California Independent
System Operator Corporation

February 18, 2010

Via Electronic Filing

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: California Independent System Operator Corporation 2009 Participating Load Pilot Project Report, Assessment of Smaller Demand Resources Providing Ancillary Services, in compliance with Order No. 719;
Docket Nos. RM07-19-001, RM07-19-___ and ER09-1048-___

Dear Secretary Bose:

Pursuant to Paragraph 581 of the Commission's Order No. 719[1], the California Independent System Operator Corporation (ISO) submits the attached report. Through notice dated December 30, 2009 in Docket No. ER09-1048, the Commission granted the ISO an extension of time to February 18, 2010 to file this report. On April 28, 2009, the ISO submitted its initial compliance filing required under Order No. 719. The Commission's Order on Compliance Filing[2] issued on November 19, 2009 largely accepted the ISO's initial compliance filing but ordered the ISO to submit an additional compliance filing within 30 days. Subsequently, the ISO sought and received a further extension for a 90-day reply period, rather than the 30-day reply period specified in the Compliance Order.

The attached report provides details concerning the pilot programs conducted to assess the technical feasibility and value to the market of smaller demand response resource providing ancillary services.

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[1] *Wholesale Competition in Regions with Organized Electric Markets*, 125 FERC ¶60,071 (October 17, 2008) (Docket Nos. RM07-19-000 and AD07-7-000),
[2] *Cal. Indep. Sys. Operator Corp*., 129 FERC ¶ 61,157 (2009).

I. Communications

Communications regarding this filing and service should be addressed to the following individuals:

Nancy Saracino
General Counsel
*Daniel J. Shonkwiler
Assistant General Counsel
Baldassaro "Bill" Di Capo
Counsel
California Independent System
Operator Corporation
151 Blue Ravine Road
Folsom, CA 95630
Tel: (916) 351-4400
Fax: (916) 608-7296
E-mail: dshonkwiler@caiso.com
bdicapo@caiso.com

*Michael Ward
Alston & Bird LLP
The Atlantic Building
950 F Street, NW
Washington, DC 20004
Tel: (202) 756-3300
Fax: (202) 756-3333
E-mail: michael.ward@alston.com

* Persons designated for receipt of service.

II. Documents Submitted

The documents submitted are the following:

1. This transmittal letter
2. California Independent System Operator Corporation 2009 Participating Load Pilot Project Report, Assessment of Smaller Demand Resources Providing Ancillary Services
3. Attachment A 2009 Pacific Gas and Electric Company Participating Load Pilot Evaluation
4. Attachment B 2009 SCE (Southern California Edison Company) Participating Load Pilot Feasibility Report
5. Attachment C San Diego Gas & Electric Company Participating Load Pilot 2009 Evaluation

Respectfully submitted,

/s/ Baldassaro "Bill" Di Capo

Baldassaro "Bill" Di Capo
Counsel
California Independent System
Operator Corporation
151 Blue Ravine Road
Folsom, CA 95630
Tel: (916) 351-4400

California Independent
System Operator Corporation

California ISO

2009 Participating Load Pilot Project Report

February 18, 2010

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1 Executive Summary

This report documents the experience and results from the Participating Load Pilot ("PLP") projects that the ISO and the three California Investor Owned Utilities conducted, in collaboration, over summer 2009. These PLP projects were consistent with, and responsive to, the Commission's Order No. 719 and the Commission's prior orders regarding the ISO's new market design under MRTU (Market Redesign and Technology Update). In Order No. 719, the Commission directed regional transmission operators and independent system operators "to perform an assessment, through pilot projects or other mechanisms, of the technical feasibility and value to the market of smaller demand response resources providing ancillary services, including whether (and how) smaller resources can reliably and economically provide operating reserves."[1]

In the ISO's opinion, the PLP projects pushed the boundary on the concept of "smaller demand resources providing ancillary services." For instance, PG&E structured its PLP project around three, large single-site commercial and industrial customers, targeting specific end-uses at each customer facility. Both the large retail store and the local government building in PG&E's pilot targeted air conditioning load, and the industrial bakery targeted an industrial scale pan washing machine. The coincident load of all three facilities was measured at 0.269 MW. At this small megawatt size, PG&E submitted offers into the ISO's ancillary service market at the very minimum size accepted by ISO systems, down to 10 KW (0.01 MW). The megawatt curtailment size of PG&E's PLP resources were below the ISO's allowable 1 MW minimum load drop for Participating Loads; however, these small demand response resources were accepted for this pilot as they were important for testing and understanding the limitations of demand response resources participating in ISO markets.

The PLP projects originated from the Technical Design Sessions held in July and August 2008, involving the ISO and various California stakeholders, including the California Public Utilities Commission, the Investor-owned Utilities, and third party demand response providers, to better understand how retail demand response programs could be integrated into ISO markets. Pilot projects were seen as a way to test the waters and to investigate the business, regulatory and technical challenges, along with the cost, of integrating retail demand response into the ISO market. After receiving the CPUC's support and budget approval in December 2008, the IOUs were able to develop and operate PLP projects in the ISO market over the summer of 2009 in support of the

[1] Wholesale Competition in Regions with Organized Electric Markets, 125 FERC ¶60,071 (October 17, 2008) (Docket Nos. RM07-19-000 and AD07-7-000), ¶ 581, requires RTOs and ISOs, in cooperation with their customers and stakeholders, "to perform an assessment, through pilot projects or other mechanisms, of the technical feasibility and value to the market of smaller demand response resources providing ancillary services, including whether (and how) smaller resources can reliably an economically provide operating reserves and report their findings to the Commission."

CPUC's effort to understand how to reshape utility demand response programs to best align with the ISO's new market design.[2]

Each utility PLP project focused on different retail customer segments to explore how residential, commercial, and industrial loads could best be configured to satisfy the ISO's requirements to provide ancillary services, specifically non-spinning reserves, in the form of economically bid demand response resources. The ISO was interested in how well these PLP resources could perform in the ISO market and how these PLP projects would satisfy the ISO technical standards for resources providing ancillary services. In particular, the ISO was interested in three specific objectives, which were to:

1. Better understand the performance and reliability of demand response resources;
2. Develop real-time telemetry alternatives given the aggregated nature of these resources; and
3. Identify operational issues associated with managing aggregated demand response resources in the ISO markets and systems and document those observations and "lessons learned" for future implementation efforts

The PLP projects evaluated smaller demand response resources ranging from an aggregation of 3,200 residential and commercial air-conditioning units that could shed over 5 MW of load when dispatched to the industrial pan-washer mentioned above that could shed approximately 143 kW when dispatched by the ISO. The PLP projects, configured both as single and aggregate customer service accounts, could curtail load to the megawatt quantity of their awarded capacity amount within 10-minutes of receiving a dispatch instruction from the ISO's automated dispatch system. Further, the actual, real-time load of each PLP resource could be viewed by ISO operators in the control room through the ISO's energy management system so that during an ISO initiated dispatch, the ISO could see, in real time, the load drop on any of the PLP resources. The fact that the PLP resources could timely respond to ISO dispatch instructions and convey real-time telemetered load data to the ISO, demonstrated that these small demand resources could comply with the ISO's standards for the provision of ancillary services, specifically non-spinning reserve, like a supply-side resource.

The PLP projects were operated by the IOUs and their important achievements are summarized as follows:

Pacific Gas & Electric (PG&E)

PG&E's PLP project targeted single (versus aggregated), larger load consuming customers in the commercial and industrial sector. PG&E's recruitment goal was three to five individual customers that had loads greater than 200 kW and that were already using the existing Automated Demand Response (Auto-DR) infrastructure.[3] These particular

[2] *Decision Adopting Bridge Funding for 2009 Demand Response Programs*, D.08-12-038 (issued December 18, 2008), at pp.. 18-20

[3] *Automated Demand Response* (aka *Auto-DR*), is a technology developed by the Demand Response Research Center (DRRC) that enables a facility energy management control systems to link to external

customers were already familiar with demand response and had the ability to perform pre-defined load curtailments. The innovative objective of the PLP project was to take these customers with Auto-DR capability and demonstrate how their facilities could be integrated into the ISO's ancillary services market, bidding non-spinning reserve. PG&E entered into agreement with three customers for their PLP project, including an industrial sized bakery, a large retail store, and a local government administrative building.

PG&E's PLP project achieved two significant milestones. First, the PLP project affirmed that customers with Auto-DR capability can automatically respond to dispatch instructions issued by the ISO and curtail loads, based on pre-defined instructions, with no human in the loop. Developing the technical solutions to automate the exchange of information between all systems involved in the dispatch, response, and real-time telemetry of data, end-to-end, was a notable achievement of this PLP project. The second milestone achieved was demonstration that a real-time feedback mechanism would enable the fine-tuning of load curtailment so that the PL resource could more tightly follow ISO dispatch instructions. For example, if the primary demand response mechanism of a demand response resource is cycling air-conditioning load through temperature reset, additional "tuning" may be accomplished through dimming lighting loads or incrementally adjusting the temperature reset, up or down, based on the load curtailment feedback that the resource is sending to the resource operator's load management system. This feedback loop concept is an interesting technology that requires further study and development, so that demand response resources can more accurately follow ISO dispatch instructions in the future.

Southern California Edison (SCE)

SCE's PLP project aggregated over 3,200 air-conditioning cycling devices, primarily installed on residential and a limited number of commercial customers at the Fort Irwin National Training Center, northeast of Barstow, California. When dispatched by the ISO, SCE was able to successfully turn-off, as an aggregated resource, the 3,200 air conditioning units installed at Fort Irwin, for 10 to 20 minutes, resulting in a load reduction of 5+/- MW on the ISO Controlled Grid for that duration.

SCE's PLP project affirmed that small, aggregated loads, acting as a demand response resource, can provide fast and measureable demand response and are able to provide real-time visibility to the ISO, and, ultimately, enhance the reliable operation of the electrical system in ways that are comparable to dispatching a generator for the equivalent amount of energy and reliability services. SCE also achieved a technical milestone in its PLP project by demonstrating how a "proxy" for real-time telemetry, based on sampling and statistics, can serve as a viable and more cost-effective alternative for providing real-time visibility to the ISO of the performance of small, aggregated demand response resources.

San Diego Gas & Electric (SDG&E)

utility-generated price or emergency signals. The utility-generated signals initiate pre-programmed, customer-defined strategies to shift, reduce or shed loads for brief periods of time.

SDG&E's PLP project aggregated medium sized (greater than 200 kW) commercial and smaller industrial loads. SDG&E targeted a minimum of 3 MW for participation in the PLP project. The underlying customer loads were incorporated into a custom load aggregation that could then be scheduled and bid as a single demand response resource in the ISO's ancillary services market.

SDG&E's PLP project allowed bundled commercial and small industrial customers to either directly enroll in the PLP program or sign-up through a third-party aggregator. SDG&E aggregated both directly enrolled and third-party aggregator customers into a single PLP resource that was scheduled, bid and settled in the ISO market.

SDG&E's PLP project was important for its realistic and forward-looking demonstration of how diverse customer loads could be aggregated into a single demand response resource capable of meeting the ISO's ancillary service timing and technical requirements.

The ISO can confidently state that the PLP projects have demonstrated and affirmed that smaller demand response resources can successfully participate in and enhance ISO markets and reliably provide ancillary services, on a basis closely comparable to supply-side resources. The PLP projects provided invaluable insights along the entire demand response supply chain, from the end-use customer and aggregators to the IOUs and the CPUC, about integrating retail demand response into wholesale markets. The ISO believes the PLP projects will help advance state and federal policies to promote the further integration and comparable treatment of demand response resources in organized markets. This ISO report and the attached IOU PLP reports should prove to be valuable information sources for FERC and its stakeholders to better understand the technical feasibility of small demand response resources providing ancillary services in the organized markets.

2 Background

2.1 FERC Order

The Federal Energy Regulatory Commission issued Order No. 719 *Final Rule on Wholesale Competition in Regions with Organized Electric Markets* on October 17, 2008.[4] Order No. 719 directed all Regional Transmission Operators and Independent System Operators, in cooperation with their customers and other stakeholders, to perform an assessment, through pilot projects or other mechanisms, of the technical feasibility and value to the market with smaller demand response resources providing ancillary services, including whether (and how) smaller demand response resources can reliably and economically provide Operating Reserves and report their findings to the Commission.[5]

[4] Wholesale Competition in Regions with Organized Electric Markets, Final Rule, 123 FERC ¶61,017. 73 Fed/ Reg. 64,000 (2008). Order 719 was published in the Federal Register on October 28, 2008, and became effective on December 29, 2008.
[5] Order No. 719 at P97.

Separately, the Commission had already directed the ISO specifically to undertake such efforts in its September 2006 and July 2007 orders regarding the ISO's new market.[6]

2.2 CPUC Directive

The PLP projects were developed by each of the three IOUs through a process conducted by the CPUC as part of an overall effort to consider how to reshape utility demand response programs to better align with the ISO's new market design, and to identify issues and gain experience in operating demand resources in the wholesale market from "bid to bill." Each IOU PLP project was developed to explore the feasibility of configuring end-use customer loads so that they could provide ancillary services, specifically non spinning reserves, to the ISO in the form of economically bid demand response resources. The PLP effort was an outgrowth of the ISO's collaborative activities with California stakeholders such as the CPUC, the IOUs, demand response providers, and end use customers (both bundled and direct access) to promote the development of demand response resources and their integration into the ISO's markets.

As the ISO has previously reported to the Commission in status reports, the ISO's collaborative efforts with stakeholders on of demand response have included the ISO's participation in the CPUC's rulemaking on development of demand response methodologies and alignment of IOU programs with the ISO's new market (CPUC Proceeding R.07-01-041)[7] and, most recently, ISO participation in the IOUs' applications brought before the CPUC seeking approval of specific demand response programs and budgets for the IOU demand response program cycle 2009-2011. (CPUC Proceedings A.08-06-001, A.08-06-002 and A.08-06-003.)

2.3 Motivation to Conduct the Participating Load Pilot Projects

For many years, the ISO has had large pumping loads scheduling and bidding in its market as Participating Load. These pumping loads have contributed significant ancillary service capacity and real-time imbalance energy to the ISO. The ISO has had a keen interest in building on this success by increasing participation from other types of demand response resources in its market to gain a better understanding of how, for example, smaller, aggregated loads could integrate into the ISO market and operations.

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[6] *California Independent System Operator Corp*. 116 FERC 61,274 (issued September 21, 2006) and *California Independent System Operator Corp*. 119 FERC ¶ 61,313 (issued June 25, 2007).

[7] Specifically, in guidance issued on February 27, 2008 to the IOUs by the administrative law judge in Rulemaking (R.) 07-01-041 filed on February 27, 2008, the CPUC provided guidance to the three IOUs to develop programs that would integrate with the ISO's markets. The CPUC expressed strong interest in requiring the IOUs to modify or create products that can operate as participating load under release 1 of the ISO's new markets. Such products would allow Demand Response to be bid-in and compete with other resources in the wholesale markets: ancillary services, day-ahead and day-of energy markets.

In addition, in the consolidated IOU applications proceedings, (A.08-06-001, A.08-06-002 and A.08-06-003), the administrative law judge issued an August 7, 2008 ruling that required the IOUs to resubmit their demand response plans to include a pilot program to explore integration of demand response programs with ISO markets.

This desire to integrate demand response into the ISO is similarly shared by the CPUC whose policy, as articulated in the California Energy Action Plan II,[8] is to consider energy efficiency and demand response as preferred resources in the "loading order" for resource procurement to meeting California's growing energy needs. Integrating these preferred resources into the ISO's market and operations and ensuring such resources can support and enhance the reliable operation of the grid is imperative to making the loading order a practical and sustainable reality.

The CPUC, through the IOUs, is investing significant financial resources into retail demand response programs. The total adopted budget for all three IOUs' demand response programs for 2009-2011 is $336,324,491. Table 1 below shows the total aggregate megawatt quantity of demand response enrolled in the three IOU demand response programs.

Table 1- Summary of Utility Demand Response Programs for 2009

Program Type	Enrolled MW[9]
Price-Responsive	1,068
Reliability-based	2,199

Given the significant investment and the large megawatt quantity of demand response resources under CPUC jurisdiction, it is easy to see why the CPUC is interested in ensuring that California ratepayers realize the full benefits of its investment and, specifically, that no unnecessary or double procurement of resources is occurring between the CPUC and the ISO. Thus, the CPUC is driving California's IOUs to develop retail demand response programs that will integrate with the ISO's market design and gave its r strongest support for the Participating Load Pilot projects by approving funding for the projects in D.08-12-038, the CPUC's Bridge Funding Decision. The CPUC's motivation for supporting the PLP projects-- to bridge the divide between retail and wholesale demand response--is conveyed in the CPUC's final decision adopting the IOU demand response budgets for 2009 through 2011 (D.09-08-027):

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[8] California's Energy Action Plan, which is an articulation of energy policy by California's energy agencies, is driven by the loading order contained in the document. Since it was first issued in 2003, the loading order has been integrated into decisions governing energy policy and procurement in California. Desired energy resource procurement is prioritized under the loading order as follows:

1. Energy Efficiency & Demand Response
2. Renewable Generation
3. Clean and Efficient Fossil-fired Generation

Information regarding the Energy Action Plan can be accessed on the CPUC's website at http://www.cpuc.ca.gov/PUC/energy/resources/Energy+Action+Plan/.

[9] Aggregated data from the month of August 2009 provided by the utilities in monthly reports to the CPUC on the operation of interruptible and demand response programs, specifically:

- Report of Pacific Gas and Electric Company (U 39 M) On Interruptible Load and Demand Response Programs for October 2009, dated November 23, 2009, Table I-1
- Report of Southern California Edison Company (U338-E) on Interruptible Load Programs and Demand Response Programs, dated November 23, 2009, Attachment A, Table I-1
- Report of SDG&E (U 902 M) on Interruptible Load and Demand Response Programs for October 2009, dated November 20, 2009, TableI-1

> *Currently, the utilities' demand response programs provide load drops based on triggers that either are internal to the utility and not necessarily tied to market prices, or are connected to emergency conditions as declared by ISO. Additionally, the notification times required by the retail programs are not well synchronized with ISO market operations. In other words, existing utility retail programs do not incorporate market signals under the ISO's new market, and so are not fully integrated with the anticipated wholesale markets: they can only qualify for ISO purposes as Non-Participating Load. This lack of integration lessens the ability of demand response to reduce electricity prices in the market because demand response cannot necessarily be called upon to reduce load at times of high prices or low reserve margins that do not result in an actual ISO electricity emergency.*
>
> *Recognizing this disconnect and the important role demand response can play in the ISO's new market, the Guidance Ruling directed the utilities to submit plans in this proceeding outlining their strategies on how and when they will integrate their demand response retail programs with the ISO's new market. In particular, the ruling emphasized the importance of positioning demand response resources as a tool to mitigate scarcity prices.*
>
> *In D.08-12-038, the Bridge Funding Decision in this proceeding, the Commission authorized four utility Participating Load Pilots, which are intended to enable the utilities to take existing retail demand response resources and dispatch these resources in the electric wholesale market and test ancillary services feasibility in summer 2009. The Commission expects much will be learned through these pilots to further shape the utilities' plans to integrate their programs with the ISO's new market. This decision includes discussion of other participating-load related pilots, as well as the utility plans for transition existing programs away from non-participating load to either Proxy Demand Resource or Participating Load.* [10]

The policy alignment between FERC's directives in Order No. 719, *inter alia*, and the CPUC's recent decisions related to demand response, created the environment and motivation necessary to successfully pull together the financial, technical and staffing resources to design and implement the PLP projects, in short order, over summer 2009.

3 Participating Load in the ISO

3.1 Description

Since 1999, the mechanism for Demand Response resources to participate directly in the ISO's market has been the ISO's Participating Load Agreement. Under current Participating Load requirements, individual or aggregated loads of 1 MW or greater can

[10] Decision 09-08-027 at pp 121-22. The decision can be accessed on the CPUC's website at http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/106008.pdf

provide ancillary services[11] (non-spinning reserves) and real-time imbalance energy to the ISO.[12] The Participating Load Agreement[13] enables load to participate as price-responsive demand in the ISO's ancillary services, non-spinning reserves market and in the ISO's real-time imbalance energy market.

Although loosely referred to both within the ISO and externally as a "program," Participating Load is more properly characterized as a mechanism which enables demand response resources to interface with the ISO as a dispatchable resource, akin to a generator, and is able to provide, among other things, settlement-quality meter data to the ISO. In addition to satisfying the physical interface requirements to the ISO and its systems, the terms of the Participating Load Agreement provide that the relationship between the resource and the ISO shall be governed by the ISO Tariff, in a manner similar to a supply-side resource operating on the ISO-controlled grid.

3.2 Procedural History of Participating Load

The ISO's Participating Load Agreement was filed as part of the ISO Tariff Amendment No. 17 on June 17, 1999 and was subsequently accepted by the Commission in August 1999.[14] The Participating Load Agreement has, as a primary component, a provision in which the load operator agrees to be bound by the ISO Tariff in connection with its participation in the ISO markets.

Subsequently, participation by loads in the ISO's markets was further addressed in ISO Tariff Amendments No. 29. The ISO filed is proposed Amendment 29, and Commission accepted the tariff amendments in calendar year 2000.[15] With FERC's order approving Amendment No. 29, a tariff section was added to address Participating Loads.[16]

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[11] The ISO is proposing to change the minimum offer requirement for ancillary services, for all resources, including Participating Load resources, to 500 kW, as outlined in the ISO's *Draft Final Proposal Participation of Non-Generator Resources in California ISO Ancillary Services Markets*. This document can be found on the ISO website using the following link: http://www.caiso.com/1c91/1c919e0e11c30.pdf

[12] Under the initial release of the ISO's new market design on March 31, 2009, Participating Loads were limited to participation as contingency-only non-spinning reserves and to real-time imbalance energy participation limited to the dispatch of the underlying energy associated with the A/S capacity reservation. These limitations are proposed to be eliminated with the ISO's Participating Load Refinements that are to be implemented in 2011.

[13] The Participating Load Agreement is the vehicle that allows Demand Response resources to participate in ISO's wholesale markets in a manner akin to a supply-side generator. The Participating Load Agreement enables Demand Response resources to interface with the ISO as a dispatchable resource and to create a relationship governed by the ISO Tariff.

[14] The Commission accepted the Tariff revisions and proposed effective dates in Amendment No. 17, with certain modifications, by order issued on August 16, 1999. *California Independent System Operator Corporation*, 88 FERC ¶ 61,182 (1999)

[15] FERC accepted ISO Tariff Amendment No 29 in its June 29, 2000 Order [*California Independent System Operator Corporation*, 91 FERC ¶ 61,324], which accepted Amendment No. 29 additions and modifications to the ISO Tariff,

[16] When originally added, this Section was numbered as Section 2.2.16. The Section states:

> **4.7 Relationship between the ISO and Participating Loads.**
> The ISO shall only accept bids for Supplemental Energy or Ancillary Services, or Schedules for self-provision of Ancillary Services, from Loads if such Loads are Participating Loads which meet standards adopted by the ISO and published on the ISO

3.3 Inception of the Participating Load Pilot Projects

The PLP projects originated from the Technical Design Sessions held in July and August 2008 between the ISO and various California stakeholders, including the CPUC, the IOUs, and demand response providers, to better understand how retail demand response programs could be integrated into ISO markets. Pilot projects were seen as a way to test the waters, to investigate the business, regulatory and technical challenges, along with the cost, of integrating retail loads into the ISO market. With the CPUC's support and budget approval in December 2008, the IOUs were able to develop and operate PLP projects in the ISO market over summer 2009 in support of the CPUC's effort to understand how to reshape utility demand response programs to best align with the ISO's new market design.[17]

After funding was approved in December 2008, the IOUs began to design, in earnest, their respective PLP pilot projects, starting in February 2009. The PLP project development, implementation, and customer marketing phase ran from January 2009 to July 2009. During this period, the ISO developed and filed with FERC on June 26, 2009, the Participating Load Pilot Agreement, which was signed by each utility and had a requested effective date of June 29, 2009.[18] On July 23, 2009 and July 24, 2009, just like a generator, each PLP project underwent Ancillary Service Certification testing, with each PLP project successfully passing the test by demonstrating the ability to curtail load over a 10-minute period, and the ISO operator, in the control room, having the ability to see the load curtailment in real-time. Finally, the PLP projects were released into production on July 29, 2009 and ran through October 31, 2009.[19] Figure 1 provides a graphical representation of the PLP project timeline.

Home Page. The ISO shall not schedule Energy or Ancillary Services from a Participating Load other than through a Scheduling Coordinator.

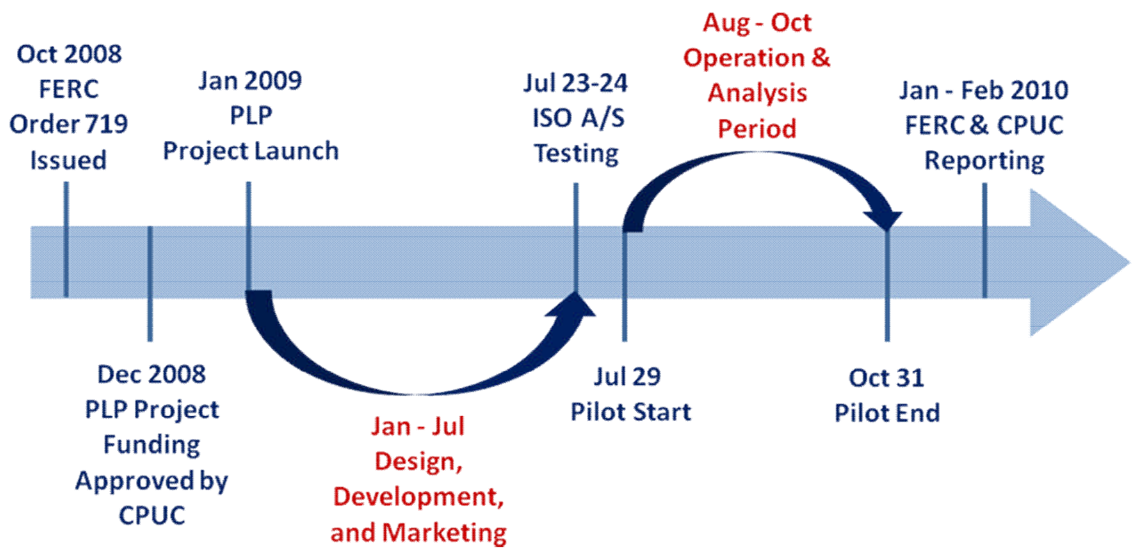
[17] *Decision Adopting Bridge Funding for 2009 Demand Response Programs*, D.08-12-038 (issued December 18, 2008), at pg. 18-20. The decision can be accessed on the CPUC's website at http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/95495.pdf.

[18] The Participating Load Pilot Agreement for each IOU can be found using the following link:

- SCE: http://www.caiso.com/23d9/23d9e0515ede0.pdf
- SDG&E: http://www.caiso.com/23d9/23d9df0f515f0.pdf
- PG&E: http://www.caiso.com/23d9/23d9dfdc56e00.pdf

[19] SDG&E's PLP project continues on, albeit with only minor activity, while the PG&E's and SCE's PLP resources were end dated in the ISO's systems after October 31, 2009.

Figure 1- PLP Project Timeline Overview



4 Operation of the Participating Load Pilots in the ISO Market

4.1 Description of Participating Load Functionality under the ISO's Initial Market Design Release

Under the ISO's initial market design release,[20] Participating Loads must be scheduled and settled at Custom Load Aggregation Points (Custom LAP). A Custom LAP consists of a set of one or more price nodes designated by the scheduling coordinator for the load serving entity and approved by ISO. A Custom LAP must, at a minimum, be entirely within a Sub-LAP.[21] The term Aggregated Participating Loads is sometimes used to distinguish Participating Loads scheduled at Custom LAPs from Pumping (pumped storage) Participating Loads. Under the initial market design release, Participating Loads may bid only into the day-ahead energy market, and the day-ahead non-spinning reserve ancillary services market. They may not bid in the residual unit commitment or real-time ancillary services markets. Also, their bidding into the real-time imbalance energy market is limited to energy associated with the awarded day-ahead non-spinning reserve capacity. These limitations, as described above, are proposed to be eliminated with the ISO's Participating Load Refinements that are to be implemented in 2011.

Under the ISO's initial market design release, Participating Loads must register and use a "load" resource and a "pseudo-generator" resource, both defined at the Custom LAP. As is the case in these pilot projects, the pseudo-generator is used to schedule or bid ancillary

[20] The ISO launched its Market Redesign & Technology Upgrade (MRTU) market design on March 31, 2009.

[21] ISO tariff Appendix A defines a Sub LAP as "a CAISO defined subset of PNodes [Price Node] within a Default LAP." Default LAP is the load aggregation point were all bids for demand are submitted and settled, except as provided for in the ISO tariff, such as demand that is associated with a Custom LAP.

services (non-spinning reserve), and bid real-time imbalance energy. In the day-ahead scheduling process, the load and pseudo generation resources representing a Participating Load are treated independently. Thus, to ensure adequate load is scheduled to cover the non-spinning reserve award (and avoid potential ancillary services no-pay charges), the scheduling coordinator for the Participating Load self-schedules an adequate amount of load to cover its non-spinning reserve bid quantity. However, this self-schedule is not a mandatory requirement. If adequate load is not self-scheduled, then the scheduling coordinator incurs the risk of insufficient load to cover the non-spinning reserve award, and potential exposure to ancillary services no-pay charges.

Under the initial market design, a scheduling coordinator representing Participating Loads can bid to provide the following services:

- Day-ahead energy market;
- Day-ahead non-spinning reserve ; and
- Real-time Imbalance Energy (as described, initially limited to real-time energy associated with awarded day-ahead non-spinning capacity).

The Participating Load model under the initial market design relies on (1) a simple price-sensitive demand curve submitted in the day-ahead market, and (2) an accompanying pseudo-generator supply curve for use in the real-time market that represents the Participating Load's real-time energy dispatch capability.

Each scheduling coordinator for the PLP resources bid or scheduled all or part of the PLP resources at the Custom LAP for energy in the day-ahead market using the unique load Resource ID provided by, and registered with, the ISO.

4.2 Participating Load Certification to Offer Non-Spinning Reserves

The PLP resources had to individually specify the quantity of demand curtailment that each PLP resource intended to certify as available for non-spinning reserve. This demand curtailment is the amount of load that a resource can interrupt within ten (10) minutes of when the ISO issues dispatch instruction. This demand is the maximum quantity that each Participating Load resource could bid as non-spinning reserve.

Prior to any of the PLP resources receiving their ancillary service certification, the respective utilities operating the PLP projects had to perform a certification test with the ISO. Each test included the following:

- Confirmation of telemetry – The ISO observed that the load telemetry was in place and operational and providing required data points;
- Confirmation that the load telemetry met ISO required scan rates and processing cycle times; and
- Confirmation of load control performance – The PLPs demonstrated the ability to curtail their demand consumption when dispatched by the ISO.

4.3 Daily Operation of the Participating Load Pilot Projects

As described above in Section 4.1, the underlying load of a PLP resource was pulled out and established under a unique Custom LAP, separate from the utility's bulk load, which is scheduled at the Default LAP.[22] On a daily basis, the underlying load that is set apart in this Custom LAP, which represents the load of the PLP resource, was forecast and scheduled into the ISO's day-ahead market by the utility's scheduling coordinator.

Along with this load schedule, the utility's scheduling coordinator bid the dispatchable portion of a PLP resource as a pseudo generator into the ISO's day-ahead market as non-spinning reserve with the contingency flag on the resource set to "yes." The scheduling coordinator also submitted an associated real-time energy bid on the resource for the dispatch of the energy behind the non-spinning reserve capacity if/when that energy is needed by the ISO in the form of a load curtailment. If successful in the day-ahead market, the non-spinning reserve capacity of the PLP resource would be awarded and committed to the ISO for the committed period(s).

In real-time, the PLP resource was available for ISO dispatch should the ISO need the energy behind the PLP resource in the event of a contingency. Dispatches to address contingency events are rare; therefore, the PLP projects mainly relied on exceptional dispatches from the ISO to dispatch the resources for "test events." Exceptional dispatches were especially common for SCE and SDG&E as they tested their PLP projects quite frequently throughout the summer season.

4.4 Metering Requirements for the Participating Load Pilot Projects

Each of the PLP resource was represented in the ISO markets as a scheduling coordinator metered entity. As such, each of PLP resource had to have a certified interval recording meter based on the relevant local regulatory authority requirements.[23]

The ISO Tariff Section 10.2.9.2 and the ISO's Business Practice Manual for Metering state that, subject to any exemption granted by ISO, scheduling coordinator metered entities must record meter data in Standard Time as follows:

- At five minute intervals for Participating Loads providing ancillary services and/or real-time imbalance energy
- At one hour intervals for all other meter data

In the case of the PLP resources, the local regulatory authority (i.e., the CPUC in this case) does not require meter data to be more granular than 15-minute metering intervals. Thus, the ISO granted an exemption allowing the 5-minute interval reading needed for settlement quality meter data to be constructed by dividing a 15-minute meter data

[22] Default LAP is the load aggregation point were all bids for demand are submitted and settled, except as provided for in the ISO tariff, such as demand that is associated with a Custom LAP.
[23] "Local Regulatory Authority" is an ISO defined term. Order No. 719 uses the term "electric retail regulatory authority." Additional information on ISO metering requirements can be found in MRTU Business Practice Manual for Metering at: http://www.caiso.com/1840/1840b2f9238c0.html.

interval reading into three 5-minute interval values. This exemption was directly applicable to SDG&E's PLP project whose customers had 15-minute interval meter data. In PG&E's case, PG&E was able to reprogram the meters of the customers participating in its PLP project to read in 5-minute intervals. In SCE's case, a further exemption was granted, as outlined in SCE's Participating Load Pilot Agreement where it states:

> *With respect to metering requirements, because the loads that will participate in the SCE PLP program will be very small, SCE and ISO have acknowledged that it will not be practical or cost effective, at least for the near future, to individually meter 100 percent of the endpoint loads for purposes of satisfying the ISO's requirements currently in place for Participating Load. Therefore, the PLP Agreement provides that the ISO and SCE will develop a methodology for submitting proxy meter data for these loads for ISO settlement purposes.* [24]

SCE's PLP project utilized substation circuit level Supervisory Control and Data Acquisition (SCADA) as a metering proxy for settlement in lieu of actual interval metering at each customer premise.

In addition, each IOU, as the scheduling coordinator for their respective PLP resource(s) had to apply Distribution Loss Factors to adjust the interval settlement quality meter data to the ISO no later than the day specified in the ISO's settlement payment calendar. The meter data was submitted using one of ISO's approved Meter Data Exchange Formats (MDEF or CSV) format. [25]

Figure 2 provides an overview of ISO metering requirements as generally applied to Participating Load resources.

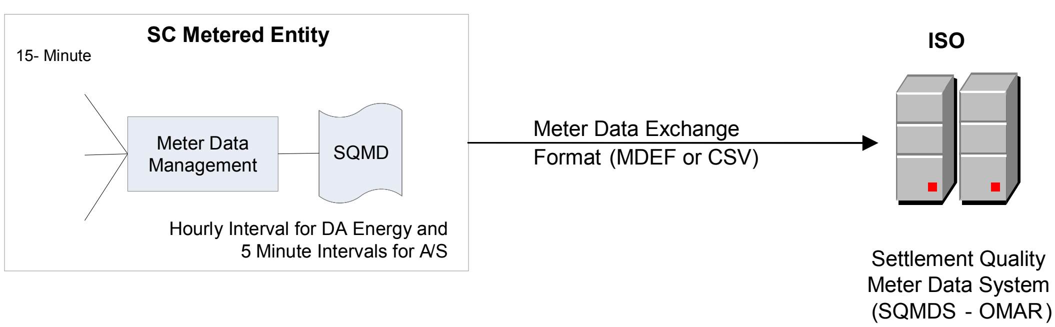


Figure 2- Metering Requirements for Settlement Purposes

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[24] *Participating Load Pilot Agreement between Southern California Edison Company and the California Independent System Operator,* Docket No. ER09-1363-000, June 26, 2009, Section II- Description of the Participating Load Pilot Agreement.
[25] MDEF and CSV formats are available on the ISO Website at: http://www.caiso.com/docs/2005/10/28/2005102810455620 24.html.

4.5 Telemetry Requirements for the Participating Load Pilot Projects

4.5.1 Overview

Participating Loads providing ancillary services must provide real-time telemetered data to the ISO Energy Management System. Because FERC Order No. 719 requires an assessment of the technical feasibility of small demand response resources providing ancillary services, a fundamental objective of the PLP projects was to test the ancillary service capability of small demand resources. In the case of the PLP projects, this meant that it would be necessary to develop a method to produce real-time telemetered data for such resources according to ISO technical standards.

4.5.2 Telemetry Timing Requirements

The PLP resources were required to provide telemetered data to the ISO EMS on a four-second basis. Where load aggregation was required (SDG&E), each meter behind the server had to be polled no less frequently than once per minute.

Figure 3 below provides a high level overview of the telemetry data flow timing for the PLP Resources that were directly communicating through an Energy Data Acquisition and Concentration (eDAC) device[26] or an Inter-control Center Communications Protocol (ICCP) connection to the ISO EMS.

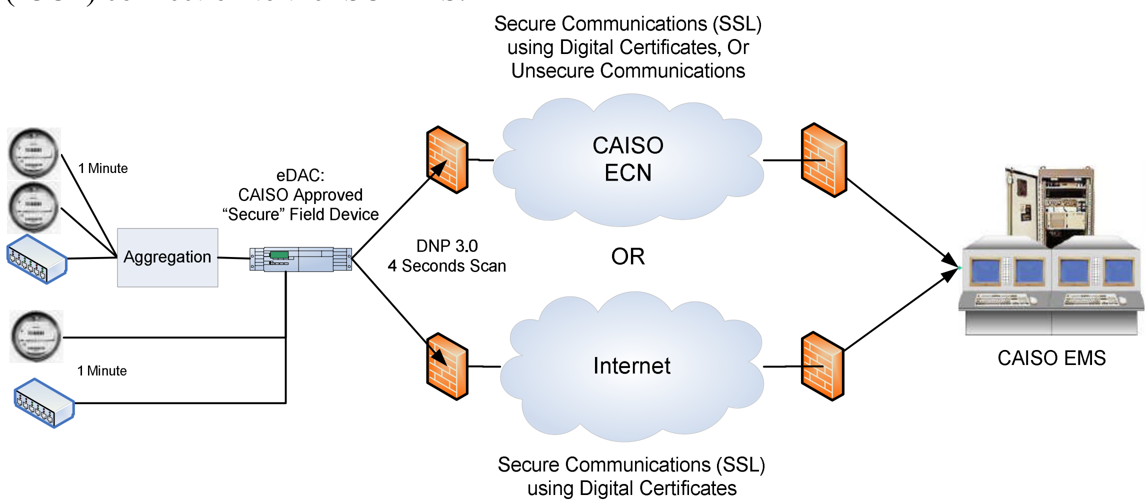

Figure 3- Participating Load Pilot Ancillary Service Telemetry Requirements

4.5.3 Telemetry Configurations

For communicating with the ISO EMS, the PLP resources required an eDAC device or an ICCP connection with the ISO. Each utility's PLP project satisfied the ISO's telemetry requirements, but each in a different way. This was the strength of the overall pilot, as the ISO was able to learn from implementing the three (3) configurations for interfacing these PLP resources with the ISO's EMS. The three telemetry options explored and the respective utility that deployed the option were:

[26] The eDAC is a "real time" data collection device or system that is capable of reliable acquisition, concentration, and timely communication of telemetry data to the ISO's EMS using DNP protocol, as set forth in the ISO's standards for EMS Telemetry for the provision of ancillary services.

1. ICCP connection over the Energy Communication Network (SDG&E)
2. eDAC device over the ISO's Energy Communication Network (SCE)
3. eDAC device over a secure internet connection (PG&E)

A high-level summary of the three utility PLP telemetry configurations is described on the following pages. Detailed descriptions and configurations of how each PLP project satisfied the ISO's real-time telemetry requirements can be found in the respective IOU PLP project reports found in the attachments A-C.[27]

[27] A discussion about telemetry can be found in the following sections in the respective IOU PLP project reports attached: Attachment A- PG&E- Section 5.3; Attachment B- SCE- Section 5.2 and 10.1.1; and Attachment C- SDG&E- Section 3.2.

SDG&E Configuration
ICCP over the Energy Communications Network

ICCP was developed to allow two or more utilities to exchange real-time data, schedule, and control commands. ICCP is an option for Participating Load resources to communicate real-time data to the ISO's EMS. To increase reliability and security, all ICCP communications must take place over the ISO's Energy Communications Network.

Figure 4 below illustrates the overall data flow of the ICCP connection option over the ECN and is described with an overview of the numbered components below:

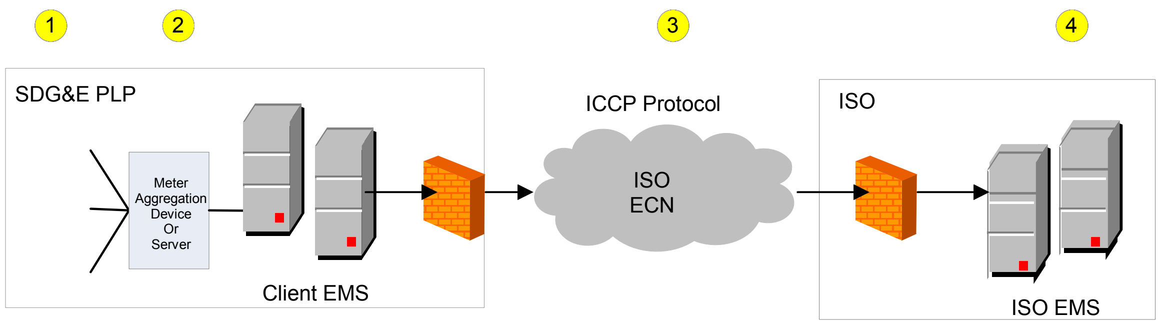

Figure 4- Telemetry Data Flow Using ICCP over the ECN

1. **PLP Real-time Data:** Aggregated load data that is timely and accurately supplying the real-time data needed for ISO telemetry.
2. **Client EMS:** The PLP operator captures and conveys aggregated PLP resource data through an Energy Management System, or other suitable device, capable of communicating via ICCP to the ISO.
3. **ECN Communication with ISO:** This option shows transmission of telemetry from an EMS to the ISO using the Energy Communications Network (ECN), a private communications network established by ISO. Communication links to the ECN usually go through a firewall(s) and High Voltage Protection.
4. **ISO Systems:** The destination of the telemetry via ICCP is the ISO EMS.

SCE Configuration
eDAC Device over the Energy Communications Network

Figure 5 below illustrates the overall data flow of the ECN connection configuration and is described below:

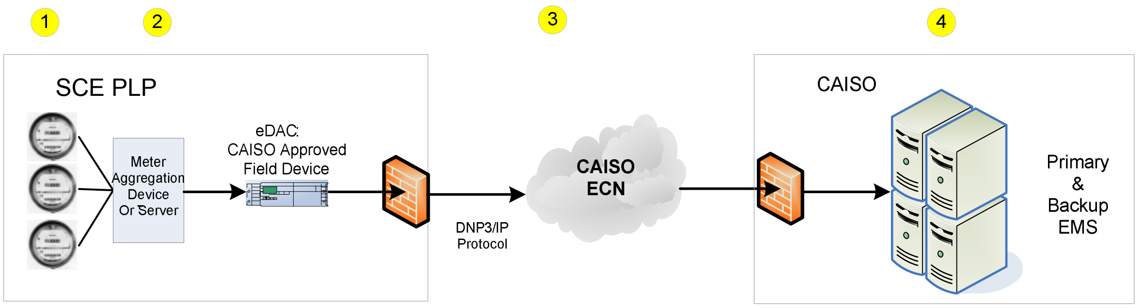

Figure 5- Telemetry Data Flow using an eDAC Device over the ECN

1. **PLP Real-time Data:** PLP Resources, in aggregate, provide meter or other real-time data feeds that are capable of timely and accurately supplying the data needed for ISO telemetry. In SCE's case, SCE conveyed a proxy telemetered value to the ISO that was a statistically derived value of the overall population of packaged air-conditioning units based on a representative sample of A/C cycling units that had two-way communicating devices installed.
2. **eDAC device Integration:** The interface between the eDAC device and the real-time data feed from the demand resource can be any protocol convenient to the resource itself.
3. **ECN Communication with ISO:** This option shows transmission of telemetry from the eDAC device to the ISO using the Energy Communications Network (ECN), a private communications network established by the ISO. Communication links to the ECN usually go through a firewall(s) and High Voltage Protection.
4. **ISO Systems:** The destination of the telemetry is the ISO EMS. The PLP Resource telemetry data arrives at the ISO on the TCP/IP transport layer using DNP3 - LEVEL 2 protocol.

PG&E Configuration
eDAC Device over Secure Internet Connection

Figure 6 identifies the overall data flow of the Public Internet connection option and is described below:

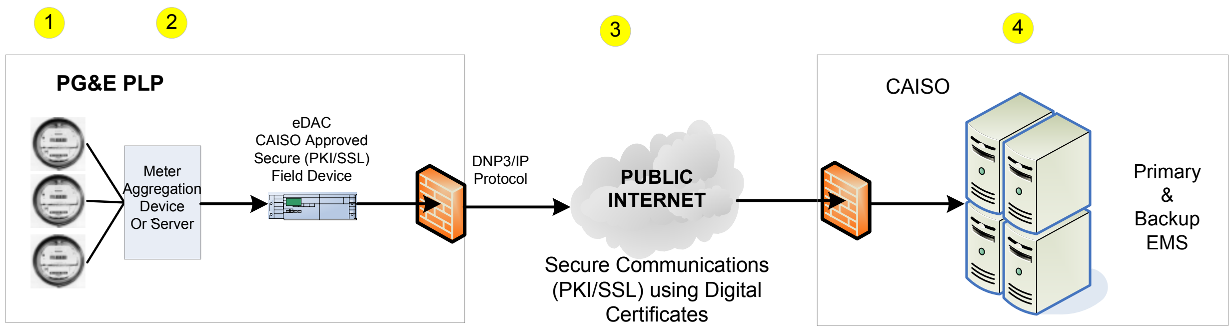

Figure 6- Secure Telemetry Data Flow using an eDAC Device over the Internet

1. **PLP Real-time Data:** The three PLP Resources operated by PG&E provided individual, real-time data feeds that timely and accurately supplied the data needed for ISO telemetry.
2. **eDAC device Integration:** The interface between the eDAC device and the real-time data feed from the demand resource can be any protocol convenient to the resource itself.
3. **Internet Communication with ISO:** an Internet Service Provider (ISP), using Private Line, Frame Relay, DSL and/or ISDN services (dial-up is not an acceptable form of Internet connectivity to the ISO).
4. **ISO Systems:** The destination of the PLP Resource telemetry is the ISO EMS System. All PLP resource telemetry arrives at the ISO on the TCP/IP transport via the Internet as PKI encrypted DNP 3.0 - LEVEL 2.

4.6 Settlement of Participating Loads in the ISO Market

The ISO has included a more detailed overview of the financial settlement of Participating Loads, along with illustrative examples, in Appendix I- *Settlement of Participating Loads* attached to this report.

5 Description of the Participating Load Pilot Projects

5.1 Pacific Gas & Electric

PG&E's primary objective for its PLP project was to understand and develop the internal and external processes, communication systems and strategies, and technologies needed to integrate demand response into the ISO market. The PLP project helped inform PG&E's developing business case for launching potentially larger scale demand response programs that utilize commercial and industrial customer load as a demand response resource that can participate in the ISO market.

PG&E's PLP project focused on the following four objectives:

- Understanding the technical feasibility of large commercial & Industrial (C&I) loads providing energy and ancillary services in the ISO market.
- Developing the internal and external process specifications for the utility to provide energy and ancillary services as a Participating Load.
- Analyzing the economics of the large commercial and industrial sectors participating in the ISO's ancillary services market, from a customer and societal point of view, to inform future program design.
- Identifying the potential barriers to integrate demand response into the ISO market as a resource that is comparable to a supply-side resource.

PG&E's PLP project targeted single (versus aggregated), larger load consuming customers in the commercial and industrial sector. PG&E's recruitment goal was three to five individual customers that had loads greater than 200 kW and that were already using the existing Automated Demand Response (Auto-DR) infrastructure.[28] PG&E ended up entering into an agreement with three customers, including an industrial sized bakery, a large retail store, and a local government administrative building. These particular customers were familiar with demand response and had the ability to perform pre-defined load curtailments using the Auto-DR technology; however, the innovative aspect of the

[28] To learn more about how the Auto-DR technology was deployed in the PG&E PLP project, please review the paper prepared by the Lawrence Berkeley National Laboratory titled *Open Automated Demand Response Communications in Demand Response for Wholesale Ancillary* found using the following link: http://www.openadr.org/pdf/lbnl-2945e.pdf

PLP project was taking these customers and demonstrating how these retail facilities could be integrated into the ISO's ancillary services market, bidding non-spinning reserve, and could automatically respond to ISO dispatch instructions.

PG&E's PLP project achieved a significant milestone by affirming that customers with Auto-DR capability can automatically respond to dispatch instructions issued by the ISO and curtail loads based on pre-defined instructions, with no human in the loop. Developing the technical solutions to automate the exchange of information between all systems involved in the dispatch, response, and real-time telemetry of data, end-to-end, was the notable achievement of this PLP project.

A more detailed description and analysis of PG&E's PLP project can be found in Attachment A- *PG&E PLP Project Report*.

5.2 Southern California Edison

SCE modified its existing Demand Response Spinning Reserve Pilot (DRSRP) project to evaluate its capability to operate as a Participating Load, offering non-spinning reserves, in the ISO market. The DRSRP was originally developed in 2006 to evaluate the potential for re-positioning a traditional utility load management asset, i.e. air-conditioning cycling, to become a system reliability asset that lower costs and improves the functioning of competitive wholesale electricity markets.[29]

The objectives of SCE's PLP project were to:

- Develop the processes, procedures, and systems, both internal to SCE and external interfacing with the ISO, to aggregate air-conditioning cycling loads that can be bid, dispatched and settled as a Participating Load that offers non-spinning reserves in the ISO market.
- Develop the methodologies and algorithms for forecasting and estimating the amount of available load curtailment based on statistical sampling of air-conditioning cycling loads and reconciling the estimated load curtailment with the performance observed at an aggregation point, such as at the circuit level or at the feeder SCADA meter.
- Propose methodologies and algorithms for estimating the load curtailment of small aggregated loads for ISO settlement purposes based on interval metering at an aggregation point rather than from revenue quality metering at each end-use load point.
- Determine whether the methodologies proposed for proxy telemetry and metering were sufficiently accurate for ISO real-time monitoring and settlement purposes.

[29] Additional information about the Demand Response Spinning Reserve Demonstration project can be found in this report at: http://eetd.lbl.gov/CERTS/pdf/62761.pdf

SCE's PLP project aggregated over 3,200 air-conditioning cycling devices, primarily installed on residential and a limited number of commercial customers at the Fort Irwin National Training Center, north east of Barstow, California. When dispatched by the ISO, SCE was able to successfully turn-off the 3,200 air conditioning units installed at Fort Irwin, in aggregate, for 10 to 20 minutes resulting in a load reduction of 5+/- megawatts on the ISO Controlled Grid for that duration.

SCE's PLP project affirmed that small, aggregated loads, acting as a demand response resource, can provide fast and measureable demand response and are able to provide real-time visibility to the ISO, and, ultimately, enhance the reliable operation of the electrical system in ways that are comparable to dispatching a generator for the equivalent amount of energy and reliability services. SCE also achieved a technical milestone in their PLP project by demonstrating how a "proxy" for real-time telemetry, based on sampling and statistics, can be a viable and more cost-effective alternative to provide real-time visibility to the ISO from small, aggregated demand response resources.

A more detailed description and analysis of SCE's PLP project can be found in Attachment B- *SCE PLP Project Report.*

5.3 San Diego Gas & Electric

SDG&E's PLP project was designed to develop an understanding of the issues, required systems, and level of effort needed to fully integrate retail demand response programs into ISO markets. SDG&E's pilot was unique in that it allowed for third-party demand response aggregators to participate, reflecting SDG&E's desire to implement a "…pilot reflective of the 'real world' with Pilot specific objectives focused on practical understanding of an Aggregator based model."[30]

SDG&E's specific objectives for its PLP project were to:

- Identify and assess the costs, barriers, and necessary incentives to provide the technology for telemetry and Auto-DR capability.
- Determine and assess demand response program design, systems, and processes required to support the full scale integration of retail demand response into the ISO market.
- Assess the capabilities of different types of loads to perform effectively in ISO markets.

SDG&E's PLP project allowed bundled commercial and small industrial customers to either directly enroll in the PLP program or sign-up through a third-party aggregator. SDG&E aggregated both directly enrolled and third-party aggregator customers into a single PLP resource that was scheduled, bid and settled in the ISO market. SDG&E's challenge was aggregating a sufficient number of customers to meet its three (3) MW

[30] *SDG&E Evaluation of 2009 Participating Load Pilot*, Attachment C, at pg. 3.

load reduction target for its PLP project since this class of customer can typically only reduce their electricity consumption by 10% to 20% of their total load.

SDG&E's PLP project was important for its realistic and forward-looking demonstration of how diverse customer loads could be aggregated into a single demand response resource capable of meeting the ISO's ancillary service timing and technical requirements.

A more detailed description and analysis of SDG&E's PLP project can be found in Attachment C- *SDG&E PLP Project Report.*

6 Performance and Settlement Results

The PLP projects provided an important learning experience for all parties involved. Noteworthy was that fact that it was the first time that the California IOUs scheduled, bid and settled demand response resources directly in the ISO market on a basis comparable to a generator. In addition, it was the first time that residential, commercial and industrial loads were structured to offer ancillary services to the ISO, satisfying all of the ISO's requirements for the provision of non-spinning reserves. As such, the PLP resources were able to provide the ISO operator with real-time visibility to the load through the ISO energy management system, and they were able to respond to an ISO dispatch instruction, automatically in certain cases, and deliver the energy behind the awarded ancillary service capacity within 10-minutes.

The following section provides summary data on ISO certification and dispatch of the PLP projects and the quantities of energy and ancillary services bid and awarded to each PLP resource, including how effectively the PLP resources complied with dispatch instructions and delivered the energy behind the ancillary service capacity.

Note that there may be discrepancies between ISO data reported here and data reported in the attached IOU PLP project reports. There are different reasons why such data discrepancies can occur. The most likely reason is that the ISO is using the most current settlement data available as opposed to the initial settlement data that was available to the IOUs when they assembled their reports.

6.1 PLP Project Reporting Period

The reporting period for the results presented in this section of the report is shown in Table 2 below and represents the duration of the PLP projects over summer 2009:

Table 2- PLP Project Reporting Period

PLP Project	Reporting Period	
	Begin Date	*End Date*
PG&E	Jul 29, 2000	Oct 31, 2009
SCE	Jul 29, 2009	Oct 31, 2009
SDG&E	July29, 2009	Dec 31, 2009*

*Technically the SDG&E PLP Project is on-going; however, for data reporting purposes, the ISO has summarized results through December 2009 for the SDG& PLP resource.

6.2 Ancillary Service Certification Results

From July 22 - 27, 2009, the ISO successfully conducted the Ancillary Service Certification testing for all five of the PLP resources. The formal Ancillary Services Test Results form for each PLP resource is attached in Appendix III of this report. The testing procedure used for the PLP resources was very similar to how the ISO conducts ancillary service certification testing for generators. For example, the load had to verifiably curtail to a specified megawatt level within 10-minutes of the ISO issuing its instruction. Passing the certification test allowed the three IOUs to be eligible to bid their PLP resources into the ISO market beginning on trade day July 29, 2009.

A summary of the PLP resources and their Ancillary Service Certification test results are described below:

6.2.1 PG&E Certification Results

PG&E's PLP project included three single-site PLP resources, including:

- A local county office building
- A large retail furniture and home goods store
- An industrial bakery

Each of the PLP resources was tested and certified by the ISO to bid up to 0.2 MW of non-spinning reserve capacity per PLP resource. The certification test demonstrated that each of PG&E's PLP resources had a very quick response time, well within the 10-minute requirement to deliver the energy behind the awarded capacity.

6.2.2 SCE Certification Results

SCE air-conditioning cycling project took place at Fort Irwin, a large military installation located in California's Mojave Desert. SCE modeled the air-conditioning load from the base housing units and a limited number of commercial facilities by sampling a limited population of the air-conditioning units and creating a statistical representation of the overall air-conditioning load. The PLP resource representing the overall curtailable air-conditioning load was tested and certified by the ISO for 5 MW.

6.2.3 SDG&E Certification Results

SDG&E, working with its project partner APX, aggregated commercial and small industrial bundled customers throughout the SDG&E service territory to create a single demand response resource for scheduling and bidding in the ISO market. The challenge of this particular PLP project was the ability to curtail load from an aggregation of customers to the megawatt level of the ISO dispatch instruction and to propagate an accurate, real-time telemetry value representing those aggregate loads back to the ISO in a timely manner. SDG&E's PLP resource was tested and certified by the ISO for 3 MW.

6.2.4 PLP Project Summary Ancillary Service Certification Results

Table 3 below summarizes the Ancillary Service Certification results for each of the five (5) PLP resources.

Table 3- PLP Project Ancillary Service Certification Results

PLP Project	**Ancillary Service Certification Test Results**	
	Certified Range (MW)	Certified PMax * (MW)
SCE A/C Cycling	0 - 5	5
PG&E- Local Gov't Bldg	.02 - .10	0.40
PG&E- Large Retail Store	.02 – .20	0.20
PG&E- Industrial Bakery	.02 - .20	0.58
SDG&E Aggregation	0 – 3	3

* PMax represents the maximum load consumption of a PLP resource

6.3 Dispatch Events

The PLP Projects bid non-spinning reserves in the ISO market as contingency flagged resources. A contingency flagged resource means that the ISO will dispatch the energy behind the ancillary service capacity of such a resource only in the event of a contingency on the grid. For instance, a contingency can be caused by the loss of a transmission line, a generator, or other piece of equipment causing stress or a significant overload on the grid. Because contingency events are infrequent, the ISO and the IOUs had to rely upon Exceptional Dispatches to instruct the PLP resources for testing purposes.[31] Table 4 below summarizes the number of ISO dispatches issued to each PLP project during the reporting period.

[31] Exceptional dispatches are a way for the ISO operator to manually enter dispatch instructions into the day-ahead and real-time market optimization software so that such dispatches can be accounted for and communicated to scheduling coordinators. Exceptional dispatches are not derived through the Integrated Forward Market or Real-time Market optimization applications and are not used to establish the locational marginal price at the applicable PNode where a resource resides. See Tariff Section 34.9 for additional information on exceptional dispatch.

Table 4- ISO Dispatch Events

PLP Project	ISO Dispatch Events (Count)	Dispatch Amount (MW)*
SCE A/C Cycling	12	0.87 to 6.83
PG&E- Local Gov't Bldg	7	0.049 to 0.116
PG&E- Large Retail Store	6	0.05 to 0.124
PG&E- Industrial Bakery	6	0.125 to 0.143
SDG&E Aggregation	14	0.3 to 1.8

*Data summarized from the respective IOU PLP Project Reports

6.4 Market Awards & Settlement Results

6.4.1 Ancillary Service Capacity Awards and Settlement

Participating Loads certified to provide ancillary services can offer to sell ancillary service capacity through the ISO's ancillary service capacity market or may submit to self-provide ancillary services. Resources that are awarded bids for ancillary service capacity are paid the ancillary service marginal price; whereas, self-provided ancillary services effectively reduce the aggregate ancillary service requirements that the ISO must meet, and self-provided ancillary services reduce the ancillary service obligation for the scheduling coordinator that is self-providing the ancillary service. Table 5 below describes how much non-spinning reserve capacity each PLP resource offered, was awarded or self-provided, and the payment by the ISO for that capacity, over the reporting period. Specific performance detail of each PLP resource can be found in the attached IOU PLP Project reports.

Table 5- Non-spinning Reserve Capacity Awards and Settlement

PLP Project	Total Non-spin Capacity Bid (MW)	Total Non-spin Capacity Awarded (MW)	Total Non-spin Capacity Payments ($)	Total Non-spin Capacity Self-provided (MW)
SCE A/C Cycling	0	0	$0*	37.26
PG&E Local Gov't Bldg	5.16	5.08	$39.20	0
PG&E Retail Store	13.4	13.14	$57.10	0
PG&E Industrial Bakery	15.31	14.98	$94.25	0
SDG&E Aggregation	1051.8	1051	$1,279.66	0

*SCE self-provided their non-spinning reserve capacity. As such, there was no settlement by the ISO for the ancillary service capacity accepted; instead, the capacity offset SCE's ancillary service capacity obligation.

6.4.2 Real-time Energy Awards and Settlement

The ISO's market optimization and real-time dispatch applications require an energy bid accompany an ancillary service capacity bid so that the ISO can dispatch the energy behind a non-spinning reserves capacity award, irrespective of whether the ancillary service award is for qualified self-provision or an accepted ancillary service bid. Thus, each PLP resource had an economic energy bid that would enable the dispatch of energy equivalent to the megawatt amount of non-spinning reserve capacity that was awarded to that PLP resource in a particular trading hour.

Total financial settlement amounts reported below for each of the PLP resources are small, which does not reflect on whether or not these resources where economic, but is due to the fact that the PLP resources were small in size (megawatts) and the resources were only dispatched by the ISO for short durations throughout the reporting period. The IOUs discuss in their PLP Project reports the cost-effectiveness of smaller demand resources providing ancillary services.

Table 6 below summarizes the real-time activity and settlement of energy for each of the PLP resources over the reporting period. Specific performance detail of each PLP resource can be found in the attached IOU PLP Project reports.

Table 6- Real-time Energy Awards and Settlement

PLP Project	Total Real-time Energy Offered (MW)	Total Real-time Instructed Energy (MWh)	Total Real-time Energy Delivered (MWh)	Total Energy Payments to PL Resources ($)
SCE A/C Cycling	40	5.59	5.59	$461
PG&E Local Gov't Bldg	0.227	0.225	0.225	$26
PG&E Retail Store	13	0.07	0.07	$22
PG&E Industrial Bakery	15	0.35	0.35	$117
SDG&E Aggregation	879	1.8	1.8	$223

6.5 Compliance Results

Resources that are awarded ancillary service capacity in the ISO market are required to convert that capacity into energy if dispatched by the ISO in real-time or keep that capacity unloaded and available for potential dispatch of energy in real-time. If a resource fails to fulfill these requirements, then that resource is not entitled to its full ancillary service capacity payment. The ISO's no pay settlement charge eliminates ancillary service capacity payments to the extent that the capacity obligations were not fulfilled.

No pay applies in each settlement interval for the PLP resources that were scheduled to provide non-spinning reserve capacity for the following reasons:

- **Undelivered Capacity** – If energy from a PLP resource's ancillary service award is dispatched, then that PLP resource is responsible for delivering at least 90% of the expected energy attributed to that dispatched ancillary service capacity in order to avoid a no pay charge.

- **Unavailable Capacity** – No pay charges apply when ancillary service capacity is unavailable because it is converted to energy without an explicit ISO dispatch instruction. Uninstructed deviations in real-time may cause ancillary service capacity to be unavailable to the ISO as operating reserve.

- **Undispatchable Capacity** – Since Participating Loads submit energy bids for ancillary service capacity that could have ramp rates that are not sufficient to deliver the full ancillary service capacity awarded within 10 minutes, No pay charges for undispatchable capacity related to ramp rate limitations apply.

In some cases, more than one of these no pay consequences can apply in a settlement interval. The no pay billable quantity is the sum of all the no pay consequences. Table 7 below is a summary of the no pay settlement that applied to each of the PLP resources over the reporting period.

Table 7- Unavailable Non-spin Capacity and associated No Pay Charges

PLP Project	Total Non-spin Capacity Awarded and Self-provided (MW)	Total Non-spin Capacity Unavailable Subject to the No Pay Provision[32] (MW)	Non-Compliance (%)	Total Non-spin Capacity Payment Rescinded Subject to the No-Pay Provision ($)
SCE A/C Cycling	37.26	4.03	10.8	$0
PG&E Local Gov't Bldg	5.08	0.19	3	$3.16
PG&E Retail Store	13.14	0.08	0.6	$0.29
PG&E Industrial Bakery	14.98	0.4	2.6	$3.69
SDG&E Aggregation	1051	1.13	0.11	$3.26

7 Observations and Lessons Learned

One of the ISO's key objectives for the PLP projects was to:

> *Identify operational issues associated with managing aggregated demand response resources in the ISO markets and systems and document those "lessons learned" for future implementation efforts.*

The PLP projects pushed the boundary of "smaller demand resources providing ancillary services." For instance, PG&E structured its PLP project around three, large single-site commercial and industrial customers, targeting specific end-uses at each customer facility. Both the large retail store and the local government building in PG&E's pilot targeted air conditioning load, and the industrial bakery targeted an industrial scale pan washing machine. The coincident load drop of all three facilities was measured at 0.269 MW. At this small megawatt size, PG&E submitted offers into the ISO's ancillary service market at the very minimum size accepted by ISO systems, down to 10 KW (0.01 MW). The megawatt curtailment size of PG&E's PLP resources were below the ISO's

[32] The Total non-spin capacity subject to the ISO no pay provision is all of the megawatt quantities calculated by the ISO's no pay compliance program. The megawatts calculated by the no pay compliance program may not be settled with a financial dollar impact for two reasons: 1) if the non-spin capacity was self-provided then the no pay megawatt is a megawatt reduction in credit due the scheduling coordinator for the ancillary service self-provision, and therefore, no explicit "No Pay" financial settlement results, and 2) if the non-spin capacity price is $0 then there is no financial settlement.

allowable 1 MW minimum load drop for Participating Loads, but these small demand response resources were accepted for this pilot and were important for testing and understanding the limitations of demand response resources participating in the ISO market.

