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DEMAND RESPONSE AS A SYSTEM RELIABILITY RESOURCE

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Disclaimer

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Preface

The Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program, managed by the California Energy Commission, conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

The PIER Program strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following RD&D program areas:

- Buildings End-Use Energy Efficiency
- Energy Innovations Small Grants
- Energy-Related Environmental Research
- Energy Technology Systems Integration
- Environmentally Preferred Advanced Generation
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy Technologies
- Transportation

Demand Response as a System Reliability Resource is the final report for the Demand Response as a System Reliability Resource project (Contract Number 500-05-001) conducted by CERTS. The information from this project contributes to the PIER Program's Energy Technology Systems Integration program area.

For more information about the PIER Program, please visit the Energy Commission's website at www.energy.ca.gov/pier or contact the Energy Commission at 916-327-1551.

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- Task 2.2. Participation in Electric Power Research Institute (EPRI) IntelliGrid
- Task 2.3. RD&D Planning for Demand Response Technology Development
- Task 2.4. Time Value of Demand Response (DR)
- Task 2.5. System Integration and Market Research: Southern California Edison (SCE)
- Task 2.6. Demonstrate Demand Response Technologies: Pacific Gas & Electric (PG&E)

Earlier phases of the research were sponsored by the PIER Program through a separate RD&D contract with LBNL/CERTS (Contract # 150-99-003). Research results from these earlier phases were reported in the Final Project Report that can be downloaded from http://energy.ca.gov/2006publications/CEC-500-2006-035/CEC-500-2006-035.PDF.

The technical tasks funded under this Agreement (Contract #500-05-001) include:

- The original contract, called Phase 1, included only two tasks. Task 2.1 revised a test plan that had been developed under the earlier PIER-funded project (Contract # 150-99-003) and conducted an initial round of tests with SCE in accordance with this test plan. Task 2.2 consisted of participation in EPRI Integrated Electric Communications System Architecture (IntelliGrid℠ Architecture) meetings and related discussions with utilities, system operators and other stakeholders in support of the PIER Program's DR objectives.
- A first amendment, called Phase 2, expanded Task 2.1, re-scoped Task 2.2 to become Task 2.3, and added Task 2.4. In Phase 2,
    - Task 2.1 was expanded to include a more expansive test plan, subsequent testing with SCE per the Phase 2 test plan, including the use of a new, near real-time metering technology.
    - Task 2.2 was re-scoped to become Task 2.3, which provided support to the PIER Program's Demand Response RD&D Advisor in planning for demand response technology RD&D.
    - Task 2.4 developed and demonstrated methods to assess the economic and system control value to the California Independent System Operator (California ISO) of fast-responding resources, such as those that can be provided through demand response.
- A second amendment, called Phase 3, further expanded Task 2.1 to include testing of a direct communication link with California ISO and surveys of a sample of participating and non-participating customers.

- A third amendment, called Phase 4, added Tasks 2.5 and 2.6, which were undertaken in support of the California Public Utilities Commission (CPUC) Order # 06-03-024, which directed California Investor Owned Utilities (IOUs) to begin to transition their demand-response resources to participate formally in California ISO markets in their 2009-2011 Demand Response program plans. Task 2.5 expanded the research with SCE that had been initiated under Task 2.1. Task 2.6 initiated a parallel scope of research with PG&E.
- A fourth and final amendment, a no-cost time extension, reopened Task 2.3, at the direction of the Commission Contract Manager. Funds were reallocated to this task to prepare an integrated PIER Smart Grid RD&D planning document, California ISO DR use cases, California ISO telemetry requirements, and design of a building load data storage platform.

Tasks and deliverables described below refer solely to accomplishments that have been completed under the funding for this Agreement, including all four Amendments.

An overview of the Demand Response as a System Reliability Resource project is provided in the Executive Summary. Additional reporting is organized separately for each technical task. Each technical task is accompanied by one or more reports or conference papers that have been published separately.

Table 1: Phases of Energy Commission Contract #500-05-001

Contract: Phase 1	Amendment 1: Phase 2	Amendment 2: Phase 3	Amendment 3: Phase 4	Amendment 4: Fund Reallocation
Tasks 2.1 & 2.2: 2005 – 2007	Tasks 2.1 & 2.2 2006 – 2008	Tasks 2.1 - 2.4 2007 – 2009	Tasks 2.5 & 2.6 2009 – 2011	Tasks 2.3 subtasks fund reallocation 2011 – 2012
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Task 2.2: Participation in EPRI IntelliGrid	Task 2.2: Participation in EPRI IntelliGrid	Task 2.2: Participation in EPRI IntelliGrid	Task 2.6: Demonstrate DR Technologies: PGE. Follow on activity to Task 2.1	Task 2.3: subtask 2: System Dynamics of Programmable Controllable Thermostats
		Task 2.3: RD&D Planning for DR Technology Development		Task 2.3: subtask 3: California ISO DR Use Cases
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Abstract

The Demand Response as a System Reliability Resource project consists of six technical tasks:

- **Task 2.1.** Test Plan and Conduct Tests: Contingency Reserves Demand Response (DR) Demonstration—a pioneering demonstration of how existing utility load-management assets can provide an important electricity system reliability resource known as contingency reserve.
- **Task 2.2.** Participation in Electric Power Research Institute (EPRI) IntelliGrid—technical assistance to the EPRI IntelliGrid team in developing use cases and other high-level requirements for the architecture.
- **Task 2.3.** Research, Development, and Demonstration (RD&D) Planning for Demand Response Technology Development—technical support to the Public Interest Energy Research (PIER) Program on five topics: *Sub-task 1.* PIER Smart Grid RD&D Planning Document; *Sub-task 2.* System Dynamics of Programmable Controllable Thermostats; *Sub-task 3.* California Independent System Operator (California ISO) DR Use Cases; *Sub-task 4.* California ISO Telemetry Requirements; and *Sub-task 5.* Design of a Building Load Data Storage Platform.
- **Task 2.4.** Time Value of Demand Response—research that will enable California ISO to take better account of the speed of the resources that it deploys to ensure compliance with reliability rules for frequency control.
- **Task 2.5.** System Integration and Market Research: Southern California Edison (SCE)—research and technical support for efforts led by SCE to conduct demand response pilot demonstrations to provide a contingency reserve service (known as non-spinning reserve) through a targeted sub-population of aggregated residential and small commercial customers enrolled in SCE's traditional air conditioning (AC) load cycling program, the Summer Discount Plan.
- **Task 2.6.** Demonstrate Demand Response Technologies: Pacific Gas and Electric (PG&E)—research and technical support for efforts led by PG&E to conduct a demand response pilot demonstration to provide non-spinning reserve through a targeted sub-population of aggregated residential customers enrolled in PG&E's AC load curtailment program, the Smart AC™ Demand Response Program.

Keywords: contingency reserves, demand response, utility load-management, reliability resource, frequency control, pilot demonstration, non-spinning reserve.

Executive Summary

The Demand Response as a System Reliability Resource project consists of six technical tasks:

- Task 2.1. Test Plan and Conduct Tests: Contingency Reserves Demand Response (DR) Demonstration
- Task 2.2. Participation in Electric Power Research Institute (EPRI) IntelliGrid
- Task 2.3. Research, Development, and Demonstration (RD&D) Planning for Demand Response Technology Development
- Task 2.4. Time Value of Demand Response
- Task 2.5. System Integration and Market Research: Southern California Edison (SCE)
- Task 2.6. Demonstrate Demand Response Technologies: Pacific Gas & Electric (PG&E)

Earlier phases of the research were sponsored by the Public Interest Energy Research (PIER) Program through a separate RD&D contract with Lawrence Berkeley National Laboratory/ Consortium for Electric Reliability Technology Solutions (Contract #150-99-003).

Task 2.1 Test Plan and Conduct Tests: Contingency Reserves Demand Response Demonstration

The Demand Response Contingency Reserves project's successful demonstration of the use of aggregated demand-side resources to provide contingency reserves gives grid operators at the California Independent System Operator (California ISO) and SCE a powerful new tool to improve reliability, prevent rolling blackouts, and lower grid operating costs.

Deploying contingency reserve is an electricity grid operator's first strategy for maintaining reliability following a major contingency, such as the unplanned loss of a large generation facility or critical transmission line. Using demand-side resources to provide contingency reserves increases the total reserves available to a grid operator and thus will avoid situations in which operators would otherwise run short of generator-provided contingency reserves and have to call for rolling blackouts.

Advances in communications and control technology now make it possible to use aggregated groups of curtailable loads, such as residential air conditioning (AC) units already equipped with load-cycling controls, as a contingency reserve resource that is potentially superior to relying on generators for this service. The natural response capabilities of these loads match the response speed, duration, and frequency required to provide contingency reserve.

In California, residential AC is one type of curtailable load that has the capability to respond faster to system disturbances than generators can. Data gathered in the tests conducted during this research show that residential AC load can be dropped nearly instantaneously (in tens of seconds or less) in response to commands from a system operator. The rapid response possible from using AC load as contingency reserves can improve power system reliability; using AC load as demonstrated in this study shows that load response can be fully deployed much more

quickly than the 10 minutes currently allowed for generators who provide contingency reserves.

The objective of Task 2.1 was to demonstrate that contingency reserves can be provided using demand-side resources in a manner that is comparable to the current provision of contingency reserves using supply-side (i.e., generation) resources. The project approach involved curtailing aggregations of residential AC units controlled by SCE's air conditioning load-cycling program in the manner similar to that used by the California ISO to deploy contingency reserves from generators. This involved both providing near-real-time observability of curtailments in progress, as well as conducting after-the-fact verifications of curtailments.

The project demonstrated that aggregated demand response could be used to provide contingency reserves in a manner comparable to provision of these reserves by generators. In 2008, when research on this task was nearing completion, the California Public Utilities Commission (CPUC) ordered California's investor-owned utilities to initiate pilot demand-response programs that could ultimately participate in California ISO's wholesale markets for day-ahead energy and contingency reserves (non-spinning reserve, initially) in conjunction with California ISO's revisions to these markets, known as the Market Redesign and Technology Update.[1] The activities represent the next logical step toward full commercialization of the concepts demonstrated in this research project. Task 2.5 and Task 2.6 included follow-on research efforts working with SCE and PG&E in direct support of this objective.

Task 2.2 Participation in EPRI IntelliGrid

EPRI's Integrated Electric Communications System Architecture (IntelliGrid℠ Architecture) task sought to develop a new communications architecture, based on the development of open standards, for the power and communications system of the future. EPRI worked with a variety of stakeholders to develop an overall vision for the architecture.

The objective of Task 2.2 was to contribute technical assistance provided by the project team to the EPRI IntelliGrid team in developing use cases and other high-level requirements for the architecture. The task was active from September 2005 through September 2006. The project approach involved participation in IntelliGrid technical meetings as a member of the IntelliGrid Project Advisory Group and a series of discussions with utilities, system operators, and other stakeholders as part of a requirements gathering process that was conducted in support of the PIER Program's Demand Response objectives.

IntelliGrid provided value to California by enabling the California investor-owned utilities (IOUs) to use IntelliGrid concepts in their Advanced Metering Initiative (AMI) developments. PG&E, who is furthest along in AMI developments, appeared to be least active and least influenced by IntelliGrid concepts. From a high level, it appeared that the PG&E AMI plans were less open and less secure than recommended by IntelliGrid.

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[1] California Public Utilities Commission. 2008. *Administrative Law Judge's Ruling Providing Guidance on Content and Format of 2009-2011 Demand Response Activity Applications*.

Task 2.3 RD&D Planning for Demand Response Technology Development

The objective of this task was to provide technical support to the PIER Program. Specifically, support was provided to the PIER Program's Demand Response RD&D Advisor in planning demand response technology RD&D by conducting research on a variety of topics. The topics are:

- *Sub-task 1.* PIER Smart Grid RD&D Planning Document
- *Sub-task 2.* System Dynamics of Programmable Controllable Thermostats
- *Sub-task 3.* California ISO DR Use Cases
- *Sub-task 4.* California ISO Telemetry Requirements
- *Sub-task 5.* Design of a Building Load Data Storage Platform

Sub-task 1. PIER Smart Grid R&D Planning Document

PG&E, SCE, and SDG&E prepared IOU Smart Grid deployment plans at the request of the CPUC. The California Energy Commission solicited three Smart Grid 2020 roadmaps representing the perspectives of the California IOUs, California publicly-owned utilities (POUs), and electric technology vendors. These three roadmaps were compiled by EPRI, Science Applications International Corporation (SAIC), and the NASA Jet Propulsion Laboratory (JPL), respectively.

The purpose of this task was to review, assess, and compare these six documents, specifically to identify the similarities and differences among the roadmaps and the deployment plans and to find dissimilarities, gaps, or omissions within the three roadmaps and the three deployment plans.

SmartGrid 2020 Roadmaps

Areas of Agreement on Smart Grid Needs:
All three reports agreed on the need for key technologies and developments, including in the areas of:

- Advanced communications and controls
- Advanced metering infrastructure (AMI)
- Automated transmission and distribution
- Market Redesign and Technology Update (MRTU) interfaces
- Development of standards and protocols
- Communication infrastructure and architecture (IOUs identified a gap in the network software architecture, which has not kept pace with easy-to-use operating systems and network hardware, and recommended a standardized system architecture design)
- Development and adoption of standardized cyber security protocols (with the lead taken by the Federal Energy Regulatory Commission [FERC], North American Electric

Reliability Corporation [NERC], and the National Institute for Standards and Technology [NIST])

- Energy storage deployment and development (although with different implementation forecasts due to different assessments of the technological readiness)
- Distributed energy resources
- Workforce safety and efficiency

Areas of Diversion:
The three reports differed somewhat on microgrids. Neither the IOU nor the POU roadmap recognized microgrids as an important aspect of the 2020 Smart Grid, while the Technology Manufacturer/Vendor Roadmap viewed microgrids as a valuable component of the 2020 Smart Grid.

In addition, only the technology manufacturers and vendor roadmap addressed the importance of net-zero new construction and retrofitting for the goal of reducing greenhouse gas emissions.

Finally, IOUs and POUs diverged in their level of support for the Smart Grid as the main vehicle for achieving California's policy goals due to concerns by POUs regarding the costs and uncertainties.

Consensus Smart Grid Challenges:
The three roadmaps identified Electric and Hybrid Electric Vehicles as posing a challenge to the future Smart Grid, due to the likelihood that mass penetration of these vehicles will burden the grid. They recommended dynamic pricing models for charging electric vehicles as well as "vehicle-to-grid" energy storage.

The roadmaps also cited the integration of renewable energy as a concern. As a result, they emphasized the importance of standards and protocols for integrating various renewables.

Finally, the three roadmaps noted that the technological capabilities of the residential and commercial AMI technologies would drastically shape demand response capabilities.

IOU SmartGrid Deployment Plans

The deployment plans of each of the IOUs have a similar structure, with concrete and detailed plans for Smart Grid implementation through 2014. However, each of the IOUs had concerns about whether future technological developments will occur to enable a Smart Grid by 2020. Therefore, the plans in the medium-term for Smart Grids between 2014 and 2020 were vague with respect to goals and milestones and contained a wide variation of cost estimates and technological progress. Policy makers should therefore continue to work with the IOUs to develop specific goals and priorities for the 2014-2020 Smart Grid.

Sub-task 2. System Dynamics of Programmable Controllable Thermostats
Thermostatically controlled devices, such as heating ventilation and air conditioning (HVAC), refrigerators, and water heaters, are particularly conducive to load management because they are ubiquitous, store energy, and are major contributors to electricity peak demands. Load

management technologies that take advantage of these opportunities have been available for some time. However, the opportunities for fine-grained control of the aggregate performance of large fleets of these technologies have not been fully explored due to the highly simplified communications and control approaches that were put in place when the technologies were first deployed.

The project approach involved research in system dynamics and controllability of a single load management technology—Programmable Communicating Thermostats (PCT) deployed in the residential sector—and on improving the controllability and reliability of the load management opportunities provided by PCTs through the use of feedback controls.

The simulation techniques developed through this work enable low-cost experimentation with advanced load management control. This experimentation would be very difficult to achieve in any other manner without inconveniencing live subjects through the deployment of unproven hardware to hundreds of houses. The control techniques developed show great promise to transform load management by enhancing controllability and robustness. Of particular promise is the low-frequency pulse width modulation (PWM) technique because it dramatically improves the way power is controlled in a house.

Sub-task 3. California ISO DR Use Cases

Both federal and state regulatory authorities have implemented policies to promote a true supply and demand market for wholesale electricity. This vision would enable the reduction of electricity demand if supply prices increased beyond the tolerance of consumers and, conversely, promote consumption when electricity is both abundant and relatively inexpensive. The key aspect that is missing to fulfill this dynamic market is the ability for consumers to receive and respond to an indicator such as price or signal (e.g., “high,” “average,” or “low”messages) to inform their electricity consumption decisions.

The sub-task utilized use cases to develop a narrative and scenarios for how a regional grid condition index could be developed, and utilized sequential steps with input from each actor (system, company, or individual) in the electricity supply chain from the wholesale market to a customer’s retail electricity service provider.

The Regional Grid Condition Index Use Case provides a communication tool that can be leveraged to develop future requirements for a system developed to provide an index-based signal to be utilized by electricity consumers. However, a continuing challenge is coordinating technology and solution suppliers to both enable the development of the index by the electric power industry and the consumption of the index by electricity consumers. This significant challenge will potentially require regulatory support as well as consumer electronics manufacturer acceptance to become reality.

Sub-task 4. California ISO Telemetry Requirements

The California ISO has nearly 30 documents that describe metering guidelines, installation, inspection and certification requirements, and another 13 or so related to direct telemetry process and requirements. These document provide a mix of "true" requirements (technology

independent functional and non-functional business and technical requirements—the "what"), and specific technology/implementation requirements and specifications (the "how"). The existing documentation provides insight into the objectives of the requirements as well as how the requirements should be met through specific technologies, standards, or a set of criteria.

In this sub-task, the team analyzed the documentation, and captured the requirements in an easy to understand matrix that maps business/operational requirements to the required implementation technology attributes. The matrix is accompanied by a clear summary of the core defining principles (and why they are important), and provides insight into how specific implementation technologies and product embodiments of those technologies can be mapped to the principles and managed over time to meet the business and operational requirements.

This phase of the project successfully captured and associated 875 requirements from 30 documents as a first step in developing potentially more flexible and economically feasible technology metering and telemetry options for market participants.

Sub-task 5. Design of a Building Load Data Storage Platform

The project team developed a prototype database that contains data that different models draw upon to perform their analyses, and developed a lightweight database for storing time-series data based on established code used for previous projects.

The conclusions are separated into two main categories: needs and solutions. With a growing number of buildings with interval meter data, energy management and control systems, energy information systems and other low-cost sensing and monitoring devices, size and availability of time-series data from building operations, distribution systems, and transmission systems are also growing. There is a need to develop flexible, scalable, secure databases to store this data, computational power to process it, and visualization tools to develop it as information to support decision making. This project looks at the various requirements for such data and develops a prototypical database and methods to analyze time-series data from a variety of buildings. This is not a full implementation of a large-scale system but a small representation of it just to demonstrate the importance of these systems and possibilities of using the data in different ways.

