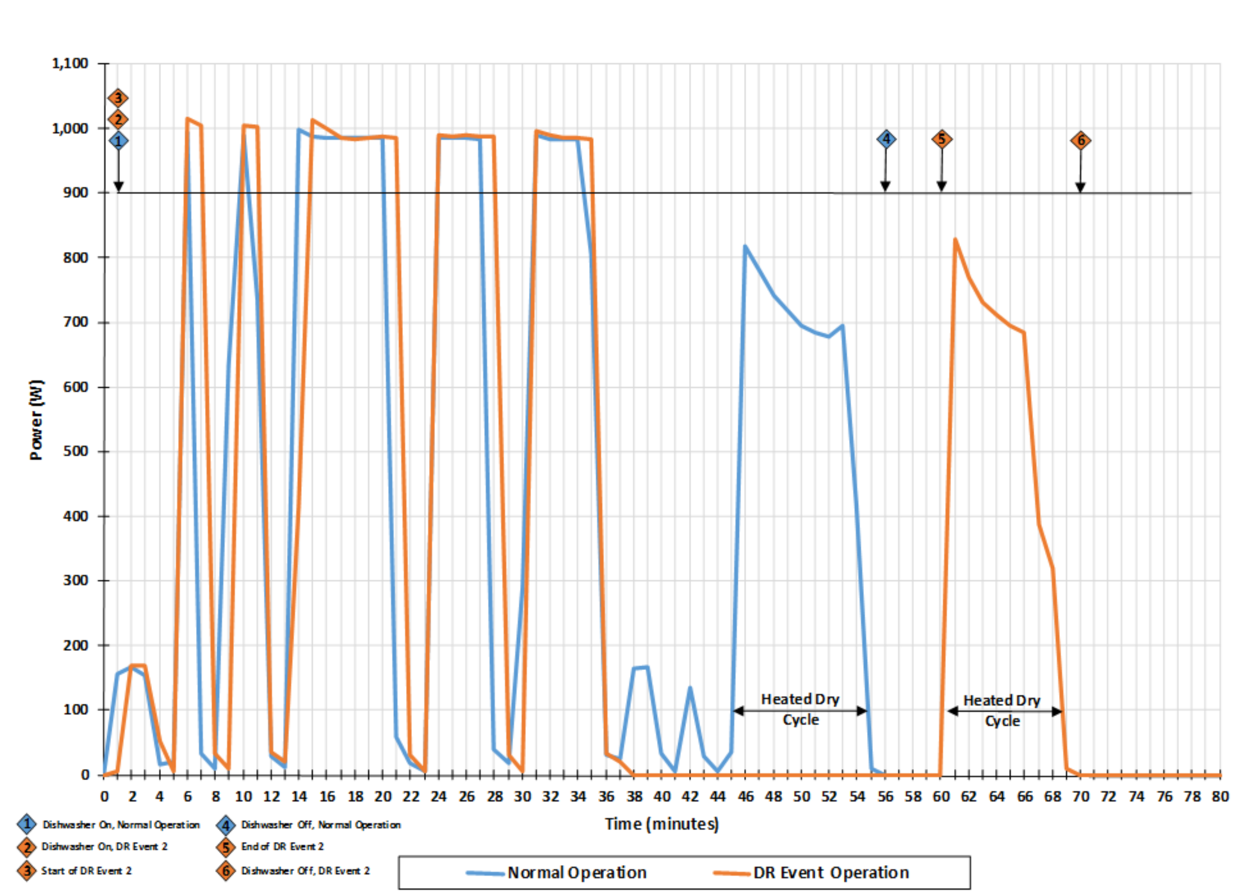
Figure 221: Clothes Washer Field DR Event



Dishwasher Tests

The dishwasher behaved as expected and similar to the price-level 4 of the lab tests. The heat drying was delayed until the DR event ended. However, the lab tests showed that for DR events that exceed the time needed to complete the heated dry cycle, the dishwasher finishes the cycle and the heater never turns on. The team did not observe this behavior during the field tests. During the field tests, a 60-minute DR event resulted in a standard dishwasher cycle of 56 minutes. Since the DR event was 60 minutes, the team expected that the heated dry cycle would not occur. However, after the 60-minute DR event concluded the dishwasher continued with the heated dry cycle.

Figure 222: Dishwasher Field DR Test



Refrigerator Tests

The team raised the internal temperature of the refrigerator by keeping the doors open for several minutes. This caused the compressor to activate. However when the DR commands were issued, the refrigerator did not respond for either the price-level 3 or 4 events. The team speculates that the internal temperature of the refrigerator and freezer could have become too high, causing the refrigerator to ignore the DR commands.

Appendix 14: Toyota Pilot Test Report

The Report of Demonstrative Experiment for ISGD

Kenichi Murakami (Toyota InfoTechnology Center U.S.A., Inc.)

1. *About*

In this report, a demonstrative experiment result for regional optimum charging control technology in a field test of Irvine Smart Grid Demonstration (ISGD) Project will be summarized and reported.

2. *Demonstrative Experiment Abstract*

A below describes the demonstrative experiment.

2.1. *Purpose*

In this demonstrative experiment, 2013 Indiana demonstrative experiment to control the charging Plugin Hybrid Vehicles (PHVs) using the demand response is used as a base technology. In ISGD project, a regional optimum charging algorithm will be tested using PHVs and prove the algorithm's usefulness.

Also through the demonstrative experiment, SEP1.x smart meters and J2931 based charging system's inoperability will be tested. The inoperability of the smart meter and the charging system was not tested in the Indiana demonstrative experiment.

2.2. *Joint Research*

Southern California Edison (SCE), University of Irvine (UCI), Toyota Motor Corporations and Sumitomo Electric Industries, Ltd. had contributed to the experiment.

2.3. *Schedule*

The demonstrative experiment was scheduled from June 8 2015 to July 31 2015. The preparation started from an end of April, 2015. To test the optimization of regional charging control, the regional charging control was enabled from July 2 2015.

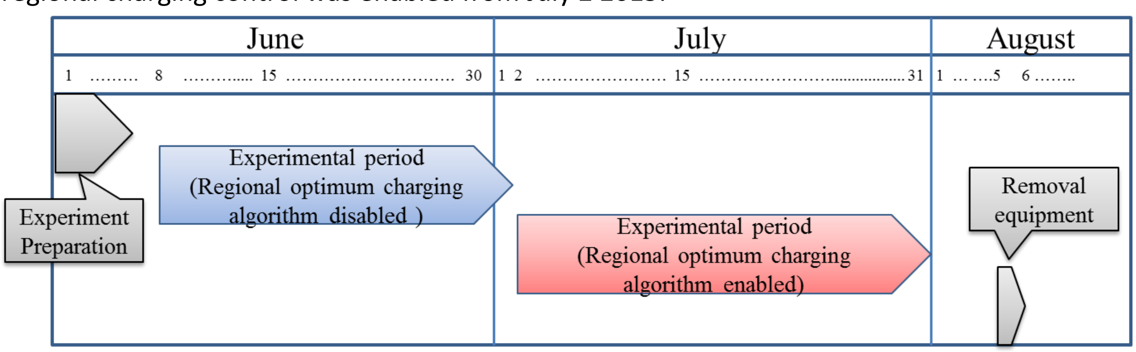


Figure 223: Dmonstrative Experiment Schedule

2.4. *Indiana Demonstrative Experiment*

The Indiana demonstrative experiment which the ISGD demonstrative experiment was based on was held on 2013.