Highlighted below are observations and the lessons learned that were directly related to the ISO's experience integrating and operating the PLP projects. Like the ISO, the IOUs had their own set of experiences and lessons learned from implementing and operating their respective PLP projects. The ISO does not reiterate IOU specific experiences in this report; instead, the ISO refers the reader to the specific IOU PLP project reports found in Attachments A-C for the important and supplemental detail concerning lessons learned that the IOU PLP project reports provide.

The ISO focuses its observations and lessons learned in the following five areas:

- Modeling and Optimization
- Load Forecasting
- Dispatch
- Telemetry
- Metering

7.1 Modeling and Optimization

7.1.1 Mixed Integer Programming Gap Issue

To effectively run its markets, the ISO must derive an optimal power flow solution and produce market results in a timely manner. The ISO employs a Mixed Integer Programming (MIP) technique to derive this optimal power flow solution. The "MIP Gap" is a measure of the difference in the objective costs between a theoretical optimal solution, ignoring commitment type decisions, and what the solution can derive in a reasonable time. The MIP Gap became an issue with very small bids, especially in PG&E's case, where energy bids were in the kilowatt range, and therefore the resources total cost is relatively very small, even if at the bid cap. In certain instances, a small bid (kilowatts) could be "economic" but may be overlooked in the final market solution, appearing sub-optimal, and not awarded or dispatched. The ISO is evaluating some possible new approaches in its optimization routine to address small supply-side and demand-side resources that can be impacted by the MIP Gap issue.

7.1.2 Full Network Model Limitations

The ISO's network model is not a program that is highly dynamic or flexible in its ability to accept frequent changes. In fact, changes to the network model require significant oversight and due-diligence to ensure that any changes are accurate, tested, and function as intended. The network model is critical ISO infrastructure and the underpinning of operating the ISO market.

Demand response resources present a challenge because they are dynamic, requiring frequent changes to their operating characteristics. For example, unlike a generator, demand response resources can have significant seasonal variability and/or experience frequent customer migrations. The other challenge is that modeling demand response resources as a generator means every new demand resource needs to be modeled at an electrical bus, with specific operating characteristics, in the ISO network model. Setting up a new generator in the ISO network model is a carefully orchestrated and time consuming process. Thus, the ability to change and/or add new demand response resources is constrained by the time it takes to alter the network model.

To address this concern, the ISO is investigating an alternative resource validation process where demand response resources would be mapped to load busses, eliminating the need to "build" in the ISO network model a pseudo generator for each new demand response resource.

7.1.3 Masterfile

Related to modeling new demand response resources in the ISO's network model is the mapping of resource parameters and characteristics in the ISO's masterfile. The data that exists in the ISO's masterfile feeds the network model and other ISO systems. The challenge is how to interpret demand resource attributes into generation parameters in the ISO masterfile; demand resources are unique and don't always fit the definitions and parameters of a generator. For the PLP projects, the ISO, working with the IOUs, had to map generation parameters into demand resource parameters in its Resource Data Template (RDT), which is used to specify the attributes of a new resource that is to be input into the masterfile. The ISO is addressing this issue with its soon to be released proxy demand resource product through a revised RDT that is specific to proxy demand resources.[33]

7.1.4 Energy Management System

7.1.4.1 Certifying New DNP 3 Capable Field Devices

One of the more significant challenges of the PLP projects was satisfying the ISO's real-time telemetry requirements necessary to participate in the ISO's ancillary services market. The ISO requires "visibility" to the resources that are providing the ISO's operating reserve capacity requirements in real-time, which, for the PLP resources, meant providing visibility to the PLP resources' real-time load consumption.
For resources providing ancillary services, the 4-second data exchanged in real-time must follow certain data communication protocols, specifically ICCP (Inter-control Center Communication Protocol), as was the case for the SDG&E PLP project, or DNP 3 (Distributed Network Protocol) for PG&E's and SCE's PLP projects.

PG&E's PLP project relied on an ISO approved device that was capable of real-time communications with the ISO's energy management system from field devices like remote terminal units and/or other intelligent electronic devices using the DNP3 protocol. Using this ISO certified communication device enabled this aspect of PG&E's PLP project to go smoothly. In SCE's case, SCE's vendor decided to modify its existing

[33] The ISO submitted its proxy demand resource tariff amendments to FERC on February 16, 2010 (Docket No. ER10-765).

hardware and software solution to meet the DNP 3 protocol stack. This proved technically challenging given the tight time constraints of the project and resulted in some delay, although the vendors' technical solution was ultimately certified by the ISO. The lesson learned from this experience was to ensure sufficient time is allotted for the certification and approval of any new DNP 3 capable communicating devices if a demand resource owner wants to deploy their own DNP 3 solution and have it certified by the ISO.

7.1.4.2 Real-time Telemetry Value

The PLP projects brought to light the issue of what megawatt value does the ISO market and energy management systems need to see in real-time from demand response resources. For resources providing ancillary services, the ISO is interested in the amount of capacity available from a particular ancillary service capable resource. This concept is straightforward for a generator as the available capacity is, in general, the difference between the units (its maximum ISO certified capacity) and its current operating point (not considering any derates on the unit, etc.). However, this concept of "available capacity" does not easily translate from a generator to a demand response resource.

For example, with a demand response resource, the ISO can easily see the total load consumption of a particular customer or an aggregation of customers. If a customer consumes up to 10 MW, but only has a maximum of 2 MW of demand response, through real-time telemetry, the ISO can easily see what that customer's total load consumption is at any time; however, this is not the equivalent of knowing a load's available capacity, i.e. the 0 MW to 2 MW of demand response. What the ISO is interested in knowing is how much of the 2 MW of demand response, out of the 10 MW total load, is available to the ISO as "available capacity." How to determine this capacity quantity distinct from the total load consumption is not trivial given the of a load is not as easily determined like it is for a generator, especially if the load cannot be turned "off," which is often the case with demand resources.

Encountering this challenge through the PLP projects, the ISO is exploring how it can employ a reference level in real-time, at the point of dispatch of the energy behind ancillary service capacity, so that the ISO, at minimum, can more easily validate if the available capacity from a demand response resource is being delivered when dispatched. The ISO has written a technical paper on this issue and will soon be sharing its proposed solution with stakeholders for their review and input.

7.1.4.3 Meaning of "Unit Connect"

The ISO's energy management system requires a "Unit Connect" status or UCON value to ensure a resource is electrically connected to the grid, i.e. its breakers are closed and the resource can transmit energy to the grid. UCON does not have the same meaning for a load as it does for a generator, especially if the demand response resource is composed of an aggregation of loads. To address the UCON value, the ISO interpreted the UCON value as "yes" or "no" in the following manner:

- UCON = Yes means the breaker is closed and the load is connected
- UCON = No means the breaker is open and the load is disconnected from grid

The interpretation is straightforward for a single load acting as a demand response resource; the load is either connected to the grid or it isn't. However, when a demand response resource is composed of an aggregation of customer loads, UCON becomes less meaningful, i.e. if one or several loads are disconnected, but not all, should UCON be a yes or no? The ISO determined that UCON would equal "No" only if all of the loads in the aggregation were disconnected, for example, in the case of an outage affecting that entire aggregation of customers.

The PLP projects were helpful in highlighting this issue and the ISO is continuing to work internally to address the interpretation and relevance of the UCON status as it applies to demand response resources.

7.2 Load Forecasting

In its current configuration, the ISO's Automated Load Forecast System (ALFS) does not incorporate a forecast for load curtailments associated with demand response resources.[34] To address this issue, the ISO is working on the next generation of ALFS which will enable ALFS to factor in the contribution from demand response resources through an additional input variable available to the ISO operator.

7.3 Dispatch

7.3.1 Unit Commitment Decisions when PMin = 0

How a demand response resource is modeled effects how that resource is dispatched according to the ISO's unit commitment algorithms. For example, PG&E's PLP project modeled a PLP resource with a PMin =0 and >0. This can be an appropriate way to model a demand response resource; however, in the ISO's real-time unit commitment system, having a PMin = 0 MW enabled the ISO to move the PLP resource in real-time to a non-zero MW value and then back to 0 MW again and again during the PLP resource's min-run time. To the PLP resource, this appears as if it is being turned on and off. The reason for this type of dispatch is that the ISO's unit commitment algorithm sees that there is no cost impact for moving the PLP resource to a non-zero MW value (curtailing the load) and then back to 0 MW again (restoring the load), multiple times if necessary, within the resource's min-run time period.

There is not a simple solution to this modeling challenge. The type of dispatches described above can be addressed by setting the PMin > 0 or by setting the PMin at values that are close to one another, e.g. = PMin + 0.1 MW. However, making these adjustments results in other challenges and consequences. For example, setting a PMin to something greater than 0 MW and establishing a minimum load cost may eliminate unwanted dispatches, but may also introduce fictitious resource parameters that are not associated with any underlying physical resource constraint. Part of the challenge is trying to fit a demand response resource into a generator box. The PLP projects were helpful in bringing this issue to light and the ISO looking to resolve these types of constraints with the implementation of its Participating Load Refinements in 2011.

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[34] Specifically, does not forecast demand response associated with conforming load, i.e. non-pumping load.

7.3.2 Dispatch of Quick Start Contingency Flagged Resources

The PLP projects bid non-spinning reserve capacity with the contingency flag set to yes, which meant the PLP resources were only available for dispatch during an ISO contingency event. The PLP resources were equivalent to "quick start" resources in that they could be held off and then dispatched when needed to deliver their full awarded capacity within 10 minutes.

During a contingency event, the ISO operator is likely facing a reliability concern that must be addressed immediately. The ISO operator often needs sizable resources that can resolve the issue. One of the important operational lessons was that very small resources, like the PLP resources, take as much time as larger resources to switch "on" in the ISO software and dispatch and, therefore, are not worth the ISO operators' time when small demand response resources provide little to no significant resolution to the real-time problem the operator is trying to address.

To solve part of this challenge, the ISO developed a software patch that would switch the PL resources "on" when they were called up during a contingency event. A consequence of this fix was that the PL resources were being left "on" in the ISO software after the contingency event was over, which resulted in dispatches after the contingency event had ended since the PL resources, once switched on, appeared to be economic resources in the ISO's system. As a result, an additional software patch was implemented that would turn-off the PL resources at the end of the day and return them to "contingency only" resources.

The PLP projects allowed the ISO to experience these important operational issues, but the fundamental issue of small resources requiring as much of the operator's attention as large resources, especially during critical reliability events when the operator is racing time and deteriorating system conditions, means that small resources may remain overlooked as the operator is determining how to dispatch the right resources, in the right amount, and in the right location to resolve the reliability concern. It would be difficult to develop a software solution to solve this challenge and to automate a response to every possible contingency event. To capture the operator's attention during contingency events, demand response resources will likely have to be of a certain minimum size, likely 10^{+} MW, and be dispatchable by location and/or region.

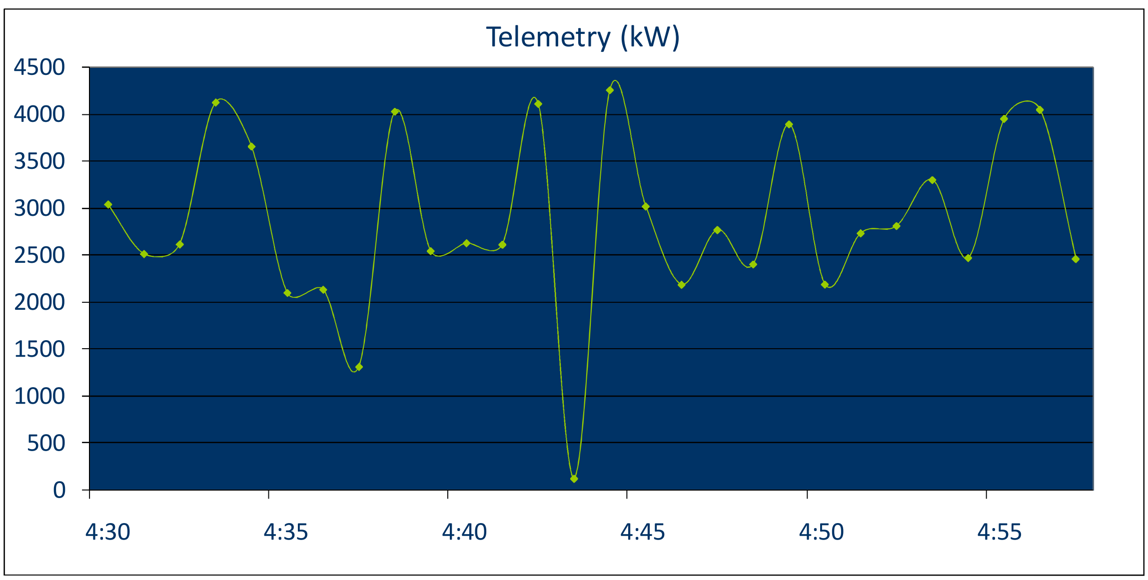
7.4 Telemetry

7.4.1 Highly Variable Loads Posed a Challenge

Demand response resources introduce unique operational challenges, distinct from generators. An issue the ISO encountered with the SDG&E PLP project was a small industrial load that was highly variable and whose demand was sizable relative to the rest of the aggregated loads in that PLP resource. For example, this particular load could cycle between approximately 200 kW to over 4,000 kW and then back to 200 kW in less than two minutes (see Figure 7 below for a graphical representation). The challenge with a highly variable load is what information should be conveyed to the ISO's energy management system about that load. In discussions with SDG&E and APX, the ISO considered solutions such as accepting an average load value over the 5-minute interval or calculating a median value for the load over a 1-minute moving window. Both of these solutions were dismissed as too complex to implement given the tight timeframe of the project, even though such concepts deserve further exploration. For the SDG&E PLP project, the ISO agreed to clip the load at a reasonable pre-determined value (1,400 kW) and send values less than or equal to that clipped MW amount to the ISO energy management system. The rationale for this approach was that when telemetry indicated at least 1,400 kW, then the plant was in operation and, as such, the corresponding capacity that was bid and awarded would be available for curtailment when dispatched by the ISO.

The ISO is contemplating the appropriateness of highly variable loads participating as a demand response resource in its markets. The ISO is concerned that, where a baseline methodology is employed, highly variable loads may not be appropriate since a baseline methodology would likely be unable to re-create an accurate load curve, but for demand response. However, such loads may be appropriate under the ISO's Participating Load model given the underlying load of a Participating Load resource is procured forward and then sold back, i.e. the baseline is effectively "procured." The shorthand term for this concept is called "buying your baseline."[35]

Figure 7- Highly Variable Load in the SDG&E PLP Resource[36]



[35] This concept of "buying your baseline" is more fully vetted in a paper issued by the Market Surveillance Committee of the California ISO titled *The California ISO's Proxy Demand Resource (PDR) Proposal* found at: http://www.caiso.com/239f/239fc54917610.pdf
[36] Graph copied from the *San Diego Gas & Electric Company Participating Load Pilot 2009 Evaluation*, at pg. 35

7.5 Metering

7.5.1 Allocating 15-Minute Interval Data into 5-minute Interval Data

In California, loads over 200 kW that are served by the IOUs record electrical energy consumption in 15-minute intervals. In some cases, as in the PG&E PLP project, certain customer revenue meters can be re-programmed to record in 5-minute intervals, matching the time interval for real-time dispatch in the ISO market. However, in many cases it may not be technically feasible or practical to re-program customer revenue meters that participate in a demand response resource in the ISO market. This was the case for customers participating in SDG&E's PLP project. The ISO allowed SDG&E to allocate the 15-minute interval meter data into 5-minute interval data for ISO settlement purposes, yet this posed a challenge. When allocating the 15-minute meter data into 5-minute data, should the 15-minute MWh data be parsed into 1) three equal 5-minute MWh portions or, 2) using real-time telemetry data that is available from that resource, shape how the MWhs are dispersed across the three 5-minute intervals.

Ultimately, how the 15-minute meter data is allocated across the 5-minute dispatch intervals impacts the settlement of the resource. Parsing the 15-minute interval data into three equal parts is simple and straightforward to implement; however, such an allocation can result in a less accurate settlement since it does not consider ramping the demand response resource in (or out) or the variability in load consumption across settlement intervals.

The ISO's preferred solution is to receive actual 5-minute interval meter data whenever possible. When not feasible, shaping the meter data is likely a more accurate solution, however, telemetry data may not be available in many cases to shape the meter data. Thus, further analysis is warranted to understand the trade-off between simplicity and accuracy and the range of error that can result in cases with and without shaping.

8 Conclusion

The ISO can confidently state that the PLP projects have demonstrated and affirmed that smaller demand response resources can successfully participate in and enhance ISO markets and reliably provide ancillary services, on a basis closely comparable to supply-side resources. The PLP projects enabled the ISO to learn important lessons, including the limits of ISO systems and operators to manage very small demand response resources, and areas, both operational and technical, which require additional study and/or refinement by the ISO to continue to lower barriers to demand response participation in ISO markets. And as important as the PLP projects were to the ISO, the PLP projects provided invaluable insights along the entire demand response supply chain, from the end-use customer and aggregators to the IOUs and the CPUC, about integrating retail demand response into wholesale markets.

Appendix I
Settlement of Participating Loads

Participating Load Settlement Description and Illustrative Examples

Below is a description, including illustrative examples that detail the financial settlement of Participating Loads under MRTU Release 1.

Settlement Example

The example in Figure 1 shows a customer with 20MW of load and an aggregated 10 MW of demand response capability. The aggregated load is located in a Custom Load Aggregation Point k (Custom LAP_k). The 20 MW of load is scheduled and settled at the Custom LAP level. For Release 1 of the MRTU, this customer can participate in the day-ahead energy, day-ahead non-spinning reserve ancillary service, and real-time imbalance energy markets (initially limited to real-time energy from awarded non-spinning reserve capacity).

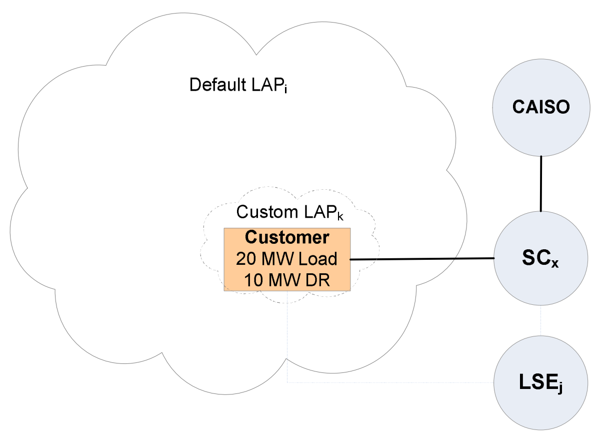


Figure 1 – Sample Scenario – 20MW PL in Custom LAP_k represented by SC_x

Example – Day-Ahead Energy

Assume a Load Serving Entity has registered a Participating Load (in a Custom LAP) of up to 20 MW, a portion of which, say up to 10 MW, is in fact curtailable and eligible to provide ancillary services (Non-spin). The pseudo-generator associated with the PL is thus registered with a of 10 MW.

The scheduling coordinator submits a Participating Load day-ahead energy bid for Hours Ending 12-22 as shown in Figure 2. According to this bid, the customer is willing to reduce its 20 MW load by 4 MWs if the price is at or above $50/MWh, and additional 2 MWhs at $60 and $80 MWh, each, and the remainder 2 MWs if the price is at or above $100/MWh. The remaining amount of the load is self scheduled as price taker and may vary during different hours of the day.

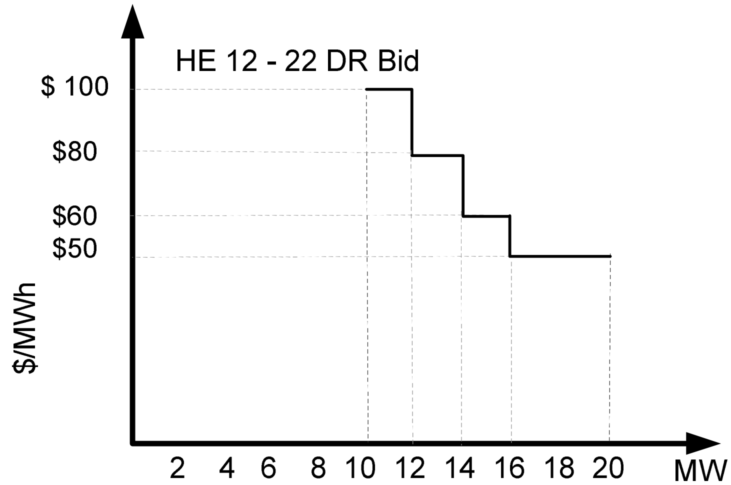


Figure 2 – PL Demand Bid Curve

The Scheduling Coordinator schedules its Day-Ahead load at the Custom LAP as shown in Figure 3. The Day-Ahead Energy for the Custom LAP clears at hourly prices shown in Figure 4 resulting in PL Demand Response awards as shown below.

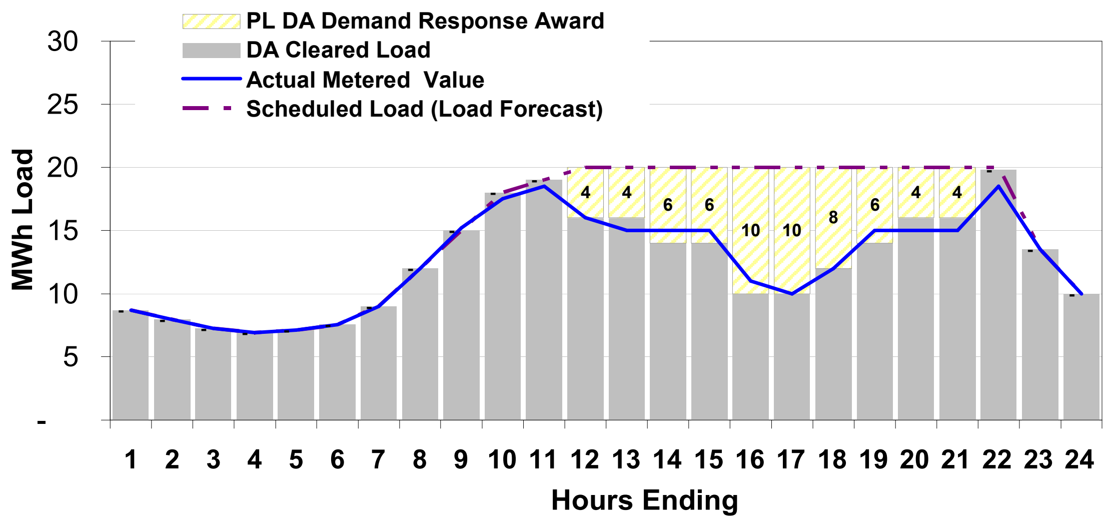


Figure 3 – Participating Load schedule at a Custom LAP

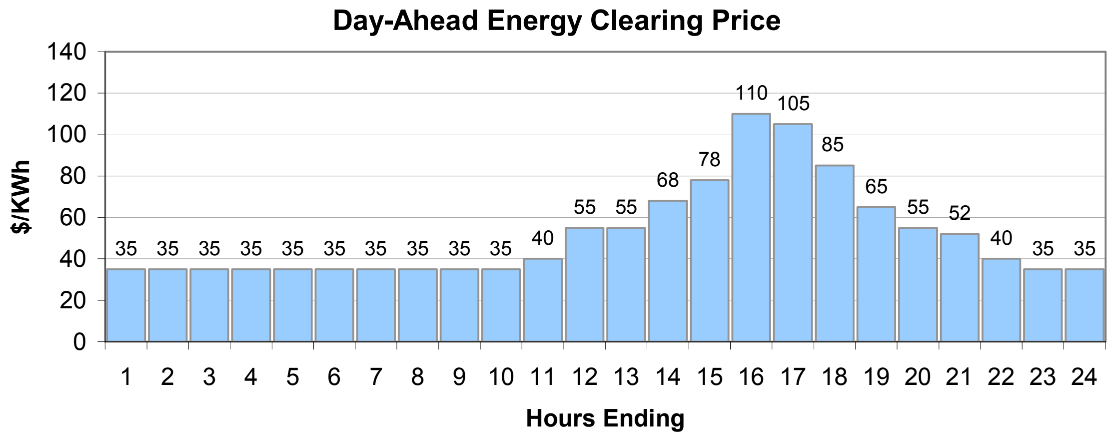


Figure 4 – Custom Lap Clearing Price for Energy

The scheduling coordinator is charged for the cleared day-ahead energy schedule based on the following formulation.

> PL day-ahead energy settlement day = ∑ T=1, 24 Custom LAP day-ahead energy clearing priceT * (baseline scheduleT – day-ahead demand response awardT). For example, for HE 19, the customer is charged $65*14 = $910.

In real time, the customer load deviates from the day-ahead schedule. The metering value reflecting its load following self curtailment is shown in Figure 3 above. Based on this metering value, the scheduling coordinator will receive a real-time energy settlement of:

> PL real-time energy settlement day = ∑ T=1,24 Custom LAP real-time energy clearing priceT * (metered valueT – day-ahead cleared scheduleT)

Example – Day-Ahead Ancillary Service

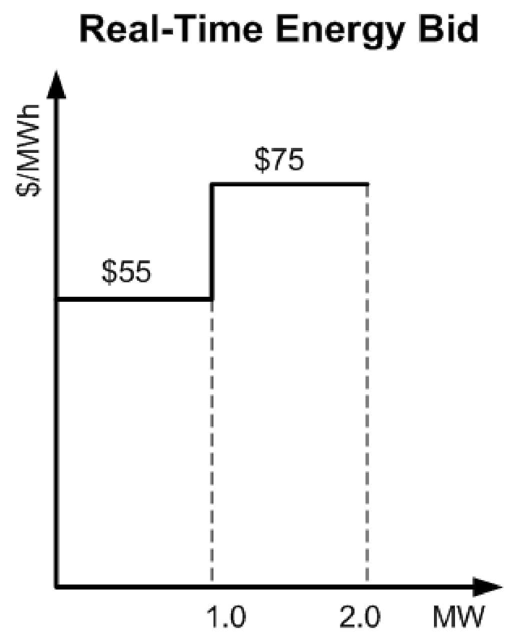
The scheduling coordinator also submits a non-spinning reserve bid of 2 MWs at $4/MW/h for Hours Ending 19-22[37]. The day-ahead non-spin clearing price at the PL location is $5/MW/h for hours 19-20 and $3/MW/h for hours 21-22; accordingly, the 2 MW non-spin bid clears for hours 19-20.

The Customer receives a settlement of:
5 ($/MW/h) * 2 (MW) * 2 (hrs) = $20 for Hour Ending 19-20 non-spinning reserve

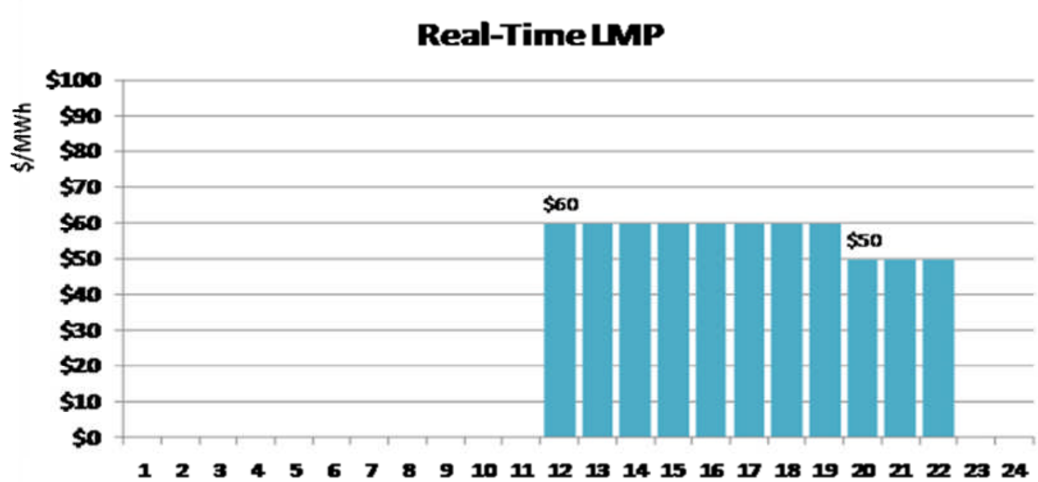
[37] Although the PL pseudo-generator is registered with a of 10 MW, only 2 MW of non-spin is bid during these hours. Since the pseudo-generator is not eligible to provide real-time imbalance energy above the ancillary services award, the pseudo-generator is effectively derated to 2 MW for these hours.

Example – Real-Time Imbalance Energy

Before the close of the real-time market, for hours ending 19-20, the scheduling coordinator submits a real-time energy bid for 2 MW of generation from the pseudo-generator associated with the PL to cover the awarded day-ahead non-spinning reserve. The pseudo-generator Energy bid is $55/MWh for the first MW and $75/MWh for the second MW as shown below.



Assume the real-time Custom LAP price is $60/MWh in hours ending 12-19 and $50/MWh in hours ending 20-22 as shown below.



Scenario 1: There is no contingency. Since the PL non-spin is contingency-only, even though during hour 19 the real-time price is above the first MW block of the pseudo generator energy bid of $55/MWh, this energy is not dispatched.

The real-time settlement is based on the deviation of the real-time meter from the day-ahead schedule. The settlement is simply (meter – day ahead schedule)*real-time price, which results in a charge to scheduling coordinator if positive (+) or a credit to scheduling coordinator if negative (-).

Consider three cases:

Case 1: meter > day-ahead schedule

For example assume for hour ending 19 the meter reads 15 MWh.
Then: real time settlement= (meter: 15 MWh – Schedule:14 MWh)*$60/MWh = +$60 (charge)

Case 2: meter = day-ahead schedule

For example for hour ending 19 the meter reads 14 MWh.
Then: real time settlement= (meter: 14 MWh – Schedule: 14 MWh)*$60/MWh = $0

Case 3: meter < day-ahead schedule

For example for hour ending 19 the meter reads 13 MWh.

Then: real-time settlement= (meter: 13 MWh – Schedule: 14 MWh)*$60/MWh = -$60 (credit)

Scenario 2: There is a contingency during hours 19-20 and the energy from non-spin is released into the real-time imbalance energy bid stack[38].

During the hours 19-20 the real-time price is above the first MW block of the pseudo generator energy bid of $55/MWh, and this energy is thus dispatched, i.e., the PL is instructed to curtail by 1 MW during the contingency.

Although telemetry is required for provision of ancillary services (non-spinning reserve for PL), and is used by ISO for reserve monitoring, the telemetered quantities are not considered for compliance monitoring or settlement purposes[39]. Only the revenue meter reads are used for the latter. Consider the following cases for hour 19, where the day-ahead schedule for the PL is 14 MW and the PL is instructed to deliver 1 MW of non-spinning energy during the hour:

[38] The assumption here is that there is a contingency without scarcity. Thus the non-spinning reserve energy bid prices are included in the real-time stack as bid rather than at the bid cap.
[39] This is one of the differences between ISO's treatment of demand response compared to some other ISOs. For example, Midwest ISO uses telemetry for compliance monitoring of Demand Response Resources (DRRs) and imposes penalties for non-performance based on both telemetry and after-the fact revenue meter reads.

Case 1: The PL resource was consuming 14 MW (at its day-ahead schedule) just before the contingency when it received the instruction to deliver 1 MW of non-spin energy. The actual PL meter read for hour ending 19 is 13 MWh. This indicates that the resource has reduced consumption by 1 MW as instructed for energy deployment from non-spin. The resource keeps its day-ahead non-spin payment and is paid for real-time energy based on the difference between actual meter (settlement meter) and day-ahead schedule, with no need to distinguish the deviation because of uninstructed over or under consumption or energy deployed from non-spin. In this case, since the locational marginal price is $60/MWh, the resource is paid $60 for real-time imbalance energy for the hour.

Note: The resource must deliver 90% of instructed non-spin energy in order to retain its non-spin capacity payment.

Case 2: The PL resource was consuming 15 MW (1 MW above its day-ahead schedule) just before the contingency when it received the instruction to deliver 1 MW of non-spin energy. The resource reduces consumption from 15 MW to 14 MW. The actual PL meter read for hour ending 19 is 14 MWh. Although the resource did reduce its consumption by 1 MW based on telemetry, it did not reduce it by 1 MW below its day-ahead schedule (the meter reads 14 MWh instead of 13 MWh). Since the resource was not operating 1 MW below its day-ahead schedule, it is subject to ancillary services no-pay, and loses the payment for 1 MW of non-spin capacity. The resource is paid or charged for real-time energy based on the difference between actual meter (settlement meter) and day-ahead schedule with no need to distinguish the deviation because of uninstructed over or under consumption or energy deployed from non-spin. For example, in this case since the meter reads a consumption of 14 MWh for hour ending 19, there is no charge or credit for real-time energy.

Case 3: PL resource was consuming 13 MW (1 MW below its day-ahead schedule) just before the contingency when it received the instruction to deliver 1 MW of non-spin energy. Since the resource is already consuming 1 MW below its day-ahead schedule, it does not reduce load any further, i.e., there is no change in its consumption before and after the contingency. The actual PL meter read for hour ending 19 is 13 MWh. Although telemetry indicates that the resource did not move in response to the instruction, since the meter reads 1 MWh below the day-ahead schedule, the resource is not subject to no-pay. The resource is paid for real-time Energy based on the difference between actual meter (settlement meter) and day-ahead schedule. For example, in this case, since the meter reads a consumption of 13 MWh and the locational marginal price is $60/MWh, the resource is paid $60 for real-time imbalance energy.

Case 4: The PL resource was consuming 11 MW (3 MW below its day-ahead schedule) just before the contingency when it received the instruction to deliver 1 MW of non-spin energy. Since the resource is already consuming more than 1 MW below its day-ahead schedule, it does not reduce load any further, i.e., there is no change in its consumption before and after the contingency. The actual PL meter read for hour ending 19 is 11 MWh. Accordingly, the resource is paid $180 for real-time imbalance energy and is not subject to ancillary services no-pay.

Note: In reality, the PL resource cannot curtail below 10 MW as stated in the example case description, under MRTU Release 1 there is no provision for non-zero minimum load for PL. Accordingly the PL is deemed to be able to reduce consumption by the amount it is consuming, which is far more than the 2 MW of ancillary services it had sold..

Case 5: The PL resource was consuming 1 MW below its day-ahead schedule just before the contingency when it received the instruction to deliver 1 MW of non-spin energy. Since the resource is already consuming far more than 1 MW below its day-ahead schedule (in fact it is consuming 13 MWh), it does not reduce load any further, i.e., there is no change in its consumption before and after the contingency. The PL meter read for hour ending 19 is 1 MWh. Since the resource is not consuming enough to accommodate the 2 MW of non-spin capacity, it is subject to no pay for the 1 MW that is not available due to the uninstructed deviation. It is paid for real-time energy based on the difference between actual meter (settlement meter) and day-ahead schedule, i.e., $60*13 = $780.

Case 6: The resource's meter read is 14 MW and no non-spin energy is dispatched. The pseudo generator submitted an Energy bid with a ramp rate of 0.15 MW/min. The Real-Time Market system (RTM) calculates that the resource can only deliver 1.5 MW in the next 10 minutes (available operating reserve calculation). Since the resource is scheduled for 2 MW of non-spin capacity, 0.5 MW is undispatchable due to the ramp rate limitation in the energy bid and will be subject to no pay.

Appendix II
PLP Project Dispatch Test Schedule

Test Dispatch of Participating Load Pilots

When testing dispatch Non-Spin of Participating Load Pilots, take the following steps:

Step	Operator's Actions
1	Operator's Sets the ED instructions using **constraint type: minimum, Instruction Type: Pretest** as: **August 6, 2009** <table><tr><td>Unit</td><td>SCID</td><td>MW</td><td>Start Time</td><td>End Time</td></tr><tr><td>CWATER_1_DRGEN</td><td>SCE1</td><td>5.00</td><td>20090806 14:00:00</td><td>20090806 14:10:00</td></tr><tr><td>IKEA_1_DRGEN</td><td>PCG2</td><td>0.04</td><td>20090806 12:00:00</td><td>20090806 13:00:00</td></tr><tr><td>OAKC_7_DRGEN</td><td>PCG2</td><td>0.12</td><td>20090806 15:00:00</td><td>20090806 16:00:00</td></tr><tr><td>MARTNZ_1_DRGEN</td><td>PCG2</td><td>0.01</td><td>20090806 17:00:00</td><td>20090806 18:00:00</td></tr></table>
2	June Xie/Bassem Moukaddem/Robert Fisher **Notify** Shift Supervisor every Test Day Morning concerning units being tested.

1 Participating Load Pilot Project Test Schedule

Participating load Pilot dispatch Test Schedule

August 6, 2009

Unit	SCID	MW	Start Time	End Time
CWATER_1_DRGEN	SCE1	5.00	20090806 14:00:00	20090806 14:10:00
IKEA_1_DRGEN	PCG2	0.04	20090806 12:00:00	20090806 13:00:00
OAKC_7_DRGEN	PCG2	0.12	20090806 15:00:00	20090806 16:00:00
MARTNZ_1_DRGEN	PCG2	0.01	20090806 17:00:00	20090806 18:00:00

August 13, 2009

Unit	SCID	MW	Start Time	End Time
CWATER_1_DRGEN	SCE1	5.00	20090813 13:00:00	20090813 13:10:00
ELCAJN_6_DRGEN1	SDG3	0.3	20090813 14:00:00	20090813 14:10:00

August 20, 2009

Unit	SCID	MW	Start Time	End Time
CWATER_1_DRGEN	SCE1	5.00	20090820 12:00:00	20090820 12:10:00
ELCAJN_6_DRGEN1	SDG3	0.3	20090820 14:00:00	20090820 14:10:00

August 27, 2009

Unit	SCID	MW	Start Time	End Time
CWATER_1_DRGEN	SCE1	5.00	20090827 11:00:00	20090827 11:10:00
ELCAJN_6_DRGEN1	SDG3	0.3	20090827 14:00:00	20090827 14:10:00

1 Participating Load Pilot Project Test Schedule

September 3, 2009

Unit	SCID	MW	Start Time	End Time
CWATER_1_DRGEN	SCE1	5.00	20090903 16:30:00	20090903 16:40:00

September 10, 2009

Unit	SCID	MW	Start Time	End Time
CWATER_1_DRGEN	SCE1	5.00	20090910 16:00:00	20090910 16:10:00
ELCAJN_6_DRGEN1	SDG3	0.6	20090910 14:00:00	20090910 14:10:00

September 17, 2009

Unit	SCID	MW	Start Time	End Time
CWATER_1_DRGEN	SCE1	5.00	20090917 15:00:00	20090917 15:10:00
ELCAJN_6_DRGEN1	SDG3	0.6	20090917 14:00:00	20090917 14:10:00

September 24, 2009

Unit	SCID	MW	Start Time	End Time
CWATER_1_DRGEN	SCE1	5.00	20090924 14:00:00	20090924 14:10:00
ELCAJN_6_DRGEN1	SDG3	1.8	20090924 14:00:00	20090924 14:10:00

September 30, 2009

Unit	SCID	MW	Start Time	End Time
ELCAJN_6_DRGEN1	SDG3	1.2	20090930 05:00:00	20090930 05:10:00

1 Participating Load Pilot Project Test Schedule

October 1, 2009

Unit	SCID	MW	Start Time	End Time
CWATER_1_DRGEN	SCE1	2.15	20091001 13:00:00	20091001 13:10:00
ELCAJN_6_DRGEN1	SDG3	0.8	20091001 14:00:00	20091001 14:10:00

October 9, 2009

Unit	SCID	MW	Start Time	End Time
ELCAJN_6_DRGEN1	SDG3	0.8	20091009 11:30:00	20091009 11:40:00

October 14, 2009

Unit	SCID	MW	Start Time	End Time
ELCAJN_6_DRGEN1	SDG3	0.8	20091014 15:00:00	20091014 15:10:00

October 15, 2009

Unit	SCID	MW	Start Time	End Time
CWATER_1_DRGEN	SCE1	2.3	20091015 11:00:00	20091015 11:10:00
ELCAJN_6_DRGEN1	SDG3	1.2	20091015 05:00:00	20091015 05:10:00

October 22, 2009

Unit	SCID	MW	Start Time	End Time
CWATER_1_DRGEN	SCE1	3.9	20091022 16:00:00	20091022 16:10:00

October 23, 2009

Unit	SCID	MW	Start Time	End Time
IKEA_1_DRGEN	PCG2	0.02	20091023 14:00:00	20091023 14:20:00

October 29, 2009

Unit	SCID	MW	Start Time	End Time
CWATER_1_DRGEN	SCE1	0.25	20091029 15:00:00	20091029 15:10:00

December 3, 2009

Unit	SCID	MW	Start Time	End Time
ELCAJN_6_DRGEN1	SDG3	0.5	20091203 14:40:00	20091203 14:50:00

Appendix III
Ancillary Service Test Results Forms

California ISO
Your Link to Power

Ancillary Services Test Results Form

As detailed in ISO Procedure G-213, the Scheduling Coordinator should respond to notification of these test results within two business days.

Unless the Scheduling Coordinator and the ISO otherwise agree, within three business days from transmittal of this form, the ISO will revise the Master File to reflect the Test Results listed under "Certified Information."

PLP Resource:	**SCE A/C Cycling**
Date Tested:	**7/27/09**
Test Administrator:	Angelica Cardozo

Notes:
Certifying values for the Demand Response Pilot ONLY.

Certified Information

Service	Certified MW	Certified Range	Certified Ramp Rate*
Non-Spinning Reserve		**0 - 5**	**5.00**
PMax	**5.00**		

* Because the Master File only accommodates one ramp rate, only the highest certified ramp rate for all services certified that the ISO has on record will be posted to the Master File.
** For Regulation: Symmetrical Reg Up and Reg Down values are necessary for proper operation of the AGC system, therefore, the single "Certified Value" for Regulation will be the lesser of Reg Up and Reg Down.

Test Details

Service	Test Start	Test Start MW	Ramp Start	Ramp Start MW	Ramp End	Ramp End MW	Test End	Test End MW	Tested Value / Ramp Rate
Non-Spinning Reserve	14:13:04	8.08	14:14:04	8.04	14:23:04	1.46	14:23:04	1.46	0.80
PMax	13:46:00	6.44					14:01:00	7.71	

California ISO
Your Link to Power

Ancillary Services Test Results Form

As detailed in ISO Procedure G-213, the Scheduling Coordinator should respond to notification of these test results within two business days.

Unless the Scheduling Coordinator and the ISO otherwise agree, within three business days from transmittal of this form, the ISO will revise the Master File to reflect the Test Results listed under "Certified Information."

PLP Resource:	**PG&E- Local Gov't Bldg**
Date Tested:	**7/22/09**
Test Administrator:	Angelica Cardozo

Notes:
Certifying values for the Demand Response Pilot ONLY.

Certified Information

Service	Certified MW	Certified Range	Certified Ramp Rate*
Non-Spinning Reserve		**.02 - .1**	**0.10**
PMax	**0.40**		

* Because the Master File only accommodates one ramp rate, only the highest certified ramp rate for all services certified that the ISO has on record will be posted to the Master File.
** For Regulation: Symmetrical Reg Up and Reg Down values are necessary for proper operation of the AGC system, therefore, the single "Certified Value" for Regulation will be the lesser of Reg Up and Reg Down.

Test Details

Service	Test Start	Test Start MW	Ramp Start	Ramp Start MW	Ramp End	Ramp End MW	Test End	Test End MW	Tested Value / Ramp Rate
Non-Spinning Reserve	15:14:23	0.40	15:15:07	0.43	15:24:23	0.33	15:24:23	0.33	0.01
PMax	14:45:00	0.39					15:00:00	0.38	0.04

California ISO
Your Link to Power

Ancillary Services Test Results Form

As detailed in ISO Procedure G-213, the Scheduling Coordinator should respond to notification of these test results within two business days.

Unless the Scheduling Coordinator and the ISO otherwise agree, within three business days from transmittal of this form, the ISO will revise the Master File to reflect the Test Results listed under "Certified Information."

PLP Resource:	**PG&E- Large Retail Store**
Date Tested:	**7/22/09**
Test Administrator:	Angelica Cardozo

Notes:
Certifying values for the Demand Response Pilot ONLY.

Certified Information

Service	Certified MW	Certified Range	Certified Ramp Rate*
Non-Spinning Reserve		**.02 - .2**	**0.10**
PMax	**0.20**		

* Because the Master File only accommodates one ramp rate, only the highest certified ramp rate for all services certified that the ISO has on record will be posted to the Master File.
** For Regulation: Symmetrical Reg Up and Reg Down values are necessary for proper operation of the AGC system, therefore, the single "Certified Value" for Regulation will be the lesser of Reg Up and Reg Down.

Test Details

Service	Test Start	Test Start MW	Ramp Start	Ramp Start MW	Ramp End	Ramp End MW	Test End	Test End MW	Tested Value / Ramp Rate
Non-Spinning Reserve	15:02:38	0.91	15:03:02	0.99	15:12:38	0.83	15:12:38	0.83	0.01
PMax	14:45:00	0.98					15:00:00	0.93	

Ancillary Services Test Results Form

As detailed in ISO Procedure G-213, the Scheduling Coordinator should respond to notification of these test results within two business days.

Unless the Scheduling Coordinator and the ISO otherwise agree, within three business days from transmittal of this form, the ISO will revise the Master File to reflect the Test Results listed under "Certified Information."

PLP Resource:	**PG&E- Industrial Bakery**
Date Tested:	**7/22/09**
Test Administrator:	Angelica Cardozo

Notes:
Certifying values for the Demand Response Pilot ONLY.

Certified Information

Service	Certified MW	Certified Range	Certified Ramp Rate*
Non-Spinning Reserve		**.02 - .2**	**0.10**
PMax	**0.58**		

* Because the Master File only accommodates one ramp rate, only the highest certified ramp rate for all services certified that the ISO has on record will be posted to the Master File.
** For Regulation: Symmetrical Reg Up and Reg Down values are necessary for proper operation of the AGC system, therefore, the single "Certified Value" for Regulation will be the lesser of Reg Up and Reg Down.

Test Details

Service	Test Start	Test Start MW	Ramp Start	Ramp Start MW	Ramp End	Ramp End MW	Test End	Test End MW	Tested Value / Ramp Rate
Non-Spinning Reserve	15:36:13	0.56	15:36:34	0.43	15:46:13	0.43	15:46:13	0.43	0.01
PMax	14:45:00	0.61					15:00:00	0.61	

California ISO
Your Link to Power

Ancillary Services Test Results Form

As detailed in ISO Procedure G-213, the Scheduling Coordinator should respond to notification of these test results within two business days.

Unless the Scheduling Coordinator and the ISO otherwise agree, within three business days from transmittal of this form, the ISO will revise the Master File to reflect the Test Results listed under "Certified Information."

PLP Resource:	**SDG&E Aggregation**
Date Tested:	**7/23/09**
Test Administrator:	Angelica Cardozo

Notes:
Certifying values for the Demand Response Pilot ONLY.

Certified Information

Service	Certified MW	Certified Range	Certified Ramp Rate*
Non-Spinning Reserve		**0 - 3**	**0.60**
PMax	**3.00**		

* Because the Master File only accommodates one ramp rate, only the highest certified ramp rate for all services certified that the ISO has on record will be posted to the Master File.
** For Regulation: Symmetrical Reg Up and Reg Down values are necessary for proper operation of the AGC system, therefore, the single "Certified Value" for Regulation will be the lesser of Reg Up and Reg Down.

Test Details

Service	Test Start	Test Start MW	Ramp Start	Ramp Start MW	Ramp End	Ramp End MW	Test End	Test End MW	Tested Value / Ramp Rate
Non-Spinning Reserve	16:04:47	3.49	16:04:48	3.48	16:47:47	3.39	16:47:47	3.39	0.01
PMax	15:45:00	3.48					16:00:00	3.54	

Attachments A
PG&E PLP Project Report

2009 Pacific Gas and Electric Company Participating Load Pilot Evaluation

December 31, 2009

Table of Contents

1. EXECUTIVE SUMMARY

The California Public Utilities Commission (Commission) provided guidance to the three (3) investor-owned utilities (IOUs) to develop Demand Response (DR) programs that would integrate with the California Independent System Operator's (CAISO) Market Redesign and Technology Upgrade (MRTU).[1] The Commission expressed strong interest in developing new or modifying existing DR products to enable them to operate as Participating Load (PL) under MRTU Release 1 and possibly under the pending Proxy Demand Resource (PDR) under Market and Performance (MAP). Such products would allow DR to be bid in and compete with other supply side resources in Ancillary Services (AS) non – spinning reserves and energy markets.

In response to the Commission's directive, Pacific Gas and Electric Company (PG&E) proposed a Participating Load (PL) pilot for summer 2009 deployment tailored for over 200 kW Commercial and Industrial (C&I) sectors utilizing the existing Auto-Demand Response (Auto-DR) infrastructure in order to acquire additional information to integrate DR with the wholesale market.

PG&E recruited up to four (4) large C&I Auto-DR customers to participate in this demonstration and install the necessary communications equipment in order to meet CAISO requirements for participation in the AS market. With the support from the Commission, CAISO and numerous outside parties, PG&E assembled and implemented a pilot that demonstrated how to integrate retail DR into the wholesale products as AS non – spinning reserves.

[1] D.09-12-039, p. 19.

2. OBJECTIVE

The Participating Load Pilot's (PLP) main objective is identify and develop processes, communication and technology needed for the integration of DR load in the MRTU market as either PL or PDR. PG&E recognized that integration (manually or automated) must happen both internally and externally during the PLP demonstration in order to participate in the CAISO market. The PLP's conclusions will inform future program and product design that will enable DR to participate in the MRTU market. The success criterion for the PLP does not only include the ability to demonstrate technology of real time communication for dispatch and schedule-bid DR resources into CAISO's MRTU market, but also to identify short and long term business requirements and customer premise requirements needed to allow such interaction.

PG&E's PLP tested the following areas:

- The technical feasibility of DR resources in large Commercial & Industrial (C&I) facilities providing energy and/or AS as PL.
- Development of specifications for internal and external process development for the utility for providing energy and AS as PL.
- The ability of retail DR resources to meet CAISO requirements.
- Barriers to the integration of DR in MRTU identified in PG&E's testimony in A.08-06-003 (Chapter 3 Section F), including:
    - Forecasting of load: The accuracy of the forecasts of the magnitude of participant load available to provide AS and energy to CAISO.
    - Bidding of DR: Methods for nominating load in CAISO's day ahead AS non – spin capacity reserve market and energy bid curve, if awarded AS non – spin.
    - Forecasting load reduction: The accuracy of forecasting the load reduction.
    - Settlement with CAISO: Methods for settling with the CAISO (including determining the amount of load dropped in response to and non - spinning reserve request).
    - Locational calling of DR: Building DR AS resources in local areas.
    - Telemetry for AS: Testing of technology for telemetry.
    - Ability to provide relevant performance results in a timely manner to Front Office personnel.

3. PARTICIPANTS

3.1 Enrollment

Enrollment and marketing to the appropriate customer base were a critical area of the PLP. One of the biggest barriers during this stage was the lack of prior history and education of bidding DR load as AS (or as described to participants “Fast DR”). The limitation of information available to potential candidates left uncertainties and unanswered questions. Providing quick and responsive load reductions within 10 minutes of an event is a new paradigm, since the majority of current retail DR participants in PG&E’s service area participate in programs that provide day-ahead notification that allows sufficient time to adjust operations to accommodate the pending curtailment.

PG&E approached customers that are already familiar with DR. With the help of Lawrence Berkeley National Lab (LBNL), PG&E targeted those customers who had participated in PG&E’s AutoDR programs (Critical Peak Pricing and Demand Bidding Programs) in previous years in order to evaluate how:

1. To meet necessary dispatch orders from the CAISO with a load shed strategy that best suits current CAISO requirements. For example reduction in Heating Ventilation Air Conditioning (HVAC) use was identified as a means to meet the necessary 10-minute response time and two-hour duration requirements for wholesale ancillary services;
2. Open ADR specification can be used to communicate wholesale DR events in an open and interoperable way; and
3. Internet can be used for fast DR to dispatch non-spinning ancillary services and still meet the 10-minute load response time.

A set of site selection criteria was developed and three to four sites were targeted [Appendix A]. Sites that had participated in PG&E’s AutoDR programs in previous years were targeted for this pilot due their familiarity with DR automation. Selection criteria included:

- Low load variability – enhances load forecasting accuracy;
- Ability to deliver resource in 10 minutes – preferably a site with both fast (lighting) and slow HVAC response;
- Low shed variability – enhances shed forecasting accuracy; and
- Minimum of 10 kW of load shed.

3.2 Analysis

Given the low number of customers targeted for the PLP, PG&E did not believe a marketing campaign to attract customers was warranted. PG&E had LBNL develop an analytical prospective participant list of customers who meet the necessary requirements and have an adequate historical participation in AutoDR. LBNL analyzed all AutoDR historical electrical 15-minute interval meter data that was available. Due to the low resolution of the meter data, it was difficult to determine the response time of the sites. However, LBNL grouped the sites that yielded the initial shed within the first 15 minutes and those that yielded additional shed within the second 15 minute period. If a site continued to shed after the first 15 minutes, it was considered that these sites as having "slower" response.

All sites targeted for the PLP met the minimum retail demand shed requirement of 10 kW. Only three of the sites using Auto-DR consistently shed lighting loads. PG&E had an additional, minor objective to demonstrate various possible load shed strategies and possibly try wireless lighting control. However, these sites with experience shedding lighting loads were recently equipped with solar panels and therefore their load shape and load variability prohibited their participation. For the remaining sites, load statistical summaries (LSS) [2]and load variability (VAR)[3] calculations[4] were completed [Appendix A].

Such analysis was very useful for the screening process but may not be scalable due to the possible lack of DR history and granular meter data each customer may currently have. Moving forward, additional analysis must be done prior to any enrollment to a program that offers AS. PG&E will strive to come up with a suitable screening structure to mitigate potential enrollment of unqualified customers in future programs.

3.3 Recruitment

The PLP target recruitment goal was identified as three to five sites. And after the LBNL analysis was completed, initial contacts with the first four sites were achieved in March 2009. Additionally, word spread that PG&E was conducting a pilot to demonstrate integration with the CAISO market. Some industrial customers who were considering enrolling in Auto-DR showed interest in participating in the PLP. However, these sites were in early stages of discussions and PG&E decided that they may not be enabled in time for the PLP go live date.

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[2] LSS shows the average, minimum, maximum and standard error of 15-min demand across each day in the period of interest.

[3] VAR is a measure of coefficient of variance; it is the ratio of standard deviation to average demand, for each hour during the time period of interest.

PG&E completed its customer presentation on March 20, 2009, and each site was visited at the end of March 2009 [Appendix B]. The customer participation agreement was finalized on April 13, 2009 [Appendix C]. Direct marketing to the customer was performed in person and PG&E presented the PLP goals, expectations and incentives to each customer. While very effective, this type of a direct marketing approach is not scalable and a better marketing approach should be developed.

One of the four sites approached decided not to participate, because its board of directors was concerned that coordination would take some of the facility engineer's time away from his duties. Three facilities, a retail store, a local government office building and an industrial bakery were successfully recruited into the PLP. Execution of the Customer Participation Agreement (CPA) was accomplished in May 2009. Of these three sites, only retail store and local government office building met the initial requirements of load and shed variability which were crucial for accurate load forecasts for these facilities. Industrial bakery highly variable load and made forecasting very difficult. Thus, this site was considered poorly suited for this pilot. However it was considered as a potential learning experience on how this particular industrial segment can be integrated with this particular product type.

3.4 Program Strategies

Table below shows the predetermined DR strategies and duration employed by each facility:

Site	DR Strategy	DR Period
Retail Store	Turning off 11 RTUs out of 43 and raising zone setpoints to 76 DegF	Noon to 6 pm
Local Govt Office	4 DegF Global Temperature Adjustment with 1 DegF increments	2 pm to 6 pm
Industrial Bakerv	Turn off Pan Washer	3 pm to 5 pm

Initially, the PLP was designed to be a Monday to Friday DR pilot. While PG&E gave the customer the option to participate in all other hours and weekends, the customers chose to keep a Monday to Friday schedule.

[4] LSS and VAR both reflect DR potential as they indicate when and where peak loads occur, or the extent to which loads vary or can be reliably predicted. The bigger the load variability, the more difficult it is to accurately forecast load.

In the future design of AS products, PG&E would encourage 24 by 7 product type if the customer can demonstrate load curtailment on hours outside the traditional retail DR window. This is quite critical to address integration of intermittent renewable resources and future CAISO ramping needs.

3.5 Program Incentives

Due to the nature of uncertainty of this pilot demonstration, PG&E made a conscious decision to not penalize participants who were unable fully to comply with a DR event dispatched by the CAISO. So the PLP, PG&E developed a simple structure for incentives.

The incentives were broken down into three different categories:

- Program Switch Incentive – this incentive was a one-time payment to the participants. Each participant's incentive varied based on its past performance under CPP. PG&E took the highest credit between the 2007 and 2008 as their base incentive. The one-time incentive is similar to a capacity payment. The one-time payment guaranteed that participants would recovery their highest potential incentive under CPP.
- Participation Incentive – For every month the participants are enrolled, PG&E provided an additional $1,000 for operation inconvenience. Part of the PLP was to make sure the underlying load is accurate for Front Office to schedule and such activity would need inputs from the site energy managers of their daily operation on an hour by hour basis. Site energy managers were asked to give PG&E information if and when unusual occurrence in their energy consumption occurred so such activity could properly be considered by the Front Office.
- Performance Incentive – For any dispatch made by the CAISO, PG&E would pay the participants an additional $0.15 per kWh for reduced energy usage.

Incentive structure created for the PLP will not take any precedence on future designs. Creation of the proper structure of penalties will be reevaluated when a new pilot or program is created to offer non-spinning or any AS product to the CAISO. PG&E envisions that capacity and energy incentives will be created with strict step performance penalties.

At the end of the PLP, retail settlements with these participants were executed without too much hardship since there were only three participants. No formal software application was used to derive final settlement numbers. PG&E did not use any current tariff or contract baseline methodology to calculate the performance incentive. It did, however, use the time regression load schedule (provided by Itron, Inc.) which was also used by PG&E to schedule the load reduction with the CAISO. PG&E pulled out from Automated Dispatch System (ADS) [define] all events dispatched by the CAISO for these resources. PG&E then used Itron's 5-minute kW regression load data and then PG&E pulled 5-minute kW revenue meter data and calculated the load drop. It was a simple subtraction of 5-minute kW regression minus 5-minute kW revenue meter data for all dispatched events. The results from that computation was then translated to kWh and multiplied by $0.15.

The summary of total incentive payments are highlighted down in section 6.5 – Program Incentives

3.6 Program Performance

With the exception of the test event that took place on July 17th, all the events were actual CAISO dispatches; exceptional, contingency or non-contingency bid price. The dispatches that are in bold lasted longer than ten minutes and are presented in detail in Appendix D. Those that are ten minutes or less in duration are not studied in detail as 10 minute ramp time requirement does not apply to these sites. [For all DR dispatched and load impacts, please refer to Appendix E]

The results from the highlighted events are summarized below:

Date/Site	Retail Store	Local Govt Office	Industrial Bakery
July 17, 2009	15:00 - 17:00	15:00 - 17:00	15:00 - 17:00
August 6, 2009		**17:00 - 18:00**	**15:00 - 16:00**
August 27, 2009			15:25 - 15:30
August 31, 2009		**14:00 - 15:00**	
September 11, 2009	14:40 - 14:43	14:40 - 14:43	
September 18, 2009	**16:00 - 16:25, 16:35 - 16:50**	**16:00 - 16:25, 16:35 - 16:51**	**16:00 - 16:25, 16:35 - 16:52**
September 21, 2009		**14:00 - 16:30, 16:40 - 17:55**	16:30 - 16:40
September 22, 2009			16:55 - 17:00
October 19, 2009	**14:00- 15:00, 17:00 - 18:00**		
October 23, 2009	**14:00 - 14:20**		

Site	Date	Ramp Rate (MW/min) (Measured/Forecasted)	Average Load Reduction (kW) (Measured/Forecasted)			
			HE 15:00	HE 16:00	HE 17:00	HE 18:00
Industrial Bakery	6-Aug	0.005/0.015	-	125/30	-	-
Local Govt Office	6-Aug	0.004/0.001	-	-	-	116/10
Local Govt Office	31-Aug	0.012/0.002	86/10	-	-	-
Retail Store	18-Sep	0.01/0.001	-	-	50/20	-
Industrial Bakery	18-Sep	0.012/0.012	-	-	143/120	-
Local Govt Office	18-Sep	0.014/0.009	-	-	76/20	-
Local Govt Office	21-Sep	0.006/0.002	72/20	86/80	51/40	49/30
Retail Store	19-Oct	0.041/0.003 0.021/0.003	124/10	-	123/10	-
Retail Store	23-Oct	0.010/0.004	87/20	-	-	-

Since the PLP only involved three sites, the total aggregate coincident resource size was estimated at 0.25 MW. On September 18, all three resources were dispatched at the same time and the resulting one hour aggregate average resource delivery was 0.269 MW. The current CAISO tariff requires PL to be above 1 MW. However for the PLP demonstration, PG&E requested a waiver to allow a lower threshold of capacity for bidding. This was achieved by having the Participating Load Agreement (PLA) submitted to the CAISO for FERC filing. The load reduction was sufficient to meet the initial goals of the pilot, including ten-minute ramp period and being available for two hours. From the four second telemetry data, we observed that usually it took less than two minutes for the load to drop down by the bid amount. In two instances, the pan washer at the bakery was turned off when a DR event was dispatched because the workers were taking a break. In order to test the communication, the pan washer was turned on immediately.

3.7 Performance Issues

While all three customers' communication infrastructure and technologies worked well, the participant (Industrial Bakery's) with varying operations and electric loads had problems making the resource available when dispatched. Increased hourly load variability reduces forecasting accuracy and therefore results in poor performance. We suggest screening for hourly load variability and excluding these types of customers from the program or possibly use an aggregation model to address this variability. The participation of this inconsistently performing customer can be improved only if it resolves hourly load variability issues. If a customer has monthly and seasonal variability issues, this should also be considered and the master file must be updated periodically to reflect these issues. In addition, the other two sites (local government office and retail store) usually over- performed. Forecasting accuracy improvements can also increase the accuracy of the load and pseudo generation schedules.

There were only two exceptional dispatch event requests made by PG&E. And the primary focus for the exceptional dispatch was used to resolve interoperability issues between ADS & DRAS (August 6th) and a recording demonstration to provide visual documentation of a typical dispatched event to any interested parties (October 23rd). Overall, the sites usually over performed during the dispatch period. This is partly due to the accuracy of the forecasts and partly due to the general fluctuation of the sheds. However, no recovery rebound was observed at any site after the dispatch period.

One of the more interesting technologies placed in Local Government Office was the feedback loop. The feedback loop – tested on September 21, 2009 – was intended to maintain shed levels at CAISO dispatched levels. This was the only day this resource was called for four hours, long enough to test the feedback. The feedback worked as expected. However the first hour the load delivered more than expected shed. This is due to the fact that the forecasted pseudo generation schedule for the first hour in general is much lower than the resource delivers. This is due to the load drop characteristics of HVAC systems. With global temperature adjustment strategy, there is an immediate and usually large load drop due to the immediate savings from fans and chillers that unload, followed by a steady state period where the savings are lower. Feedback loop technology works best to sustain the steady state period at levels that are predetermined.

In the future, combining AutoDR with a feedback loop should be the best avenue to offer AS to the CAISO. The ability to have feedback with AutoDR mimics a power producer's Automated Generation Control (AGC) and mitigates the DR load possible over/under performance.

3.8 Participants' Comments

After the PLP period ended, each site was interviewed and asked:

1. If the customer was satisfied with the project?
2. How could PG&E improve customer satisfaction?

The responses are summarized below:

Retail Store

Customer found the constant e-mails about the communication device status confusing, especially the several times that the communication problem was resolved without an intervention by the customer. The customer suggested that it would be better to notify a customer of the communication issues if the system persists in malfunctioning and there is definite need for the customer to intervene. Another feedback from this customer related to the communication of the event *start* time but not the event *end* time. The customer thought that was confusing because no matter what time the event started, it seemed to end at midnight. Over the course of the PLP tests, this was an issue that was debated by the project team and was resolved in October, 2009.

Overall, the customer did not see any adverse effects of participation and plans to participate next year.

Local Government Office

The only concern for this customer was the communication of dispatches. The customer found them to be too cryptic and suggested better language to communicate these dispatch signals to the customer. Over all, they were pleased and intend to participate if the pilot or program is offered again.

Industrial Bakery

This customer said its sole reason to participate in the PLP was the incentives. Throughout the PLP, the customer had two main concerns: No prior notifications and communication problems. The customer believed there was a 10-minute notification time before the DR event. When no prior notifications were received and last minute requests came by phone, the customer was confused. (In two cases, the DR event was dispatched when the pan washer was just turned off because the workers were going on a break). Customer also said that while initially no notifications were received, towards the end, he received double notices, while another colleague did not receive any. The notices themselves were not useful because it showed a start time but no end time. Communication problems and notices with the CLIR box was also a major concern. The customer was overwhelmed by the frequency of the e-mails.

4. TECHNOLOGY AND COMMUNICATIONS

The technology and communication infrastructure used for the Participating Load Pilot (PLP) is a functional system architecture that extends from previous research on Open Automated Demand Response Communication (OpenADR or Open Auto-DR) specifications[5]. The facilities were already participating in PG&E's 2007-2009 commercial Auto-DR programs.6 The standardized communication platform and data models helped the facilities switch to PLP with same equipment to receive DR signals and respond with pre-existing strategies. For the PLP, new real-time telemetry equipment was installed to measure energy usage and forecast shed. The equipment was used by PG&E to submit bids for the Day-Ahead (DA) market, and followed by shed measurement and validation during and after the event. The description below is streamlined for better understanding of the enabling technology and communication infrastructure for "pre-PLP event" (all-time) vs. "during- and post-PLP event."