Task 2.4 Time Value of Demand Response

Task 2.1 demonstrated that demand response could be fully deployed faster than thermal generation in providing contingency reserves. Fast-responding generation, demand response, and energy storage are valuable resources for power system operation because they enable more precise control than is possible with slower responding resources. For example, coordinated deployment of faster responding resources could improve California ISO compliance with NERC and Western Electric Coordinating Council (WECC) reliability rules for power system frequency control and do so at lower cost. Today, however, California ISO markets and operating practices do not take into full account the speed of the resources that are deployed in order to comply with these rules.

The objective of this task was to conduct research that would enable California ISO to take better account of the speed of the resources that it deploys to ensure compliance with reliability rules for frequency control. The project approach involved:

- Development of a methodology for assessing the response speed of the generation resources currently used by California ISO for regulation and load-following on a consistent basis;
- Application of the methodology to the current fleet of generators used by the California ISO to establish the relative value of faster and slower resources as measured by their contribution to the frequency control objectives of the California ISO (which are reflected in the aggregate performance of these resources in complying with NERC and WECC reliability rules); and
- Use of the findings to develop a scope for follow-on projects that take the speed of resource response rates into account more fully, so that the California ISO could implement the concepts demonstrated in this project.

During the course of this research, the project team developed a methodology and quantified the relative value of fast responsive generation resources that could be used for regulation and load following balancing services in California. Compared with slow-responding resources, fast-responding resources, including generation, demand response, and some types of energy storage can be more valuable regulation and load-following resources, if they are applied in the exact moment and at the exact amount needed.

Controls that take greater advantage of these capabilities could provide better compliance with reliability rules for power system frequency control, while at the same time requiring less total regulation capacity. Fast-responsive resources could reduce California ISO regulation procurement by up to 40% (on average). California ISO practices and markets should be modified to take greater advantage of the regulations capabilities offered by generation, demand response, and energy storage resources that could be made available to the California ISO.

Task 2.5 System Integration and Market Research: Southern California Edison (SCE)

The research completed under Task 2.1 demonstrated that aggregated demand response could be used to provide contingency reserves in a manner comparable to provision of these reserves by generators. In 2008, when research on that task was nearing completion, the CPUC ordered California's investor-owned utilities to initiate pilot demand-response programs that could ultimately participate in California ISO's wholesale markets for day-ahead energy and contingency reserves (non-spinning reserve, initially) in conjunction with California ISO's revisions to these markets, known as the Market Redesign and Technology Update.[2] These activities represent the next logical step toward full commercialization of the concepts

[2] California Public Utilities Commission. 2008. *Administrative Law Judge's Ruling Providing Guidance on Content and Format of 2009-2011 Demand Response Activity Applications*.

demonstrated in Task 2.1. Two tasks were added to provide technical support to these CPUC ordered programs at SCE (Task 2.5) and PG&E (Task 2.6).

The objective of Task 2.5 was to provide technical support to efforts led by SCE (a California IOU) to respond to CPUC Order #06-03-024, which directed IOUs to being to transition their demand-response resources to participate formally in California ISO markets. The project team provided research and technical support to efforts led by SCE to conduct demand response pilot demonstrations to provide a contingency reserve service (known as non-spinning reserve) through a targeted sub-population of aggregated residential and small commercial customers enrolled in SCE's traditional air conditioning load cycling program, the Summer Discount Plan (SDP).

During the course of this research, the project team demonstrated that small aggregated air conditioning load could act as a participating load (PL) resource. Specifically, the team found that:

- SCE's SDP program can perform to the timing requirements of a 10-minute response for non-spinning reserve ancillary service (AS).
- While SCE's SDP program can meet the 10-minute response time for AS, reacting to California ISO 5-minute instructions to modify the amount of demand response provided (described as Partial Dispatch in Section 6.3) is a significant challenge. The SDP dispatch platform can yield results within 5 minutes. However, the ability to refine the dispatch performance to something other than an all-or-nothing resource in response to varying 5-minute instructions from California ISO is a significant challenge. A few alternatives to achieve this "throttling" of the SDP resource are being explored including:
    - Modifying the cycling percentage during the course of the event where the cycling percentage would increase to provide more MW and the cycling percentage would decrease to provide less MW of demand response.
    - Dispatching and restoring different groups based on the incremental amount of DR needed by the change in dispatch instructions from California ISO.
- The first option will require significant systems development to achieve this more enhanced functionality, and the second option is a challenge given that proxy demand resource (PDR) dispatch depends on specification of a regional sub-load aggregation point (SLAP) and proxy node ("pNode").

Task 2.6 Demonstrate Demand Response Technologies: Pacific Gas & Electric (PG&E)

The objective of Task 2.6 was to provide technical support to efforts led by PG&E (a California IOU) to respond to CPUC Order #06-03-024, which directed IOUs to being to transition their demand-response resources to participate formally in California ISO markets. The project team provided research and technical support to efforts led by PG&E to conduct a demand response pilot demonstration to provide a contingency reserve service (known as non-spinning reserve)

through a targeted sub-population of aggregated residential customers enrolled in PG&E's AC load-curtailment program, the Smart AC™ Demand Response Program.

The conclusions from the work conducted in 2009 are as follows:

- AC load control programs can start resources quickly (typically within 60 seconds), and generally ramp up to full capacity in less than 7 minutes, with roughly 80% of the available demand reduction begin to be delivered in less than 3 minutes.
- AC electric demand patterns can be transmitted in near-real time, providing operators information about the resources available and confirmation of demand reductions being delivered.
- The demand reductions observed in the AC end-use data were also observable in the feeder loads; however, this is only true under hot temperatures for feeders with a high penetration of participants in air conditioner load control programs.
- The demand reductions that can be delivered vary by time of day and temperature conditions and communication network signal strength. Systematic test operations can provide valuable information about the variation and help produce better estimates of the magnitude of resources available. It can also help identify areas where the communication network requires reinforcement.
- Repeated short-term AC curtailments (15 minutes or less) did not lead to statistically significant differences in customer satisfaction or comfort.
- Many large AC load control programs exist across the United States, many of which control tens or hundreds of thousands of AC units. For example, PG&E's program currently controls over 160,000 AC units, and a full-scale use of those resources could provide approximately 100 MW of load reduction for ancillary services (AS) for most summer days, and upwards of 200 MW for system peaking conditions.
- However, several additional steps need to be undertaken to utilize air conditioning loads for grid operations and incorporate them into markets. These include determining rules on how to conduct settlement for AS bid into markets by load control programs. Generally, the bulk of the payments are related to availability, with penalties for failure to deliver the resourced bid in. AC load control is a unique resource for AS in that their capability is variable though highly predictable. In addition, telemetry requirements need to be re-defined so that they provide operators to confirm that air conditioning resources have been dispatched without imposing substantial costs. This likely means relying on samples rather than requiring telemetry of each individual unit. In addition, the processes for delivering specific amounts of resources need to be systematically done so operators can request discrete amount of resources (i.e., partial dispatch of air conditioning resources).

The conclusions from the work conducted in 2011 are as follows:

Much of the debate to date regarding settlement methods for demand reduction has focused on day-matching baselines, metering requirements, and telemetry. Our research shows that day-matching baselines are not well suited for measuring air conditioning demand reductions.

Moreover, more granular meters do not necessarily increase the accuracy of demand reduction measurement because measuring demand reduction is fundamentally different than measuring the output from generation resources.

The fact that relatively accurate estimates can be obtained using pre-calculated tables of demand reduction estimates raises several questions. Is it really necessary to use more complex and more expensive estimation approaches for each individual air conditioning curtailment event? How much value does the incremental accuracy of more complex estimation approaches and metering provide for settlement? How much value is gained by increasingly granular measurement (1-minute versus 15-minute data)?

A practical approach is recommended for settlement. It involves using tables with pre-calculated load reductions per air conditioning unit to estimate demand reductions over the summer, conducting a more detailed evaluation at the end of the summer to reconcile settlements, and updating the demand reduction tables on an annual basis using a transparent process that allows for independent verification by a third party. As the measurement uncertainty in annual evaluations improves and the number of air conditioning load operations increases, the accuracy of the tables is expected to increase. The use of such tables allows for quick settlement when resources are dispatched and provide operators a quick estimate of the demand response resources available for operations.

The accuracy of pre-calculated tables depends in part on the amount of historical curtailment data incorporated, the quality of the evaluations, and the granularity of the tables. When possible, it is highly recommended that direct load control program administrators systematically execute test operations to better define the performance of the programs and that they rely on large sample sizes, with random assignment of devices to curtailment operations, and a difference-in-differences method.

1.0 Task 2.1 Revise Test Plan and Conduct Tests for the Demand Response Contingency Reserves Demonstration

1.1. Introduction

1.1.1. Background and Overview

The Demand Response (DR) Contingency Reserves project was a pioneering demonstration of how existing utility load-management assets can provide an important electricity system reliability resource known as contingency reserve. Reliance on aggregated demand-side resources to provide contingency reserve provides grid operators at the California Independent System Operator (California ISO) and Southern California Edison (SCE) with a powerful new tool to improve reliability, prevent rolling blackouts, and lower grid operating costs.

Deploying contingency reserve is an electricity grid operator's first strategy for maintaining reliability following a major contingency—such as the unplanned loss of a large generation facility or critical transmission line. Reliance on demand-side resources to provide contingency reserves increases the total reserves available to a grid operator, and thus will avoid situations in which operators would otherwise run short of generator-provided contingency reserves and have to call for rolling blackouts.

Advances in communications and control technology now make it possible to use aggregated groups of curtailable loads, such as residential air conditioning (AC) units already equipped with load-cycling controls, as a contingency reserve resource that is potentially superior to relying on generators for this service. The natural response capabilities of these loads match the response speed, duration, and frequency required to provide contingency reserve.

In California, residential AC is one type of curtailable load that has the capability to respond faster to system disturbances than generators can. Data gathered in the tests conducted during this research show that residential AC load can be dropped nearly instantaneously (in tens of seconds or less) in response to commands from a system operator. The rapid response possible from using AC load as contingency reserves can improve power system reliability; using air-conditioning load as demonstrated in this study shows that load response can be fully deployed much more quickly than the 10 minutes currently allowed for generators who provide contingency reserves.

1.1.2. Task Objectives

The objective of Task 2.1 was to demonstrate that contingency reserves can be provided using demand-side resources in a manner that is comparable to the current provision of contingency reserves using supply-side (i.e., generation) resources.

1.2. Project Approach

The project approach involved curtailing aggregations of residential air conditioning units controlled by SCE's AC load-cycling program in manner similar to that used by the California ISO to deploy contingency reserves from generators. This involved both providing near real-

time observability of curtailments in progress, as well as conducting after-the-fact verifications of curtailments.

The project team was led by Joe Eto, Lawrence Berkeley National Laboratory. The project team consisted of Lawrence Berkeley National Laboratory (LBNL), Oak Ridge National Laboratory, RLW Analytics, BP Global, and—most important of all—Southern California Edison, which hosted the demonstration. Significant technical support and direction for the project was provided by the California ISO.

In Phase 1, the project team:

- Developed test plans and performed tests based on input from Technical Advisory Committee (TAC) members, externals reviewers, and the Commission Contract Manager.
- Target-marketed SCE's AC load-cycling program, called the Summer Discount Plan (SDP), to 350 customers on a single SCE distribution feeder.
- Developed an external website with real-time telemetry for viewing curtailments of the aggregated loads on this feeder, and
- Conducted 37 short-duration curtailments (5–20 minutes) of the air-conditioning units of participating customers on this feeder, which is comparable to the deployment of contingency reserves by California ISO.

In Phase 2 and Phase 3, the project team built on the initial findings from Phase 1 to explore four major topics necessary to transition this demonstration from a proof-of-concept into a commercial activity, including:

- Development of expanded test plans based on input from TAC members, external reviewers, and the Commission Contract Manager, and conducting of load curtailments (tests) within four geographically distinct feeders involving just under 800 customers to determine the transferability of target marketing approaches, better understand the performance of SCE's load-management dispatch system, and examine temperature-related factors affecting AC use by SCE's participating customers.
- Deployment of specialized, near-real time AC monitoring devices to better understand the effectiveness of the aggregated load curtailments observed at the feeder.
- Integration of information provided by the AC monitoring devices with information from SCE's load-management dispatch system to measure the time required for each step in the curtailment process.
- Establishing connectivity with the California ISO to explore the steps involved in responding to California ISO-initiated requests for dispatch of contingency reserves.

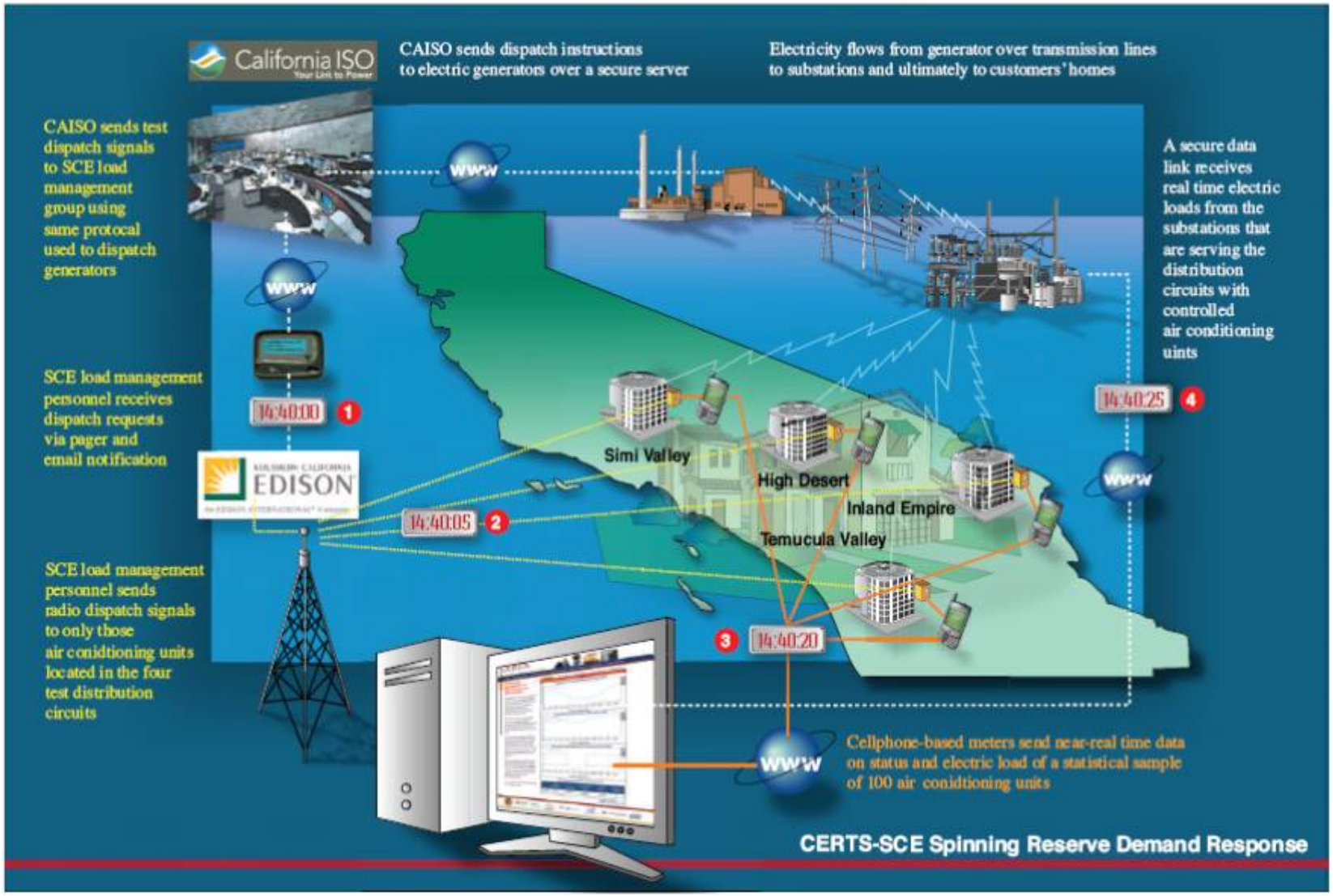

Figure 1: CERTS-SCE Spinning Reserve Demand Response

In addition, in Phase 3, the project team sought to understand, demographically, more about SCE's SDP participating and non-participating customers, including the characteristic of their households and their AC use behavior through customer surveys administered by SCE.

In all phases of the project, the recruitment of participants, the cost and installation of the AC load-cycling devices, the maintenance and operation of the load-cycling deployment systems, and the substation feeder metering associated with the testing were paid for solely by SCE; these activities were not included as costs in this Agreement.

1.3. Project Outcomes

This project was the first-ever, full-scale demonstration of the aggregation of individually small demand-response resources (residential AC units) to provide contingency reserves.

In conducting the demonstration, the project team began to address three critical institutional issues that hindered provision of contingency reserves with demand-response resources:

First and foremost, Western Electric Coordinating Council (WECC) reliability rules currently preclude provision of certain contingency reserves (i.e., spinning reserves) from demand-response resources. Although these rules were not written intentionally to exclude demand-response resources, they consider only supply-side resources because no one had previously considered using demand-response resources for this purpose.

Second, as a result of the WECC rules, system operators have had no experience relying on demand-response resources for contingency reserves. An important prerequisite to changing WECC reliability rules involves helping operators gain confidence and experience in providing contingency reserves with demand-side resources. Prior research conducted by Public Interest Energy Research (PIER) Program confirms that operators want DR to be as reliable and effective as generators in providing contingency reserves.[3]

Third, market rules related to aggregation, metering, load verification, and settlement must be reviewed and, where appropriate, modified so that aggregated demand-side resources can participate effectively and meaningfully in the California ISO's wholesale markets where contingency reserves are procured competitively.

In addition, the project team also showed, through the choice of technology employed in this demonstration (SCE's 25+ year-old AC load-cycling program), how a traditional utility load-management asset could be repositioned as a competitive asset whose value is established by wholesale markets for reliability services.[4] In doing so, the project team illustrated the potential

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[3] Kueck, J. and B. Kirby. 2004. *Demand Response Research Plan to Reflect the Needs of the California Independent System Operator*. ORNL/TM-2003/2, January.

[4] Many other demand-side technologies could provide contingency reserves in a manner comparable to that demonstrated in this project. These technologies include, in principle, other utility load-management assets as well as newer demand-response technologies, such as programmable communicating thermostats.

that these assets, which have long been paid for by utility ratepayers, can provide even greater value if the utility uses them to both improve reliability and lower the cost of securing reliability services. In this case, this could be accomplished by the utility using these assets either to meet its own contingency reserve requirement or by selling these reserves into the competitive markets that the California ISO relies on to procure them.