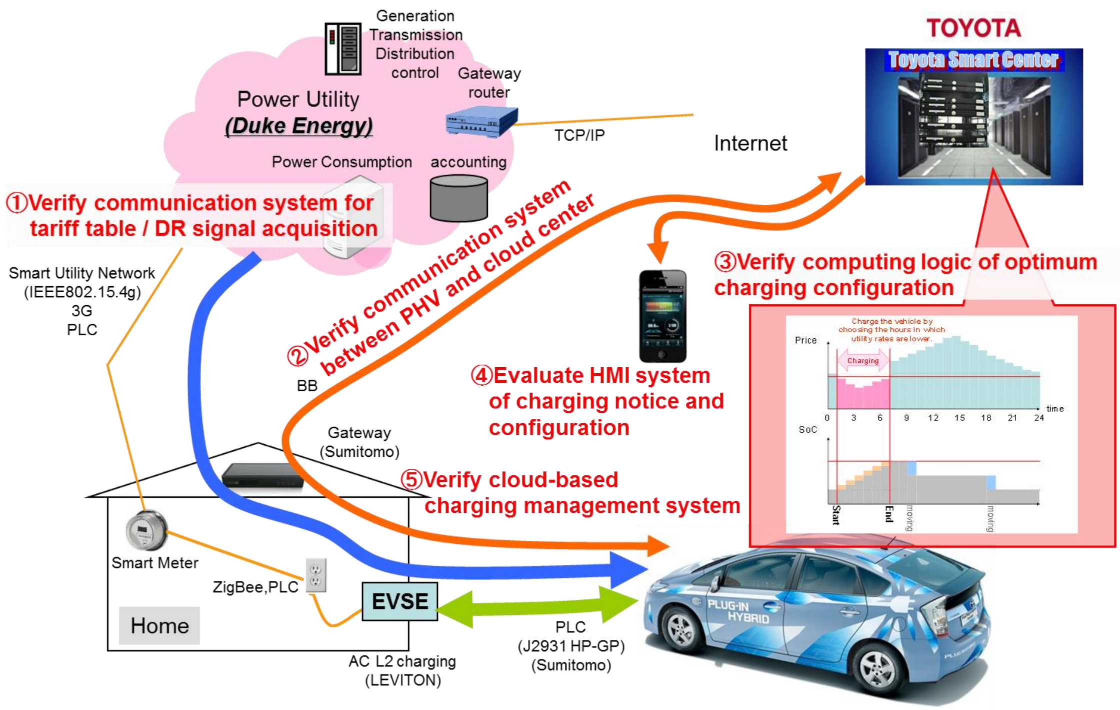


Figure 224: Indiana Demonstrative Experiment System Abstract

In the Indiana demonstrative experiment, the demand response from a utility was verified as the optimized charging control.

In the optimized charging control, the demand response and tariff information from the utility were used to calculate the best charging schedule. The calculation was done in the Toyota cloud server and the charging schedule was sent to the PHV. Based on the charging schedule, the PHV will avoid the demand response time period requested by the utility as well as take into account the PHV owner’s need. Lastly, the pricing of the electricity was also considered and the PHV started charging in the low rate time period.

Through the Indiana demonstrative experiment, the control of the charging schedule based on the demand response from the utility was verified.

Using the aforementioned charging schedule, UCI and SCE joint research was to verify the optimized charging control based on the regional base.

2.5. Proposal to ISGD Project

A below is the proposal to this demonstrative experiment.

- Calculate the optimized charging control setting from the cloud
- Control the following from the charging setting: “Minimize the effect on a grid”, “Minimize the charging cost”, “Handle the user needs in terms of SoC and a time to finish charging”
- Control the each PHV’s charging from the cloud server

Using the system with the above functions, a verification of a service with the user’s needs and the optimization of energy demand was tested.

2.6. Regional Optimization Algorithm

A charging timer was set according to a below.

①. Based on a past log data, “a departure time = a charging cable removed” was estimated.
  ➔ The estimated departure time was a charging completion time limit.

②. Based on a user’s preference for demand response setting, a usable time slot was selected.
  ➔ Not usable time slot due to a demand response was removed.

③. Based on a past log data, needed SoC was estimated.
  ➔ The charging to given SoC was completed by the estimated departure time.

④. In addition to the utility rate, a power demand information (an integrated demand based on the regional need and the charging schedule) was used for a cost function.
  ➔ This was used to avoid the heavy demand time slot.

⑤. A time slot was selected in order of a smallest cost function (if the cost function value was same, an earlier time slot was selected).

⑥. The power demand information was updated based on the given time slot.
  ➔ This was used for the next optimized charging setting as the cost function value.

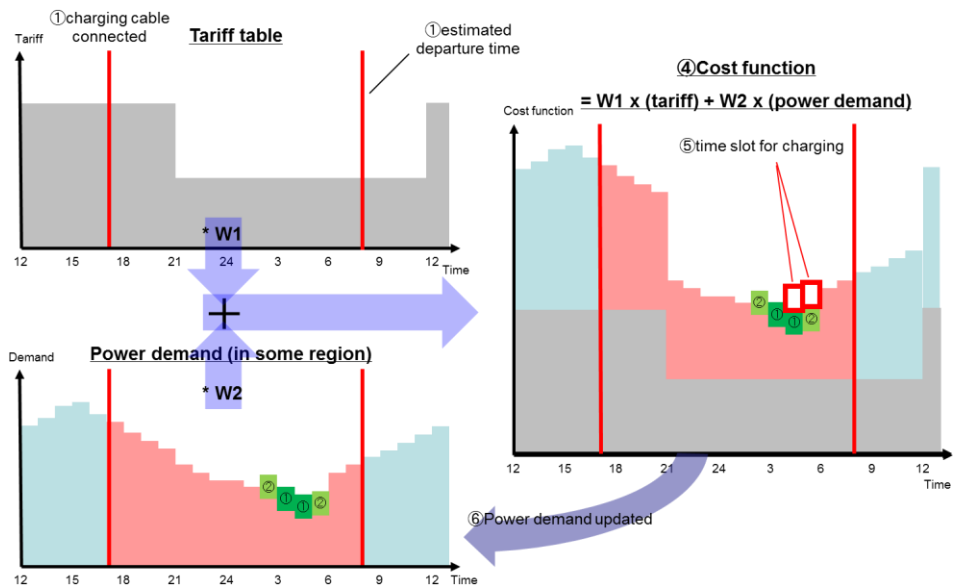


Figure 225: Regional Optimization Algorithm

2.7. System Abstract

The following diagram describes the overall system.