Pre-PLP event process: As shown in figure 1, the following process explains the system, communication exchanges, and the entities and their roles to facilitate the automation during pre-PLP event. This process by the technology and communication providers is intended primarily to link the retail resources (consumers) to the wholesale DR service providers and provides energy use measurements and shed forecasting.

a. Two-way Code Division Multiple Access (CDMA) wireless radio communication network between Metrum and participating facilities. Dual meter sockets helped the facilities to retain a PG&E revenue meter (RM) and install a new telemetry (T) meter (which measures four-second instantaneous demand and energy use in real-time).
b. The two-way Internet between Metrum Operation (Op) Center and Bow Networks (Store instantaneous demand and energy use real-time data).
c. Two-way Internet between Bow Networks (via Metrum Op. Center) and Energy Management Systems (EMS) by CAISO (Meter data for resource availability).
d. Two-way Internet between Bow Networks (via Metrum Op. Center) and PG&E procurement (secure storage of meter data and resource availability).

[5] Piette, Mary Ann, Girish Ghatikar, Sila Kiliccote, Ed Koch, Dan Hennage, Peter Palensky, and Charles McParland. 2009. Open Automated Demand Response Communications Specification (Version 1.0). California Energy Commission, PIER Program. CEC□500□2009□063.

[6] Greg Wikler, I. Bran, J. Prijyandonda, S. Yoshida, K. Smith (Global Energy Partners, LLC), M.A. Piette, S. Kiliccote, G. Ghatikar (Lawrence Berkeley National Laboratory), D. Hennage (Akuacom, Inc.) and C. Thomas (Electric Power Research Institute). 2008. Pacific Gas & Electric Company 2007 Auto-DR Program: Task 13 Deliverable: Auto-DR Assessment Study, Report to PG&E.

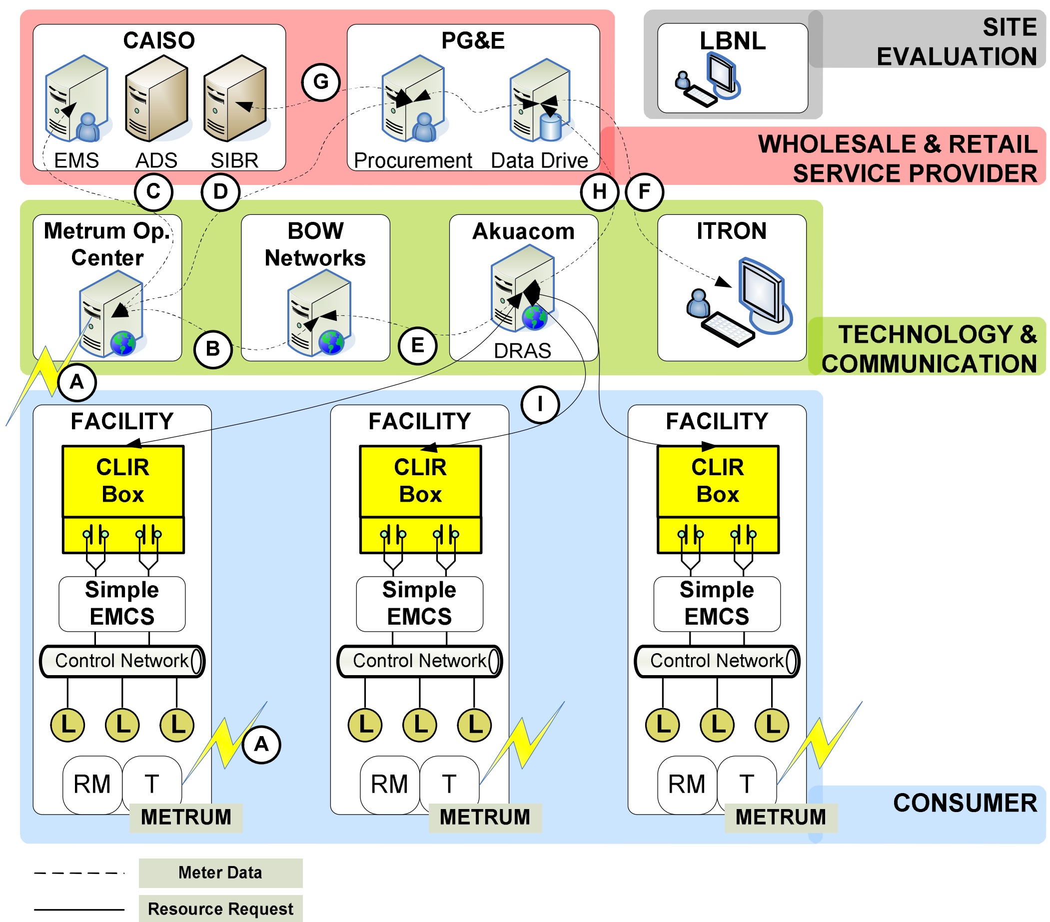
e. Two-way Internet between Bow Networks (via Metrum Op. Center) and Demand Response Automation Server (DRAS) by Akuacom (real-time metered instantaneous demand and energy use data).

f. Two-way Internet between PG&E's data storage and Itron (Meter data for load and shed forecasting).

g. Two-way Internet between CAISO Scheduling Infrastructure Business Rules (SIBR) Web-based user interface (Meter data used by PG&E to submit bids to CAISO DA market).

h. Two-way Internet between PG&E data storage and DRAS (forecast and bid information from metered data).

i. Existing two-way Internet between client within facilities and the DRAS (continuously poll for PLP event signals).



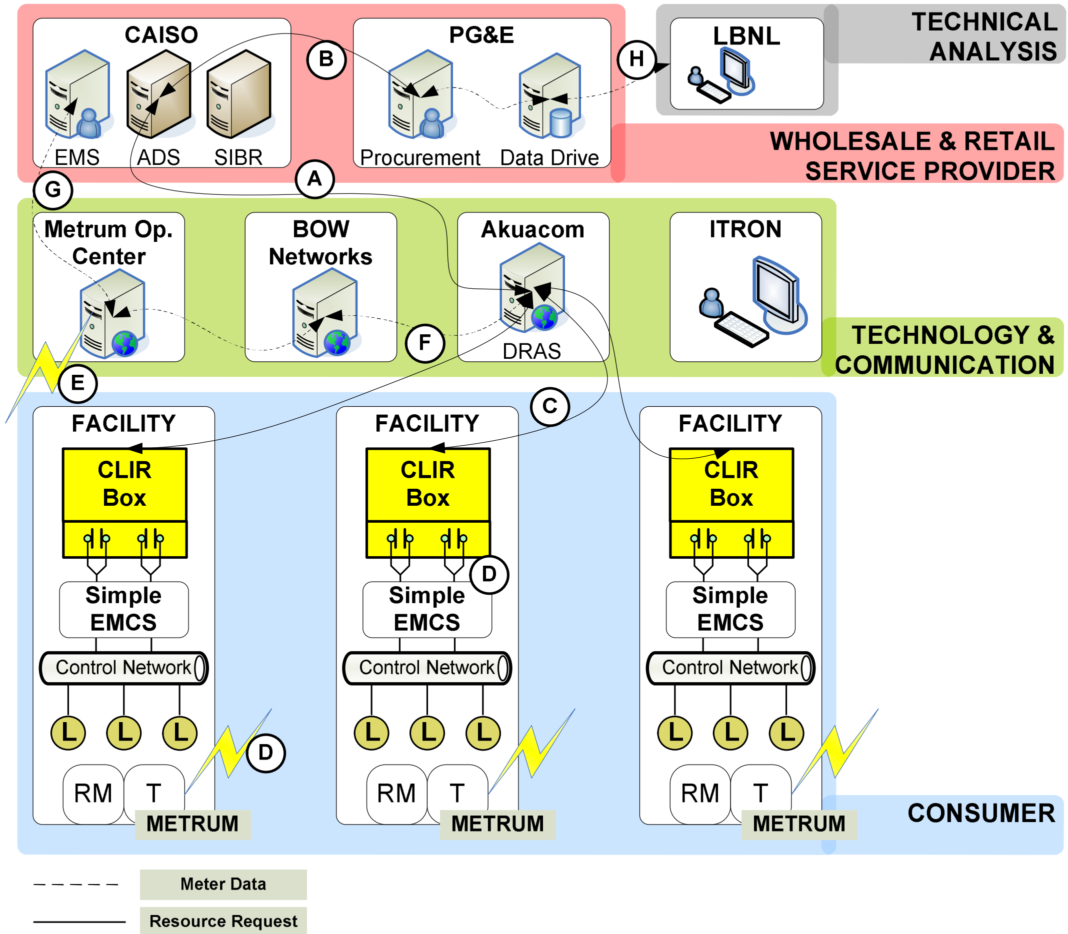
During- and post-PLP event processing: As shown in figure 2, the following process explains the systems, communication exchanges, and the entities and their roles to facilitate automation during- and post-PLP event. This process by the technology and communication providers is intended primarily to link the retail resources (consumers) to the wholesale DR service providers and enable them to dispatch DR signals, monitor and analyze shed, and customer settlements:

a. Two-way Internet between CAISO Automated Dispatch System (ADS) and DRAS (ISO operators dispatch PLP event signals using, which is received by OpenADR compatible DRAS).
b. Two-way Internet between PG&E procurement and CAISO ADS
c. Two-way existing Internet between DRAS and Participant (ADS communication translation and forwarding to the facility using existing PG&E's OpenADR communication infrastructure).
d. Existing pre-programmed strategies and Client and Logic with Integrated Relay (CLIR)[7] within facilities trigger load reduction in less than five minutes. This interface is independent of control protocols (e.g., BACnet, Modbus, etc.) used within the facility.
e. Two-way CDMA wireless radio communication network between Metrum and participating facilities. Dual meter socket helped the facilities to retain PG&E revenue meter (RM) and install a new telemetry (T) meter (Four-second telemetry data measuring facility's metered instantaneous demand and energy use in real-time).
f. Two-way Internet between Bow Networks and DRAS by Akuacom (four-second real-time telemetry metered instantaneous demand and energy use data used for monitoring and load shed sustainability[8]).
g. Two-way Internet between Bow Networks (via Metrum Op. Center) and Energy Management Systems (EMS) by CAISO (Meter data for monitoring resource response).
h. Two-way Internet between Lawrence Berkeley National Laboratory (LBNL) and PG&E secure data storage (post event analysis and settlement[9]).

[7] CLIR is a device used to translate Internet-based price- and reliability event signals from DRAS to simple dry-contact relay closures that almost all EMCS can understand.

[8] One facility's, Local Government Office, CLIR was customized to receive various pre-programmed control strategies from DRAS using OpenADR for sustained load shed and monitoring.

[9] The settlements for PL resources, typically, happen after 38 to 56 days after the resource request date (PLP event).



What communication technology was used?

For the project, two primary technologies, Internet Protocol (IP) and cellular wireless (CDMA), were used for the purposes of communication between the retail and wholesale DR service providers (CAISO and PG&E), technology and communication integrators (Metrum, Bow Networks, and Akuacom, consumers (facilities), and technical analysts with following details:

- Internet Protocol (IP) was used as the key communication transport protocol
- CDMA cellular wireless was used for real-time telemetry of instantaneous demand and energy use.
- Relay based communication using CLIR device was used to link OpenADR communications to facility EMCS with pre-programmed strategies.
- Existing facility EMCS protocols provided sheds from the end-uses.

Was the communication one-way or two-way?

The PLP required automation that needed two-way communication in real-time to measure demand and energy use within the facility (e.g., forecasting and decision process for resources dispatch) and initiate PLP event and load shed. The wireless cellular communications using CDMA provided access to facility meter data for real-time demand and energy use measurements. Although this communication is two way, only one-way communication coming from the facility was used for the project. The Auto-DR infrastructure using two-way OpenADR communication specification v1.0 existed at the facilities since they were already participating in PG&E Auto-DR programs previously.

How was the telemetry measured?

Telemetry for real-time instantaneous demand and forecasting of energy-use data was provided by Metrum and Bow Networks. Integration of this data with DR service providers, PG&E and CAISO and technology service Akuacom allowed monitoring and sustainability of load sheds within the facility.

How many telemetry meters per enrollee?

For the telemetry measurements, the dual meter socket installations within facilities helped them to keep the PG&E RM and install an additional telemetry meter with CDMA chip provided by Metrum technologies.

At what time interval was the telemetry measured (how frequently)?

The resulting telemetry meter was used to transmit four-second real-time energy use data for forecasting and measurement of energy use and shed. The RM was used by PG&E for conventional customer energy use measurements and retail revenue billing.

How was the telemetry and meter data derived?

The four-second real-time telemetry meter data of electricity use was transmitted using telemetry equipment using cellular wireless (CDMA), which was stored in a data repository for subsequent use by project participants. Prior to the event, PG&E used this four-second telemetry data to store it in secure data storage. Itron used this data from PG&E for energy use and shed forecasting. Akuacom used this for real-time feedback to dispatch pre-programmed control strategies to the facilities so that the shed amount is sustained. CAISO used this to have visibility to the operating reserves on the grid and to ensure that it is meeting the minimum operating reliability criteria at all times. The PL technical analysis team (LBNL) used this data for monitoring and shed analysis.

How was customer information protected?

The four-second real-time telemetry meter data of electricity use data was stored in Metrum networks secure database, which was transmitted to PG&E procurement's secure data drive. PG&E's data was securely accessed using username and password authentication and encrypted Internet transmission. Metrum also used generic names in order for the anonymity to exist and no outside parties can transparently know the correlation between instant usage and the participants

Was CAISO able to see all load drops to credits resources accordingly?

The four-second real time telemetry helped PG&E, CAISO, and PLP team to see the load drops in real-time against the bid amount. When needed, Akuacom also used this data to dispatch and sustain the load shed within one of the facility (Local Government Office).

Should the same technology be used moving forward or is it time to switch to a different option?

This project provided a platform for technology demonstration mainly in the areas of pre- and post- event process for real-time instantaneous demand and energy use, which was used for forecasting and monitoring of shed during the event. The cellular wireless technology demonstrated that it could be successfully used for this purposes. Other technologies that measures and provides feedback from facility EMCS could be tried in future for viability and cost effectiveness. The existing Auto-DR communication infrastructure provided an important standard communication specification, OpenADR, which allowed the existing Auto-DR customers to switch to PLP without replacing any equipment or underlying EMCS pre-programmed strategies. It is apparent that OpenADR made it possible and must be retained. In future, the current development of OpenADR within standard development organizations for U.S. Smart Grid DR standards may have feedback specifications that may allow integration for real-time energy use within facilities. This may open opportunities for other technology and communication service providers and interoperability with other low-cost technology and systems. This also ensures that both dispatch of DR event and energy use feedback is incorporated as part of communication standards that may avoid multiple data sources and communication technologies integration and interoperability concerns.

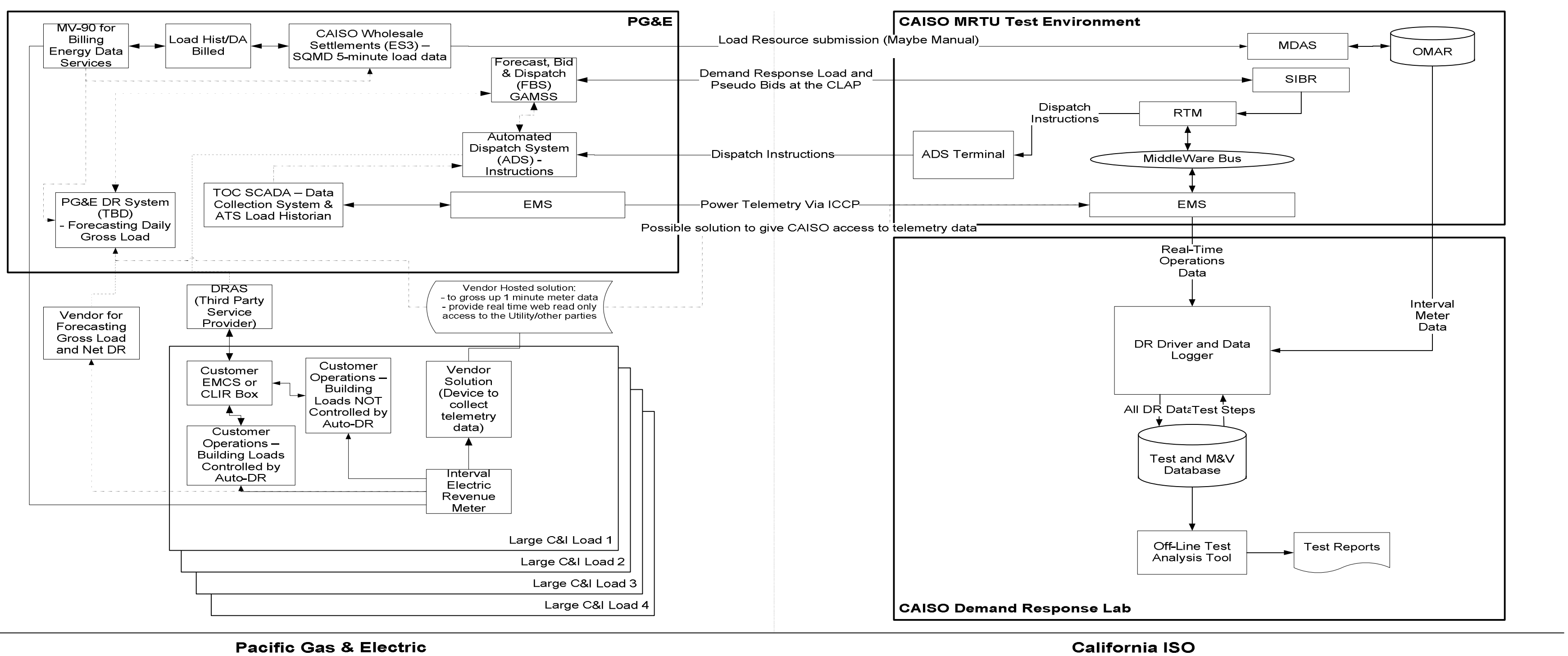
Is the available technology sufficient to perform all necessary tasks to perform at PL?

For the purposes of this pilot, the technology demonstration and DR reliability was the key and not specifically, the cost. Significant success was accomplished with reliable load shed using automation. This technology and communication for automation included real-time telemetry of instantaneous demand and energy use data, and its integration with DR service provider systems and existing Auto-DR infrastructure. Once the effectiveness of technology and communication is proved, the enabling hardware and software could be scaled for cost effectiveness. The simplification and scalability of integrated technology that’s standards-based is important for enabling future systems interoperability at low cost.

5. SYSTEM PROCESS (Bid to Bill)

As part of the PLP, PG&E was required to comprehend current functional processes by each department, understand and plan how to incorporate new software & business requirements, and finally document procedures of what had to be done to achieve the pilot's objective. It must be recognized that there are several layers of interaction between PG&E, participants, vendors and CAISO systems which have their own way of functioning. Inheriting issues and differences of how communication and system interacts. The diagram shown below highlights the required interactions amongst internal and external software-hardware.

PG&E – CAISO Process Flow (Bid to Bill)



In order to fully grasp the system and business requirements, PG&E has divided the evaluation based on the task [Appendix H]. Although systems are in place throughout the various affected parties, it is not necessarily eluding to a small work order for integration. First, not all systems are built to provide automated support to allow PG&E the ability to bid in PL or in the future, PDR. Requirements for PL and PDR for items such as meter data submission are new and it many sense not currently modified in the PG&E Back Office software. The same can be said about forecasting needs that PG&E must strive to build.

5.1 Forecasting

In order to fully comply with the current structure of the Participating Load (PL), PG&E must segregate the resources underlying base load from PG&E's Default Load Aggregation Point (DLAP). Doing such task would then require scheduling each resources base load under a Custom Load Aggregation Point (CLAP) while bidding in the forecasted DR load gross load in a pseudo generator id. This particular task has never been done and it required procurement of methods and designing new process to accommodate "Front Office" needs.

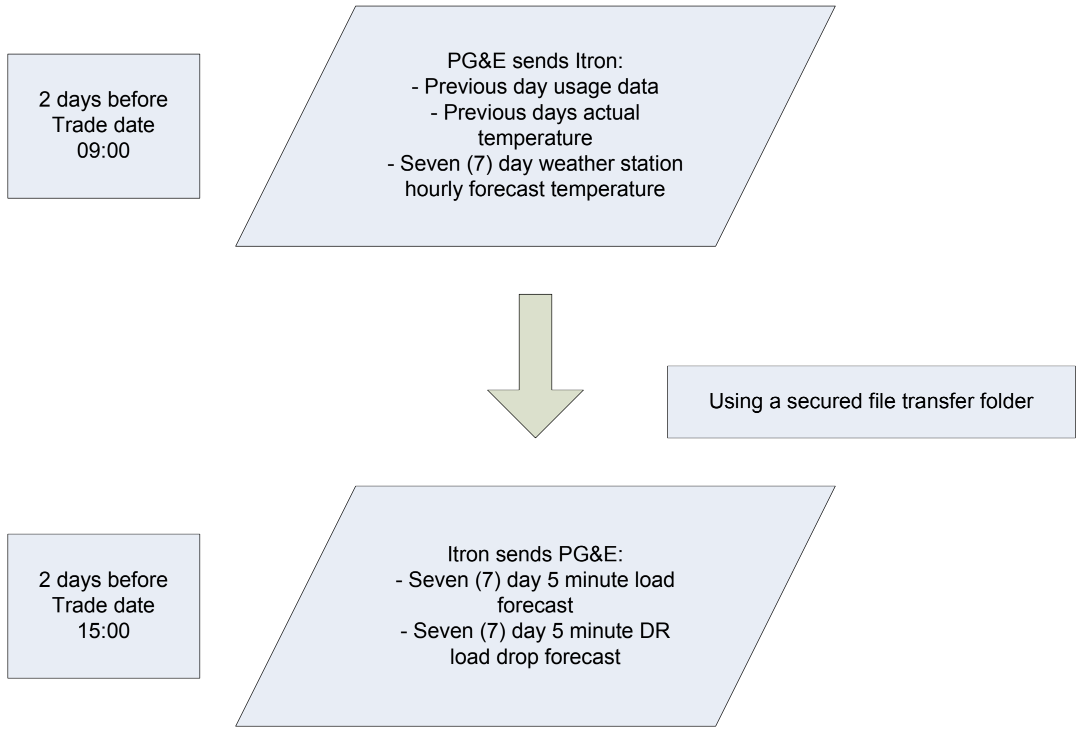
PG&E's Front Office has an abundance of experience in forecasting service territory load. However it does not have any systems to support individual participants underlying base load and potential DR load drop. Due to the granularity for forecasting, PG&E acquired Itron's Metrix IDR hosted service to achieve this particular initiative. Itron suggested that using a time series regression model would fit the bill for this and should work as long as historical usages for these three sites exist. PG&E provided Itron historical revenue usage dating back to the beginning of 2008 and specified dates-hours of which the three participants were called for any DR program. PG&E also provided historical hourly weather station data for each specific participant's location. The collection of historical data was only half of the requirements needed for this pilot.

Since these resources are classified as a PL, even though there may be no DR available to bid in, the underlying load for each participant still had to be scheduled; 24 hours – 7 days a week. A daily exchange of data had to be done to create the forecast. Those inputs are:

- Previous day's 24 hour 5 minute usage data from each participant
- Previous two days of actual temperature per weather station
- Future seven (7) day forecast temperature per weather station

The output from this exercise provided PG&E with a rolling seven (7) day forecast that captured the 5 minute load for each participant as well as 5 minute load reduction. PG&E then aggregated to hourly data since the current CAISO market accepts bids in an hourly fashion even though settlements are done in 5 minute granularity. Appropriate adjustments are made to ensure the schedules and bids account for the Distribution Loss Factors (DLF).

The processes shown down below are done two (2) days before the trade date. The timeline is as follows:



5.1.1 Evaluation

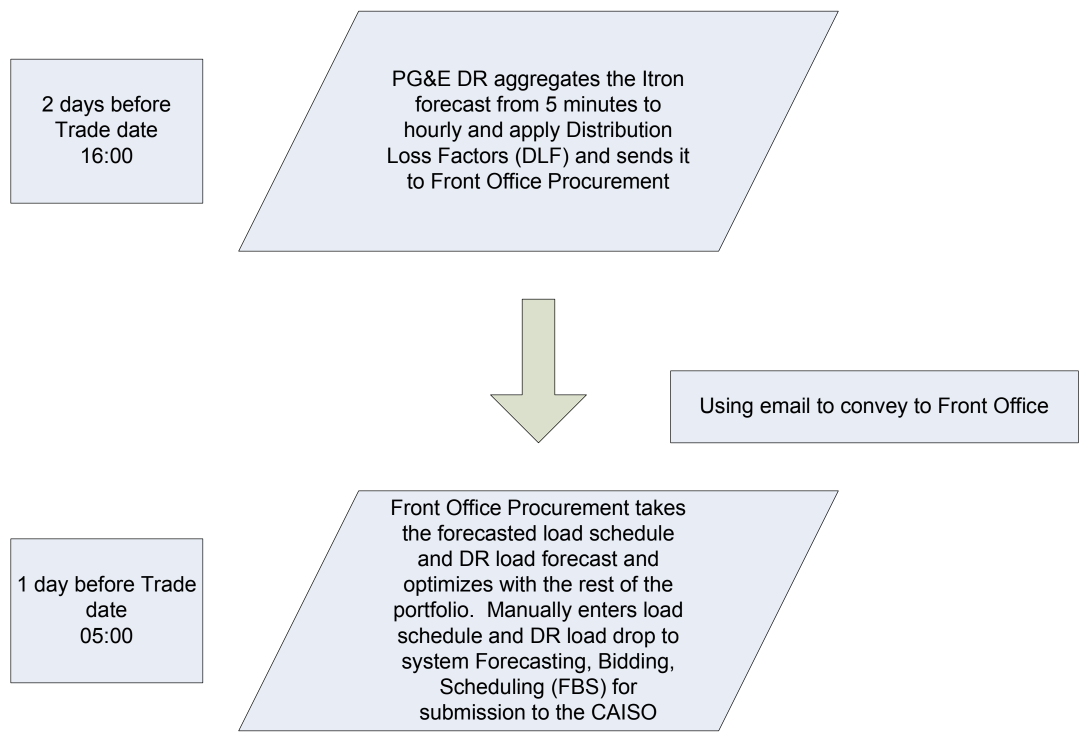
The solution Itron provided PG&E for this demonstration was adequate but not scalable. Systems internally must be properly scoped and built to achieve forecasting as the enrollments grow. This would only help assist achieving reasonable data sets for PG&E's Front Office to use when bidding in DR.

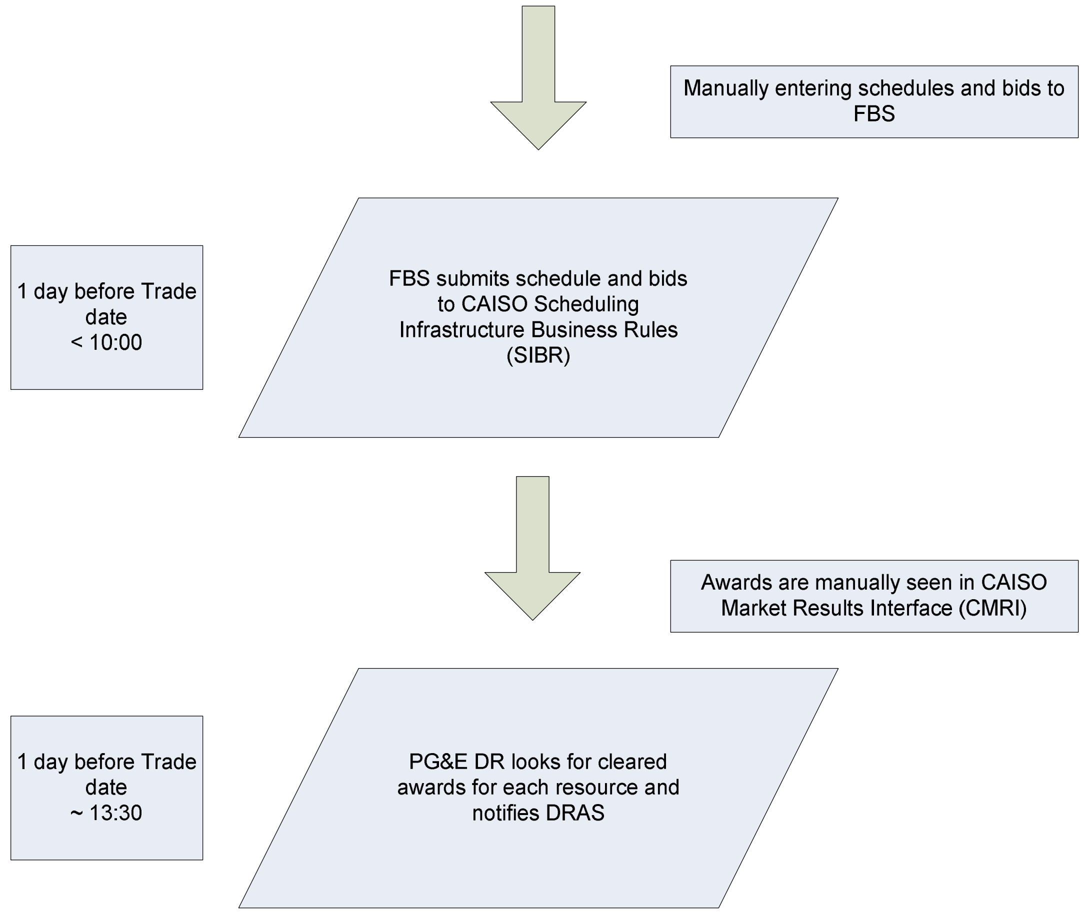
The process of delivering data between PG&E and Itron was done in a manual process. PG&E and Itron used a secure file transfer folder ('SwapDrive') for the placement of these files. Moving forward, system integration to drive a forecast of the DR load reduction would be automated, possibly with PG&E's DR Load Order Optimization Tool (LOOT) and Front Office's Forecasting, Bidding Scheduling (FBS) tool.

The understanding moving forward is that PDR will be the primary vehicle to allow retail DR to participate in wholesale products and not as much the PL model. Although PDR does not need to have the extensive operation of forecasting and the requirement of scheduling the underlying load, PG&E sees that level of detail necessary to mitigate any inherited risk when dealing with any interaction of load with the CAISO products. As the volume of potential participants in the AS market grows, adequate forecasting is needed to ensure delivery of the capacity is met. However, if no such forecasting system exists, it may create a fundamental concern in Front Office. Understating and overstating the forecasted performance has a vast effect on how PG&E Front Office conducts daily procurement activities. Having an unpredictable forecast of DR resource can be a detriment to operations.

5.2 Bidding and Scheduling

The file output is given to Front Office around 16:00 two days before the trade date. PG&E's Front Office Procurement would then use that file to be included in the 05:00 day before trade date. This would allow Front Office to dictate at what price these resources should be bid in that would make the most optimal sense. Once a price and quantity is decided, manual data input to PG&E's FBS system is done by the Front Office personnel in order to ensure schedules and bids are received by the CAISO Scheduling Infrastructure Business Rules (SIBR) system.





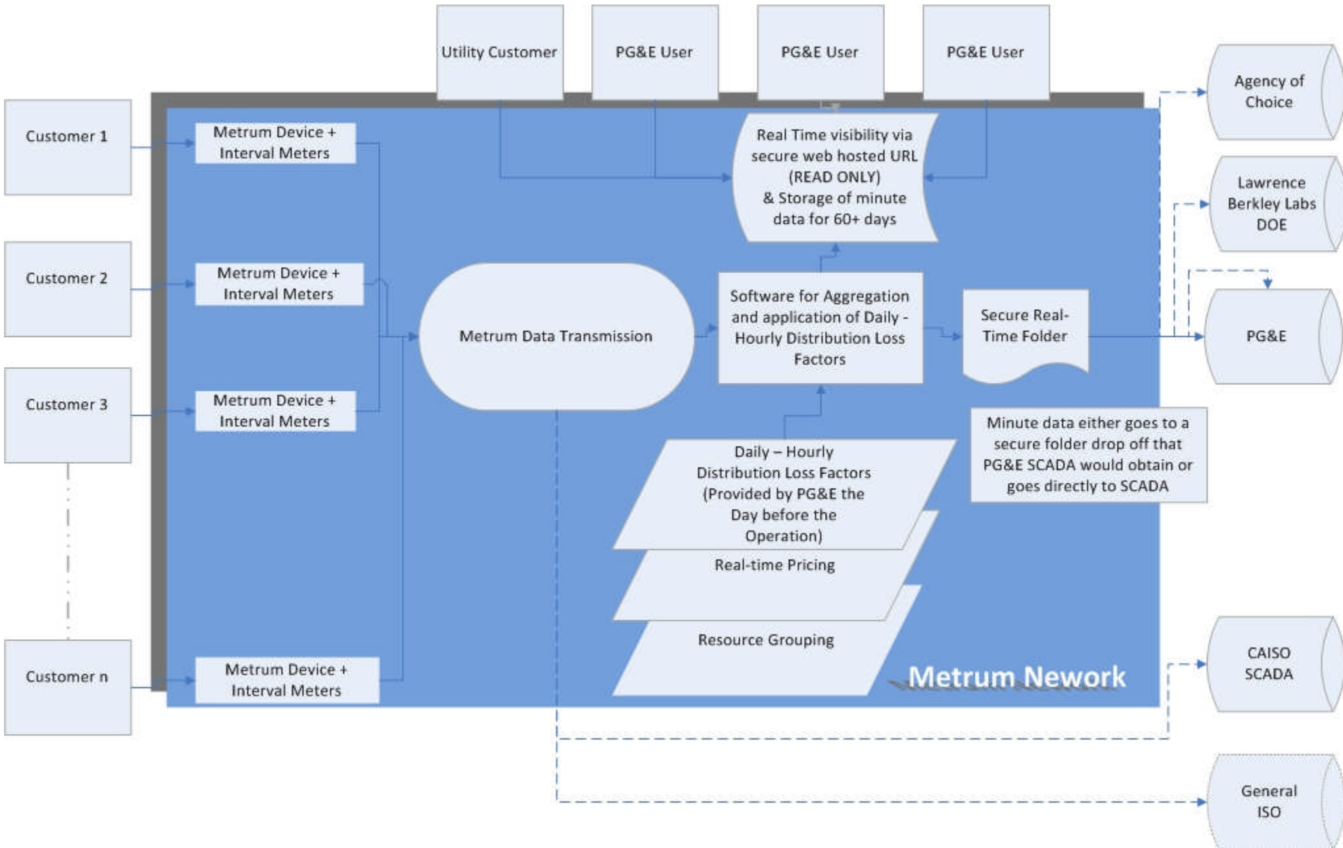
5.2.1 Evaluation

Overall the manual process for scheduling and bidding functioned adequately but is not scalable based on how it is currently functioning for this pilot. In the future, automation of these tasks needs to occur to mitigate any potential errors and leave a suitable trail for auditing. There is much work that needs to be done to avoid manually entering schedules and bids for each resource. For example, these resources were meant to participate in the Day Ahead Non-Spinning market. One day, however, PG&E accidently missed the Day Ahead market but was able to bid the resources in the Real Time market (or, at one point entering the wrong energy curve bid price that the CAISO dispatched at will, since it was economical to do so).

Automating these functions will prevent most errors that PG&E faced this season. However, going through this pilot demonstration allowed PG&E to investigate critical and necessary leg work to enhance the current systems to provide a better solution.

5.3 Telemetry

The most sought out question during the pre-implementation for this pilot was how to collect real time usage data that would be in compliance with current CAISO requirements. PG&E was able to acquire the services of Metrum Technologies to extract and deliver the sub 4 second energy demand with DLF to various outlets. PG&E then looked at various options and considered which method would be the most efficient and realistic given the short pilot time frame. Due to resource and time constraint it was unrealistic for PG&E to connect the Metrum solution to PG&E's SCADA/EMS system. The only viable option was to have Metrum directly obtain data via internet (using certification) to deliver the energy data. Metrum also provided PG&E with a secured login web based interface to view real time data. DRAS was also given a client certificate to access real time data for operation purposes. The diagram below replicates the structure done for this pilot.



5.3.1 Evaluation

Overall, Metrum was able to deliver real time feeds that met PG&E & CAISO requirements (approximating the 97% real time ‘up time’ requirement CAISO needed). Assuming the same structure flow is retained, the solution offered by Metrum is currently scalable up to 10,000 devices. [The price for scaling to a higher volume is reflected on Section 6.2 Telemetry]

However, the current structure would have to change in order to accommodate aggregation. Moving forward, aggregated resources will exist and functional requirements must be aligned with what is needed for submission to the CAISO. Also, as mentioned, the pilot was able to bridge simple connectivity directly to the CAISO. However, connectivity needs to be modified to have feeds directly to PG&E’s SCADA/EMS systems rather than directly to the CAISO’s EMS system.

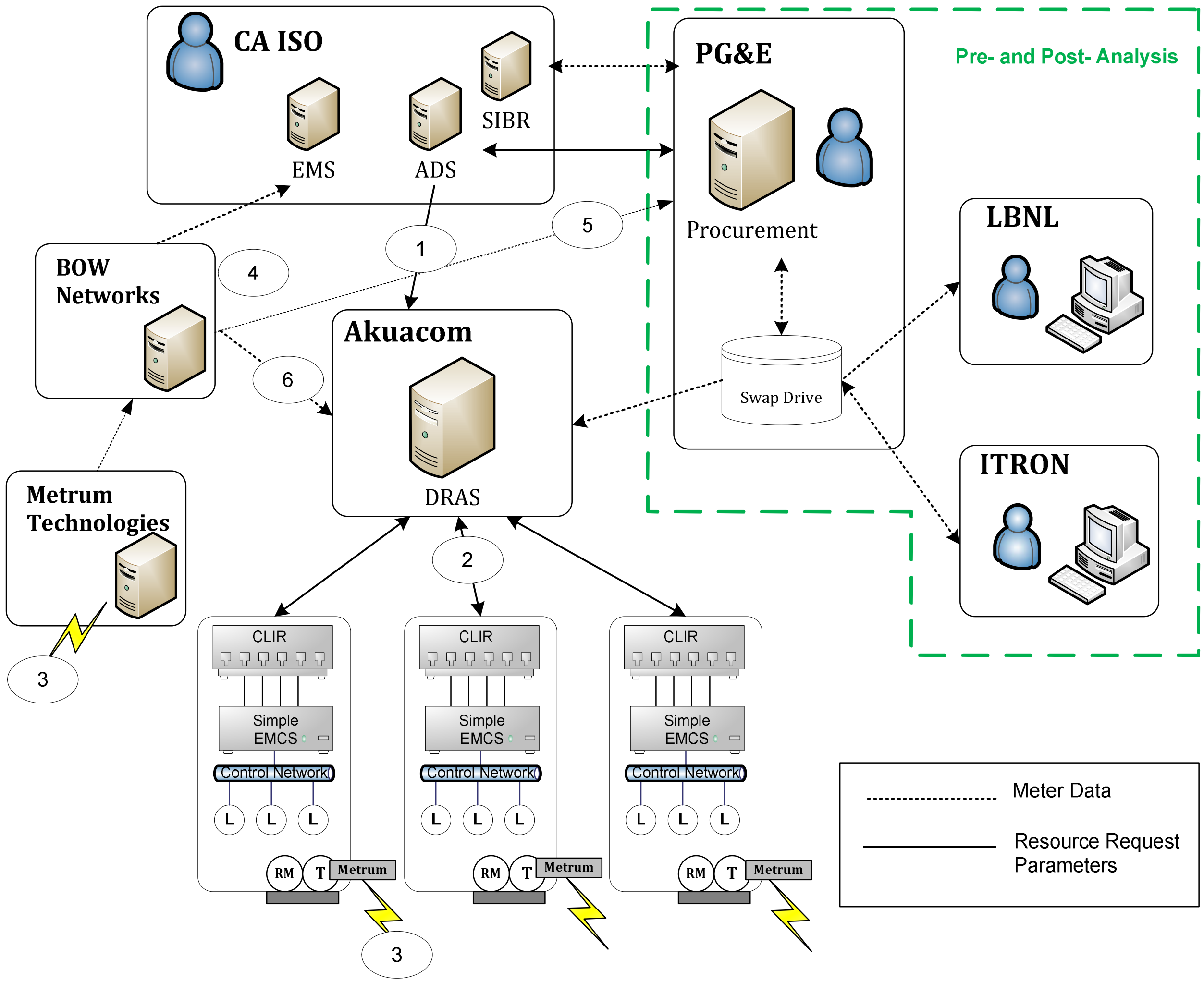
5.4 Dispatch

PG&E decided to integrate the CAISO's ADS with DRAS. This was to ensure that if and when the CAISO decides to dispatch the resources that no manual intervention had to be done by PG&E to achieve the triggering the event for the participants. CAISO instructions [Appendix F] would be sent via XML format to DRAS and DRAS would interpret the file within seconds of receiving it. Once received, DRAS would validate the instructions and create an OpenADR event that has the same start time and end time as that in the instruction provided by the CAISO.[10] The notification time for DR event is the same as the start time and the event is immediately published to all the DRAS Clients so they can achieve their instructed levels within the required 10 minute ramp period.

The DR event also contains a simple mode level (NORMAL, MODERATE, or HIGH) as well as the MW level from the instruction. In addition the DR event also contains an enumerated shed level (0-3) that is used for doing feedback. For those facilities that are using feedback, if the facility is not

[10] Note that for 5 minute dispatchable instructions an end time is not explicitly given and is assumed to be 5 minutes after the start time.

achieving its instructed level then a higher shed level is sent to that facility. Likewise if the facility is shedding more that the instructed level a lower



shed level may be sent.

Having DRAS contain all the data from awarded bids, load schedules, real time feeds, two way feedback system and direct integration with ADS allows the system operator control the resource load to meet the dispatches. In many ways, DRAS as the brain of the operation creates a parallel comparison to AGC. This control system can be used for future AS products like regulation up/down.

5.4.1 Evaluation

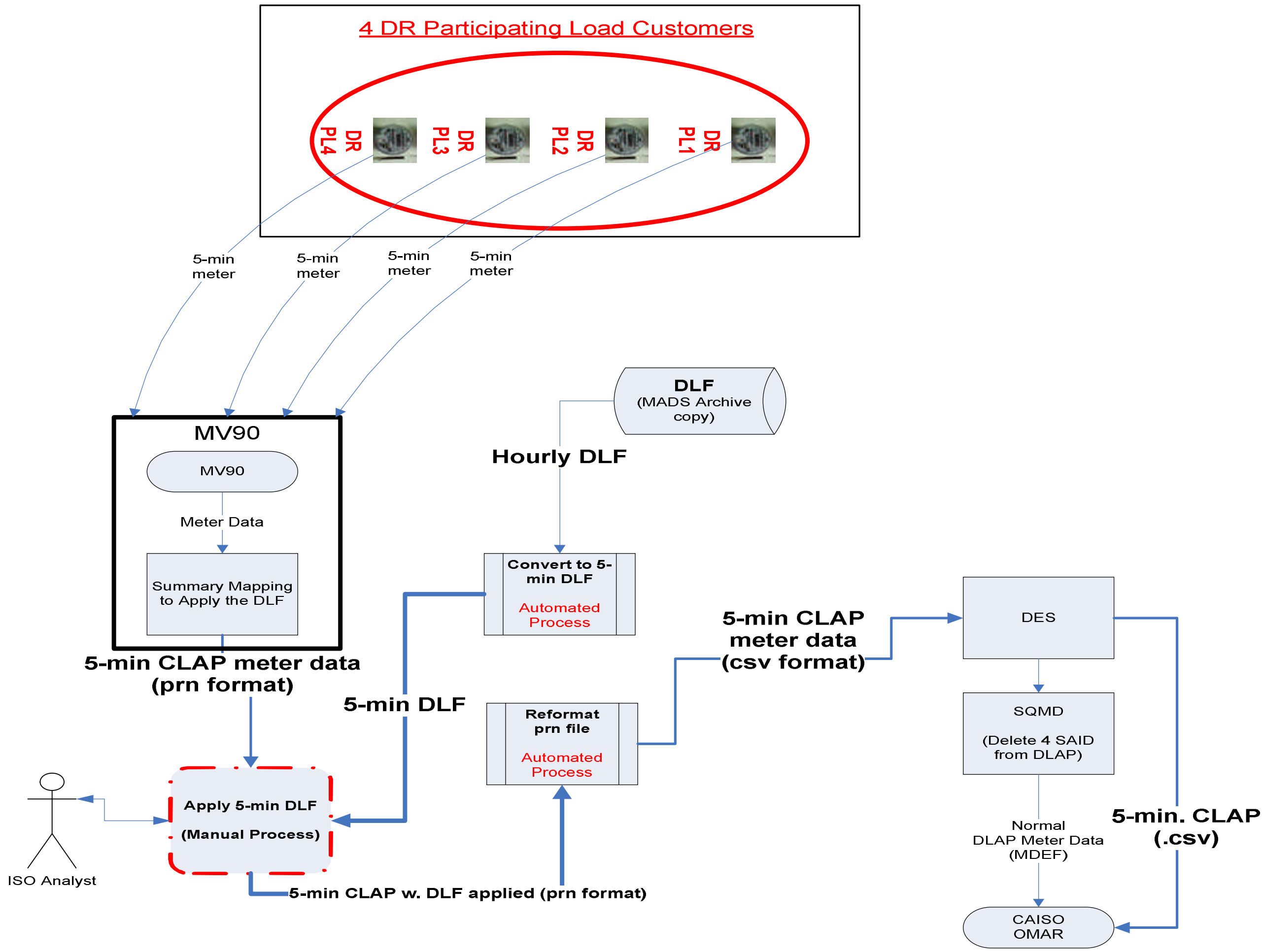
This particular task worked well and can be used for future pilot/programs. A couple of times during the pilot window, non-contingency bids were made and were dispatched by the CAISO. Twice, PG&E was not aware that the resources were dispatched by the CAISO. It was later discovered that such dispatched happened in DRAS. Another promising technology is the feedback mechanism. Although PG&E was only able to test this one time during the pilot window, the results are promising. Having the control to meet the necessary quantity the CAISO dispatches is critical. It avoids all the possible penalties and uninstructed credits/charges that may come from not following dispatch instructions. The lessons learned from this can be used to supplement on standard work currently being undertaken in various OpenADR nationwide workshops. PG&E does not see major modifications to this process, but, as the standards for communication settles, minor tweaks may be done.

5.5 CAISO Settlements

The CAISO settlement requirements created additional work and attention in order to achieve compliance for these resources. Current PG&E systems and processes to submit SQMD load meter data to the CAISO's Operational Meter Analysis and Reporting (OMAR) system are done in an hourly aggregated fashion. Unfortunately, current PG&E systems are not arranged to allow other options beside the hourly aggregation. There were other issues to address during this time. Listed below are several barriers PG&E faced:

- Applying DLF on an individual resource level; current process is done at a higher level and no current function exist to accommodate a custom additive in an individual level;
- Converting current DLF from an hourly value to a 5 minute level in order to be equivalent to the 5-minute meter data;
- Ability to submit 5-minute SQMD load data in a csv format; typically done in mdef format and in an hourly fashion;
- Separation of the three resources from the overall DLAP load; this is done to avoid double payment of the load; and
- For internal auditing purposes, database and procedural documents were initiated to track all ISO settlements related to this pilot.

PG&E Back Office was able to provide a short term option to handle the pilot. Interaction with PG&E's Energy Data Services (EDS) were done to harvest the 5-minute meter data and sent to Back Office. Back Office would apply the 5-minute DLF to make the meter data SQMD, convert the file extension to a csv format and send it off to a file folder that interacts with CAISO's OMAR. And at the same time, the Service Agreements (SA) associated to each participant is excluded from the overall DLAP load to avoid double payment. The diagram shown below highlights the work done:



5.5.1 Evaluation

The manual settlement process worked for the most part. The flow and tracking was executed quite well. However, this procedure and minor system modification is not scalable to accommodate future participants in either PL or PDR. There were many manual handoffs: mistakes were made and confusions lingered. Changes in the process and modifications to current Back Office systems and procedures must be done to avoid future mistakes. Settlements must be tracked to comply with internal and external auditing.

6. COST

For this pilot demonstration, PG&E requested $2,000,000 to integrate DR load into the CAISO MRTU Market, more specifically non spinning reserve. Currently (end of November 2009), the pilot has spent a total amount of $ $1,145,141.87 and a total end of the year forecast expenditure in the amount of $1,313,141.87. A surplus of $686,858.13 will be left over and making this pilot demonstration under budget. Surplus for this project will be used for an extension of this pilot to investigate AS in the PDR product model, if approved by the Commission.

Complete comprehensive detail breakdowns of all expenditure are highlighted below.

6.1 Program Management

Internal Program Management cost will be an ongoing cost moving forward. And as more potential enrollments occur for this particular product type, the DR operation side will need additional funds to ensure enough resources are allocated for this effort. A critical agenda that needs to be kept in mind is the additional resources needed for marketing this particular program. During this pilot, marketing was tracked as part of the Program Management expense. The cost for recruiting and analyzing these participants was $13,277.30. Mentioned before, offering AS should be treated and screened more closely than any of the other retail DR programs; not all customers can meet the needed 10 minute response time. Therefore, a greater deal of attention should be placed on this core function.

INTERNAL COST

Recurring			
PG&E Program Management	hour	$ 197,309.00	
PG&E Program Marketing	hour	$ 13,277.30	
PG&E Sourcing	hour	$ 2,735.83	
Total Internal Cost			**$213,330.56**

6.2 Telemetry

During the pilot demonstration, PG&E spent a total amount of $430,077.10 (number reflects Jan – Nov 09 expenditures) to enable the participants with real time telemetry. The original proposed budget to procure real time visibility was forecasted in the neighborhood of $900,000.00. The breakdown shown below reflects itemized spending for the telemetry.

INTERNAL-EXTERNAL COST		
Hardware	Unit	Total ($)
One time		
Pre-Implementation Connectivity to CAISO	one time	$237,997.10
Recurring		
Engineering support	hour	$112,050.00
Operation support	hour	$80,030.00
Grand Total		**$430,077.10**

Moving forward, cost to obtain this service drops dramatically. The equipment device and data harvesting costs go down dramatically. More importantly some of the larger costs, such as the connectivity set up fee will be avoided due to the structure being in place. However, it is important to remember that the pilot demonstration provided a direct connection to the CAISO via Metrum real time systems and avoided the connectivity to PG&E SCADA/EMS systems. In the future, if PG&E remains utilizing Metrum's real time systems, PG&E would take the current feed for real time directly into PG&E's SCADA/EMS systems and deliver it to the CAISO EMS using existing ECN connection. At that point, integration cost between Metrum real time feeds and PG&E's SCADA/EMS system will need to happen. Such integration and change of architecture flow is needed considering the possibility of needed aggregation once the volume of participants increases. Having this structure would allow PG&E to have greater flexibility when dealing with optimization and grouping of participants' operational parameters. Shown below are the forecasted variable costs moving forward if PG&E retains Metrum structure for providing real time data (Note: this does not contain any incremental work to integrate Metrum Technologies to PG&E SCADA/EMS systems):

6.3 Forecast

PG&E spent $85,747.22 to have a forecasting tool to accommodate some of the requirements needed for this pilot. PG&E had to acquire Itron's Metrix IDR hosted solution tool, which cost $66,200.00. Additionally, PG&E spent another $19,547.22 to provide daily weather and meter data to Itron in order to produce a reasonable forecast that is given to PG&E's Front Office.

INTERNAL-EXTERNAL COST			
Hosted Service	Unit	Total ($)	
One time			
Load Forecast Setup	one time	$ 51,200.00	
Reoccurring			
Daily Load-DR Forecasting	monthly	$ 15,000.00	
Meteorology	hour	$ 17,649.00	
Meter Data Retrieval	hour	$ 1,898.18	
Grand Total			**$ 85,747.18**

Moving forward, the hosted solution provided by Itron to forecast 24/7 load and potential DR net reduction will not be a suitable since it is not scalable. Internal systems must be built to accommodate this task along with the forecasting logic Itron currently has done for this pilot. As noted earlier, though the requirements of PDR is less rigorous and takes out the scheduling of the underlying base load needed under PL, PG&E sees great benefits to have a forecasting system. This system than can be used as an important tool when internal PG&E optimization occurs, especially when more DR loads will be bid in to the CAISO market. PG&E also believes that an accurate forecast has important benefits when additional DR resources are being bid into the market.

Forecasting data inputs such as the weather data and meter retrieval are relevant factors to achieve the objective. These tasks would be an on-going cost and possibly increase as more custom weather station points are set. Data collection done for this pilot came out of the MV-90 system currently used for legacy interval metering collection. In the future, PG&E would use the AMI system for data collection on both next day raw data and revenue data. However, the AMI system would need to be modified in order to meet DR operation requirements and may add additional cost to meet CAISO requirements. Finally, Cost to have proper systems to do the task at hand will be substantial since none of which are currently built.

6.4 Procurement Activities

The activities and expense associated to this section contains necessary work to bid, schedule, dispatch and settle with the CAISO for the pilot period. Majority of the work, except the communication between CAISO's ADS and DRAS, during this demonstration was manually done and is not scalable moving forward. The cost moving forward to accommodate bidding, scheduling and settling will take major efforts on current PG&E's enterprise systems.

6.4.1 Front Office (Merchants)

Cost related to Front Office (or Merchant) functions for this pilot revolved on the basic task of how to bid and schedule load reductions in the short term (and preliminary at best). IT work during this phase had to be done in order for Front Office to schedule the necessary base load and bid in the available DR load drop. IT incorporated the proper resource id to the current PG&E Front Office enterprise system in order to submit bids. An option of directly going to CAISO SIBR and entering the schedules and bids were considered, but not an easy task to do. So the work of coding by IT was the best alternative.

The majority of the cost captured was based on documentation of business requirements for Front Office in relation to current PL requirements and potential requirements for PDR. However, significant pilot development and operational work conducted by Front Office was absorbed by the daily activities they currently manage. Thus the final amount stated below does not capture the total cost Front Office carried out for this pilot demonstration.

INTERNAL-EXTERNAL COST			
-			
One time			
PG&E IT for Front Office	hour	$ 353.70	
PM for Front Office	hour	$ 171,894.81	
Grand Total			- **$172,248.51**

The cost presented here is considered a one-time cost. However, full system integration would bring incremental IT cost to automate a functioning systems interaction between DR applications with Front Office systems and CAISO SIBR. Similar to the Itron concept, the work done with Front Office was done to provide a working demonstration for this pilot. Future development for Front Office will need a fully automated system that can minimize data errors. The work is currently being scoped for production release to help launch future products like PDR. However it has not been built.

6.4.2 Back Office (CAISO Settlements)

Back Office (or CAISO settlement) cost was associated with producing settlement quality data that can be submitted to the CAISO for settlements for this pilot. The full amount of $137,963.56 was used to both manually and automatically generate quality meter data for submission to the CAISO. This task contains creation of incorporating DLF and excluding these participants load from the DLAP load to again avoid double payment for the load procured by PG&E.

INTERNAL-EXTERNAL COST		
-		
One time		
PG&E IT for ISO Settlements	hour	$ 18,288.56
PM for ISO Settlements	hour	$ 119,675.00
		-
Grand Total		**$137,963.56**

The cost presented here are one-time costs, and the solution delivered for this pilot is not scalable. A greater cost will be brought forward like many of the other internal task at hand. System flexibility will be needed when more DR resources are being bid in to the market. Tracking resource settlements and usage data will be a key component to hone in on, especially as the volume increases.

6.5 External System Integration

One of PG&E's system integration objectives was to have the CAISO's ADS program be able to communicate with the DRAS system. This system linkage was necessary to avoid missing any CAISO dispatches on these resources. Since Akuacom currently manages the DRAS, PG&E procured their services to create the link. PG&E spent a one-time lump sum cost in the amount of $75,000.00 to marry the two systems. This particular system integration should not change and the architecture will be brought forward to PDR.

INTERNAL-EXTERNAL COST	Unit	Months	Rate per month ($)	Total ($)
One-time				
DRAS & ADS support	lump sum			$ 75,000.00

Grand Total	**$ 75,000.00**

6.6 Program Incentives

PG&E requested $150,000 as 'Bridge Funding' for PLP participant incentives. However, only $30,774.96 was paid out. This includes the Program Incentive for participating, Switch Incentive, and the Performance Incentive for all dispatches CAISO made to these resources. CAISO made a total of 185 total 5-minute calls for these three resources for the summer of 2009.

	# of times called (5 minutes)	Max kW Capacity	Delivered Energy (kWh)	Program Incentive	Switch Incentive	Performance Incentive	Total
Total for 3 participants	185	250	1572.05	$19,823.23	$10,715.92	$ 235.81	$30,774.96

The structure of this pilot's incentive mechanism will not remain as it is as PG&E proceeds with future developments of a program that offers AS products to the CAISO.

6.7 Cost Evaluation

Though PG&E spent less than the approved budget, it still has a great deal of work that needs to be done. The costs for Front Office and Back Office (totaling $310,212.07) are one time costs for this pilot and are not scalable by any means. Similarly, the forecasting tool is a one-time hosting service fee that is not scalable. PG&E incurred many one-time non scalable costs due to the CAISO's unfinished product requirements of a DR product and current approaches for internal system changes to integrate DR (due to unfinished requirements). There was also insufficient time to fully develop proper business requirements for integration. In order to meet the summer 2009 deadline, therefore, PG&E took conservative steps to release a functioning pilot to achieve the Commissions objective of integrating DR to wholesale markets. Though the avenues to achieve these functions are not necessarily scalable, the lessons to bring forth a business document and realization of needed changes were achieved.

There were areas where notable developments, that are directly applicable to future programs, were made. Further advancements on AutoDR were realized to accommodate the sophistication of the AS product. As mentioned earlier, AutoDR was used as the primary communication for dispatch.

The accomplishment of linking CAISO's ADS to AutoDR's DRAS was quite vital. The cost of $75,000.00 was use to integrate two systems that can now be utilize for any current product offering by the CAISO (except for regulation up/down and spinning reserve). The work done here builds upon the current evolving work on AutoDR, which is on track to become a nationwide (possibly worldwide) standard.

PG&E was also able to discover viable equipment that collected real time data and has demonstrated through this pilot as a potential structure that can be used to meet CAISO telemetry requirements. The one-time expense incurred PG&E provided the infrastructure to transmit the real time data to the CAISO. Moving forward, such service expenses are expected to decrease and thus allow the future program to possibly achieve a cost effective service.

PG&E also believes it is premature to answer the question of whether the set-up cost to offer AS will be greater the on-going forward cost to operate in the CAISO market. System maintenance, performance requirements, resources to run these programs, and incentive payments needs to be closely looked at. For example, current requirements to provide AS to the CAISO states that real time must be up and running 97% of the time. That scenario brings a much higher operating cost due to the imposed requirements of constantly having a 24/7, without any lag, systems. Such requirements can be expensive. Unless the CAISO lessens the restriction, it is hard to imagine that on-going cost to offer an AS program would be less than the set-up cost.

6.7.1 Cost Effectiveness

PG&E strives to create programs that would deliver a cost effective program in a PL or PDR product. The PLP shed light on technical feasibility and the associated costs associated with developments at the customer site and for the communication between the CAISO and the customer. Costs associated with PG&E internal system development to provide PL and PDR will emerge out of that scoping. On the revenue side, the value that DR will be able to extract from the CAISO markets is still in its evolution especially with all the current dynamic pieces, such as migration to sub – LAP load bidding, direct participation and modifications to AS requirements as it pertains to non generation resources. Cost effectiveness analysis from a societal point of view will depend on what these yet to be determined cost and revenue elements will be.

To make the programs cost effective from a customer point of view, incentive structures need to offset customer costs during load reductions. However, these incentive structures also have to address the penalty structure, which PG&E omitted during this pilot. Again, due to uncertainties of the pilot, it was a marketing strategy that had to be done to entice the customers to participate.

Another driving force a future program to be more cost effective is the need for low cost, real time telemetry. In order for PG&E to meet the CAISO requirements to provide an AS product, it had to meet necessary telemetry requirements. The cost was quite substantial; PG&E ended up spending close to half a million dollars to achieve a solution for this pilot demonstration. However, spending that amount enabled PG&E to demonstrate that technologies exist to meet the requirements. And based on this demonstration, Metrum Technologies was able to offer a much lower service cost moving forward based on their findings. This also encourages other vendors to possibly develop an offering that can be lower cost solution for acquiring real time data that is acceptable to the CAISO.

7. CAISO MARKET EXPERIENCE

During the pilot demonstration, PG&E was able to observe the interaction between PG&E's resources and the CAISO market. PG&E was able to identify cases that affect how resources are enrolled and operate in the market. Unfortunately, these resources did not fully participate in other markets the CAISO offers to current generation resources. No activities involved bidding into Residual Unit Commitment (RUC), Real Time Energy, and Day-Of Non-Spinning markets or dealing with scheduling and logging and other processes like Used Limited Resource. But nevertheless, PG&E found interesting findings and questions that can contribute to establishing means to allow DR to participate in the CAISO markets.

7.1 Enrollment

As part of the enrollment process, PG&E was required to provide the CAISO with distinct location and connectivity of the three loads acting as "pseudo generators." This exercise was needed to ensure the right foundation of Energy Management System (EMS) Model and the Full Network Model (FNM). Unfortunately this exercise of identifying bus level point is quite rigorous and once more non-trivial. PG&E had to provide the CAISO levels of details that are not at all transparent. This indicates future issues that a Demand Response Provider (DRP) may have to face when identifying the best way to aggregate resources. Mapping these resources is quite important as it is needed for market optimization during market runs against other bids. This may be a disadvantage for any DRP that would like to set up a CLAP. The timing is quite crucial to this particular set up and such timing should be understood for all DRP providers when trying to enter the market with a specific defined CLAP (especially with the current proposed business rules for PDR in regard of registering resources). More importantly, setting CLAP to acquire a resource id is heavily dependent on when the CAISO updates their FNM database, which can be once every quarter.

Another question mark during the enrollment process related to the Resource Data Template (RDT). Though the CAISO clearly provides definition and explanation of such columns within the RDT, it did not explain how such characteristics affect one another in the market. PG&E ran into a situation [described below in Production] where a field was defined, but it was not explained as to how the market would react to such characteristics.

7.2 Market Simulation

Another critical junction prior to putting these resources into production systems was conducting market simulation. Market simulation involved a process for the Scheduling Coordinators (SC) to induce any unusual occurrence that may be seen as an issue. [Appendix G highlights PG&E's scheduled testing] However, upon starting market simulation, PG&E's DR team was told that the two-week window proposed by the CAISO would be the only time such testing would occur. Such a testing window was insufficient due to the unknown nature of how these pseudo generators would react and how providing PDR resources would affect the market. At the same time, the market replicated in the simulation was based on previous data that may have not been parallel to current market conditions. PG&E's DR team believes that these are issues, if handled appropriately by having accessibility to market simulation with parallel market data, can mitigate potential issues down the road and hopefully indicate problems that can be solved prior to migration into the production system.

During market simulation, PG&E was able to test the bandwidth for how low a bid can possibly be (keeping in mind that some of the resources on a given hour were able to give less than 10kW). Bids below 10kW prevented the market from clearing the resources and even omitted them from market optimization. This particular discovery became a PDR/future PL enchantment requirement that no resource can bid less than 10kW in the market. However, this discovery only looked at what is the minimum bid the market can take without having any issues but does not address whether 10kW is the right amount of bid the CAISO finds relevant for capacity in the ancillary service market.

7.3 Production Market

PG&E began the PLP on July 29, 2009 and concluded on October 31, 2009. This gave PG&E three-plus (3+) months to gain market knowledge and observe interactions between the CAISO and the DR resources. In most cases PG&E experienced some unusual behavior on the CAISO operation after a contingency was called upon on these resources. Resources after the contingency were being dispatched more often and at times twice a day (separate issue explained below). The issue was raised to the CAISO after a couple of dispatches were executed and no market alerts indicated that a contingency state was ever declared by the CAISO operations. After an investigation by the CAISO, a problem was discovered that was due to the existing operation set up in the CAISO software. To identify contingency resources, participants must exclude awarded (by unchecking flags for contingency load in CAISO's user interface). This would then identify contingent resources to the CAISO command to mitigate any existing reliability issues. It basically puts these contingent resources as part of the existing non-contingent bid stacks. And once a contingency is considered over, the flags are automatically put back on the contingency state. Unfortunately, the exposed pilot resources are smaller than 1 MW system requirement thus the system omitted to look for these resources and put the proper flags back on. Without the contingency flag checked in the CAISO system, these resources were being classified as non-contingent resources. Leaving these resources exposed to the market prices as oppose to a declaration of contingency then dispatching based on local area need and/or price. This issue was corrected by the CAISO by adding additional checks to make sure proper characteristics are in place.

One other finding during this time was the recognition of the PMin and how having a '0' for PMin has a different interpretation in the CAISO system. This particular experience came about after recognizing one of the resources (Local Government Office) was getting called more than once a day. In the RDT sent to the CAISO, PG&E had a start up of once a day for all three and a PMin of 0. However, the CAISO dispatched Local Government Office at 14:00 on the 31st of August for about an hour and then again at 17:00 for an additional hour. PG&E followed up with the CAISO about such operational instructions. Upon further investigation, the CAISO treats a PMin of '0' as a resource that does not shut down at any point of time, thus exposing the resource to be called more than once. The CAISO system also sees this resource as an economic option since it is available and no cost for startup is associated for dispatch. This particular issue goes back to the underlying questions of how RDTs need to be clearly explained from an operation standpoint.

