REPORT

PG&E Demand Response Transmission and Distribution Pilot – Phase II Final Report

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1 Introduction

Pacific Gas and Electric Co. (PG&E) is one of the largest electric utilities in the United States, serving approximately 5.2 million electric service accounts and over 15 million people in Northern and Central California. PG&E's service territory covers 70,000 square miles and includes 18,616 miles of electric transmission circuits and 141,215 circuit miles of electric distribution lines. With over 750 substations and nearly 3,000 distribution circuit feeders, the load patterns and excess distribution capacity vary substantially across the territory. Because of its diversity, PG&E has 15 distinct operating areas technically referred to as Sub-load Aggregation Points (Sub-LAPs) by the California Independent System Operator.

PG&E plays a vital role in designing, building, reinforcing, and maintaining the local transmission and distribution network—electric pathways—to deliver power from where it is produced to where it is used. Both transmission and distribution infrastructure is sized to meet the aggregate demand of end users when it is forecasted to be at its highest, during peak demand.

Much like highways and streets, failure to build sufficient capacity for peak hours leads to congestion, but in the case of the electric system, it can also lead to costly power outages. When demand exceeds local transmission or distribution capacity, equipment is overloaded, it degrades more quickly, and the risk of power outages grows considerably. Again, like highways and streets, expanding the electric grid to accommodate growth in local peak energy use requires large capital investments to build infrastructure with a relatively long lifespan.

Since upgrades and reinforcement of specific distribution components (e.g., area substations and distribution circuits) tend to happen infrequently, a common practice is to install excess capacity when a component is upgraded. The excess capacity helps accommodate additional load growth and can also be used to provide relief to neighboring components that are overloaded by transferring loads when needed.

Not all distribution investments are driven by local, coincident peak loads. Some investments are tied to customer interconnection costs and are essentially fixed. Other investments must take place because of aging or failed equipment or because of the need to improve reliability and modernize the grid.

Because transmission and distribution equipment is sized to meet coincident, local peaks, and alternative to growth related infrastructure construction is to manage local, coincident demands that are shared across many customers in order to avoid or defer infrastructure upgrades and expansions. If a customer helps reduce coincident demand, either by injecting power within the distribution grid or by reducing demand, the unused capacity can accommodate another customer's load growth and thereby help avoid or defer investments required to meet load growth. When transmission and distribution investments are avoided or deferred, it frees up capital for other alternate uses, improving the efficient use of resources.

PG&E has a long history of demand management programs. However, historically, demand management programs were designed to reduce demand when the overall system peaked and had not been employed to manage local peaks, which are far more diverse. Demand management resources were not designed to provide transmission distribution relief and few programs were designed for local dispatch. Because of the lack of experience, T&D planners do not incorporate the ability to actively manage loads into transmission and distribution investment or upgrade decisions and operators lacked visibility into demand resources, which were not fully integrated with operations.

DR T&D Pilot Objectives

PG&E initiated the Demand Response (DR) Transmission and Distribution (T&D) Pilot to assess and test the feasibility of integrating demand management resources into transmission and distribution planning operations. The California Public Utilities Commission (CPUC) Decision (D.) 12-04-045[1] approved the DR T&D Pilot in March 2011 to be conducted in two phases.

1. A needs assessment to identify operation and planning needs and define key steps required for integration of load management into distribution planning and operations.
2. A series of demonstration projects to overcome existing gaps and test integration of DR resources into T&D operations and planning.

Since the approval of the DR T&D Pilot, the number of initiatives to integrate distributed energy resources (such as DR) into T&D planning and operations has grown. In September 2013, the CPUC initiated Rulemaking (R.) 13-09-011 to “enhance the role of demand response programs in meeting the state’s long term clean energy goals while maintaining system and local reliability.” The ensuing decision, D. 14-05-025[2], extended the DR T&D Pilot and approved bridge funding for the completion of Phase 2.

Needs Assessment and Regulatory Drivers

Prior to implementing the demonstration projects, PG&E commissioned a needs assessment to identify operation and planning needs used to define the demonstration projects. The recommendations were based on interviews with distribution operators, operating engineers, and distribution planners and were split into short- and mid-term. These recommendations were used to inform a variety of field demonstrations and experiments designed to explore how to leverage DR resources for integration into T&D planning, operations, and processes.

The primary short-term recommendations were to:

- Focus the demonstration projects on operations. Integration into planning is more likely to proceed if load management proves valuable for operations.
- Demonstrate the ability to attain deep penetration of load management in distribution systems. In order for load management to provide distribution relief, the penetration needs to be deep enough to provide meaningful demand reductions. It may be necessary to test different incentives, recruitment tactics (direct mail, phone, door-to-door), and load control options (e.g., 100% shed) to better understand how to attain high penetration levels.
- Focus on tools and demonstrations for operating engineers. Operating engineers are central to integration of load management into distribution operations and planning. They model the effect

[1] http://docs.cpuc.ca.gov/PublishedDocs/PUBLISHED/GRAPHICS/165317.PDF

[2] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M091/K392/91392798.PDF

of high temperatures on grid operations and develop the operations game plan that operators implement when loads approach or exceed normal equipment ratings. In particular, the 72 hours leading up to heat waves (or other potential emergency conditions that can be anticipated in advance) are critical.

- Address key data gaps faced by operating engineers:
  - ✓ Develop multi-day load forecasts for specific substation banks and distribution circuits.
  - ✓ Map load reduction capability and utilization to the electrical distribution system.
  - ✓ Provide visibility into load management activations and load reductions.

The mid-term recommendations were to:

- Link load management dispatch to SCADA system monitoring. Operating engineers in particular would like the ability to set a load threshold for each distribution circuit to trigger load management before emergency conditions are reached. Monitoring local loads and thresholds decentralizes load management dispatch and ties back to distribution operating needs.
- Expand the time horizon for distribution forecasting. Distributed resources generally require a 3-5 year lead time to make a significant impact on load growth projections and thereby defer traditional distribution capacity expansion projects.
- Address distribution planning needs. To integrate load management into planning, distribution planning engineers need data about existing load management resources and how they map to electrical distribution feeder circuits. They also need information on historical load management events so they can add it back to historical load data to fully understand load growth patterns. Last, they need some preliminary information about the penetration of load management that can be achieved for specific electrical distribution circuits and the corresponding costs. Ideally, the penetration estimates are based on empirical demonstrations that concretely demonstrate the levels of load management penetration that can be achieved.
- Integrate load management into the Distribution Management System (DMS). Load management tools should complement and mesh into tools used for operations rather than add another dimension of complexity. That is, load management tools developed in the initial phases cannot remain stand-alone tools, but need to be integrated directly into distribution management. The integration needs to not only factor todays existing tools but also how they are expected to evolve given PG&E's ongoing efforts to modernize the grid.

Several more recent regulatory initiatives also influenced the design of the demonstration projects. These include the Targeted Demand Side Management (TDSM) initiatives, CPUC Code 769, which requires each investor-owned utility to submit a distribution resource plan proposal to identify optimal locations for the deployment of distributed resources, the Distributed Energy Resource Alternative Planning Standard (DERAPS) , and the Integrated Distributed Energy Resource (IDER) proceeding.

The demonstration projects were implemented in two primary phases—2012 to 2014 and 2015 to 2016. In addition to the funding allocated by the two CPUC decisions, the DR T&D Pilot also leveraged and coordinated with projects funded by the Electric Program Investment Charge (EPIC), the SmartAC™ (SAC) program, the Base Interruptible program (BIP), and the DR Emerging Technology (DRET) program.

Summary of Demonstration Projects

The nine DR T&D Pilot demonstration projects summarized in this report provide concrete experience in addressing several of the operation and planning needs to integrate DR resources. They also support the more recent regulatory initiatives to integrate distribution energy resources into T&D planning and operations. Additionally, the pilot's findings will inform future initiatives to use DR resources in serving T&D planning and operations, as well as PG&E's Distributed Resources Plan and IDER efforts that support both the directives in CPUC Code 769 and PG&E's internal DERAPS.[3]

Table 1-1 lists the nine individual initiatives that are summarized in this report, including indicators of whether or not a formal project report is available on the California Measurement Advisory Council (CALMAC) website or if it is internally documented at PG&E.

A full description of each demonstration project, including implementation and key findings, is included as separate sections in this report. The demonstrations addressed several of the operational and planning needs, produced concrete experience with targeted use of resources for T&D capacity relief, and also helped identified refinements needed to further integrate DR resources into T&D planning and operations.

[3] Approved in June 2015.