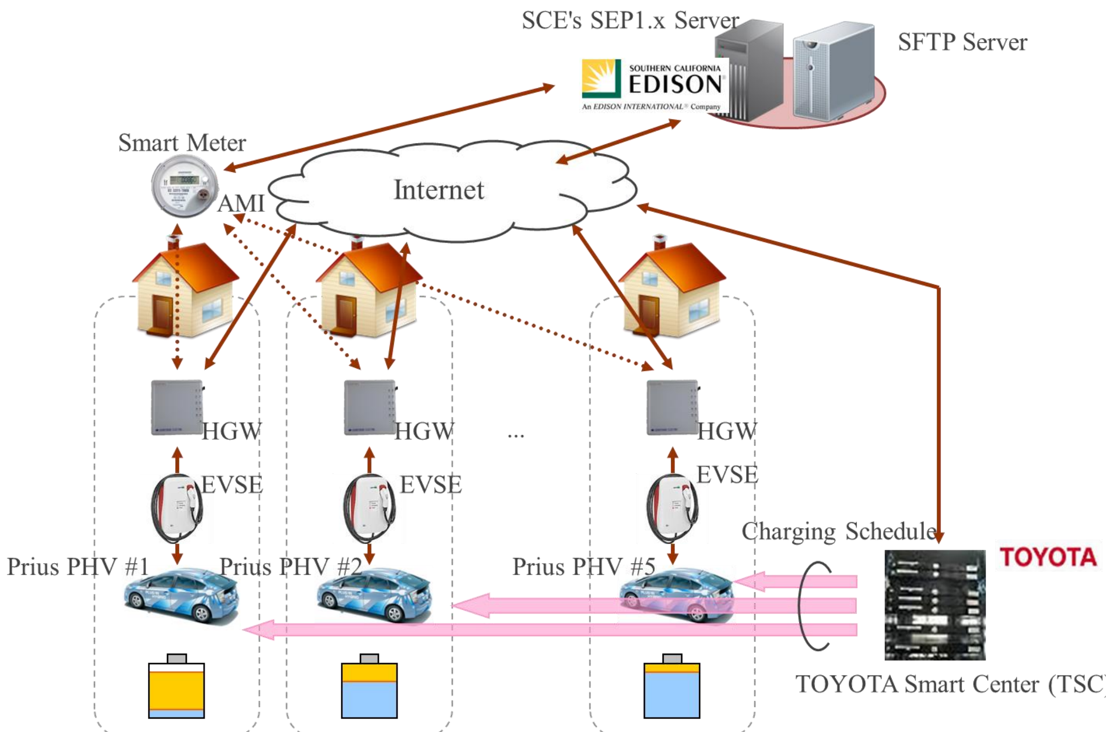


Figure 226: System Abstract

The system comprise of Toyota Smart Center, Home Gateway (HGW), EVSE, smart meter, the utility’s demand response serve and SFTP server.

Toyota Smart Center (TSC) was built on a cloud. TSC calculated the charging schedule for PHVs based on the tariff and demand response information from the utility server.

When calculating the charging schedule, a PHV’s log was used to estimate the departure time. The charging schedule was adjusted accordingly so that the charging ends at the estimated departure time.

In addition, to avoid a heavy load with multiple PHVs charging at the same time, the time slots for each charging were dispersed under the same transformer.

The SFTP server was used to collect the charging related logs from TSC.

2.8. Communication Flow

The below diagram shows the communication flow for the system.

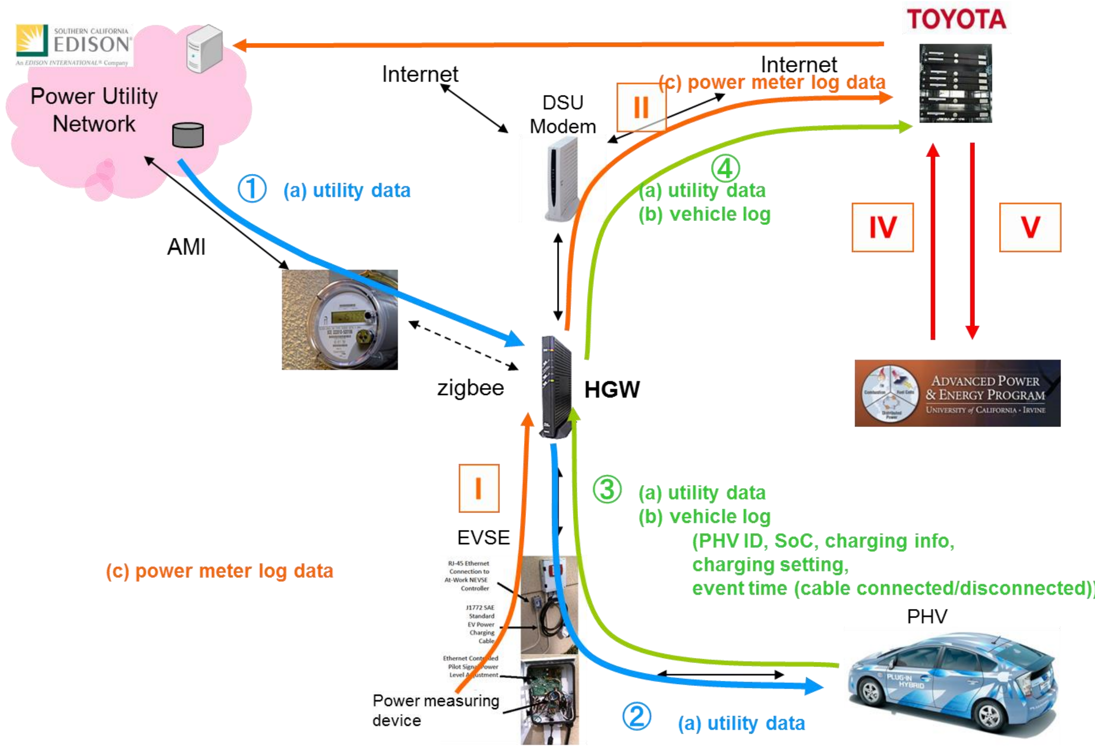


Figure 227: Communication Flow

The communication flow is broken down into two parts.

a) Control Information

The information needed to calculate the charging schedule. This was processed as below.

①. The utility data (demand response and tariff) was distributed to HGW via the smart meter from the utility server.
SEP 1.x protocol was used. ZigBee was used to connect between the smart meter and HGW.

②. The utility data from the DR server was sent from the HGW to a vehicle through the EVSE. The connection between EVSE and the vehicle was done by Power Line Communication (PLC).

③. The received utility data was added with a vehicle log (PHV ID, Charging Information, etc) and sent to the HGW.

④. The received utility data (with vehicle log) from the vehicle was sent from HGW to Toyota Smart Center.

b) Log Data

Power Meter Log Data was collected by EVSE and processed as a below.

①. The collected Power Meter Log Data was sent from the EVSE to the HGW.

②. The HGW sent the Power Meter Log Data from EVSE to Toyota Smart Center.

③. To accumulate the Power Meter Log Data, Toyota Smart Center sent the data to SFTP server.

2.9. Electricity Price and DR Setting

For the electricity price, below pricings were used for the entire area of demonstrative experiment along with ISGD project.

- 00:00 – 15:00 ··· ¢ 15
- 15:00 – 24:00 ··· ¢ 30

Figure 228: Electricity Price for the Demonstrative Experiment Area

The demand response was not used for the experiment.

2.10. Electricity Demand Prediction

In the regional optimum charging, the charging schedule was assigned to the low electricity usage time slot.

To predict the electricity usage for a day, a last year's electricity usage data was used to calculate this year's electricity usage.

Time Start	Time End	Last year 15 days average (kW)
7/28/2015 2:00	7/28/2015 3:00	0.348346909
7/28/2015 3:00	7/28/2015 4:00	-0.220204137
7/28/2015 4:00	7/28/2015 5:00	-1.036957322
7/28/2015 5:00	7/28/2015 6:00	-6.627303764
7/28/2015 6:00	7/28/2015 7:00	-9.692541082
7/28/2015 7:00	7/28/2015 8:00	-8.261720041
7/28/2015 8:00	7/28/2015 9:00	-3.856295501
7/28/2015 9:00	7/28/2015 10:00	2.5176694
7/28/2015 10:00	7/28/2015 11:00	3.466820086
7/28/2015 11:00	7/28/2015 12:00	4.392627869
7/28/2015 12:00	7/28/2015 13:00	3.984752431

Figure 229: Electricity Usage Prediction

The charging schedule was calculated based on the electricity usage prediction by using this year's electricity usage (a location and hourly time slot).