Key findings from the demonstration project included the following:

- Target-marketing a utility's air-conditioning load-cycling program to customers served by a single distribution feeder can be a successful strategy. SCE successfully recruited a high proportion (nearly one-third) of eligible customers to participate in the Phase 1 demonstration. This is a dramatic increase in participation from the typical one- to two-percent response rate that SCE obtains from its traditional mass-marketing approach for the load-cycling program. For this demonstration, the traditional mass-marketing technique was augmented with direct phone and door-to-door solicitations, endorsements from city officials, and marketing at community-based events.
- Repeated curtailment of customers' air-conditioning in a manner similar to the deployment of contingency reserves can be accomplished *without a single customer complaint*. In Phase 1, SCE curtailed the participating customers' air-conditioning units 37 times during the final portion of Southern California's cooling season for durations lasting from five to nearly 20 minutes. This is in contrast to "normal" curtailments for residential customers participating in the SDP, which are triggered by California ISO-declared stage-two emergencies or local SCE transmission emergencies, typically lasting from one to four hours. After each normal curtailment event, SCE typically receives hundreds of requests by customers seeking to withdraw from the program. However, SCE received no complaints resulting from the curtailments conducted in all Phases of this demonstration.
- The surveys conducted in Phase 3 indicated that customers were unaware that curtailments had taken place. Customer survey results interestingly reported that five households (9%) noticed interruptions during the summer. One home claimed to have noticed three five-minute interruptions to their service, while the other four homes reported noticing interruptions of 15 minutes, 30 minutes, and one hour. To the project team's knowledge, no interruptions of this length were conducted on the circuit. These people might be incorrectly attributing some other AC problem or natural AC cycling to a program interruption. Regardless, all five households who noticed interruptions reported that they never became "uncomfortably warm" nor were they "inconvenienced" by the interruptions.
- Load curtailments can be fully implemented much faster than ramp-up of thermal generation. In Phase 1, considering only a single distribution feeder, full response was measured in 20 seconds. In Phase 2 and Phase 3, the SCE load-management dispatch system consistently demonstrated full response from all four distribution feeder groups in less than 80 seconds. This performance includes fixed delays totaling one minute, which are inherent in the preparation and transmission protocols of SCE's current

dispatch system. In the future, these fixed delays might be improved or eliminated through enhancements to SCE's dispatch software. The actual time between the instant when an individual tower is directed to send a dispatch signal to a distribution feeder group and the time when the switches within this group confirm receipt of the signal is consistently less than 20 seconds. The project team also examined a variety of scenarios in which load shedding and restoration was initiated by simulated requests received from the California ISO's automated dispatch system, and found that a complete end-to-end dispatch could be completed reliably in less than two minutes. This response is significantly faster than the requirements for contingency reserve, which allow generators up to 10 minutes to provide full output. Moreover, the data collected suggest that it is technically feasible to further reduce the latencies associated with each step in the curtailment process and thus achieve full response nearly instantaneously.

- Real-time visibility of load curtailments can be achieved using an open platform and secure website. The project team demonstrated a highly flexible, open (yet secure) data integration, archiving, and presentation platform that allowed external audiences (e.g., electricity grid operators) to view curtailments in real time. The project team maintains that viewing the aggregate behavior of the controlled loads on this feeder can be directly compared to viewing the performance of generators, which are routinely equipped with comparable telemetry. In the future, reliance on flexible, open platforms, such as the one demonstrated in this project, will lower the costs associated with ensuring that operators have real-time information about aggregated loads and with verifying the performance of these programs in real time.
- The aggregate impact of DR from many small, individual sources can be estimated with varying degrees of reliability through analysis of distribution feeder loads.[5] The project team developed a new analytical method to both quantify the magnitude of DR and establish the statistical significance of this estimate. The project team demonstrated that the method could be applied with roughly comparable results using either high-time-resolution, real-time (eight-second) or low-time-resolution, archived (two-minute) distribution feeder data. The project team also found that applying the method to data combined from multiple feeders further improved the statistical reliability of the estimates. However, the method did not provide statistically significant results for two of the four distribution feeder groups. The reasons for this unexpected finding were explored and found to be related to problems with the dispatch signals sent from one of the transmission towers in the SCE's load-management dispatch system for one feeder and due to the small number of participants in and low AC use by these participants in the second feeder.
- Monitoring individual AC units helps to evaluate the efficacy of the SCE load-management dispatch system and better understand AC energy use by participating customers. A significant number of installed monitoring devices were not able to

[5] This year's research did not examine the frequency responsive capability of demand response in provision of spinning reserve.

confirm receipt of dispatch signals from the SCE load-management dispatch system, which among other things pointed to a limitation of the communication portion of the system, as previously noted. The project team also found very modest levels of AC energy use by many of the monitored units on the days when curtailments were conducted, which both gave insight into AC energy use patterns related to temperature and geographic location and helped us more accurately analyze the extent of actual (and potential) load curtailment.

- Monitoring individual AC units provides an independent data source to corroborate the estimates of the magnitude of aggregate load curtailments and gives insight into results from estimation methods that rely solely on distribution feeder data. When estimates of actual load curtailed based on distribution feeder data were statistically significant, they were also close in magnitude to estimates based on AC monitoring data. The project team was able to further close the gap between the absolute values from these two sources by adjusting the sample of monitored units to include data from only those units that confirmed receipt of dispatch signals. In other words, monitoring AC units allowed the project team to decide with greater confidence that units that did not confirm receipt of load-shed signals likely did not take the requested action; by narrowing the sample to the units that the project team knew had received the dispatch signal, the actual curtailment could more accurately be measured.
- Analysis methods developed for this project could one day be used to predict the magnitude of load curtailments as a function of weather and time of day. The project team developed statistical methods to estimate the load that would have been experienced without a curtailment and means for comparing this estimated load to actual loads observed during curtailments. The project team also conducted exploratory analyses that confirmed a relationship among the magnitude of the load curtailment, ambient weather conditions, and, to a lesser but still important extent, time of day. The methods are all based on after-the-fact review of distribution feeder loads. Ultimately, it should be feasible to predict the magnitude of a load curtailment as a function of time of day and expected weather conditions. Additional curtailments under a wider range of weather conditions along with more information on the behavior of individual units would be required for this analysis.

1.4. Conclusions and Recommendations

1.4.1. Conclusions

This project demonstrated that aggregated DR could be used to provide contingency reserves in a manner comparable to provision of these reserves by generators. In 2008, when research on this task was nearing completion, the California Public Utilities Commission (CPUC) ordered California's investor-owned utilities (IOUs) to initiate pilot demand-response programs that could ultimately participate in California ISO's wholesale markets for day-ahead energy and contingency reserves (non-spinning reserve, initially) in conjunction with California ISO's

revisions to these markets, known as the Market Redesign and Technology Update (MRTU).[6] The activities represent the next logical step toward full commercialization of the concepts demonstrated in this research project. Task 2.5 and Task 2.6, described later in this report, included follow-on research efforts working with SCE and Pacific Gas & Electric (PG&E) in direct support of this objective.

1.4.2. Recommendations

Based on the above findings, the project team recommends the following activities toward full commercialization of DR as resources in California ISO contingency reserve markets:

- Utilities should consider refining and using targeted marketing approaches to capture additional location-specific benefits from customer demand-response programs. Maximizing the effectiveness of target marketing requires careful coordination among multiple groups within a utility and among contractors supporting the utility in its marketing efforts. The sequencing of mass mailing, targeted mailings, and targeted telemarketing, along with recruitment procedures (mail-in and call-in) and ultimately installations should be planned as a whole. The execution of these elements, especially when conducted by different departments (some of whom rely on contractors), should be centrally coordinated to minimize customer confusion and process applications and installations efficiently.
- Utilities should consider monitoring individual end-use devices to obtain an independent estimate of load curtailments and assess the performance of the load-management dispatch system. Monitoring need not be ongoing if its sole purpose is to document the time required for loads to respond. For the purposes of independently estimating load curtailments, samples of 20 to 30 individually monitored AC units appear to be adequate to characterize populations of 200 to 400 or even 600 participants.
- Utilities should continue efforts to advance the accuracy and precision of methods that use distribution feeder data to estimate load curtailment impacts. Estimating the magnitude of curtailed load by analyzing distribution feeder data requires methods that can reliably extract the "signal" that indicates the aggregate effect of responding AC units from the ever-present background "noise" (i.e., the stochastic nature of the loads) on distribution feeders. The strength of the signal depends on the number of participants on a feeder, as well as the load relief provided by each participant. In this regard, it will be important to understand the relationship between program recruitment methods and the energy use behavior of program participants. The relative amount of noise in distribution feeder data compared to the strength of the signal provided by responding participants diminishes as the number of feeders is combined. Thus, although low participation on any given feeder may make it difficult to estimate load curtailment, combining data from multiple feeders will likely improve relative precision,

[6] California Public Utilities Commission. 2008. *Administrative Law Judge's Ruling Providing Guidance on Content and Format of 2009-2011 Demand Response Activity Applications*.

other things (such as the amount of load relief provided by each participant) being equal.

1.4.3. Benefits to California

The California ISO's, CPUC's, and California IOU's current efforts to increase reliance on DR to provide contingency reserves—which were significantly advanced through the demonstrations conducted under this task—will improve system reliability, prevent rolling blackouts, and lower system operating costs.

1.4.4. Task References

A complete discussion of the research and findings is contained in two technical reports:

Eto, J., J. Nelson-Hoffman, C. Torres, S. Hirth, R. Yinger, J. Kueck, B. Kirby, C. Bernier, R. Wright, A. Barat, and D. Watson. 2007. *Demand Response Spinning Reserve Demonstration*. May. (LBNL-62761). http://certs.lbl.gov/pdf/62761.pdf.

Eto, J., J. Nelson-Hoffman, E. Parker, C. Bernier, P. Young, D. Sheehan, J. Kueck, and B. Kirby. 2009. *Demand Response Spinning Reserve Demonstration—Phase 2 Findings from the Summer of 2008*. (LBNL-2490E). http://certs.lbl.gov/pdf/lbnl-2490e.pdf.

A refereed conference paper was published based on the findings from the work conducted in 2008:

Eto, J., J. Nelson-Hoffman, E. Parker, C. Bernier, P. Young, D. Sheehan, J. Kueck, and B. Kirby. 2012. *The Demand Response Spinning Reserve Demonstration—Measuring the Speed and Magnitude of Aggregated Demand Response*. Proceedings of the 45th Annual Hawaii International Conference on System Sciences. Wailea, HI. Jan. 4-7, 2012. http://ieeexplore.ieee.org/xpl/articleDetails.jsp?reload=true&arnumber=6149131&contentType=Conference+Publications

2.0 Task 2.2 Technical Participation in IntelliGrid Activities

2.1. Introduction

2.1.1. Background and Overview

The Electric Power Research Institute's (EPRI's) Integrated Electric Communications System Architecture (IntelliGrid SM Architecture) task sought to develop a new communications architecture, based the development of open standards, for the power and communications system of the future. Figure 2 shows the variety of stakeholders that EPRI worked with to develop an overall vision for the architecture.

Figure 2: Schematic view of architecture from EPRI IntelliGrid

2.1.2. Task Objectives

The objective of Task 2.2 was to contribute technical assistance to the EPRI IntelliGrid team in developing use cases and other high-level requirements for the architecture. The task was active from September 2005 through September 2006.

Note that the PIER Program, distinct from this Agreement, also provided direct support to EPRI for IntelliGrid activities (see California Energy Commission Contract #500-01-006).

2.2. Project Approach

The project approach involved participation in IntelliGrid technical meetings as a member of the IntelliGrid Project Advisory Group (PAG) and a series of discussions with utilities, system operators, and other stakeholders as part of a requirements-gathering process conducted in support of the PIER Program's DR objectives. All activities were undertaken in close coordination with the PIER Program's Demand Response RD&D Advisor.

The project team attended a workshop on May 17, 2005; an IntelliGrid steering committee meeting in Washington DC on August 2-3, 2005; a working session on August 15, 2005; and participated in web conferences on September 19, and October 11, 13, and 21.

In December 2005, the project team conducted a survey of all IntelliGrid participants from California IOUs. The intent of the survey was to determine the value and usefulness of IntelliGrid to these California IOUs, and ultimately to the ratepayers of California.

2.3. Project Outcomes

The project team attended numerous PAG meetings and workshops in 2005, and gained valuable insights into IntelliGrid and the associated projects. The information gathered and the knowledge gained from utilities and other IntelliGrid partners has helped guide the PIER Program in ways that were both relevant and useful to the industry. In addition, through this process, the results of related Energy Commission and LBNL research were transferred to IntelliGrid private sector partners, especially to the utilities. The project outcomes are summarized below and in three documents that were prepared during the course of the project as internal memos to the Energy Commission:

Survey of IntelliGrid Project Advisory Group Members

This survey assessed the degree to which IntelliGrid members, who were employees of California IOUs, participated in and benefited from IntelliGrid activities. Key observations from the IntelliGrid PAG survey include:

- Advanced Metering Initiative (AMI) was of great use in the development of roadmaps and project planning.
- AMI cases used by California IOUs were based on those created in cooperation with Intelligrid and their participation on the PAG.
- Utilities became aware of, and then specified standards based upon, Intelligrid.
- Utilities planned to use knowledge gained from Intelligrid as part of their AMI planning process.

Meeting notes from the IntelliGrid Steering Committee, Washington, DC, August 2005

The Intelligrid Steering Committee is responsible for the direction, effectiveness, and activities of the larger Intelligrid PAG. The PAG consists of representatives from major utilities nationwide, including California IOUs—PG&E, SCE, and San Diego Gas & Electric (SDG&E)—who are stakeholders in the IntelliGrid activity. The role of the IntelliGrid Steering Committee is to assess and understand the needs, requirements, and concerns of the utility industry at large as represented by members of the PAG. Ultimately, the role of the IntelliGrid Steering Committee is to make the IntelliGrid activities relevant and meaningful to California utilities and ratepayers.

The August 2005 meeting included members from the U.S. Department of Energy, the Energy Commission, Bonneville Power Administration Consolidated Edison, Electricité de France, Long Island Power Authority, and TXU Business Services. One of the key purposes of the

meeting was to evaluate the status and influence of IntelliGrid. Key observations from the IntelliGrid Steering Committee meeting include:

- The complexity of IntelliGrid requires communication at different staff levels and different technical levels.
- There was a need to create a consistent message between white papers, presentations, and other outreach activities.
- There is a need to get vendors involved who will ultimately develop products by themselves.

In addition, results from an anonymous survey of 15 IntelliGrid partners include:

- Some frustration with lack of progress.
- Members expect a difference between being a member and just watching from outside.
- IntelliGrid message needs to be translated for various audiences.
- IntelliGrid should influence standards, not be one.
- Utilities don't even use existing standards—why will they use IntelliGrid influenced standards?

Summary of LBNL IntelliGrid Activities for 2005

The project team concluded that participation was valuable for the following reasons:

- Involvement provided the Energy Commission with insight into and an evaluation of IntelliGrid (as well as associated projects), which helps the Commission make decisions about IntelliGrid in the future.
- Knowledge gained from utilities and other IntelliGrid partners helps guide the PIER Program and LBNL's Demand Response Research Center (DRRC) in ways that will be relevant and useful to the industry.
- The results of related Energy Commission and LBNL research on advanced metering infrastructure, DR, and associated communications technology were transferred to IntelliGrid's private sector partners (e.g., utilities).

2.4. Conclusions and Recommendations

2.4.1. Conclusions

IntelliGrid provided value to California by enabling the California IOUs to use IntelliGrid concepts in their AMI developments. PG&E, who is furthest along in AMI developments, appeared to be least active and least influenced by IntelliGrid concepts. From a high level, it appeared that the PG&E AMI plans were less open and less secure than recommended by IntelliGrid.

IntelliGrid PAGs conducted valuable work, using input from utilities to define use cases, and reference designs. Unfortunately, the IntelliGrid message may not have received the "traction" necessary to adequately influence the future of the grid. The following may be factors:

- The work conducted by PAGs, and the IntelliGrid message itself were complex.
- The value proposition and proactive steps moving forward were not entirely clear.
- The marketing approach was not evaluated.

2.4.2. Recommendations

The project team recommends re-scoping this activity as follows:

- Focus should be expanded beyond the activities of IntelliGrid, to also include additional organizations such as GridWise/GridWorks, Power Systems Engineering Research Center, and the Galvin Electricity Initiative that are pursuing closely related objectives.
- Where possible, cross-pollinate and seek constructive harmonization among these and other organizations, which collectively seek to develop what has now come to be known as the "smart grid."

2.4.3. Benefits to California

The IntelliGrid Consortium's vision is "a new electric power delivery infrastructure that integrates advances in communications, computing and electronics to meet the energy needs of the future." Progress toward this vision, which now extends beyond scope of what was the IntelliGrid Consortium, will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services products to the marketplace.

3.0 Task 2.3 RD&D Planning for DR Technology Development

3.1. Introduction

3.1.1. Background and Overview

The objective of this task was to provide technical support to the PIER Program. Specifically, support was provided to the PIER Demand Response RD&D Advisor in planning DR technology RD&D by conducting research on a variety of topics. The topics are:

- Sub-task 1. PIER Smart Grid R&D Planning Document
- Sub-task 2. System Dynamics of Programmable Controllable Thermostats
- Sub-task 3. California ISO DR Use Cases
- Sub-task 4. California ISO Telemetry Requirements
- Sub-task 5. Design of a Building Load Data Storage Platform

Sub-Task 1: PIER Smart Grid R&D Planning Document

PG&E, SCE, and SDG&E prepared California IOU Smart Grid deployment plans at the request of the CPUC. The Energy Commission solicited three Smart Grid 2020 roadmaps representing the perspectives of the California IOUs, California publicly-owned utilities (POUs), and electric technology vendors. These three roadmaps were compiled by EPRI, Science Applications International Corporation (SAIC), and the NASA Jet Propulsion Laboratory (JPL), respectively.

The purpose of this task is to review, assess, and compare these six documents, specifically to identify the similarities and differences among the roadmaps and the deployment plans and to find dissimilarities, gaps, or omissions within the three roadmaps and the three deployment plans.

Sub-Task 2: System Dynamics of Programmable Controllable Thermostats

DR in the form of load-management technologies can be used to modify power consumption to address electricity supply constraints. Thermostatically controlled devices, such as heating ventilation and air conditioning (HVAC) equipment, refrigerators, and water heaters are particularly conducive to load management because they are ubiquitous, store energy, and are major contributors to electricity peak demands. Load management technologies that take advantage of these opportunities have been available for some time; however, the opportunities for fine-grained control of the aggregate performance of large fleets of these technologies have not been fully explored due to the highly simplified communications and control approaches that were put in place when the technologies were first deployed.

Sub-Task 3: California ISO DR Use Cases

This use case describes consumers utilizing a regional grid condition signal to enable more informed decisions regarding electricity usage. The regional grid condition signal provides both information as well as actionable data to adjust the operation of consumer devices to help

support grid conditions and provide savings to all consumers. The regional grid condition signal includes:

- Market prices—in an Independent System Operator (ISO) or Regional Transmission Organization (RTO) market, the condition of the grid can be understood by the magnitude of the price in a specific location and the differences in prices across locations.
- Location—the ISOs and RTOs represent transmission grid conditions through locational marginal prices. The difference in price indicates congestion in the transmission system such that lower cost generation cannot reach the load in the higher cost area. This information can be captured in a locational index that would utilize a standardized messaging format across different regions for consumption by devices.
- Reliability index—an input or adjustment by the utility distribution company to a higher or lower number depending on the distribution grid condition in the local area.
- Advisory indicator—a trend indication up or down, or a series of the forecast reliability index over some period of time.