Table 1-1: DR T&D Pilot Demonstration Projects

	Initiative	Objective	Documentation Availability
1	Development of a Distribution Operations-focused internal "dashboard" with which to visualize the DSM resources in constrained substations	Visualize resources available for operations at specific locations	PG&E Internal
2	2015 Real-time Monitoring System (RTMS) dispatched cellular data loggers at SAC participant premises in constrained substations	Provide operating engineers and operators near real-time visibility into load management activations and load reductions	CALMAC
3	Configuration to enable Distribution Operations dispatch of BIP and SAC at targeted substations	Test ability to dispatch locally	PG&E Internal
4	Targeted Observed Triggered Automated Load (TOTAL)	Link load management dispatch to SCADA system monitoring and test decentralized load management dispatch	PG&E Internal
5	Development of a framework to integrate DER impacts into distribution load growth projection tools	Incorporate DER resources into T&D planning	PG&E Internal
6	Development of a distributed energy resource (DER) valuation framework	Allow comparison of distributed resources to traditional distribution equipment for planning	PG&E Internal
7	Targeted marking to increase penetration of the SAC program in constrained substations	Assess the ability to attain deep penetration of DR resources at specific locations and the costs associated with doing so	PG&E Internal
8	Residential Behavioral Demand Response (BDR)	Test ability to attain deep penetration of load management, quickly and cost effectively	CALMAC
9	Bring Your Own Thermostat (BYOT)	Leverage third-party resources to test ability to attain deep penetration of load management, quickly and cost effectively	CALMAC

2 DSM Dashboard

Project Description and Objectives

Through PG&E's Demand Response DRT&D pilot, the Targeted Demand Side Management initiative resulted in the successful development of a dashboard that allows T&D planners to quickly and easily visualize demand side management (DSM) resources on constrained substations. The first four substations[4] that were integrated into the internally developed dashboard were chosen because they had substantial customer bases and easily deployable programs already established. These first four substations successfully demonstrated the proof-of-concept of using the dashboard to identify distributed energy resources (DERs), including DR, that could be targeted to curtail local load. The second set of substations[5] was chosen with the same criteria, in addition to operating above their nameplate capacities.[6]

The primary objective of the overall TDSM initiative was to develop a process to integrate customer-side programs into a least-cost planning framework to support distribution or transmission system reliability.

Project Implementation and Results

In order to fully use the capabilities of the dashboard, PG&E first needed to identify constrained substations. Constrained substations are defined as those that have projected load overtaking capacity within the next five years. PG&E uses a combination of internal tools and data, such as live Supervisory Control and Data Acquisition (SCADA) data, to identify the timing, magnitude, and duration of the identified peaks. The dashboard (Figure 2-1) allows PG&E to identify which customers have critical load shapes that best match the substation's peak load shape or the top percentile of customers whose load aligns with the peak. Additionally, the dashboard provides information on DR participation and percent savings by customer segment and by technology family, which can be filtered by feeder. Ultimately, the information presented in the dashboard allows PG&E to identify customers and customer groups to directly target, making its existing Customer Energy Solutions (CES) products more effective.

Using the information presented in the dashboard, PG&E achieved the following savings from the TDSM initiative for the Phase 1 substations:

- Barton: 3.7 MW (151% of the target reduction);
- Bogue: 2.15 MW (106% of the target reduction);
- Lammers/Banta: 2.21 MW (95% of the target reduction); and
- Martell: 0.81 MW (103% of the target reduction).

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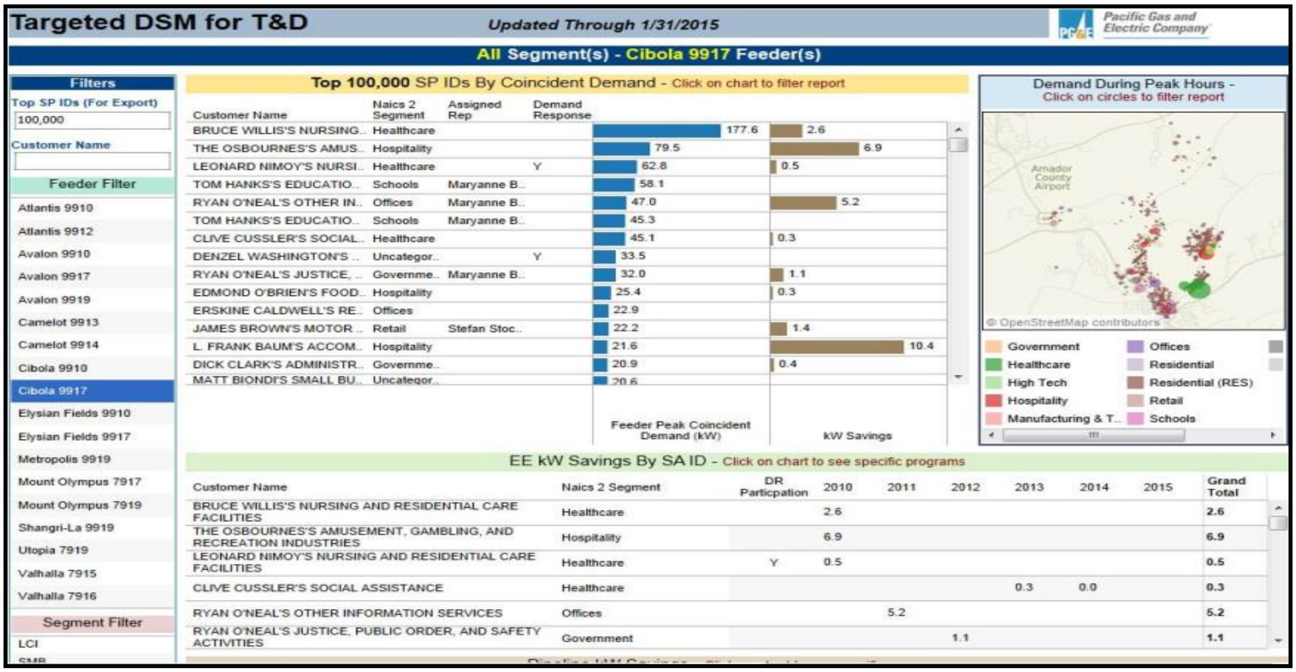
4 Bogue, Martell, Barton, and Lammers/Banta were the four substations targeted in Phase 1 (2014 – 2015).

5 Sycamore/Notre Dame, Esquon, Rincon, Linden, Middle River, Belle Haven, and Los Gatos are the substations targeted in Phase 2 (2016 – 2017).

6 The CPUC requires PG&E to operate all assets based on the nameplate capacity from the manufacturer, rather than the actual, field-tested capacity.

Figure 2-1: Screenshot of Example Output from the Dashboard



Key Learnings and Future Opportunities

The TDSM initiative demonstrated the usefulness of the dashboard to visualize customer load characteristics and DSM resources on constrained substations. Because the local customer composition drives peak load at any particular substation, each area may require different customer and technology strategies rather than a one-size-fits-all solution. This primary learning validates that an effective mix of DR programs, distributed energy resources, and energy efficiency programs used to curtail load at a particular substation must take into account the load usage patterns of the customers in addition to the attributes of the EE and DR resources that can be deployed specifically on each substation. Among substations, the local customer composition may dictate different mixes of DER, EE, and DR in the appropriate strategy used to curtail peak demand at that substation. Additional learnings include the following:

If PG&E continues to use the dashboard to inform future TDSM initiatives, there are many opportunities to continue to build out and improve upon features of the dashboard. These include:

- Automatic near real-time data updates;
- Scaling the platform to include all 3,200+ feeders in PG&E's territory;
- Providing specific and actionable insights for DSM deployment for CES lines of business; and
- Expanding the DER portfolio to include storage and distributed generation to systematically identify local gaps for additional product development.

3 RTMS-dispatched Cellular Data Loggers for SmartAC

Project Description and Objectives

Through the Electric Program Investment Charge (EPIC) program, PG&E successfully deployed a sample of cellular communicating data logging devices at premises with central air conditioning CAC Direct Load Control (DLC) devices in order to collect and display data in systems that can be used to gain insights into the performance of these DLC devices at both the customer and local levels. This collection of devices and applications is referred to as the Real-time Monitoring System (RTMS). The project's primary objectives were to:

1. Enable near real-time visibility of CAC DLC installations to T&D operations.
2. Improve PG&E's ability to estimate CAC DLC load impacts at the distribution system level to better understand localized impacts of CAC DLC devices on meeting distribution feeder level reliability concerns.
3. Enable DR program administrators to have near real-time visibility on any problems with direct load control devices before, during, or after an event is called to support T&D operations.

Project Implementation and Results

For this project, cellular communicating data loggers were purchased and installed on premises with one-way DLC devices for a sample of residential and commercial customers participating in PG&E's SmartAC™ (SAC) program. In addition to installing these loggers, PG&E used a newly developed database management system to schedule data collection, store the load measurements, and display information about the availability and performance of the load control system in near real-time. PG&E operated the RTMS dashboard over the course of summer 2015 to observe the operational status of the CAC load control program and provided recommendations to the designer of the dashboard throughout the project. This dashboard was used to track specific load control operations on two targeted substations—Barton and Bogue, located in Fresno and Marysville, California, respectively, as well as a representative sample of the SAC program population. PG&E conducted two types of load control tests specifically on the Barton and Bogue populations over the course of the summer (notch tests[7] and multiple-hour tests[8]) to assess the ability of the system to observe the operational readiness of the system and estimate load impacts in near real-time on those substations' distribution circuits.