3. Demonstrative Experiment Result

The demonstrative experiment result is described below.

3.1. Errors During the Demonstrative Experiment

During the demonstrative experiment, some errors had occurred with a ZigBee connections and while receiving a tariff information. The errors happened at the pre testing and during setting up the devices at the demonstrative experiment.

A below table shows the summary of errors.

Table 80: Issues during Demonstration Experiment

No.	Date	Object equipment	Content of issue	Cause	Countermeasure
1	5/27/2015	HGW, Smart Meter	Don’t establish connection between HGW and Smart Meter	It doesn't set a correct EUI 64 address of a ZigBee device in a Smart Meter.	It set a correct EUI 64 address of a ZigBee device in a Smart Meter.
2	6/12/2015	SCE Server, HGW	Don’t send electricity price information at 00:00	Unknown reasons. It holds the potential for the SCE server doesn't send a correct information or a Smart Meter or a HGW can't receive information normally, etc.	SCE staff registers the tariff information on the SCE server every day.
3	7/20/2015	HGW	HGW can’t receive SEP 1.x message	Sumitomo engineer didn't awake to the changing from SEP 1.x to 2.0 by initialization when ZigBee connection reestablished.	Setting changed from SEP2.0 to SEP 1.x.
4	7/3/2015	SCE Server	Don’t send electricity price information at 00:00	SCE staff didn’t set tariff information every day.	-

3.2. Analysis Target

There were five families for the demonstrative experiment. As the two families' systems had trouble with a ZigBee connection, the three vehicles were actually analyzed.

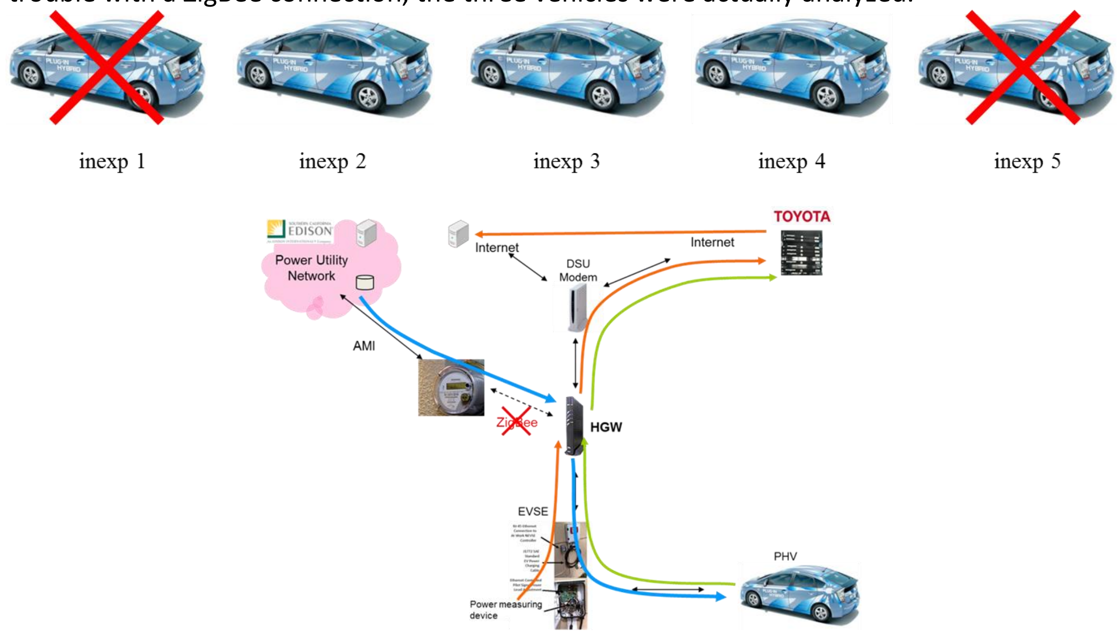


Figure 230: Analysis Target Vehicles

3.3. Method of Data Analysis

A charging time was collected from a collected log data and analyzed by comparing the below points.

- Charging Time Difference between Vehicles

  The charging time between vehicles was compared to check the regional optimization was done properly.
- Comparison with Electricity Pricing Information

  The charging time was checked whether the charging was done at the low electricity price time slot for each vehicle.
- Comparison to Electricity Usage Prediction

  The charging time was checked whether the charging was done at the low electricity usage time slot for each vehicle.

The result of above comparisons was used to check the regional optimum charging was done properly.

LogDate	connected	operation	charge state	SoC at connected	optimum charging setting	peak avoid?
11-Jul	21:15:55	0	-1	23.4375	2:00:58	1
12-Jul	21:40:44	0	0	21.875	2:00:48	1
13-Jul	21:40:44	0	-1	21.875	4:42:46	1
28-Jul	23:20:16	0	0	24.21875	4:00:19	1
30-Jul	23:48:36	0	0	24.21875	4:05:42	1
31-Jul	23:48:36	0	-1	24.21875	0:59:33	1

LogDate	chargingstarted time	finished time	reason	SoC when completed	LastCommTime
11-Jul	0:23:28	3:53:08	fully charged	85.546875	7/11/2015 3:53
12-Jul	21:45:56	23:47:23	schedule changed	85.546875	7/12/2015 23:47
13-Jul	0:48:16	6:17:55	fully charged	85.546875	7/13/2015 6:17
28-Jul	23:25:23	5:51:27	fully charged	85.546875	7/29/2015 5:51
30-Jul	23:53:47	23:53:53	schedule changed	85.546875	7/30/2015 23:53
31-Jul	0:55:02	5:42:27	fully charged	85.546875	7/31/2015 5:42

Figure 231: Log Data Format

3.4. Change in Charging Schedule

The change in charging schedule during the demonstrative experiment for the three test vehicle was verified.

The demonstrative experiment ran from Jun8 2015 to July 31 2015 (54 days). The regional optimum charging setting was enabled from July 2 2015 to July 31 2015 (30 days).

After July 2, the three vehicles' charging start time were delayed to a later time of a day. The result showed that with the consideration of the electricity price, electricity demand and the predicted departure time, the optimum charging had worked accordingly.

For Inexp2 and inexp3, there were charging start time difference. This was caused by a lack of electricity price information which was not sent. The lack of information caused the problem with optimum charging.

For inexp4, even after July 2 the charging schedule remained same as before July 2. This was due to conditioning multiple vehicles to not charge at the same time by the regional optimum charging. When only one or two vehicles were charging, the similar phenomenon was not happening. As a result, the regional optimum charging was working properly.