In addition to providing electricity consumers with information regarding the grid condition, enabling a signal that can be received and processed by devices to automatically react to the signal according to consumer preferences accomplishes the objectives to align end-user response based on grid conditions and maintain reliability while keeping the choice in the hands of the consumer.

Sub-Task 4: California ISO Telemetry Requirements

The California ISO has nearly 30 documents that describe metering guidelines, installation, inspection, and certification requirements and another 13 or so related to direct telemetry process and requirements. These documents provide a mix of "true" requirements (technology-independent functional and non-functional business and technical requirements—the “what”), and specific technology/implementation requirements/specifications (the “how”). The existing documentation provides insight into the objectives of the requirements as well as how the requirements should be met through specific technologies, standards, or a set of criteria. In this phase of the project, the team analyzed the documentation and captured the requirements in an easy-to-understand matrix that maps business/operational requirements to the required implementation technology attributes. The matrix is accompanied by a clear summary of the core defining principles (and why they are important), and provides insight into how specific implementation technologies and product embodiments of those technologies can be mapped to the principles and managed over time to meet the business and operational requirements.

Sub-Task 5: Design of a Building Load Data Storage Platform

As the use of DR increases—and in particular Automated Demand Response (AutoDR), where loads are shed according to predictable routines—there is an increasing need for the analysis of building performance in DR programs. Currently, different groups perform analysis using their own developed models. Because this is new research, much of the data and code ends up stored in ad hoc forms developed by different entities. Data storage tends to be primitive, developed

for use with specific projects, and tends to not be used following the specific analysis performed. Additionally, models and analysis are often viewed as one-off, and are not typically designed to run continuously against large data sets with standard interfaces. A second issue with the status quo is that models are typically tested against the data and against themselves, but models are not often compared head-to-head against one another to test predictive power and the statistical certainties of their prediction. The use of statistical metrics to compare models in this space is relatively rare; the use of computer science metrics to compare models is practically non-existent, even for ones as simple as speed of execution.

As this work continues to be successful, the type of analysis currently being performed must scale up. The project team envisions a future in which a large fraction of buildings, either state-wide, nationally, or worldwide, have their load data stored so it can be analyzed by various models and algorithms, not only for DR performance, but also for other activities such as monitoring, fault detection, and controls. There is an immediate need to address this gap of enterprise-level data storage, scalability, and model evaluation in a head-to-head fashion.

The project team set up scalable data storage for recorded building load data, designing this platform to be scalable and powerful, so that it can meet the needs of a myriad of projects while remaining efficient and elegant. The project team also took several modeling methods that have been developed by different groups at LBNL and applied them to data in the database. The project team studied the successes and failures of the architecture of the data storage as well as generated an analysis that was used to begin evaluating the performance of models against one another, using both statistical/predictive metrics (how well do these models make predictions) and computer science metrics (how much resources do these models need to work).

3.2. Project Approach

Sub-Task 1: PIER Smart Grid R&D Planning Document

The roadmaps and deployment plans were reviewed and assessed separately as two different groups, and the deployment plans were compared to the roadmaps. A set of overarching conclusions and recommendations were prepared.

Sub-Task 2: System Dynamics of Programmable Controllable Thermostats

The project approach involved research in system dynamics and controllability of a single load management technology—Programmable Communicating Thermostats (PCT) deployed in the residential sector—and on improving the controllability and reliability of the load management opportunities provided by PCTs through the use of feedback controls. The research was conducted through simulation studies that were based on models of the DR network hardware, software, and communications, as well as research on and review of three Smart Grid Roadmap reports.

Sub-task 2 was led by Dave Auslander and the research was conducted primarily by Bill Burke, both from UC Berkeley.

The project team used the simulations to conduct advanced controls research from the perspective of two distinct yet coupled categories of load management control:

1. Systemic control, which aims to modulate the aggregate power consumption to achieve a common goal. It assumes that a super-agent, such as an ISO, power company, or commercial aggregator, communicates with each consumer individually and directs their consumption toward the common goal.
2. Individual control, which considers each consumer connected to a common DR network as an autonomous agent. Each agent makes independent decisions about how much electricity to consume based on information exchanged with other agents through the network. The information exchange is guided by the common goal established by the super-agent.

The coupling between the two types of control occurs through communications between agents and the super-agent. The robust control of residential DR network with low-bandwidth input was designed to enable control of residential DR networks. The project team simulated these systems to have full control over them:

- The project team created a modular and extensible systemic simulation of DR networks composed of large numbers of independent houses with random parameters. The parameters were chosen based on a stochastic flow chart. The expanded simulation also included autonomous occupants. Individual occupants were not commonly modeled because of their variability, but the solution developed by the project team treats this variability directly. The super-agent uses discrete control logic and communications with the agents to implement systemic control. These advanced controls for demand response networks were designed to create a hierarchical system consisting of systemic and local controls.
- The project team also constructed and verified a modular and extensible dynamic simulation of an advanced load management system capable of examining the response to different systemic and individual demand response control strategies. The load group simulation was designed to consider individual and systemic control directly by modeling large groups of agents separately from the super-agent. The agents were fully independent of one another (and the super-agent), and each one consisted of a dynamic simulation, addressable communications, and discrete controls. The super-agent used discrete control logic and communications with the agents to implement systemic control.
- The team also focused on the fundamental performance characteristics of low-frequency pulse width modulation (PWM) design to improve the control of HVAC compressors for advanced load management. The most common type of residential HVAC compressor operates at only a single speed and is either off or on at full power. Because of maintenance and reliability concerns, the compressors must cycle at relatively low frequencies. Furthermore, heat transfer dictates that the system (i.e., house) reacts slowly to the HVAC input and environmental inputs, meaning there is considerable residual in the system output (inside temperature).
- The team also created a residential occupied neighborhood simulation (RON-Sim), which included dynamic occupants. In this simulation, each house contained a number

(usually one or two) of independent occupants and each occupant had a unique, randomly selected, set of comfort and schedule parameters. The parameters were chosen based on a stochastic flow chart using predefined ranges of values. The occupant interactions with the house were governed by a stochastic state machine. A sampling of the states were: away from home, at home and asleep, at home and comfortable, at home and uncomfortably hot, and at home and uncomfortably cool. The occupant experienced the environment (via inside temperature and time of day) and moved through the states based on random decisions guided by the unique comfort and schedule parameters. Further, when in an 'at home' state, the occupant could interact with the thermostat to become more comfortable by changing the set-point temperature. Through this interaction, the occupant modified the power demand of its house, and therefore the aggregate demand was modified by the population of occupants.

Sub-Task 3: California ISO DR Use Cases

This project utilized use cases to develop a narrative and scenarios for how a regional grid condition index could be developed and utilized by different actors to provide information related to the electric system status and potential costs. The narrative and scenarios utilized sequential steps with input from each actor (system, company, or individual) in the electricity supply chain from the wholesale market to a customer's retail electricity service provider. A scenario is a sequence of events that describes one way to use a particular system to achieve a business goal or objective. The scenario contains steps that tell the story in detail. Each step identifies an actor who is performing the action in the step and a description of what that actor's action accomplishes to incrementally move towards the business objective as well as identifying the actor and actions for any subsequent steps.

Sub-Task 4: California ISO Telemetry Requirements

This project was essentially a research effort to review existing California ISO documentation to capture and correlate the functional and non-functional requirements as well as business rules applicable to California ISO market participants related to metering and telemetry. The business rules provided the business need and context to determine why a certain piece of information or a process step is needed. The business rules are the foundation for the lower-level requirements that provide the details for what needs to be done (non-functional requirements) and how it should be done (functional requirements). The relationships and hierarchy of California ISO metering and telemetry requirements were captured in the resulting matrix.

Sub-Task 5: Design of a Building Load Data Storage Platform

This work mainly involved collecting and managing large data sets of building electric load data. The project team developed a prototype database that contains data that different models draw upon to perform their analyses. The project team developed a lightweight database for storing time-series data based on established code used for previous projects.

Framework for Running Models

Using the Python programming language[7], the project team developed a framework that automated the comparison of results from different statistical models when applied to various datasets. The framework is able to perform the following tasks:

- Extract datasets from the database
- Create data structures required by the models, such as matrices of explanatory variables
- Run the models on the selected datasets
- Quantify the model performance according to a variety of metrics, such as root mean squared error (RMSE)
- Tabulate the results

Optionally, the framework is able to vary meta-parameters such as the number of days of data used to fit the models and the number of parameters of the Self-Exciting Threshold AutoRegressive (SETAR) models (see below) to quantify how the accuracy of model predictions varies as a function of these parameters.

This framework is configured to run on the National Energy Research Scientific Computing Center (NERSC) supercomputer machines at LBNL. The advantages of running on NERSC are that the project team has a common platform to measure data access and model performance runtimes and are able to run all the models in parallel, drastically reducing the time to recover the analysis potentially by several orders of magnitude. By constructing a general framework, we gain two more advantages. The first advantage is that we are easily able to extend the analysis by adding new models, datasets, and performance metrics over time. The project team can also continuously run analysis with little overhead; even after the project ends, we are able to continue generating analysis with small amounts of human-time, extending the utility of this project beyond the end date. Because the framework is responsible for accessing the data, it is easy to switch from the prototypical database to the BigData database when that becomes available. The second advantage is that the framework can be used for future projects to parallelize analyses elsewhere, because the framework naturally runs in a parallel environment (although it will run on single processor machines as well).

Statistical Models for Initial Comparison

The framework is written so that it can work with any statistical model that is provided. The current project used the framework to compare two statistical models:

- Linear regression with the following explanatory variables: time of week, outdoor temperature, and holiday indicator variables. This is a standard model used at LBNL. It has the advantages of being widely familiar and computationally fast. However,

[7] Python is dynamic programming language that is used in a wide variety of application domains. Python is often compared to Tcl, Perl, Ruby, Scheme, or Java. (http://www.python.org)

statistical assumptions built into the model are not true of real data, and the model does not exploit temporal correlation in the data.

- SETAR model was used for computational speed and simplicity. The project team constrained the number of threshold parameters in the model to a small number (less than four). These models incorporate temporal correlation and exploit cyclical variation in the data. However, they are computationally expensive and can perform badly if data contain outliers or have certain characteristics that differ from the assumptions in the model.

Data Sets for Initial Model Comparisons

The project team had about 80 facility-years of data provided by PG&E, as well as data from other sources. Given the short time available for this project, the project team used a restricted subset of the data by pre-selecting data that do not have an obvious change in behavior (such as a large change in base load) during the interval being fit. In the future, the project team intends to automate the recognition of such changes and to develop ways to model such data sets, but our current SETAR implementation does not cope well with these characteristics.

Alternatively, if time permits the project team may fit all of the available data and simply quantify the poor performance of the problematic datasets.

3.3. Project Outcomes

Sub-Task 1: PIER Smart Grid R&D Planning Document

All three roadmap reports addressed the Smart Grid of 2020 based on a different set of assumptions. It was not always possible to present common ground among them.

The EPRI report reflected the common viewpoint of the major California IOUs on the roadmap for the Smart Grid of 2020. The roadmap defined key capabilities and needs in six broad technical areas (referred to as "domains"): (1) communications infrastructure and architecture, (2) customer systems, (3) grid operations and control, (4) renewables and distributed energy resources integration, (5) grid planning and asset efficiency, and (6) workforce effectiveness. The report also identified existing Smart Grid activities and assumptions about the factors that will continue to drive Smart Grid development. The report highlighted challenges, such as maintaining and/or increasing reliability in the face of increased grid complexity, and managing technologies at different levels of maturity. The EPRI report also provided a gap analysis and recommendations for policy makers.

The JPL report addressed the roadmap for the Smart Grid of 2020 primarily from a technology perspective. The report identified eight critical technologies and corresponding use cases, each of which was instrumental in meeting the 2020 California Smart Grid goals. The critical technologies included rooftop photovoltaics, energy storage, combined heat and power (including both natural gas and biomass), AMI, DR capabilities, distribution, automation, electric vehicle accommodation, and microgrid accommodation. The report provided a specific and necessary sequence of events and timeframe, from the 2010 Baseline to 2020, for each

technology. JPL viewed the rapid development of numerous standards as highly important to the progress of adoption for many of these key technologies. Additionally, the report authors argued that policy makers and manufacturers should emphasize and demonstrate the benefits and importance of each key technology to promote adoption among utilities and consumers.

The SAIC report utilized the Smart Grid Maturity Model (SGMM) to analyze the current status and implementation plans for each of the participating Publicly Owned Utilities (POUs) with respect to seven use cases (the SGMM defined the cases). These use cases involved: substation automation, advanced metering, distributed energy resources, demand response, distribution automation, electric vehicle charging, and asset management. The report created separate roadmaps for "leaders" and "followers," resulting in two technology roadmaps and fourteen implementation roadmaps for the seven use cases. Each of the roadmaps spanned the years 2011 to 2020 in two-year timeframes. The report detailed a number of important differences between POUs and IOUs, which included the small size and lower capitalization of many POUs, along with the lack of business models to follow.

PG&E, which serves the San Francisco Bay Area, drafted its Smart Grid deployment plan in June 2011 for its service area. The four major components of the PG&E Smart Grid Implementation plan were enhanced consumer awareness, integration of renewable energy, improvement of grid infrastructure, and market forecasting improvement. However, the PG&E plan contained less emphasis on renewable integration than the IOU Smart Grid roadmap prepared by EPRI. PG&E planned to spend $800 million to $1.2 billion over the next twenty years on Smart Grid projects. These projects had an unknown cost benefit, ranging from $1 to $2 billion. Like the other IOU plans, this document contained more specific timetables and goals through the short term (through 2014), with PG&E touting their recent Smart Meter deployment. PG&E leaders were optimistic that they would meet the four goals in their report for implementing Smart Grid technologies by 2020.

SCE, which serves the Los Angeles Metropolitan Area, drafted a deployment plan for the Smart Grid with four major components: enhanced consumer awareness, substation and distribution automation, transmission automation, and improved asset management. The SCE Plan outlined $400 million in Smart Grid investments, while allocating an additional $130 million to research and development of further technologies.

Like the other IOU deployment plans, the SCE implementation plan was more specific for the short-term goals and milestones (through 2015). However, the plan did not contain much detail about deployment plans for the 2015-2020 time period. By contrast, the PG&E and SDG&E plans spent more time discussing future technologies regarding renewable integration than SCE.

SDG&E, which serves the San Diego Metropolitan Area, released its Smart Grid deployment plan in June 2011 for its service area. The SDG&E plan emphasized the anticipated benefits of the Smart Grid, including integration of renewable energy from the state's 33 percent Renewable Portfolio Standard by 2020. SDG&E planned to invest $3.6 billion in the Smart Grid by 2020 and anticipated economic benefits between $3.8 and $7.1billion. Like the other IOU

deployment plans, the SDG&E implementation plan was more specific for the short-term (through 2014). The SDG&E plan acknowledged that customers in its service area were early adopters and would quickly take advantage of consumer-oriented Smart Grid implementation efforts. Additionally, while SDG&E was proceeding with the Smart Grid deployment plan within the parameters of current California laws, SDG&E will likely continue to facilitate Smart Grid implementation even without further policy drivers, based on the strong business case for deployment.

Sub-Task 2: System Dynamics of Programmable Controllable Thermostats

Collectively, findings from this sub-task are as follows:

- The preliminary work on robust control of residential demand response network with low bandwidth input was concerned with the control of residential DR networks with low input bandwidth. It was nearly impossible to exactly model a very high order nonlinear stochastic system such as a residential DR Network, because it is rarely possible to even recognize every state. Unfortunately, much traditional controller design is rooted in accurate system modeling. Additionally, low input bandwidth makes control difficult because the input cannot keep up with the output fluctuations. These types of systems present considerable difficulty for controller design. However, the project team demonstrated the robust control of residential DR network with low bandwidth input, a sliding mode controller, using the load group simulation. Preliminary results indicated that the design methodology has great promise by producing good performance while controlling the aggregate demand to a defined reference.
- The project team determined that traditionally low-frequency PWM systems use a non-linear hysteresis controller for temperature setpoint following. The cycle rate was not directly defined; instead the width of the hysteresis band determined it. Hysteresis control was very simple to implement, model free, and robust. Unfortunately, it had a number of disadvantages when viewed from a modern perspective. Operating the HVAC compressor using low-frequency PWM offered performance comparable to hysteresis control but with dramatically improved control for load management. There are a number of advantages using low-frequency PWM control over traditional control of HVAC compressors. Firstly, any linear or non-linear control design technique producing a proportional input signal can be used to control the unit. Another advantage is that the power consumption of the unit can be explicitly controlled using tunable saturation limits, which is particularly important for load management and real-time energy pricing. Finally, operation of multi-stage and variable HVAC compressors becomes much easier with a proportional control signal.
- The project team obtained interesting results to demonstrate the capabilities of the simulation. Several different individual and systemic control scenarios applied to a network of residential intelligent thermostats were examined. The project team's first demonstration showed the basic case of a PCT with static thermostat setback control. Dynamics to the agents and super-agent to implement payback smoothing were added.

Then, an intelligent agent responding to energy price sent from the super-agent was demonstrated.

- The team demonstrated that RON-Sim has the potential to better vet advanced DR control techniques. Firstly, it showed a difference in aggregate response between the unoccupied and occupied neighborhood. Secondly, an accurate measure of the discomfort inflicted by DR strategies can be determined by examining the comfort of the occupants.

Sub-Task 3: California ISO DR Use Cases

The resulting "Regional Grid Condition Index" has been utilized to facilitate further discussion with stakeholders including the ISO/RTO Council (IRC), federal and state regulators, and Utility Distribution Companies to help articulate both the need and complexity of providing simple-to-understand information for electricity consumers.

Sub-Task 4: California ISO Telemetry Requirements

This project is part of the first phase in a multi-phase project to review the metering and telemetry documents, link them in a traceable fashion to the underlying rationale, and evaluate technology alternatives that might support those base requirements. The goal is to provide the California ISO and external entities with a more diverse set of options clearly linked to market and resource types, and their specific operational and business requirements with associated costs. The larger project will be broken down into four phases to be compatible with resources and funding availability as well as allowing for course corrections necessary for later phases. These proposed phases are:

- Research and summarize metering and telemetry requirements from existing California ISO documentation
- Review, Compare and Summarize other ISO and RTO Documentation
- Technology Assessment, Implementation Options, Cost and Recommendations
- Update California ISO Documentation

Sub-Task 5: Design of a Building Load Data Storage Platform

The project produced:

- The database of building load data
- Python programs for extracting the data and generating matrices of explanatory variables
- Evaluation of model fit for each of the models when applied to each of the data files, for some sets of meta-parameters (such as the time duration of the data used to fit the model, the time horizon for making forecasts, the number of data points to be added before re-fitting the model, etc.)
- Evaluation of computation time for each of the model fits

The details of each end product will be described in detail with a presentation to the funders. With smart meter deployments, data sharing and analytics for a large number of networked buildings is more important than ever to evaluate and coordinate building operations to respond to grid needs.