The primary results from the project were the following:

- The RTMS dashboard provided visibility of the daily operational status (i.e., whether the cellular data loggers had called in and whether the CAC units were operating) for approximately 99% of the sampled premises during the period;

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7 Notch tests are load control operations in which the compressor load on participating CAC units is completely interrupted (i.e., 100% load shed) for a period of 15 minutes. The tests were only conducted on weekdays during a 5-9 PM window.

8 Multiple-hour tests were designed to measure the full operational capability of the CAC load control system to suppress loads on the designated substations during times when loads were peaking.

- The average notch test load impact per CAC load control device was 0.57 kW at Barton and 0.73 kW at Bogue—the load impacts varied significantly from test to test, depending on ambient temperature and timing of the notch, which varied across test window;
- The average notch test load impact measured at the substation level (from aggregate feeder loads) was 617 kW at Barton and 526 kW at Bogue—the impact varied in a manner similar to variations displayed on a per device measurement; and
- The average multiple-hour test load impacts per device were 0.33 kW and 0.29 kW for devices located in Barton and Bogue, respectively. These load impacts were lower than those for the notch tests because multiple-hour tests employed 50% cycling rather than the full shed strategy used for notch tests.

Key Learnings and Future Opportunities

Both the notch and multiple-hour tests were conducted under relatively cool weather conditions, due to the priority of SAC and SmartRate™ event days. Thus, this project likely underestimated the full capability of CAC load control as a resource. Nevertheless, these tests demonstrated that the impacts of CAC load control are readily observable using the RTMS loggers deployed on substation feeders, as well as on Supervisory Control and Data Acquisition (SCADA) measurements taken at the feeder level. This finding provides additional support for using load control and demand response to support distribution operations.

This project has demonstrated the usefulness of the RTMS dashboard for observing the operational readiness and performance of PG&E’s load control system, using both a customer- and location-specific approach, which could be useful for load relief on targeted distribution feeders. Additionally, PG&E successfully tested a data collection and management system that provides increased visibility into SAC operations without incurring the significant costs associated with a wholesale replacement of an existing one-way load control communication system with two-way load control devices. This type of approach will become increasingly important and useful as load control is integrated into the modern grid in California.

The results of this technology demonstration project[9] offer additional opportunities for PG&E to leverage the RTMS technology. Given that load impacts of CAC load control operations are readily observable using SCADA when the market penetration of CAC load control is high, SCADA could be used to monitor the load impacts of CAC load control on circuits with high CAC penetration on a targeted basis, when it becomes necessary to do so. Another opportunity is to redeploy the available loggers to obtain visibility of the operational status of the CAC load control system at different substations. Finally, the loggers could be redeployed in order to oversample and monitor a particular device type of the population of the total CAC load control system.

Ultimately, due to the successful results and insights gained from the loggers at the two substations, PG&E redeployed loggers from the Barton and Bogue substation locations to deepen the sample of the overall SAC program participant population by geographic concentrations, control device technology,

[9] EPIC 1.24 http://www.pge.com/includes/docs/pdfs/about/environment/pge/epic/EPIC-Final-Report.pdf

customer segment, and control strategies. Finally, PG&E will continue to offer recommendations to refine the RTMS dashboard since gaining experience in implementing the near real-time dashboard.

4 Configuration to Enable Distribution Operations Dispatch of BIP and SAC at Targeted Substations

Project Description and Objectives

Demand response resources such as PG&E's Base Interruptible Program (BIP) and SmartAC™ (SAC) programs are known to provide reliable and fast load shed when called on for event dispatch. If dispatch systems are programmed to dispatch the program locally in areas that are experiencing capacity constraints, these programs' reliable load shed can be directed to these areas if and when capacity constraints result in operating conditions where reliability is at risk.

However, these legacy demand response programs were not initially designed with flexible dispatch in mind. The systems that serve as the operation backbone for these programs are capable of locational dispatch; however, significant resources are necessary to develop the program's capability to be dispatched locally. The DR T&D Pilot co-funded work to enable event dispatch of the SAC and Base Interruptible Program (BIP) demand response programs by substation.

Project Implementation and Results

The SAC dispatch systems were configured in 2016 to support dispatching the program at five additional targeted substations that PG&E Distribution Operations identified as likely to be constrained during the summer season: Linden, Los Gatos, Notre Dame, Rincon, and Sycamore. Currently, SAC's operations are governed by three primary IT systems: 1) SEELoad, the Demand Response Management System by Lockheed Martin, which processes enrollments and dispatches events; 2) the Goodcents workorder management system; and 3) Yukon, the device addressing software managed by Eaton's Cooper Power Systems. All three of these systems require configuration to support event dispatch by substation, and additional costs are incurred in paging and project management. The SAC program funded the project management, paging, and updates to the Yukon and GoodCents databases, while the DR T&D Pilot funded the updates to SEEload. During the DR season of 2016, conditions did not present that required SAC events at the five substations.

In 2014, the BIP dispatch system was programmed to respond to known system capacity constraints in the Bakersfield area, specifically the Lerdo, Famoso, and Magunden substations. No BIP events were dispatched in 2014 that specifically targeted the four substations.

Key Learnings and Future Opportunities

For substations with significant participant penetration, BIP and SAC can bring much to bear if transmission and/or capacity constraints are identified in those locations. However, in the case of SAC in particular, the systems that govern the program's operations require significant time and resources to configure in order to support this level of locational dispatch. To take fullest advantage of these programs' capabilities to deliver fast and reliable load reductions, Distribution Operations should identify substations to target well before the onset of the load control season, specifically, in the fall and winter months so that programming can take place in the first months of the year. It is prudent program management practice to make important updates to the program's operational system during the winter months when the program won't be called upon. Further, given the long lead time and significant costs required to update SAC dispatch systems, Distribution Operations should focus on substations that are likely to remain constrained in future years. For example, while one substation may be expected to be constrained in the coming summer season, it may not be constrained in future summer seasons due to capacity upgrades in neighboring substations. Distribution Operations should take a holistic, multi-year view as to which areas SAC should direct resources for supporting locational dispatch. While the legacy one-way communicating system can support locational dispatch, it requires long lead time and significant dedicated effort. The next-generation two-way communicating direct load control system may be able provide more flexible support for transmission and distribution operations, potentially supporting dispatch by any of PG&E's 800-plus substations.

5 Targeted Observed Triggered Automated Load (TOTAL)

Project Description and Objectives

As PG&E's operational backbone, the T&D system is the locus where three current PG&E strategic operational initiatives are coming together:

1. Leverage demand resources to preserve grid health and deferring capital investments;
2. Use automation to preserve grid health and defer capital investments; and
3. Evolve demand response operations for operation under non-traditional use cases.

The T&D Overload-triggered Automated Locational Dispatch of Demand Response and Distributed Energy Resources (TOTAL-DRDER) project was conceived as a laboratory-scale proof of concept (PoC) effort. TOTAL-DRDER's specific objectives were to confirm by experiment, using existing systems and equipment, that a transmission or distribution system concern can trigger specific demand response resources to shed load instantaneously and automatically, without human intervention. The PoC also demonstrated that once T&D operating conditions revert to normal ranges, load is automatically restored.

In the laboratory setting, this experiment is approached as an information technology (IT) challenge that bridges several functional areas. Lockheed Martin's SEELoad software was programmed for SmartAC™ (SAC) program dispatch, the Eaton's Cooper Power Systems' Yukon headend software was used to address and dispatch load control devices, and PG&E's line sensor system was configured to communicate conditions to an Eaton SMP gateway.