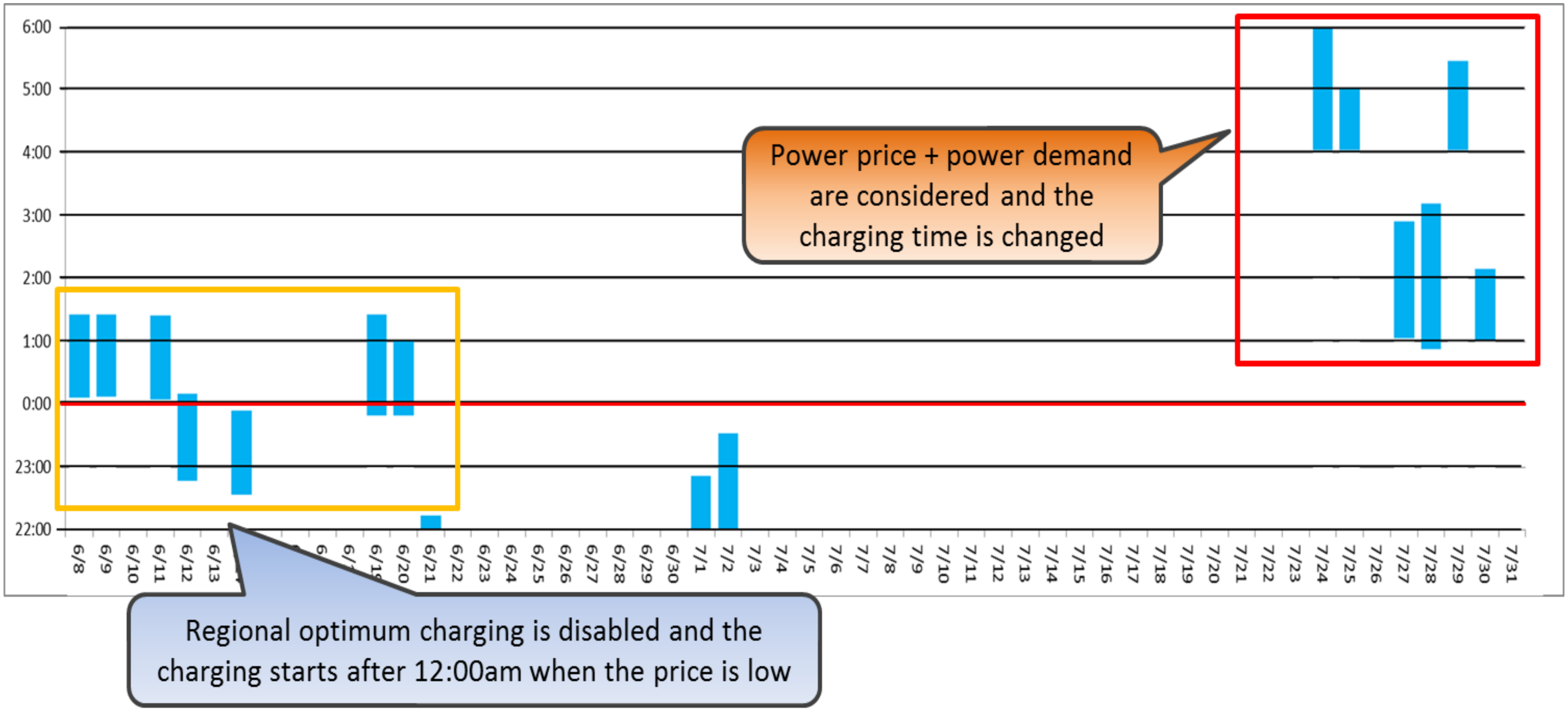


Figure 232: Variation of a charging schedule for a vehicle (inexp 2)

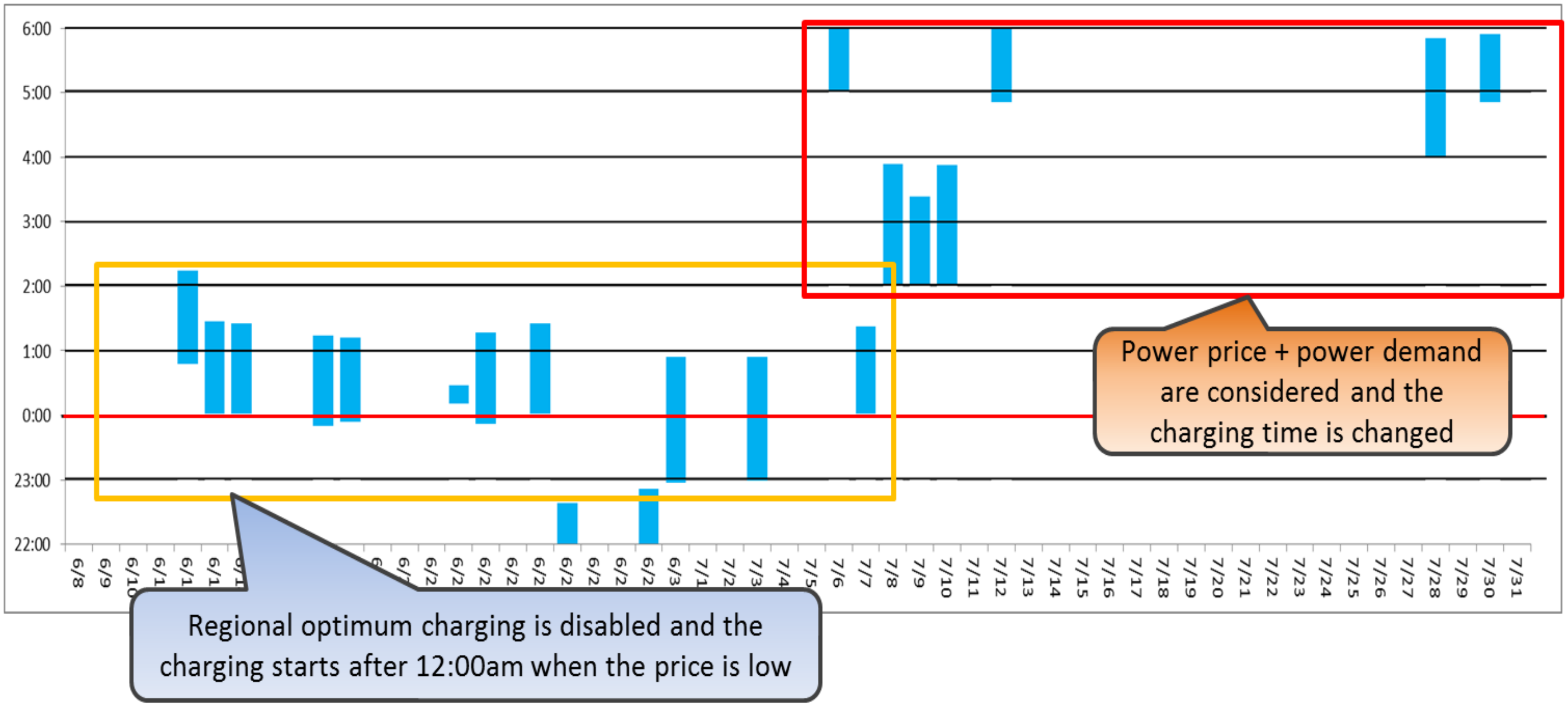


Figure 233: Variation of a charging schedule for a vehicle (inexp 3)