3.4. Conclusions and Recommendations

3.4.1. Conclusions

Part 1 Conclusions

Sub-Task 1: PIER Smart Grid R&D Planning Document

Areas of Agreement on Smart Grid Needs:
All three reports agreed on the need for key technologies and developments, including in the areas of:

- Advanced Communications and Controls
- Advanced Metering Infrastructure
- Automated Transmission and Distribution
- Market Redesign and Technology Upgrade (MRTU) interfaces
- Development of Standards and Protocols
- Communication Infrastructure and Architecture (IOUs identified a gap in the network software architecture, which has not kept pace with easy-to-use operating systems and network hardware, and recommended a standardized system architecture design)
- Development and adoption of standardized cyber security protocols (with the lead taken by the Federal Energy Regulatory Commission [FERC], North American Electric Reliability Corporation [NERC], and the National Institute for Standards and Technology [NIST])
- Energy Storage deployment and development (although with different implementation forecasts due to different assessments of the technological readiness)
- Distributed Energy Resources
- Workforce Safety and Efficiency

Areas of Diversion:
The three reports differed somewhat on microgrids. Neither the IOU nor POU Roadmap recognized microgrids as an important aspect of the 2020 Smart Grid, while the Technology Manufacturer/Vendor Roadmap viewed microgrids as a valuable component of the 2020 Smart Grid.

In addition, only the technology manufacturers and vendor roadmap addressed the importance of net-zero new construction and retrofitting for the goal of reducing greenhouse gas emissions.

Finally, IOUs and POUs diverged in their level of support for the Smart Grid as the main vehicle for achieving California's policy goals due to concerns by POUs regarding the costs and uncertainties.

Consensus Smart Grid Challenges:
The three roadmaps identified Electric and Hybrid Electric Vehicles as posing a challenge to the future Smart Grid, due to the likelihood that mass penetration of these vehicles will burden the grid. They recommended dynamic pricing models for charging electric vehicles as well as "vehicle-to-grid" (V2G) energy storage.

The roadmaps also cited the integration of renewable energy as a concern. As a result, they emphasized the importance of standards and protocols for integrating various renewables.

Finally, the three roadmaps noted that the technological capabilities of the residential and commercial AMI technologies would drastically shape Demand Response capabilities.

Part 2 Conclusions

The deployment plans of each of the IOUs have a similar structure, with concrete and detailed plans for Smart Grid implementation through 2014. However, each of the IOUs had concerns about whether future technological developments will occur to enable a Smart Grid by 2020. Therefore, the plans in the medium-term for Smart Grids between 2014 and 2020 were vague with respect to goals and milestones and contained a wide variation of cost estimates and technological progress. Policy makers should therefore continue to work with the IOUs to develop specific goals and priorities for the 2014-2020 Smart Grid.

Sub-Task 2: System Dynamics of Programmable Controllable Thermostats

The simulation techniques developed through this work enable low-cost experimentation with advanced load-management control. This experimentation would be very difficult to achieve in any other manner without inconveniencing live subjects through the deployment of unproven hardware to hundreds of houses. The control techniques developed show great promise to transform load management by enhancing controllability and robustness. Of particular promise is the low-frequency PWM technique because it dramatically improves the way power is controlled in a house.

Sub-Task 3: California ISO DR Use Cases

The Regional Grid Condition Index Use Case provides a communication tool that can be leveraged to develop future requirements for a system that provides an index-based signal to be utilized by electricity consumers. However, the coordination of technology and solution suppliers to both enable the development of the index by the electric power industry as well as the consumption of the index by electricity consumers remains a significant challenge that will potentially require regulatory support and consumer electronics manufacturer buy-in to become reality.

Sub-Task 4: California ISO Telemetry Requirements

This phase of the project successfully captured and associated 875 requirements from 30 documents as a first step in developing potentially more flexible and economically feasible technology metering and telemetry options for market participants.

Sub-Task 5: Design of a Building Load Data Storage Platform

The conclusions are separated into two main categories: needs and solutions. With a growing number of buildings using interval meter data, energy management and control systems, energy information systems, and other low-cost sensing and monitoring devices, the size and availability of time-series data from building operations, distribution systems, and transmission systems are also growing. There is a need to develop flexible, scalable, secure databases to store this data, computational power to process it, and visualization tools to develop it as information to support decision-making. This project looks at the various requirements for such data, develops a prototypical database, and analysis methods to analyze time-series data from a variety of buildings. This is not a full implementation of a large-scale system but a small representation of it just to demonstrate the importance of these systems and possibilities of using the data in different ways.

3.4.2. Recommendations

Sub-Task 1: PIER Smart Grid R&D Planning Document

To make sure the overall Smart Grid deployment remains cohesive throughout California in areas served by both POUs and IOUs, California policy makers could take the following steps:

- Develop a thorough cost-benefit analysis for Smart Grid deployment.
- Collaborate with federal leaders to develop standards to close existing gaps in the present cyber security standards.
- Coordinate the various standardization efforts conducted by the private sector in communication infrastructure and architecture to ensure scalability.
- Encourage deployment of energy storage technologies through opening electricity markets to energy storage competition.
- Devote more resources to research microgrid deployment, such as analyzing the existing research gaps (like technical feasibility-related issues) and the policies and financial mechanisms to foster widespread adoption.
- Fund more studies on the effects of Level 3 electric vehicle charging on the grid and of V2G charging effects on the vehicle batteries.
- Develop interoperability requirements and data exchange specifications.
- Dedicate resources for smaller POUs for adopting Smart Grid technologies where it makes business sense for them to do so.
- Continue customer education efforts on energy efficiency and demand response options.
- Develop incentives for low-income consumers who cannot afford to buy smart appliances.

- Encourage information sharing between electric and gas industries to support demand response and optimize energy efficiency.

Policy makers will need to monitor the implementation of the deployment plans in the coming years to ensure that IOUs follow through on the plans and further refine the goals for the years leading up to 2020 as new information becomes available.

In order to provide more realism in terms of technology adoption and cost, the utilities cost and benefit estimates could greatly benefit from increased collaboration with industry.

Policy makers should also be aware that the IOUs in the deployment plans tend to focus on technologies that bolster their core business models but may not reflect the larger public interest in Smart Grid deployment. Policy makers will need to evaluate the need to push for IOU action in these areas versus deference to IOU interests.

The Energy Commission could assist Smart Grid implementation efforts by conducting further research in the following areas:

- Policy and technology needs to encourage further deployment of microgrids
- Integrating an advanced charging infrastructure for electric vehicles
- A policy and technology needs assessment for demand response technology deployment with the Smart Grid by 2020

Sub-Task 2: System Dynamics of Programmable Controllable Thermostats

The application of feedback control theory to load management has the potential to dramatically change the way that utilities and ISO's view demand. It could change demand from a weakly predictable stochastic phenomenon to a highly controllable and reliable tool to balance the grid. Therefore, the project team recommends further research in several areas:

- Deeper control research using the simulation tools available
- Analysis of the impact load management has on occupants
- Energy products that these systems can provide to the California ISO and utility companies

These recommendations were proposed to the Energy Commission and the research continued under Energy Commission Contract #500-99-013.[8]

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8 *Development of Smart Grid Implementation Plans Associated with Legacy Distribution Automation Equipment Upgrades, Demand Response Infrastructure, and the PCT Reference Design*, Basic Ordering Agreement #BOA-99-184-P.

Sub-Task 3: California ISO DR Use Cases

This initial use case served to introduce the concept of a Regional Grid Condition Index. More detailed use cases are needed to drive out requirements for different scenarios. For example:

- Control center operator selects a contingency
- Energy trader submits bid to generation market
- Protection engineer analyzes fault
- Field person diagnoses and replaces meter

In order to gain acceptance and participation to further develop this concept, industry collaboration is needed. The Smart Grid Interoperability Panel (SGIP) provides a forum through Domain Expert Working Groups (DEWGs) for collaboration to identify gaps in current industry standards (such as the gap identified for providing customer actionable information described above) and derive the requirements that standards need to address. Collaborating with SGIP will enable the participation of IRC members as well as utilities (investor-owned, municipal, and co-op) in further developing the Regional Grid Condition Index concept. However, a sponsor organization is needed to help drive progress and outcomes for this effort.

Sub-Task 4: California ISO Telemetry Requirements

The project team recommends pursuing subsequent phases to expand the research, perform the technology assessment, update applicable requirements, and pilot the identified alternatives for technology and standards.

- Phase 2: Review, Compare, and Summarize other ISO and RTO Documentation
- Phase 3: Technology Assessment, Implementation Options, Cost, and Recommendations
- Phase 4: Update California ISO Documentation
- Phase 5: Pilot Deployment of Selected Options

Sub-Task 5: Design of a Building Load Data Storage Platform

One of the major expectations with the research in recent years on low-cost sensors and monitoring devices is that they will provide a variety of time-series data collected from various locations on the electricity grid. There are various entities interested in this data and the various forms of information it may provide to stakeholders. As this project is just a small fraction of proof-of-concept, the project team suggests the following future research areas:

- Evaluating commercially available databases and data management tools for their appropriateness to store and query large time-series data sets
- Developing tools and applications for different stakeholder that utilize these data sets
- Evaluating the utilization of these data sets for calibrating and validating models
- Building a large database through partnering with a utility or an entity such as the US Green Building Council to populate the database with actual load data

- Evaluating computational requirements for metrics and analysis methods
- Developing prototypical systems to exercise select set of concepts to facilitate the development of tools and applications

3.4.3. Benefits to California

The research conducted under this task will collectively advance California's understanding of demand response opportunities including remaining research challenges. Successfully addressing these challenges will improve system reliability, prevent rolling blackouts, and lower system operating costs.

Sub-Task 1: PIER Smart Grid R&D Planning Document

Recommendations from this task can help with policy decisions that will lead to further assessment of what Smart Grid research and technology needs are; will help California achieve a leadership position in the deployment of state-of-the-art, efficient grid technologies; and achieve the ultimate goal of developing an optimal and cost-effective Smart Grid by 2020.

Sub-Task 2: System Dynamics of Programmable Controllable Thermostats

The main benefit for California is the ability to demonstrate the feasibility of using an advanced load management system in a controllable and reliable way. This will provide confidence to energy planners seeking to improve load-management control strategies in ways that improve reliability and reduce the cost of electricity production and distribution.

Sub-Task 3: California ISO DR Use Cases

The initial use case developed with this project has introduced the concept of a Regional Grid Condition Index to describe the challenge of combining aspects of the electricity supply chain cost and constraints with the retail electricity delivery aspects including distribution and rates.

Successful completion of a robust set of Regional Grid Condition Index use cases to derive the applicable requirements will lead to the standards enabling the Regional Grid Condition Index as well as the ability to implement the functionality into technologies for creating, disseminating and utilizing the index for both grid and consumer benefit.

Sub-Task 4: California ISO Telemetry Requirements

Phase 1 has resulted in the identification and collection of metering and telemetry requirements for California ISO electricity markets and market participants with different resource types. This results in a summary of telemetry and metering requirements for market participants to utilize as a reference to identify the applicable California ISO documentation sources for the applicable requirements.

Subsequent phases will identify, recommend, and test alternative technologies and standards for possible utilization by California ISO and market participants to maintain a reliable wholesale market electricity supply while potentially lowering the barrier to participation.

Sub-Task 5: Design of a Building Load Data Storage Platform

With the deployment of thousands of smart meters and the Green Button initiative, deployment of low-cost distribution system measurement devices as well as at least 75 phasor measurement units in California's transmission system, California will greatly benefit from investing in infrastructures to store and utilize this data in order to better plan and operate the electricity grid. This project was a starting point in considering the issues and developing metrics using a small subset of the data.

3.4.4. References

Sub-Task 1

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Sub-Task 2

The outcomes from this project are reported in a number of published journal articles cited below:

Burke, W.J., and D.M. Auslander. 2008. *Modular and Extensible Systemic Simulation of Demand Response Networks.* October, CIGRE Canada Conference on Power Systems.

Burke, W.J., and D.M. Auslander. 2009. *Low Frequency Pulse Width Modulation Design for HVAC Compressors.* 2009 ASME/IEEE International Conference on Mechatronic and Embedded Systems and Applications.

Burke, W.J., and D.M. Auslander. 2008. *Robust Control of Residential Demand Response Network with Low Bandwidth Input.* October, ASME Dynamic Systems and Controls Conference. <http://scitation.aip.org/getabs/servlet/GetabsServlet?prog=normal&id=ASMECP002008043352000413000001&idtype=cvips&gifs=yes&ref=no>

Sub-Task 3

Presentation: "ISO Smart Grid Roadmap Use Case—Consumers Utilize a Regional Grid Condition Signal." J. Laundergan, EnerNex; and H. Sanders, California ISO.

Sub-Task 4

Presentation: "CAISO Metering & Telemetry Requirements Matrix." J. Laundergan, EnerNex.

Presentation: "CAISO Metering & Telemetry Requirements Summary," J. Laundergan, EnerNex.

Presentation: "CAISO Metering & Telemetry Requirements Summary," J. Laundergan, EnerNex.

Sub-Task 5

Presentation: "Demonstration of Building Load Database and Analysis Framework." N. Addy, P. Price, L. Fenga, and S. Kiliccote, Lawrence Berkeley National Laboratory.

4.0 Task 2.4 Time Value of Demand Response

4.1. Introduction

4.1.1. Background and Overview

Task 2.1 demonstrated that demand response could be fully deployed faster than thermal generation in providing contingency reserves. Fast-responding generation, demand response, and energy storage are valuable resources for power system operation because they enable more precise control than is possible with slower responding resources. For example, coordinated deployment of faster responding resources could improve California ISO compliance with NERC and WECC reliability rules for power system frequency control and do so at lower cost. Today, however, California ISO markets and operating practices do not take into full account the speed of the resources that are deployed to comply with these rules.

4.1.2. Task Objectives

The objective of this task was to conduct research that would enable California ISO to take better account of the speed of the resources that it deploys to ensure compliance with reliability rules for frequency control.

4.2. Project Approach

The project approach involved:

- Development of a methodology for assessing the response speed of the generation resources currently used by California ISO for regulation and load-following on a consistent basis;
- Application of the methodology to the current fleet of generators used by the California ISO to establish the relative value of faster and slower resources as measured by their contribution to the frequency control objectives of the California ISO (which are reflected in the aggregate performance of these resources in complying with NERC and WECC reliability rules); and
- Use of the findings to develop a scope for follow-on projects that take the speed of resource response rates into account more fully, so that the California ISO could implement the concepts demonstrated in this project.

The project team was led by Yuri Makarov, Pacific Northwest National Laboratory.

4.3. Project Outcomes

The project team developed a new methodology and used it to quantify the relative value of fast responsive generation resources in improving the deployment of regulation and load following balancing services in California.

The major findings are as follows:

- There are more than 120 generation units connected to the California ISO's Automatic Generation Control (AGC) system, which is the means by which California ISO sends dispatch commands to the units providing regulation. Figure 3 shows that the California ISO's units on regulation cover a wide range of ramping capability from 1% (some steam turbine and combined cycle units) to 100% (some hydro units) of their capacity. The limited regulation, ramping, and ramp duration capabilities of steam turbine and combined-cycle units results in the use of multiple units in the regulation process at the same time.

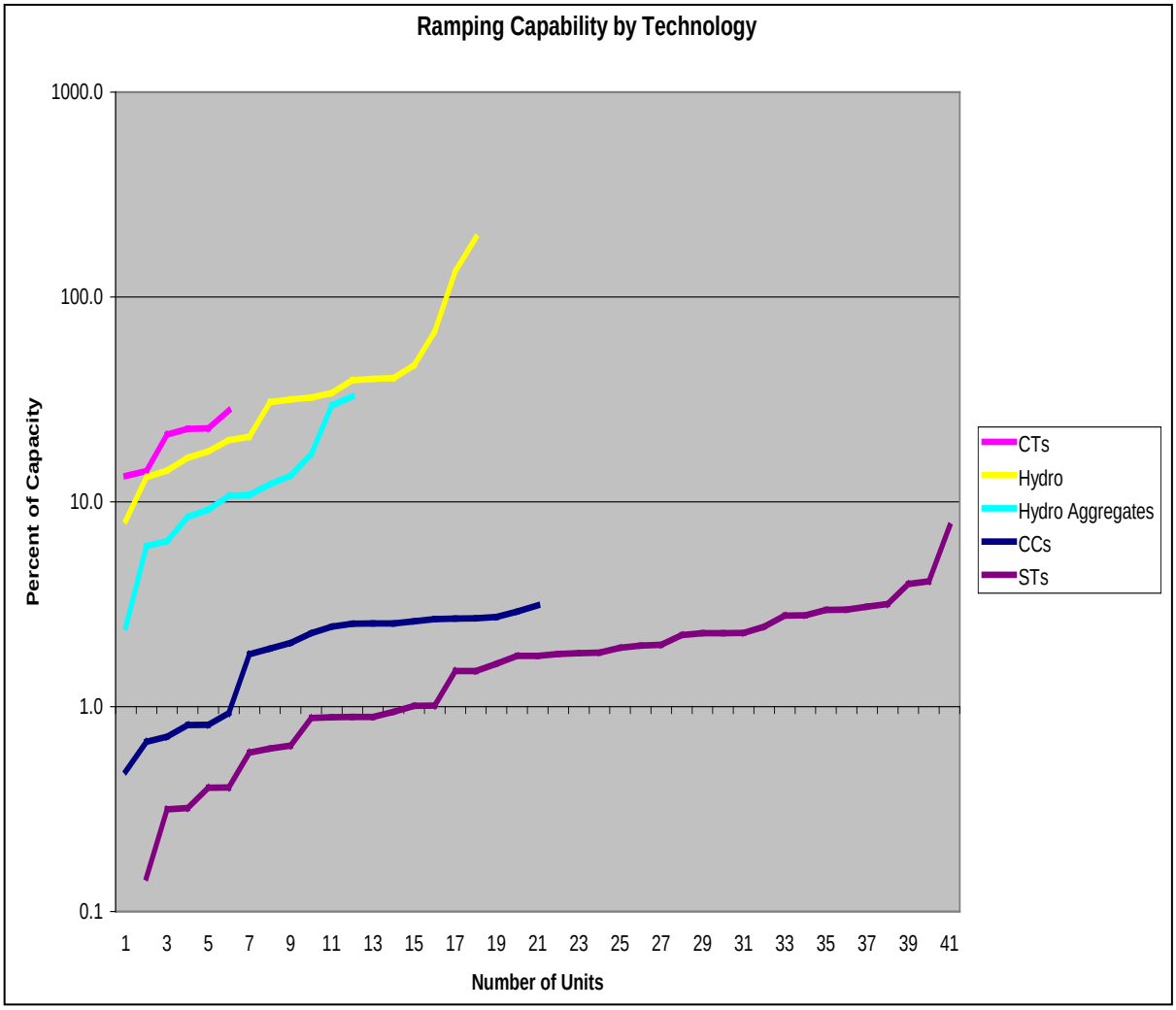

Figure 3: Ramping Capability by Technology

- The units relied on by California ISO for regulation can provide significant total ramping capability (about 160 MW/min) for one to two minutes, but ramps of longer duration become difficult as the faster responding units exhaust their regulation range. In addition, upward or downward ramping may be limited as the units provide regulation depending on how much they are directed to deviate from their Preferred

Point of Operation (POP). If the faster units are directed to deviate significantly from their POP in one direction, the overall ramping capability of the AGC system in this direction can become limited.