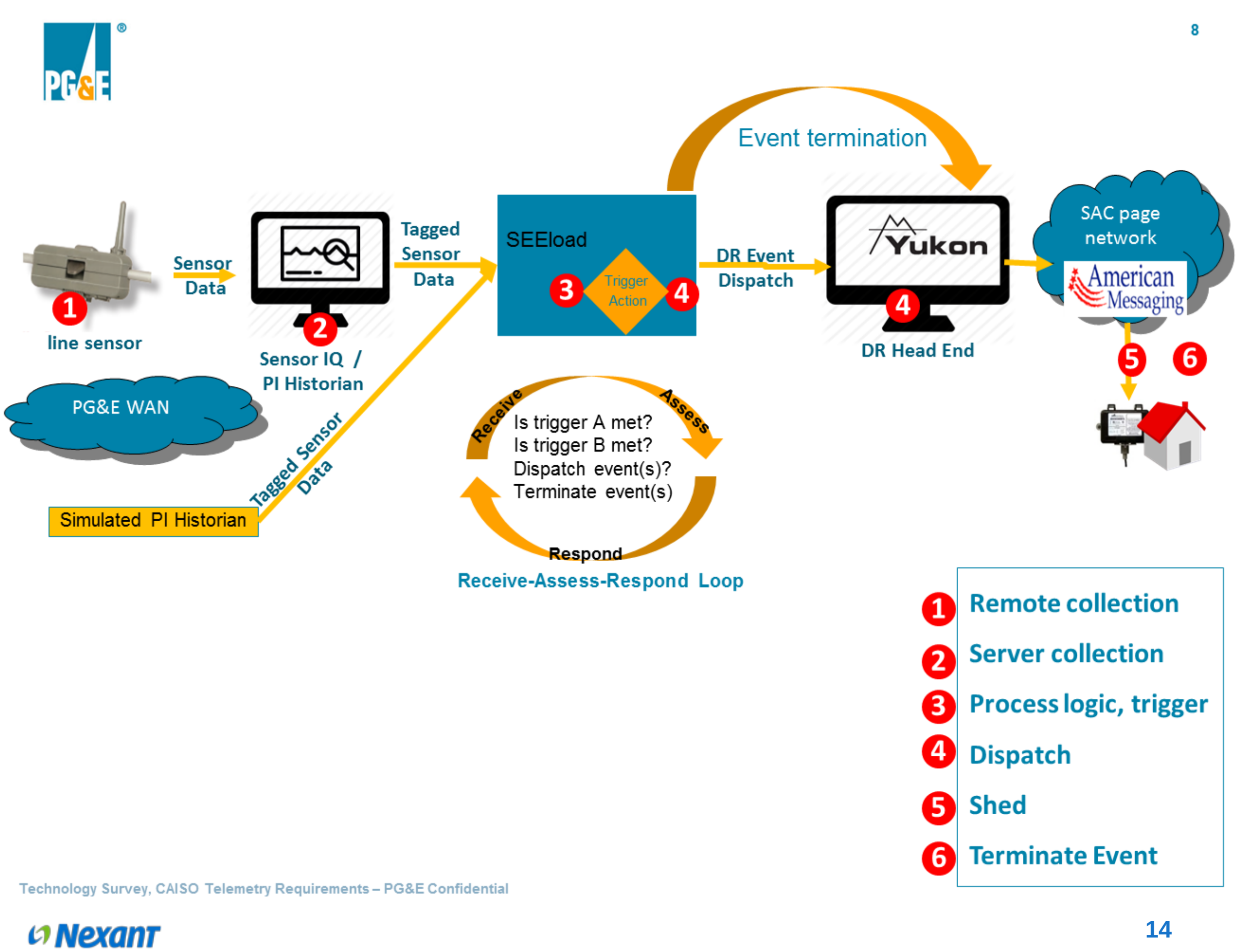
Project Implementation and Results

In December 2016, Lockheed Martin, Eaton's Cooper Power Systems, and PG&E staff successfully demonstrated, in seven end-to-end test runs, that demand response resources can indeed be used in an automated fashion to respond to specific critical conditions in either the transmission or distribution network. The proof of concept demonstrated the following capabilities:

1. End-to-end connectivity;
2. Automation based on rules-based logic;
3. Interface with SCADA;
4. Interface with DR platforms;
5. Customizability for any DR program characteristics; and
6. Secure through authentication and encryptions.

Figure 5-1 illustrates the operational concept demonstrated by TOTAL-DRDER. The SEEload system serves as the hub for an automated “receive-assess-respond” loop that checks for specific triggers to be met. The triggers are initiated by line sensors that send their data through PG&E’s WAN to the Sensor IQ/Historian system, which in turn provides tagged data to SEEload. If the tagged data indicates that the trigger criteria are met, SEEload sends a signal to dispatch load control to Yukon, which sends the signal to load control devices via a paging network. Once the event is dispatched, SEEload continuously monitors incoming data for the criteria to trigger event termination. When those criteria are met, the signal to terminate the event is then sent forward to Yukon.

Figure 5-1: TOTAL Demonstration Process Flow



The TOTAL-DRDER PoC specifically demonstrated a use case involving large transmission service level customers that provide more than 1 MW of demand response each via a DRAS system. Two scenarios were designed to represent transmission line overloads, transformer trips, transformer overloads, and substation overloads.

The first scenario represented a compounded transmission line overload: Beginning with an initial signal that the Taft-Chalk Cliff line went down, followed by a second signal that the Midsun-Midway line went down. As a result, a signal that the Midway-Taft substation is overloaded is received. Two separate automated responses to these conditions were tested, to shed 5 MW of DR resources if the substation was up to 5% overloaded and to shed 10 MW of DR resources if the substation was overloaded by more than 5%.

The second scenario also began with a signal that the Midsun-Midway line was going down, followed by a signal that the Midway transformer tripped. As a result, a further signal was sent that another transformer on Midway is overloading. In response to these conditions, 5 MW of DR resources are automatically shed if the transformer is up to 5% overloaded and 10 MW of DR resources are automatically shed.

Key Learnings and Future Opportunities

The TOTAL-DRDER PoC demonstrated, at laboratory scale, that existing equipment and architecture can be assembled and programmed to provide an automated end-to-end path for system sensors to detect conditions that represent a risk to the integrity PG&E's T&D systems, resulting in an automated dispatch of DR resources.

The line sensors that were used to simulate system conditions are already in use to monitor conductors in PG&E's distribution system. In the future, the sensors that are currently deployed could be used to detect conditions where conductors may become overloaded (e.g., due to a rerouting of load during a heat storm), resulting their degradation or in the lines tripping offline. For broad applicability of this functionality, the current limited network of distribution line sensors would need to be expanded.

The concept demonstrated by TOTAL-DRDER can also be directly extended to the protection of distribution transformers, where Rogowski coils can be used in the same fashion as the line sensors were used here. Extending the use of line sensors into the realm of transmission conductors, thereby opening the door to using this concept to protect the transmission system, would likely to require a longer path to adoption, as line sensors have yet to be integrated into the PG&E transmission system as standard equipment.

The SAC program offers a wide network of CAC units that could potentially be harnessed for this kind of application of automated, localized dispatch of DR resources. However, many use cases, that is, system conditions that could trigger such a dispatch, will require fast response. The current SAC communications system relies on the public paging network which can result in some latency in response to the signal to shed. The SAC program may eventually fully migrate to a more advanced two-way communications backbone, which would reduce communications latency, but its full deployment throughout the SAC system is an investment that PG&E or future third-party direct load control providers still need to evaluate.

While line sensors are not yet integrated as standard equipment on the PG&E transmission system, automating a Special Protection Scheme (SPS) for a single transmission customer is probably the most accessible use case for the TOTAL-DRDER concept, requiring a smaller network of sensors and few, or even single, customer agreements that lay out terms for automated load shed. Automating SPS protocol on the distribution system would be more complicated in that those schemes currently involve a greater number of checks and balances when they are implemented, due to the larger number of customers affected.

Additionally, PG&E's Distributed Energy Resource Management System (DERMS) program is interested in incorporating the functionality demonstrated by TOTAL-DRDER to facilitate emergency DER dispatch, to add value to the system that is currently being designed to provide economic dispatch of DERs.

6 Framework to Integrate DER Impacts into Distribution Load Growth Projection Tools

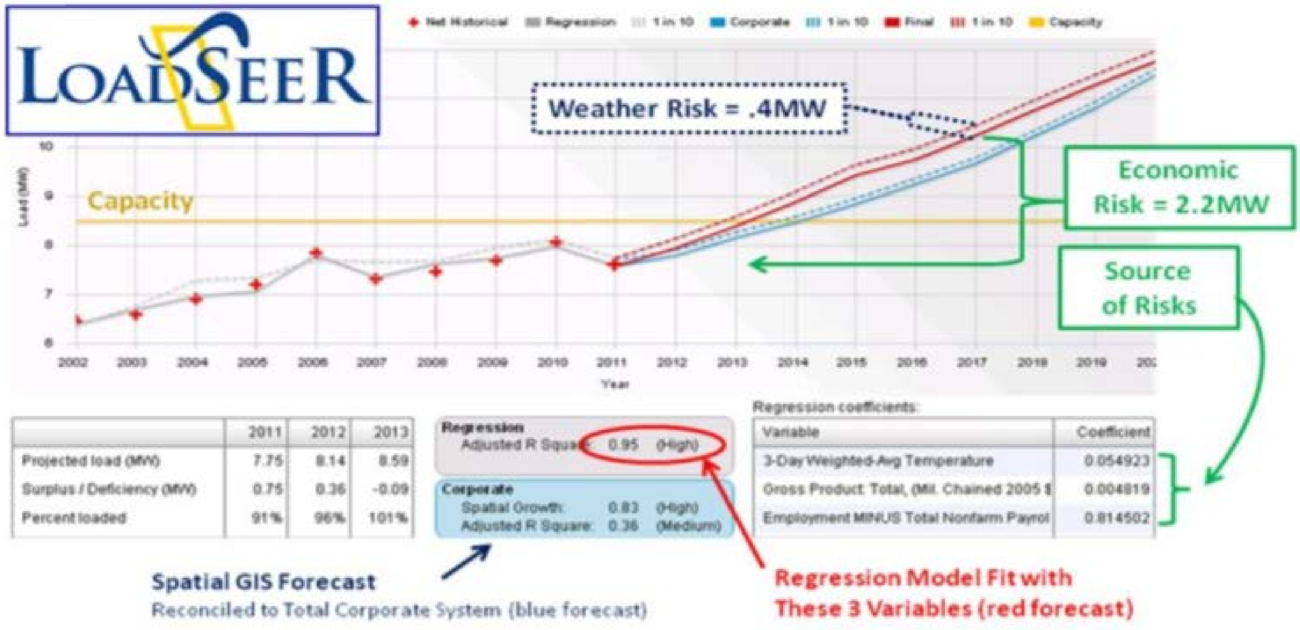
Project Description and Objectives

Distribution planning engineers need data about existing load management resources and how they map to electrical distribution circuits in order to integrate load management into planning. Information on historical load management events is also needed so that it can be added back to historical load data to fully understand load growth patterns. Additionally, distribution planning engineers need to be able to model the addition of demand response (DR) resources at specific locations to determine whether the resource can help defer the need for infrastructure investments.