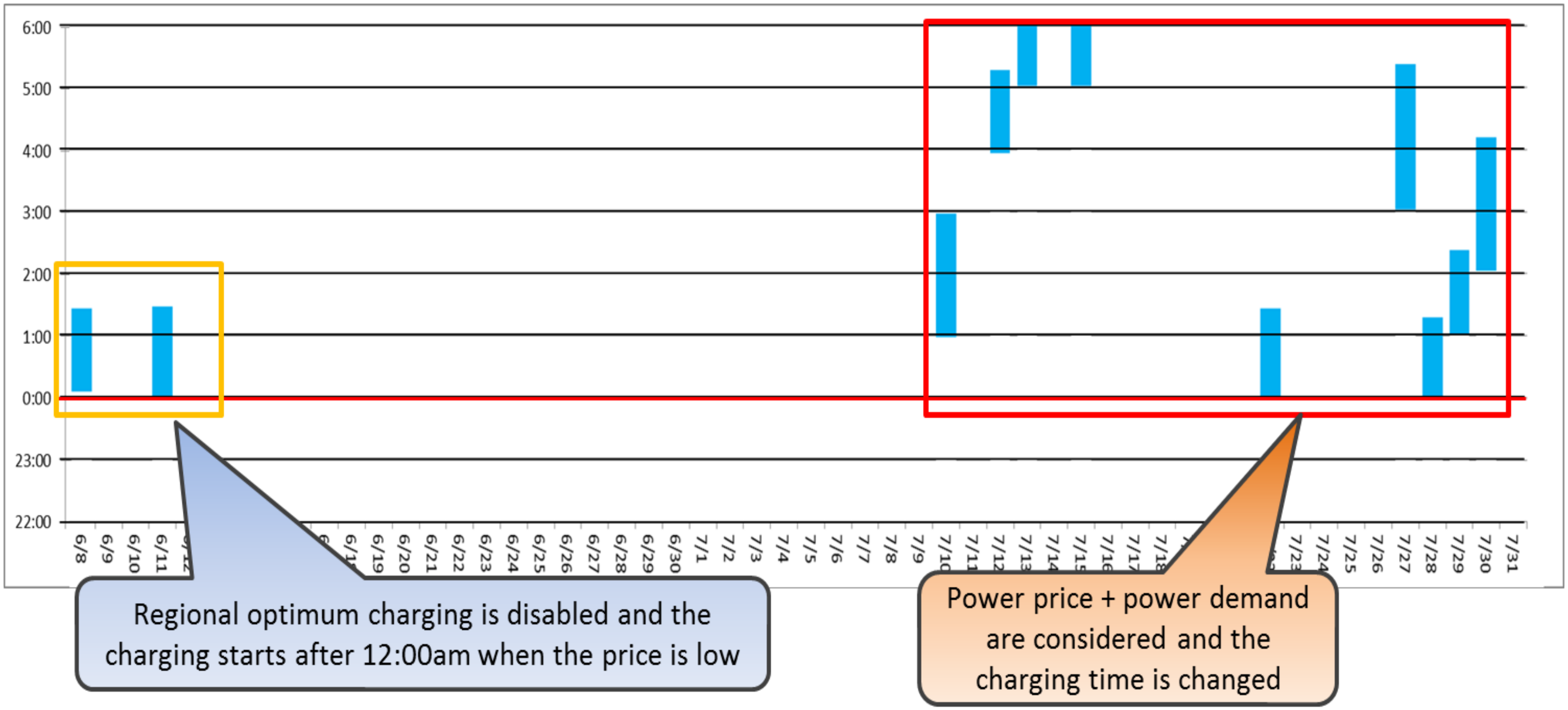


Figure 234: Variation of a charging schedule for a vehicle (inexp 4)

3.5. Charging Schedule Adjustment between Vehicles

Next explains how the charging schedule between vehicles was affected by the regional optimum charging.

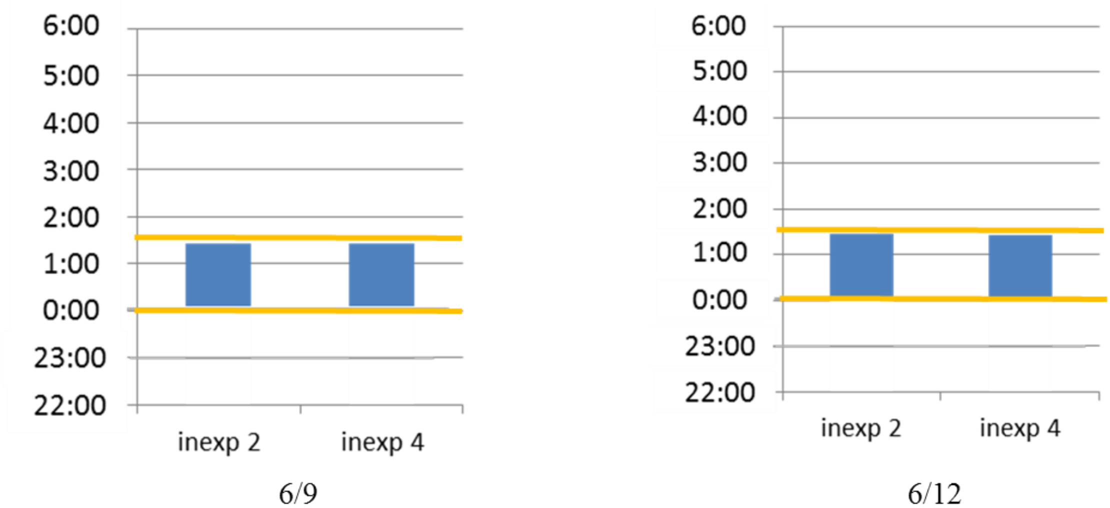


Figure 235: Regional optimum charging control is NOT enabled

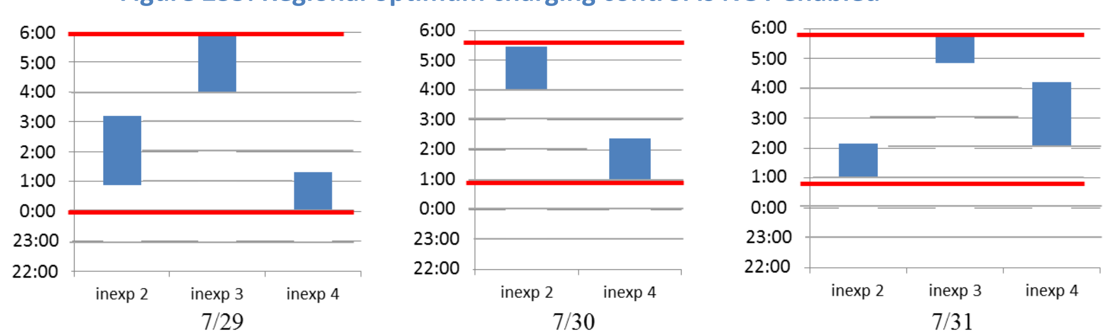


Figure 236: Regional optimum charging control is enabled

Figure 235 shows the charging schedule between vehicles with the regional optimum charging OFF.

When the regional optimum charging is OFF, each vehicle started charging from 0:00 when the electricity price was low. There were no adjustments between the vehicles to start charging.

Figure 236 shows the charging schedule between vehicles with the regional optimum charging ON.

When the regional optimum charging is ON, each vehicle started charging after 0:00. However, each vehicle was allotted different time slot to avoid the same time charging.

By comparing the above two cases, the regional optimum charging not only answered users' needs but avoided same time charging to lessen the impact on a utility's grid.

3.6. Same Day Charging Time Allotment

Next explains the charging time between vehicles on a same day.

On July 29, the three vehicles were set to charge at different time slot from 0:00 to 6:00. These time slots were low in electricity price and electricity usage as well as enough charging time to depart at expected departure time of 7:30 to 8:30.

For inexp 2 and inexp4, some of the charging time was overlapped. This was likely due to the server and the vehicle communication being 15 mins interval and there was a delay of start charging. The charging time overlap was within a margin of error.

For July 30 there were only two vehicles. The timing was both low in electricity price and usage. The two vehicle charged at the different time.

For July 31, similar result with different timing allocated for the each vehicle.