- The California ISO AGC system calls on faster units with high ramp rates to respond first, followed by calls on slower units to respond. As a result, the faster responding units initially are responsible for providing a larger share of the regulation requirement.
- The California ISO AGC system was developed based on the operating characteristics of conventional regulation resources, which are limited in their ramping capability, but are far less limited in terms of the total amount of energy they can provide. Newer sources of regulation, such as flywheels or battery energy storage differ from conventional regulation resources on both counts. They can provide dramatically better ramping capability, but typically have limited energy storage capability.
- The California ISO wholesale market through which the resources used to provide regulation are procured is based on the capacity offered by these resources, not the amount of energy they can provide. The payments for regulation capacity do not take into account the speed or rate at which units respond to commands from the California ISO AGC system.
- There appear to be opportunities to improve the algorithms used by the California ISO AGS system to take greater advantage of the ramping and energy limit-related characteristics of both conventional and new sources of regulation in ways that would improve California ISO compliance with reliability rules for frequency control, while at the same time lowering the total amount regulation that must be procured.

4.4. Conclusions and Recommendations

4.4.1. Conclusions

During the course of this research, the project team developed a methodology and quantified the relative value of fast responsive generation resources that could be used for regulation and load following balancing services in California. Compared with slow responding resources, fast-responding resources including generation, demand response, and some types of energy storage can be more valuable regulation and load following resources if they are applied in the exact moment and at the exact amount needed.

Controls that take greater advantage of these capabilities could provide better compliance with reliability rules for power system frequency control, while at the same time requiring less total regulation capacity. Fast-responsive resources could reduce California ISO regulation procurement by up to 40% (on average). California ISO practices and markets should be modified to take greater advantage of the regulations capabilities offered by generation, demand response, and energy storage resources that could be made available to the California ISO.

4.4.2. Recommendations

The project team recommends continued research to:

- Determine the specific changes that might be needed in the California ISO AGC system to effectively accommodate new types of fast regulation resources and minimize the California ISO regulation procurement.
- Supplement and verify the current experience-based approach used to calculate the required regulation procurement against a more "scientific" method, such as that proposed by the project team. The objective is to minimize the amount of regulation procured by providing better differentiation among requirements at different operating hours during a day and in response to changing seasonal and monthly operating conditions.

The project team also recommends that the California ISO undertake the following:

- Analyze the advantages, disadvantages, and options for incorporating ramping considerations into the ancillary service (AS) market design and settlement process (pricing), and consider creating better market opportunities and incentives that are based on the speed at which resources respond.
- Develop a method for smoother transitions between operating hours, and consider whether the changing number and composition of the regulating units between hours create performance problems today or will do so in the future.
- Study low probability, high ramp events.
- Consider establishing a more relaxed target for compliance with Control Performance Standard 2[9]; modifying this target, along with a more scientific analysis of regulation requirements could further minimize regulation procurement requirements without compromising California ISO's frequency control performance.
- Conduct a Balancing Authority ACE Limit (BAAL) study as soon as there is greater certainty that a BAAL standard will be adopted by NERC and on the requirements it would place upon California ISO; the study may involve an assessment of advantages of the distributed frequency-based control for the California ISO system. The market-related issues that arise should also be investigated.
- Conduct a Frequency Responsive Reserves (FRR) study as soon as there is greater certainty that a FRR standard will be adopted by NERC and on what requirements it would place on California ISO.

[9] Control Performance Standard 2 refers to NERC rules that define minimum performance obligations for balancing authorities to contribute to maintaining interconnection frequency within safe operating limits.

4.4.3. Benefits to California

The benefits to California would be a significant reduction in the amount and cost of regulation procured by the California ISO with no decrease in frequency control performance (i.e., reliability). These reductions will improve system reliability; prevent rolling blackouts, and lower system operating costs.

4.5. References

The research conducted and findings are fully documented in a separate technical report:

Makarov, et. al. *Assessing the Value of Regulation Resources Based on Their Time Response Characteristics.* June 2008. http://certs.lbl.gov/pdf/task-2-4-regulation-resources.pdf.

5.0 Task 2.5 System Integration and Market Research: Southern California Edison (SCE)

5.1. Introduction

5.1.1. Background and Overview

The research completed under Task 2.1 demonstrated that aggregated demand response could be used to provide contingency reserves in a manner comparable to provision of these reserves by generators. In 2008, when research on that task was nearing completion, the CPUC ordered California's investor-owned utilities to initiate pilot demand-response programs that could ultimately participate in California ISO's wholesale markets for day-ahead energy and contingency reserves (non-spinning reserve, initially) in conjunction with California ISO's revisions to these markets, known as the Market Redesign and Technology Update (MRTU). These activities represent the next logical step toward full commercialization of the concepts demonstrated in Task 2.1. Task 2.5 was added to provide technical support to this CPUC ordered program at SCE.

5.1.2. Task Objectives

The objective of Task 2.5 was to provide technical support to efforts led by SCE to respond to CPUC Order #06-03-024, which directed IOUs to being to transition their demand-response resources to participate formally in California ISO markets. This task provided technical support to the activities related to AC load cycling undertaken by SCE in 2009.

5.2. Project Approach

The project team provided research and technical support to efforts led by SCE to conduct demand response pilot demonstrations to provide a contingency reserve service (known as non-spinning reserve) through a targeted sub-population of aggregated residential and small commercial customers enrolled in SCE's traditional AC load cycling program, the Summer Discount Plan.

The project team was led by Joe Eto of LBNL. The project team also involved KEMA, a leading authority in energy consulting, testing, and certification. SCE also separately retained KEMA and BPL Global to provide technical services in support of the project. This second set of activities was not funded by the PIER Program.

SCE's 2009 Participating Load Pilot (PLP) explored the technical and economic feasibility of small (i.e., less than 5 kW per endpoint) SCE-aggregated DR in Participating Load (PL) and/or future proxy demand resource (PDR) products for the MRTU markets of the California ISO. The SCE PLP Feasibility Report was filed with the CPUC on December 30, 2009, and details the pilot objectives, design, implementation, results, and conclusions. The results and conclusions are summarized here with emphasis on how the results and conclusions were used to inform the 2010 PDR Pilot, as well as the proposed modifications to SCE's DR programs necessary to allow them to participate as PDR.

The 2009 SCE PLP controlled 3,255 air conditioners in residential homes and commercial buildings located in Ft. Irwin, CA during a series of short-duration curtailment events over the course of the summer. Rather than telemeter the full population of air conditioners in the PLP, a statistically designed sample of 555 AC units from the full population was chosen and a load-monitoring communicating-current transformer was installed on each of the selected units.

The PLP explored the technical feasibility of using a representative sample of monitored AC units as a proxy for a telemetry system comprising the entire population, as is required by MRTU AS and energy markets. Both California ISO and SCE acknowledged that full-population telemetry would prohibit a PL program of individual loads of no more than a few kW per customer from being cost-effective in the foreseeable future. However, both parties wanted to ensure that the load drop estimates from events made using the loads from the representative sample would be accurate enough to use for bidding and settlement purposes.

The 2010 PDR Pilot utilized provisions of the SCE SDP tariff with enhanced program customers, which allow both unlimited interruptions during the program season and up to two tests per cycling season with maximum test duration of 30 minutes each. The SDP resource is available between June 1 and October 1. The pilot explored the potential for distribution substation circuit Supervisory Control and Data Acquisition (SCADA) data to act as a proxy for both Settlement Quality Meter Data (SQMD) and an aggregation of individual customer load telemetry for PDR. In addition, the temperature forecast served to inform the amount of PDR that would be bid into either the day-ahead or real-time market by predicting the amount of AC load available.

5.3. Project Outcomes

The principal project findings from activities conducted in 2009 are summarized as follows:

Over the course of 20 weeks, SCE conducted 32 PL events. Twelve of these events were coordinated with California ISO, whereby SCE bid the PLP resource into the California ISO's day-ahead market for non-spinning reserves. California ISO dispatched the resource pursuant to a predetermined schedule, and SCE submitted settlement data for both the load and DR elements of the PL. Of the 12 events scheduled with California ISO, two were bid and settled but not successfully dispatched. The other 20 events were conducted independent of California ISO, where SCE performed testing without bidding or dispatch instruction from California ISO. These California ISO independent or "test" dispatches were run to collect additional data for evaluation of the PLP systems and development of statistical tools for algorithm development. Figure 4 provides an overview of all dispatch events, including the event date, duration, and the performance of the PL resource.

PLP events occurred at varying times of the day and on varying days of the work week. SCE and KEMA attempted to engineer dispatches to include a range of test event times, durations, and temperatures so that load characteristics could be thoroughly explored. However, SCE did not dispatch the PLP on weekends and it is not within the current scope to incorporate or analyze the different AC load patterns that may arise from weekend usage.

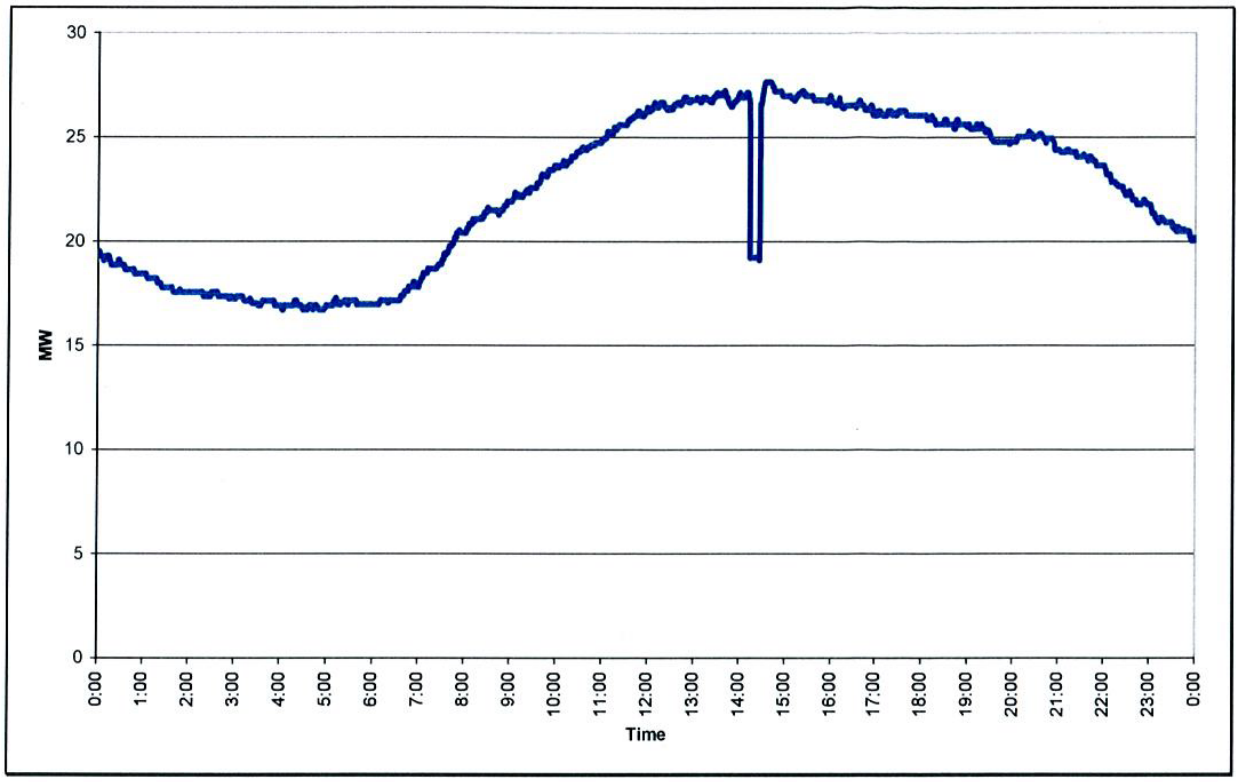

Figure 4: Tiefort Substation: Typical load on PLP testing day

The PLP events were also prescheduled with California ISO so that SCE knew when the dispatch signal would arrive. For a production program, the dispatch signal for AS will not be predictable. However, since the dispatch processes for both California ISO and SCE contained significant manual processes in support of the pilot, it was necessary to schedule the PLP events. In the future, California ISO signals would need to automatically connect to the load control systems to dispatch the proper DR resource. The resource performance would also need to be monitored to determine whether additional resources should be dispatched, or some of the resource should be restored, to conform to the California ISO dispatch instruction. Systems and program development is being explored to understand the scope of work required to enable this level of functionality and automation. Task 2.3, Subtask 4 began the work required to address the telemetry requirements that must be harmonized and integrated for monitoring DR resources.

The PLP demonstrated the technical feasibility of small aggregated AC load to act as a PL resource and identified that this type of resource would be more closely aligned with the California ISO proposed PDR market product which requires that only the DR performance be bid and settled in the wholesale market. Essentially, the PLP resource was able to comply with the California ISO's market process and system requirements for bidding, dispatch, and settlement. However, the economic feasibility remains a question as the costs for developing and deploying a small aggregated load resource is unknown.

Results of the pilot showed that while SCE was able to coordinate the bidding, dispatch, and settlement of the PL resource, many processes would require a level of automation to be performed in support of an actual retail DR program. In addition, the core PL business requirement to schedule the "underlying load" for the DR resource is extremely challenging to meet for small aggregated loads. As a result, small aggregated load DR programs that are integrated into the California ISO wholesale market in the future will likely utilize PDR rather than PL.

The principal project findings from activities conducted in 2010 are summarized in a report submitted by SCE to the CPUC.

See *Report on the Transition of Southern California Edison (SCE) Demand Response (DR) Programs into Market Redesign & Technology Update.* 2010. Southern California Edison, which a can be downloaded from:
http://www3.sce.com/sscc/law/dis/dbattach3e.nsf/0/0CB693A87C9BBD838825782D0082C428/$FILE/A.08-06-001_Report+on+the+Transition+of+SCE+DR+Programs+into+MRTU.pdf

The principal project findings from activities conducted in 2010 are summarized as follows:

The 2010 pilot focused on further development of the capabilities of the SCADA system to provide telemetry and settlement data and refinement of temperature data in developing a load forecast. Twelve substations were selected for the PDR Pilot based on total SDP Enhanced enrolled tonnage and temperature factors, while avoiding the districts that typically have regional SDP events called over the course of the summer. Two 30-minute tests were conducted at each of the substations using the Alhambra Control Platform (ACP) AC control switches installed at customer sites enrolled in the SDP Enhanced program. Tests were conducted on 17 different dates, from July through September 2010. Test locations, dates, and times were scheduled based on 5–10 day prior outdoor temperature forecasts obtained from the United States National Oceanic and Atmospheric Administration (NOAA) and either dispatched or rescheduled based on shorter-term forecasts and resource availability. Test events were conducted at temperatures ranging from approximately 80 to 104 degrees.

Subsequent analysis of the data collected resulted in valuable information which provided SCE and California ISO with a better understanding of the technical challenges and possible approaches for integrating small aggregated DR into a PDR resource.

- Developed and evaluated algorithms for monitoring substation circuit SCADA data, as well as temperature forecast data to estimate available load.
- Developed and evaluated algorithms to estimate actual load drop after event dispatch based on available substation circuit SCADA data.
- Developed baseline analyses to analyze test event results, calculate performance, and inform alternative baseline methods for forecasting and evaluation.
- Identified and implemented enhancements to the SCE database used to identify target populations, resulting in improved load reduction estimates.

- During execution of the pilot, discovered significant issues with the currently adopted 10-in-10 baseline approach, as well as with some alternative baselines. These issues, as well as a new Linearly Adjusted (LA) 10-in-10 baseline approach to develop an AS baseline developed during this pilot, are described in Section 8.5; for the purposes of pilot analysis, the new LA 10-in-10 approach is utilized because it provided the most consistently reasonable representation of what the load would have been in the absence of a DR event occurring.

Due to test constraints and cooler temperatures during the first seven events, minimal load drop and restoration were initially documented. Following in-depth analysis of tests 8 and 9, a program logic issue was identified that impacted the timely restoration of the load at the substation level and caused restoration to occur one hour later than the restoration signal was sent. SCE suspended testing pending resolution of the logic issue and, following a one-week turnaround, the issue was resolved and tests 10 through 24 were conducted using program logic that enabled correct restoration following the event.

5.4. Conclusions and Recommendations

5.4.1. Conclusions

During the course of this research, the project team demonstrated that small aggregated AC load could act as a PL resource. The data collected and subsequent analysis provided a better understanding of the technical challenges and possible approaches for integrating small aggregated DR into a PDR resource. The team found:

- Monitoring of the test event SCADA data revealed significantly more variability in the loads of the substation when dispatching at the substation level in a more general population during the 2010 pilot than was found at the Ft. Irwin location in 2009, which was essentially conducted in an isolated distribution environment.
- Evaluation of the test event SCADA data indicated that measurement of the rebound is highly dependent upon the selection of the post-dispatch endpoint and that this decision would impact performance assessment. In addition, the randomization routine that prevents all air conditioners from turning on simultaneously after post-event restoration significantly reduces the "rebound" effect noted during the 2009 pilot which did not utilize randomization during restoration.[10]
- Development of an algorithm based on temperature and load is significantly impacted by the ability to accurately forecast and measure outdoor air temperatures.
- SCE's SDP program can perform to the timing requirements of a 10-minute response for non-spinning reserve AS.

[10] Rebound refers to the increase in load above the baseline that is often observed following curtailments of air conditioning loads when the air conditioning units simultaneously restart once the curtailment has ended.

5.4.2. Recommendations

While SCE's SDP program can meet the 10-minute response time for AS, reacting to California ISO's five-minute instructions to modify the amount of DR provided (described as Partial Dispatch in Section 6.3) is a significant challenge. The SDP dispatch platform can yield results within five minutes. However, the ability to refine the dispatch performance to something other than an all-or-nothing resource in response to varying five-minute instructions from California ISO is a significant challenge. We recommend exploring alternatives to achieve a 'throttling' of the SDP resource, including:

- Modifying the cycling percentage during the course of the event where the cycling percentage would increase to provide more MW or decrease to provide less MW of DR.
- Dispatching and restoring different groups based on the incremental amount of DR needed by the change in dispatch instructions from California ISO.

The first option above will require significant systems development to achieve this more enhanced functionality. The second option above is a challenge given the regional sub-load aggregation point (SLAP) and pNode basis for PDR dispatch.

5.4.3. Benefits to California

Successfully addressing technical and institutional issues that hinder transformation of legacy utility load management programs, such as SDP, to provide AS in California ISO's wholesale markets will improve system reliability, prevent rolling blackouts, and lower system operating costs.

5.5. References

The principal project findings from activities conducted in 2009 are summarized in a report submitted by SCE to the CPUC.

See "2009 SCE Participating Load Pilot Feasibility Report" which can be downloaded from: http://www3.sce.com/sscc/law/dis/dbattach3e.nsf/0/8CEDA19110F726598825769B00817D3C/$FILE/A.08-06-001+et+al.+-++2009-11+DR+App+-+SCE+PLP+Feasibility+Report.pdf.

In addition, the project team prepared a second report on additional research conducted during 2009.