Project Implementation and Results

PG&E distribution planning utilizes LoadSEER (Spatial Electric Expansion and Risk), a spatial load forecasting software tool designed specifically for T&D planners to estimate load growth and project the impact of resources on the need for infrastructure upgrades. The objective of LoadSEER is to statistically represent the geographic and economic factors, distributed resources, and weather diversity across a utility's service territory. Then, it can use that information to forecast circuit and bank level peak loads, sub-sections of the circuit, acre-level changes, and impacts from various scenarios over the planning horizon. Figure 6-1illustrates a screenshot of an example output from the LoadSEER dashboard.

Figure 6-1: Screenshot of Example Output from LoadSEER



To ensure that both energy efficiency (EE) and DR resources are incorporated into T&D planning processes, EE and DR load shapes were incorporated into LoadSEER. This incorporation accomplished two outcomes:

1. Planners gained visibility into existing resources on circuit feeder and substation loads; and
2. Planners were able to assess the impact of EE and DR on the timing and need for distribution capacity upgrades at the substation bank or circuit feeder level.

Key Learnings and Future Opportunities

This early work funded by the DR T&D Pilot demonstrated that EE and DR resources can be integrated into planning at the local level. Not only did the project lead to better planning, but in some instances it materially impacted the planning assessments. This work was later taken up under EPIC 2.23 and expanded to include all distributed energy resources (EE, DR, distributed generation, energy storage, and electric vehicles.) in support of the mandates under AB317, PUC 769, and the DRP and IDER OIRs.

7 Development of a Distributed Energy Resource (DER) Valuation Framework

Project Description and Objectives

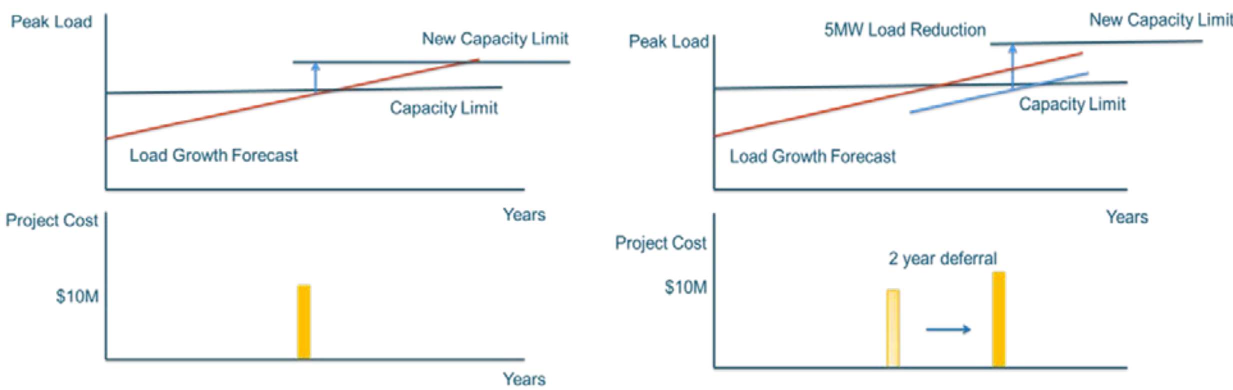
A key element of the integration of distributed energy resources (DER) into distribution system planning is estimating location-specific distribution marginal capacity costs. The CPUC, in D.14-11-042, identified the lack of a consistent methodology to estimate location-specific distribution marginal capacity costs for specific DERs as barrier to integration of resources into system planning.

The DR T&D Pilot funded two studies to address the gap in locational valuation – a white paper on Locational Distribution Avoided Costs, produced by Energy and Environmental Economics (E3), followed by the development of a Locational Distribution Avoided Costs Framework. The two core concepts underlying these studies are the Present Worth method, used to quantify the value of deferral of capacity upgrades and the determination of a dependable capacity contribution, which is analogous to effective load carrying capacity (ELCC) at the distribution level.

Project Implementation and Results

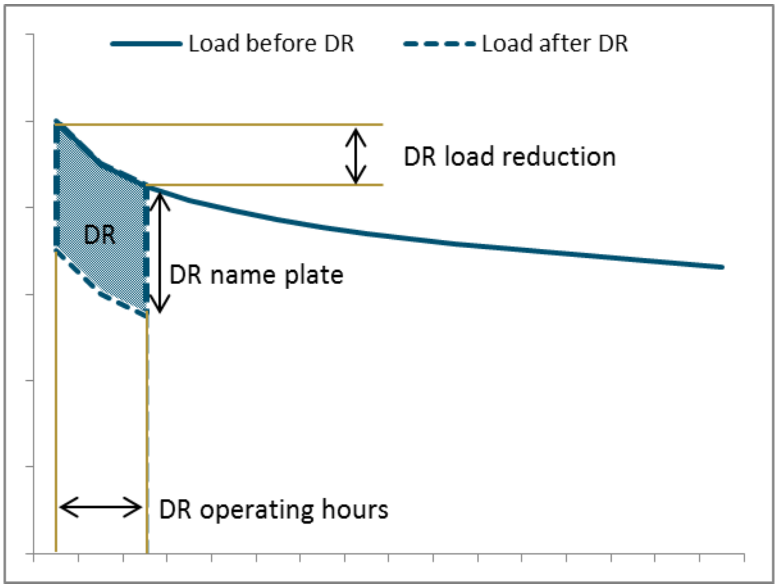
Figure 7-1 illustrates the effect of reducing local coincident peaks on the timing and magnitude of distribution investments. By reducing the coincident demand, the unused capacity can accommodate additional load growth that eventually occurs over time, which helps avoid or defer investments required to meet load growth. The present worth method compares the net present value of investment with and without deferral of the capacity upgrade due to demand reductions.

Figure 7-1: Reducing Coincident Peaks and Deferring Distribution Investments



The second core issue is how operation limitations and dispatch practices influence the dependable capacity contribution of resources and, by connection, their value. If DR resources are not designed to shave peaks, but instead are delivered all at once, they may shift peak to a different period. Figure 7-2 illustrates this concept. Rather than scheduling DR reduction in a precise manner so that the needed reduction are delivered for each hour, DR participants are often dispatched all at once when system load is expected to be particularly high. When dispatched in this manner, demand response resources produce sizeable reductions but those reductions do not translate to comparable reductions in the peak load because a new peak is created. The value of DR can be improved by using more precise dispatch that shaves the load duration curve. This can be accomplished through staggering start times and event duration within existing program rules, so the largest reductions are delivered when they are needed most and the right amount of reductions is delivered for periods when fewer resources are needed. The framework rates resources based on their dependable capacity contribution, factoring in limitations of the resource.

Figure 7-2: Illustration of DR Load Reduction MW vs. DR Nameplate MW



This early work completed by E3 under the DR T&D Pilot was later taken up and expanded upon under the DRP OIR Locational Net Benefit Analysis (LNBA) Working Group resulting in the creation of a publicly-available tool that will be used to estimate indicative locational benefits of DER deployments.[10] The updated DR Cost-effectiveness Protocols that were approved by CPUC Resolution E-4788 look to the results of the DRP LNBA estimates to inform future localized avoided costs estimates for DR resources:

> "It is anticipated that the Distribution Resource Plan proceeding (R.14-08-013) will eventually adopt a locational net benefits methodology that can be used by the DR Cost-effectiveness Protocols to capture the value of avoided T&D costs for cost-effectiveness analysis." – Resolution E-4788, page 8.

Key Learnings and Future Opportunities

The combined effect of the work initiated by Integral Analytics and E3 under the DR T&D Pilot, and later carried to fruition under EPIC 2.23 and the DRP LNBA Working Group, allow PG&E to identify local areas where DR resources (or DERs more generally) are helping to defer traditional capacity build-outs. In turn, this is used to estimate an indicative value of those traditional project deferrals that can inform DR program cost effectiveness.

8 Targeted SmartAC Marketing

8.1 2015 Direct Mail and Telemarketing Campaign

Project Description and Objectives

A marketing effort was undertaken in early summer 2015. It was designed to meet two goals: 1) increase PG&E's SmartAC™ (SAC) program enrollment among customers served by one of four substations,

10 See http://drpwg.org/wp-content/uploads/2016/07/R1408013-et-al-SCE-LNBA-Working-Group-Final-Report.pdf

specifically targeted for peak load management during the summer of 2015, and 2) gain learnings on how the program offer could be modified to enhance program impact in those constrained areas.