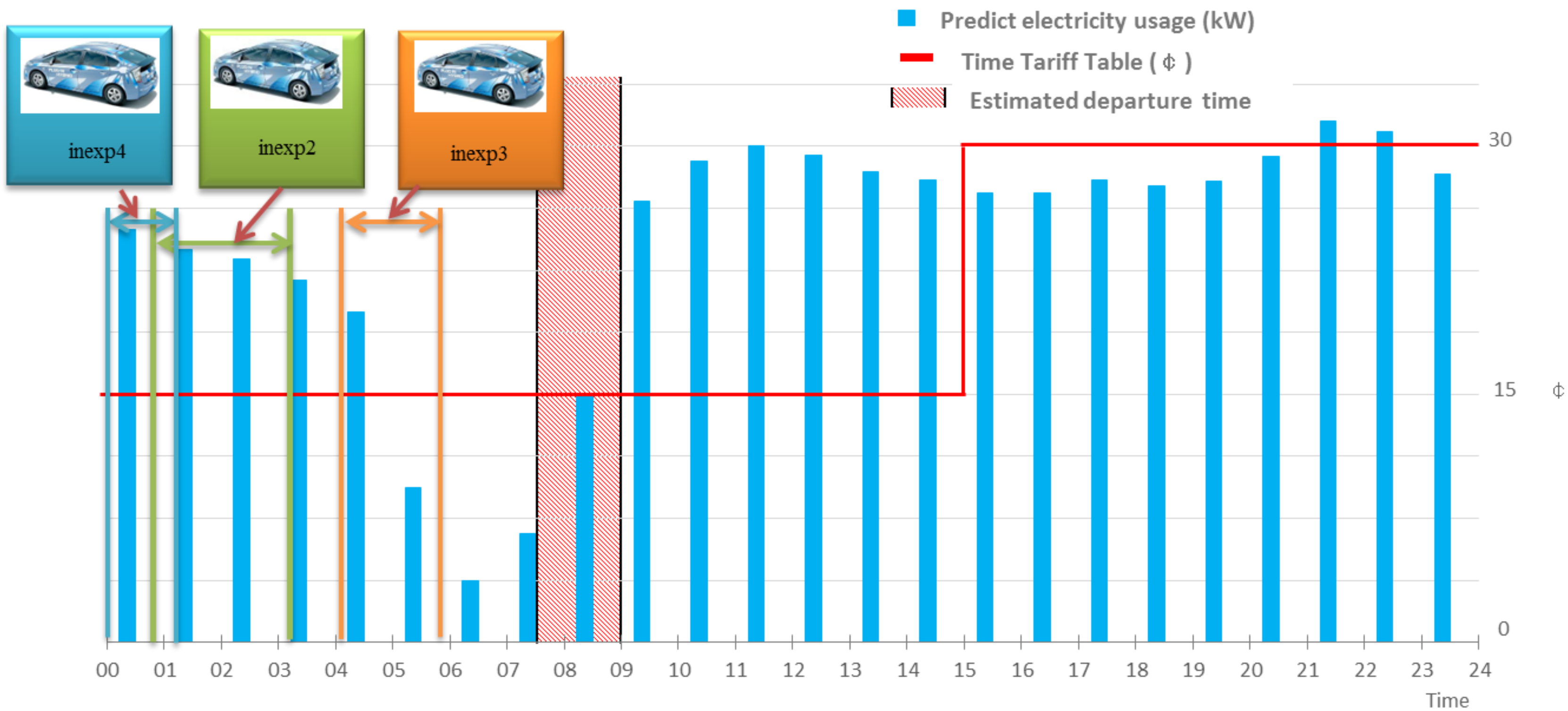


Figure 237: Allocate time slot for charging in the same day (7/29)

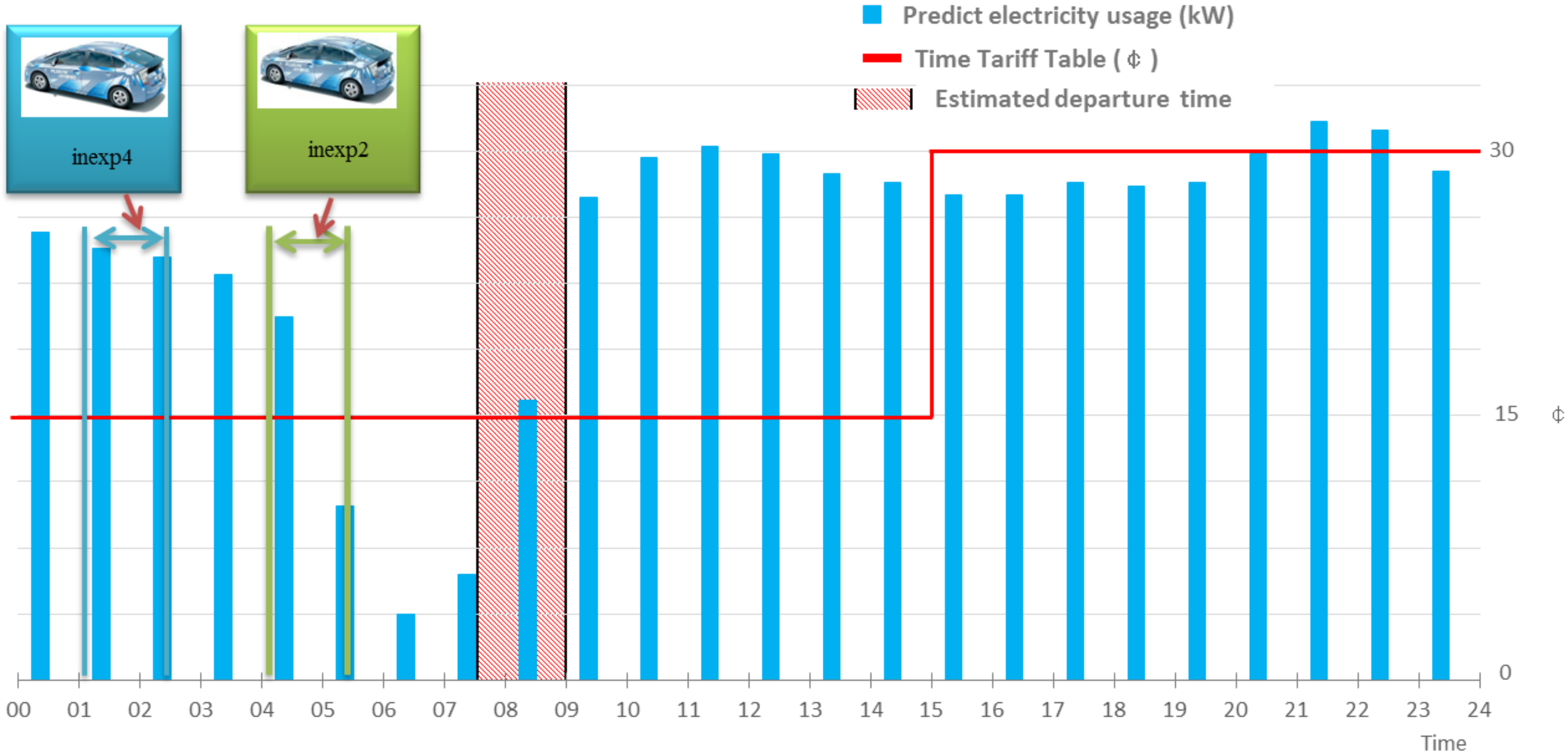


Figure 238: Allocate time slot for charging in the same day (7/30)