Gifford, W., S. Bodmann, P. Young, KEMA, J. H. Eto, and J. Laundergan. *Customer Impact Evaluation for the 2009 Southern California Edison Participating Load Pilot.* 2010. LBNL-3550E. http://certs.lbl.gov/pdf/lbnl-3550e.pdf

6.0 Task 2.6 Demonstrate DR Technologies: Pacific Gas & Electric (PG&E)

6.1. Introduction

6.1.1. Background and Overview

Similar to Task 2.5, Task 2.6 was added to provide technical support to the CPUC-ordered pilot demand response program at PG&E.

6.1.2. Task Objectives

The objective of Task 2.6 was to provide technical support to efforts led by PG&E (a California IOU) to respond to CPUC Order #06-03-024, which directed IOUs to being to transition their demand-response resources to participate formally in California ISO markets.

6.2. Task Approach

The project team provided research and technical support to efforts led by PG&E to conduct a demand response pilot demonstration to provide a contingency reserve service (known as non-spinning reserve) through a targeted sub-population of aggregated residential customers enrolled in PG&E's AC load curtailment program, the Smart AC™ Demand Response Program.

The project team was led by Joe Eto, LBNL. The project team also involved Freeman, Sullivan & Company (FSC). PG&E separately retained FSC and other subcontractors and vendors to provide technical services in support of the project. This second set of activities was not funded by the PIER Program.

Research was conducted in 2009 to provide direct technical support to conduct the PG&E pilot program and in 2011 to evaluate a variety of short-duration load curtailment measurement approaches based on information collected during the 2009 pilot and through related PG&E AC load control programs.

2009 Activities

The main objectives of the 2009 pilot were to:

- Simulate the provision of spinning and non-spinning reserve with air conditioner load control.
- Assess how much time elapsed before air conditioning units started reducing loads and how long it took to ramp up to full capacity.
- Test out the ability to provide near real-time visibility of load.
- Determine if the demand reductions observed with the sample were also observable with feeder data.
- Assess the magnitude and variation in the demand reductions.
- Determine if short-duration air conditioner curtailments affected customer comfort and/or led to participation fatigue.

Four distribution feeder circuits were chosen for study—two in a relatively hot climate (Fresno) and two in warmer Bay Area suburbs (Antioch and Fairfield). The difference in climate is important in that past studies have indicated air conditioner demand and load-control performance varies dramatically with ambient temperature.

The feeders were selected for the study because they met all key criteria to meet the research objectives, specifically:

- One-minute feeder measurements (kW, Amps, MVAR and temperatures) could be accessed through a secure data port maintained by PG&E.
- The circuit did not contain large commercial and industrial loads.
- A sufficient number of participants on PG&E's direct load control program, SmartAC, already existed on the feeder so that recruiting goals could be met quickly (within one month).

The number of direct load-control participants was increased on each of the selected feeders to ensure that approximately 500 SmartAC customers were present. Two technologies with the capability of shutting down the air conditioner compressor remotely were used: load control switches and programmable communicating thermostats. For each feeder, the goal was to include 400 AC units with direct load-control switches and about 100 AC units with programmable communicating thermostats. Figure 5 shows a diagram of the project components.

The usage was recorded for each of the air conditioner units through the course of the study. For 129 randomly selected units, data was recorded at one-minute intervals using technology that allowed for near real-time transmittal of the air conditioner end-use data. Data for the remaining units was recorded at five-minute intervals using standard end-use data recorders without the capability of transmitting data on a near real-time basis.

PG&E's direct load-control system was programmed to cause a complete shutdown of all air conditioner compressors for the participants on the feeders under study. Simulated AS operations were conducted on all four feeders simultaneously, twice each weekday, at varying hours between noon and 7:00 pm. For each test operation, the air conditioner compressors were instructed to shut down for a 15-minute period; control of the units was released over a random two-minute interval after the test event period concluded. After the testing period, instructions to shut down air conditioner compressors were re-sent five minutes after the initial transmittal in case individual units did not receive the initial curtailment instructions.

During the study period, 71 test control operations were conducted, producing observation of load control over a wide range of times and temperatures. The first 10 test operations were used to refine the dispatch procedures and ensure the devices were correctly programmed. Of the 71 operations, 68 included all four feeders and all air conditioner units in the program. For each test operation, the meters with real-time transmittal capability reported the measurements for the 15 minutes before, during, and after each test operation. The data was integrated with feeder load data and displayed live via the internet. Both the California ISO and PG&E's

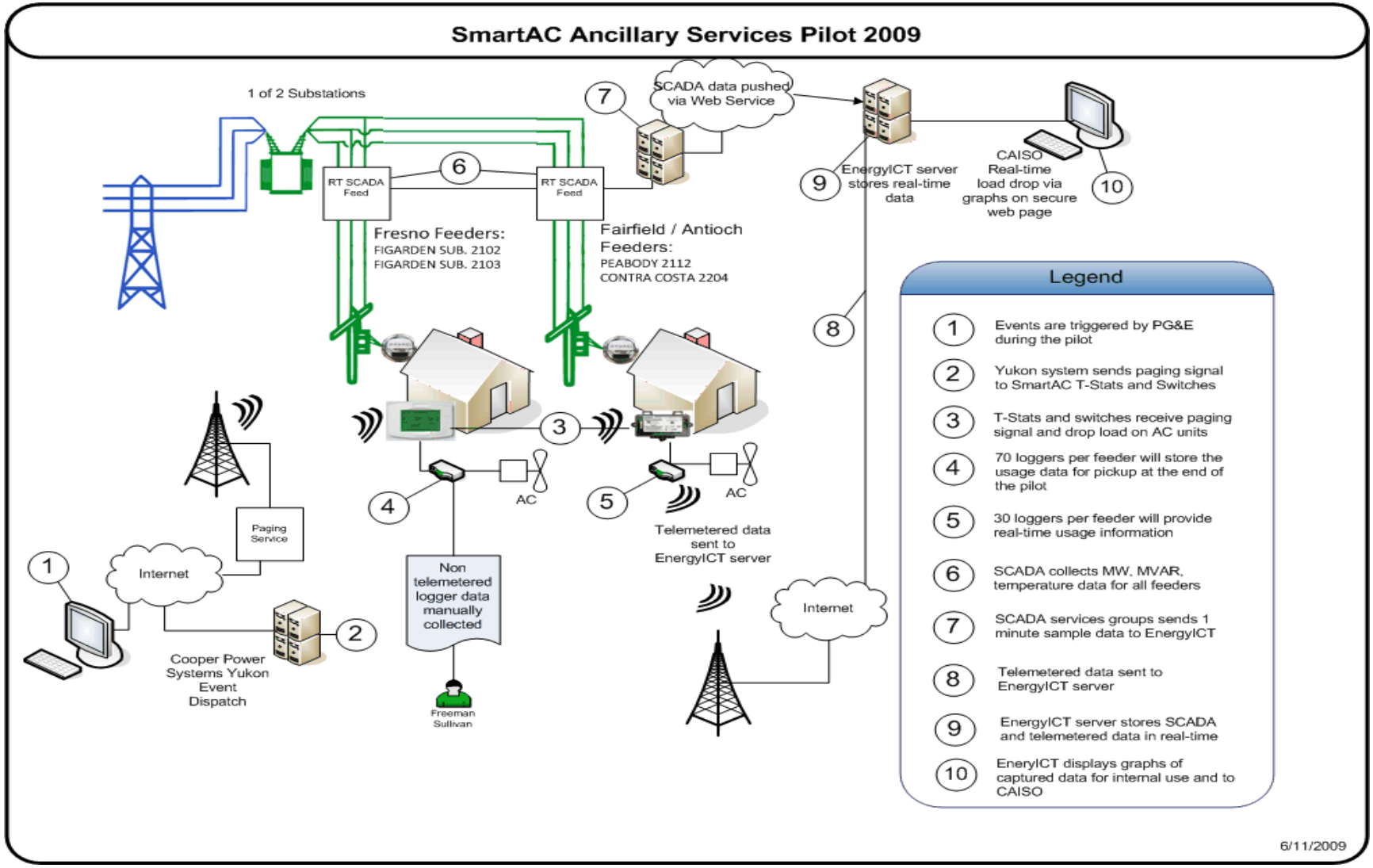

Figure 5: SmartAC Ancillary Services Pilot 2009

operations department were able to view air conditioner and feeder demand levels before, during, and after each test operation.

Figure 6 displays a screenshot of the output from the telemetry system for one of the 71 test operations. The screen updated every minute based on the measurements taken in the prior minute. The system displayed a graph of the load measurements from the feeder (top left corner); a graph of the load measurements from the sample (bottom left corner); the sample load impacts scaled for the number of participating air conditioner units (top right corner); and useful statistics describing the load response (e.g., average load impact per control unit, percent of appliances in operation, etc.). Users could at any time select which feeder to view or jointly view the loads for all feeders and all sampled air conditioner units on a summary tab. With the system, operators were able to determine how long it took for control to take effect, how long it took for loads to come under full control, and the overall magnitude of load reduction that was achieved.

Figure 6: Screenshot of the output from the telemetry system

In the example display screenshot, the load-control operation is observable on both the feeder measurements (upper left quadrant) and in the sample observations (lower left quadrant). The impacts could be clearly observed on feeder loads on hotter days when most air conditioner units were operating. This was not true for cooler days when fewer units were in operation. It is also important to recall that the feeders were selected precisely because of the high penetration of air conditioner load control and the availability of one-minute feeder data. Most feeders have a lower penetration of air comparison load control, in which case AC operations are harder to visually detect with feeder data, although they were clearly visible in the sample.

The large number of test operations provided the ability to estimate the load impacts that could be obtained from air conditioner direct load control at different times of day and under different temperature conditions. It also allowed for a detailed assessment of when and how frequently curtailments could be directly observed on the feeder loads. In addition, it provided data from the nearly 2,000 customers on whether or not repeated short AC load control operations affected their comfort levels.

The start time, ramp speed, and ability to be synchronized with the electric grid determine the usefulness of resources for grid operations. Delays can occur at the following stages of the communication:

- Creation of the control message sent to devices
- Connecting to the outgoing modem used to transmit the signal to paging companies
- Acknowledgement of the load control signal by the paging systems
- Transmittal of the signals from the paging network to the control devices
- Receipt of the load control signal by the devices

The amount of delay associated with the first three reasons was directly measured using communication logs maintained by the AC load control operation system. However, it was not possible to directly measure the time required for the paging company to transmit the signals to the control devices because communications logs for the paging system were not available to PG&E.

The air conditioner load can take on three states—full load, fan load, and no load. As a result, it is necessary to distinguish the normal patterns of air conditioning units turning off from instances where the AC compressors shut down due to load control operations. To do so, the project team relied on the sample of air conditioner units with one-minute data and a statistical technique known as survival analysis (also known as time-to-event and time-to-failure analysis). The survival analysis was designed to answer two questions: how long after the start of the test event does it take for AC units to respond to the control signals; and when is the full impact of the load control reached?

To distinguish normal patterns of air conditioning units shutting down from load control operations, the project team used the 15 minutes prior to each test operation as a control period. The weather conditions, occupancy patterns, and participant characteristics during the 15 minutes *immediately prior* to the test operation are similar to those during the *actual* test

operation. In each case, the project team took a snapshot of the number of units on at the start of the period and determined the share of them that remained as time elapsed. By comparing the rates at which AC units shut down for these two periods, it was possible to identify the time (in seconds) elapsed before the load control operations induced AC units to shut down.

Because spinning reserves are short in duration, the air conditioner demand absent curtailment operations can be estimated based on the usage patterns observed in periods immediately before and shortly after each operation. The customer is not directly notified of operation, so they are unlikely to change their behavior and influence the baseline or the magnitude of demand reductions. This approach was implemented using aggregated air conditioner load from the sampled participants in each feeder. The estimates were produced using regression because it automated the process and produced standard errors that corrected for auto-correlation. The model explained most of the variation in air conditioner loads.

The effect of the test operations on customer comfort and perceptions was assessed by administering surveys to pilot participants and to a control group of air conditioner load control participants that were not part of the pilot. The control group was called for one system-wide event during the summer on September 8th, which lasted four hours. The pilot participants were called for the same event but also experienced an additional 71 short operations (twice every weekday during the months of August and September). None of the events were preannounced, but customers could opt out during events via web or by calling PG&E.

Because there can be substantial variation across cities and even within cities (e.g., housing vintage, income, etc.), the control group was selected prior to administering the surveys using two main steps. First, the eligible population of participants in the SmartAC program who did not participate in the pilot was narrowed to those linked to the same weather station and in the same primary city area as customers located in the pilot study feeders. Second, control group candidates were selected based on how well they matched the pilot participants across observable customer and neighborhood characteristics. To do so, the project team used propensity score matching. This technique requires estimation of the probability customers were part of the pilot feeder population (based on observable characteristics), scores pilot participants and control group candidates, and selects the closest match for each participant (a nearest-neighbor algorithm).

2011 Activities

In 2011, LBNL and FSC developed and tested a method for assessing the accuracy of shorter-term AC load control demand reduction estimation approaches and compares the accuracy of various alternatives for measuring AC reductions using three data sources: feeder data, household data and AC end-use data. The method relies on inserting pre-determined values measured in prior studies into naturally occurring electricity use. It then measures how well each approach estimates (or "predicts") the known demand reductions under different conditions.

Table 2 summarizes the estimation approaches the project team evaluated and provides greater detail for the fifth step in the simulation framework described above. A total of 10 different

demand reduction estimation approaches were applied to feeder, household, and AC end-use data. The least technical approach—a set of tables that provides estimates of the load curtailment based on daily maximum temperature, region, and hour of day—is used as a benchmark to assess the extent to which more complex demand reduction estimation approaches improve accuracy. The approaches can be classified into two broad categories: within- and between-subject estimators.

Table 2: Demand Reduction Estimation Methods Tested

Type of Estimator	Method	No.	Calculation	Data Source				Summary Description
				Individual AC	Aggregated AC	Feeder	House Data	
Within- subject estimators	Day-matching baseline	1	10-in-10 with a 20% in-day adjustment cap	X	X	X	X	A subset of weekdays when units were not cycled is identified and the average is calculated for each hour to produce a baseline. The days are selected from the 10 non-event weekdays closest to the load curtailment day. The baseline is calibrated or adjusted using information about demand patterns in the hours preceding the curtailment (in-day adjustment). Demand reductions are calculated as the difference between the adjusted baseline and metered load. The process for weather-matching baselines is similar except that the baseline load profile is selected from non-event days with similar daily maximum temperatures and then calibrated with an in-day adjustment.
		2	10-in-10 without an in-day adjustment cap	X	X	X	X	
		3	Top 3 in 10 without an in-day adjustment cap	X	X	X	X	
	Weather-matching baseline	4	Profile selected based on daily maximum temperature without an in-day adjustment cap	X	X	X	X	
	Regression	5	Treatment variables and no day or hourly lags or leads	X	X	X	X	Regression analysis quantifies how different, observable factors such as weather, hour of day, day of week, location, and load curtailments affect AC electricity use patterns. With regressions, the impacts are usually directly estimated through the model parameters that reflect the effect of load control operations – known as treatment variables. With treatment variables, the impacts are the difference between the regression estimates of AC use with and without load control. Regression models can be informed by electricity use patterns in the day prior (day lags) and in the hours before or after an event (lags or leads).
		6	Treatment variables with a day lag	X	X	X	X	
		7	Treatment variables with hourly lags and leads	X	X	X	X	
		8	No treatment variables but use of hourly lags and leads	X	X	X	X	
Between- subject estimators	Random assignment of load control operations	9	Comparison of Means		X		X	AC load control program participants are randomly assigned to groups that do and do not have their AC unit instructed to reduce or shed AC load. Any differences between the two groups are random, not systematic. The group that is not subject to the load curtailment is typically referred to as the control group and provides information about normal electricity use patterns in the absence of AC curtailment. Impacts are calculated as the difference in average demand between the group that is and is not dispatched (comparison of means). The estimate can be refined by assessing inherent differences between the two groups in hot non-event days and netting them out of the demand reduction calculation (difference-in-differences).
		10	Difference-in-differences		X		X	

Type of Estimator	Method	No.	Calculation	Data Source				Summary Description
				Individual AC	Aggregated AC	Feeder	House Data	
Pre-calculated load reduction estimate tables		11	Multiply the number of AC units in each geographic location by the corresponding estimate of demand reductions per AC unit for the corresponding area, hour of day, and temperature bin.		X	X		Empirical data on AC end use (absent curtailments) is used to produce estimates of average load by geographic location, hour of day, and temperate bins (based on cooling degree days). The historical evaluation data is used to estimate how the percent load reductions vary with temperature conditions and geographic locations. The percent load reductions are also estimated by geographic location, hour of day, and temperate bins. The percent load reductions are then applied to estimates of AC end-use (absent curtailment) to produce tables. The tables contain estimates of the per AC unit demand reduction for specific geographic locations, hour of day, and 10 temperature profiles.

Within-subject estimators use customer's electricity use patterns during days when AC units are not curtailed to estimate AC load absent curtailment operations during actual event days. They include demand reduction calculation methods such as individual customer regressions and day- and weather-matching baselines. They work because the AC curtailment is introduced on some days and not on others, making it possible to observe behavior with and without the load control in effect.

Within-subject approaches can be less reliable when curtailment events lack comparable non-event periods. For example, if an AC load control program is utilized on all of the hottest days, much like AC programs have normally been operated, there may not be any similarly hot days left over for comparison. However, contingency reserve operations are typically triggered by random generation or transmission outages. They tend to be short in duration and do not always affect the same hours. As a result, there are typically a large number of similar non-curtailment periods.

Between-subject estimators rely on an external control group of AC units that are not curtailed to provide information about AC units that were curtailed and would have used electricity if they were not instructed to shed load. The project team considered two simple options that rely on random assignment to load control operations: a simple comparison of means and a difference-in-differences calculation.

6.3. Project Outcomes

2009 Activities

The outcomes from the 2009 pilot are organized around (1) start time and ramp speed, 2) demand reductions; and (3) effects of the curtailments on customer comfort.

Start time and ramp speed: The median time to response was 60 seconds. By 120 seconds (two minutes), responses had occurred in 92% of the tests; responses had occurred in 95% of the tests within 126 seconds. The average time to response was 69.4 ± 8.9 seconds.

To determine the total ramp time, the project team relied on the same 129 air conditioner units with one-minute interval data, except that the focus was on how the rate at which resources came online. Because air conditioner demand levels differ for each event due to weather and time of day, the loads were normalized to the demands observed in the five minutes immediately preceding each event. Described differently, the graph shows the air conditioner electricity demand during the event as a percentage of the air conditioner electricity demand immediately prior to the event. The graph excludes the same events that were excluded from the analysis of load control start time, namely: mild days when demand reductions were not observed due to the lack of air conditioner use, and the week when operating procedures were being finalized.

During test operations, the curtailment instructions caused most air conditioner units to shut off within the first three minutes of dispatch instructions. On average, by the second minute, 65% of the demand reduction had been attained. By the third minute after the dispatch, on average, 80% of the resources were available. Thereafter, the ramp rate for the remaining air conditioner load reduction resources slowed down. By the tenth minute, on average, 98% of the attainable reductions had been achieved. The demand reduction from a centrally dispatched system was not immediate for all events. In few instances, the demand reductions took up to seven minutes. These were generally instances where delays were experienced in the communication time from the load control operating system to the devices.