Project Implementation and Results

The 2015 SAC targeted marketing campaign was conducted in the spirit of a similar 2014 initiative. In 2014, PG&E experimented with offering customers either an enhanced one-time program participation incentive of $100 or the standard offer of $50. In both cases, once customers were enrolled and program equipment was installed on their central air conditioning (CAC) units, their CAC units would be subject a 50% cycling strategy during load control events. As common sense might dictate, the $100 incentive offer was far more popular, and resulted in a significant uplift in response rates relative to the standard offer. The 2014 marketing effort utilized direct mail and telemarketing communications channels.

In June of 2015, PG&E initiated another targeted SAC marketing campaign, focused on customers served by the Bogue, Barton, Lammers, and Martell substations. Approximately 14,000 customers were reached through direct mail, with fairly even representation among all four substations (around 4,000 contacted customers each), except the Martell substation which had the fewest customers contacted (less than 2,000). Table 8-1 presents the counts of customers reached through the direct mail campaign by substation in 2015.

Table 8-1: 2015 SAC Targeted Marketing – Number of Customers Contacted by Direct Mail

Substation	Number of Customers Contacted by Direct Mail
Bogue	3,712
Barton	4,668
Lammers	3,747
Martell	1,790
Total	13,917

Customers on the direct mail contact list were screened using an enhanced targeting model that combined both propensity to enroll in SAC and load drop capacity. This enhanced targeting model was an improvement over the model used in the 2014 effort that only took into account the estimated propensity of a customer to enroll. The 2015 direct mail campaign consisted of a bilingual (English and Spanish language) package that included an introduction letter, an enrollment form, and a frequently asked questions booklet. The introductory letter highlighted grid reliability and helping the community as benefits of enrolling in the program. It also highlighted that the equipment installation is free and does not require an appointment. The program's one-time $100 enrollment incentive called out prominently. Figure 8-1 shows the English-language cover of the frequently asked questions booklet that was included in the mailing.

Figure 8-1: 2015 SAC Targeted Marketing – Direct Mail Frequently Asked Questions Booklet

The direct mail campaign was followed by a telemarketing campaign that reached 10,303 customers in the weeks directly after the June mailing . Like the 2014 SAC marketing drive, both the 2015 direct mail and the telemarketing efforts were conducted in an experimental manner. Two offers were developed, both utilizing the $100 incentive that proved the most effective in 2014: One offer was for SAC participation with 100% CAC cycling when load control events are launched and another offer was for participation with the standard 50% CAC cycling during events. Here, the objective was to test whether the stronger $100 incentive would be enough to entice customers to accept the more impactful 100% cycling strategy. The experiment, however, demonstrated that the offering 100% cycling over 50% cycling produces a strong headwind against enrollment. The 50% cycling offer produced 38% more enrollments than the 100% cycling offer.

The overall response rates, across all four substations, for the direct mail campaign was 0.7%. The telemarketing response rate was 2.2%. These response rates translate into a cost per acquisition (CPA) of $498 for the direct mail and $405 for telemarketing. It is important to note that these relatively low response rates (and consequently high CPAs) reflect that the 100% cycling strategy that was tested in the campaign proved unpopular. The CPAs cited here are exclusive of the one-time participation incentives.

Key Learnings and Future Opportunities

Leveraging the knowledge and customer relations of marketing and phone-based teams provides unique “boots-on-the-ground” information for developing and implementing targeted marketing campaigns. The key learning from the 2015 SAC targeted marketing activities was that deeper program participation should not be expected to be achieved by upping the CAC cycling strategy to 100%. At least with the $100 incentive, and in this region of PG&E’s service territory, the more aggressive cycling strategy made for an unpopular program offering.

8.2 2016 Direct Mail and Door-to-door Marketing Campaign

Project Description and Objectives

The (SAC) program piloted a door-to-door (D2D) marketing approach in August 2016, providing an opportunity to study whether D2D marketing is an effective method for achieving deep enrollment penetration for demand response programs, and if so, how to improve future D2D campaigns. This marketing aimed to significantly increase program participation in a geographically targeted manner to boost SAC’s ability to address peaking conditions local to those areas. Following the pilot, a study was conducted to examine the effectiveness of the campaign across the four PG&E substations that were included in the pilot. The study identifies the key drivers of the campaign’s outcomes, assesses opportunities to improve future customer targeting and D2D marketing efforts, and quantifies the cost of recruitment through door-to-door marketing.

Project Implementation and Results

Prior to the D2D campaign in August, a supporting direct mail marketing campaign was launched in May 2016, continuing through July 2016. The campaign began with a bilingual (Spanish and English) marketing package that included an introductory letter, a frequently asked questions booklet, and a program application form. Unlike the 2014 and 2015 SAC marketing pushes, there was no telemarketing component in 2016. The letter and informative material used messaging that emphasized helping the community and contributing to the maintenance of a resilient power grid. Additionally, the material promoted SAC participation as a means to help manage electric bills, and noted that statewide electric rates are beginning to change. Energy efficiency programs were cross-promoted in the letter in the context of evolving electric rates as well. Finally, the introductory letter highlighted that enrolling in SAC would not require an appointment and that equipment installation is free. The direct mail campaign was directed only at customers from the four substations that were targeted for increased SAC enrollment in 2016. The mailing lists were once again generated using a targeting model that combined an estimate of propensity to enroll with capacity to drop load.

The incentivization strategy for the 2016 D2D marketing effort in took its cues from the 2014 and 2015 SAC marketing experiments and offered $100, in contrast to the standard program offer of $50 and only offered the 50% CAC cycling option. The mail campaign was directed at approximately 14,000 customers: about 10,300 Sycamore and Notre Dame substation customers, 3,100 Rincon substation customers, and 600 Linden substation customers.

The introductory package was followed up with a postcard mailing that continued promoting the theme of participating in the program in the spirit of helping the community and reminding customers of the $100 enrollment incentive. The postcards further informed customers that a SAC installation contractor would be in the neighborhood soon, to provide free "same day enrollment and installation." Both English and Spanish versions of the postcards were mailed. Figure 8-2 presents an image used in the English language follow-up postcard.

Figure 8-2: 2016 SAC Targeted Marketing – English Language Follow-up Postcard Image

Table 8-2 summarizes the response rates for the 2016 direct mail marketing campaigns. The campaigns were most effective with customers served by the Notre Dame and Sycamore substations, with all three of the mail pieces there garnering more than a 4% response rate in those locations. The introductory package was not successful on its own with customers on the Rincon and Linden substations, however it may have paved the way for the more successful follow-up postcards. The English language postcard resulted in a 3.2% response rate at Sycamore and the English and Spanish postcards generated 3.7% and 4.2% response rates, respectively, at Linden.

Table 8-2: 2016 SAC Targeted Marketing – Direct Mail Response Rates

<table>
<tr><th>Substation</th><th>Introductory Package (Bilingual) Response Rate</th><th>Postcard (English Response Rate</th><th>Postcard (Spanish) Response Rate</th></tr>
<tr><td>Notre Dame</td><td rowspan="2">4.4%</td><td rowspan="2">4.7%</td><td rowspan="2">5.4%</td></tr>
<tr><td>Sycamore</td></tr>
<tr><td>Rincon</td><td>1.0%</td><td>3.2%</td><td>1.4%</td></tr>
<tr><td>Linden</td><td>1.0%</td><td>3.7%</td><td>4.2%</td></tr>
</table>

The CPA for the direct mail campaign was $101. This CPA represents the fact that the SAC program offers promoted by the 2016 campaign were a composite of the best of the offers that were tested in 2014 and 2015: namely, the higher $100 incentive and the less aggressive 50% CAC cycling option. Note that this CPA is exclusive of the $100 per customer participation incentive.

With respect to the D2D marketing effort that followed the direct mail campaign in August 2016, detailed outcomes of the D2D marketing effort is provided in Table 8-3 for each of the substations targeted by the campaign. Across the four substations, approximately 33% of the homes approached had customers who answered the door, and of those customers, approximately 22% signed up for the program, yielding an overall signup rate of 7.3%.

Table 8-3: Detailed Door-to-Door Marketing Campaign Results

<table>
<tr><th>Substation</th><th>D2D Representative Door Knocks</th><th>D2D Representative Homes Approached</th><th>D2D Representative Customer Contacts</th><th>D2D Representative Signups</th><th>Completed Work Orders</th></tr>
<tr><td>Notre Dame</td><td rowspan="2">16,126</td><td rowspan="2">12,577</td><td rowspan="2">4,251</td><td>294</td><td>235</td></tr>
<tr><td>Sycamore</td><td>738</td><td>562</td></tr>
<tr><td>Rincon</td><td>3,487</td><td>2,474</td><td>848</td><td>90</td><td>48</td></tr>
<tr><td>Linden</td><td>845</td><td>845</td><td>121</td><td>33</td><td>22</td></tr>
<tr><td>Total Counts:</td><td>20,458</td><td>15,896</td><td>5,220</td><td>1,155</td><td>867</td></tr>
</table>

The marketing campaign resulted in an uplift in program penetration for substation areas where significant potential for additional enrollment existed. Table 8-4 summarizes the impact of the marketing campaign in terms of net change in program participation. For the Notre Dame and Sycamore substations, program participation as a percentage of eligible customers was boosted significantly. In the Rincon substation, central air conditioning (CAC) saturation is quite low, and a very high percentage of eligible customers were already enrolled in the program. The Linden substation is much smaller than the other areas, and program participation did not change significantly.