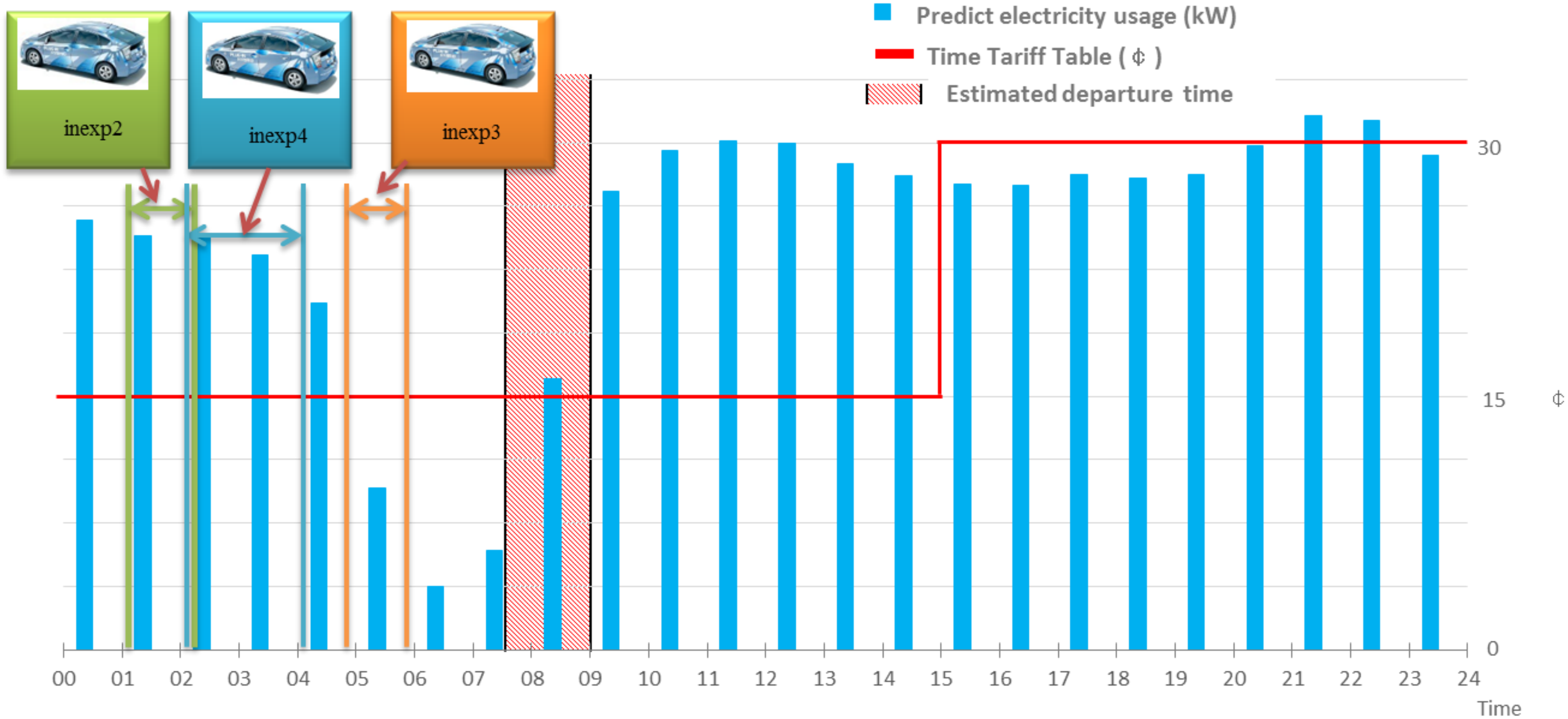


Figure 239: Allocate time slotfor charging in the same day (7/31)

4. *Summary*

For this demonstrative experiment, the following technical elements for a smart grid were being verified.

4.1. *SEP1.x Smart Meter Connectivity with J2931 based System*

In Indiana demonstrative experiment, a tariff and DR information were sent using SEP 2.0. For this demonstrative experiment, SEP1.x was used. The connectivity test with the SEP1.x smart meter had proved following.

- Connection between HGW and the smart meter using ZigBee
- Receiving SEP1.x format message through the smart meter
- Control charging according to the received message
- Realize the expansion of connectivity under different HAN (SEP 1.x & SEP 2.0)

4.2. *Regional Optimum Charging according to the Vehicle Usage*

By doing demonstrative experiment using real vehicles within small community, the regional optimum charging was verified with the following results.

- From two types of pricing, used the low price time
- From the electricity demand prediction, used the low electricity demand time
- Dispersing the charge time of multiple vehicles

Through this demonstrative experiment, not only the utility's demand response but the regional optimum charging was used to control the charging of a small community.

Appendix 15: Summary of Lessons Learned by Project Domain and Lesson Category

ISGD Technology Domains/Lessons Learned	Lessons Learned Categories				
	Standards	Technical Maturity	Regulatory Landscape	Market Landscape	Deployment /Integration
Smart Energy Customer Solutions					
1. Smart inverter standards are too immature to support product development and market adoption	✓				
2. Proper integration of components from multiple vendors is critical to the successful operation of energy storage systems		✓			
3. Improved battery system diagnostic capabilities are required to help identify the causes of failures		✓			
4. Manufacturer implementations of the SAE J1772 EVSE standard limit the usefulness of electric vehicle demand response	✓	✓			
5. Distributed energy resources should be designed and tested to ensure communications and operations compatibility with utility control systems		✓			✓
6. Remotely monitoring new technologies after field deployment is critical to timely identification and resolution of unknown issues					✓
7. Targeted "behind the meter" data collection will help future demonstration analytics					✓
8. Consistent implementation of Smart Energy Profile demand response messaging across customer device types would simplify aggregated demand response	✓				
9. Assessing the impacts of energy efficiency measures requires isolating customer behavioral changes					✓
10. When deploying systems with components from multiple vendors, construct a careful commissioning plan					✓
11. Energy storage degradation should be factored into device control algorithms and relevant utility load management tools		✓			
12. Demand response devices should be capable of decreasing and increasing energy demand	✓			✓	
13. Energy storage that supports islanding should be sized appropriately and should only island during actual grid outages	✓				✓
14. Back-up power for data acquisition systems should be provided when data collection is needed during power outages					✓
15. Minimizing impact on distribution transformer requires coordination of PV, EV, load, and storage strategies					✓
16. Islanded microgrid management requires coordinated management of generation, energy storage and load, which requires forecasts of each					✓
17. Reliability of HAN device to back office communications may be improved with simpler communications approaches		✓			✓

Next-Generation Distribution System					
1. Low-latency radios require technical improvements or government allocation of radio spectrum		✓	✓		
2. Permitting is a significant challenge for siting smart grid field equipment outside of utility rights-of-way			✓		
3. Radio communications-assisted distribution circuit protection schemes are difficult to implement	✓				✓
4. Distribution volt/VAR control applications should be aware of system configuration changes to maximize CVR benefits					✓
5. Distribution volt/VAR control capabilities can achieve greater benefits when combined with management of transmission substation voltage schedules					✓
Interoperability & Cybersecurity					
1. Continued development of the IEC 61850 standard and vendor implementations of this standard are required to achieve a mature state of interoperability	✓			✓	✓
2. Achieving interoperability requires concentrated market-based development and enforcement of industry standards	✓			✓	
3. An enterprise service bus can simplify the development and operation of visualization capabilities		✓			
4. Utilities need to perform a system integrator role in order to realize smart grid objectives					✓
5. Effective communications with software vendors is critical for smart grid deployments					✓
6. Acceptance testing should include integrated testing of software products and field devices in a lab environment					✓
Workforce of the Future					
1. Impacts to departmental boundaries and worker roles and responsibilities that result from smart grid deployments need to be identified and resolved					✓
2. Build time into any smart grid deployment planning for an iterative training development process					✓
3. The large volumes of data generated by advanced grid components will require data scientists to help manage and convert it into meaningful information					✓
4. Software project management requires specialized expertise					✓

[i] Although the settings were intended to be universal, two of the four URCIs had lower trip settings in order to clear end-of-line faults within an acceptable timeframe.