The load-reduction potential from air conditioner control varies substantially, with more resources becoming available on the hotter days that typically drive system peaking conditions for most utilities. There are also differences in impacts across feeders, which are explained by several factors. The air conditioner loads reflect not only temperature conditions, but the size of homes (which determines the size of the units), age of homes, household characteristics, and operation patterns.

In the milder regions (relative to Fresno) of Antioch and Fairfield, participants tended to use air conditioners at lower temperatures while Fresno participants typically increased air conditioning consumption when temperatures exceed 90°F. In addition, the reductions as percentage of the baseline also varied. Approximately 80% of the air conditioning electric demand was reduced during operations in the Antioch and Fairfield feeders with some variation across events. However, on average, less than 60% of the air conditioner electric demand was reduced during operations in the two Fresno feeders. This pattern was identified via the real-time monitoring system shortly after operations started and was investigated by measuring the strength of the paging signals in each area. The difference in the demand reductions largely was due to weaker paging network in the areas where the Fresno feeders were located, even though curtailment signals were sent over two paging systems to ensure robust coverage.

The variation in the communication network coverage also has implications for the type of devices utilized. Load control switch devices are typically situated outside homes and can more easily receive and respond to weaker paging signals. On the other hand, thermostats are typically inside homes and are less likely to receive and respond to weaker paging signals.

Both switch devices and thermostats were operated on shed mode and, in theory, should have produced similar demand reductions if they received the curtailment signal. However, the percent of air conditioner load curtailed varied by device types within each feeder. In the Fresno I feeder, on average, switch devices reduced loads by 71%, while thermostats only reduced them by 39%. In the Fresno II feeder, the difference was even larger. Switch devices reduced air conditioner loads by 77%, on average, while thermostats only curtailed 28% of the load. The differences between thermostat and switch device demand reductions were smaller for two feeders with stronger paging network signals. In the Antioch feeder, on average, switch devices reduced loads by 82% and thermostats delivered 69% reductions. In Fairfield, switch devices and thermostats reduced loads by 84% and 67%, respectively.

Effect of Curtailments on Customer Comfort: Among respondents, 91% of the control group and 87% of the pilot participants were satisfied with their relationship with PG&E. On average, the control group and pilot participants rated their experience with the load control program as 7.84 and 7.64, respectively on a scale of 1 to 10, with the majority of both groups reporting that they were overall satisfied with the SmartAC program. About 17% of both the control group and the pilot participants reported that PG&E had turned down their air conditioner during the summer. Survey respondents that reported experiencing an event were asked how many events they experienced. Customers in the control group (who in fact experienced a single event) reported on average 3.23 events throughout the summer, while similar customers in the pilot

group (who experienced 69 to 72 events) reported an average of 2.79 events throughout the summer.

The small differences in customer satisfaction or perception about the number of events were not statistically significant. The findings indicate that repeated short-term control of AC units in the PG&E pilot did not affect customer satisfaction, perceptions, or comfort. The findings suggest that residential air conditioner loads can be used to provide AS with little or no effect on customer comfort or satisfaction.

2011 Activities

In total, the project team evaluated 10 estimation approaches that relied on either feeder data, household data, or end-use AC data. Each combination of data source and estimation approach is considered as a separate alternative. Results are shown for bias, using the mean percent error (MPE), and for goodness-of-fit, using the mean absolute percent error (MAPE), and normalized root mean square error (CV RMSE). To illustrate, a bias statistic of 5% indicates that the approach tends to overestimate demand reductions by 5%. In contrast, the goodness-of-fit metrics selected indicate the magnitude of the errors for individual curtailment periods, with lower values indicating less error. MPE can be positive or negative, while MAPE and CV RMSE can only be positive.

Table 3 shows results for the within-subjects estimation approaches and compares those results with the impact estimate tables for the average event day. The within-subjects approaches include three different day-matching baseline methodologies, a weather-baseline methodology, and four regression models. As a reference, the table also shows impact estimate tables, which are the least technical approach available, and serve as a benchmark to test more sophisticated approaches. The impact estimate results shown here are for a sample of 500 customers drawn, 100 times, and show both the median result and a 90% confidence band around that result.

Feeder data provides the worst results across the board, regardless of the estimation approach employed. Simply put, feeder data includes a lot of irrelevant load variation that dilutes the signal and makes it harder to detect. It includes load variation due to customers that are not enrolled in the AC load curtailment program (including commercial and industrial businesses), as well as end-uses that are not AC related. It is difficult to pinpoint the amount of load being curtailed by an AC program because the program signal is very small, while the noise of other loads is large. For the average feeder, the curtailment events led to an average reduction of 0.2% for the feeder loads. Even for the feeders with the highest penetration of load control devices, the curtailments rarely exceed more than 1% or 2% of the feeder loads. While demand reductions can be observed in feeders with high AC load control penetration on very hot afternoons, they are not a viable option for settlement. Not only does it lead to inaccurate demand reduction estimates, but many utilities such as PG&E cannot readily access sub-hourly data for a large share of their feeders.

Table 3 also shows that baseline approaches are inferior to regression approaches. The day-matching baselines that are typically used for large commercial and industrial (C&I) sector customers produced the least accurate estimates of residential AC demand reductions. They

both exhibited larger bias and more error for individual curtailment periods (goodness-of-fit). This is likely because residential AC loads are far more weather-sensitive than large C&I loads. Weather-matching baselines tend to provide results that are lower in bias and have better goodness-of-fit than day-matching approaches because they better account for residential AC weather sensitivity. They work well with aggregated AC end-use data, less so with household data. The regressions are much better at providing accurate estimates of load curtailments than day- or weather-matching baselines. They produce the most accurate results and perform with both AC end-use and household data. Regression methods 1 and 4 do particularly well.

As the table shows, alternatives that rely on AC end-use data tend to do the best job of estimating the true demand reductions. Individual AC loads show a very clear usage pattern—they are either on or off—those patterns are very difficult to predict, as any individual AC unit's load can be rather volatile. Aggregated AC data can be more accurate because it is easier to predict the aggregate behavior of many customers than to accurately predict the individual behavior of one customer.

Even though it provides the most accurate results, collecting large amounts of AC end-use data is an expensive proposition. Generally, data loggers must be installed on individual AC units and retrieved at the end of a study period or have data transmittal capability. Data collection of AC end-use data requires large expenditures in both labor and capital. On the other hand, household-level data is much easier to collect, especially as smart meters become more and more common.

Several evaluations have recently relied on smart meter data from tens or hundreds of thousands of households with very little incremental cost. While household load data is "noisier" than AC end-use data because it includes the load of many other household devices, the AC load is still quite easy to detect, especially on hotter days. This makes it an affordable and very useful data source.

The impact estimate tables provide fairly good results. In terms of bias, they consistently do better than baseline approaches, and the median result only shows bias of 0.1%, which is better than even the regression approaches. Their goodness-of-fit statistics are not quite as good, indicating that while they do a good job of estimating demand reductions for the average event day, there is considerable variation across individual event days. In addition, goodness-of-fit does not improve as sample size increases; the results shown in the table are for a sample of 500 customers, but our results for a sample of 2,000 customers are very similar. Importantly, the quality of results using this approach depends on the amount of historical event data incorporated, the quality of the underlying evaluations, and the granularity of the cell tables.

Table 3: Within-Subjects Methods Results

No.	Result Type				Bias (MPE)				Goodness-of-Fit (MAPE)				Goodness-of-Fit (CV RMSE)			
	Data Source				Ind. AC	Agg. AC	Household	Feeder	Ind. AC	Agg. AC	Household	Feeder	Ind. AC	Agg. AC	Household	Feeder
1	Within-Subjects	Baseline Methods	Day-matching	1	-136%	-105%	-123%	-1810%	141%	111%	120%	2114%	1.82	1.26	1.88	29.84
2				2	94%	14%	-36%	-526%	129%	32%	70%	1663%	2.24	0.50	0.92	20.10
3				3	960%	9%	-11%	-203%	146%	31%	49%	932%	2.72	0.43	0.57	12.27
4			Weather-Matching	4	55%	-3%	-6%	-463%	99%	29%	25%	1165%	1.64	0.35	0.40	15.30
5		Regression Methods		5	80%	3%	0%	-89%	23%	24%	29%	304%	0.26	0.26	0.25	3.17
6				6	2%	5%	12%	-140%	26%	25%	32%	367%	0.29	0.29	0.27	3.62
7				7	6%	15%	14%	-98%	30%	30%	36%	331%	0.30	0.31	0.28	4.01
8				8	-3%	-2%	-8%	-72%	31%	24%	24%	549%	0.35	0.22	0.30	7.26
11	Impact Estimate Tables	Percentiles		5%	-6%				33%				0.39			
				50%	0%				36%				0.41			
				95%	7%				40%				0.44			

However, considering the simplicity of this very low-cost approach, impact estimate tables provide a good method of achieving a relatively accurate settlement. Regression approaches are preferable for accurate ex post measurement and verification, but impact estimate tables are quite capable of providing quick, unbiased results for settlement purposes.

Table 4 shows results for the two between-subjects methods. The first approach is a simple comparison of means, while the second approach is a difference-in-differences calculation. With the first approach, demand reductions are estimated as the difference between the group that did not have their AC loads curtailed and one that did. With the second approach, the difference between the two groups is also calculated for the curtailment day. However, differences between the two groups observed during days without curtailments and similar weather are then subtracted out. This additional step nets out differences that are irrelevant and mainly due to sampling variation. It improves precision of the estimates, particularly if smaller samples are employed. The table also shows results for the impact estimate table approach using a sample size of 500 customers.

- By definition, between-subjects approaches require aggregating multiple customers into two groups to make a comparison. Thus, individual AC data does not lend itself to doing this type of comparison. In addition, it is not possible to carry out a meaningful comparison between randomly assigned groups of feeders. Thus, the table only shows results for aggregated AC data and household data. In comparing the results of AC end-use and household data, it is important to keep in mind that collecting AC end-use data is prohibitively expensive in comparison to extracting household data from smart meters that have or will be deployed. Collecting AC data for an entire summer for a sample of 500 customers can cost from $300,000 to $600,000.
- Despite the fact that the aggregated AC data source only has 500 customers, it exhibits less bias and better goodness-of-fit than household data with a sample size of 500 or 1,000 customers. This echoes the results shown in the within-subjects comparison; aggregated AC data includes only the "signal" of AC usage with none of the "noise" of other end-uses found in household data. With household sample sizes of 2,000 or more, household data does do better than 500 AC units. Increasing the sample size tightens up the confidence bands for both bias and goodness-of-fit statistics considerably.
- The difference-in-differences approach is more accurate than the simple comparison of means. The additional step of netting out random differences that are mainly due to sampling variation improves measurement precision considerably, especially for smaller sample sizes.
- Both impact estimate tables and between-subjects approaches do not tend to over or underestimate impacts, provided sample sizes are large enough. However, goodness-of-fit is considerably improved when using the between-subjects approaches, indicating that these approaches do much better for individual event days. Some other considerations regarding the use of impact estimate tables have already been described above.

Table 4: Between-Subjects Methods Results

No.	Result Type			Bias (MPE)				Goodness-of-Fit (MAPE)				Goodness-of-Fit (CV RMSE)			
	Data Source			Agg. AC	Household			Agg. AC	Household			Agg. AC	Household		
	Sample Size			500	500	1000	2000	500	500	1000	2000	500	500	1000	2000
9	Between Subjects	Comparison of Means	5%	-32%	-72%	-57%	-41%	20%	36%	25%	17%	0.23	0.33	0.24	0.17
			Median	-2%	-7%	4%	-2%	30%	58%	40%	27%	0.34	0.54	0.37	0.24
			95%	39%	78%	56%	32%	50%	106%	92%	64%	0.55	0.97	0.73	0.52
10		Diff-in-diff	5%	-16%	-21%	-13%	-9%	18%	28%	21%	15%	0.20	0.28	0.21	0.15
			Median	0%	0%	0%	-1%	26%	42%	30%	21%	0.30	0.41	0.29	0.20
			95%	14%	22%	13%	10%	36%	58%	42%	28%	0.43	0.58	0.39	0.27
11	Impact Estimate Tables	Percentiles	5%	-6%				33%				0.39			
			Median	0%				36%				0.41			
			95%	7%				40%				0.44			

- Comparing Tables 3 and 4, it is clear that a between-subjects design using household data and a sample size of 2,000 customers does a better job of estimating curtailment on both average and individual event days than any within-subjects approach; in addition, it also does a better job of estimating curtailment on individual days than the impact estimate tables.
- AC load control devices are well suited for between-subject approaches that rely on random assignment. It is possible to randomly assign and/or rotate curtailment operations rather than have to deny or delay an intervention for a subset of customers. For example, with many systems, it is possible to instruct the load control device of a house to shed load and to instruct the load control devices at an adjacent house not to do so. This approach was successfully executed in the 2011 evaluation of PG&E's SmartAC program, where approximately 140,000 AC units were randomly assigned to 10 different groups and test operations were systematically called for research purposes (George, 2012). For each curtailment event, one or two groups were curtailed and the remaining groups served as controls.

6.4. Conclusions and Recommendations

6.4.1. Conclusions

The conclusions from the work conducted in 2009 are as follows:

Air conditioner load control programs can start resources quickly, typically, within 60 seconds and generally ramp up to full capacity in less than seven minutes, with roughly 80% of the available demand reduction begin to be delivered in less than three minutes.

Air conditioner electric demand patterns can be transmitted in near real time, providing operators information about the resources available and confirmation of demand reductions being delivered.

The demand reductions observed in the air conditioner end-use data were also observable in the feeder loads; however, this is only true under hot temperatures for feeders with a high penetration of participants in air conditioner load control programs.

The demand reductions that can be delivered vary by time of day and temperature conditions and communication network signal strength. Systematic test operations can provide valuable information about the variation and help produce better estimates of the magnitude of resources available. It can also help identify areas where the communication network requires reinforcement.

Repeated short-term AC curtailments (15 minutes or less) did not lead to statistically significant differences in customer satisfaction or comfort.

Many large AC load control programs exist across the United States, many of which control tens or hundreds of thousands of AC units. For example, PG&E's program currently controls over 160,000 AC units, and a full-scale use of those resources could provide approximately 100

MW of load reduction for AS for most summer days, and upwards of 200 MW for system peaking conditions.

The conclusions from the work conducted in 2011 are as follows:

Much of the debate to date regarding settlement methods for demand reduction has focused on day-matching baselines, metering requirements, and telemetry. Our research shows that day-matching baselines are not well suited for measuring AC demand reductions. Moreover, more granular meters do not necessarily increase the accuracy of demand reduction measurement because measuring demand reduction is fundamentally different than measuring the output from generation resources.

The fact that relatively accurate estimates can be obtained using pre-calculated tables of demand reduction estimates raises several questions. Is it necessary to use more complex and more expensive estimation approaches for each individual AC curtailment event? How much value does the incremental accuracy of more complex estimation approaches and metering provide for settlement? How much value is gained by increasingly granular measurement (one-minute versus 15-minute data)?

A practical approach is recommended for settlement. It involves using tables with pre-calculated load reductions per AC unit to estimate demand reductions over the summer; conducting a more detailed evaluation at the end of the summer to reconcile settlements and updating the demand reduction tables on an annual basis using a transparent process that allows for independent verification by a third party. As the measurement uncertainty in annual evaluations improves and the number of AC load operations increases, the accuracy of the tables is expected to increase. The use of such tables allows for quick settlement when resources are dispatched and provide operators a quick estimate of the DR resources available for operations.

6.4.2. Recommendations

Several additional steps need to be undertaken to utilize AC loads for grid operations and incorporate them into markets. These include determining rules on how to conduct settlement for AS bid into markets by load control programs. Generally, the bulk of the payments are related to availability, with penalties for failure to deliver the resourced bid in. AC load control is a unique resource for AS in that their capability is variable though highly predictable. In addition, telemetry requirements need to be re-defined so that they provide operators to confirm that AC resources have been dispatched without imposing substantial costs. This likely means relying on samples rather than requiring telemetry of each individual unit. In addition, the processes for delivering specific amounts of resources need to be systematically done so operators can request discrete amount of resources (i.e., partial dispatch of AC resources).

The accuracy of pre-calculated tables depends in part on the amount of historical curtailment data incorporated, the quality of the evaluations, and the granularity of the tables. When possible, it is highly recommended that direct load control program administrators systematically execute test operations to better define the performance of the programs and that

they rely on large sample sizes, with random assignment of devices to curtailment operations, and a difference-in-differences method.

6.4.3. Benefits to California

Successfully addressing technical and institutional issues that hinder transformation of utility load management programs, such as Smart AC, to provide AS in California ISO's wholesale markets will improve system reliability, prevent rolling blackouts, and lower system operating costs.

6.5. References

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7.0 Glossary

Acronym	Definition
AC	Air Conditioning
ACP	Alhambra Control Platform
AGC	Automatic Generation Control
AMI	Advanced Metering Initiative
AS	Ancillary Service
AutoDR	Automated Demand Response
BAAL	Balancing Authority ACE Limit
C&I	Commercial and industrial sector
California ISO	California Independent System Operator
CERTS	Consortium for Electric Reliability Technology Solutions
CPUC	California Public Utilities Commission
CV RMSE	Normalized Root Mean Square Error
DEWG	Domain Expert Working Group
DR	Demand Response
EPRI	Electric Power Research Institute
FERC	Federal Energy Regulatory Commission
FRR	Frequency Responsive Reserve
FSC	Freeman, Sullivan & Company
HVAC	Heating Ventilation and Air Conditioning
IOU	Investor Owned Utility
IRC	ISO/RTO Council
ISO	Independent System Operator
JPL	Jet Propulsion Laboratory
LBNL	Lawrence Berkeley National Laboratory
MAPE	Mean Absolute Percent Error

Acronym	Definition
MRTU	Market Redesign and Technology Upgrade
NERSC	National Energy Research Scientific Computing (Center)
NIST	National Institute of Standards and Technology
ORNL	Oak Ridge National Laboratory
PAG	IntelliGrid Project Advisory Group
PCT	Programmable Communicating Thermostat
PDR	Proxy Demand Resource
PG&E	Pacific Gas and Electric Company
PIER	Public Interest Energy Research
PL	Participating Load
PLP	Participating Load Pilot
PNNL	Pacific Northwest National Laboratory
pNode	Proxy Node
POP	Point of Operation
POU	Publicly Owned Utility
PWM	Pulse Width Modulation
RD&D	Research Development and Demonstration
RMSE	Root Mean Squared Error
RON-Sim	Residential Occupied Neighborhood Simulation
RTO	Regional Transmission Organization
SAIC	Science Applications International Corporation
SCADA	Supervisory Control And Data Acquisition
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SDP	Summer Discount Plan
SETAR	Self-Exciting Threshold AutoRegressive (model)

Acronym	Definition
SGIP	Smart Grid Interoperability Panel
SGMM	Smart Grid Maturity Model
SLAP	Sub-Load Aggregation Point
SQMD	Settlement Quality Meter Data
TAC	Technical Advisory Committee
WECC	Western Electric Coordinating Council