Table 8-4: Enrollment Opportunity and Results by Substation

Substation	2012 Local Peak Load (MW)	Total # of Residential Customers	Share of Customers w/ Central AC	# of Eligible Customers	Pre-D2D Enrollment		Post-D2D Enrollment	
					# of SAC Participants	SAC Penetration	# of SAC Participants	SAC Penetration
Notre Dame	21.3	5,683	57%	3,228	269	8%	439	14%
Sycamore	57.2	18,535	57%	10,528	802	8%	1,276	12%
Rincon	20.1	12,688	12%	1,523	595	39%	620	41%
Linden	5.9	1,614	67%	1,077	79	7%	80	7%

Interviews with the D2D pilot's project team revealed insights into ways a D2D campaign for SAC could be improved in the future: while the customer list used for the D2D site visits was generated using an estimate of likely CAC load drop, factors such as building vintage and weather sensitivity of electric loads were not incorporated, which might have indicated the likelihood of actual CAC ownership, was not used in generating the list of customers to visit. Additionally, despite being categorized as medium and high value customers via meter data, visits and re-visits to customer homes were not prioritized based on their value designation.

An analysis of the cost effectiveness of the door-to-door marketing campaign found that recruitment costs were quite high (>$400/kW of load reduction capacity, or $205 per acquisition), meaning that while it is possible to significantly improve program penetration through D2D marketing, it does come at a significant price. This price may, however, still pale in comparison to the cost per kW of deferring infrastructure expansion. While there may be opportunities to reduce the marginal recruitment cost of this marketing method through refining the targeting model and more aggressive recruiting methods for higher value customers, careful consideration should be made to understand whether the potential benefits of high program penetration are warranted.

Key Learnings and Future Opportunities

The pilot yielded a number of key learnings pertaining to the successful use of the D2D marketing channel to provide deeper program penetration in a targeted manner:

- Door-to-door marketing yielded a 33% customer contact rate and 22% customer sign-up rate (as a percent of customers successfully contacted), yielding an overall sign-up rate of 7.3% of targeted customers. This indicates that minimal and efficient touchpoints, beginning with a contact through normal communications channels (here, direct mail) and then allowing direct installers to follow up can result in substantially higher program take-up rates.
- Door-to-door marketing is quite expensive and resulted in an extremely high capacity cost for the Smart AC program (>$400/kW) based on the experience from this pilot.
- Despite filtering customers for potential load drop, there were still a significant number of customers included in the marketing campaign who did not have compatible CAC units. Even with canvassers screening for CAC ownership during in-person visits, 5.6% of the customers who initially signed up for the program through the D2D marketing effort did not actually have compatible CAC units upon technician inspection, making up 22.9% of the cancellations from the marketing campaign.

Opportunities for improvement include the following:

- The customer generation list should take into consideration factors that include the likelihood of CAC ownership in addition to likely load drop;
- The customer list should be prioritized based on customer value designation; and
- Canvassers should maintain customer-level information during door-to-door visits to allow for granular understanding of which customers answered, reasons for non-participation, etc.

9 Residential Behavioral Demand Response

Project Description and Objectives

Opower (now Oracle) implemented the Behavioral Demand Response (BDR) study, as part of PG&E's DR T&D Pilot. The study began in the summer of 2015 and continued through 2016. The BDR study targeted residential customers that are served by 31 specific substations within PG&E's system that have been identified as high priority areas for reducing peak loads. Unlike other DR programs, BDR does not offer any financial incentives for customers to reduce their usage, nor does it require the installation of technology at the customer's premise. Instead, it provides customers with pre- and post-event communications and social comparisons specifically aimed at reducing usage on event days. The fundamental concepts of BDR are very similar to those in PG&E's well-established Home Energy Report (HER) program; however, the key difference is that BDR is designed to target only a few hours on days when electricity demand is high.

The primary objective of the first year of the study was to assess the potential of a non-rate and non-devices type of DR program in the PG&E service territory. The objective of the second year of the study was to ascertain whether there were differences in performance (i.e., load reduction) between the 2015 and 2016 participant cohorts and whether customers behaved differently in year two than in year one. Both studies analyzed the impacts between the groups of customers receiving both home energy reports (HERs) and BDR treatments, customers receiving only the HER or BDR treatment, and customers receiving neither of the treatments.

Project Implementation and Results

The BDR study was implemented as a randomized control trial (RCT) within the structure of the existing HER program. The experimental design is summarized in Table 9-1. More than 100,000 customers were a part of the experiment, where, overall 55,000 customers received the BDR treatment and 47,400 customers did not receive the BDR treatment and were used as a control group.

Table 9-1: BDR Experimental Design

Cohort	Assignment	HER Recipients	HER Control Customers	Total
2015	BDR Treatment	30,200	9,800	40,000
	BDR Control	26,400	8,500	34,900
	Total	56,600	18,300	74,900
2016[11]	BDR Treatment	11,474	3,526	15,000
	BDR Control	9,497	3,003	12,500
	Total	20,971	6,529	27,500
Total	BDR Treatment	41,674	13,326	55,000
	BDR Control	35,897	11,503	47,400
	Total	**77,571**	24,829	**102,400**

The design can be interpreted as facilitating two separate BDR experiments—one within a sample of HER recipients and the second within a sample of non-HER recipients, the control customers. This study design allows for BDR impacts to be estimated separately within each HER group and then compared to assess whether BDR impacts differ between HER recipients and control customers. Load impacts were estimated by using a regression model to calculate the difference in average peak period usage on event days between treatment and control customers.

The primary results from the study were the following:

- For persistent customers enrolled in every event for 2015 and 2016, the average event day (based on all 2015-2016 events) percent reduction was 2.1%;
- On the average 2016 event day (based on the three events), BDR produced a 2.1% (0.05 kW per customer) reduction in peak usage;
- On the average 2016 event day, the 2015 cohort generated a 2.3% (0.05 kW per customer) load reduction compared to the 2016 cohort's impact load reduction of 1.7% (0.04 kW per customer)[12];
- On the average 2016 event day, HER recipients generate smaller impacts than HER control customers, 1.7% (0.04 kW per customer) compared to 2.9% (0.07 kW per customer), respectively; and
- The largest statistically significant impacts in absolute and percentage terms—0.11 kW per customer and 3.8%, respectively, were observed in Stockton[13].

[11] The 2016 cohort was not sampled separately from within HER recipients and HER control customers, but rather from the entire HER-eligible population.

[12] The difference in load impacts by cohort is not statistically significant at the 95% confidence level.

[13] Four out of eleven divisions analyzed had statistically significant load impacts.

Key Learnings and Future Opportunities

The load impacts in 2016 were similar to those in 2015 for the group of persistent customers enrolled in every 2015 and 2016 event; however, it is important to note that temperatures were lower for the 2016 events relative to 2015 events. Additionally, high air conditioning usage customers were found to deliver higher impacts, though low air conditioning users tended to reduce a larger percentage of their base load. While load impacts segmented by high/low air conditioning usage are not statistically significant, there are opportunities for further study and potential for targeting high air conditioning users in future BDR implementations.

An analysis of 2015 and 2016 non-event days showed that impacts on non-event days immediately following event days tended to be larger than the average non-event day. This suggests some amount of spillover for load reduction actions that customers implemented during, or immediately before, event days. Additionally, spillover effects were not found to be limited to days immediately following event days—some modest energy savings were observed several weeks after the previous event. If demand reductions from an event day persist into the following days, future BDR programs could consider avoiding consecutive event days, especially given the trend of lower impacts on the second day.

Finally, the current study was confined to 31 substations where PG&E was attempting to limit load growth, so it is unknown whether load reductions in other areas would be comparable to what was observed in the study. Additional testing could be performed to include samples of customers outside the currently targeted substations to study the persistence of BDR impacts for HER recipients in other locations and under repeated exposure.

10 Bring-your-own-thermostat (BYOT)

Project Description and Objectives

The bring your own thermostat (BYOT) pilot was part of PG&E's DR T&D Pilot and co-funded through the Emerging Technologies (DRET) program. PG&E partnered with three technology vendors[14] to recruit pilot participants within eight PG&E substation areas determined to have local capacity constraints in the overall SmartAC™ (SAC) program area. PG&E successfully implemented the pilot and called four, four-hour long events in September 2016.

The pilot's primary objective was to determine the viability of leveraging already installed smart thermostat technologies as a DR resource that could be ramped up in a relatively short amount of time to provide load relief on capacity-constrained areas on the grid.