One particular topic that was not completely analyst revolved around the 1 MW threshold currently imposed by the CAISO for any PL. Leading up to demonstration, PG&E was well aware that it may not meet the 1 MW CLAP requirement and needed an exception from the CAISO in order to fully participate in the market. The three participants resided in three different sub-LAPs and had no more than 250 kW peak capacity each. And since they all physically resided in different sub-LAPs, aggregation of these three resources was out of the picture. As demonstrated during market simulation, PG&E was able to push the boundaries as to what the minimum bid the CAISO market can endure, but it never specifically rationalize whether the 0.01 MW threshold is pertinent to the market. This particular information is vital seeing as these resources are being optimized with supply side resources. Current proposal made in Non-Generation AS by the CAISO has made reference to adopt a lower threshold of 0.50 MW as oppose to the 1 MW currently in place. However, no validations currently exist as to whether .50 MW is the proper minimum threshold.

7.4 CAISO Settlements

The complete PG&E settlements for the summer of 2009 with the CAISO will not be known until the beginning of the first quarter of 2010. PG&E will produce a complete report of the ISO settlements that will be delivered sometime in the first quarter of 2010. The report will contain, total amount of load purchased for the CLAP, awarded pseudo gen bids for each resource, (if any) uninstructed deviation credits/charges, AS Pay/No Pay, and other CAISO charge codes that was associated to these resources.

7.5 Market Conclusion

At the end of it all, the findings represented here clearly reaffirms how the current CAISO systems is very 'generation-centric'. And when more load competes with generation, the systems currently defined needs to be robust to accommodate load acting as a resource; not only based on characteristics but a clear cut definition on how each characteristics interact when it's in the market. Also, more analysis is needed to ensure what the minimum threshold for providing AS and energy should really be to be viable to the market. These particular initiatives will be an ongoing process as the market moves down to direct participation and other future product offerings by the CAISO.

The conclusions of the PLP were communicated to the CAISO and were presented during the download session held on December 3rd 2009.

8. CONCLUSION – NEXT STEPS

PG&E appreciates the Commission's keen interest in the advancement of retail DR to the CAISO wholesale market. The achievements and findings during this window have given PG&E a better comprehension on the integration issues that must be addressed to further advance DR in the wholesale market. PG&E was able to explore and realize that it is technically feasible to offer AS to the CAISO, but requires abundance of system modifications and new developments to meet the core requirements. Most of these requirements are not fully finalized to build an end to end automated system. PG&E also realized that the test participants enrolled in this pilot have had extensive knowledge and relevant history regarding DR. They also have made a significant investment in sophisticated equipment and EMS systems, which have made them a great candidates for this challenging product. However, it does not translate that each potential participant will have the same ease of performance if enrolled. There is no assurance that these potential participants may have the same type of understanding as the ones in this pilot (even within a customer or market segment there remains great variation in energy use patterns). The conclusion from this pilot has generated answers that are quite useful for advancing DR.

As the momentum builds to transition majority of DR loads to the CAISO market using PDR in the near term, the lessons learned from this pilot have PG&E a better understanding of what needs to happen to properly and efficiently accomplish the task at hand. Moreover, it has also provided findings in the CAISO market that needs to be investigated in order for DR loads to integrate better in the wholesale market. Moreover, the integration of intermittent renewable resources and future CAISO market enhancements and product offerings will make the road to accomplishing the key objectives of delivering meaningful DR into the wholesale market quite challenging.

PG&E will propose a future DR program that would enable retail participants to bid their DR loads in the CAISO AS market. This future program will be built around AutoDR, which this PL pilot has shown to provide reliable communication and mimics a power producer's AGC. Consequently, PG&E will use the future program to hone its efforts on areas not quite strongly addressed in the pilot (for example, marketing initiatives, a dynamic incentive and penalty structure, and more load controls to gain a greater level of ease on load reduction and avert risk).

9. APPENDIX

9.1 Appendix A

Pre-Analysis of Participants in 2008 Auto-DR programs for

The Participating Load Pilot -- February 13, 2009

The goal of the document is to describe the analysis of the 2008 Auto-DR participants to provide guidance in the PLP site selection.

1. **Criteria**

Sites best suited for this study should have:

- Low load variability
- Low shed variability
- Minimum of 10 kW demand reduction.
- Flatter load profiles
- Both fast (lighting) and slow (HVAC) response

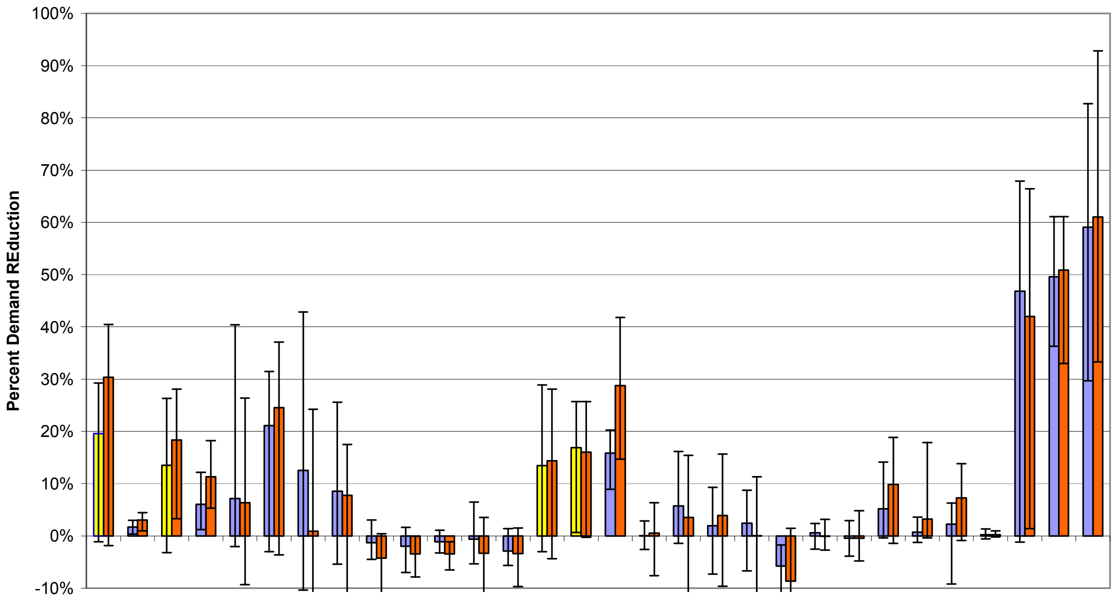
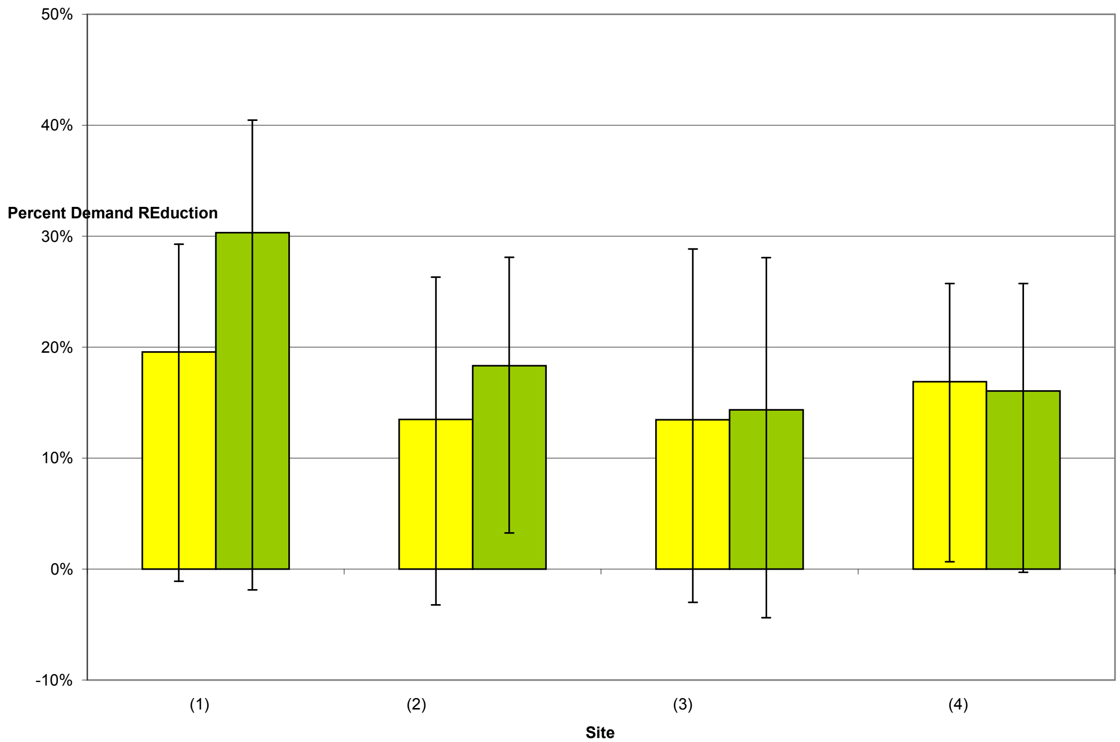


Figure above shows the average load drop (bars) over 11 CPP events between noon and 12:15pm and noon and 12:30pm as well as minimum and maximum load shed (lines over the bars) from all the events.

- First 15 minutes - the load drop within the first 15 minutes should be positive indicating a demand reduction between noon and the next 15 and 30 min. periods.
- Second 15 minutes - if the demand reduction in the 30 min. period is greater than the first 15 min. period, it indicates that demand continue to drop which indicates a slower response time.
- Size of reduction - The demand reduction needs to exceed the standard deviation so as to consider the sheds "visible".

- Participation - Finally, we have to consider that while the averages are above the standard deviation, the sites for recommended selection must have persistent participation, delivering same or similar shed for each event.

Figure below show the four sites (Local Office (1), Local Government Office (2), Retail Store (3) and Retail Store (4)) that meet the initial criteria.



As seen from the min-max lines on top of the average bars, there is still a lot of variability in sheds. Table shows each event and demand reduction by percentage of total for the first 15 and 30 minutes. Local Office (1) and Retail Store (4) reduced their demand less than 10% only one out of eleven days. Local Government Office (2) totally missed the 10% target only once within the 30 min period. Retail Store (3) missed the 10% mark three times but has participated with visible sheds (sheds within the standard deviation) two out of three times. Since there are no trend logs available from these sites, we don't know what actually happened on those days. Shed variability tend to increase when building loads are sensitive to occupancy and outside air temperatures. Unfortunately, all four buildings are weather sensitive. There may be additional sensitivity in Retail Store (3) & (4) buildings towards occupancy which LBNL has not considered before.

2. **Strategies:**

- **Local Office (1)**: Office building. Temp adjustment, recently housing the DR lighting study so some additional response from lighting systems.
- **Local Government Office (2)**: Office building. Temp adjustment only
- **Retail Store (3) and (4)**: Retail. RTU shut down and temperature adjustment.

3. **Load Variability:**

We still need to understand the "predictability" of the loads too be able to accurately forecast loads for the next 24 hours. A good indicator is load variability calculations. The lower the load variability, the more predictable the loads may be. We define load variability as the deviation of the load in each hour from an average calculated over all days excluding DR days and holidays. The deviation is defined as the average value of the difference between the load in a given hour and the sample average load for that hour. This is converted to a percent deviation by dividing by the sample average. This variability coefficient can take on any value greater than zero, with low values indicating low variability. Tables below shows load variability of these sites. All four sites show low load variability during summer months between noon and 6 pm.

Retail-Store (3)

Month	0:00	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	Average
May	0.13	0.14	0.14	0.13	0.10	0.10	0.10	0.21	0.22	0.14	0.16	0.18	0.18	0.09	0.13	0.13	0.09	0.09	0.09	0.14	0.15	0.12	0.12	0.12	0.13
Jun	0.04	0.05	0.04	0.03	0.03	0.02	0.01	0.06	0.11	0.08	0.12	0.14	0.14	0.14	0.13	0.12	0.10	0.10	0.10	0.11	0.11	0.11	0.07	0.03	0.08
Jul	0.04	0.05	0.04	0.03	0.02	0.02	0.05	0.07	0.08	0.08	0.10	0.10	0.10	0.07	0.06	0.05	0.05	0.05	0.04	0.06	0.07	0.05	0.07	0.08	0.06
Aug	0.13	0.15	0.15	0.14	0.10	0.10	0.09	0.11	0.09	0.09	0.10	0.11	0.11	0.09	0.08	0.07	0.09	0.08	0.08	0.09	0.10	0.08	0.09	0.12	0.10
Sep	0.02	0.02	0.02	0.02	0.02	0.09	0.10	0.14	0.11	0.06	0.06	0.07	0.09	0.08	0.07	0.07	0.08	0.08	0.07	0.08	0.08	0.07	0.06	0.02	0.07
Oct	0.07	0.05	0.05	0.07	0.03	0.04	0.05	0.10	0.09	0.04	0.06	0.07	0.08	0.09	0.08	0.08	0.08	0.08	0.07	0.07	0.08	0.22	0.11	0.07	0.08
Summer	0.09	0.10	0.10	0.10	0.07	0.08	0.08	0.14	0.16	0.09	0.11	0.12	0.12	0.10	0.10	0.10	0.09	0.09	0.08	0.10	0.10	0.13	0.10	0.09	0.10

Retail-Store (4)

Month	0:00	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	Average
May	0.01	0.01	0.01	0.03	0.02	0.02	0.04	0.10	0.20	0.19	0.08	0.08	0.09	0.06	0.07	0.08	0.08	0.09	0.09	0.12	0.11	0.09	0.10	0.02	0.08
Jun	0.02	0.05	0.03	0.03	0.03	0.03	0.03	0.06	0.20	0.20	0.10	0.09	0.08	0.08	0.08	0.09	0.09	0.10	0.10	0.11	0.10	0.09	0.14	0.06	0.08
Jul	0.07	0.05	0.07	0.06	0.13	0.13	0.22	0.13	0.17	0.18	0.08	0.07	0.07	0.06	0.06	0.06	0.05	0.05	0.05	0.06	0.05	0.06	0.06	0.01	0.08
Aug	0.02	0.02	0.05	0.04	0.04	0.05	0.04	0.06	0.17	0.19	0.06	0.06	0.05	0.08	0.06	0.07	0.06	0.05	0.05	0.06	0.05	0.06	0.06	0.02	0.06
Sep	0.02	0.03	0.03	0.05	0.04	0.04	0.03	0.10	0.19	0.19	0.09	0.07	0.07	0.07	0.07	0.07	0.07	0.08	0.08	0.09	0.08	0.08	0.09	0.02	0.07
Oct	0.02	0.04	0.04	0.04	0.04	0.03	0.10	0.18	0.19	0.20	0.06	0.06	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.07	0.29	0.05	0.08
Summer	0.03	0.04	0.04	0.05	0.06	0.07	0.10	0.12	0.19	0.19	0.09	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.09	0.08	0.08	0.17	0.04	0.09

Local Office (1)

Month	0:00	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	Average
May	0.10	0.10	0.08	0.10	0.09	0.12	0.12	0.10	0.11	0.12	0.12	0.13	0.14	0.09	0.13	0.13	0.13	0.14	0.15	0.15	0.12	0.12	0.11	0.10	0.12
Jun	0.09	0.08	0.07	0.08	0.07	0.10	0.08	0.08	0.09	0.10	0.12	0.12	0.14	0.15	0.15	0.17	0.18	0.19	0.19	0.18	0.17	0.14	0.10	0.11	0.12
Jul	0.10	0.10	0.09	0.10	0.11	0.15	0.14	0.11	0.13	0.12	0.12	0.13	0.15	0.12	0.13	0.12	0.12	0.10	0.11	0.11	0.11	0.13	0.11	0.10	0.12
Aug	0.08	0.06	0.06	0.06	0.06	0.12	0.12	0.09	0.08	0.10	0.10	0.10	0.11	0.12	0.11	0.10	0.12	0.12	0.14	0.13	0.12	0.13	0.09	0.05	0.10
Sep	0.11	0.10	0.10	0.10	0.11	0.09	0.07	0.07	0.07	0.07	0.08	0.08	0.10	0.11	0.11	0.11	0.12	0.13	0.14	0.15	0.11	0.10	0.14	0.13	0.10
Oct	0.16	0.16	0.15	0.16	0.15	0.14	0.11	0.09	0.10	0.11	0.09	0.09	0.10	0.11	0.10	0.12	0.13	0.14	0.12	0.11	0.11	0.14	0.16	0.16	0.13
Summer	0.12	0.12	0.11	0.12	0.12	0.12	0.11	0.11	0.10	0.11	0.11	0.12	0.13	0.13	0.14	0.15	0.15	0.16	0.16	0.15	0.13	0.14	0.13	0.12	0.13

Local Government Office (2)

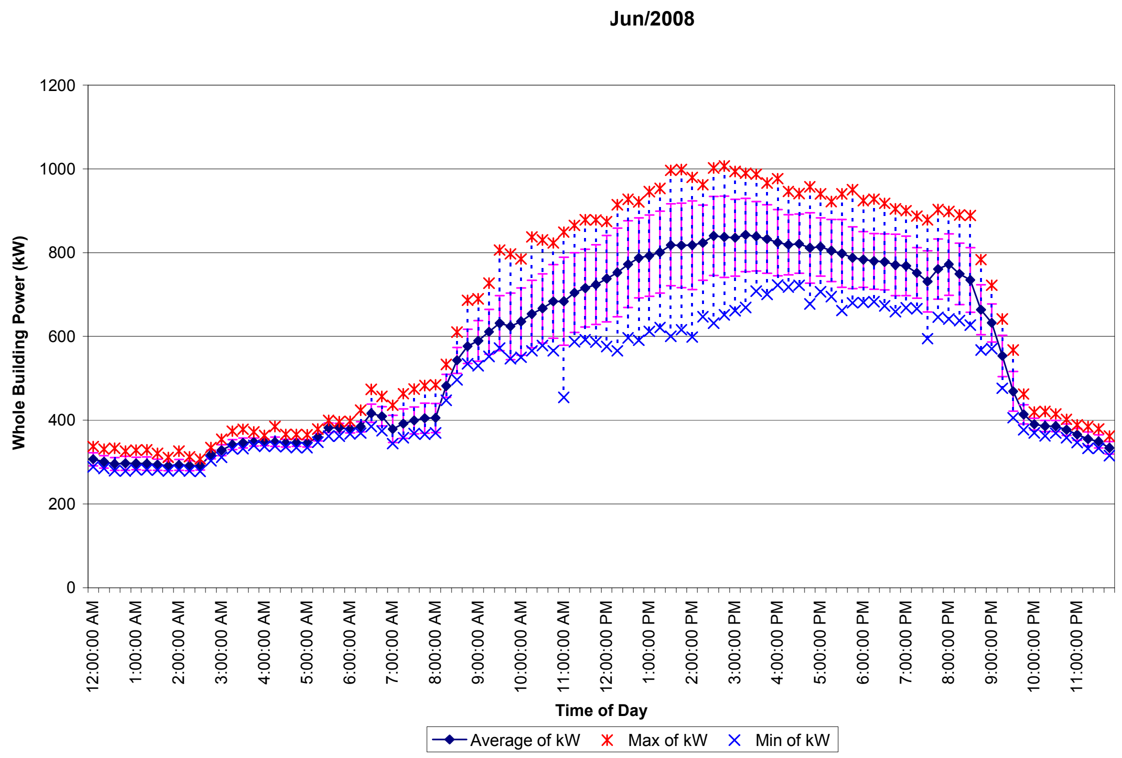
Month	0:00	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	Average
May	0.08	0.09	0.08	0.06	0.07	0.07	0.33	0.34	0.16	0.22	0.21	0.18	0.15	0.10	0.12	0.13	0.12	0.13	0.15	0.16	0.16	0.13	0.10	0.08	0.14
Jun	0.01	0.01	0.01	0.01	0.01	0.02	0.27	0.25	0.22	0.18	0.14	0.12	0.11	0.10	0.09	0.10	0.10	0.10	0.12	0.14	0.04	0.03	0.02	0.02	0.09
Jul	0.02	0.02	0.02	0.01	0.02	0.02	0.36	0.45	0.25	0.24	0.19	0.15	0.14	0.10	0.11	0.11	0.07	0.08	0.09	0.12	0.05	0.04	0.03	0.02	0.11
Aug	0.06	0.06	0.06	0.06	0.06	0.06	0.34	0.33	0.19	0.17	0.13	0.11	0.10	0.09	0.09	0.08	0.10	0.09	0.09	0.12	0.06	0.06	0.06	0.04	0.11
Sep	0.05	0.02	0.02	0.01	0.01	0.02	0.29	0.34	0.19	0.18	0.18	0.13	0.09	0.10	0.09	0.11	0.12	0.14	0.15	0.17	0.11	0.15	0.08	0.07	0.12
Oct	0.04	0.04	0.02	0.03	0.02	0.16	0.17	0.14	0.06	0.07	0.15	0.13	0.12	0.12	0.13	0.13	0.14	0.17	0.29	0.16	0.11	0.08	0.07	0.06	0.11
Summer	0.05	0.06	0.05	0.04	0.05	0.08	0.30	0.34	0.20	0.21	0.18	0.15	0.13	0.11	0.12	0.12	0.12	0.14	0.19	0.16	0.14	0.11	0.07	0.06	0.13

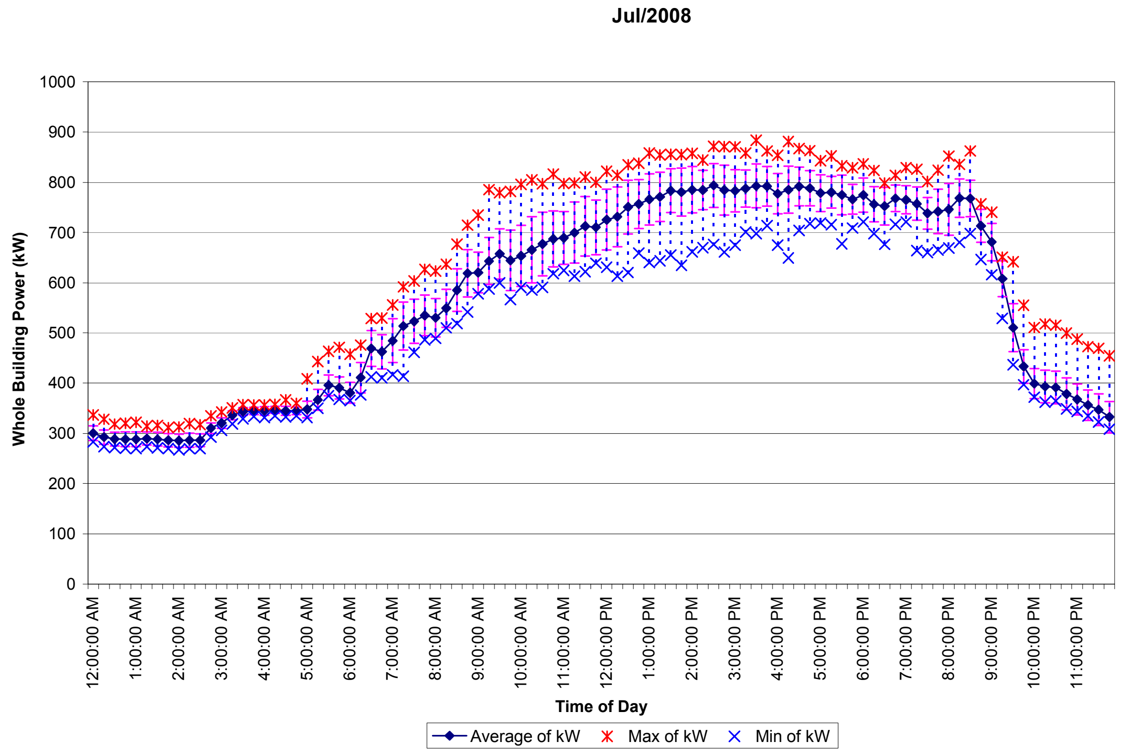
Conclusion:

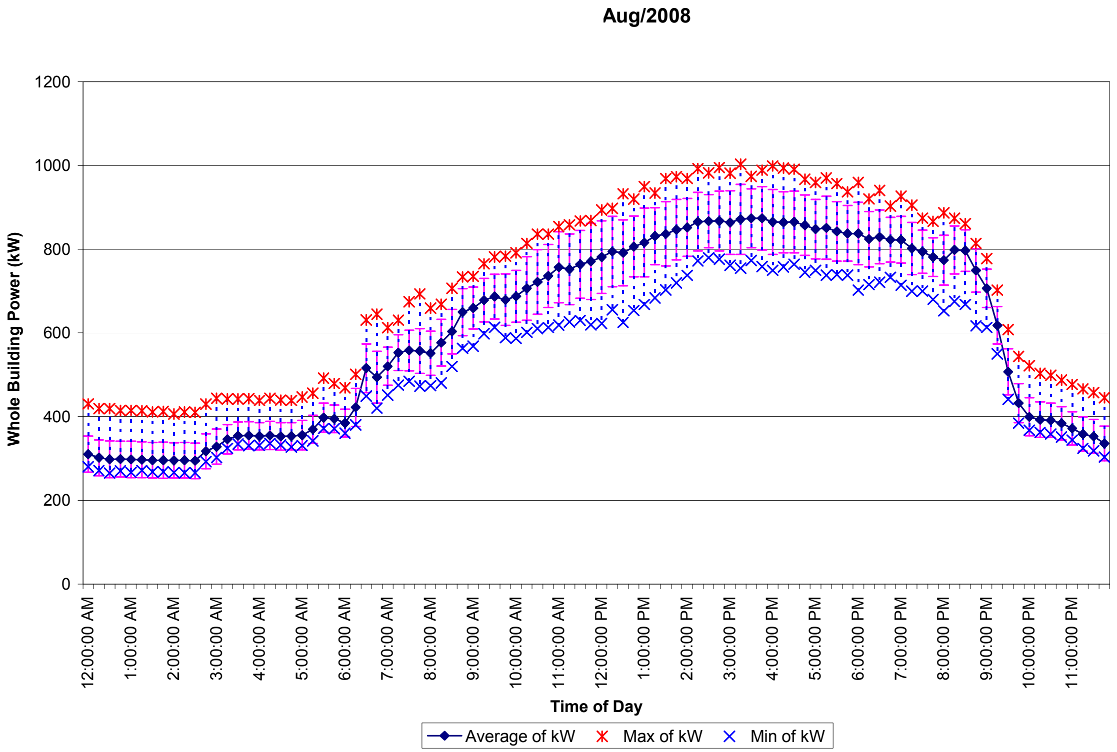
Based on the above methodology, the Auto-DR participants that are most appropriate for the participating load pilot are Retail Store (3), Retail Store (4), Local Office (1) and a Local Government Office (2). These sites are most appropriate because they have low load variability, and consistent automated response to DR events in 2008. All of the sites have participated in the program at least two years. Local Office (1) has been a participant since 2005 and Local Government Office (2) since 2004. LBNL has historical meter data and understand trending capabilities for all four sites. PG&E should discuss the PLP timeline with the customer to understand whether there are any retrofit, controls, occupancy or other changes planned that may modify the facilities' loads during the project timeline.

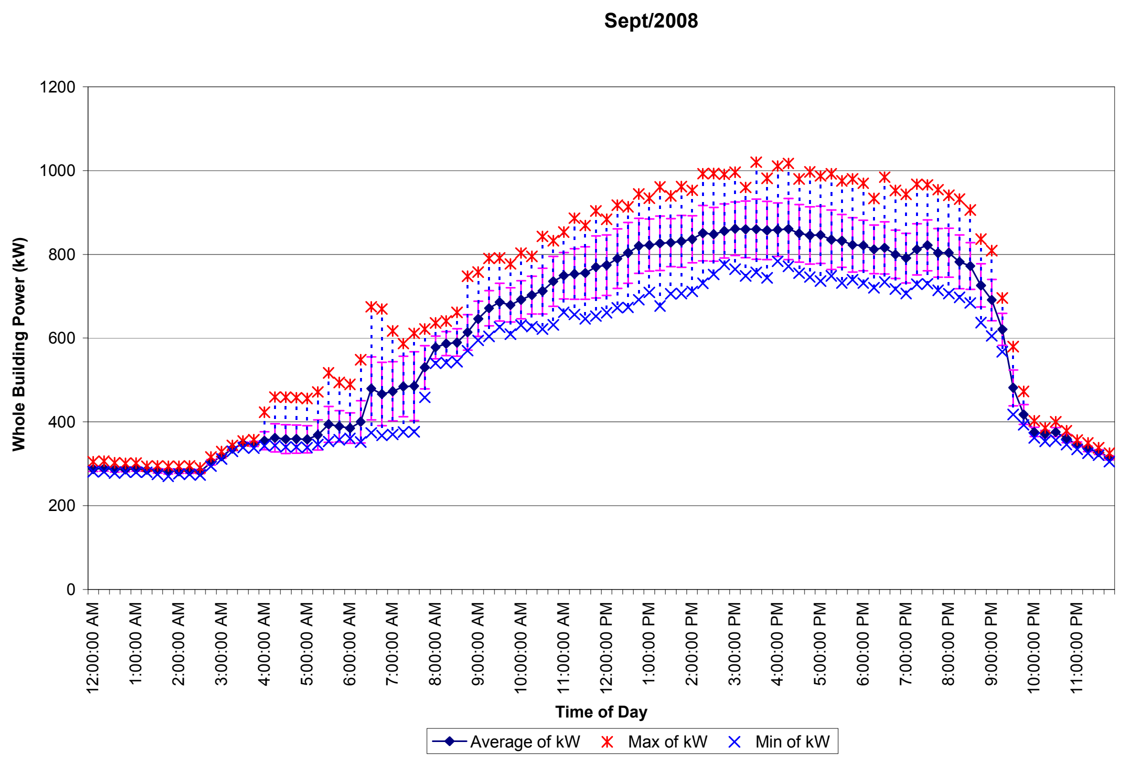
Average Monthly Load Profiles with 15 minute Minimum, Maximum, Average and Standard Deviation.

Retail Store (3)

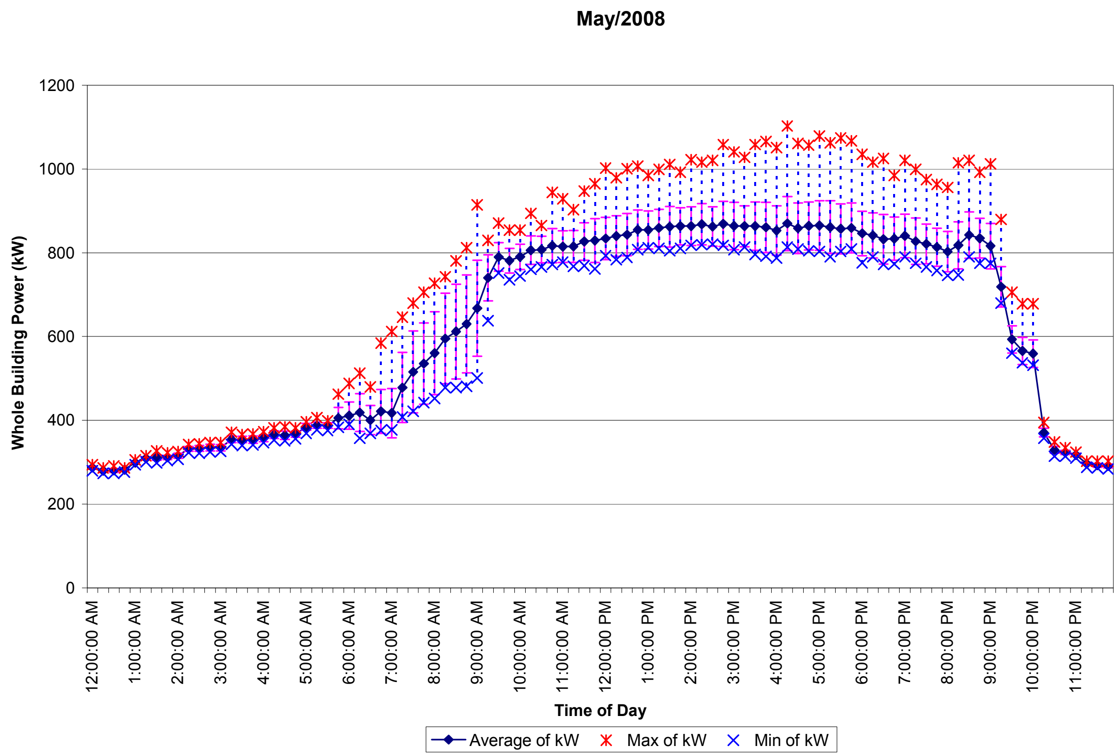


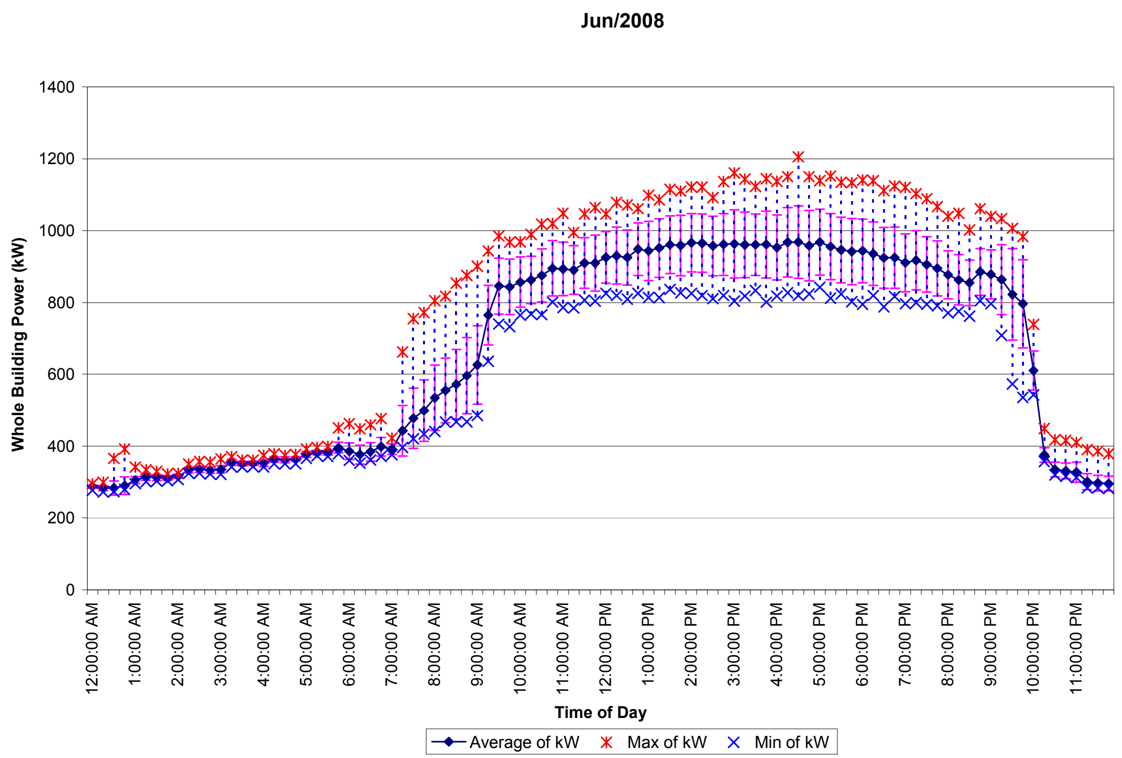

Jul/2008
Whole Building Power (kW)
1000
900
800
700
600
500
400
300
200
100
0
12:00:00 AM
1:00:00 AM
2:00:00 AM
3:00:00 AM
4:00:00 AM
5:00:00 AM
6:00:00 AM
7:00:00 AM
8:00:00 AM
9:00:00 AM
10:00:00 AM
11:00:00 AM
12:00:00 PM
1:00:00 PM
2:00:00 PM
3:00:00 PM
4:00:00 PM
5:00:00 PM
6:00:00 PM
7:00:00 PM
8:00:00 PM
9:00:00 PM
10:00:00 PM
11:00:00 PM
Time of Day
Average of kW
Max of kW
Min of kW

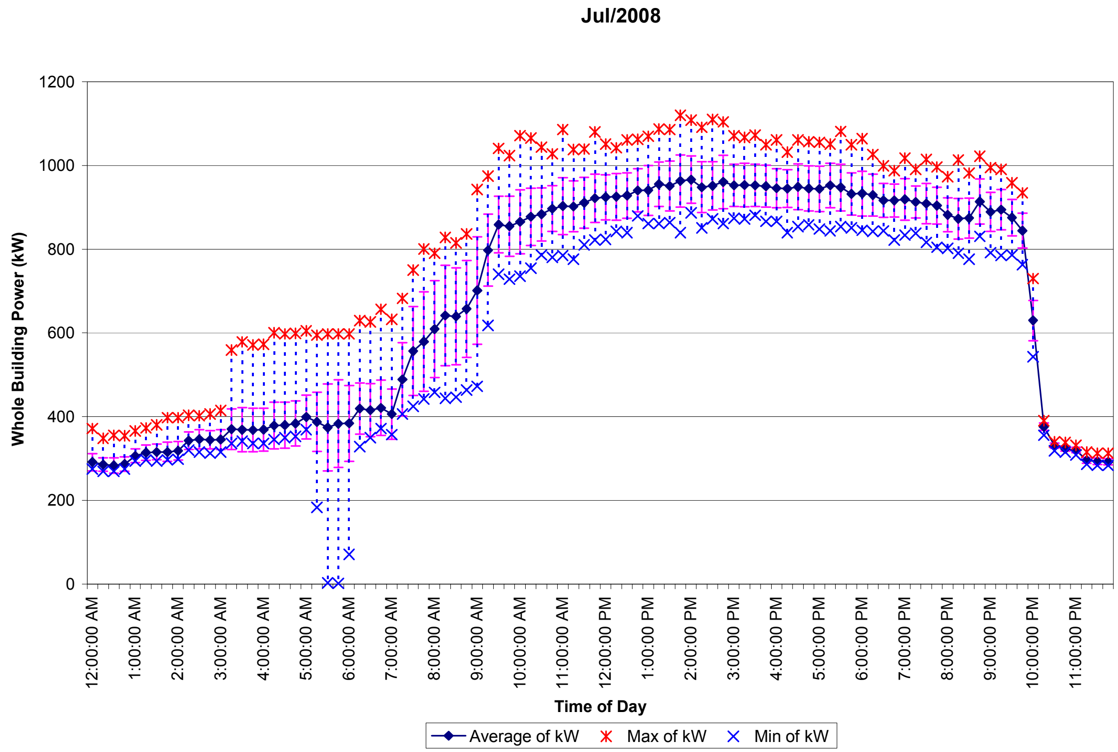

Aug/2008
1200
1000
800
600
400
200
0
Whole Building Power (kW)
12:00:00 AM
1:00:00 AM
2:00:00 AM
3:00:00 AM
4:00:00 AM
5:00:00 AM
6:00:00 AM
7:00:00 AM
8:00:00 AM
9:00:00 AM
10:00:00 AM
11:00:00 AM
12:00:00 PM
1:00:00 PM
2:00:00 PM
3:00:00 PM
4:00:00 PM
5:00:00 PM
6:00:00 PM
7:00:00 PM
8:00:00 PM
9:00:00 PM
10:00:00 PM
11:00:00 PM
Time of Day
Average of kW
Max of kW
Min of kW

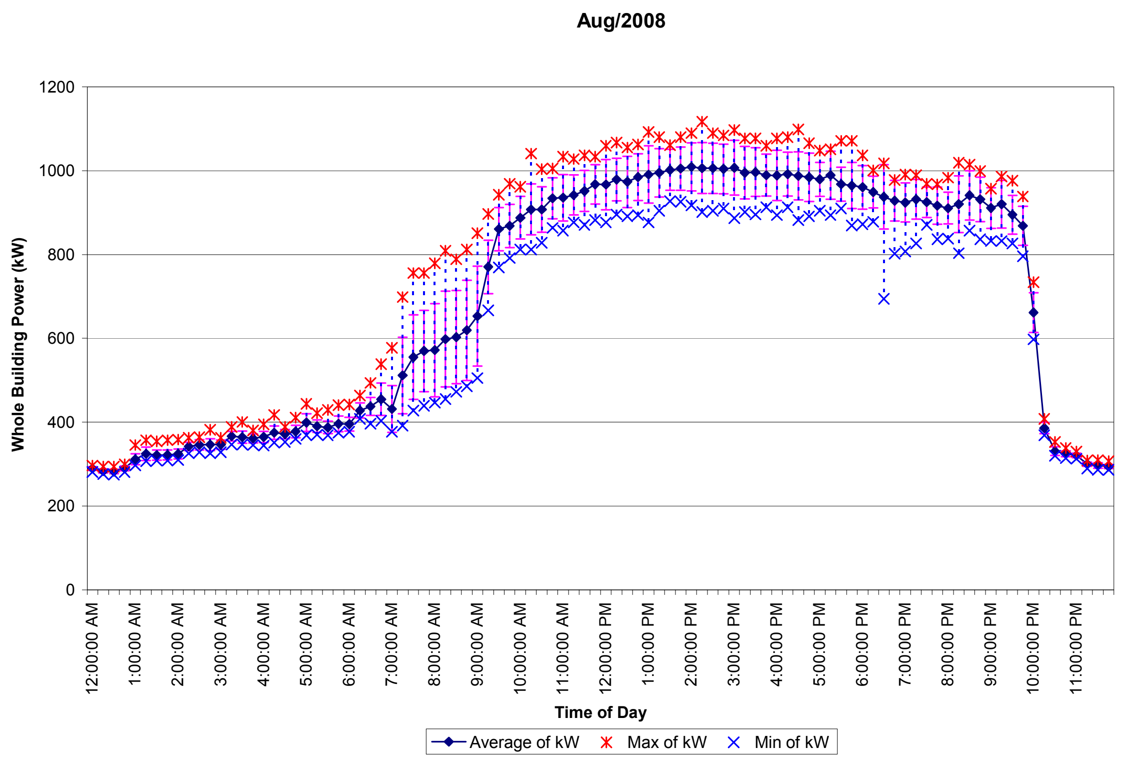

Sept/2008
Whole Building Power (kW)
0
200
400
600
800
1000
1200
12:00:00 AM
1:00:00 AM
2:00:00 AM
3:00:00 AM
4:00:00 AM
5:00:00 AM
6:00:00 AM
7:00:00 AM
8:00:00 AM
9:00:00 AM
10:00:00 AM
11:00:00 AM
12:00:00 PM
1:00:00 PM
2:00:00 PM
3:00:00 PM
4:00:00 PM
5:00:00 PM
6:00:00 PM
7:00:00 PM
8:00:00 PM
9:00:00 PM
10:00:00 PM
11:00:00 PM
Time of Day
Average of kW
Max of kW
Min of kW

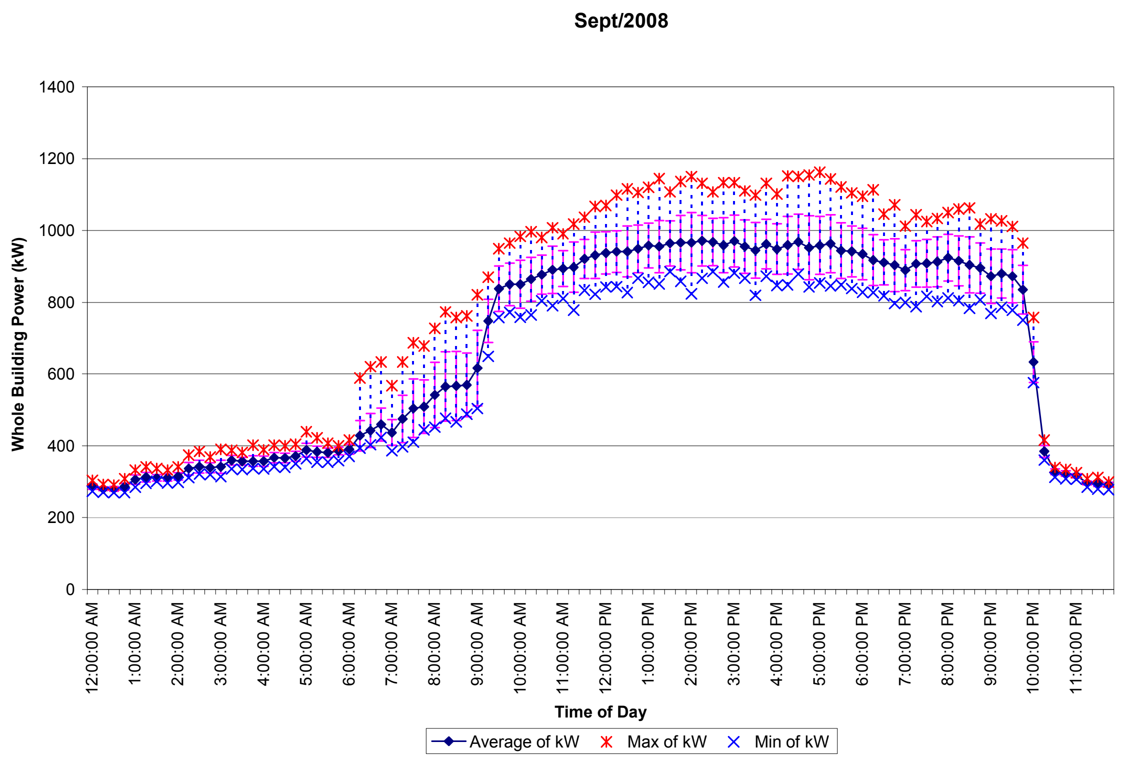
Retail Store (4)

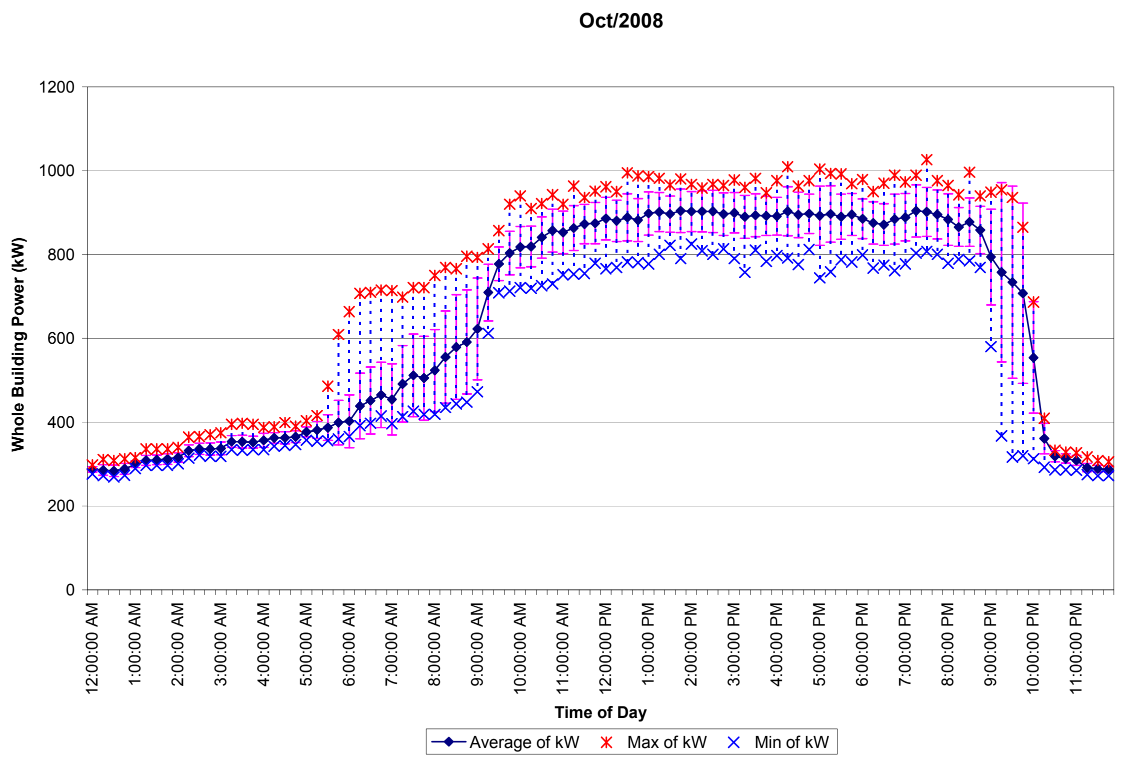



Jun/2008
1400
1200
1000
800
600
400
200
0
Whole Building Power (kW)
12:00:00 AM
1:00:00 AM
2:00:00 AM
3:00:00 AM
4:00:00 AM
5:00:00 AM
6:00:00 AM
7:00:00 AM
8:00:00 AM
9:00:00 AM
10:00:00 AM
11:00:00 AM
12:00:00 PM
1:00:00 PM
2:00:00 PM
3:00:00 PM
4:00:00 PM
5:00:00 PM
6:00:00 PM
7:00:00 PM
8:00:00 PM
9:00:00 PM
10:00:00 PM
11:00:00 PM
Time of Day
Average of kW
Max of kW
Min of kW

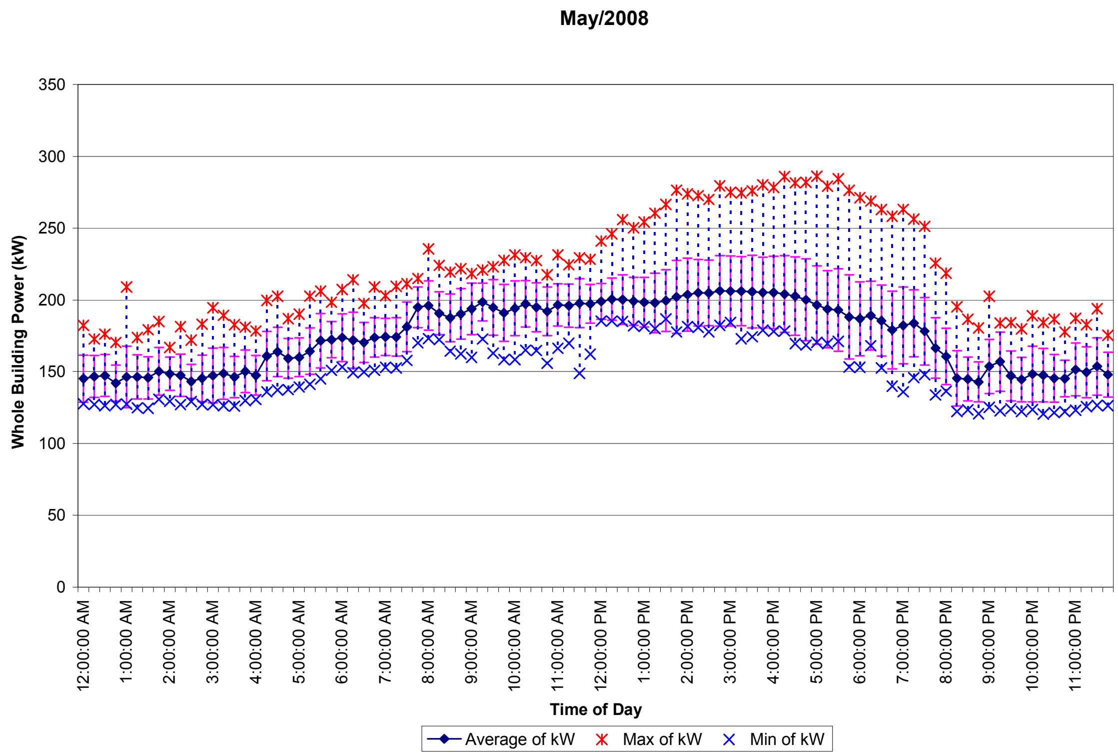

Jul/2008
Whole Building Power (kW)
1200
1000
800
600
400
200
0
12:00:00 AM
1:00:00 AM
2:00:00 AM
3:00:00 AM
4:00:00 AM
5:00:00 AM
6:00:00 AM
7:00:00 AM
8:00:00 AM
9:00:00 AM
10:00:00 AM
11:00:00 AM
12:00:00 PM
1:00:00 PM
2:00:00 PM
3:00:00 PM
4:00:00 PM
5:00:00 PM
6:00:00 PM
7:00:00 PM
8:00:00 PM
9:00:00 PM
10:00:00 PM
11:00:00 PM
Time of Day
Average of kW
Max of kW
Min of kW

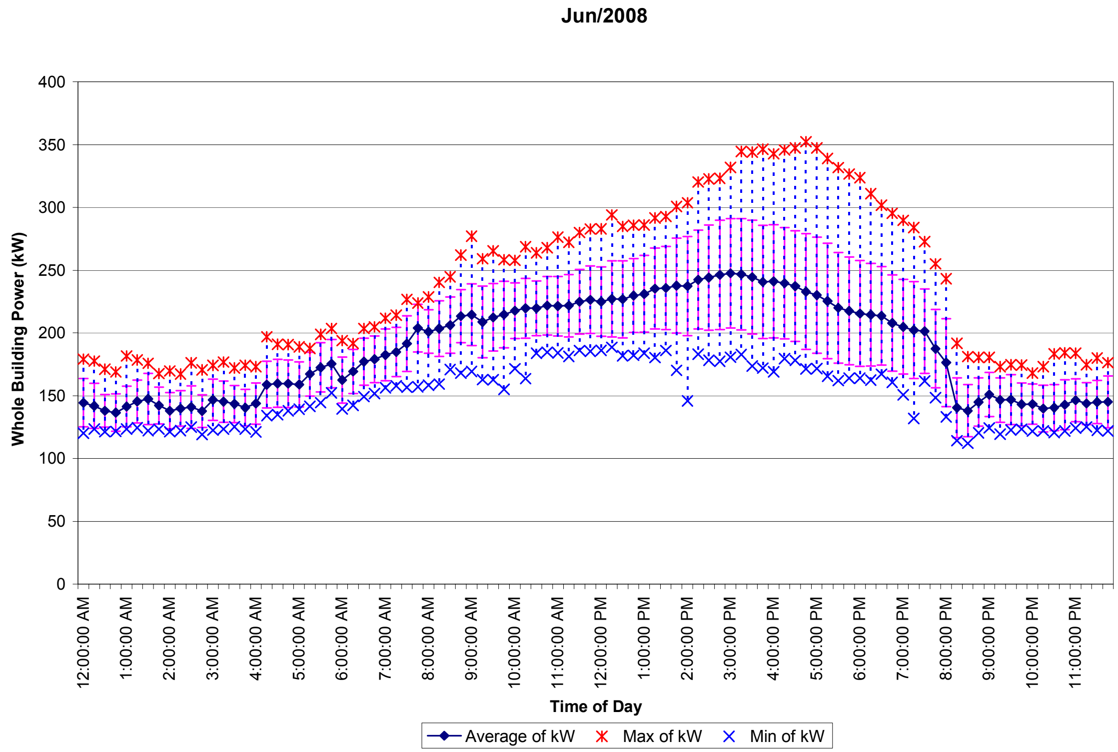

Aug/2008
1200
1000
800
600
400
200
0
Whole Building Power (kW)
12:00:00 AM
1:00:00 AM
2:00:00 AM
3:00:00 AM
4:00:00 AM
5:00:00 AM
6:00:00 AM
7:00:00 AM
8:00:00 AM
9:00:00 AM
10:00:00 AM
11:00:00 AM
12:00:00 PM
1:00:00 PM
2:00:00 PM
3:00:00 PM
4:00:00 PM
5:00:00 PM
6:00:00 PM
7:00:00 PM
8:00:00 PM
9:00:00 PM
10:00:00 PM
11:00:00 PM
Time of Day
Average of kW
Max of kW
Min of kW

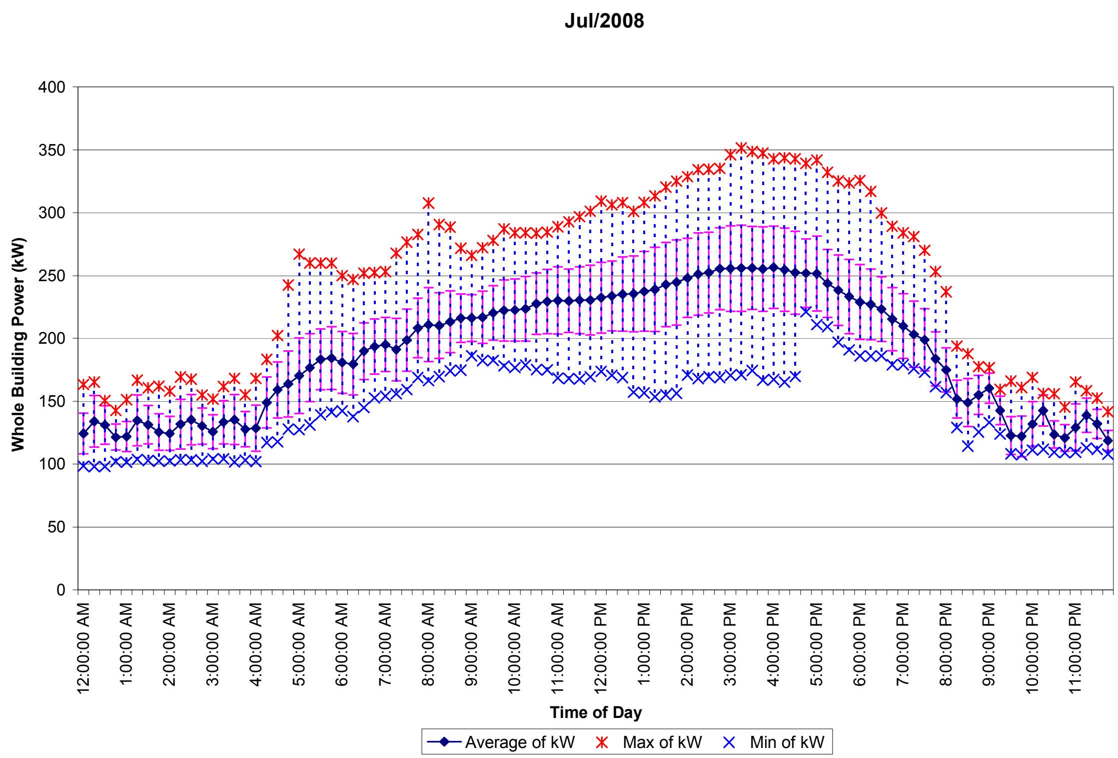

Sept/2008
Whole Building Power (kW)
0
200
400
600
800
1000
1200
1400
12:00:00 AM
1:00:00 AM
2:00:00 AM
3:00:00 AM
4:00:00 AM
5:00:00 AM
6:00:00 AM
7:00:00 AM
8:00:00 AM
9:00:00 AM
10:00:00 AM
11:00:00 AM
12:00:00 PM
1:00:00 PM
2:00:00 PM
3:00:00 PM
4:00:00 PM
5:00:00 PM
6:00:00 PM
7:00:00 PM
8:00:00 PM
9:00:00 PM
10:00:00 PM
11:00:00 PM
Time of Day
Average of kW
Max of kW
Min of kW

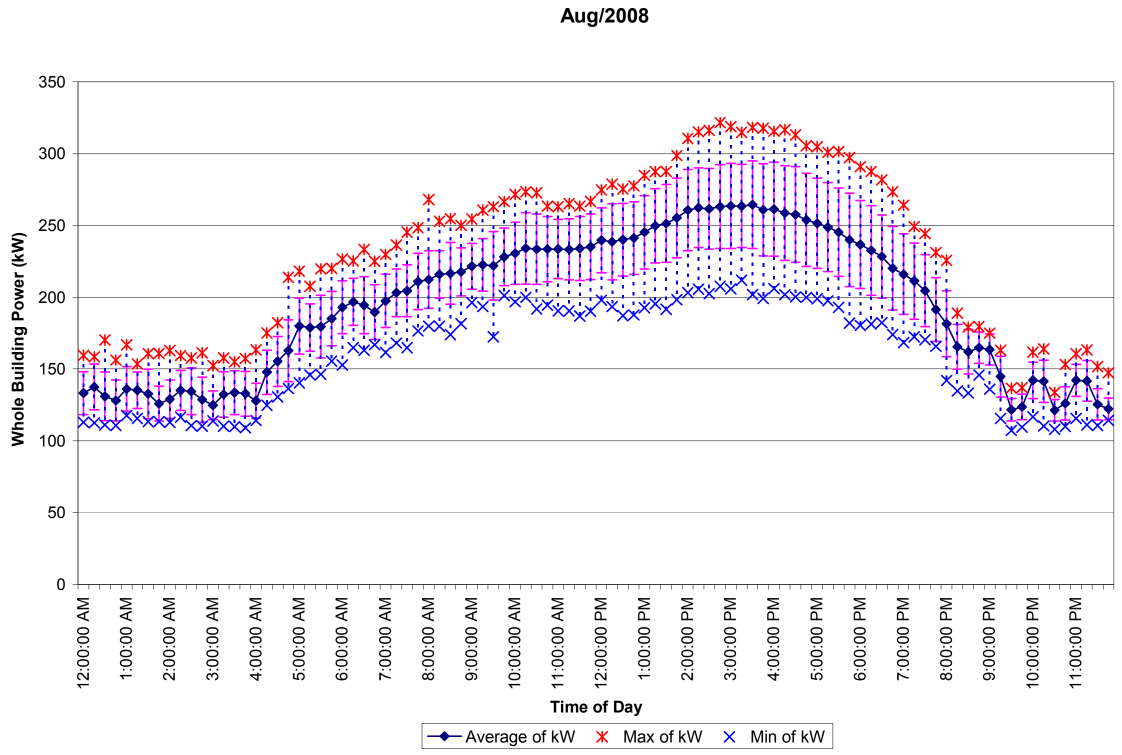

Oct/2008
Whole Building Power (kW)
1200
1000
800
600
400
200
0
12:00:00 AM
1:00:00 AM
2:00:00 AM
3:00:00 AM
4:00:00 AM
5:00:00 AM
6:00:00 AM
7:00:00 AM
8:00:00 AM
9:00:00 AM
10:00:00 AM
11:00:00 AM
12:00:00 PM
1:00:00 PM
2:00:00 PM
3:00:00 PM
4:00:00 PM
5:00:00 PM
6:00:00 PM
7:00:00 PM
8:00:00 PM
9:00:00 PM
10:00:00 PM
11:00:00 PM
Time of Day
Average of kW
Max of kW
Min of kW

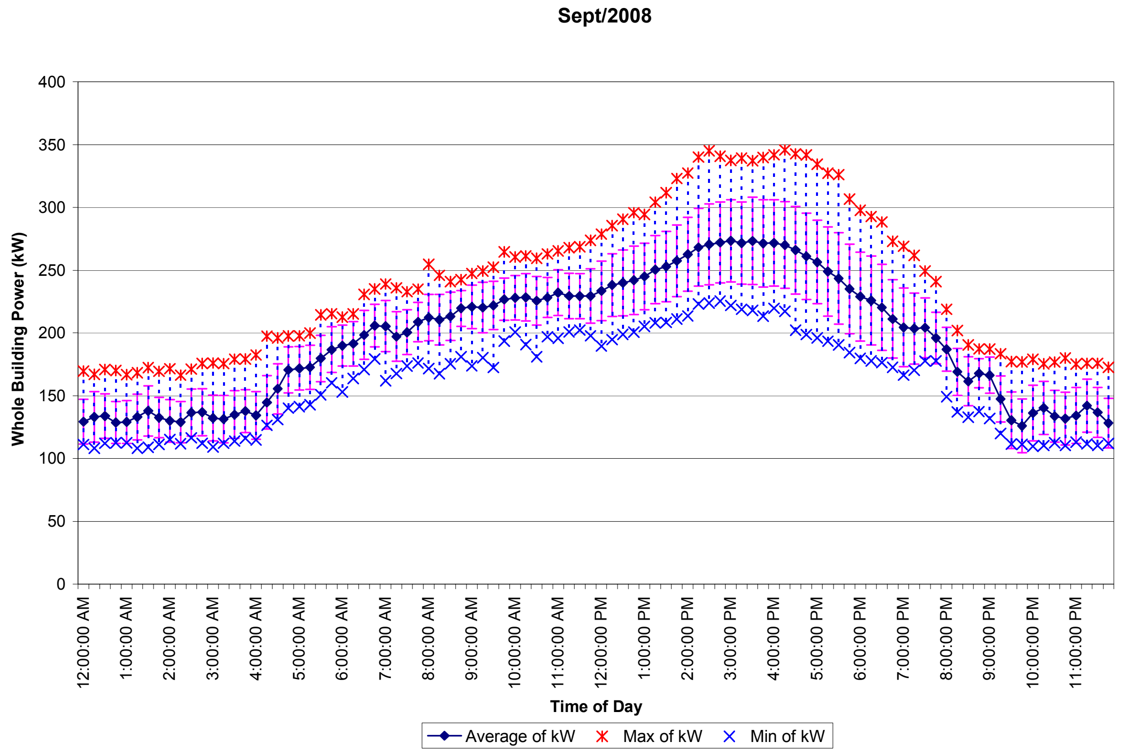
Local Office (1)