Project Implementation and Results

Three third-party thermostat suppliers participated in the pilot and vendors leveraged customers who had already adopted smart thermostat technologies to recruit pilot participants. Customers were screened by PG&E from participation if they were not located in the eight pilot substations, had an address in the vendor's records that could not be matched to PG&E records, were medical baseline

[14] Referred to here as Vendor 1, Vendor 2, and Vendor 3.

customers, or were participants in other demand response programs. The final pilot participants were offered varying financial incentives by the thermostat manufacturers in exchange for allowing their thermostat to be temporarily set back on event days. All BYOT participants were called for the four events. A matched control group was constructed for the recruited customers and a difference-in-differences model was used to estimate load impacts.

The primary results from the pilot were the following:

- Vendor 1's marketing approach produced about 10 times more participants than either that of Vendor 2 or Vendor 3 in about half of the time.
  - ✓ Vendor 1 recruited 639 pilot participants (502 enrolled), Vendor 2 recruited 64 participants (39 enrolled), and Vendor 3 recruited 77 participants (49 enrolled).
- Vendor 1 customers provided consistent and statistically significant load impacts across the four events with an average percent load reduction of 18.6% and an average per customer load reduction of 0.43 kW over the four-hour event period.
- On an aggregate basis, San Jose had the largest impact at 84 kW, and Stockton and Palo Alto had similar aggregate impacts at 43.3 kW and 41.8 kW, respectively.
- Neither the Vendor 2 nor Vendor 3 customer load impacts were statistically significant.[15] These estimates were constrained by much smaller sample sizes of customers enrolled.

Key Learnings and Future Opportunities

Because the Vendor 2 and Vendor 3 customer load impacts were non-significant, the analysis focused on Vendor 1. As seen in other thermostat load control programs, the load impacts from controlling the Vendor 1 thermostat diminish over the event period. The declining load reduction later in the event could be explained by a number of factors. First, approximately 40% of thermostats that started an event did not complete it (i.e., participants opted out at some point during the event). Second, heat gain may be overcoming the impact of the cycling so that the customer's air conditioner begins to cycle at its normal rate as the event proceeds. However, load impact degradation as events wear on may also be due to the setback strategy of the vendor, which was not explicitly provided to PG&E. Vendor 1 stated that "each Vendor 1 learning thermostat has the potential to respond differently to an event rather than receiving a prescriptive adjustment or predetermined standard number of degrees temperature setback." Based on this statement, it's not clear exactly what the setback strategy is for the entire event, nor is it clear how the vendor balances customer comfort and the cycling strategy, or how that strategy might change throughout the event to balance customer comfort and load impacts. However, the evidence observed from the load impacts points to some sort of customized descending temperature set back strategy which could account for at least some of the diminishing load impacts.

From an implementation aspect, each of the vendors took different approaches in customer recruitment and support offered for any customer questions. All three vendors received the same financial compensation per enrolled customer. However, each had very different strategies with what to do with

[15] The impacts for Vendor 2 and Vendor 3 have very wide 95% confidence intervals that in some cases contain zero or negative impacts.

the money relative to their customers. Vendor 1 passed the most money through to its customers via a $60 incentive (Vendor 3 paid $25 and Vendor 2 paid $0) and was able to recruit ten times the customers in less than half the time of the other two vendors. However, the installed base of customers for each vendor and the number of customers being recruited by the other two vendors wasn't clear,[16] so it isn't possible to compare the actual customer offer acceptance rates between the vendors. Should the BYOT pilot be continued for the 2017 season, there is a significant opportunity to learn more about customer acceptance and participation at varying levels of incentives. It would also be informative to observe the override rates from customers who received a larger incentive compared to customers who received a smaller or no incentive through a controlled experiment. This information would be very useful for developing cost-effective program offerings in the future.

When factoring in the recruitment cost per customer, which was uniform across the geographic regions, San Jose (0.5 kW) and Stockton (0.39 kW) clearly provided the best value at nearly twice the average kW impact per customer compared to Palo Alto (0.21 kW). Based on this difference in performance, it could be argued to only continue the pilot in the San Jose and Stockton areas. However, it would be beneficial to conduct a cost-effectiveness analysis to determine the break-even impact per customer required to make the program cost effective at a given level of per customer enrollment incentive. Therefore, it makes sense to continue the pilot in the San Jose and Stockton areas, and it may make sense to continue the pilot in the Palo Alto region if deemed cost effective.

Finally, the average per customer load impacts from controlling the Vendor 1 thermostats (0.43 kW) were only slightly smaller than the load impacts obtained from the SAC program during the previous summer (0.51 kW per customer). This suggests that as the market penetration of Vendor 1 thermostats increases or the geographical scope of the program is expanded beyond the pilot substation areas, the program could become a significant demand response resource.

11 Summary

At the conclusion of the needs assessment phase of the DR T&D Pilot, PG&E developed a broad array of demonstration projects and initiatives designed to test the integration of DR resources into T&D operations and planning. The total of nine 2015-2016 DR T&D Pilot demonstration projects served, in a crosscutting manner, to fill a number of T&D operations and planning needs that were identified in the needs assessment phase of the pilot.

By and large the T&D pilot demonstration projects addressed several of the short-term and mid-term needs for integration of DR into T&D operations and planning. The demonstrations accomplished the following:

- Focused on operations and tools for operating engineers. Operating engineers are central to integration of load management into distribution operations. They model the effect of high

[16] Vendor 3 did not provide the number of customers contacted, and Vendor 2 stated approximately two to three thousand customers were contacted in each of three marketing waves, but it isn't clear if the same set of customers were contacted each time, or if unique groups were contacted for each wave.

temperatures on grid operations and develop the operations game plan that operators implement when loads approach or exceed normal equipment ratings.

- Provided visibility into DR activations and load reductions. Operators needed visibility into DR resources to confirm dispatch and performance. PG&E deployed a Real-time Monitoring System that provided near real-time visibility of CAC direct load control operations to distribution operators and operating engineers.
- Demonstrated the ability to attain deep penetration of load management in targeted areas. For DR to defer distribution infrastructure costs, enough resources of sufficient magnitude need to be acquired quickly enough. SAC engaged in two years of specialized marketing initiatives to iteratively build knowledge of effective program offers and marketing channels, and apply them to targeted areas of the distribution system where constraints have been identified. Additionally, two new demand response products and delivery models were tested (BDR and BYOT), again in a targeted manner among customers served by constrained substations, that demonstrated the possibilities for third-parties to bring a new load management products to a targeted market, and deliver valuable load reductions to PG&E relatively quickly.
- Linked dispatch to system monitoring. A central concept for integrating DR into distribution operations is the ability to automatically dispatch resources based on monitoring of distribution system conditions, based on thresholds set by operating engineers. The TOTAL-DRDER demonstration developed a complete monitoring, communications, and logic system to automatically dispatch demand response resources. The demonstration made use of line sensors, which communicate information to distribution system operators and engineers through the SCADA system. TOTAL-DRDER demonstrated, for the first time, an end-to-end link between line sensors and the dispatch system of a demand response resource. It allowed operating engineers to set a load threshold at individual distribution circuits which, if exceeded, automatically triggered load management before emergency conditions were reached. Tying load management dispatch to monitoring of local loads decentralizes dispatch, moves toward an automated distributed system, empowers operating engineer, and provide a failsafe mechanism for traditional central dispatch. The demonstration was especially valuable because it showed that an automated approach is possible with tools and equipment currently in place. It also indicates how much more is achievable with the continued expansion of the SCADA network and through upgrading load control device communications technologies from one-way to two-way functionality.
- Addressed distribution planning immediate needs. Before the demonstrations, distribution planning engineers lacked data from three sources: 1) existing load management resources mapped to electrical distribution circuits, 2) historical load management events necessary to fully understand load growth patterns, and 3) information about the penetration of load management that could be achieved at specific electrical distribution circuits and the corresponding costs. Due to the DR T&D Pilot initiatives, planners are now able to integrate both EE and DR resources into local planning assessments using LoadSEER software. They also have visibility into where resources are located, and are able to estimate the magnitude of load management penetration that can be achieved at specific locations. In addition, the development of a publicly-available DER valuation tool enables planners to compare DER resources to traditional distribution solutions.

- **Integrated load management resources into the distribution management system.** Two of PG&E's largest existing resources, BIP and SAC, were configured to support calling targeted events in locations where distribution system operators identified capacity constraints. The effort moved DER operations away from the legacy stand-alone dispatch models towards full integration with the active management of the distribution system.

In addition to fulfilling the CPUC's mandates through D. 12-04-045 and D.14-05-025, these efforts have benefited and informed other areas of PG&E regulatory and operational initiatives and strategy, including TDSM initiatives, compliance with CPUC Code 769, DERAPS, and participation in the IDER CPUC proceeding. While the T&D pilot demonstration projects expanded the functionality of DR resources and helped better integrate distributed resources into operations, additional efforts are needed to further refine integration of DR resources into T&D operations and planning. These efforts are being undertaken as part of the Distributed Resource Plan Demonstrations and Integrated Distributed Energy Resources proceedings.