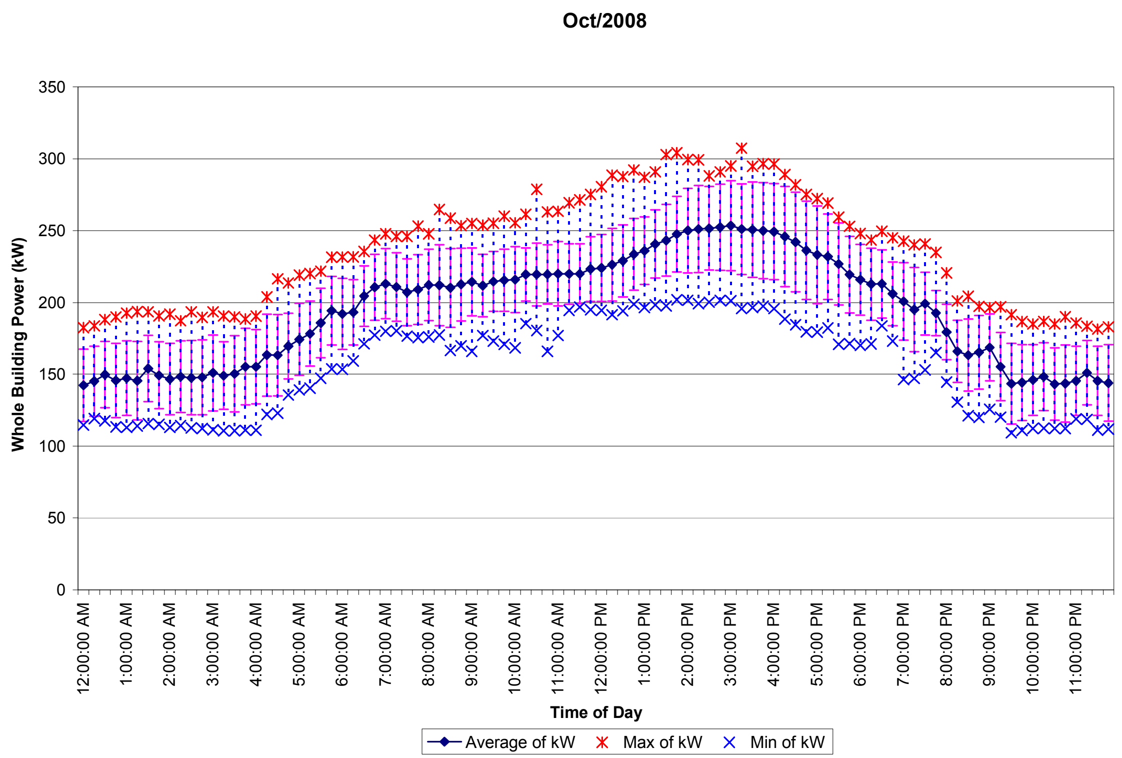


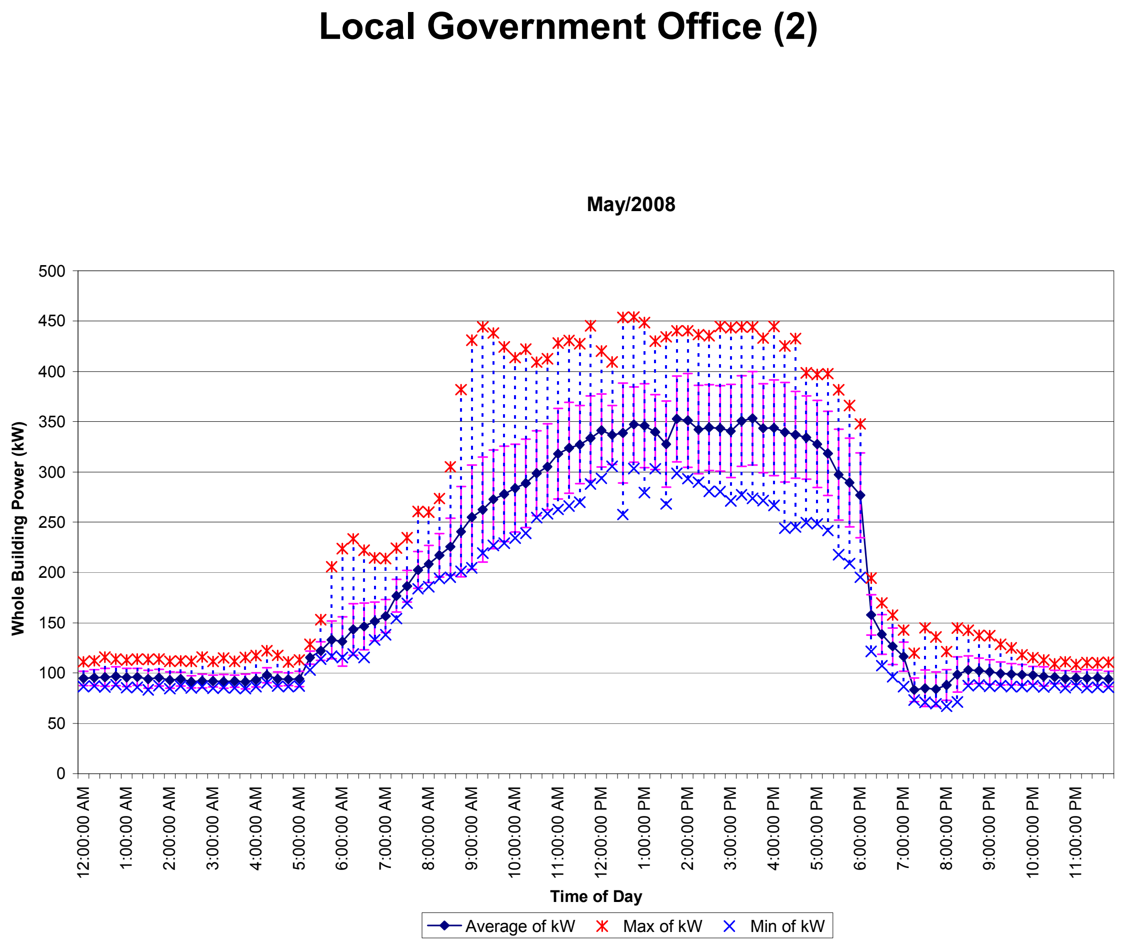

Jun/2008
Whole Building Power (kW)
400
350
300
250
200
150
100
50
0
12:00:00 AM
1:00:00 AM
2:00:00 AM
3:00:00 AM
4:00:00 AM
5:00:00 AM
6:00:00 AM
7:00:00 AM
8:00:00 AM
9:00:00 AM
10:00:00 AM
11:00:00 AM
12:00:00 PM
1:00:00 PM
2:00:00 PM
3:00:00 PM
4:00:00 PM
5:00:00 PM
6:00:00 PM
7:00:00 PM
8:00:00 PM
9:00:00 PM
10:00:00 PM
11:00:00 PM
Time of Day
Average of kW
Max of kW
Min of kW

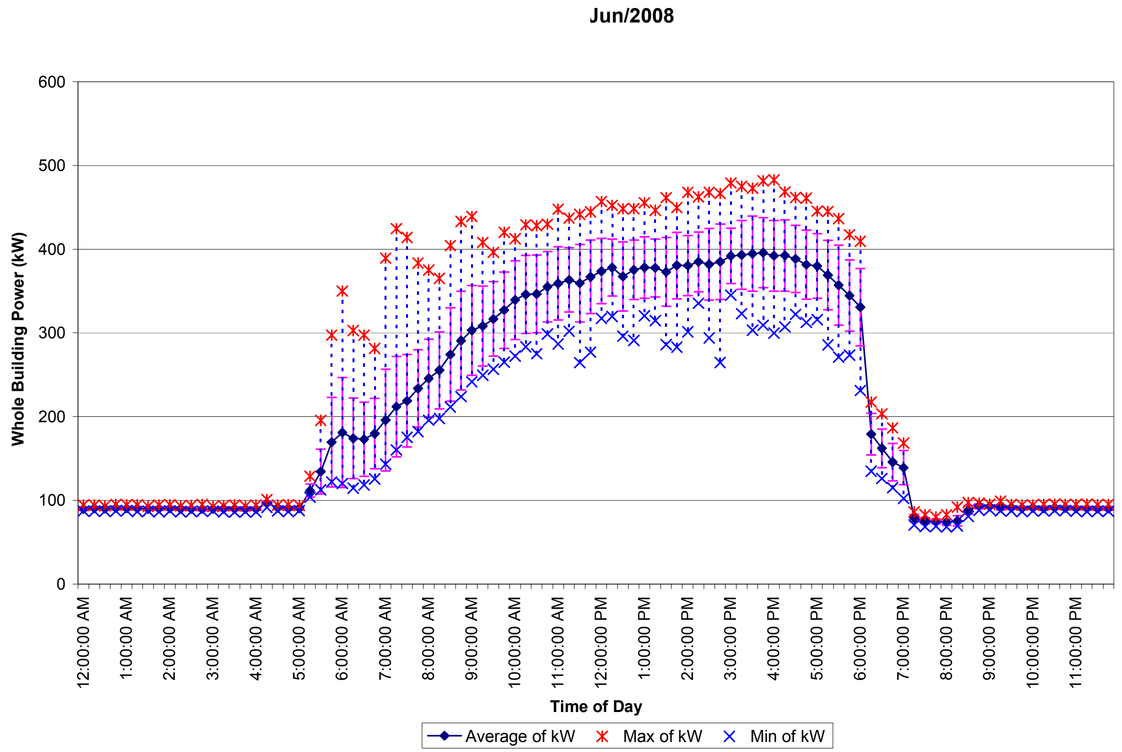

Jul/2008
Whole Building Power (kW)
400
350
300
250
200
150
100
50
0
12:00:00 AM
1:00:00 AM
2:00:00 AM
3:00:00 AM
4:00:00 AM
5:00:00 AM
6:00:00 AM
7:00:00 AM
8:00:00 AM
9:00:00 AM
10:00:00 AM
11:00:00 AM
12:00:00 PM
1:00:00 PM
2:00:00 PM
3:00:00 PM
4:00:00 PM
5:00:00 PM
6:00:00 PM
7:00:00 PM
8:00:00 PM
9:00:00 PM
10:00:00 PM
11:00:00 PM
Time of Day
Average of kW
Max of kW
Min of kW

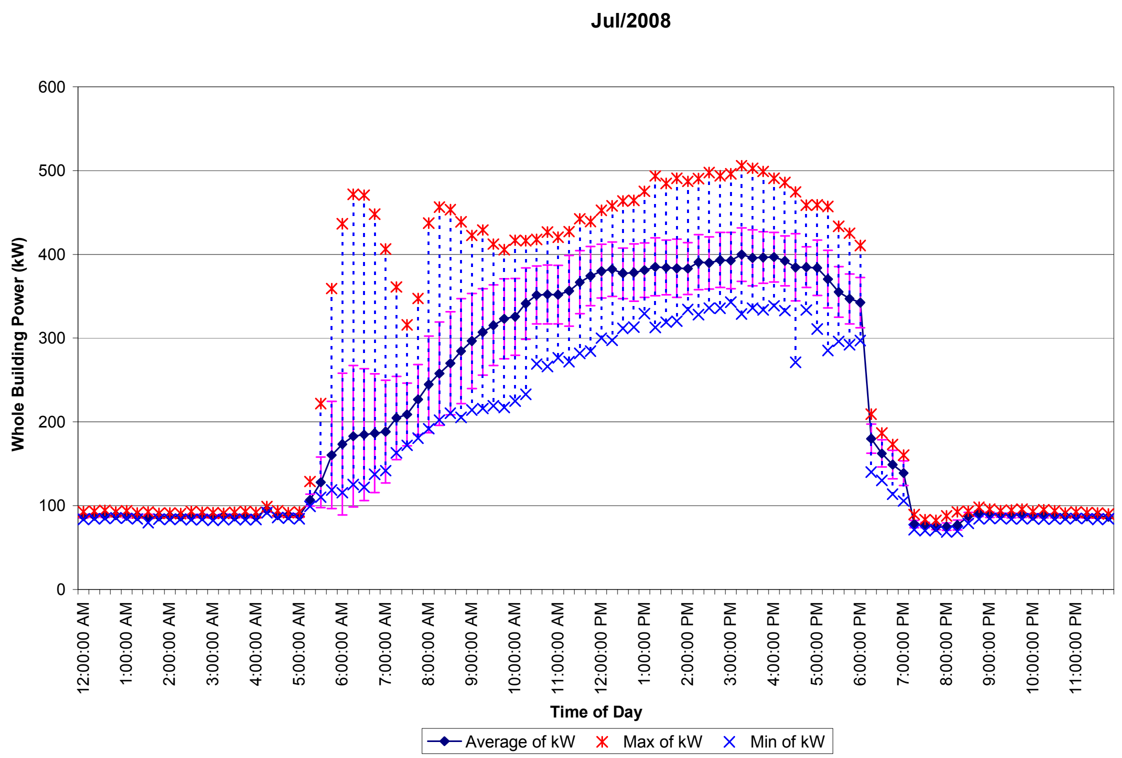

Aug/2008
Whole Building Power (kW)
350
300
250
200
150
100
50
0
12:00:00 AM
1:00:00 AM
2:00:00 AM
3:00:00 AM
4:00:00 AM
5:00:00 AM
6:00:00 AM
7:00:00 AM
8:00:00 AM
9:00:00 AM
10:00:00 AM
11:00:00 AM
12:00:00 PM
1:00:00 PM
2:00:00 PM
3:00:00 PM
4:00:00 PM
5:00:00 PM
6:00:00 PM
7:00:00 PM
8:00:00 PM
9:00:00 PM
10:00:00 PM
11:00:00 PM
Time of Day
Average of kW
Max of kW
Min of kW

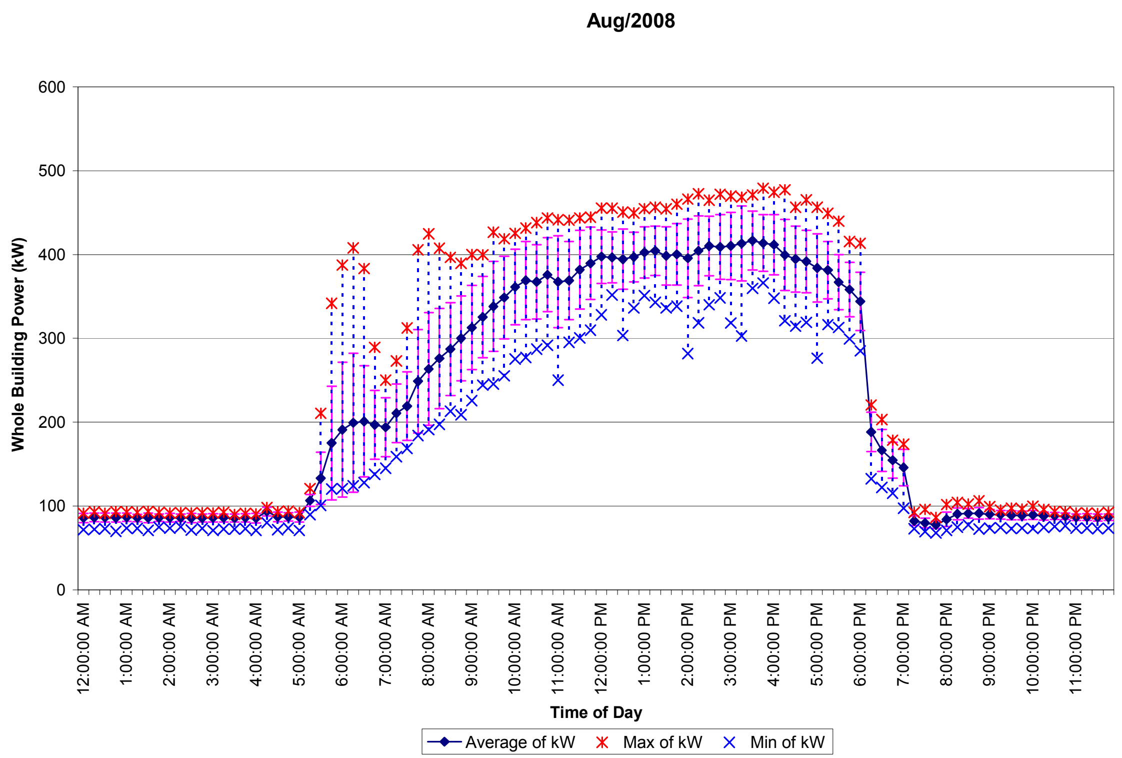

Sept/2008
Whole Building Power (kW)
400
350
300
250
200
150
100
50
0
12:00:00 AM
1:00:00 AM
2:00:00 AM
3:00:00 AM
4:00:00 AM
5:00:00 AM
6:00:00 AM
7:00:00 AM
8:00:00 AM
9:00:00 AM
10:00:00 AM
11:00:00 AM
12:00:00 PM
1:00:00 PM
2:00:00 PM
3:00:00 PM
4:00:00 PM
5:00:00 PM
6:00:00 PM
7:00:00 PM
8:00:00 PM
9:00:00 PM
10:00:00 PM
11:00:00 PM
Time of Day
Average of kW
Max of kW
Min of kW

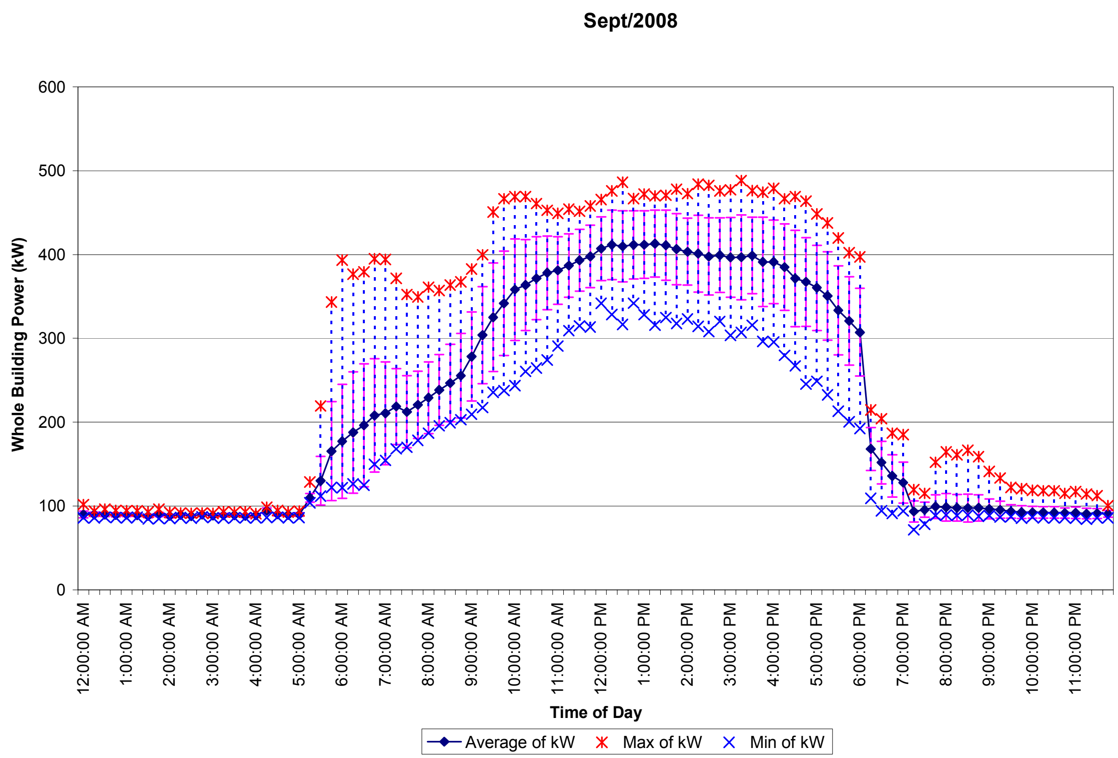

Oct/2008
Whole Building Power (kW)
350
300
250
200
150
100
50
0
12:00:00 AM
1:00:00 AM
2:00:00 AM
3:00:00 AM
4:00:00 AM
5:00:00 AM
6:00:00 AM
7:00:00 AM
8:00:00 AM
9:00:00 AM
10:00:00 AM
11:00:00 AM
12:00:00 PM
1:00:00 PM
2:00:00 PM
3:00:00 PM
4:00:00 PM
5:00:00 PM
6:00:00 PM
7:00:00 PM
8:00:00 PM
9:00:00 PM
10:00:00 PM
11:00:00 PM
Time of Day
Average of kW
Max of kW
Min of kW

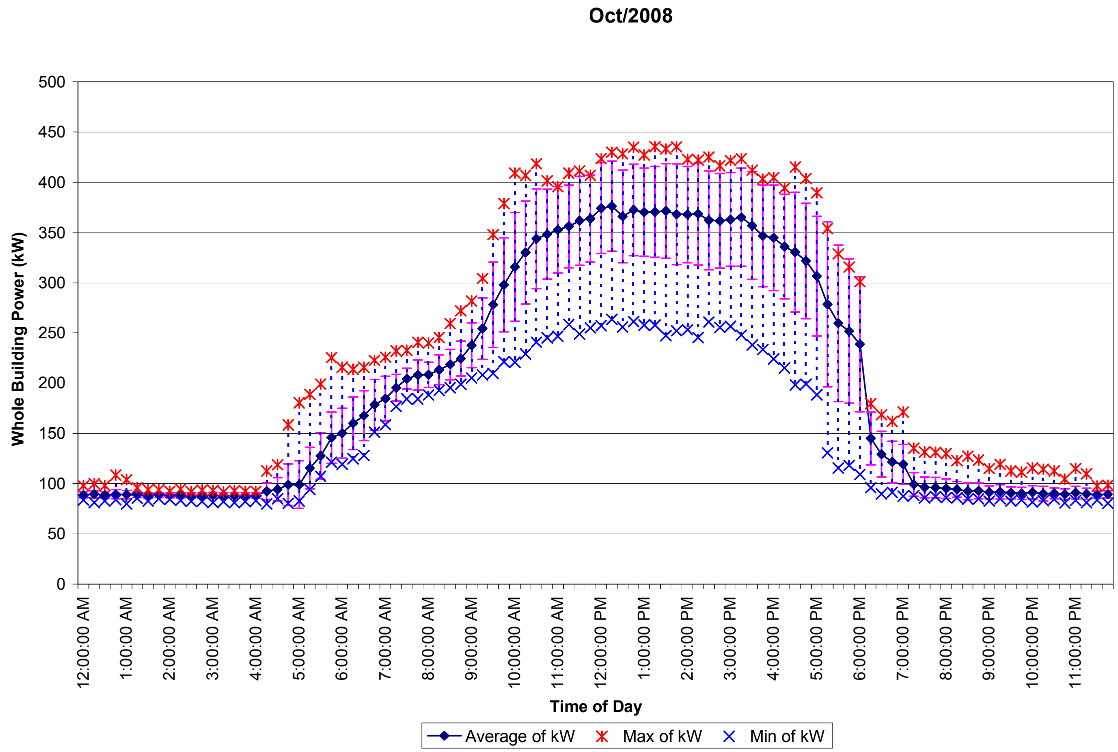

Local Government Office (2)
May/2008
Whole Building Power (kW)
500
450
400
350
300
250
200
150
100
50
0
12:00:00 AM
1:00:00 AM
2:00:00 AM
3:00:00 AM
4:00:00 AM
5:00:00 AM
6:00:00 AM
7:00:00 AM
8:00:00 AM
9:00:00 AM
10:00:00 AM
11:00:00 AM
12:00:00 PM
1:00:00 PM
2:00:00 PM
3:00:00 PM
4:00:00 PM
5:00:00 PM
6:00:00 PM
7:00:00 PM
8:00:00 PM
9:00:00 PM
10:00:00 PM
11:00:00 PM
Time of Day
Average of kW
Max of kW
Min of kW


Jun/2008
Whole Building Power (kW)
600
500
400
300
200
100
0
12:00:00 AM
1:00:00 AM
2:00:00 AM
3:00:00 AM
4:00:00 AM
5:00:00 AM
6:00:00 AM
7:00:00 AM
8:00:00 AM
9:00:00 AM
10:00:00 AM
11:00:00 AM
12:00:00 PM
1:00:00 PM
2:00:00 PM
3:00:00 PM
4:00:00 PM
5:00:00 PM
6:00:00 PM
7:00:00 PM
8:00:00 PM
9:00:00 PM
10:00:00 PM
11:00:00 PM
Time of Day
Average of kW
Max of kW
Min of kW


Jul/2008
600
500
400
300
200
100
0
Whole Building Power (kW)
12:00:00 AM
1:00:00 AM
2:00:00 AM
3:00:00 AM
4:00:00 AM
5:00:00 AM
6:00:00 AM
7:00:00 AM
8:00:00 AM
9:00:00 AM
10:00:00 AM
11:00:00 AM
12:00:00 PM
1:00:00 PM
2:00:00 PM
3:00:00 PM
4:00:00 PM
5:00:00 PM
6:00:00 PM
7:00:00 PM
8:00:00 PM
9:00:00 PM
10:00:00 PM
11:00:00 PM
Time of Day
Average of kW
Max of kW
Min of kW


Aug/2008
Whole Building Power (kW)
600
500
400
300
200
100
0
12:00:00 AM
1:00:00 AM
2:00:00 AM
3:00:00 AM
4:00:00 AM
5:00:00 AM
6:00:00 AM
7:00:00 AM
8:00:00 AM
9:00:00 AM
10:00:00 AM
11:00:00 AM
12:00:00 PM
1:00:00 PM
2:00:00 PM
3:00:00 PM
4:00:00 PM
5:00:00 PM
6:00:00 PM
7:00:00 PM
8:00:00 PM
9:00:00 PM
10:00:00 PM
11:00:00 PM
Time of Day
Average of kW
Max of kW
Min of kW


Sept/2008
Whole Building Power (kW)
0
100
200
300
400
500
600
12:00:00 AM
1:00:00 AM
2:00:00 AM
3:00:00 AM
4:00:00 AM
5:00:00 AM
6:00:00 AM
7:00:00 AM
8:00:00 AM
9:00:00 AM
10:00:00 AM
11:00:00 AM
12:00:00 PM
1:00:00 PM
2:00:00 PM
3:00:00 PM
4:00:00 PM
5:00:00 PM
6:00:00 PM
7:00:00 PM
8:00:00 PM
9:00:00 PM
10:00:00 PM
11:00:00 PM
Time of Day
Average of kW
Max of kW
Min of kW



Oct/2008
Whole Building Power (kW)
500
450
400
350
300
250
200
150
100
50
0
12:00:00 AM
1:00:00 AM
2:00:00 AM
3:00:00 AM
4:00:00 AM
5:00:00 AM
6:00:00 AM
7:00:00 AM
8:00:00 AM
9:00:00 AM
10:00:00 AM
11:00:00 AM
12:00:00 PM
1:00:00 PM
2:00:00 PM
3:00:00 PM
4:00:00 PM
5:00:00 PM
6:00:00 PM
7:00:00 PM
8:00:00 PM
9:00:00 PM
10:00:00 PM
11:00:00 PM
Time of Day
Average of kW
Max of kW
Min of kW

9.2 Appendix B

Customer Presentation

Pacific Gas & Electric Ancillary Service Non-Spinning Participating Load Pilot (PLP)

Pacific Gas and Electric Company

PLP History

- California Public Utilities Commission (CPUC) has ordered the 3 CA Investor Owned Utilities to come up with a Pilot Program that would study and conduct migration of retail Demand Response into the wholesale CAISO Market.
- PG&E has propose to conduct a Pilot that will encompass the acquisition of Auto-DR Customers and start bidding their Net DR load into the wholesale market; known as Ancillary Service – Non Spinning Product.
- Ancillary Service is a "fast DR" that would need to respond to CAISO dispatches and will need the capabilities to reduce in less than 10 minutes of the dispatch time.
- Economic analysis of the large C&I sector's participation in CAISO AS markets from the customer and societal points of view. The findings will inform future program design.

Pacific Gas and Electric Company

Why participate???

- The purpose of this Pilot is to test out end to end implementation of having retail DR load "play" in the wholesale CAISO Market as "fast DR." That being said, this Pilot is the first to incorporate attributes that mimic supply side resources
- This Pilot has attributes that brings a portion of SmartGrid forth to the present state

Pacific Gas and Electric Company

Affecting Your Operations

- Auto-DR load shed strategies will incorporate participants ability to perform without compromising operations. PG&E will account for all operating limitations the facility can or cannot do so it wont jeopardize the operation
- There is no direct load control here; participants still have the right to opt out during a dispatch (event) if it means saving a potential catastrophic occurrence

PLP Incentives

- ***Program Switch incentive:***
  - One time enrollment incentive; the higher incentive credit received from Auto-DR Critical Peak Pricing and/or Demand Bidding Program between the years 2007 or 2008.
- ***Participation incentive:***
  - $1000.00 per month while enrolled in the pilot; pilot will be administered from June 1st to October 31st, 2009 – a total of 5 months of operations (subject to change if the Pilot Program is delayed)
- ***Performance incentive:***
  - For any events or dispatch instructions by PG&E of Customers' load, PG&E will pay $0.15 per kWh
- ***Penalties:***
  - None. PG&E will not penalize Customer for under delivery or non-performance when dispatch occurs

PLP Qualifications

- To participate in the Pilot Program, customer must meet the following criteria's:
  - Must be Bundled retail PG&E customer; no Direct Access
  - Must have Auto-DR in place
  - Must have a 15-minute interval equipment
  - Must have less than 4-6 second telemetry polling at the customer premise (which PG&E will provide at no cost)
  - Cannot participate in any other DR program

Pacific Gas and Electric Company

PLP Program policy

- Participants must be actively communicating to PG&E/LBNL (or another PG&E approved third-party) about unusual energy consumption activities two days before the operation
- Participate in the Pilot from June 1^{st} – October 31^{st}
- Event will not be more than 72 hours (12 days and 6hr per day max)
- Reduce load when CAISO dispatch AS event
- Work with PG&E on event notification process

Pacific Gas and Electric Company

9.3 Appendix C

Generic Participation Agreement

2009 MARKET REDESIGN AND TECHNOLOGY UPGRADE (MRTU) ANCILLARY SERVICE – NON-SPINNING PILOT PROGRAM

CUSTOMER PARTICIPATION AGREEMENT

#1290-XXX-0XX

THIS CUSTOMER PARTICIPATION AGREEMENT ("Agreement") is made and entered into this ____the day of _________ 2009 between Global Energy Partners, LLC ("GEP"), and _______________ ("Customer").

GEP is under Contract No 2500174390 with Pacific Gas & Electric Company ("PG&E"), to deliver peak demand reduction through the Market Redesign and Technology Upgrade Ancillary Service Pilot Program for demand response. The Pilot Program, which is funded by California utility ratepayers under the auspices of the California Public Utilities Commission (CPUC), is designed to create and study demand reduction for California by providing incentives to Auto DR Customers to install telemetry equipment and measures for a sustainable load shed strategies. For the 2009 DR season, PG&E will be conducting a Pilot Program that will practice bidding DR resources net load into the California Independent System Operator's Market Redesign and Technology Upgrade Ancillary Service Non Spinning market (CAISO MRTU).

In order to qualify for the Pilot Program, Customer shall:

Be a current PG&E Auto DR customer on a retail electric rate

Be equipped with an active electrical 15-minute-interval meter serviced by PG&E

Allow PG&E to install telemetry equipments in the participating facilities premise that monitor energy consumption in real time

Not be participating in any other PG&E DR programs

Not be a Direct Access customer

Provide PG&E or other 3rd parties identified by PG&E energy usage information especially change in patterns on an as-needed basis

Have no Net Energy Metering (NEM) or standby generation (solar, co-generation, etc.)

The Customer agrees to participate in PG&E's MRTU Ancillary Service Pilot Program with the understanding that the Customer shall receive an incentive for the participation in this demand response pilot:

One time program switch incentive ($______________); the higher incentive credit received from Auto-DR Critical Peak Pricing and/or Demand Bidding Program between the years 2007 or 2008. Incentive will be paid at the end of the pilot. If customer participates less than the 5 months of which the pilot is operating, PG&E will prorate the program switch incentive based on the number of months customer was enrolled in the pilot.

$1000.00 per month while enrolled in the pilot; pilot will be administered from June 1st to October 31st, 2009 – a total of 5 months of operations (subject to change if the Pilot Program start date is delayed). Payments would be made month to month.

For any events or dispatch instructions by PG&E of Customers' load, PG&E will pay $0.15 per kWh. Payments would be made month to month.

PG&E will not penalize Customer for under delivery or non-performance when dispatch occurs

The Customer acknowledges that they have the right to opt out this pilot once and participate in other DR programs during the 2009 DR seasons.

The following Customer sites are included under this Agreement (attach additional pages as necessary):

Site: ____

Utility Service Agreement ID. #:____________________________________

Utility Acct. Site Address: ____

Utility Acct. City: ____

Utility Acct. Zip: ____

Utility Acct. Rate Code: ____

The Customer agrees to grant access to its facilities for GEP Representatives and Pacific Gas & Electric Company Representatives to perform the pre-installation and post-installation site inspections, and additionally to the California Public Utilities Commission (CPUC) and their subcontractors to inspect and verify installation and operation. Such access shall be requested by the requesting parties within a reasonable time prior to the requested site visit.

Advertising: GEP agrees not to use the names or identifying characteristics of the Customer's Facility for published project reports, advertising, sales promotion or other publicity without the Customer's written approval. The Customer agrees not to use the name of GEP on their published material.

CPUC Required Disclosure Statement:

California consumers are not obligated to purchase any full fee service or other service not funded by this program. This program is funded by the California utility ratepayers and administered by PG&E under the auspices of the CPUC.

Los consumidores en California no están obligados a comprar servicios completos o adicionales que no estén cubiertos bajo este programa. Este programa está financiado por los usuarios de servicios públicos en California bajo la jurisdicción de la Comisión de Servicios Públicos de California (CPUC).

Both GEP and Customer agree: 1) Indemnification: Each party shall indemnify the other for any losses or damages, except to extent that the losses or damages arise from the other parties' negligence or willful misconduct. 2) Incidental and Consequential Damages: NEITHER PARTY SHALL BE LIABLE TO THE OTHER FOR ANY INCIDENTAL, SPECIAL OR CONSEQUENTIAL DAMAGES.

GEP is receiving funds from PG&E for implementation of this project, but GEP and Customer acknowledge that PG&E is not liable to either GEP or Customer for any losses or damages, including incidental or consequential damages, arising from this Agreement. Furthermore, GEP and Customer acknowledge PG&E makes no representation or warranty, and assumes no liability with respect to quality, safety, performance, or other aspect of any design, system or appliance installed pursuant to this Agreement, and expressly disclaims any such representation, warranty or liability.

GEP attests that it meets all PG&E's insurance requirements for Contractors when performing work at the utility's and its Customer's sites, including Workers Compensation, Employer's Liability, General Liability, and Automobile Bodily Injury and Property Damage Liability Insurances. GEP agrees to comply with all federal, state, and municipal laws, ordinances, rules, orders, and regulations, which apply to its actions at the Facility or to the Project.

10. Any notices required pursuant to this Agreement shall be served at the following addresses:

Customer

Name: ______________________________

Title: ______________________________

Company: ______________________________

Address: ______________________________

Phone: ______________________________

FAX: ______________________________

Email: ______________________________

Global Energy Partners, LLC

Name:

Title

Company:

Address:

Phone:

FAX:

Email:

IN WITNESS WHEREOF, GEP and Customer have executed this Agreement on the day and year first set forth above.

Customer

By: ____ **Date: ________________________**

Name, Title

Print Name: ________________________________

Global Energy Partners, LLC

By: ____ **Date: ________________________**

Name, Title

Print Name: ________________________________

9.4 Appendix D

Analysis of DR Events

This appendix presents the results from Participating Load Pilot conducted during the summer of 2009. For each participating load dispatch and for each site, we present measured loads, forecasted loads, a comparison of the forecast and measured loads and a table summarizing the ramp time and average hourly load reductions. This analysis is only done for events that lasted ten minutes or longer that were captured by the five-minute interval meters. These events are highlighted in the table below. With the exception of the dispatch on July 17, which was a test (exceptional) dispatch, all dispatches were triggered by the CAISO's Automated Dispatch System (ADS) and propagated without a human in the loop.

In the following section, for each building we first present the load profile for the day with measured five-minute data and hourly load schedule. Second, the difference between the five-minute forecasted and measured data and the hourly pseudo generation schedule is presented. Ideally, if the forecasts were 100% accurate, the difference would be zero until the dispatch period. During the dispatch period, the difference and the hourly generation schedule should track each other closely.

Load shed summary tables for each event for each site display measured versus forecasted ramp rate and the average load. Ramp rate is calculated using the load reduction within the first 10 minutes of the dispatch.

Retail Store

Five-minute measured data for Retail Store has low resolution. This is also observable from the load profiles presented below.

September 18, 2009

There were two separate dispatches. The first one started at 4 pm and lasted for 25 minutes and the second one started at 4:35 pm and lasted 15 minutes. The measured data on this day is on average 150 kW higher than the forecasted data. Retail Store's load profile shows that it participated in the first event and did not participate in the second event.

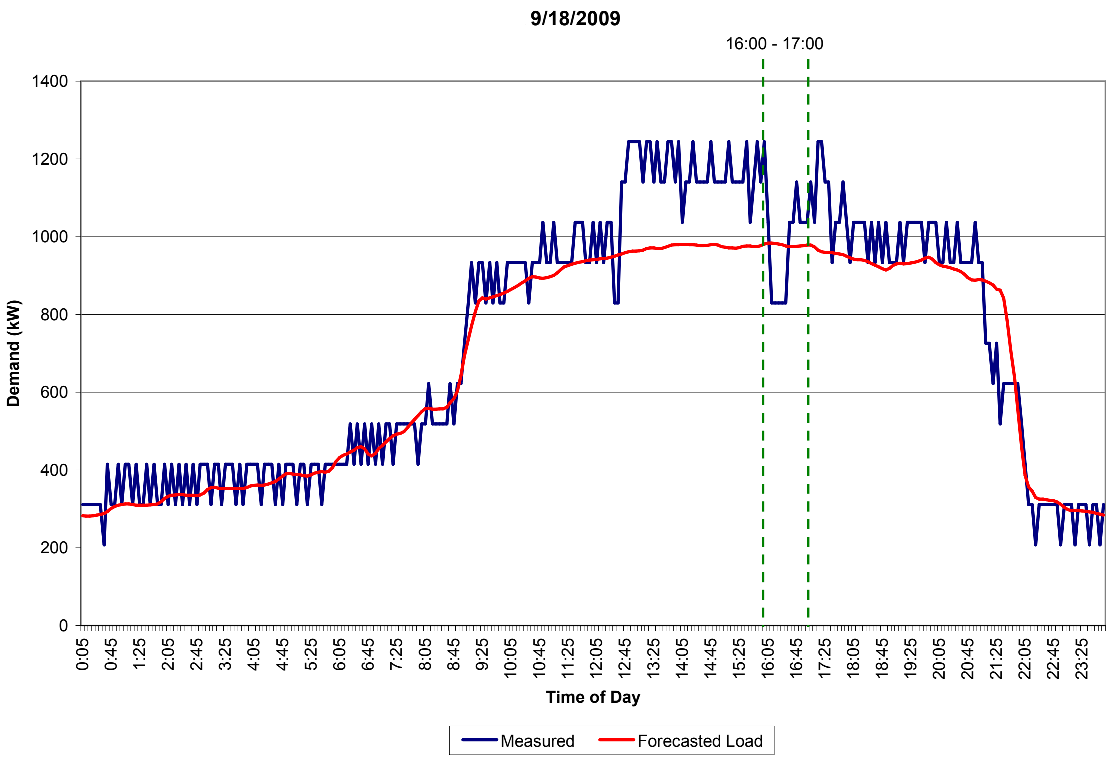


Figure 1. Measured and forecasted loads for Retail Store on 9/18/2009

The difference between measured and forecasted loads seems to follow each other closely until the afternoon where there is a large error between noon and 5 pm. The demand reduction within this period is visible and exceeds the bid amount for the first dispatch. There is a significant load drop one hour before the store closing indicating that there may have been a change in the store hours.

Load shed summary table shows that on this date, load reduction was double the forecasted amount and ramp rate was four to five times more than the forecasted ramp rate.

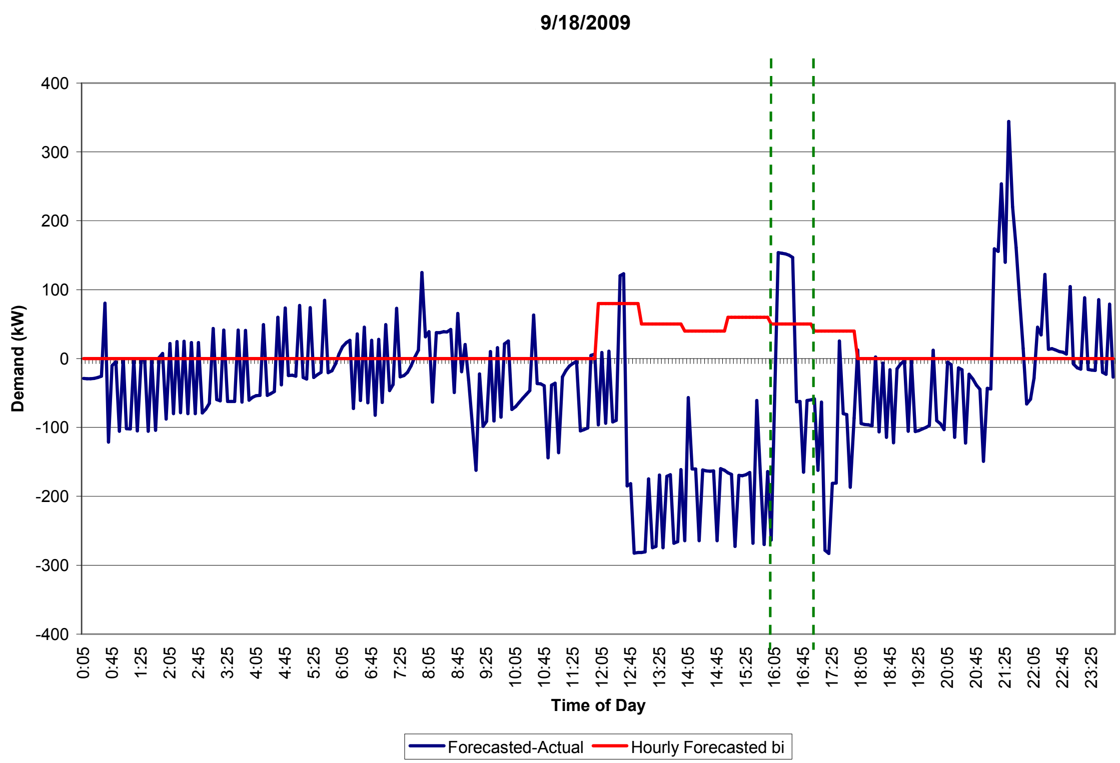


Figure 2. The difference between measured and forecasted loads and hourly generation schedule.

Table 1. Load shed summary table (9/18/2009)

Ramp Rate (MW/min) (Measured/Forecasted)	Average Load Reduction (kW) (Measured/Forecasted)			
	HE 15:00	HE 16:00	HE 17:00	HE 18:00
0.01/0.001	-	-	50/20	-

October 19, 2009

Two one-hour dispatches were called for Retail Store on October 19th, 2009. The first one was between 2 pm and 3 pm and the second one took place between 5 pm and 6 pm. Both events exceeded the forecasted load reduction and the average ramp rate was three times the forecasted amount.

On this date and the following dates, there is significant difference between the forecasted and measured loads during the morning period between 9 am and 10 am, suggesting that the store opening hours are moved from 9 am to 10 am. Forecasting algorithms do not automatically capture this change and continue to over forecast loads during the morning hours for the rest of the pilot.

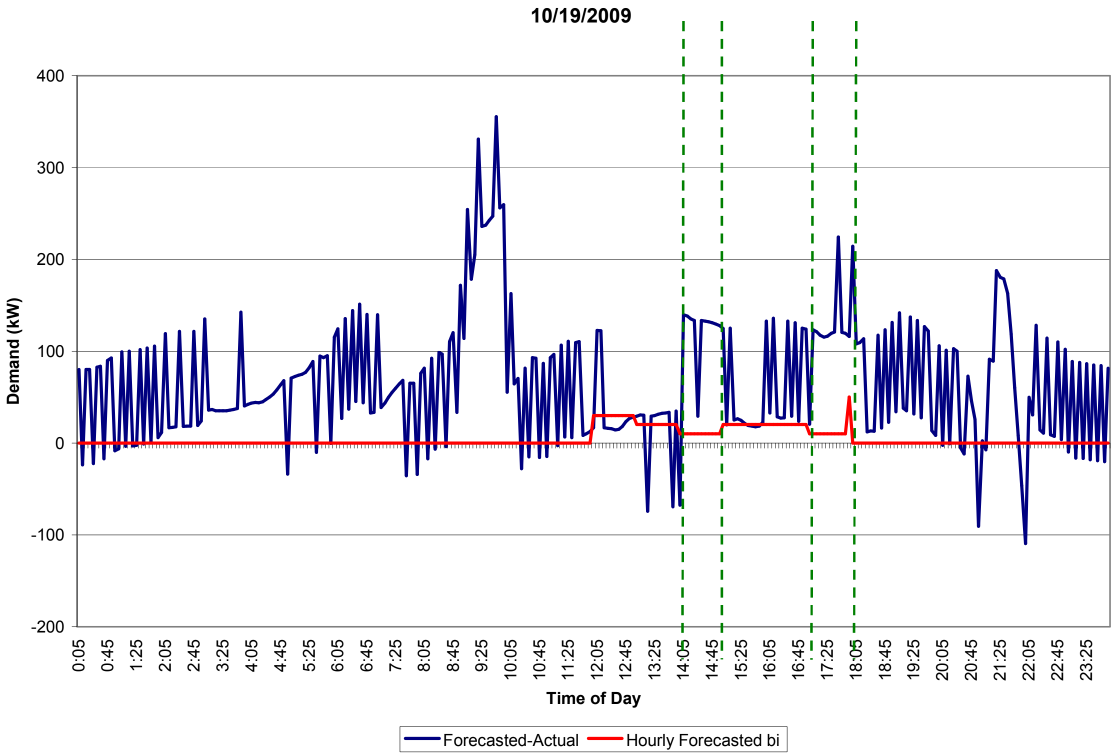


Figure 3. The difference between measured and forecasted loads and hourly generation schedule

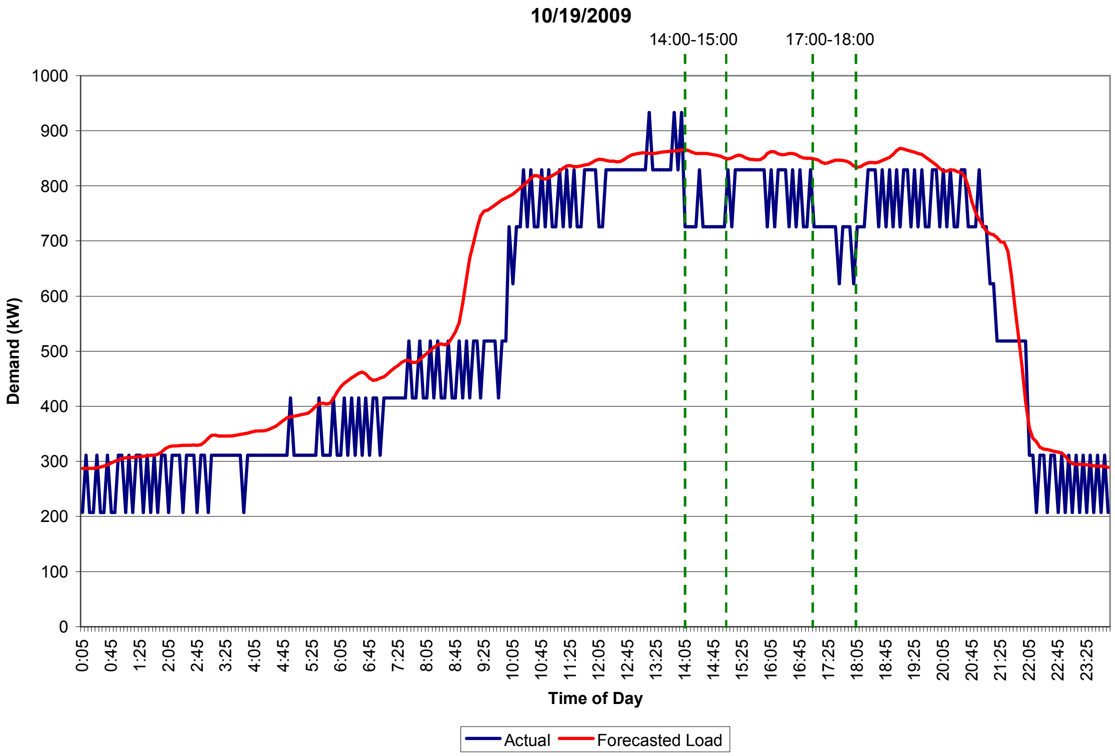


Figure 4. Measured and forecasted loads for Retail Store on 10/19/2009

Table 2. Load shed summary table (10/19/2009)

Ramp Rate (MW/min) (Measured/Forecasted)	Average Load Reduction (kW) (Measured/Forecasted)			
	HE 15:00	HE 16:00	HE 17:00	HE 18:00
0.041/0.003 0.021/0.003	124/10	-	123/10	-

October 23, 2009

The dispatch on this date was only 20 minutes and the forecasted loads were higher than the actual loads. The measured load reduction was more than the forecasted load reductions and the measured ramp rate was also higher than forecasted ramp rate.

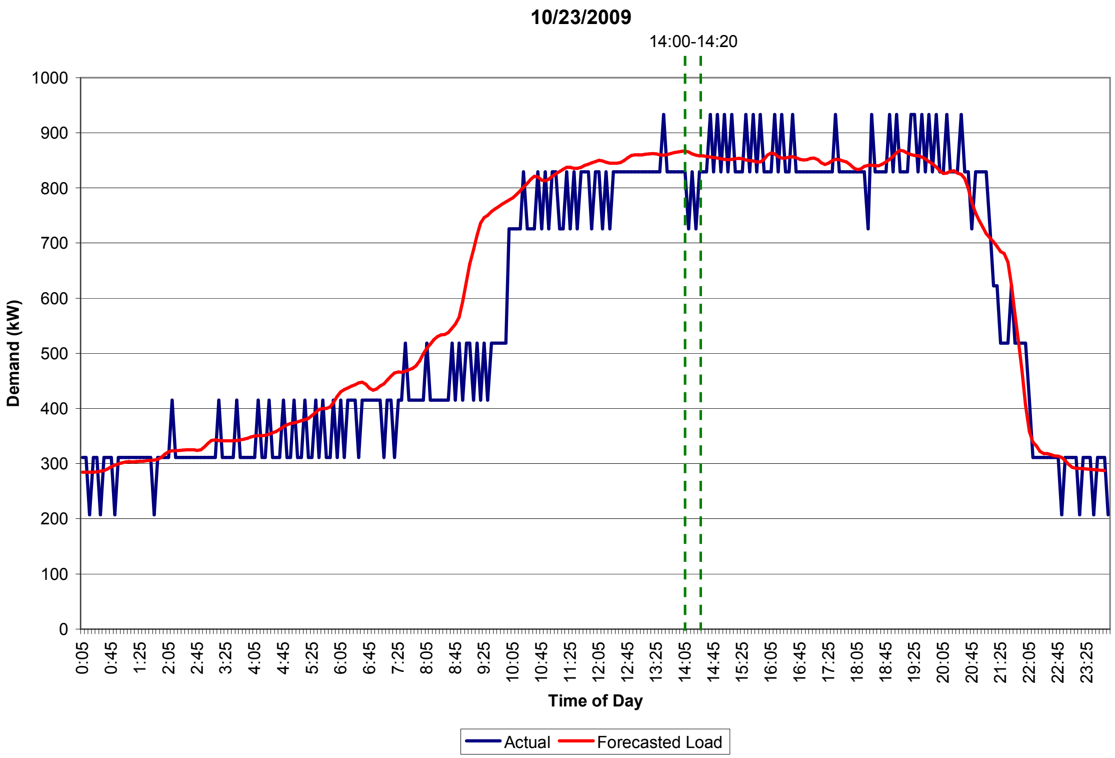


Figure 5. Measured and forecasted loads for on 10/23/2009

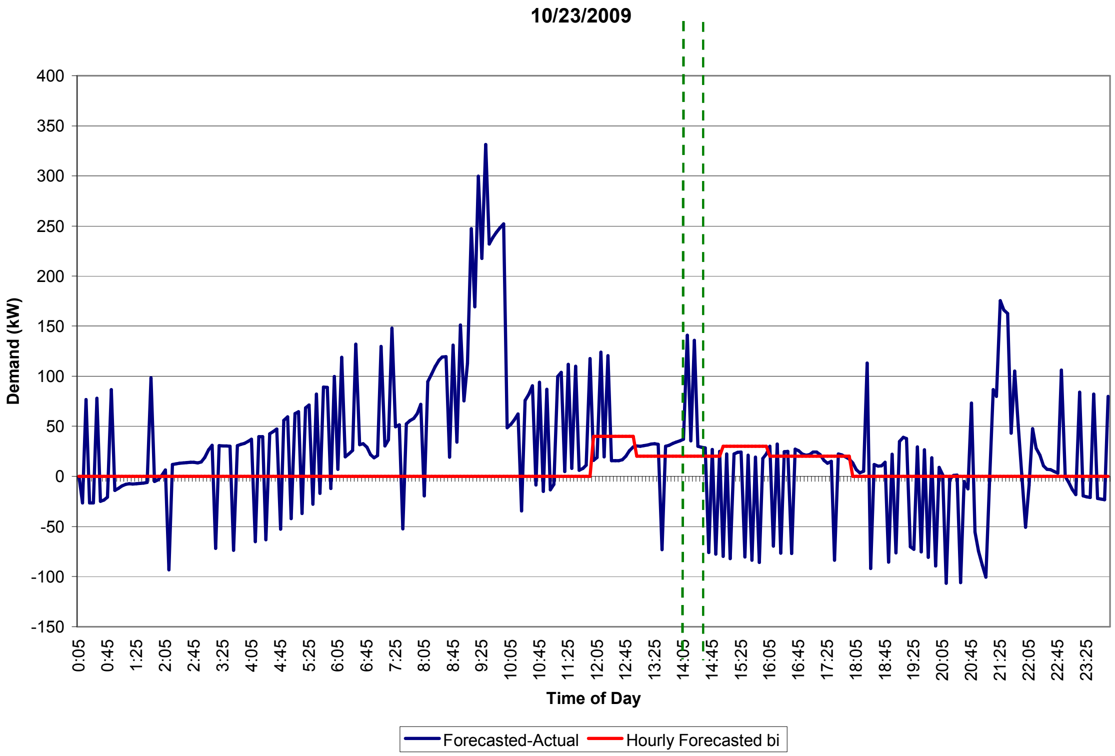


Figure 6.The difference between measured and forecasted loads and hourly generation schedule

Figure 7. Load shed summary table (10/23/2009)

Ramp Rate (MW/min) (Measured/Forecasted)	Average Load Reduction (kW) (Measured/Forecasted)			
	HE 15:00	HE 16:00	HE 17:00	HE 18:00
0.010/0.004	87/20	-	-	-

Local Government Office

August 6, 2009

This resource was dispatched between 5 pm and 6 pm on it first dispatch date. Forecasted loads were higher than the measured loads on this day. However, the load reduction was larger than the forecast error and considered “visible”. This site’s forecasted reduction was low for all the events so the measured reductions surpassed the forecasted reductions in most days. During off peak periods, the forecasts match the measured data. During the occupied periods however, the error between the measured and forecasted load is quite high. Even so, the demand shed is outside of this error.

Forecasted ramp rate and demand shed remains lower than the measured ramp rate and demand shed on this day.

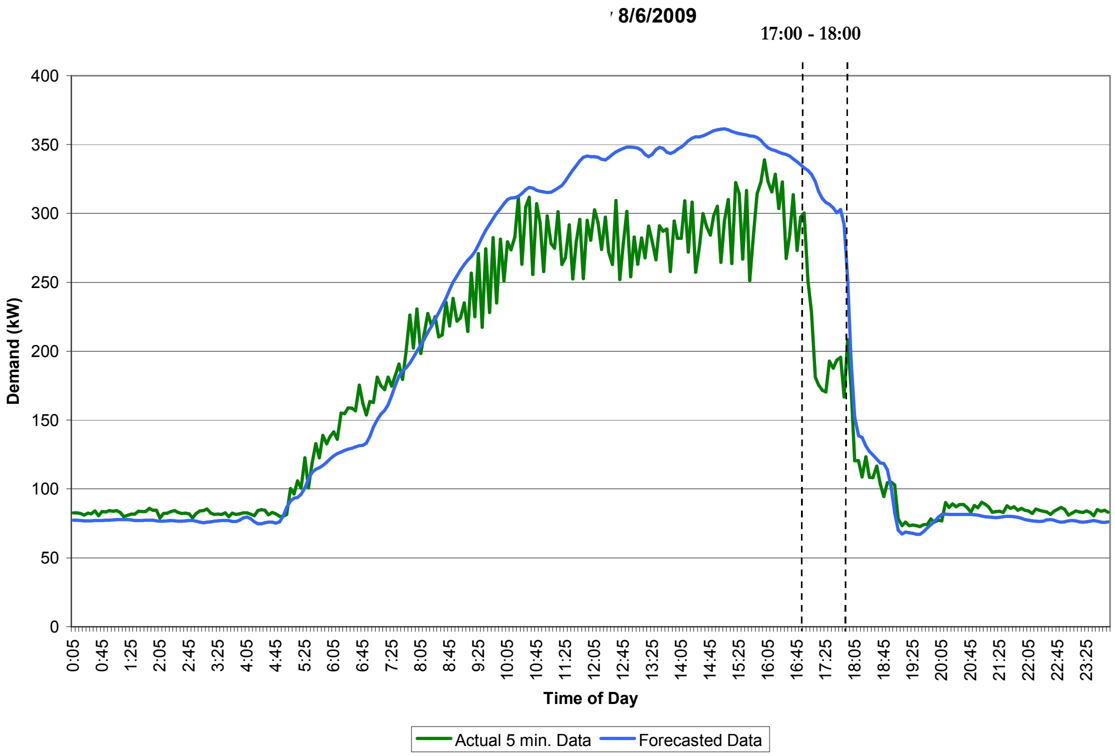


Figure 8. Measured and forecasted loads for Local Government Office on 8/26/2009

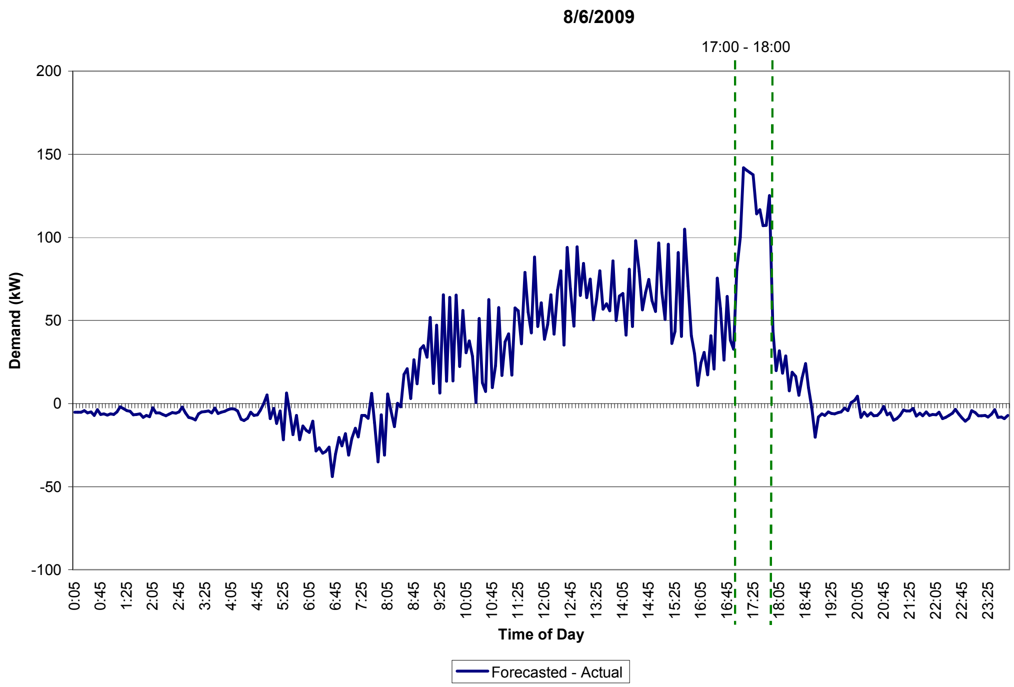


Figure 9.The difference between measured and forecasted loads and hourly generation schedule

Table 3. Load shed summary table (8/6/2009)

Ramp Rate (MW/min) (Measured/Forecasted)	Average Load Reduction (kW) (Measured/Forecasted)			
	HE 15:00	HE 16:00	HE 17:00	HE 18:00
0.004/0.001	-	-	-	116/10

August 31, 2009

On this date, the forecasted loads are lower than the measured loads. However, the measured demand shed remains to be higher than the forecasted shed. The error between the forecast and the measured loads is still very high on this date.

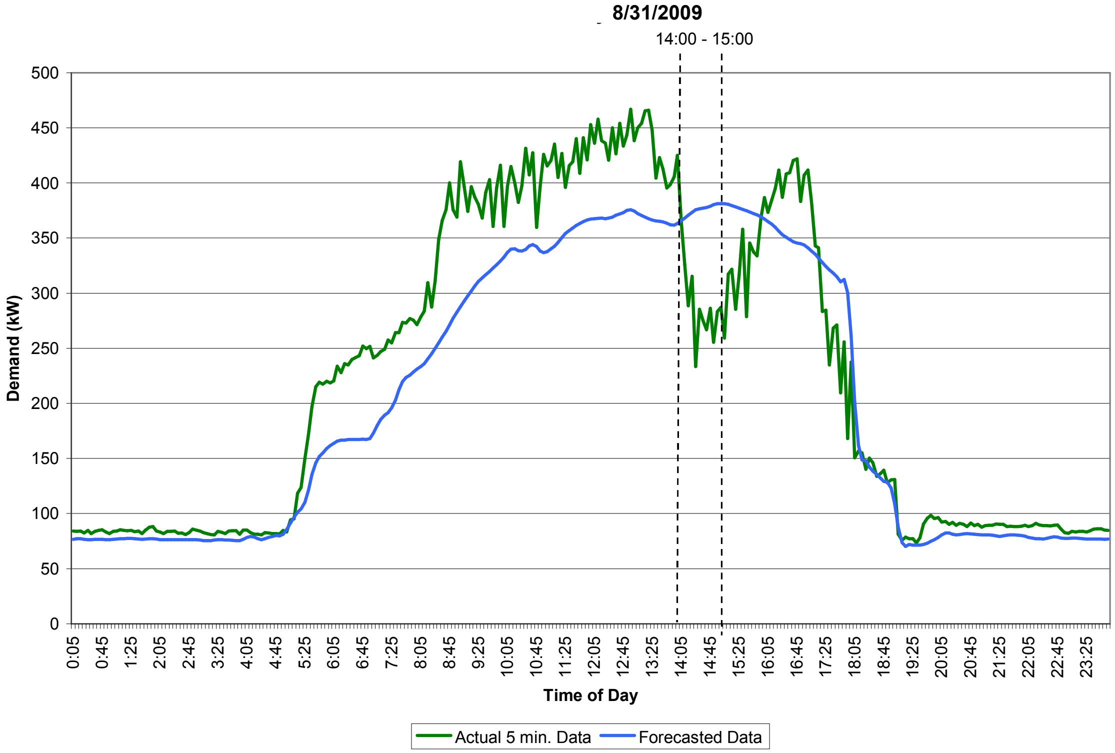


Figure 10. Measured and forecasted loads for Local Government Office on 8/31/2009

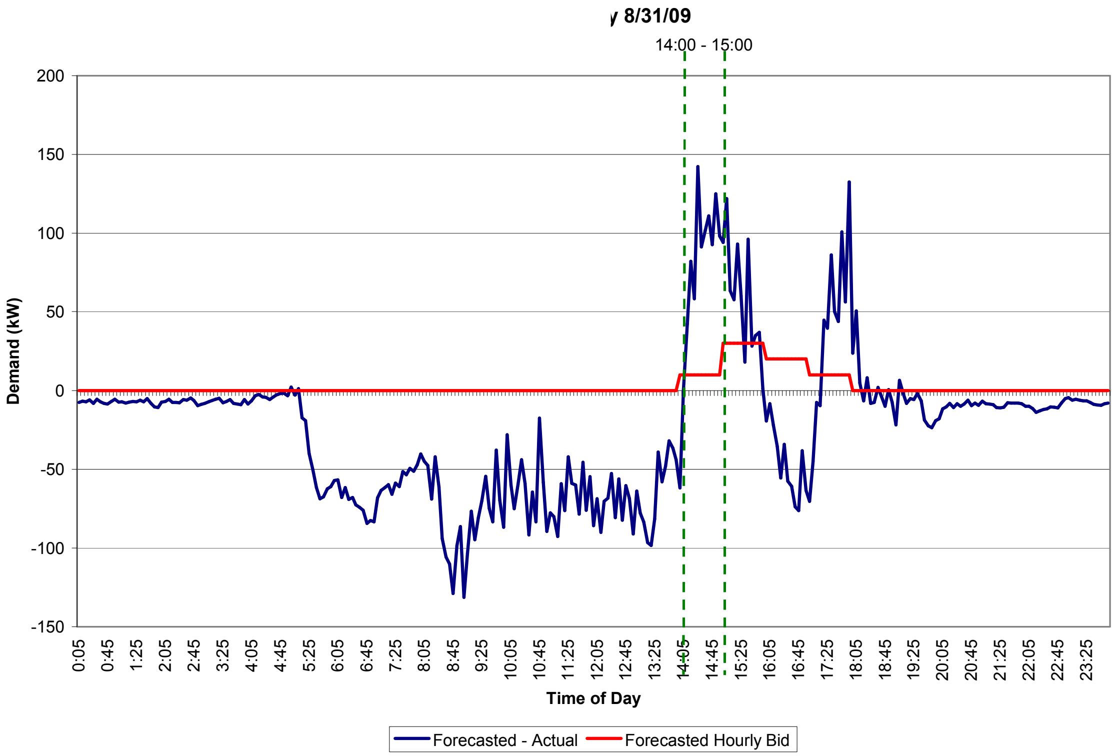


Figure 11.The difference between measured and forecasted loads and hourly generation schedule

Table 4.Load shed summary table (8/31/2009)

Ramp Rate (MW/min) (Measured/Forecasted)	Average Load Reduction (kW) (Measured/Forecasted)			
	HE 15:00	HE 16:00	HE 17:00	HE 18:00
0.012/0.002	86/10	-	-	-

September 18, 2009

This event is similar to the event on August 31st because the forecast is lower than the measured loads, which yields high error. However the load shed is outside of this error and exceed the forecasted shed.

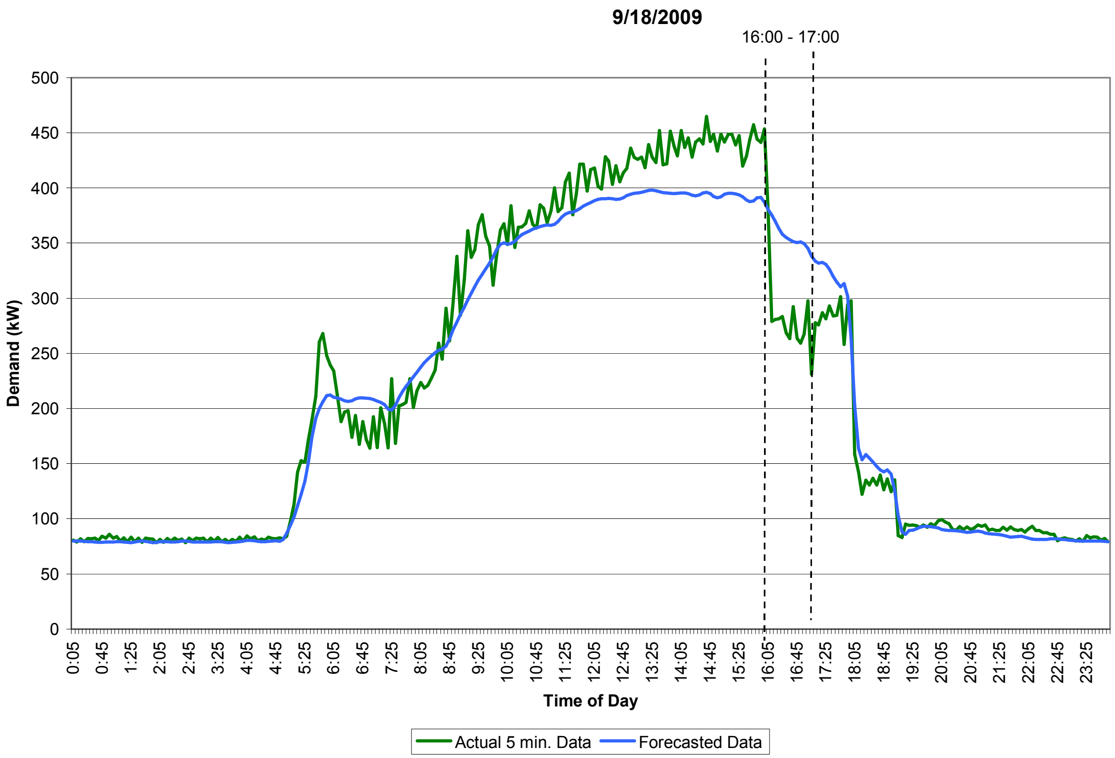


Figure 12. Measured and forecasted loads for Local Government Office on 9/18/2009

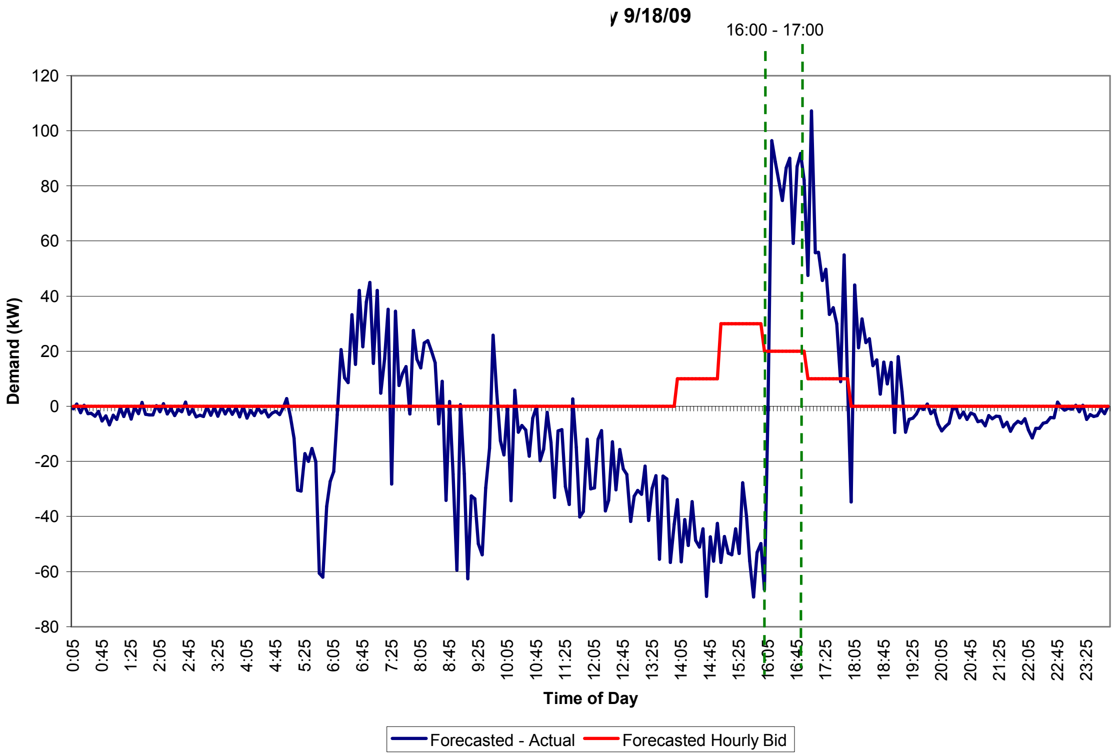


Figure 13.The difference between measured and forecasted loads and hourly generation schedule

Table 5. Load shed summary table (9/18/2009)

Ramp Rate (MW/min) (Measured/Forecasted)	Average Load Reduction (kW) (Measured/Forecasted)			
	HE 15:00	HE 16:00	HE 17:00	HE 18:00
0.014/0.009	-	-	76/20	-

September 21, 2009

This is the only day where this facility was dispatched for four hours and the feedback loop, designed to maintain the load reduction at the forecasted levels was tested. When the dispatched was received, it seems like the facility overshoot the shed amount. One reason for this is that the load reduction forecasts do not reflect the load shed characteristics of the building accurately. Global temperature adjustment typically yields a significant amount of savings in the first hour. This is because when the set points are adjusted, the chillers unload and the fans back off for a period of time yielding aggregate savings from these two components. Over time, when the temperatures in the space start increasing, chillers and fans start to return to their original operations.

For the remaining of the dispatch period, the measured load shed trail the forecasted load shed nicely, staying just above the forecasted sheds.

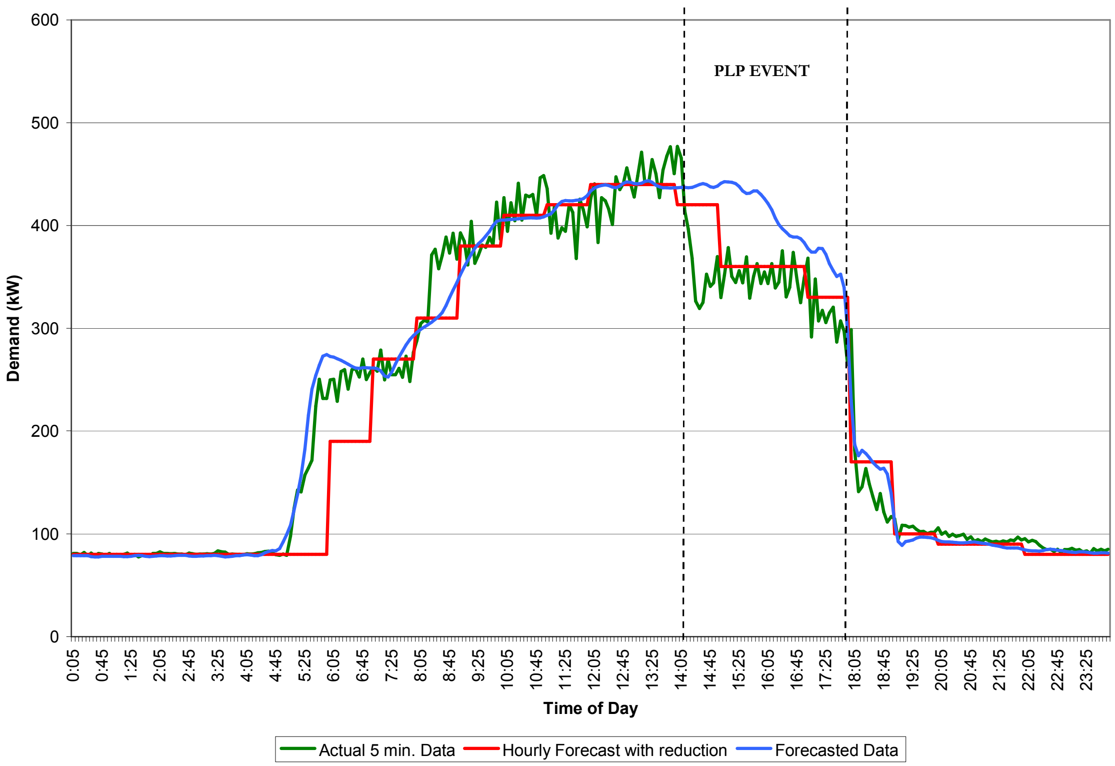


Figure 14. Measured and forecasted loads for Local Government Office on 9/21/2009

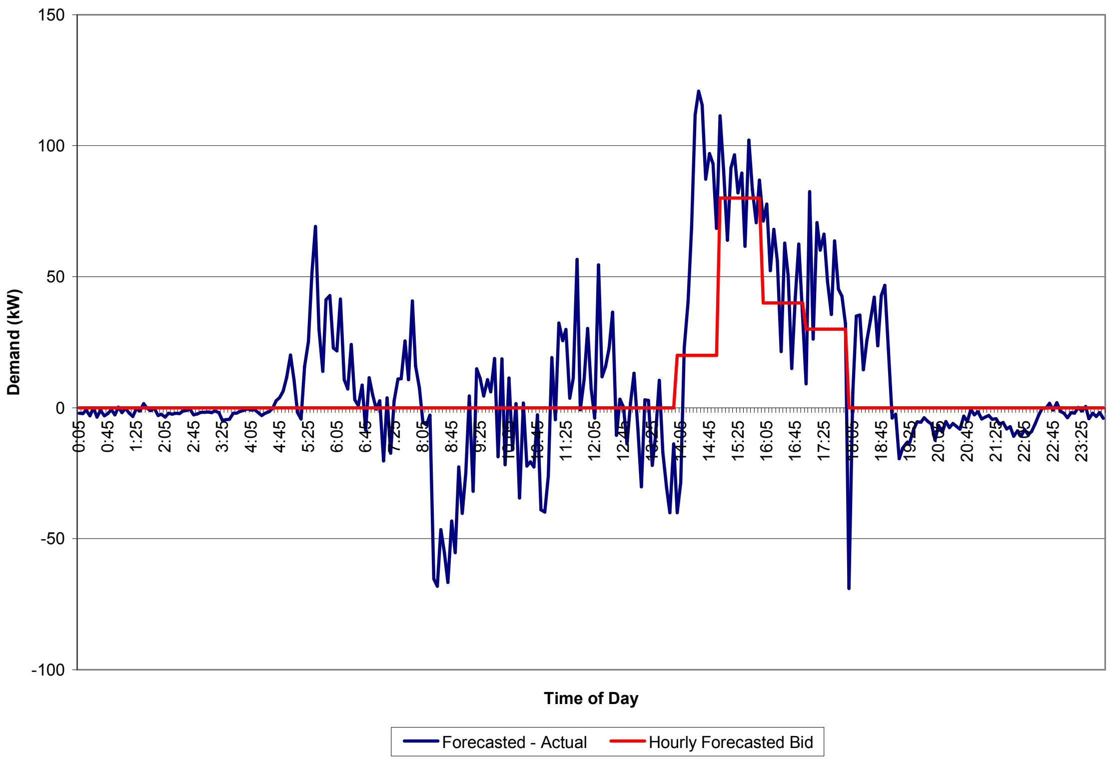


Figure 15.The difference between measured and forecasted loads and hourly generation schedule

Table 6.Load shed summary table

Ramp Rate (MW/min) (Measured/Forecasted)	Average Load Reduction (kW) (Measured/Forecasted)			
	HE 15:00	HE 16:00	HE 17:00	HE 18:00
0.006/0.002	72/20	86/80	51/40	49/30

Industrial Bakery

This facility was not included in the initial set of sites that were selected because it did not meet the low load variability criteria. Never the less, it was included in the study to show how a facility with similar load characteristics would do under the Participating Load Program. Part of the reason for high variability is because many of the operations at this facility are conducted manually and which depend on the users and their time limitations. For example, we know that somewhere between 2 and 3 pm, the workers go on a break but it seems like this break time is never the same. There were several days when the breaks were taken right before the dispatch. Since during the break the pan washer is turned off, no resource was available when they were dispatched.

August 6, 2009

This is one of the days that the pan washer was turned off right before the event started and remained off until after the break period. There is a large error between the forecasted and measured loads and this creates a noise in the measured loads causing the savings to be unrecognizable.

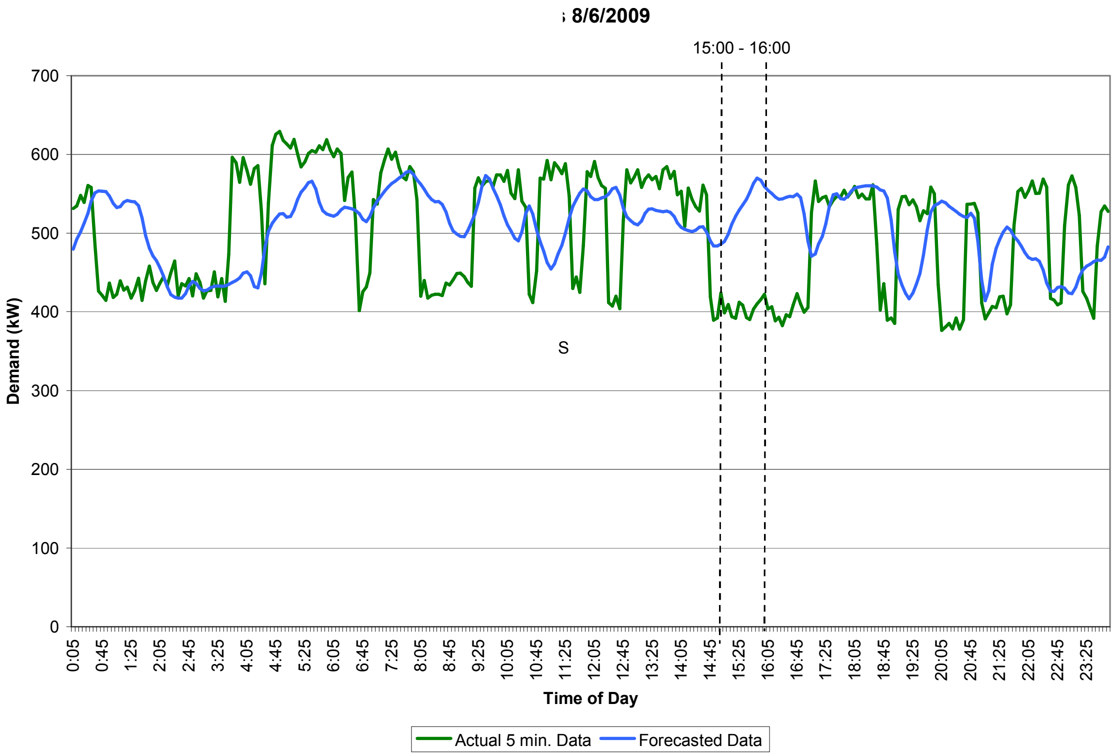


Figure 16. Measured and forecasted loads for Industrial Bakery on 8/6/2009

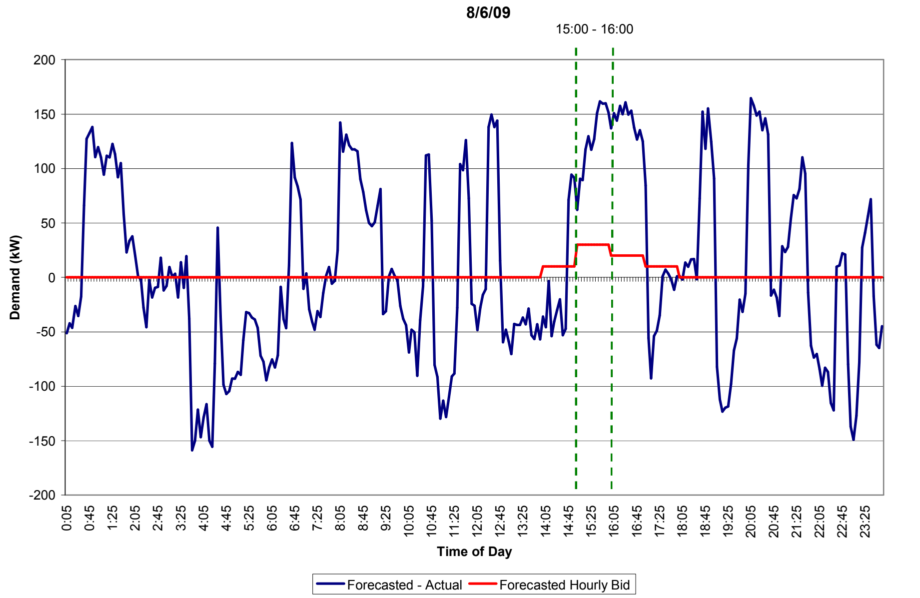


Figure 17.The difference between measured and forecasted loads and hourly generation schedule

Table 7. Load shed summary table (8/6/2009)

Ramp Rate (MW/min) (Measured/Forecasted)	Average Load Reduction (kW) (Measured/Forecasted)			
	HE 15:00	HE 16:00	HE 17:00	HE 18:00
0.005/0.015	-	125/30	-	-

September 18, 2009

This is another day that the pan washer was turned off right before the event started and remained off until after the break period. Again, the large error between the forecasted and measured loads creates a noise in the measured loads causing the savings to be unrecognizable.

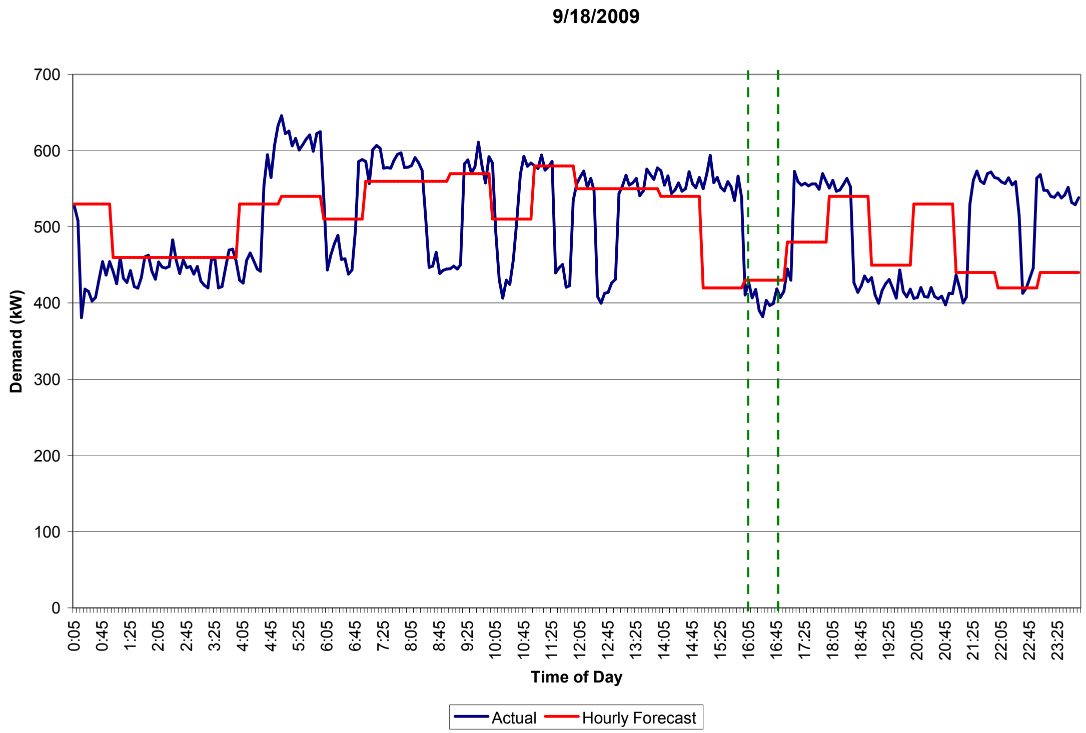


Figure 18. Measured and forecasted loads for Industrial Bakery on 9/18/2009

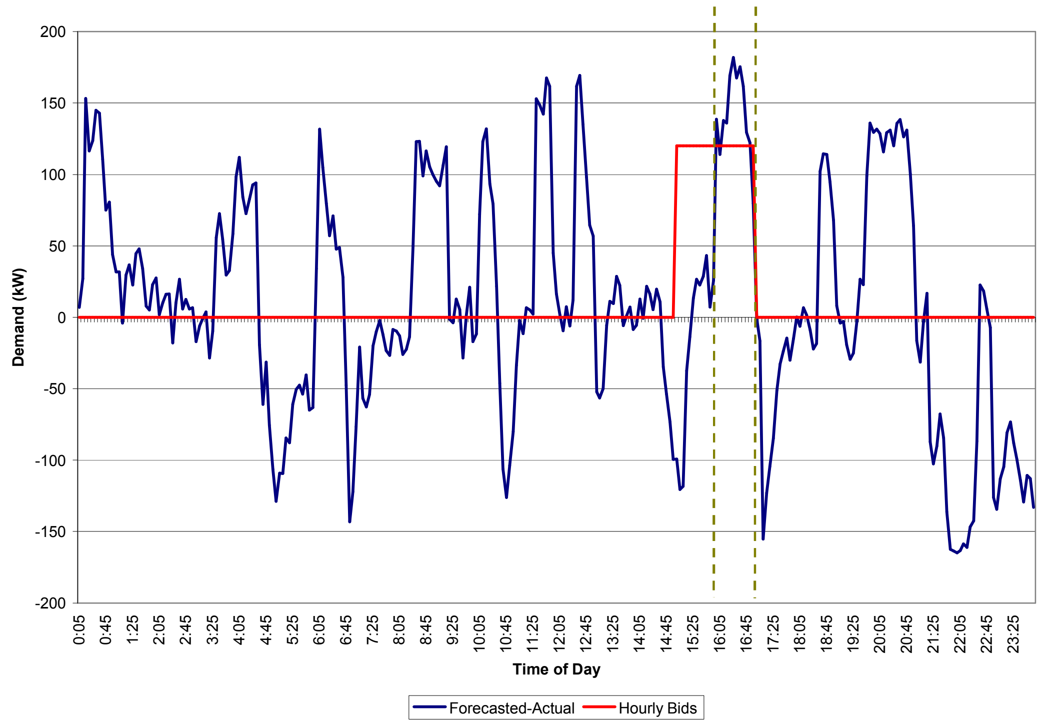


Figure 19.The difference between measured and forecasted loads and hourly generation schedule

Table 8. Load shed summary table (9/18/2009)

Ramp Rate (MW/min) (Measured/Forecasted)	Average Load Reduction (kW) (Measured/Forecasted)			
	HE 15:00	HE 16:00	HE 17:00	HE 18:00
0.012/0.012	-	-	143/120	-

9.5 Appendix E

Performance and Load Impacts

Shown below are each dispatch order given by the CAISO.

Resource Id	Start Time	DOT (MW)	DOT (kW)	Load Schedule	Actual Meter Data (kW)	Reduction (kW)	Reduction (kWh)	Performance
RETAIL STORE	8/6/2009 12:02	0.04	40	890	725.76	164.24	13.687	411%
RETAIL STORE	8/6/2009 12:07	0.04	40	890	622.08	267.92	22.327	670%
RETAIL STORE	8/6/2009 12:12	0.04	40	890	725.76	164.24	13.687	411%
RETAIL STORE	8/6/2009 12:17	0.04	40	890	725.76	164.24	13.687	411%
RETAIL STORE	8/6/2009 12:22	0.04	40	890	725.76	164.24	13.687	411%
RETAIL STORE	8/6/2009 12:27	0.04	40	890	725.76	164.24	13.687	411%
RETAIL STORE	8/6/2009 12:32	0.04	40	890	725.76	164.24	13.687	411%
RETAIL STORE	8/6/2009 12:37	0.04	40	890	725.76	164.24	13.687	411%
RETAIL STORE	8/6/2009 12:42	0.04	40	890	725.76	164.24	13.687	411%
RETAIL STORE	8/6/2009 12:47	0.04	40	890	725.76	164.24	13.687	411%
RETAIL STORE	8/6/2009 12:52	0.04	40	890	829.44	60.56	5.047	151%
RETAIL STORE	8/6/2009 12:57	0.04	40	890	725.76	164.24	13.687	411%
RETAIL STORE	9/11/2009 14:42	0.04	40	1000	725.76	274.24	22.853	686%
RETAIL STORE	9/18/2009 16:02	0.05	50	980	829.44	150.56	12.547	301%

RETAIL STORE	9/18/2009 16:07	0.05	50	980	829.44	150.56	12.547	301%
RETAIL STORE	9/18/2009 16:12	0.05	50	980	829.44	150.56	12.547	301%
RETAIL STORE	9/18/2009 16:17	0.05	50	980	829.44	150.56	12.547	301%
RETAIL STORE	9/18/2009 16:22	0.05	50	980	829.44	150.56	12.547	301%
RETAIL STORE	9/18/2009 16:37	0.05	50	980	1140.48	-160.48	0.000	-321%
RETAIL STORE	9/18/2009 16:42	0.05	50	980	1036.8	-56.8	0.000	-114%
RETAIL STORE	9/18/2009 16:47	0.05	50	980	1036.8	-56.8	0.000	-114%
RETAIL STORE	10/19/2009 14:02	0.01	10	860	725.76	134.24	11.187	1342%
RETAIL STORE	10/19/2009 14:07	0.01	10	860	725.76	134.24	11.187	1342%
RETAIL STORE	10/19/2009 14:12	0.01	10	860	725.76	134.24	11.187	1342%
RETAIL STORE	10/19/2009 14:17	0.01	10	860	829.44	30.56	2.547	306%
RETAIL STORE	10/19/2009 14:22	0.01	10	860	725.76	134.24	11.187	1342%
RETAIL STORE	10/19/2009 14:27	0.01	10	860	725.76	134.24	11.187	1342%
RETAIL STORE	10/19/2009 14:32	0.01	10	860	725.76	134.24	11.187	1342%
RETAIL STORE	10/19/2009 14:37	0.01	10	860	725.76	134.24	11.187	1342%
RETAIL STORE	10/19/2009 14:42	0.01	10	860	725.76	134.24	11.187	1342%
RETAIL STORE	10/19/2009 14:47	0.01	10	860	725.76	134.24	11.187	1342%
RETAIL STORE	10/19/2009 14:52	0.01	10	860	725.76	134.24	11.187	1342%
RETAIL STORE	10/19/2009 14:57	0.01	10	860	829.44	30.56	2.547	306%
RETAIL STORE	10/19/2009 17:02	0.01	10	850	725.76	124.24	10.353	1242%
RETAIL STORE	10/19/2009 17:07	0.01	10	850	725.76	124.24	10.353	1242%

RETAIL STORE	10/19/2009 17:12	0.01	10	850	725.76	124.24	10.353	1242%
RETAIL STORE	10/19/2009 17:17	0.01	10	850	725.76	124.24	10.353	1242%
RETAIL STORE	10/19/2009 17:22	0.01	10	850	725.76	124.24	10.353	1242%
RETAIL STORE	10/19/2009 17:27	0.01	10	850	725.76	124.24	10.353	1242%
RETAIL STORE	10/19/2009 17:32	0.01	10	850	622.08	227.92	18.993	2279%
RETAIL STORE	10/19/2009 17:37	0.01	10	850	725.76	124.24	10.353	1242%
RETAIL STORE	10/19/2009 17:42	0.01	10	850	725.76	124.24	10.353	1242%
RETAIL STORE	10/19/2009 17:47	0.01	10	850	725.76	124.24	10.353	1242%
RETAIL STORE	10/19/2009 17:52	0.01	10	850	622.08	227.92	18.993	2279%
RETAIL STORE	10/19/2009 17:57	0.01	10	850	725.76	124.24	10.353	1242%
RETAIL STORE	10/23/2009 14:02	0.02	20	900	725.76	174.24	14.520	871%
RETAIL STORE	10/23/2009 14:07	0.02	20	900	829.44	70.56	5.880	353%
RETAIL STORE	10/23/2009 14:12	0.02	20	900	725.76	174.24	14.520	871%
RETAIL STORE	10/23/2009 14:17	0.02	20	900	829.44	70.56	5.880	353%
LOCAL GOVT OFFICE	8/4/2009 16:02	0.02	20	350	337.5	12.5	1.042	63%
LOCAL GOVT OFFICE	8/4/2009 16:07	0.02	20	350	363.42	-13.42	0.000	-67%
LOCAL GOVT OFFICE	8/4/2009 16:12	0.02	20	350	347.22	2.78	0.232	14%
LOCAL GOVT OFFICE	8/4/2009 16:17	0.02	20	350	304.92	45.08	3.757	225%

LOCAL GOVT OFFICE	8/4/2009 16:22	0.02	20	350	350.1	-0.1	0.000	-1%
LOCAL GOVT OFFICE	8/4/2009 16:27	0.02	20	350	374.22	-24.22	0.000	-121%
LOCAL GOVT OFFICE	8/4/2009 16:32	0.02	20	350	308.52	41.48	3.457	207%
LOCAL GOVT OFFICE	8/4/2009 17:32	0.01	10	310	306.9	3.1	0.258	0.31
LOCAL GOVT OFFICE	8/5/2009 17:12	0.01	10	310	287.82	22.18	1.848	222%
LOCAL GOVT OFFICE	8/6/2009 17:02	0.01	10	310	181.08	128.92	10.743	1289%
LOCAL GOVT OFFICE	8/6/2009 17:07	0.01	10	310	175.68	134.32	11.193	1343%
LOCAL GOVT OFFICE	8/6/2009 17:12	0.01	10	310	171.72	138.28	11.523	1383%
LOCAL GOVT OFFICE	8/6/2009 17:17	0.01	10	310	170.28	139.72	11.643	1397%
LOCAL GOVT OFFICE	8/6/2009 17:22	0.01	10	310	192.6	117.4	9.783	1174%
LOCAL GOVT OFFICE	8/6/2009 17:27	0.01	10	310	187.56	122.44	10.203	1224%
LOCAL GOVT OFFICE	8/6/2009 17:32	0.01	10	310	193.32	116.68	9.723	1167%

LOCAL GOVT OFFICE	8/6/2009 17:37	0.01	10	310	195.66	114.34	9.528	1143%
LOCAL GOVT OFFICE	8/6/2009 17:42	0.01	10	310	166.68	143.32	11.943	1433%
LOCAL GOVT OFFICE	8/6/2009 17:47	0.01	10	310	208.44	101.56	8.463	1016%
LOCAL GOVT OFFICE	8/6/2009 17:52	0.01	10	310	172.44	137.56	11.463	1376%
LOCAL GOVT OFFICE	8/6/2009 17:57	0.01	10	310	120.6	189.4	15.783	1894%
LOCAL GOVT OFFICE	8/31/2009 14:02	0.01	10	380	325.8	54.2	4.517	542%
LOCAL GOVT OFFICE	8/31/2009 14:07	0.01	10	380	288.54	91.46	7.622	915%
LOCAL GOVT OFFICE	8/31/2009 14:12	0.01	10	380	315.18	64.82	5.402	648%
LOCAL GOVT OFFICE	8/31/2009 14:17	0.01	10	380	233.28	146.72	12.227	1467%
LOCAL GOVT OFFICE	8/31/2009 14:22	0.01	10	380	285.48	94.52	7.877	945%
LOCAL GOVT OFFICE	8/31/2009 14:27	0.01	10	380	275.4	104.6	8.717	1046%
LOCAL GOVT OFFICE	8/31/2009 14:32	0.01	10	380	266.76	113.24	9.437	1132%

LOCAL GOVT OFFICE	8/31/2009 14:37	0.01	10	380	286.2	93.8	7.817	938%
LOCAL GOVT OFFICE	8/31/2009 14:42	0.01	10	380	255.24	124.76	10.397	1248%
LOCAL GOVT OFFICE	8/31/2009 14:47	0.01	10	380	283.14	96.86	8.072	969%
LOCAL GOVT OFFICE	8/31/2009 14:52	0.01	10	380	287.1	92.9	7.742	929%
LOCAL GOVT OFFICE	8/31/2009 14:57	0.01	10	380	259.2	120.8	10.067	1208%
LOCAL GOVT OFFICE	8/31/2009 17:02	0.01	10	320	342.9	-22.9	0.000	-229%
LOCAL GOVT OFFICE	8/31/2009 17:07	0.01	10	320	341.28	-21.28	0.000	-213%
LOCAL GOVT OFFICE	8/31/2009 17:12	0.01	10	320	283.14	36.86	3.072	369%
LOCAL GOVT OFFICE	8/31/2009 17:17	0.01	10	320	284.58	35.42	2.952	354%
LOCAL GOVT OFFICE	8/31/2009 17:22	0.01	10	320	234.9	85.1	7.092	851%
LOCAL GOVT OFFICE	8/31/2009 17:27	0.01	10	320	268.2	51.8	4.317	518%
LOCAL GOVT OFFICE	8/31/2009 17:32	0.01	10	320	271.08	48.92	4.077	489%

LOCAL GOVT OFFICE	8/31/2009 17:37	0.01	10	320	209.52	110.48	9.207	1105%
LOCAL GOVT OFFICE	8/31/2009 17:42	0.01	10	320	255.96	64.04	5.337	640%
LOCAL GOVT OFFICE	8/31/2009 17:47	0.01	10	320	167.94	152.06	12.672	1521%
LOCAL GOVT OFFICE	8/31/2009 17:52	0.01	10	320	237.42	82.58	6.882	826%
LOCAL GOVT OFFICE	8/31/2009 17:57	0.01	10	320	150.66	169.34	14.112	1693%
LOCAL GOVT OFFICE	9/11/2009 14:42	0.02	20	410	307.98	102.02	8.502	510%
LOCAL GOVT OFFICE	9/18/2009 16:02	0.03	30	360	279	81	6.750	270%
LOCAL GOVT OFFICE	9/18/2009 16:07	0.03	30	360	280.8	79.2	6.600	264%
LOCAL GOVT OFFICE	9/18/2009 16:12	0.03	30	360	281.34	78.66	6.555	262%
LOCAL GOVT OFFICE	9/18/2009 16:17	0.03	30	360	283.14	76.86	6.405	256%
LOCAL GOVT OFFICE	9/18/2009 16:22	0.03	30	360	268.56	91.44	7.620	305%
LOCAL GOVT OFFICE	9/18/2009 16:37	0.03	30	360	263.52	96.48	8.040	322%

LOCAL GOVT OFFICE	9/18/2009 16:42	0.03	30	360	259.2	100.8	8.400	336%
LOCAL GOVT OFFICE	9/18/2009 16:47	0.03	30	360	267.48	92.52	7.710	308%
LOCAL GOVT OFFICE	9/21/2009 14:02	0.02	20	440	414.18	25.82	2.152	129%
LOCAL GOVT OFFICE	9/21/2009 14:07	0.02	20	440	396.36	43.64	3.637	218%
LOCAL GOVT OFFICE	9/21/2009 14:12	0.02	20	440	368.1	71.9	5.992	360%
LOCAL GOVT OFFICE	9/21/2009 14:17	0.02	20	440	326.34	113.66	9.472	568%
LOCAL GOVT OFFICE	9/21/2009 14:22	0.02	20	440	319.14	120.86	10.072	604%
LOCAL GOVT OFFICE	9/21/2009 14:27	0.02	20	440	325.08	114.92	9.577	575%
LOCAL GOVT OFFICE	9/21/2009 14:32	0.02	20	440	352.62	87.38	7.282	437%
LOCAL GOVT OFFICE	9/21/2009 14:37	0.02	20	440	340.74	99.26	8.272	496%
LOCAL GOVT OFFICE	9/21/2009 14:42	0.02	20	440	343.98	96.02	8.002	480%
LOCAL GOVT OFFICE	9/21/2009 14:47	0.02	20	440	369.9	70.1	5.842	351%

LOCAL GOVT OFFICE	9/21/2009 14:52	0.02	20	440	329.76	110.24	9.187	551%
LOCAL GOVT OFFICE	9/21/2009 14:57	0.02	20	440	351.72	88.28	7.357	441%
LOCAL GOVT OFFICE	9/21/2009 15:02	0.08	80	440	378.36	61.64	5.137	77%
LOCAL GOVT OFFICE	9/21/2009 15:07	0.08	80	440	350.28	89.72	7.477	112%
LOCAL GOVT OFFICE	9/21/2009 15:12	0.08	80	440	344.34	95.66	7.972	120%
LOCAL GOVT OFFICE	9/21/2009 15:17	0.08	80	440	356.04	83.96	6.997	105%
LOCAL GOVT OFFICE	9/21/2009 15:22	0.08	80	440	343.98	96.02	8.002	120%
LOCAL GOVT OFFICE	9/21/2009 15:27	0.08	80	440	369.36	70.64	5.887	88%
LOCAL GOVT OFFICE	9/21/2009 15:32	0.08	80	440	329.04	110.96	9.247	139%
LOCAL GOVT OFFICE	9/21/2009 15:37	0.08	80	440	350.28	89.72	7.477	112%
LOCAL GOVT OFFICE	9/21/2009 15:42	0.08	80	440	362.88	77.12	6.427	96%
LOCAL GOVT OFFICE	9/21/2009 15:47	0.08	80	440	343.44	96.56	8.047	121%

LOCAL GOVT OFFICE	9/21/2009 15:52	0.08	80	440	354.6	85.4	7.117	107%
LOCAL GOVT OFFICE	9/21/2009 15:57	0.08	80	440	343.62	96.38	8.032	120%
LOCAL GOVT OFFICE	9/21/2009 16:02	0.04	40	400	362.7	37.3	3.108	93%
LOCAL GOVT OFFICE	9/21/2009 16:07	0.04	40	400	339.12	60.88	5.073	152%
LOCAL GOVT OFFICE	9/21/2009 16:12	0.04	40	400	344.88	55.12	4.593	138%
LOCAL GOVT OFFICE	9/21/2009 16:17	0.04	40	400	375.3	24.7	2.058	62%
LOCAL GOVT OFFICE	9/21/2009 16:22	0.04	40	400	330.48	69.52	5.793	174%
LOCAL GOVT OFFICE	9/21/2009 16:27	0.04	40	400	339.84	60.16	5.013	150%
LOCAL GOVT OFFICE	9/21/2009 16:42	0.04	40	400	324.72	75.28	6.273	188%
LOCAL GOVT OFFICE	9/21/2009 16:47	0.04	40	400	348.48	51.52	4.293	129%
LOCAL GOVT OFFICE	9/21/2009 16:52	0.04	40	400	368.28	31.72	2.643	79%
LOCAL GOVT OFFICE	9/21/2009 16:57	0.04	40	400	291.42	108.58	9.048	271%

LOCAL GOVT OFFICE	9/21/2009 17:02	0.03	30	360	347.94	12.06	1.005	40%
LOCAL GOVT OFFICE	9/21/2009 17:07	0.03	30	360	307.08	52.92	4.410	176%
LOCAL GOVT OFFICE	9/21/2009 17:12	0.03	30	360	317.34	42.66	3.555	142%
LOCAL GOVT OFFICE	9/21/2009 17:17	0.03	30	360	305.46	54.54	4.545	182%
LOCAL GOVT OFFICE	9/21/2009 17:22	0.03	30	360	314.82	45.18	3.765	151%
LOCAL GOVT OFFICE	9/21/2009 17:27	0.03	30	360	320.4	39.6	3.300	132%
LOCAL GOVT OFFICE	9/21/2009 17:32	0.03	30	360	286.56	73.44	6.120	245%
LOCAL GOVT OFFICE	9/21/2009 17:37	0.03	30	360	307.26	52.74	4.395	176%
LOCAL GOVT OFFICE	9/21/2009 17:42	0.03	30	360	297	63	5.250	210%
LOCAL GOVT OFFICE	9/21/2009 17:47	0.03	30	360	264.24	95.76	7.980	319%
LOCAL GOVT OFFICE	9/21/2009 17:52	0.03	30	360	298.8	61.2	5.100	204%
INDUSTRIAL BAKERY	8/6/2009 15:02	0.12	120	530	409.25	120.75	10.063	101%

INDUSTRIAL BAKERY	8/6/2009 15:07	0.12	120	530	393.7	136.3	11.358	114%
INDUSTRIAL BAKERY	8/6/2009 15:12	0.12	120	530	391.78	138.22	11.518	115%
INDUSTRIAL BAKERY	8/6/2009 15:17	0.12	120	530	412.03	117.97	9.831	98%
INDUSTRIAL BAKERY	8/6/2009 15:22	0.12	120	530	408.48	121.52	10.127	101%
INDUSTRIAL BAKERY	8/6/2009 15:27	0.12	120	530	392.45	137.55	11.463	115%
INDUSTRIAL BAKERY	8/6/2009 15:32	0.12	120	530	390.05	139.95	11.663	117%
INDUSTRIAL BAKERY	8/6/2009 15:37	0.12	120	530	403.68	126.32	10.527	105%
INDUSTRIAL BAKERY	8/6/2009 15:42	0.12	120	530	409.82	120.18	10.015	100%
INDUSTRIAL BAKERY	8/6/2009 15:47	0.12	120	530	415.78	114.22	9.518	95%
INDUSTRIAL BAKERY	8/6/2009 15:52	0.12	120	530	422.3	107.7	8.975	90%
INDUSTRIAL BAKERY	8/6/2009 15:57	0.12	120	530	403.58	126.42	10.535	105%
INDUSTRIAL BAKERY	8/26/2009 15:02	0.12	120	520	402.91	117.09	9.758	98%

INDUSTRIAL BAKERY	8/26/2009 15:07	0.12	120	520	406.66	113.34	9.445	94%
INDUSTRIAL BAKERY	8/26/2009 15:12	0.12	120	520	423.55	96.45	8.038	80%
INDUSTRIAL BAKERY	8/26/2009 15:17	0.12	120	520	405.7	114.3	9.525	95%
INDUSTRIAL BAKERY	8/26/2009 15:22	0.12	120	520	412.99	107.01	8.918	89%
INDUSTRIAL BAKERY	8/26/2009 15:27	0.12	120	520	408.29	111.71	9.309	93%
INDUSTRIAL BAKERY	8/26/2009 15:32	0.12	120	520	396	124	10.333	103%
INDUSTRIAL BAKERY	8/26/2009 15:37	0.12	120	520	403.97	116.03	9.669	97%
INDUSTRIAL BAKERY	8/26/2009 15:42	0.12	120	520	405.41	114.59	9.549	95%
INDUSTRIAL BAKERY	8/26/2009 15:47	0.12	120	520	401.95	118.05	9.838	98%
INDUSTRIAL BAKERY	8/26/2009 15:52	0.12	120	520	415.39	104.61	8.718	87%
INDUSTRIAL BAKERY	8/26/2009 15:57	0.12	120	520	418.46	101.54	8.462	85%
INDUSTRIAL BAKERY	8/26/2009 16:02	0.12	120	560	384.58	175.42	14.618	146%

INDUSTRIAL BAKERY	8/27/2009 15:27	0.12	120	540	400.99	139.01	11.584	116%
INDUSTRIAL BAKERY	9/18/2009 16:02	0.12	120	550	428.64	121.36	10.113	101%
INDUSTRIAL BAKERY	9/18/2009 16:07	0.12	120	550	434.98	115.02	9.585	96%
INDUSTRIAL BAKERY	9/18/2009 16:12	0.12	120	550	424.51	125.49	10.458	105%
INDUSTRIAL BAKERY	9/18/2009 16:17	0.12	120	550	433.44	116.56	9.713	97%
INDUSTRIAL BAKERY	9/18/2009 16:22	0.12	120	550	434.21	115.79	9.649	96%
INDUSTRIAL BAKERY	9/18/2009 16:37	0.12	120	550	438.34	111.66	9.305	93%
INDUSTRIAL BAKERY	9/18/2009 16:42	0.12	120	550	448.13	101.87	8.489	85%
INDUSTRIAL BAKERY	9/18/2009 16:47	0.12	120	550	448.9	101.1	8.425	84%
INDUSTRIAL BAKERY	9/21/2009 16:32	0.12	120	550	404.54	145.46	12.122	121%
INDUSTRIAL BAKERY	9/21/2009 16:37	0.12	120	550	409.54	140.46	11.705	117%
INDUSTRIAL BAKERY	9/22/2009 16:57	0.12	120	550	438.82	111.18	9.265	93%

9.6 Appendix F

Sample of ADS XML instructions DRAS would receive:

Dispatch Signal Propagation

This pilot demonstration had the DRAS is directly interfaced to the CAISO Automated Dispatch System (ADS). It polls the ADS Server to receive dispatch instructions as depicted in the following general pseudo code from the “ADS API Specification”:

```
// Check for new batches
Batches = getDispatchBatchesSinceUID( LastDispatchUID )
// Iterate batches returned (may be zero if no new)
For Each Batch in Batches
    // Retrieve Instructions
    BatchData = getDispatchBatch( Batch.BatchUID )
    // Decode and decompress
    DecodeAndDecompress( BatchData )
    // Optional Step: Validate receipt
    validateDispatchBatch( Batch.BatchUID )
    // Process Batch Data (your logic)
    Process( BatchData )
    // Update the last batch uid processed
    Set LastDispatchUID = Batch.BatchUID
End for each
```

The connection to the ADS Server is secured using SSL with both client and server side certificates.

Instructions from the ADS arrive in the form of XML documents. The following fields from the XML document are examined by the DRAS to determine the appropriate course of action:

- <batchType>0</batchType> - This is the type of instruction. The two types that are relevant are “5 minute dispatchable” and “OOS Instructions”.
- <startTime>2006-10-13T14:10:00Z</startTime> - This is the start time of the instruction
- <endTime>2006-10-13T14:15:00Z</startTime> - This is the end time of the instruction
- <dot>12.0</dot> - This is the level in MW that the resource is being instructed to go to.

9.7 Appendix G

Market Simulation Schedule for summer of 2009 Participating Load Pilot:

Date: 06/26/09 Prepare Market Simulation

Objective:

Confirm SC connectivity instructions to testing environment

Confirm activation of security certificates for ADS ….etc

Confirm activation of security certificates for OMAR

Resolve any connectivity issues into the CAISO Market Simulation environment

Date: Mon, June 29th Starting Market Simulation

Objective:

CAISO support 08:00-17:00

SC submit DA schedules and bids for TD June 30th (default bids reside in the system and can be overwritten)

Perform SIBR test

Perform Display test OASIS/CMRI

Plan:

Time	Test Step	Responsibility
0800	CAISO support Opens	CAISO/SCs
9:55	DA Market schedule submission deadline for TD June 30th	SCs
1000	Run IFM Market for TD	CAISO
1300	Post Market Results	CAISO
1300 - 1600	Test OASIS/CMRI	CAISO/SCs
1700	Close	CAISO/ SCs

Date: Tue, June 30th, Test SIBR for DA and RT

Objective:

CAISO support 08:00-17:00

SCs submit DA schedules and bids for July 1st and RT submission for TD June 30th (default bids reside in the system and can be overwritten).

Perform SIBR test for DA and RT

Plan:

Time	Test Step	Responsibility
0800	CAISO support Opens	CAISO/ SCs
9:55	DA Market schedule submission deadline for TD June 30th	SCs
1000	*Run DA Market for July 1st*	CAISO
1000 - 1700	*RT Market schedule submission close 75 mins before the TH*	SCs
1000 - 1700	*Run RT Market for TD June 30th for HE 11-17 (other hours pre-processed)*	CAISO

1000 - 1700	*Post market Results*	CAISO
1700	Close	CAISO/ SCs

Date: Wed, July 1st Test Contingency Dispatch and Exceptional Dispatch

Objective:

CAISO support 08:00-17:00

SC submit DA schedules and bids for July 2nd and RT submission for TD July 1st (default bids reside in the system and can be overwritten)

Perform Contingency Dispatch

Perform Exceptional Dispatch

Perform ADS Test

Plan:

Time	Test Step	Responsibility
0800	CAISO support Opens	CAISO/ SCs
0800 - 1000	Run DA Market for July 2nd	CAISO
1000 - 1700	SCs submit RT Bids for July 1st	SCs
1000 - 1700	Run RT Market for TD July 1st for HE 11-17 (other hours pre-processed)	CAISO
1400 - 1500	Contingency Dispatch: PG&E RESOURCES	CAISO/ SCs
1500-1600	Exceptional Dispatch: PG&E RESOURCES	CAISO/ SCs
1100 - 1700	ADS send out Instructions	CAISO/ SCs
1700	Close	CAISO/ SCs

Date: Thu, July 2nd Test OMAR Connections, Test SDG3 Telemetry Connection

Objective:

CAISO support 08:00-17:00

SC submit DA schedules and bids for July 3rd and RT submission for TD July 2nd (default bids reside in the system and can be overwritten)

If necessary, continue to perform Contingency Dispatch and Exceptional Dispatch

SC submit test meter Data through OMAR

Test Telemetry Connection (coordinated through EMS engineer- additional details to follow)

Perform EMS Point to Point test with real or mocked-up data

Plan:

Time	Test Step	Responsibility
0800	CAISO support Opens	CAISO/ SCs
0800 - 1000	*Run DA Market for July 3rd*	CAISO
1000 - 1600	*Run RT Market for TD July 2nd for HE 11-17 (other hours pre-processed)*	CAISO
1400 - 1500	*Contingency Dispatch: PG&E RESOURCES*	CAISO/ SCs
1500-1600	*Exceptional Dispatch: PG&E RESOURCES,*	CAISO/ SCs
1000 - 1200	SCs submit Test meter data for the CLAPs through OMAR	CAISO/SCs
1700	Close	CAISO/ SCs

Date: Mon July 6th Test Contingency Dispatch with SC Bids

Objective:

CAISO support 08:00-17:00

SC submit DA schedules and bids for July 7th and RT submission for TD July 6th

SC submission includes the bid scenarios that SC would like to test

Perform Contingency Dispatch

Plan:

Time	Test Step	Responsibility
0800	CAISO support Opens	CAISO/ SCs
0800 - 1000	*Run DA Market for July 7th*	CAISO
1000 - 1700	*SCs submit RT Bids*	SCs
1000 - 1700	*Run RT Market for TD July 6th for HE 11-17 (other hours pre-processed)*	CAISO
1400 - 1500	*Contingency Dispatch: PG&E RESOURCES*	CAISO/ SCs
1100 - 1700	*ADS send out Instructions*	CAISO/ SCs
1700	Close	CAISO/ SCs

Date: Tue, July 7th Test Exceptional Dispatch with Bids

Test PCG2 Telemetry Connections

Objective:

CAISO support 08:00-17:00

SC submission DA for July 8th and RT schedules for TD July 7th

SC submission includes the bid scenarios that SC would like to test

Perform Exceptional Dispatch

Telemetry Connections and Point to Point Tests: (Additional Coordination with RIG engineer required- details to follow)

Perform telemetry Point to Point test with real data or dummy data.

PCG2 connects to CAISO EMS system

Perform telemetry Point to Point test with real data or dummy data

Plan:

Time	Test Step	Responsibility
0800	CAISO support Opens	CAISO/ SCs
0900 -1000	*Perform PCG2 telemetry Point to Point test*	CAISO/PCG2
0800 - 1000	*Run DA Market for July 8th*	CAISO
1000 - 1600	*Run RT Market for TD July 7th for HE 11-17 (other hours pre-processed)*	CAISO
1400-1500	*Exceptional Dispatch: PG&E RESOURCES*	CAISO/ SCs
1700	Close	CAISO/ SCs

Date: Wed, July 8th Test Contingency Dispatch with SC Bids

Objective:

CAISO support 08:00-17:00

SC submits DA schedules and bids for July 9th and RT submission for TD July 8th

SC submission includes the bid scenarios that SC would like to test

Perform Contingency Dispatch

Plan:

Time	Test Step	Responsibility
0800	CAISO support Opens	CAISO/ SCs
0800 - 1000	*Run DA Market for July 9th*	CAISO
1000 - 1700	*SCs submit RT Bids*	SCs
1000 - 1700	*Run RT Market for TD July 8th for HE 11-17*	CAISO
0100 - 2400	*Run RT Market for TD July 8th for HE 01-24*	CAISO/SCs
1400 - 1500	*Contingency Dispatch: PG&E RESOURCES*	CAISO/ SCs
1100 - 1700	*ADS send out Instructions*	CAISO/ SCs
1700	Close	CAISO/ SCs

Date: July 9th Exceptional Dispatch with Valid Results

Objective:

CAISO support 08:00-17:00

SC submits DA schedules and bids for July 10th and RT submission for TD July 9th

SC submission includes the bid scenarios that SC would like to test

Perform Exceptional Dispatch

SC gets valid results through ADS

Time	Test Step	Responsibility
0800	CAISO support Opens	CAISO/ SCs
0800 - 1000	*Run DA Market for July 10th*	CAISO
1000 - 1600	*Run RT Market for TD July 9th for HE 11-17 (other hours pre-processed)*	CAISO
0100 - 2400	*Run RT Market for TD July 9th for HE 01-24*	CAISO/SCs
1400 - 1500	*Exceptional Dispatch: PG&E RESOURCES*	CAISO/ SCs
0100 – 2400	ADS send out Instructions	CAISO/SCs
1700	Close	CAISO/ SCs

Date: July 10th Test SCE1 Telemetry Connection, Contingency Dispatch with Valid Results

Objective:

CAISO support 08:00-17:00

SC submits DA schedules and bids for July 11th and RT submission for TD July 10th

SC submission includes the bid scenarios that SC would like to test

Perform Contingency Dispatch

SC gets valid results through ADS

Time	Test Step	Responsibility
0800	CAISO support Opens	CAISO/ SCs
0800 - 1000	*Run DA Market for July 11th*	CAISO
1000 - 1600	*Run RT Market for TD July 10th for HE 11-17 (other hours pre-processed)*	CAISO
0100 - 2400	*Run RT Market for TD July 10th for HE 01-24*	CAISO/SCs
1400 - 1500	*Contingency Dispatch: PG&E RESOURCES*	CAISO/ SCs
0100 – 2400	ADS send out Instructions	CAISO/SCs
1700	Close	CAISO/ SCs

Date: July 12th Day-ahead Market for July 13th

Objective:

SC submits DA schedules and bids for July 13th

CAISO Run Day-ahead Market

SC gets valid results through OASIS/CMRI

Time	Test Step	Responsibility
0800 - 1000	SC submits DA schedules and bids for July 13th	SCs
1000	*Close Day-ahead Market*	CAISO
1000 - 1300	*Run DA Market*	CAISO
1300	*Post DA market*	CAISO

Date: July 13th Continue test, Contingency Dispatch with Valid Results

Objective:

CAISO support 08:00-17:00

SC submits DA schedules and bids for July 14th and RT submission for TD July 13th

SC submission includes the bid scenarios that SC would like to test

Perform Contingency Dispatch

SC gets valid results through ADS

Time	Test Step	Responsibility
0800	CAISO support Opens	CAISO/ SCs
0800 - 1000	*Run DA Market for July 14th*	CAISO
1000 - 1600	*Run RT Market for TD July 13th for HE 11-17 (other hours pre-processed)*	CAISO
0100 - 2400	*Run RT Market for TD July 13th for HE 01-24*	CAISO/SCs
1400 - 1500	*Contingency Dispatch: PG&E RESOURCES*	CAISO/ SCs
0100 – 2400	ADS send out Instructions	CAISO/SCs
1700	Close	CAISO/ SCs

Date: July 14th Continue test, Exceptional Dispatch

(if can coordinate with actual dispatch, view Telemetry)

Objective:

CAISO support 08:00-17:00

SC submits DA schedules and bids for July 15th and RT submission for TD July 14th

SC submission includes the bid scenarios that SC would like to test

Observe telemetry to reflect DR instruction

Time	Test Step	Responsibility
0800	CAISO support Opens	CAISO/ SCs
0800 - 1000	*Run DA Market for July 15th*	CAISO
1000 - 1600	*Run RT Market for TD July 14th for HE 11-17 (other hours pre-processed)*	CAISO
0100 - 2400	*Run RT Market for TD July 14th for HE 01-24*	CAISO/SCs

1400 - 1500	*Exceptional Dispatch: PG&E RESOURCES*	CAISO/ SCs
1400 – 1500	Observe telemetry Changes	CAISO/SCs
1700	Close	CAISO/ SCs

Date: July 15th Conclusion

Objective:

CAISO support 08:00-17:00

SC submits DA schedules and bids for July 16th and RT submission for TD July 15th

SC submission includes the bid scenarios that SC would like to test

Overall Markets Sim evaluation

Time	Test Step	Responsibility
0800	CAISO support Opens	CAISO/ SCs
0800 - 1000	*Run DA Market for July 16th*	CAISO
1000 - 1600	*Run RT Market for TD July 15th for HE 11-17 (other hours pre-processed)*	CAISO
1100 - 1400	*Discussion the Market Simulation*	CAISO/ SCs
1400 - 1500	*Conclusion: Next Step*	CAISO/ SCs
1700	Close	CAISO

Date: July 22nd AS Acceptance Test

Objective:

A/S certification testing (15:00 – 16:00)

Time	Test Step	Responsibility
1500 - 1600	CAISO testing 3 DR Pseudo Generators	CAISO/ SCs

9.8 Appendix H

Project Milestone

Task	Estimated Time Frame		Actual Time Frame		Complete (%)
	Start	Finish	Start	Finish	
CPUC Approval of Bridge funding for Pilot	12/18/2009	12/18/2009	12/18/2009	12/18/2009	100%
PG&E Demand Response	12/18/2008	12/31/2009	1/15/2009	10/31/2009	100%
Define Business Requirements and affected departments	1/1/2009	3/31/2009	1/15/2009	5/1/2009	100%
PG&E's Commercial & Industrial Participating Load Pilot Operation	7/1/2009	10/31/2009	7/29/2009	10/31/2009	100%
CAISO	1/15/2009	12/31/2009	1/15/2009	12/3/2009	100%
Participating Load Agreement	1/15/2009	4/1/2009	1/15/2009	4/10/2009	100%
MRTU Release to Production	3/31/2009	4/1/2009	3/31/2009	4/1/2009	100%
Complete EMS	3/1/2009	3/6/2009	3/1/2009	3/5/2009	100%
Complete Full Network Model	3/5/2009	3/17/2009	3/5/2009	3/16/2009	100%
Complete Resource Data Template	4/21/2009	4/24/2009	4/21/2009	4/24/2009	100%
Analyze Pilot - Develop Recommendation to Stakeholders and CPUC	11/1/2009	12/31/2009	11/1/2009	12/3/2009	100%
Front Office (Energy Procurement)	2/15/2009	10/31/2009	2/15/2009	10/31/2009	100%
Configuration of systems and Policy & Procedures	2/15/2009	6/1/2009	2/15/2009	7/15/2009	100%
Scheduling	5/31/2009	10/30/2009	7/29/2009	10/31/2009	100%

Schedule Dispatch, if any	6/1/2009	10/31/2009	7/29/2009	10/30/2009	100%
Back Office (Settlements)	3/15/2009	10/31/2009	3/15/2009	1/15/2009	93%
Configuration of systems and Policy & Procedures	2/15/2009	6/1/2009	2/15/2009	7/15/2009	100%
Submission of meter data	7/1/2009	12/31/2009	9/10/2009	12/13/2009	100%
ISO Settlements	9/10/2009	12/13/2009	9/10/2009	1/15/2010	80%
Energy Data Services	3/15/2009	10/31/2009	3/15/2009	11/2/2009	100%
Configuration of systems and Policy & Procedures	3/15/2009	5/15/2009	3/15/2009	7/1/2009	100%
Implementation and Operation	6/1/2009	10/31/2009	7/31/2009	11/2/2009	100%
Meteorology (Weather Data)	4/15/2009	10/31/2009	4/15/2009	10/31/2009	100%
Configuration of systems and Policy & Procedures	4/15/2009	5/1/2009	4/15/2009	5/15/2009	100%
Implementation and Operation	5/20/2009	10/31/2009	7/1/2009	10/31/2009	100%
Metering Field Services	5/1/2009	6/1/2009	5/1/2009	6/20/2009	100%
Reprogram Meter to 5 minutes	5/1/2009	5/15/2009	5/1/02009	6/20/2009	100%
Installation of Telemetry at customer site	5/22/2009	6/1/2009	6/10/2009	6/12009	100%
External Modifications to PG&E Vendors	4/8/2009	6/22/2009	4/1/2009	8/6/2009	100%
Demand Response Automated Server (DRAS) - CAISO ADS Communication	4/8/2009	6/22/2009	4/1/2009	8/6/2009	100%
Forecasting (Outsource)	3/15/2009	10/31/2009	3/15/2009	10/31/2009	100%
Sourcing	3/15/2009	4/15/2009	3/15/2009	4/27/2009	100%
Implementation and Operation	5/15/2009	10/31/2009	5/15/2009	10/31/2009	100%
Customer Recruitment	2/1/2009	4/20/2009	2/1/2009	4/20/2009	100%

Recruitment Pitch (Marketing)	2/1/2009	3/31/2009	2/1/2009	4/10/2009	100%
Execution of Customer Participation Agreement (CPA) - Signed Agreement	4/1/2009	4/20/2009	4/1/2009	5/28/2009	100%
Telemetery (Outsource)	1/15/2009	10/31/2009	1/15/2009	11/1/2009	100%
Internal & External Solution Research	1/15/2009	4/1/2009	1/15/2009	3/1/2009	100%
Sourcing	4/1/2009	5/15/2009	4/1/2009	5/19/2009	100%
Implementation and Operation	6/1/2009	10/31/2009	6/12/2009	11/1/2009	100%
Testing	6/5/2009	6/29/2009	6/29/2009	7/22/2009	100%
Telemetery	6/5/2009	6/29/2009	7/7/2009	7/7/2009	100%
CAISO A/S Testing	6/5/2009	6/29/2009	7/22/2009	7/22/2009	100%
Interface Testing w/CAISO on scheduling, settlements and dispatch	6/5/2009	6/29/2009	6/29/2009	7/22/2009	100%
Participant Load reduction	6/5/2009	6/29/2009	7/22/2009	7/22/2009	100%
Internal testing	6/5/2009	6/29/2009	6/29/2009	7/22/2009	100%

Attachments B
SCE PLP Project Report

2009 SCE Participating Load Pilot

Feasibility Report

1. Table of Contents

2. Executive Summary

The objective of SCE's 2009 Participating Load Pilot (PLP) was to explore the technical and economic feasibility of small (less than 5 kW per endpoint) SCE-aggregated Demand Response (DR) in Participating Load (PL) and/or future Proxy Demand Resource (PDR) products for the Measurement and Performance (MAP) markets of the California Independent System Operator (CAISO). The SCE Participating Load Pilot was successful in meeting the deliverables outlined in the Detailed Implementation Plan filed with the California Public Utility Commission (CPUC) on March 11, 2009:

- SCE Launched the PLP by installing proxy telemetry devices in May, dispatching test events starting in June, completing CAISO ancillary services testing in July and bidding, dispatching and settling the PLP resource with CAISO from August through October.
- SCE and its contractor, KEMA, developed algorithms for utilizing 555 proxy telemetry sensors into a forecast of available load for curtailment and provided this proxy telemetry data to CAISO per ancillary services requirements.
- SCE and KEMA developed algorithms to estimate actual load drop after event dispatch based on available SCADA data and interval meter data with additional verification provided by telemetry information.
- Over the course of 20 weeks, SCE conducted 32 Participating Load events. 12 of these events were coordinated with CAISO where SCE bid the PLP resource into the CAISO's day-ahead market for non spinning reserves. The other 20 events were conducted independent of CAISO where SCE did not bid the resource and dispatched the PLP resource without coordination or dispatch instruction from CAISO.

The PLP has demonstrated the technical feasibility of small aggregated air conditioning load to act as a PL resource and has identified that this type of resource would be more closely aligned with the CAISO proposed Proxy Demand Resource (PDR) market product which requires that only the demand response performance be bid and settled in the wholesale market. Essentially, the PLP resource was able to comply with the CAISO's market process and system requirements for telemetry, bidding, dispatch and settlement. However, the economic feasibility remains a question as the costs for developing and deploying a small aggregated load resource remains unknown. The CPUC recently opened another phase of the Demand Response proceeding to explore "direct participation" per Federal Energy Regulatory Commission (FERC) rule 719 and the results of this proceeding will likely have an impact on the economic feasibility question.

3. Introduction

In response to the California Independent System Operator's (CAISO) urging that some Participating Load (PL) be ready when Market Redesign and Technology Upgrade (MRTU) Release 1 was deployed, Southern California Edison Company (SCE) proposed to modify its current Demand Response Spinning Reserve Pilot (DRSRP) to evaluate its capability as PL. The objective of SCE's PLP is to explore the technical and economic feasibility of small SCE-aggregated Demand Response (DR) as a potential participant in the MRTU Measurement and Performance (MAP) markets for PL and/or Proxy Demand Resource (PDR) products. SCE and CAISO expected that many lessons would be learned throughout the PLP which may result in recommended changes to CAISO PL requirements or technical specifications to make small aggregated DR load feasible in MRTU MAP.

The scope of the project included developing a "telemetry proxy" to determine available DR, bidding the PLP resource into the CAISO PL ancillary services market, dispatching the PLP resource as scheduled by CAISO upon acceptance of SCE's bid, and settlement of the PLP resource performance based on observed load drop at a specific aggregation point. The greatest challenge to small loads participating in ancillary services is the current CAISO metering requirements including real time 4-second telemetry for monitoring available load and 5-minute metering intervals for settlement. Therefore, the pilot explored the development of a statistical sampling telemetry proxy and utilizing substation circuit level Supervisory Control and Data Acquisition (SCADA) as a metering proxy for settlement in lieu of actual metering at each customer site.

The success criteria for SCE's PLP include:

- Developing processes, procedures and systems both internal to SCE and external interfacing with CAISO to aggregate the PLP resource for bidding into

CAISO wholesale markets as PL, dispatching the resource as a non-spinning reserve ancillary service and settlement of the resource after a PLP event.

- Developing methodologies and algorithms for forecasting and estimating the amount of DR load available by utilizing statistical sampling of the end-use loads as “proxy telemetry” for the entire load and reconciling the estimated load drop with the performance observed at an aggregation point such as the appropriate circuit or feeder SCADA meter.
- Proposing methodologies and algorithms for estimating load drop for small aggregated load DR in the MRTU market for settlement purposes utilizing interval metering at an aggregation point instead of at individual end loads.
- Determining whether the developed methodologies for proxy telemetry and settlement are sufficient for CAISO monitoring and settlement purposes. This will help determine both the economic and technical feasibility of small aggregated load DR functioning as PL or PDR in the MRTU market.

SCE worked with many organizations who were critical to this effort including the CAISO, the California Public Utilities Commission (CPUC), the Dutch energy consultancy KEMA, Lawrence Berkeley National Laboratory (LBNL), BPL Global, equipment installer Good Cents Solutions, Corporate Systems Engineering (CSE) and the National Training Center and Ft. Irwin. KEMA developed the statistical tools used to monitor, forecast and settle the Participating Load. BPL Global provided SCE with telemetry sensors that were used to monitor the participating load and provided data hosting and monitoring services, and Good Cents Solutions installed the telemetry sensors and provided field service at the customer site. Corporate Systems Engineering (CSE) manages the existing Load Control System, updated the test platform for the DRSRP to support the Participating Load Pilot, and manufactures the Summer Discount Plan (SDP) devices. Finally, LBNL provided input on the design of the statistical tools KEMA constructed, guidance on the methodologies employed and extended the research by supporting additional analysis on the effects of short-term curtailment on indoor temperatures at the test site.

This is a feasibility report based on the first year of SCE's three year Participating Load Pilot. The data and information gathered for this first year have resulted in recommendations on how to proceed in subsequent years. This report will provide an overview of the steps taken during the first year of the pilot, provide details on how the pilot was conducted and detail the results generated so far.

4. Customer Enrollment

SCE recruited the National Training Center and Ft. Irwin, thirty four miles north east of Barstow, as the program participant for the Participating Load Pilot. For several reasons, Fort Irwin was the ideal program participant.

Figure 1 A Google Earth Image of the Ft. Irwin Complex

- *Marketing & Installation*: Ft. Irwin is a participant in SCE's Summer Discount Program (SDP), with over 3,200 air conditioning cycling devices installed at the complex. As a result, there was no need to conduct a marketing campaign to recruit residential and commercial customers to the PLP.
- *Ideal climate*: The Ft. Irwin complex is located in the Mojave Desert, where temperatures are consistently high during the summer months. Accordingly, SCE could anticipate significant air conditioning load during the PLP testing period.
- *Ideal location on the grid*: In what amounts to the electrical equivalent of a cul-de-sac, Ft. Irwin lies at the end of a transmission circuit where there are basically no other customers. This relative isolation provided SCE with a significant

advantage during the pilot as the SCADA systems monitoring the two substation circuits provided three-second telemetry reporting on the total base load.

- *Base layout similar to a civilian city*: The structures at Ft. Irwin contained within the red polygon in Figure 1 closely resemble the types of structures one might find in a Southern California suburb such as Irvine or Rancho Cucamonga. This similarity offers SCE the opportunity to extrapolate our findings here at Ft. Irwin to other portions of our service territory.
- *Small size*: The base complex indicated by the red polygon in Figure 1 is only a few kilometers across. For the reasons discussed in the systems section of this report, this compact size made the customer ideal for the telemetry system that SCE selected for the PLP.

SCE provided Fort Irwin an incentive payment of $100 for each of the 3,255 air conditioner cycling switches participating in the PLP. Using SCE's historical average of 1.4 kW of load per SDP switch, we estimated a total of approximately 4.6 MW of air conditioning load. However, SCE's observations during the PLP tests indicate that this resource may have represented as much as 8.13 MW of load due to a larger population of commercial & industrial complex air conditioners. This analysis is discussed further in the Event Performance section of the report.

SCE's contact with base residents during the PLP was minimal. However, a survey of base leadership as well as base residents is currently being conducted to determine their thoughts and reactions to pilot participation.

5. Systems and Technology Utilized in the PLP

For the PLP, SCE utilized 4 distinct sub-systems: the load control system; the load telemetry system; the CAISO data processing gateway (DPG); substation level circuit SCADA. In addition, indoor temperature sensors were used to understand impact to customers but were not directly involved in the monitoring, dispatching or settlement of the ancillary services resource.

This section of the final report will address each of these sub-systems in turn. Broadly speaking, the systems utilized in this pilot were acquired to serve a handful of primary business requirements:

- Turning load on and off (the *Load Control System*)
- Measuring the quantity of load available in real time (*Telemetry System*)
- Quantifying, or "Settling", the amount of load that was curtailed (*Substation level SCADA*)
- Sending telemetry information over the CAISO secure data line called the Energy Communications Network (ECN) into the CAISO *DPG*
- The measurement of indoor ambient air temperature in a sampling of the participating structures was fulfilled by the *Indoor Temperature Sensors*

5.1 Load Control System

For this pilot, SCE used its existing Alhambra Control System (ACS) network of one-way, VHF-controlled air conditioning cycling switches that was built for the SDP. A testing application previously utilized for the Demand Response Spinning Reserve Pilot[1] (DRSRP) was updated so that the Ft. Irwin switches could be turned off independent of the rest of the full population of over 360,000 SDP participants.

[1] 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). Available at http://certs.lbl.gov/certs-load-pubs.html

5.2 Load Telemetry System

The underlying technical requirements for both the Telemetry System and the CAISO connectivity system were driven by the CAISO's specifications for a data processing gateway (DPG) to provide the CAISO with near real-time visibility of the resource availability per the requirements for spinning reserves ancillary services. The DPG technical specification clearly explains the requirements for a load supplying non-spinning reserves, best explained by Figure 2.

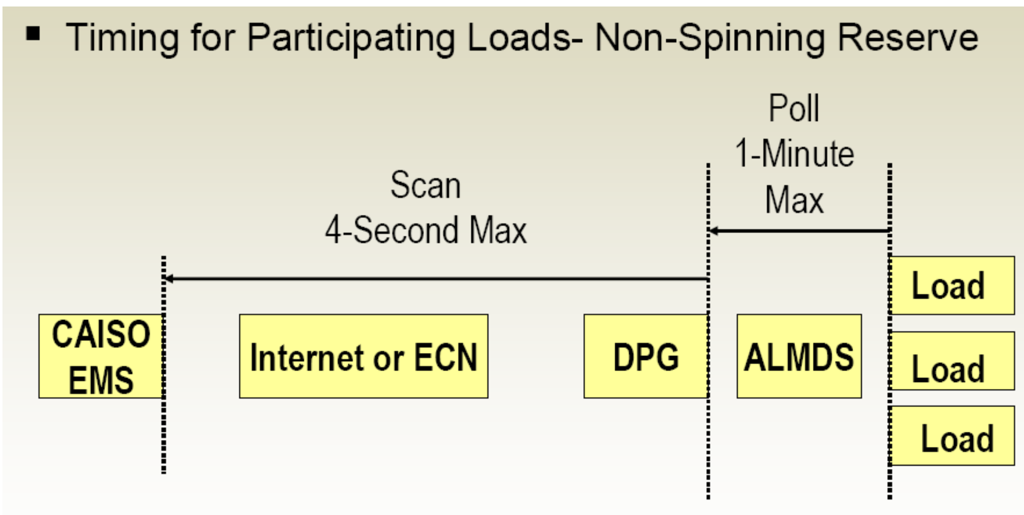


Figure 2 Timing for Participating Loads - Non Spinning Reserve

In essence, the CAISO's standards require the polling of individual loads every minute. The sum of all these aggregated loads is maintained in a subsystem called the Aggregated Load Meter Data System (ALMDS). ALMDS, in turn, reports this sum to the CAISO's Energy Management System (EMS) every 4 seconds. The DPG system enables the secure transmission of this data between ALMDS and EMS. In practice, the DPG and ALMDS subsystems are usually combined.

SCE's PLP proxy telemetry system reported an aggregate estimate of the air conditioning load into the ALMDS/DPG. This aggregated estimate was based on an algorithm described in Section 10.2.4 utilizing the telemetry monitoring of 555 air conditioners out of the total 3,255 air conditioners controlled through the pilot. The load reporting from each individual telemetry device was updated whenever an individual end point load changed by 200 watts or every minute – whichever happened first. CAISO agreed that this approach was appropriate for the pilot, and SCE proceeded to draft a series of technical requirements with which to approach potential telemetry hardware suppliers. SCE's technical requirements can be summarized as follows:

- Device must report load fluctuations of greater than +/- 3 amps in real time to ALMDS/DPG
- Device must possess some non-volatile memory capability
- Device must possess a unique ID that can be used to mark data transmissions back to the ALMDS/DPG
- Device must be enclosed in a weather-proof, tamper-proof container
- Device must be able to withstand weather conditions present throughout SCE's service territory
- Device must be UL-listed.

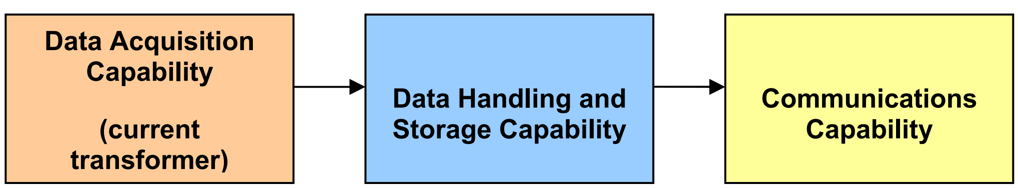


Figure 3 The Three Components of a Viable Telemetry System

The proxy telemetry sensor SCE was searching for was essentially a current transformer (CT) that had some type of integral data handling/storage and communications capability, but was not too expensive to install on individual household air conditioners. Unfortunately, the broader telemetry market is geared more towards offering relatively sophisticated data logging devices with significantly more capability than SCE required and which cost thousands of dollars each.

After researching telemetry hardware manufacturers, SCE identified 4 potential hardware suppliers. SCE purchased 12 devices from each manufacturer and performed testing of both the unit accuracy and telecommunications capability utilizing SCE's in-house meter testing group and Information Technology telecommunications group.

After testing, SCE selected proxy telemetry hardware from BPL Global. BPL Global had also provided the network management and monitoring function for the DRSRP. As described in the application for PLP funding, SCE was leveraging the team and experience from the DRSRP and BPL Global's ability to seamlessly integrate the previous data hosting with the new proxy telemetry devices was a significant factor in the selection.

BPL Global's system, called "Power SG," utilizes a wireless mesh network. Each endpoint load sensor (which can also function as a load controller) communicates back to a data collector via short range radio in the 2.4 GHz spectrum. Each of these nodes has a theoretical open air, line of sight range of about 600 feet. The data collectors are each equipped with a General Packet Radio Service (GPRS) modem that allows them to communicate over standard cellular phone provider networks. One data collector can support up to 5,000 endpoint sensors. The flow of information typically flows from the load sensors back to the Power SG software suite. However, full two way connectivity enables load sensors in the field to be queried independently. The devices also had the capability to interrupt load to their air conditioner, but SCE chose not to utilize this functionality for the PLP .

These technical characteristics provided the Power SG with an assortment of advantages:

- Seamless integration between devices in the field and BPL's web-based network management and monitoring software suite.
- High ratio of load sensors to data concentrators reduced cellular data transmission fees.

– Mesh network provided additional network robustness.

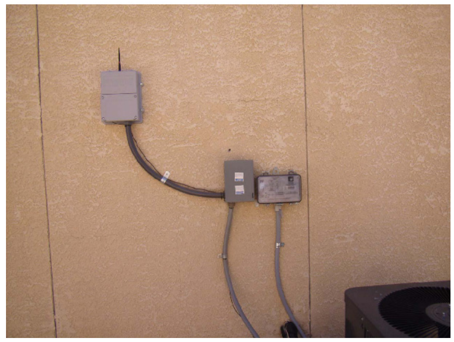


Figure 4 Power SG Load Sensor/Controller Installed on an Air Conditioner (at upper left)

Figure 5 Power SG Data Concentrator Attached to a Street Lamp

The BPL Global PowerSG system provided individual device updates from each of the end points whenever the load changed by 200w or at least once an hour over 99% of the time during the PLP. Whether a similar mesh network system would be the best choice for a larger scale DR program requiring telemetry is an open question and is addressed in Section 7.4.2.

Figure 6 A Power SG Data Repeater

5.3 CAISO Connectivity Systems

SCE utilized the proxy telemetry data from the 555 monitored air conditioners as input for an estimation algorithm (detailed in Section 10) developed by KEMA to estimate the total air conditioning load for all 3,255 air conditioners as telemetry data for CAISO. BPL Global received the data from the proxy telemetry sensors, processed the data through KEMA's estimation algorithm and transmitted the estimated air conditioning load to CAISO utilizing CAISO's standard DNP 3.0 communications protocol which is commonly used in SCADA applications in the electric and water industries. The SCE PLP resource successfully passed CAISO Ancillary Services Certification testing on July 27, 2009. Completion of this testing certified Edison's telemetry connectivity and allowed SCE to bid the PLP resource into the CAISO wholesale market.

5.4 Substation Level Circuit SCADA

Ft. Irwin's previously mentioned isolation on the grid allowed SCE to utilize substation level SCADA as a source of data for determining how much load was actually curtailed from each PLP event. Importantly, this option may not be available in future stages of the PLP, and is addressed in Section 7.4.1.

5.5 Indoor Temperature Sensors

One of the secondary objectives of the PLP is to determine whether or not the short (less than half an hour) duration DR curtailments of air conditioning impact the comfort of the building occupants or whether occupants even notice the events. BPL Global offers an indoor temperature sensor that utilizes the same 2.4 GHz RF communications as the Power SG load controllers. LBNL purchased approximately 100 of these devices and installed them in structures participating in the pilot. SCE and the PLP team were able to monitor the maximum, minimum and average indoor temperatures from the monitored buildings and determine how quickly the building indoor temperatures increased during the 5, 10 and 20 minute duration PLP events. Analysis of the indoor temperature data is continuing in collaboration with LBNL and results will be included in the update described in Section 11.

Figure 7 BPL's Indoor Temperature Sensor

5.6 Future Role of Edison SmartConnect™ in Ancillary Services

SCE is in the process of deploying approximately 5 million Edison SmartConnect™ meters as part of its Advanced Metering Infrastructure (AMI) initiative. The Edison SmartConnect™ meters will provide 1 hour interval meter data for residential customers and 15-minute interval meter data for small commercial and industrial customers with less than 200 kW of peak electric demand.

5.6.1 *Edison SmartConnect™ data for ancillary services settlement*

CAISO has proposed that 15-minute interval data can be utilized for settlement for the new Proxy Demand Resource (PDR) product by taking the 15-minute data and dividing by 3 to develop the 5-minute interval data required for settlement. This approach is further discussed in Section 10.4.1. It is theoretically possible, but outside of the current Edison SmartConnect™ scope, to configure residential meters for 15-minute interval meter reads as the small commercial and industrial meters are being configured. Thus, because the Edison SmartConnect™ initiative will support only hourly interval data for residential customers, the 5-minute proxy interval data will not be available to support the PL Pilot settlements without technical changes, SCE business case justification and regulatory support for reducing the data interval.

5.6.2 *Edison SmartConnect™ data for telemetry*

Edison SmartConnect™ is able to provide near real-time usage information to in-home devices through the Home Area Network (HAN) ZigBee communications and Smart Energy Profile data exchange. However, the AMI infrastructure is not set up to provide this near real-time information back to a central office for purposes of supplying telemetry information in support of ancillary services. While it is theoretically possible that the near real-time usage information could be provided through the HAN to an internet connection, cell phone modem, or another data transmission point in order to approximate telemetry requirements for ancillary services, this functionality will not be available without technical changes, SCE business case justification and regulatory support.

5.6.3 Load Control possibilities

SCE plans to develop an Advanced Load Control System (ALCS) which will enable direct load control signals to be sent through the Edison SmartConnect^{TM} infrastructure to the HAN and customer end-point devices such as programmable communicating thermostats (PCT). The customer program for utilizing the PCT and other HAN devices will initially be Peak Time Rebate (PTR) which incentivizes customers to use less power during peak day afternoons. Additional work will be required to explore and develop retail programs, tariffs and systems which can utilize this new infrastructure to provide ancillary services in the wholesale market where the signals sent to HAN devices would be based on wholesale market dispatches with 10 minute notification and the expectation that the dispatch will be precise. For example, a bid of 5 MW may result in a wholesale dispatch of 4 MW and systems would need to determine which end devices to trigger in order to achieve the proper performance. This functionality will not be available without technical changes, SCE business case justification and regulatory support.

6. Event Information

Over the course of 20 weeks, SCE conducted 32 Participating Load events. 12 of these events were coordinated with CAISO where SCE bid the PLP resource into the CAISO's day-ahead market for non spinning reserves. CAISO dispatched the resource per a predetermined schedule and SCE submitted settlement data for both the load and demand response elements of the Participating Load. 2 of the 12 events scheduled with CAISO were bid and settled, but not successfully dispatched. The other 20 events were conducted independent of CAISO where SCE did not bid the resource and dispatched the PLP resource without coordination or dispatch instruction from CAISO. These CAISO independent, or "Test", dispatches were run to collect additional data for evaluation of the PLP systems and development of statistical tools for algorithm development. A full list of these events, and the performance of the Participating Load resource during them, can be found in Section 10.3. Table 1 provides an overview of the PLP dispatch dates with CAISO coordinated events marked in blue and test events marked in orange (note that some days had multiple test events).

Table 1 Calendar of PLP Events

June 2009

	1	2	3	4	5	6
7	8	9	10	11	12	13
14	15	16	17	18	19	20
21	22	23	24	25	26	27
28	29	30				

July 2009

			1	2	3	4
5	6	7	8	9	10	11
12	13	14	15	16	17	18
19	20	21	22	23	24	25
26	27	28	29	30	31	

August 2009

						1
2	3	4	5	6	7	8
9	10	11	12	13	14	15
16	17	18	19	20	21	22
23	24	25	26	27	28	29
30	31					

September 2009

		1	2	3	4	5
6	7	8	9	10	11	12
13	14	15	16	17	18	19
20	21	22	23	24	25	26
27	28	29	30			

October 2009

				1	2	3
4	5	6	7	8	9	10
11	12	13	14	15	16	17
18	19	20	21	22	23	24
25	26	27	28	29	30	31

SCE Independent Event	CAISO Coordinated Event

PLP events occurred at varying times of the day and during 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 air conditioning load patterns that may arise from weekend usage.

The PLP events were also prescheduled with CAISO so that SCE knew when the dispatch signal would arrive. For a production program, the dispatch signal for ancillary services will not be predictable. However, since the dispatch processes for both CAISO and SCE contained significant manual processes in support of the pilot, it was necessary to schedule the PLP events. In the future, CAISO signals would need to automatically connect to the load control systems to dispatch the proper demand response 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, in order to conform to the CAISO dispatch instruction. Significant systems and program development is being explored to undserstand the scope of work required to enable this level of functionality and automation.

7. Assessment of Technical Feasibility

Bidding, dispatching and settling any resource in the CAISO's Day Ahead Market requires integrating that resource into multiple pre-existing market processes and systems that have been developed over years of coordination between the CAISO and market participants. These market processes and systems are strictly organized and this section analyzes how well the PL resource integrated with these market participation systems and standards.

The basic theme of this section is that while SCE was able to coordinate the bidding, dispatch and settlement of the Participating Load resource, many processes that are automated in typical market processes were run as manual processes for the PLP. Section 7.4.3 will provide recommendations for how these processes can be automated in a future automated DR system.

7.1 Bidding

Each of the steps below was performed manually to facilitate the PLP. Each will require a level of automation in order to be performed in support of an actual retail DR program.

1. SCE's Tariff Programs and Services (TP&S) group schedules an event with Edison's Grid Control Center (GCC) operation.
2. KEMA prepares a PLP load forecast based on temperature forecast and estimated load drop figures from prior PL events. KEMA passes this load forecast to TP&S.
3. TP&S submits the load forecast to SCE'S Energy Supply & Management (ES&M) group for use in bid preparation.

4. The Pre-scheduling desk in the ES&M group submits the PLP bid for non-Spinning reserve into the CAISO MRTU Day Ahead Market by 10:00 AM on the day before the event is scheduled.
5. CAISO processes the bid, and informs ES&M whether or not the bid has been awarded. This happens before 1 PM on the day before the event is scheduled. (NOTE: in the PLP, all bids were submitted via the exceptional dispatch process and the bids were never rejected. In a future program, exceptional dispatch would not be used. Therefore, multiple bid award statuses would need to be tracked which would further heighten the need for automation).
6. ES&M calls TP&S to inform them that the bid has been awarded.
7. TP&S monitors real-time telemetry to verify resource availability. In a production program, ES&M may update the bid if significant deviation occurs between real-time telemetry and the original bid value.

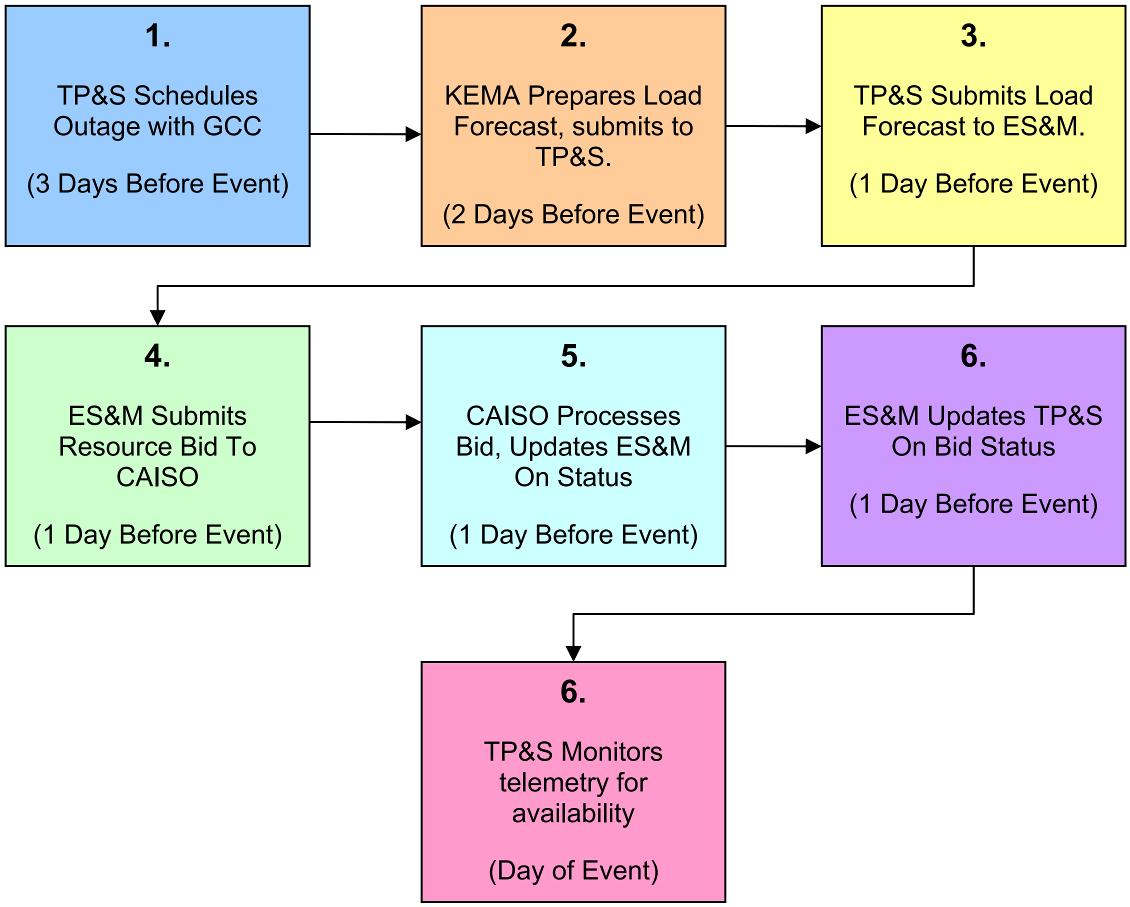


Figure 8 Bidding Process Flow

7.2 Dispatch

The dispatch process comprised another series of manual processes developed to support the PLP. As with the bidding processes, these dispatch processes and systems will require a significant level of development and automation in order to support any potential future programs. They are reproduced here in order of their occurrence.

1. ES&M receives a preparatory Automated Dispatch System (ADS) instruction from CAISO ADS. These are generator commands that provide five minutes worth of dispatch instructions (e.g., ramp up to X level,

maintain X output, etc.). ES&M then calls TP&S and notifies them that the ADS signal has been received.

2. TP&S calls GCC and notifies them to prepare for dispatch.
3. ES&M receives second ADS instruction to immediately curtail load. ES&M notifies TP&S to dispatch the PLP resource.
4. TP&S notifies GCC to curtail the load.
5. ES&M receives ADS instruction to restore load. ES&M notifies TP&S to dispatch the PLP resource.
6. TP&S notifies GCC to restore the load.

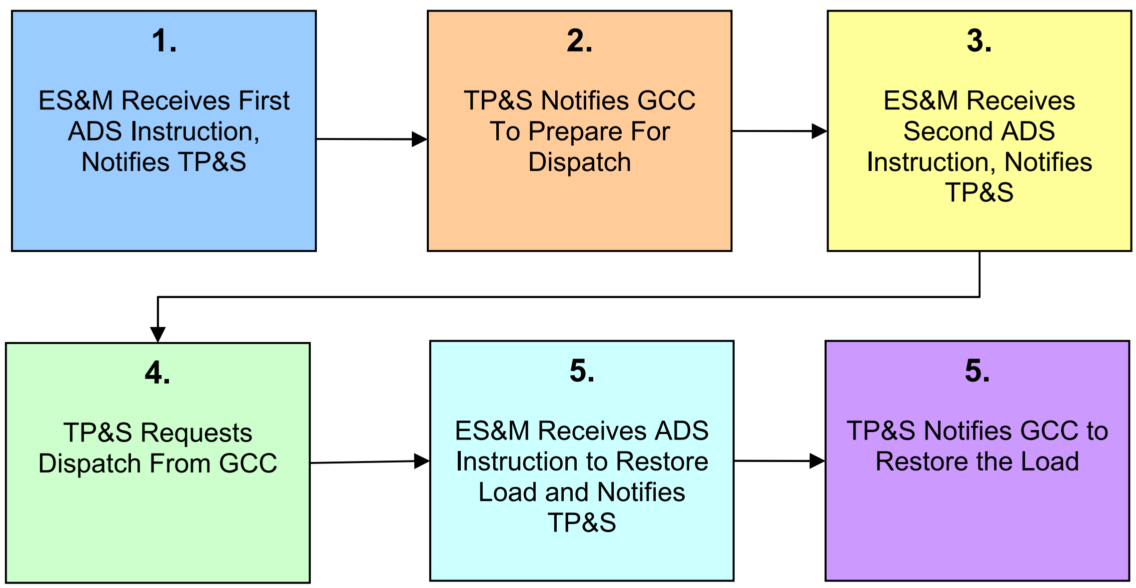


Figure 9 Dispatch Process Flow

Due to the manual nature of the dispatch process, the PLP did encounter some challenges and delays with the process. For example, telephone communications were sometimes challenging when ES&M attempted to contact TP&S and when TP&S attempted to contact SCE's Grid Control Center (GCC). This included simultaneous calls coming in to the recipient, delays in one party calling the other due to competing priorities and other obstacles one would expect when a three step telephone call process is required to dispatch a resource. However, SCE was able to successfully demonstrate that the PLP resource could be dispatched in compliance with the non-spinning reserve requirements.

7.3 Settlement

SCE utilized the settlement data calculated by KEMA for submittal to CAISO. Participating Load requires settling both the underlying load and the Demand Response and two different data sources were utilized for quantifying these components for the PLP. The SCE PLP team has explored correlation between observed load drop utilizing the communicating CTs and the observed load drop via SCADA systems at the circuit or feeder level. The load portion of the PL settlement is derived from the total load estimation algorithm based on the proxy telemetry information. The demand response portion of the PL settlement is derived from the observed load drop at the dual circuits feeding the base utilizing SCADA data. The PLP settlement data was submitted to CAISO per the 45 and 90 day requirements for providing metering information for wholesale settlement. SCE also plans to engage the Electric Power Research Institute (EPRI) to perform “shadow settlements” which SCE could use to compare with the CAISO invoices related to the PLP resource.

7.3.1 PLP Load Drop Quantification

SCE utilized the SCADA data to quantify the load drop for each PLP dispatch. For each PLP dispatch the curtailed load is compared with a baseline load which is produced from an algorithm developed by KEMA. This algorithm utilizes data from non-dispatch event days with a similar load profile to the day with the load drop that is to be estimated. This methodology is detailed in Section 10.2.3.

7.3.2 *PLP Load Quantification*

The PLP load, which represented the load of the air conditioners participating in the pilot, was calculated based upon the proxy telemetry data. Data from the proxy telemetry sensors were entered into the algorithm for estimating the total air conditioning load (see Section 10.2.4). Scheduling different amounts of load based on time of day becomes a dynamic bid not supportable without significant automation. Therefore, CAISO and SCE's ES&M recommended keeping the PLP load forecast at 5 MW since there would not be any schedule deviations associated with this variance. However, the estimated load was provided to the CAISO through the ALMDS/DPG to fulfill their near real-time load monitoring requirements for non-spinning reserve ancillary services as previously described.

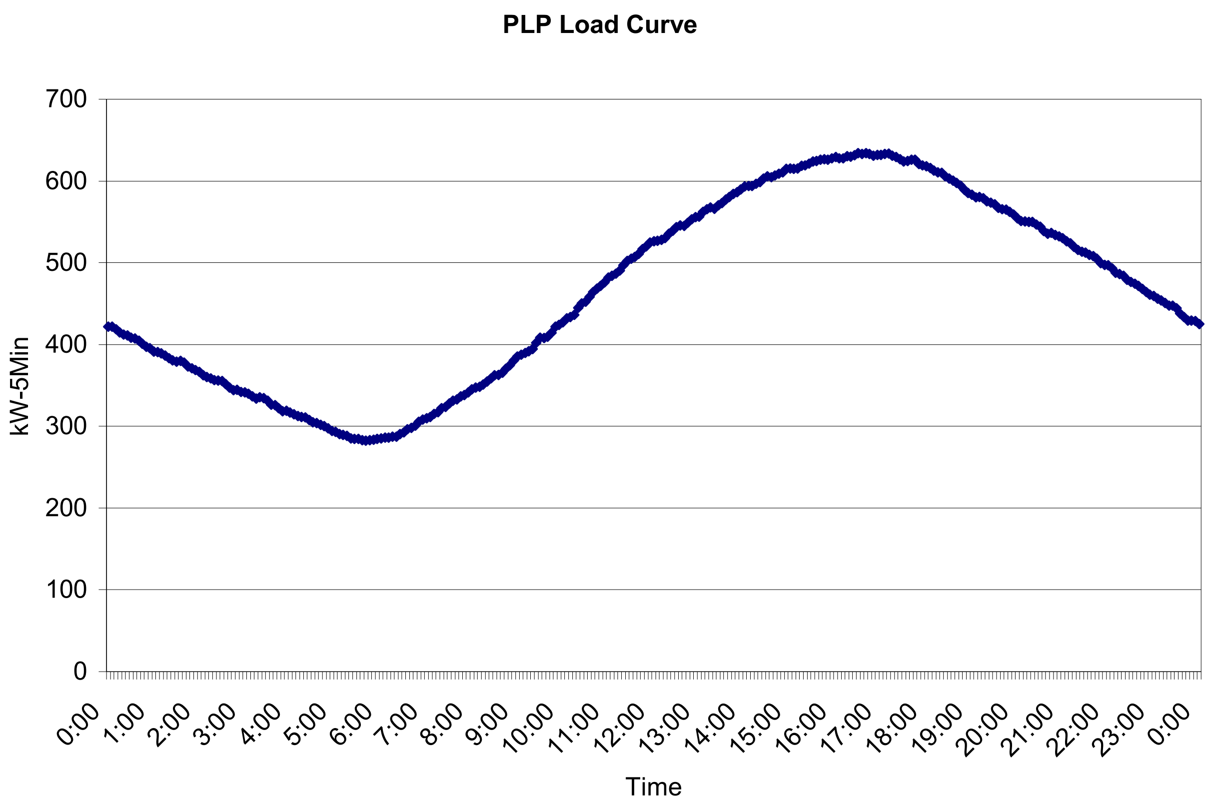


Figure 10 PLP Air Conditioning Load Curve

7.4 Technical Challenges for Program Expansion

7.4.1 Settlement Data Sources

To settle PL resources, CAISO requires 5-minute data intervals. This means that any PL resource must be equipped with a metering device which can collect usage data that is at least as granular as 5 minutes.

The highly granular circuit level SCADA at Ft. Irwin's substation could be aggregated to 5 minute data and then utilized as a proxy meter to measure the base's power consumption. Unfortunately, this "electrical cul de sac" arrangement is rarely found in SCE's service territory. Substations are usually located in arrangements where it is very difficult to assign customers to specific circuits circuits. For the most part, a sudden and substantial drop in power consumption on the substation which fed Ft. Irwin could easily be attributed to one of SCE'S demand response events. However, a sudden, substantial or coincidental load drop on a more typical substation circuit might be the result of any number of activities, such as an industrial customer on that same circuit cycling off an energy-intensive piece of process machinery, or a municipal customer toggling off street lights. This assumes, of course, that load drops will even be noticeable when examining the SCADA data, which is another area of uncertainty.

One proposal for PDR suggests that the CAISO allow the aforementioned 5-minute data intervals to be derived by dividing a 15-minute data interval by 3. Should CAISO accept this suggestion, the advanced meters with 15-minute interval data could be used as sources for settlement data. This could allow commercial and industrial customers to participate in ancillary services. The PLP settlement data derived from SCADA data was compared to the 15 minute interval data to explore the robustness of this approach and the findings are summarized in Section 10.4.1.1.

7.4.2 *Telemetry System Range Issues*

As mentioned in Section 5, SCE decided to utilize a telemetry system which communicated via a short range wireless mesh network. One of the principal challenges of such a network is that if the distances between communicating sensors, or nodes in the network, increases beyond the range of each node, data repeaters are required to bridge the gap between the two stranded sensors. Additionally, obstructions like tall trees, hilly terrain and tall buildings can act to block signals, forcing the installation of repeaters to “work around” the obstacle.

At Ft. Irwin, neither of these issues proved to be a problem, as base housing participating is clustered closely together. The topography of the base is also basically flat, and devoid of any large trees, heavy vegetation, or tall structures which might obstruct the signal of the Power SG sensor/controllers. In a more typical operating environment, program participants are more likely to be farther apart than 600 feet, and broken terrain, vegetation and tall buildings will be prevalent. These obstacles combined with a sample strategy of monitoring only 1 out of every 10 participating air conditioners could increase the need for signal repeaters thereby increasing the cost of deployment.

7.4.3 *System Automation*

The PLP required a number of manual workarounds to bid, dispatch and settle the PL resource. Equipping the resource with telemetry, by comparison, remained a largely automated process. Replacing the aforementioned manual workarounds with automation will need to be a critical component of any production level PL program. Any automated PL system would need to fulfill the following requirements[2]:

- Automate notifications to stakeholders when a DR resource bid has been submitted, accepted and dispatched.

[2] The requirements list should not be interpreted as a comprehensive listing of system requirements, only a high level overview.

- Process weather and historical load data to automatically prepare and submit Load Forecasts to the ES&M pre-schedule system
- Track the acceptance or rejection of the bids mentioned in Step 1 as they are reviewed by CAISO in the DAM process. Notify TP&S as bids are accepted or rejected.
- Monitor real-time telemetry of load in the hours leading up to each bid dispatch. Automatically notify ES&M when substantial deviations in expected load occur. Modify bids as necessary to reflect changes in real time telemetry data.
- Create an automated system enabling receipt of the CAISO ADS instructions to initiate dispatch, maintain and end the load curtailment in a manner comparable to that used for generators.
- Collect, process and submit Settlement data to Power Procurement settlements group.

8. Compatibility with Proposed PDR Standards

This section highlights SCE's most salient challenges in evaluating the PDR product's ability to include resources comprised of small aggregated loads of the type utilized in this pilot. SCE hopes to further explore these and other aspects of PDR challenges with the 2010 iteration of the PLP which SCE proposes to utilize as a PDR resource (rather than a PL resource) and conduct testing in a more general population circuit if approved by the CPUC.

8.1 Primary difference between PL and PDR

One of the core business requirements of Participating Load requires the market participant to forecast and report the quantity of "underlying load" for the Demand Response resource. For large, unitary, loads this is relatively simple. If, for example, the demand response resource is a single large pump at a water handling facility, it is very easy to forecast that underlying load: the pump will either be on or off for the operating interval in question. For small aggregated loads, like those used in this pilot, this requirement becomes much more challenging. Accurately forecasting the underlying load for aggregated air conditioning loads requires accurately predicting the number of air conditioners that will be on in a future interval and determining the tonnage for those air conditioners. If the air conditioners are spread over a wide geographic footprint, with several micro-climates, the task becomes even more difficult.

The PDR product was proposed, in part, to address this difficulty. Market participants that bid their resource as a PDR do not need to schedule underlying load. However, PDR may create some requirements on market participants that could pose challenges for resources comprised of small aggregated loads. Some of these challenges are described in the sections below.

8.2 PDR Registration

CAISO requires market participants to "register" their PDR by, among other things, listing the MW value of the PDR. This requirement should be relatively easy to meet for both unitary and aggregated loads. However, the CAISO also states that "once an aggregation is registered, the Demand Response Provider (DRP) cannot change the makeup of that registration without having to resubmit the aggregation for approval."[3] If a PDR is comprised of 1,000 aggregated air conditioners, and 10 leave the aggregation agreement in a short period of time, does the PDR need to be re-registered? What if 100 leave? SCE's experience from administering mass-market small load programs like the SDP has been that enrollments are constantly changing as participants relocate or simply decide that they no longer wish to participate. This would introduce the need to constantly re-register the PDR which could become overly burdensome for market participants.

8.3 Resource Availability & Outage Reporting

CAISO also states that "if an underlying resource in an aggregate PDR has an outage, the entire PDR shall be ineligible to participate in the market."[4] For loads aggregated from only a handful of resources, this requirement is both easy to ascertain and sensible. This task becomes more difficult for small aggregated loads: if 10 air conditioners in a PDR comprised of 1,000 are malfunctioning or not available, should this PDR be ineligible to participate in the market? What if 100 air conditioners are malfunctioning? It is not clear how this requirement will apply to small aggregated loads.

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[3] CAISO "*Draft External Business Requirements Specificatio, Demand Response – Proxy Demand Resource (PDR)", Version 1.0, October 19, 2009*", Page 14. Available at http://www.caiso.com/244c/244ced8051fe0.pdf

[4] CAISO "*Draft External Business Requirements Specificatio, Demand Response – Proxy Demand Resource (PDR)", Version 1.0, October 19, 2009*", Page 22. Available at http://www.caiso.com/244c/244ced8051fe0.pdf

9. Other Lessons Learned

9.1 Rebound effect

At the end of curtailment events, it is typical for aggregated load to quickly return to a level at or above the level prior to dispatch. On a typical warm day the load generally increases to a level above what would have occurred in the absence of a dispatch event and this is commonly referred to as the "rebound" period.

On warm summer days, most A/C units cycle on and off according to their thermostat setting. Prior to a curtailment event, a unit is either on or off. During a curtailment period a unit that was off prior to dispatch may or may not have cycled on during that event period. Similarly, an A/C unit that was on prior to dispatch may or may not have cycled off.

A post-curtailment event rebound occurs when more units turn on at the end of the event than would have been on had the curtailment event not occurred. While the curtailment events do not make units that would be on anyway run higher, the curtailments have the effect of aligning the phases of many units in the system to some degree. As time goes by, the units fall back out of phase with one another and the rebound fades away. The magnitude and duration of rebound, therefore, depends on the procedures used to "release" A/C units from centralized load control. For 2009, we selected a procedure that dramatized the effect, but intend to explore other procedures in the future using the information gathered this year.

The characteristics of rebounds vary, but in general there is an initial spike with a peak occurring in the first 5 to 10 minutes following the end of the event. The dispatch signals in the 2009 PLP act on the entire population of A/C units, so the spikes are more pronounced than they would have been under a scenario of a staggered release of the units (also known as a randomized restoration which is analogous to a generator ramping). Following the spike, the load then declines in the next 10 to 20 minutes into a steady trend trajectory that resembles what would have been expected in the absence of a curtailment event. This trend is illustrated by Figure 11 showing the load rebound that was observed on September 23rd.

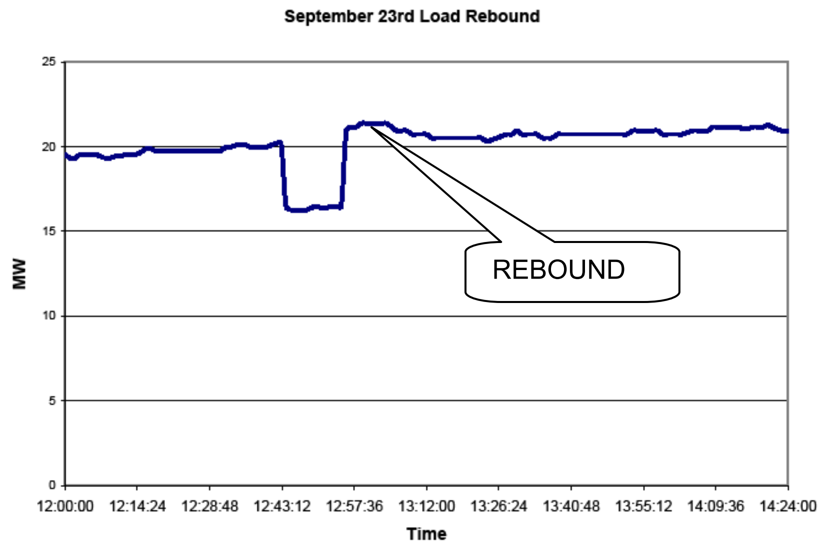

Figure 11 September 23rd Load Rebound illustrating a rebound

On average, the rebound resulted in a 6% increase in load compared to what the load-matching technique described in Section 10.2 estimated for what the load would have been in the absence of a demand response event. At minimum, a 2% rebound was observed after the PLP dispatch and a maximum of 10% was observed as shown in Figure 12 and Figure 13 below.

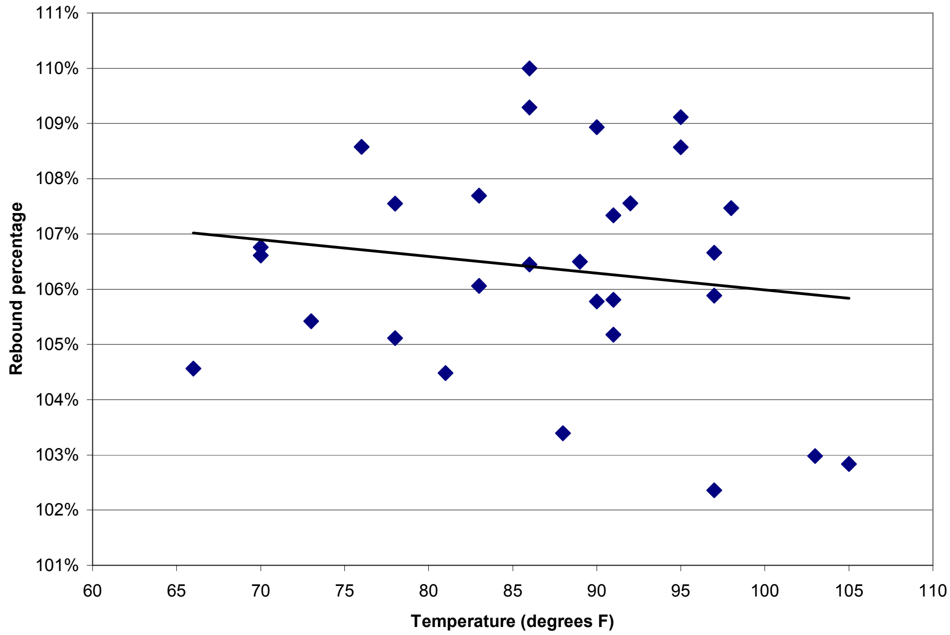

Figure 12 Rebound as a percentage of predicted average load at given temperatures

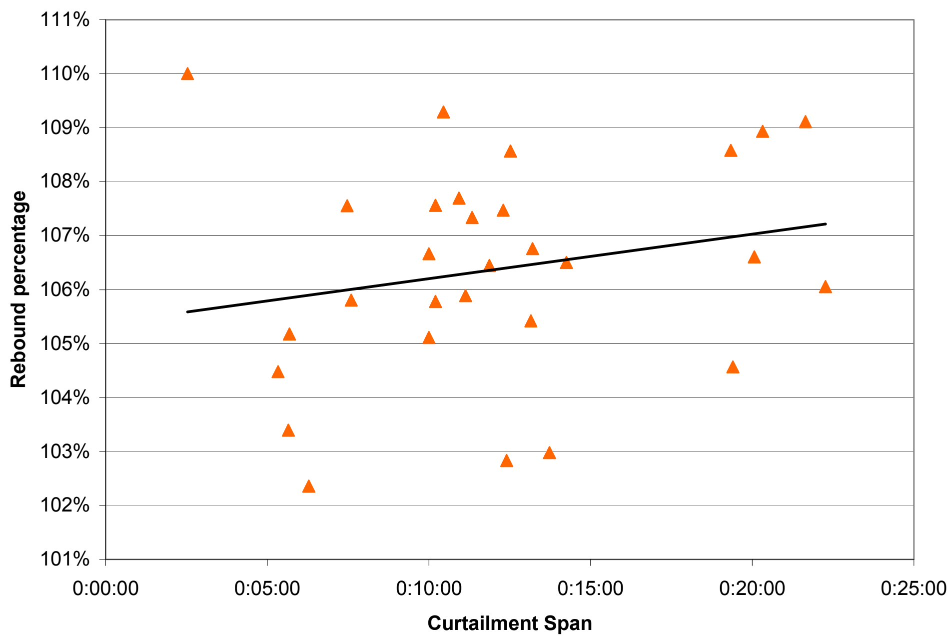

Figure 13 Rebound as a percentage of average load for different curtailment spans

In addition, the energy under the rebound portion of the load curve can be significant. On average, the energy of the rebound amounted to 20% of the energy curtailed during the duration of the PLP demand response event. This amount of rebound energy as a percent of the demand response energy curtailed varied from a minimum of 1% to a maximum of 40% as shown in Figure 14 and Figure 15 below.

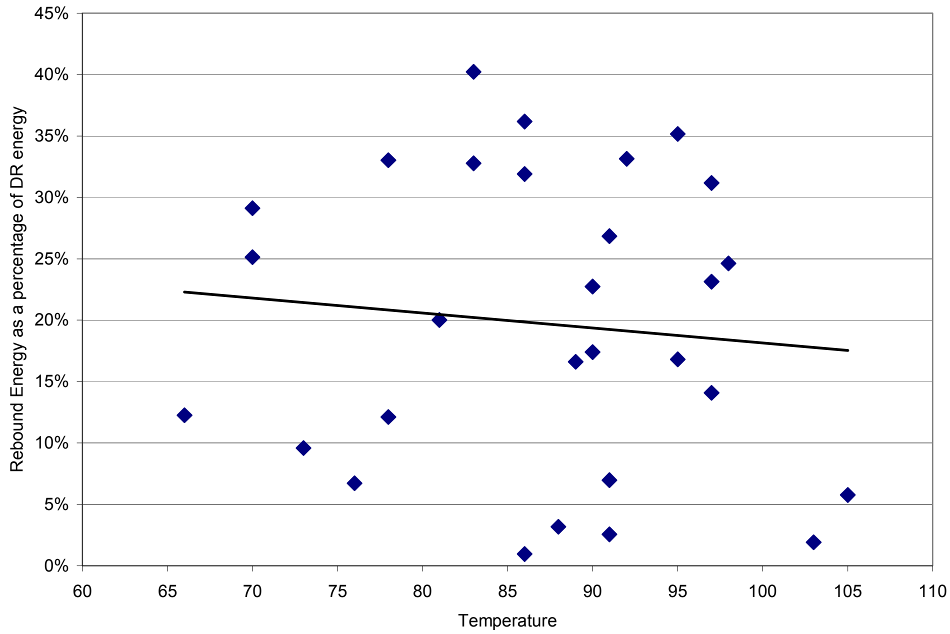

Figure 14 Rebound Energy as a percentage of DR Energy at given temperatures

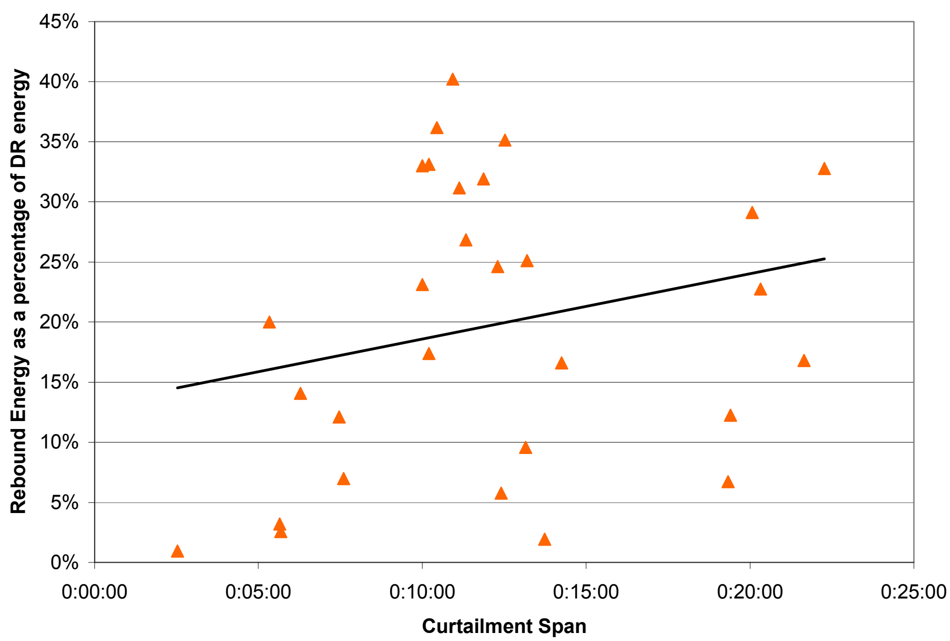

Figure 15 Rebound Energy as a percentage of DR Energy for different curtailment spans

9.2 Temperature as a predictor of underlying load

A strong and significant linear relationship exists between outdoor air temperature and A/C load. This allows temperature to function as an alternative estimator of available load reduction, and can also be used to test for bias in the telemetry sample distribution.

Linear regression analysis methods used in the load impact analysis calculations indicate that sample telemetry data can explain 94 percent of the variation in the SCADA data across curtailment events (Figure 16). For a robustness test, a similar model was calculated using outdoor temperature as the explanatory variable instead of sample telemetry data. The explanatory power of temperature as a variable was not as strong as telemetry data. However, temperature was able to explain 88 percent of the variation in the SCADA data (Figure 17). Temperature was also tested as an explanatory variable for the aggregated telemetry sample load drop where it was able to explain 83 percent of the variation (Figure 18).

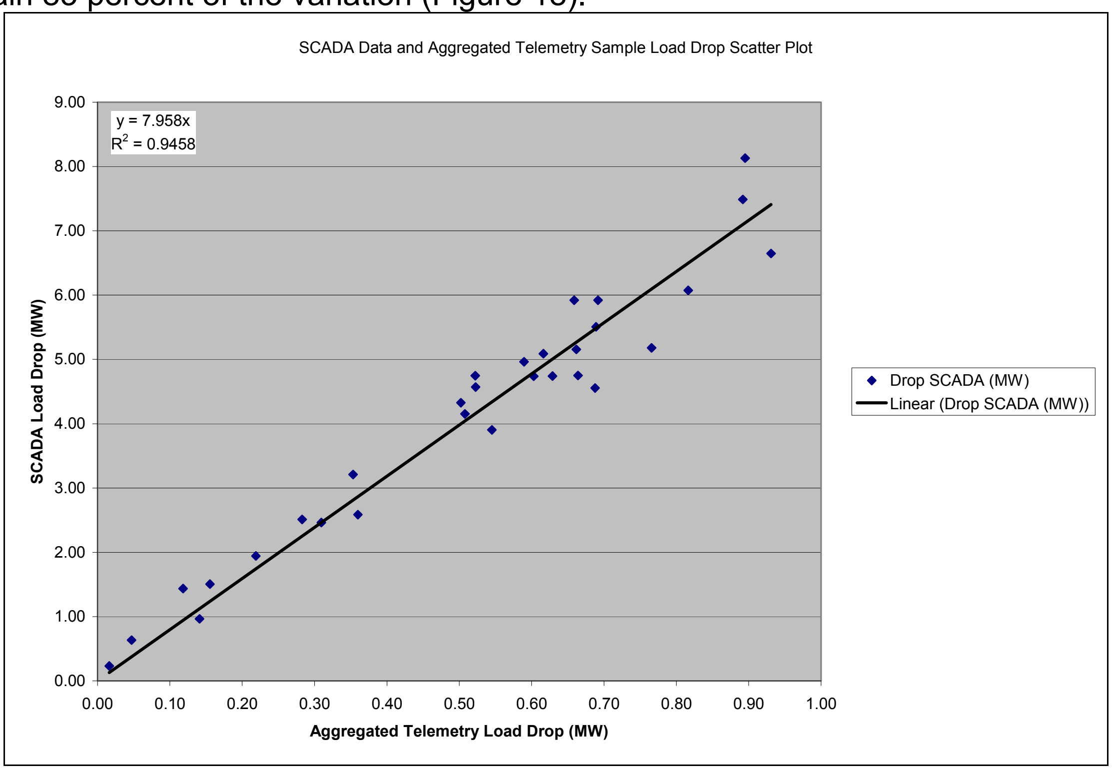

Figure 16 SCADA Data and Aggregated Telemetry Sample Load Drop Scatter Plot

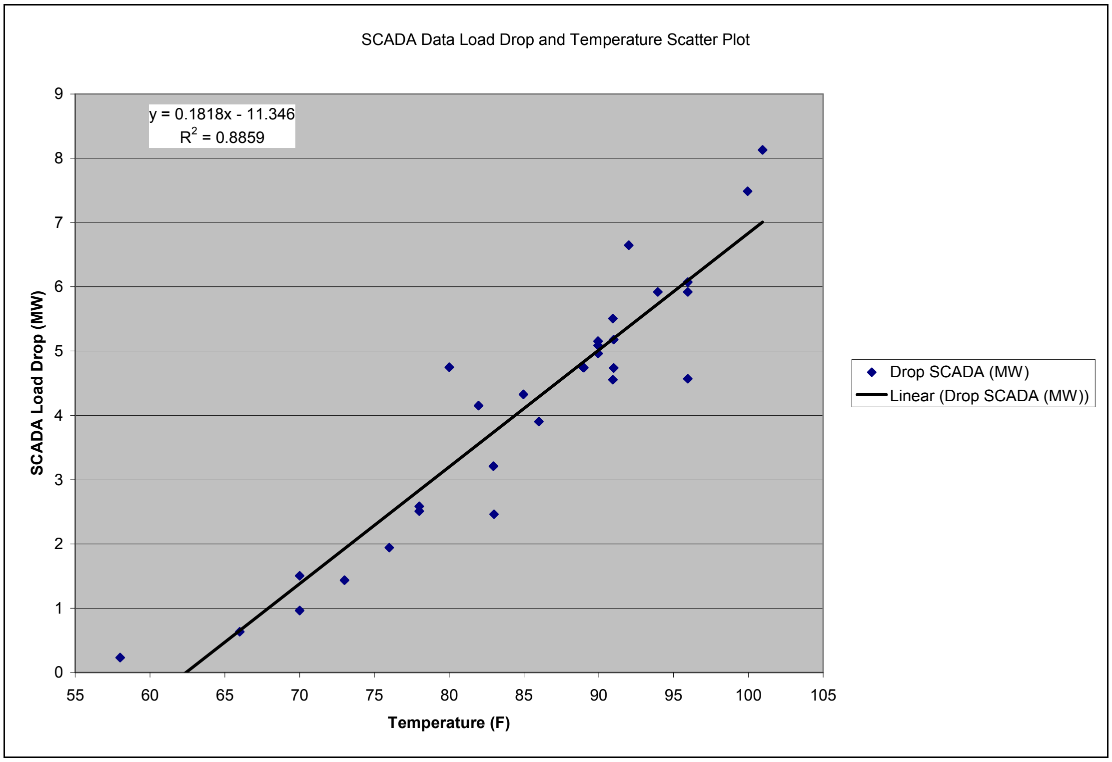

Figure 17 SCADA Data Load Drop and Temperature Scatter Plot

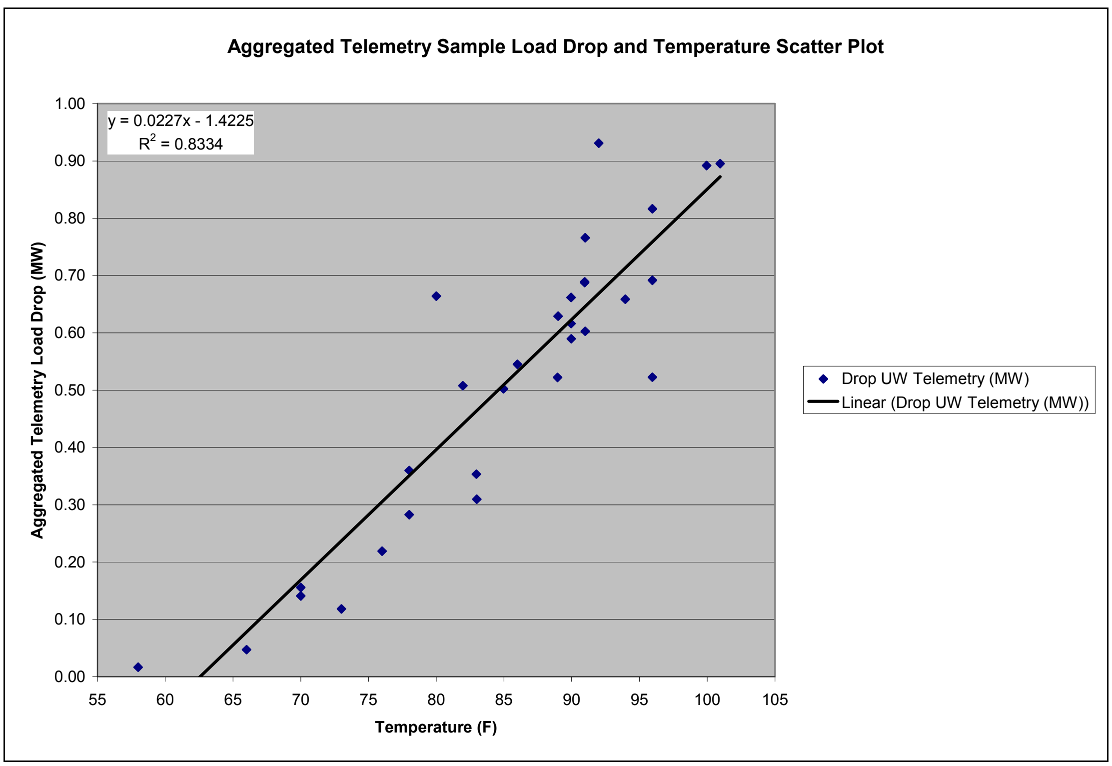

Figure 18 Aggregated Telemetry Sample Load Drop and Temperature Scatter Plot

At both the telemetry sample level and the SCADA level, temperature is a very good predictor of load reduction. While not as accurate as telemetry data, it is possible that the performance of a temperature based model may lie within the statistical standards established for CAISO settlement, and could potentially be more cost effective. Theoretically, the telemetry data should be a more accurate estimate of SCADA load reduction than temperature. Keeping this in mind, the performance of a temperature model can potentially be used as a lower bound in testing for a balanced telemetry sample.

10. Presentation of Algorithms

10.1 Testing Scope

As described below, SCE's PLP explored enhancements from some of the current CAISO requirements for PL. The intent of the PLP is to explore measurement and verification criteria for small SCE-aggregated DR load and to determine whether the proxies developed for telemetry and metering are acceptable to CAISO.

10.1.1 Telemetry

The SCE PLP team developed telemetry proxy algorithms to forecast load reductions based on sample CT data. This report summarizes the methodologies and algorithms developed and utilized for the PLP to satisfy the CAISO requirements for near real-time monitoring of non-spinning reserve ancillary services resources.

10.1.2 Bidding & Scheduling

SCE placed bids for non-spinning reserve ancillary service into CAISO's Day-Ahead Market on Wednesdays (for performance on Thursdays) from August 6, 2009 through October 29, 2009 and scheduled the Aggregated Pricing Note (APNode) load for the PLP starting July 27 and ending October 31, 2009.

10.1.3 Dispatch

In total, SCE conducted 32 PLP dispatches between June 18, 2009 and October 30, 2009 and 12 of the dispatches were 10 minute events conducted in response to CAISO exceptional dispatches of the PLP resource. The CAISO-independent dispatches performed by SCE varied in duration from 5 to 20 minutes.

10.1.4 Metering & Settlement

To develop proxy data for Settlement, SCE engaged KEMA and LBNL to create the methodologies and algorithms outlined in the next section. The SCE PLP team has explored correlation between observed load drop utilizing the proxy telemetry sensors and the observed load drop via SCADA systems at the circuit or feeder level. The load portion of the PL settlement is derived from the total load estimation algorithm based on the proxy telemetry information. The demand response portion of the PL settlement is derived from the observed load drop at the dual circuits feeding the base utilizing SCADA data.

10.2 Analysis Methodology

10.2.1 Overview

The Tiefort substation has two sub-feeder circuits, Abrams and Alvord, which supply Ft. Irwin with all of its power. The voltage for the substation and the three current components and reactive power for Abrams and Alvord for timestamps throughout the day for each day are contained in the streams of SCADA output and power is calculated for the system as follows:

Tiefort power (MW) = Abrams power (MW) + Alvord power (MW)

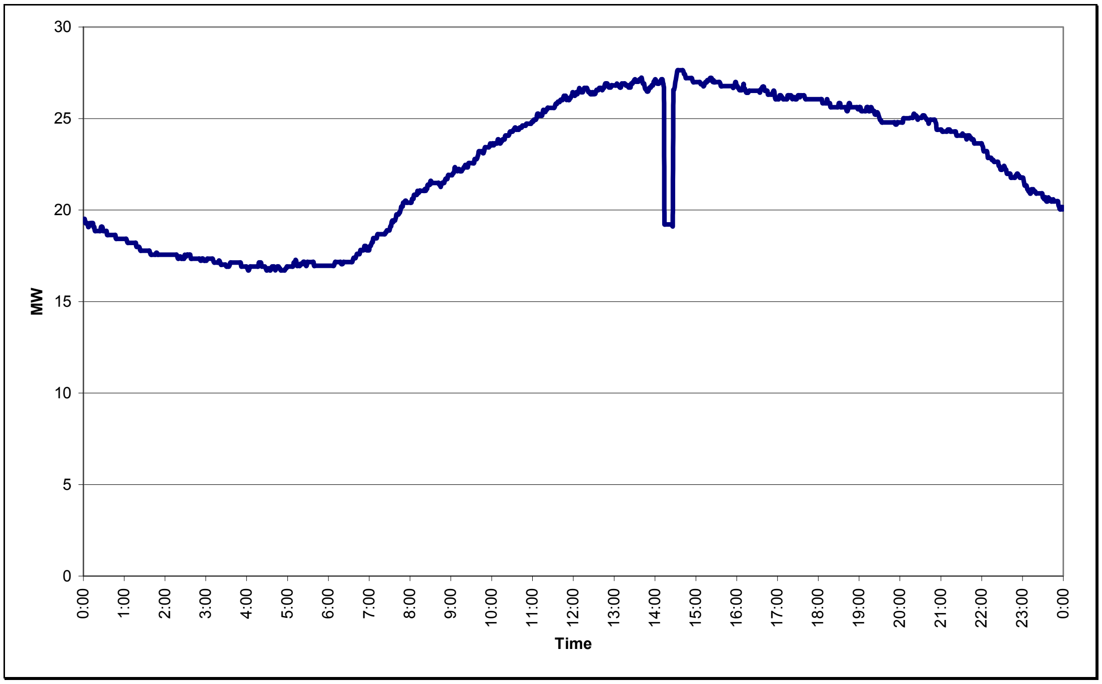

Figure 19 Tiefort Substation - Typical Load on PLP testing day

The actual start and end times of each PLP curtailment are identified by SCADA data around the known dispatch time a current value is significantly less than a timestamp just seconds prior to it. In the case of the PLP and Tiefort substation, these drops tended to be about 25 percent of the load. The curtailment end time is identified in the same manner – finding the easily recognizable timestamp with a significant jump (~25%) in current and assigning the prior timestamp as the curtailment end.

To best assess the amount of demand response achieved for each test, methodology developed for the CERTS Spinning Reserve collaboration with SCE and LBNL and documented in "2008 Demand Response Spinning Reserve Demonstration – Phase 2 Findings from the Summer of 2008 by Eto *et al*.[5]" was leveraged and adapted to fit the data profile for Ft. Irwin.

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[5] 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. Available at `http://certs.lbl.gov/certs-load-pubs.html`.

In this study, a load-matching technique was developed to select patterns of loads in periods from days without curtailments that were "closest" to loads on the days with curtailments (and that were recorded at the same time of day as the curtailment). The basic intuition behind this step is that, for any given feeder, the evolution of loads over the course of a day follows a repeatable pattern. By finding matching patterns of loads from similar non-curtailment days for the time immediately prior to the time of a curtailment, we can use the loads recorded at the time of the curtailment from these non-curtailment days to estimate what the load would have been on the curtailment day.

10.2.2 Forecasting what the SCADA load would have been in the absence of load curtailment

The procedure for forecasting what the SCADA load would have been in the absence of load curtailment is a multi-step process, which can be summarized in the following steps: [6]

1. Measure the load during the interval period immediately preceding the curtailment.
2. Select 12 days from the rest of the feeder data when the load during the same interval immediately preceding the curtailment was closest to that on the curtailment day.
3. Average the loads from the 12 historic days, and take the ratio between the result and the same preceding interval on the curtailment day to obtain an adjustment factor.
4. Take the average load from the 12 historic days for the curtailment interval itself. Use the ratio determined in step 2 to adjust the average for the

[6] From section 7.2 of 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. Available at http://certs.lbl.gov/certs-load-pubs.html.

curtailment interval. This is the best estimate of what the load would have been had the curtailment not occurred.

5. Interval periods with any overlap of a curtailment were excluded along with the next 30 minutes worth of readings following events so that rebounds did not feed into the algorithm.

10.2.3 Estimating the Load Impacts of Each Curtailment:

For each of these test events, the estimated load reduction was calculated by subtracting the actual average load from the estimated average load for a period closely matching the time span for the test event. The difference between these is the average amount by which the load was reduced during period.

10.2.4 Total Air Conditioning Load Estimate Based on Proxy Telemetry

There were 555 A/C units out of a total population of approximately 3,255 that were equipped with telemeter monitoring devices. The data from the 555 unit sample were utilized to estimate the load of the total population as described below.

10.2.4.1 Device-level Weights and Alternative Method:

Originally the monitored devices were selected through model based statistical sampling so that the Participating Load could be estimated for the population by weighting up the loads from the installed devices according to their tonnage. The set of sampled units, however, did not match the set of installed units due to compatibility issues with the proxy telemetry devices and some of the air conditioner units at Ft. Irwin.

As an alternative to the original weighting method based on the original sample design, the team developed a technique to use the data from the current set of installed devices to get Participating Load population estimates which are designed to best match load drops during previously observed tests.

The alternative method took the combined unweighted load drop from the installed devices during the test events along with the associated estimated drops from the SCADA data and determined an inflationary factor that related them to one another. Only the load from the devices that had a history of responding to the dispatches were used in the aggregation that was then matched to the SCADA data in determining the inflationary factor. The metered single-phase units still stand for the entire population of Ft Irwin's A/C population, but have weights calibrated to prior tests' SCADA-based ex-post estimates.

As an example, suppose that during a test event the estimated load drop using SCADA data was 5 MW and the unweighted combined drop in load from the telemetry devices was 1 MW. Then an inflationary factor to apply to the 1 MW observed unweighted drop would be 5, so that 5*(1 MW) matched the 5 MW drop in SCADA load.

10.2.4.2 Results:

Applying the calculated factor to the combined telemetry data for the events, the estimated population drop was within 10 percent of the estimated drop in load from the SCADA data in 24 of the 30 test events and every one where the outside temperature was over 80 degrees. As expected, the relationship deteriorated to some degree as the outside temperatures dropped. This is due to air conditioners representing a small proportion of the overall system load during the fall compared with the summer. Overall, this methodology of using the past event history to produce an inflationary factor to apply to the unweighted combined load of the 500+ units produced results that compare favorably to the drop differences when the population Participating Load estimates were produced using device-level weights.

10.2.5 Combining Load and Demand Response Data During Dispatch or Restoration Intervals

For settlement purposes, the Participating Load is submitted as positive load values. For the PLP, the Demand Response quantification was based on Circuit SCADA Data (Section 10.2.3) which was subtracted from the estimate of what the SCADA load would have been in the absence of load curtailment (Section 10.2.2). These settlement data are reported in 5-minute aggregated periods with times in the submittal indicating the end of the interval (i.e. 23:05 corresponds with 23:00 to 23:05). The load estimation portion of the PL was estimated utilizing the algorithm for estimating the total load based on the 555 proxy telemetry data points.

10.2.6 Review

Detailed procedures have been implemented in a manner intended to extract maximum value from the actual recorded performance of loads at Ft. Irwin on an on-going basis. Pattern matching using SCADA loads recorded at the same time of day from non-event days is used to measure the depth of curtailments on event days. Reconciliation between telemetered and estimated curtailments based SCADA loads for past events is used to estimate performance based on telemetered data for future events. Both procedures are updated prior to each new event in order to incorporate all information recorded since the time of the last curtailment.

10.3 Observations

High level descriptions of the 2009 PLP events:

Table 2 Load drop observations

Date	Test	Curtailment Start	Curtailment End	Curtailment Span	Estimated drop from SCADA (MW)	Estimated drop from weighted Telemetry (MW)	PLP drop as a percent of SCADA drop
6/18/2009	1	11:04:18	11:09:38	0:05:20	3.21	2.89	90%
6/18/2009	2	13:01:07	13:06:46	0:05:39	4.33	4.12	95%
6/18/2009	3	15:03:23	15:10:59	0:07:36	4.75	4.28	90%
6/18/2009	4	17:01:22	17:07:03	0:05:41	4.96	4.83	97%
6/25/2009	5	13:01:22	13:12:42	0:11:20	5.09	5.05	99%
6/25/2009	6	15:01:58	15:13:06	0:11:08	4.55	5.63	124%
7/1/2009	7	12:59:52	13:09:59	0:10:07	5.92	5.40	91%
7/1/2009	8	15:00:24	15:10:24	0:10:00	6.07	6.69	110%
7/9/2009	9	15:04:03	15:25:42	0:21:39	5.51	5.64	103%
7/16/2009	10	15:30:26	15:42:50	0:12:24	8.13	7.33	90%
7/27/2009	11	14:13:12	14:26:56	0:13:44	7.49	7.31	98%
8/6/2009	12	14:00:19	14:11:15	0:10:56	4.15	4.16	100%
8/13/2009	13	13:05:21	13:19:36	0:14:15	5.15	5.42	105%
8/20/2009	14	12:02:04	12:12:16	0:10:12	5.92	5.67	96%
8/27/2009	15	11:02:16	11:12:43	0:10:27	4.57	4.28	94%
9/10/2009	16	16:04:49	16:11:06	0:06:17	6.65	6.83	103%
9/17/2009	17	15:00:37	15:13:08	0:12:31	5.18	5.62	108%
9/22/2009	18	15:00:17	15:20:36	0:20:19	4.74	4.61	97%
9/23/2009	19	12:43:09	12:55:01	0:11:52	3.90	4.00	102%
9/24/2009	20	14:06:05	14:16:17	0:10:12	4.74	4.42	93%
9/28/2009	21	9:00:53	9:08:21	0:07:28	2.59	2.64	102%
9/29/2009	22	15:50:49	16:13:05	0:22:16	4.75	4.87	103%
9/30/2009	23	13:21:21	13:41:25	0:20:04	1.51	1.14	76%
10/1/2009	24	13:01:09	13:14:21	0:13:12	0.96	1.03	107%
10/2/2009	25	10:00:49	10:20:13	0:19:24	0.63	0.35	55%
10/15/2009	26	11:03:28	11:16:37	0:13:09	1.43	0.87	60%
10/16/2009	27	16:35:16	16:37:48	0:02:32	2.46	2.27	92%
10/19/2009	28	12:30:36	12:49:56	0:19:20	1.94	1.61	83%
10/22/2009	29	16:00:35	16:10:35	0:10:00	2.51	2.07	83%
10/30/2009	30	10:45:26	10:54:44	0:09:18	0.23	0.12	52%

Table 3 Algorithm Performance

Date	Test	Estimated Drop Difference (PLP-SCADA) in MW	Error Bound for Estimated Average Load Drop Difference at 90% Confidence (MW)	Statistically significant difference at 90% Confidence?	Drop Forecast	Forecast Temp	Actual (SCADA) Temp
6/18/2009	1	-0.26	0.26	YES			81
6/18/2009	2	-0.27	0.31	NO			88
6/18/2009	3	-0.57	0.33	YES			91
6/18/2009	4	0.04	0.25	NO			91
6/25/2009	5	0.00	0.28	NO			91
6/25/2009	6	1.22	0.37	YES			97
7/1/2009	7	-0.56	0.34	YES			98
7/1/2009	8	0.88	0.39	YES			97
7/9/2009	9	0.04	0.39	NO			95
7/16/2009	10	-0.43	0.37	YES			105
7/27/2009	11	-0.26	0.42	NO			103
8/6/2009	12	0.17	0.42	NO	5.13	91.0	83
8/13/2009	13	0.11	0.30	NO	7.50	101.0	89
8/20/2009	14	-0.41	0.31	YES	6.40	98.0	90
8/27/2009	15	-0.35	0.26	YES	6.40	97.0	86
9/10/2009	16	0.18	0.42	NO	6.80	100.0	97
9/17/2009	17	0.44	0.66	NO	5.90	95.0	95
9/22/2009	18	-0.13	0.49	NO			90
9/23/2009	19	0.10	0.38	NO	4.65	88.0	86
9/24/2009	20	-0.32	0.46	NO	5.40	91.0	92
9/28/2009	21	0.05	0.26	NO			78
9/29/2009	22	0.12	0.45	NO			83
9/30/2009	23	-0.36	0.40	NO			70
10/1/2009	24	0.07	0.53	NO			70
10/2/2009	25	-0.29	0.28	YES			66
10/15/2009	26	-0.57	0.34	YES	2.28	75.0	73
10/16/2009	27	-0.19	0.26	NO	4.30	86.0	86
10/19/2009	28	-0.34	0.38	NO			76
10/22/2009	29	-0.44	0.51	NO	3.90	84.0	78
10/30/2009	30	-0.11	0.26	NO	0.00	60.0	58

10.4 Comparison with other measurement & verification approaches

10.4.1 Proposed and Possible PDR measurement & verification approaches

10.4.1.1 10 day in 10 day proposed baseline methodology for PDR

The wholesale market product called PDR was still being developed during execution of the 2009 PLP. As a result, the PLP utilized the load-matching technique for developing a baseline described in Section 10.2. Because the CAISO Draft Final Proposal for the Design of Proxy Demand Resource (PDR)[7] outlines an aggregated 10 day-in-10 day (10-in-10) methodology, SCE compared the PLP load-matching technique to the proposed aggregated 10-in-10 methodology for calculating baselines.[8]

In order to make an appropriate comparison between the 10-in-10 and Past Similar Day (PSD) load drop estimation methods, the aggregation periods of SCADA data are the same for both the 10-in-10 and PSD. In each one the data is chosen to be similar in length to the event itself. This is done to minimize errors when the load data is averaged over the aggregation period. The span of days used as an input to the ten-in-ten selection algorithm is June 1st, 2009 to October 30th, 2009 – the day of the final curtailment event.

The estimated load reduction for each PDR event is produced with the actual observed load during the event and a baseline of historical days selected according to the following criteria:

- Exclude previous event days, defined as a day when either a PDR event or outage occurred.
- Exclude different day-types, where day-type is either 1) a weekday or 2) a weekend or NERC holiday.

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[7] CAISO Draft Final Proposal for the Design of PDR 09/02/2009 http://www.caiso.com/241d/241da56c5950.pdf

[8] From section 3.8 of the Proxy Demand Resource Draft Implementation Plan. Available at http://www.caiso.com/2478/24786cd75ad80.pdf

– Count backwards from event day until target number of days is reached.
– Exclude days earlier then 45 days prior to event.

All of the 30 PDR events occurred on a weekday, between June 18th and October 30th, and for each event 10 baseline days were identified, although some days were excluded per the criteria above.

The two estimation methods produced very comparable estimates of load drop for tests with outside temperature around eighty degrees or more. Starting around September 28th (test 21) the comparability of the two sets of estimates began to deteriorate. For tests in cooler weather, the 10-in10 tended to overestimate the load drop compared to the PSD approach.

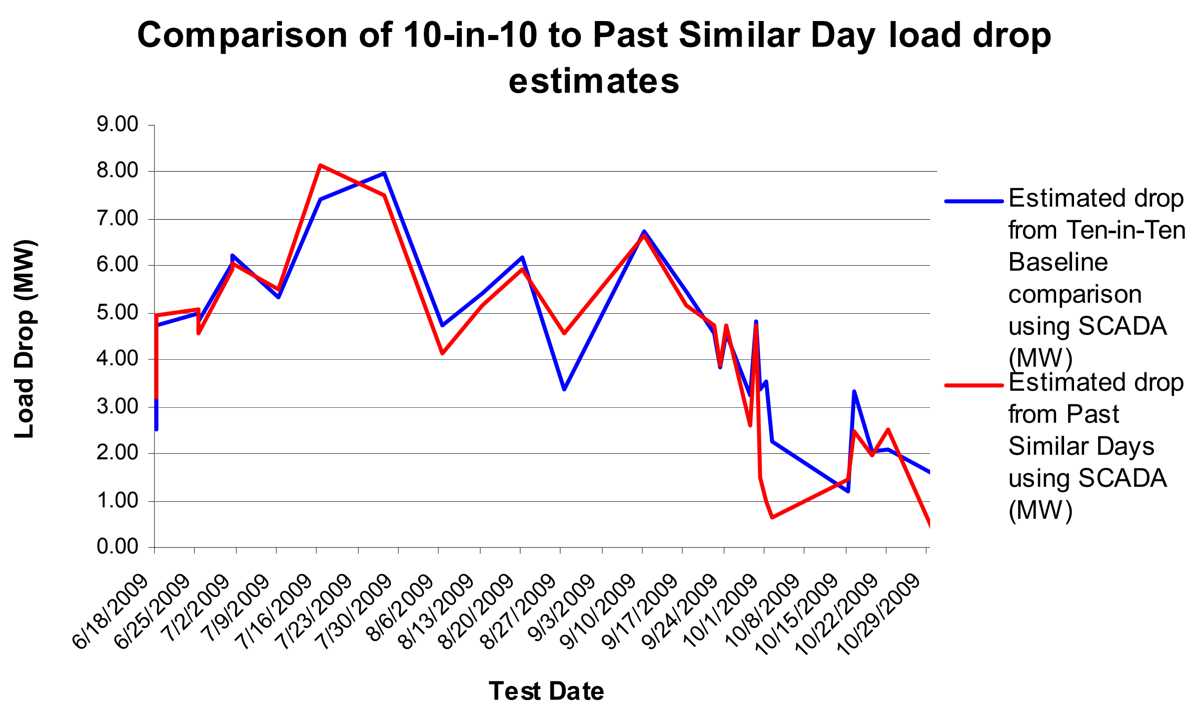

Figure 20 10 in 10 Comparison Chart

Table 4 10 in 10 Comparison Table

Date	Test	Outside Temperature (degrees Fahrenheit)	Estimated drop from Ten-in-Ten Baseline comparison using SCADA (MW)	Estimated drop from Past Similar Days using SCADA (MW)	Absolute Difference (MW)	Ten-in-Ten as a percentage of Past Similar day (MW)
6/18/2009	1	81	2.51	3.21	0.70	78%
6/18/2009	2	88	3.75	4.33	0.58	87%
6/18/2009	3	91	4.64	4.75	0.11	98%
6/18/2009	4	91	4.73	4.96	0.23	95%
6/25/2009	5	91	5.00	5.09	0.09	98%
6/25/2009	6	97	4.81	4.55	0.26	106%
7/1/2009	7	98	6.06	5.92	0.14	102%
7/1/2009	8	97	6.21	6.07	0.14	102%
7/9/2009	9	95	5.32	5.51	0.19	97%
7/16/2009	10	105	7.43	8.13	0.70	90%
7/27/2009	11	103	7.96	7.49	0.47	106%
8/6/2009	12	83	4.75	4.15	0.60	114%
8/13/2009	13	89	5.41	5.15	0.25	105%
8/20/2009	14	90	6.20	5.92	0.28	105%
8/27/2009	15	86	3.37	4.57	1.20	74%
9/10/2009	16	97	6.75	6.65	0.10	102%
9/17/2009	17	95	5.45	5.18	0.27	105%
9/22/2009	18	90	4.57	4.74	0.17	96%
9/23/2009	19	86	3.84	3.90	0.06	99%
9/24/2009	20	92	4.57	4.74	0.16	97%
9/28/2009	21	78	3.23	2.59	0.65	125%
9/29/2009	22	83	4.83	4.75	0.08	102%
9/30/2009	23	70	3.39	1.51	1.88	225%
10/1/2009	24	70	3.54	0.96	2.58	368%
10/2/2009	25	66	2.26	0.63	1.63	357%
10/15/2009	26	73	1.19	1.43	0.24	83%
10/16/2009	27	86	3.32	2.46	0.86	135%
10/19/2009	28	76	2.05	1.94	0.11	105%
10/22/2009	29	78	2.07	2.51	0.44	83%
10/30/2009	30	58	1.56	0.23	1.33	677%

10.4.1.2 15 minute interval meter data

A possible alternative to using SCADA-estimated load drops for settlement was to estimate the demand response to test events with TOU-8 15 minute interval meter data. This was investigated by first dividing the fifteen minute intervals evenly into five minute intervals, the interval length used in the settlement worksheets. The energy readings were then converted to average load for the five minute interval. The average load data was then input to the10-in-10 load drop algorithm, described in Section 10.4.1.1, which produced estimates of the load drops in each of the test events after 8/5/2009, the date that the meter was replaced.

Following the average load drop estimation, the resulting estimates were converted back into energy. The average load drops and the curtailment proportions for the five-minute aggregated periods were then converted to demand response (DR) by multiplying the curtailment proportion by the energy drops for five minute periods that happened to overlap with the span of a test event.

In the settlement worksheets, DR could not exceed the kWh from the PL, calculated using the weighted total of the telemetered average load for matching five-minute aggregated intervals and then converted to kWh. To make a fair comparison, the TOU-8 meter data-measured DR was capped at the same level as the SCADA-measured DR.

The estimated DR using the TOU-8 meter data tended to be less than with the more reliable SCADA data both overall and on the hotter test days and about the same in the cooler days. They tended to be the same on those days because the estimated savings energy eclipsed the estimated energy consumption from the air conditioner population. This was due to a relatively low proportion of the total household energy consumption going to space cooling, making cooling load and energy very difficult to estimate using feeder-level data.

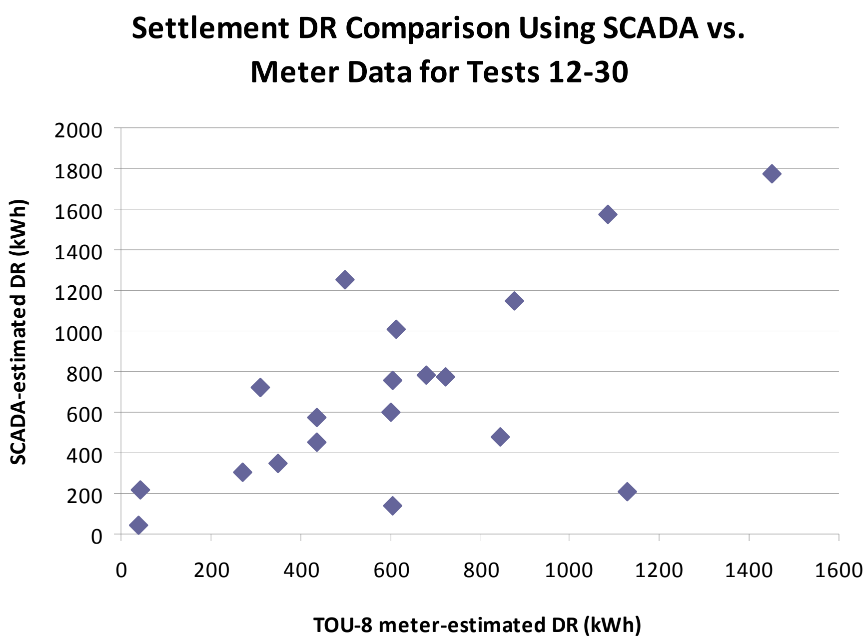

Figure 21 Settlement Methods Comparison Graph

Table 5 Settlement Methods Comparison Table

		Demand Response (kWh)	
Test	Temperature	TOU-8	SCADA
12	83	607	760
13	89	501	1249
14	90	612	1012
15	86	681	784
16	97	436	577
17	95	876	1148
18	90	1085	1576
19	86	723	776
20	92	309	720
21	78	273	306
22	83	1452	1775
23	70	845	475
24	70	1126	213
25	66	604	140
26	73	352	352
27	86	43	217
28	76	602	602
29	78	438	448
30	58	40	40
	Total kWh	11,605	13,169

10.4.1.3 Meter Before / Meter After methodology for short duration events

Another approach called “meter before / meter after” has been discussed in lieu of a baseline calculation approach for short duration demand response events like those that may be associated with ancillary services. The “meter before / meter after” baseline methodology identifies the last reading before the start of each event and the first reading after the end of each event in the SCADA data. The load estimate for the curtailed period is the line segment connecting these two points. To achieve a single number for load reduction during each event, the average of the observed load and the average of the estimated load during the event are calculated. The average of the estimated load is the average of the two segment endpoints. The calculated load reduction is the difference between the estimated load and the observed load for each curtailment event.

In general for the short duration events utilized for the PLP, the meter before / meter after methodology yielded similar results to the load-matching technique described in Section 10.2. On average, the meter before / meter after methodology resulted in estimating 9% more load drop than the load-matching technique. There was one outlying event where the meter before / meter after methodology resulted in estimating the load drop as 11.5 MW compared with the load-matching technique estimate of 5.1 MW. Otherwise, the meter before / meter after methodology yielded results +23% or – 27% relative to the load-matching technique estimate.

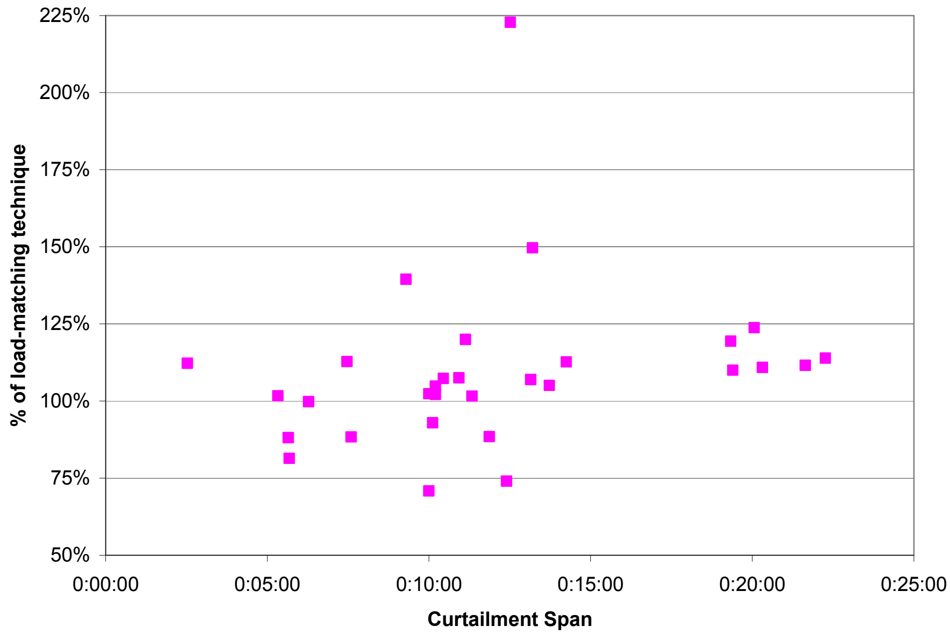

Figure 22 Meter Before / Meter After load drop estimate as a percentage of the load matching technique utilized for the PLP

As noted in Section 9.1, there is a rebound effect associated with the utilization of aggregated air conditioning load for demand response. The selection of the "meter after" point can have a significant effect on the calculation if the point resides within the rebound period by increasing the load estimate.

11. Ongoing Analysis

The SCE team made every effort to completely analyze the data generated during the 2009 PLP for inclusion in this report. However, due to the volume of information generated as well as the common occurrence of each answer generating additional questions, some questions remain unanswered as the analysis continues. This section outlines some items still under development and SCE proposes to provide an update to this report at the end of the 1st quarter of 2010 which will include finalization of these items as well as formalizing responses to any questions that arise by stakeholders and observers after their review of this report.

11.1 Customer Feedback

SCE is conducting a survey of both Ft Irwin leadership as well as the base residents who were selected to receive the indoor air temperature sensors. The responses to the survey may provide insight into how residents utilize their air conditioning as well as whether the short duration PLP events were noticed during the summer. The survey responses are still being collected prior to analysis, so the reporting of the results will not be available until Q1 2010.

11.2 Market Assessment and Financial Feasibility

SCE and the other IOUs continue participation in the DR cost effectiveness proceeding at the CPUC. SCE would like to review the results of the PLP with the team most involved with the cost effectiveness work to ensure consistency of methodology, factors and approach. A complete review was not completed in time to include a financial feasibility section within this report. However, SCE will review financial feasibility with the cost effectiveness team while also monitoring both the CAISO PDR proceeding and

CAISO Direct Participating proceeding to understand how market and retail rules will affect the cost effectiveness of any potential future programs.

11.3 Older SDP algorithms

SCE has utilized algorithms to analyze the enrolled MW in SDP and also review the performance of past events. SCE will review the algorithms utilized for SDP and compare them to the results generated by the PLP.

11.4 Sample Population Variation

SCE utilized 555 telemetry sensors to estimate the near real time load for a population of 3255 air conditioners. This is a 17% sample population. SCE and KEMA will perform an analysis of the 2009 data to determine how the precision of the estimated total load is affected or degraded as the size of the statistical sample is reduced. This analysis may provide insight into what may be a good size for sampling if a proxy telemetry sample is acceptable for future ancillary services. For example, the load estimate may become significantly less accurate with a sample population lower than 9%. In that case, SCE may recommend that 1 out of 10 aggregated units be equipped with telemetry sensors to provide proxy telemetry data.

11.5 Impact of PLP events on indoor air temperature

As mentioned in Section 5.5, analysis of the indoor temperature data is continuing in collaboration with LBNL. Preliminary analysis shows significantly less than a degree of temperature rise in the 110 buildings monitored with temperature sensors during all 30 PLP events.

12. Conclusions

The objective of SCE's 2009 PLP was to explore the technical and economic feasibility of small SCE-aggregated Demand Response (DR) as a potential participant in the MRTU Measurement and Performance (MAP) markets for PL and Proxy Demand Resource (PDR) products. The SCE Participating Load Pilot was a success by meeting the deliverables outlined in the Detailed Implementation Plan filed with the CPUC on March 11, 2009:

- SCE Launched the PLP by installing proxy telemetry devices in May, dispatching test events starting in June, completing CAISO ancillary services testing in July and bidding, dispatching and settling the PLP resource with CAISO from August through October.
- SCE and KEMA developed algorithms for converting a statistical sampling of the monitored current at customer sites into a forecast of available load for curtailment and provided this proxy telemetry data to CAISO per ancillary services requirements
- SCE and KEMA developed algorithms to estimate actual load drop after event dispatch based on available SCADA data and interval meter data with additional verification provided by telemetry information.

The SCE team is still in the process of analyzing the vast amount of data collected during PLP execution. While SCE has demonstrated that small aggregated DR load is technically feasible for participation in MRTU MAP market for PL and PDR products, the economic feasibility question will take more time to develop and will likely leverage the results of a 2010 PLP which SCE hopes to propose.

SCE will also develop recommendations for CAISO based on PLP results. These recommendations will be primarily based on reducing the cost of implementation as well as maintaining a network of small aggregated load PL or PDR resources while maintaining a predictable and reliable level of resource performance.

12.1 Remaining Questions for a 2010 PLP

While the 2009 PLP successfully addressed a number of outstanding issues concerning the technical and economic viability of a small aggregated loads participating in the wholesale markets, some questions remain. These include:

- Can small aggregated loads reliably participate as a PDR in the wholesale markets for energy and ancillary services?
- How effective is a mesh networking technology for telemetry in a more typical operating environment?
- Non-spinning reserves resources are typically bid many hours during the year, and called upon to perform with little warning. However, in this pilot SCE had ample warning to prepare for dispatch, as the dispatch time was known a week in advance. As a result, manual processes were able to support pilot operations. However, a significant level of automation would be required to receive and dispatch wholesale market ADS commands that are not scheduled in advance.
- How distinguishable will the A/C load and dispatch be on a more general population substation SCADA system that may have more “noise” from different loads and what is the lowest level of sample telemetry that can be provided before the resource can no longer be reliably counted on for non-spinning reserves?
- How reliable is an air-conditioning-based resource when developed in a region where summer temperatures are not uniformly hot and dry?
- What sort of marketing and customer education issues must SCE resolve to develop and enroll customers in a CAISO wholesale market compatible program?

- How will randomization impact performance and potentially reduce the rebound effect when utilizing a randomization dispatch and restore which is similar to a generation ramp rate?
- What will be the effect of a 50 percent cycling strategy or Programmable Communicating Thermostats (PCTs) be on resource performance and the rebound effect?

12.2 Telemetry for small aggregated loads

The CAISO requirement that all loads functioning as an Ancillary Service be equipped with telemetry capable of 1-minute aggregation to an ALMDS/DPG, with 4 second reporting from there seems to be driven by two primary factors: (1) having real-time telemetry available allows market participants to view their load's availability in real-time, allowing for adjustment of bids under circumstances where actual load value deviates from the quantity of load that was forecast and bid; and (2) the telemetry requirement gives the CAISO real-time load visibility of the load resource for use in grid management operations.

The SCE PLP demonstrated that under the ideal circumstances of the Ft. Irwin complex, a 15 percent proxy telemetry solution could be installed to provide a telemetry proxy estimation without monitoring each individual end point load. The question remains whether the cost of telemetry is outweighed by the benefit that telemetry provides. The value of telemetry for ancillary services must be considered in the context of other forms of "load intelligence." Here Section 9.2 is apropos; as it illustrates the potential of accurate weather data to forecast the availability of small, aggregated air conditioning load. Importantly, said weather data is not quite as accurate in predicting load as telemetry, but given the fact that accurate weather data is already readily available, while a telemetry proxy would need to be deployed at potentially a significant expense, its value should not be discounted. SCE recommends an examination of the

Ancillary Services Telemetry requirement to determine whether a proxy telemetry approach or even a temperature based estimation for air conditioning load would provide load estimates that are "good enough" for wholesale market operations.

13. GLOSSARY

Term or Acronym	Definition
A/C	Air Conditioner
ADS	Automated Dispatch System
AMI	Advanced Metering Infrastructure
CAISO	California Independent System Operator
CERTS	Consortium for Electric Reliability Technology Solutions
CLAP	Custom Load Aggregation Point
CT	Current Transformer
DDR	Dispatchable Demand Resource
DLC	Direct Load Control
DR	Demand Response
DRSRP	Demand Response Spinning Reserves Pilot
FERC	Federal Energy Regulatory Commission
MAP	Markets & Performance (formerly MRTU Release 1A)
MRTU	Market Redesign & Technology Update
PDR	Proxy Demand Resource
PL	Participating Load
PLP	Participating Load Pilot
SCADA	Supervisory Control And Data Acquisition
SCE	Southern California Edison
SDP	Summer Discount Plan
WG2	Working Group 2

Attachments C
SDG&E PLP Project Report

SAN DIEGO GAS & ELECTRIC COMPANY
Participating Load Pilot
2009 Evaluation

February 1, 2010
Version 1.0

1 Executive Summary

1.1 Pilot Description

The San Diego Gas and Electric (SDG&E) Participating Load Pilot (Pilot) allowed Commercial and small Industrial customers to aggregate as a single Participating Load resource to interface with the CAISO wholesale market. The Pilot was available to commercial and industrial customers, greater than 200 kW, receiving Bundled Utility service, Direct Access ("DA") service or Community Choice Aggregation ("CCA") service, and being billed on a Utility commercial, industrial or agricultural rate schedule. Pilot participants nominated a dispatchable amount of load on a monthly basis from August to December as one of two products: load that could be interrupted weekdays 11 AM to 7 PM (Weekday Peak), and load that could be interrupted any day and any hour (All Day). Each of these products required interruption with 10 minutes notice. The Pilot tariff[1] filed with the California Public Utilities Commission (Commission) paid a monthly capacity payment dependent on the product for which capacity was nominated with a reduction to that payment if the load did not perform as expected during an event.

On a daily basis, the dispatchable portion of the participating customer's load was bid into the CAISO Day Ahead Market as Non-Spinning Reserve, a contingency resource that is expected to fully respond to a real-time energy dispatch within 10 minutes of notification. Dispatch of capacity for contingency events is relatively rare in the CAISO market so a number of test dispatches were called to assure exercise of all systems end to end. There was no distinction between actual contingency dispatches and test dispatches for the Pilot participants who received no prior notice of test events and were expected to respond on every occurrence.

While the design and implementation contemplated that both SDG&E bundled service customers as well as DA customers would be eligible for participation, only bundled customers participated in the Pilot during 2009. The Pilot was also indifferent as to whether customers were represented by demand response aggregators (Aggregators) or participated directly (Directly-enrolled Participants). To assure that dispatch mechanisms would be exercised and a reasonable amount of data could be collected for analysis, the Pilot dispatched the Participants a minimum of three times each month. To provide some certainty that participants would not be over used, a monthly maximum of five events was established.

1.2 Pilot Objectives

The intent of implementing the Participating Load Pilots was to develop an understanding of the issues, systems and effort required to fully integrate utility demand response programs into the CAISO market. In order to make this effort as effective as possible SDG&E focused on implementing a Pilot reflective of the 'real world' with Pilot specific objectives focused on practical understanding of an Aggregator based model.

SDG&E's goal was to be agnostic to end-use telemetry solutions so as to work with third party aggregators to aggregate various types of participant's load. The Pilot implementation required the design, installation, and testing of near real-time telemetry from Pilot Participants to the CAISO such

[1] SDG&E Schedule PLP, Participating Load Pilot Demand Response Program. See http://www.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_PLP.pdf.

that the CAISO is able to monitor curtailments in real-time. Participants included both Directly-enrolled Participants and Aggregators, both with and without AutoDR (Automated Demand Response) capabilities and with a number of end-use customers representing the various customer types in the marketplace.

Using this 'real world' design, Pilot specific objectives included:

- Identifying and assessing the costs, barriers and necessary incentives to provide technology for required telemetry and AutoDR capabilities.
- Determining and assessing program design, systems and processes required to support full scale integration into CAISO MRTU market.
- Assessing capabilities of different customers and load types to perform effectively.

1.3 Implementation

Implementation of the Pilot was an extensive effort that was compressed due to the mandate delivered in the Commission Decision (D) 0812038 adopted December 18, 2008 (Decision Adopting Bridge Funding for 2009 Demand Response Programs) to be operational for the summer of 2009. To ensure that the Pilot would be operational by summer 2009, detailed design and technical development phases overlapped. This required some iterative work to assure that the tariff reflected all elements of the Pilot as implemented.

A high level overview of the activities during 2009 is shown in Figure 1.

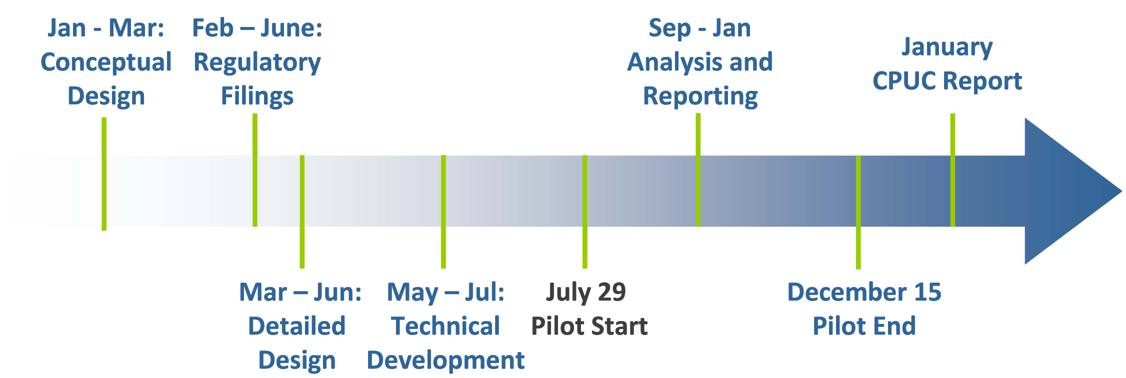

Figure 1: Pilot Chronology

The initial conceptual design elements were established in conjunction with the CAISO which was ordered by the Federal Energy Regulatory Commission (FERC), through Order 719, to perform an assessment of the technical feasibility and value to the market of using ancillary services from small demand response units.

The Pilot tariff was consolidated under a supplemental advice letter filed with the Commission on June 10, 2009 that provided clarifications and elaborations to an original tariff filing that preceded the final design and development phases. To establish standing and eligibility in the CAISO wholesale market, SDG&E executed a Participating Load Pilot Agreement with the CAISO which in turn was filed with the Federal Energy Regulatory Commission on June 26, 2009 for an effective date of June 29, 2009.

Prior to actual system development for Pilot specific applications, an inventory of existing SDG&E Demand Response applications was undertaken to determine if any could be leveraged due to the compressed implementation timeframe. Several elements and applications from the Capacity Bidding

Program were leveraged to meet the needs of the Pilot. Development work for new applications specific to the Pilot focused on telemetry and event notification. All development work to provide functional applications for operation of the Pilot was completed prior to the Go-live date.

SDG&E participated in the CAISO Participating Load Pilot Market Simulation from June 29 to July 10 2009. The market simulation was run in conjunction with the other utility pilots and provided an opportunity to see the "bid to bill" process function within the CAISO markets. This critical step provided the assurance that Pilot processes and practices as well as the CAISO systems were production ready for operation in the financially binding CAISO markets.

Pilot participants were brought into the testing process in July with telemetry connectivity testing followed by telemetry end to end testing. These were completed prior to the final functional load response test, which was performed on July 22, 2009 to assure that the participants could respond to a curtailment notification with load drops visible through real-time telemetry.

The final step prior to being accepted as a Participating Load (PL) resource capable of bidding Non-spinning reserves into the wholesale market was an Ancillary Services certification test with the CAISO. This test was successfully completed on July 23 and demonstrated that the CAISO had telemetry visibility to an actual load drop within 10 minutes of issuing a dispatch instruction.

The SDG&E Pilot commenced operations on the CAISO Participating Load Pilot start date of July 29, 2009 with the self scheduling of the underlying load of the participating customers as required by the CAISO Participating Load Design. The capacity available for curtailment was first bid in and accepted as Non-Spinning Capacity Reserves on August 6, 2009 and continued through December 15, 2009.

1.4 Summary Conclusions

The Pilot was implemented and successfully operated during the summer of 2009 meeting the established objectives for the first year of the Pilot. It was demonstrated that small Commercial and Industrial customers could be aggregated into a single real-time dispatchable resource meeting the minimum load size of 1 MW for presentation to the CAISO wholesale market. It was further demonstrated that a telemetry solution could be enabled to collect disparate installations and locations into a single aggregated signal for delivery to the CAISO although the value and cost effectiveness of an end to end telemetry is still debatable.

Event analysis establishes that the aggregated resource can perform in real-time as a contingency resource capable of curtailing load within 10 minutes of a dispatch instruction from the CAISO through the use of an automated notification system to the participating customer.

While not obvious at the Pilot's inception, it became evident that there are opportunities for different products to be included in subsequent phases to better align capabilities of specific customer segments with the needs of the wholesale market and to make Demand Response more cost effective than some traditional Demand Response programs.

The Pilot provided valuable experience to all the Participants, including participants at SDG&E providing an opportunity to understand firsthand what was required for further integration with the CAISO. Throughout the Pilot there was evidence of the importance of education in such a transformative endeavor. Such a significant undertaking should be managed with implementations on smaller scales allowing for adjustments to support a fuller scale implementation. The Pilot has been turned into a Case Study example to train and educate the different stakeholders within SDG&E and is planned to be used as a basis to develop additional customer outreach efforts in preparation for further integration and the January 2011 filing for 2012-2014.

2 Pilot Participation

The Pilot divides participants into two enrollment types: directly-enrolled and aggregator-led. While all participants were aggregated into a single resource for interaction with the CAISO wholesale market, there were distinctions and challenges associated with each type. There was one Directly-enrolled Participant in the Pilot that incurred the obligation to provide a monthly nomination, telemetry connectivity and the ability to receive and respond to curtailment notifications in real-time. The two Aggregator Participants in the Pilot were bound to the same requirements, providing a single monthly nomination, combined telemetry for their customers in aggregate as well as the responsibility to notify their customer of Pilot events. The Aggregators had an existing telemetry design to be leveraged, as well as processes in place to monitor and respond to dispatches in real time.

2.1 Recruitment

Recruitment for Pilot participation presented challenges due to the timing of the approval of the Pilot tariff and the start date for the Pilot. The three most significant obstacles were:

- Difficulties in implementing and testing telemetry in time for pilot participation.
- Unknown effort or misinterpretation of effort involved to meet requirements.
- Effort involved in the face of uncertainty regarding length of pilot.

Aggregators which already participated in other Demand Response programs were particularly well suited for the Pilot. Based on their existing relationships with customers, Aggregators readily understood the response capabilities of existing loads and typically had existing technology in place to support two-way communications, thus giving them a head start on meeting telemetry requirements and established notification processes. The suitability to the 11-7 product stems from participation in traditional DR programs designed to meet peak load needs. Further, by having the ability to combine various customers, a smoother and more predictable dispatchable load could be nominated into the Pilot. Therefore, Aggregators who had existing contracts for other DR programs with SDG&E were contacted to identify their desire and capability for participation in the pilot.

Additionally, there was a limited marketing outreach to Aggregators and directly to utility customers through SDG&E Account Executives. Key bundled customers who were not currently enrolled in a program with an Aggregator were identified for targeted outreach.

The response from Aggregators was strong. Aggregators which have been following the evolution of DR within the market and were interested in preparing strategically were particularly enthusiastic about participating in the pilot. All of the Aggregators initially indicated that there would be minimal impact to their operations.

Candidates for direct participation expressed much more concern about the impact to their operations as did the end-use customers enrolling with the Aggregators. Those enrolling with Aggregators put a high reliance on the Aggregators' ability to limit impacts to their operations.

In order to focus on success, general criteria were identified for acceptance into the Pilot. Those expressing interest were assessed against these criteria for acceptance and those that appeared unlikely to meet the criteria were dissuaded from participation. Key elements of the criteria included:

- Experience and understanding of demand response programs and processes
- Identification of end-use customers

- Ability to provide required telemetry within the specified timeframes
- Ability to meet SDG&E's credit requirements

2.2 Enrollment

There were two Aggregator Participants and one Directly-enrolled Participant enrolled in the Pilot. Together, these Participants comprised 8 customers consisting of 9 unique sites[2]. As is illustrated in Figure 2 below, the Hotel / Entertainment segment represented the largest number of sites in the Pilot, consistent with SDG&E's service territory. The customer mix for the program was rather varied nonetheless with civic/community spaces, office buildings, retail and small industrial.

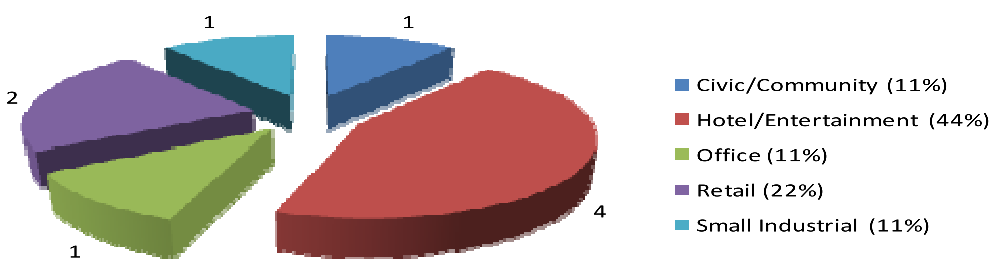

Figure 2: Distribution of Enrolled Sites by Segment

7 of the 8 customers participated in the Pilot via an Aggregator, with the one Directly-enrolled Participant being a light-industrial customer with primary voltage service and the ability to shed from 1.2 MW to over 3 MW of load for the Pilot. This customer was representative of a small number of identified customers in SDG&E's territory that may have atypical parameters, but may have a significant level of load available for curtailment. While inclusion of this customer presented a number of complications, it also presented a number of learning opportunities.

A majority of customers were enrolled in the first two months of the Pilot, with one customer added in October. Note that one customer left the program at the end of October. Table 1 shows the number of enrolled customers for each Participant.

	August	September	October	November	December
Aggregator 1	2	2	2	2	2
Aggregator 2	2	4	5	4	5
Directly-enrolled Participant	0	1	1	1	1
	4	**7**	**8**	**7**	**8**

Table 1: Enrolled Sites by Month

[2] These premises consisted of 15 service accounts and 17 utility meters.

Curtailable load represented by Pilot customers is shown in Figure 3. Note that this chart groups some segments because Aggregator nominations were not customer-specific.

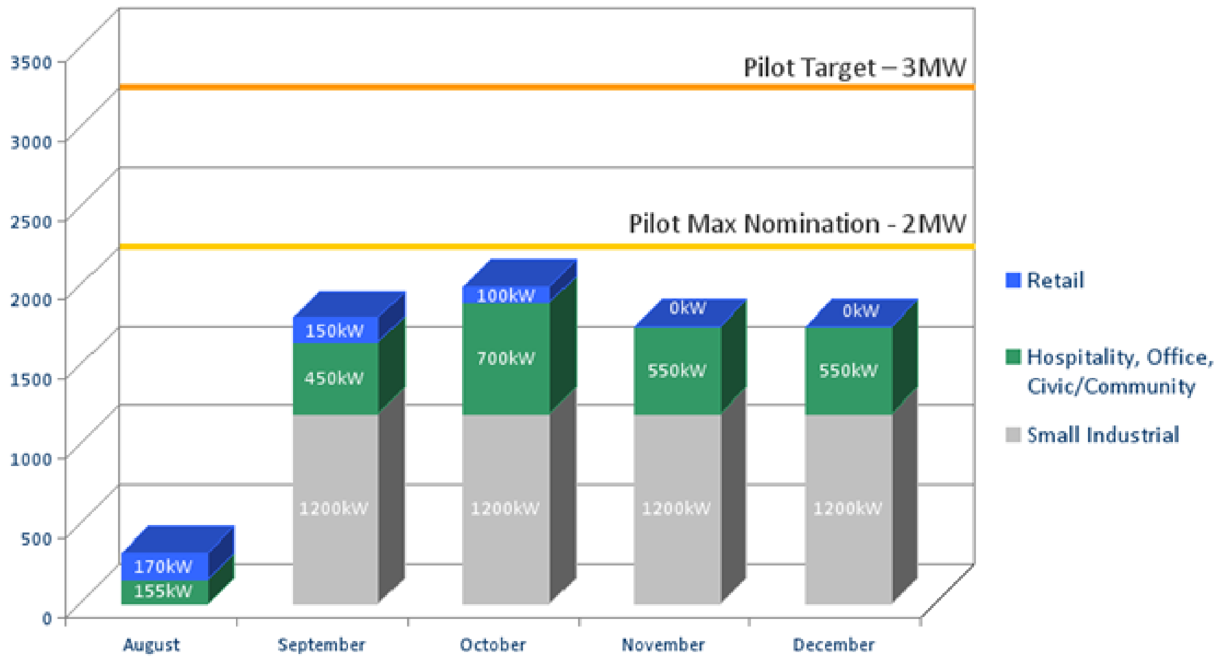

Figure 3: Pilot Nominations by Segment

3 Implementation and Operation

3.1 Nominations and Scheduling

The Pilot was designed to operate in the CAISO market as a Participating Load (PL) resource. To facilitate processing in the market systems, CAISO PL resources have both a load and generation location modeled in the CAISO system. The load is modeled in the CAISO network to represent the specific location(s) as a Custom Load Aggregation Point (CLAP) and becomes the basis for energy settlement A pseudo generator that represents the dispatchable portion of the load is also modeled and used within the CAISO market systems to accept and settle capacity bids and as a target of dispatch orders. The pseudo generator for the Pilot was modeled for a maximum dispatchable load of 3.0 MW. These issues are discussed in further detail in section 4.6.1.

In order to accommodate both Bundled and Direct Access customers in the Pilot, two separate pseudo generators and CLAPs were established and registered to separate Scheduling Coordinators. Based on enrollments during Phase 1 only bundled customers participated in the Pilot and only the resources registered to the Scheduling Coordinator ID SDG3 were scheduled with the CAISO. Resources to support Direct Access customers were established and registered with the CAISO to the Scheduling Coordinator ID APXY.

3.1.1 Participant Nominations

The Nomination process was modeled after the Capacity Bidding Program (CBP), with formal capacity nominations provided by Participants by the 25th calendar day of each month for the following month. Given that the nomination was static for each hour of the product period and for the entire month, rather than on a next day basis, any risks needed to be factored into the total nomination. The small number of end-use customers within each of the aggregation groups meant that a lack of performance by even a single customer would have a significant impact on performance. The need for the resource to respond quickly made it especially difficult for the group to mitigate impacts from one individual customer, or address the deviations in load that occur throughout the day or as a result of weather.

Participants found themselves providing nominations much lower than they might have otherwise made if there was a more dynamic option that mirrored the wholesale market bidding process which is done daily and is variable each hour. Participant nomination models had to assume the lowest level of demand that would be available throughout each Month would be the amount to nominate to the Pilot.

Figure 4 illustrates nominations for the Pilot.

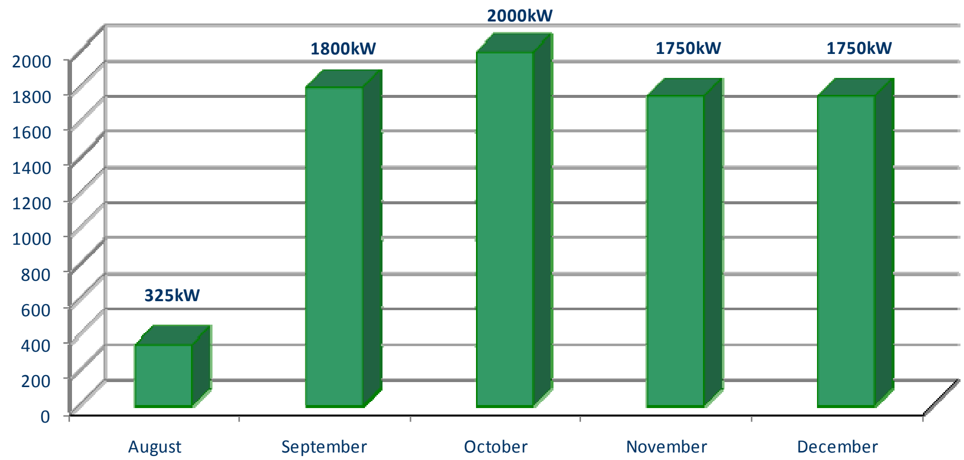

Figure 4: Monthly Total Pilot Participant Nominations

3.1.2 Scheduling and Bidding Management

3.1.2.1 Load Forecasts

There were two distinct issues associated with load forecasting due to the structure of the CAISO Participating Load (PL) requirements and the design of the SDG&E Pilot. The structure of the CAISO PL requires that the entire underlying load, not just the dispatchable portion, associated with a meter be contained and scheduled in a custom load aggregation for the purpose of scheduling demand. The dispatchable portion of a Participating Load is scheduled and bid as a supply resource and treated as such by the CAISO. SDG&E used a standard forecasting process to forecast the demand to be scheduled at the custom load aggregation and relied on Participants to determine the amount of curtailable, or dispatchable, load that would be presented as a supply resource in the nomination process.

To derive the hourly load forecast for the underlying load to be scheduled at the custom load aggregation, SDG&E retrieved interval data from the meter list of current Pilot enrollees and ran a regression model to produce a forecast of the total load of the Pilot bundled customers. Although the customers may have only nominated for the 11-7 weekday Pilot product, an hourly load forecast for 24x7 was produced. This was based on the requirement by the CAISO to have Participating Load scheduled and metered at the custom load aggregation location defined in the CAISO network model. No Direct Access customers participated in the Pilot during 2009, so the process designed to acquire hourly load forecasts for Direct Access customers was not utilized.

While a forecasting process would typically be used to determine the Load Reduction to be offered to the market, the design of the Pilot required Participants to communicate this reduction through their nominations. The Aggregators in the Pilot used their own forecasting methodologies to determine their nominations. SDG&E aggregated the nominations by product type, 11-7 and 24x7, and used those values as the basis for bidding Non-Spinning capacity into the CAISO market. Each Participant was left to its own method to determine the amount of Load Reduction to nominate on a monthly basis. Any overly optimistic or conservative forecasts made by Participants would result in an impact to retail settlement calculations for Participants as well as potential wholesale settlement penalties for SDG&E.

3.1.2.2 Bidding and Scheduling

The forecast, nomination, event and customer operating information were used to present bid and schedule data to the CAISO market. The forecast of the underlying load was self-scheduled at the custom load point. The aggregated amount nominated by the Participants was used to develop the bid at the pseudo-generation location. Load Reduction bid amounts were suspended if the maximum number of events allowed by the Pilot were reached.

To facilitate the scheduling of the underlying load at the custom load point, a unique demand location (CLAP_BUNDLD_DRL) was created in the CAISO full network model at the Custom Load Aggregation Point (CLAP). The hourly load forecasts included Participants in both Pilot products and became the MW values for the self-scheduled (price-taker) quantities. Based on CAISO PL requirements, the load associated with the enrolled customers was self-scheduled at this location all days and all hours for the duration of the pilot.

The monthly quantities submitted by the Participants became the basis for the Non-Spinning bids submitted to the CAISO at the pseudo generation resource. To reflect the specific products and the operational behavior of the clients, bids were developed such that the bid information submitted to the CAISO was accurate. To reflect the participation levels of the two products, the quantities and hours bid were neither static nor continuous throughout the day. The typical bid pattern for the 24x7 product covered 10 PM to 6 AM period, while the 11-7 product bids corresponded to the product hours of 11 AM to 7 PM. This pattern is represented graphically in Figure 5 below.

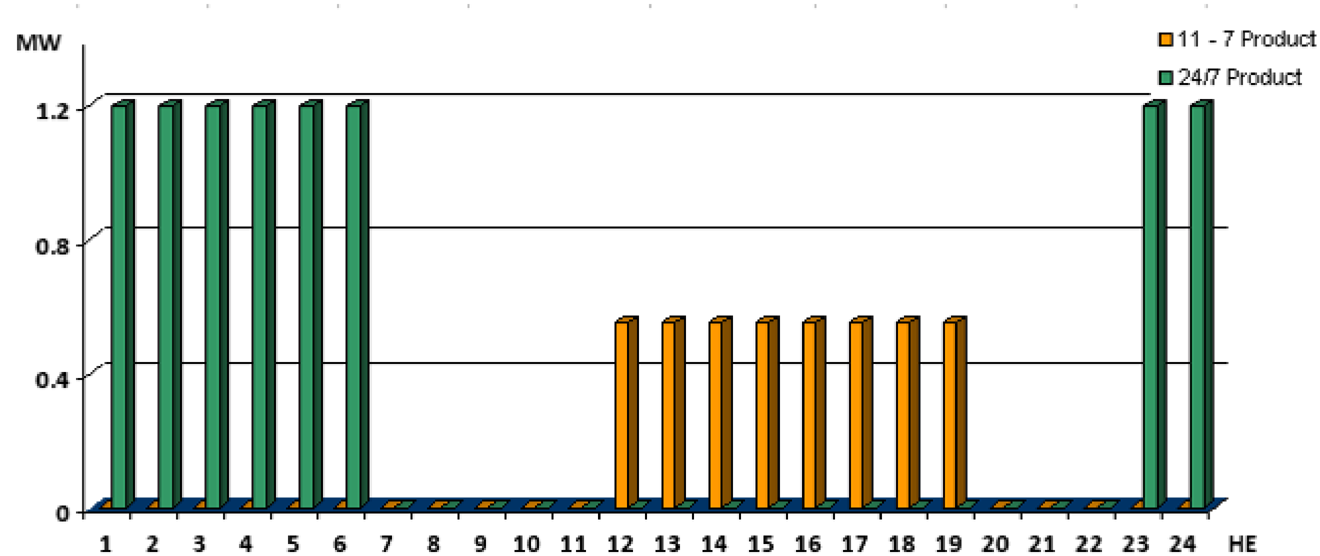

Figure 5: Typical Bid Pattern

3.1.2.3 Bid Prices

The prices applied to the bids were developed to increase the likelihood of capacity bids being accepted by the market and to generally minimize the chances of being dispatched for energy outside of a test or true contingency situation. The purpose of this strategy was to meet the objectives of the pilot to make DR capacity available to the wholesale market while meeting the requirements of the Pilot tariff.

To ensure that the capacity portion (Ancillary Services Non-Spinning Reserves) of the bids would likely clear the Day Ahead market, the capacity price was set at $0.01 (one cent). This was equivalent to bidding as a price-taker without the risk of being selected if the capacity prices were negative. Once notification was received that the capacity bid cleared the market, real-time energy bids were submitted with a $500 price to minimize the chance of being dispatched for energy except in the case of a true system contingency. In the case of a scheduled CAISO test, the energy bid for the test hour was reduced to $1.00 to avoid any appearance that the Pilot was being used to extract monies inappropriately from the market. To execute such tests, a contingency dispatch was issued which assures that the resource will be selected out of merit order and paid its bid price or better.

3.1.3 Scheduling and Bid Submittal

Once monthly nominations were received and approved, a monthly capacity Bidding Plan was created. Further, hourly load forecasts, corresponding to the meters associated with the monthly nominations, were created and submitted. On a daily basis, SDG&E submitted the Load Schedule at the custom load aggregation as a self-schedule, and the AS bid quantities on the pseudo generator into the CAISO Scheduling Infrastructure and Business Rules (SIBR) application.

After the Day Ahead market results were published and the next day Real-time markets were open for bid submittal, energy bids (per the Bidding Plan) were submitted for the amount of AS Non-Spinning Capacity awarded each hour. Submittal of Real-time energy bids was necessary, since, in the absence of a bid, the CAISO SIBR software creates default energy bids for capacity awards. Automatically-created default energy bids would have resulted in an energy bid price of $2.00 (no registered default bid amounts were submitted in the Resource Data Template for the Pilot), potentially facilitating unwanted energy dispatches.

3.2 Telemetry

A major difference between the Pilot and typical utility DR programs is its telemetry requirement. The telemetry data provided the CAISO the ability to observe load drops during delivery and the opportunity to determine if enough load reduction is available before dispatch.

For the Pilot, all Participant telemetry data was measured directly with equipment installed on premises. Each enrolled customer needed new equipment installed for this purpose. Design and installation of the telemetry was provided for the directly-enrolled customer; however, each Aggregator designed and installed a proprietary telemetry solution for their own customers. The exact equipment installed and communications medium depended upon specific on-site conditions as well as Aggregator preference.

Each of the 9 sites had telemetry installed for the Pilot. Each installation consisted of a single telemetry meter with the exception of one installation that required 3 such devices, for a total of 11 used for the Pilot. As described below, the Directly-enrolled Participant had a pre-existing meter suitable for telemetry.

For the telemetry data to be of use to CAISO operations, it was combined to the same level as the capacity bids were submitted (i.e., to the CLAP[3] modeled for the Pilot). To support this requirement and provide 24x7 operations, APX acted as a concentrator for all telemetry data for the Pilot – receiving telemetry from the Aggregators, directly-polling the directly-enrolled Participant, combining

[3] Note that the Pilot design allowed for a bundled CLAP and an unbundled CLAP, but only bundled participants were enrolled in 2009.

all telemetry to the CLAP, and finally making these data available to the CAISO. Just as APX performed these functions, the Aggregators were also required to combine their own telemetry values to the CLAP. This layered "fan-in" approach allowed for increasing standardization and streamlining the closer the data came to the CAISO.

Together, these requirements resulted in a wide range of tasks including design and implementation of customer-side solutions, development of Web services for Aggregators to submit telemetry, as well as systems programming and configuration for point combination and interface with the CAISO.

The following sections detail the implementation and operations for telemetry in the Pilot.

3.2.1 Overview

Figure 6 provides an overview of telemetry and systems used for each step from the customer to the CAISO. Note that the arrows indicate push or pull interactions, all telemetry data flow is from left to right.

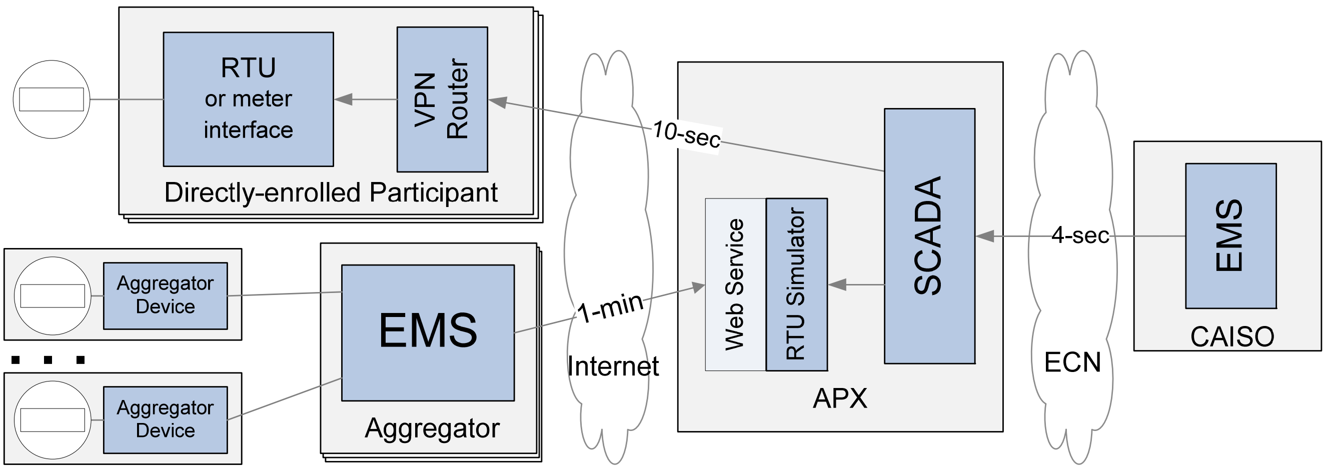

Figure 6: Telemetry Overview

As is shown in the figure, the directly-enrolled Participant was polled by the existing APX SCADA system. Each of the two Aggregators in the Pilot designed their own disparate solutions for collecting and processing telemetry. To simplify interfacing with the Aggregators, a Web service was implemented to provide a standard interface for sending telemetry to APX. Data submitted to the Web service was forwarded to an RTU that was polled by the SCADA system. All telemetry points were combined in the SCADA system for retrieval by the CAISO EMS over the Energy Communication Network (ECN).

3.2.2 Telemetry Points

Pilot telemetry was combined to a Custom Load Aggregation Point (CLAP) to match the location modeled specific to the Pilot resource(s) used in the CAISO market systems.

For each CLAP, there were two points:

- Total Delivered Power across all Participants. An analog point provided in megawatts to two decimal places.
- Connectivity status of the resource (UCON). This is a binary point defined to be 0 if no telemetry was being retrieved for any resource; otherwise, a 1.

The Pilot distinguished between two resources: one for SDG&E Bundled customers and one for Direct Access customers. As a result, there were two CLAPs defined; however, since no Direct Access customers participated in 2009, the points for the Direct Access resource reported 0.00 MW and 0 UCON.

Further details on how these points were calculated for the Pilot are provided in section 3.2.5.2.

The CAISO required that telemetry for the Pilot resource be scaled up by appropriate distribution loss factors (DLFs). Such factors account for energy loss in the distribution system. DLFs are forecasted day-ahead for each voltage level resulting in a specific factor for each Participant. For the purposes of the Pilot it was decided that a single factor would be used for each voltage level:

Service Level	Pilot Distribution Loss Factor
Primary voltage	1.011
Secondary voltage	1.048

Table 2: Distribution Loss Factors used in the Pilot

The decision to use one factor per voltage level was made to simplify the implementation required by the Aggregators considering that these numbers change very little in the SDG&E territory.

3.2.3 Direct Enrolled Participant

The directly-enrolled Participant was a light-industrial customer with primary voltage service. Further description of this customer is in section 2.2.

Telemetry for the directly-enrolled Participant was polled by APX. This solution extended the reach of the APX SCADA system over a persistent virtual private network (VPN) directly to the customer site. In this way, the end point was directly interrogated using Modbus or DNP protocols irrespective of the underlying network topology. The VPN connection was made over the public Internet and maintained between existing APX-side equipment and a customer-side Cisco 1841 Integrated Services Router (ISR). The ISR was connected at the customer premises directly to a pre-existing GE PQM II meter. The SCADA system directly polled this meter every 10 seconds using the Modbus/RTU protocol. The network connectivity was installed specifically for the Pilot and is provided over satellite. Figure 7 shows an overview of this telemetry solution with specifics in the following sections.

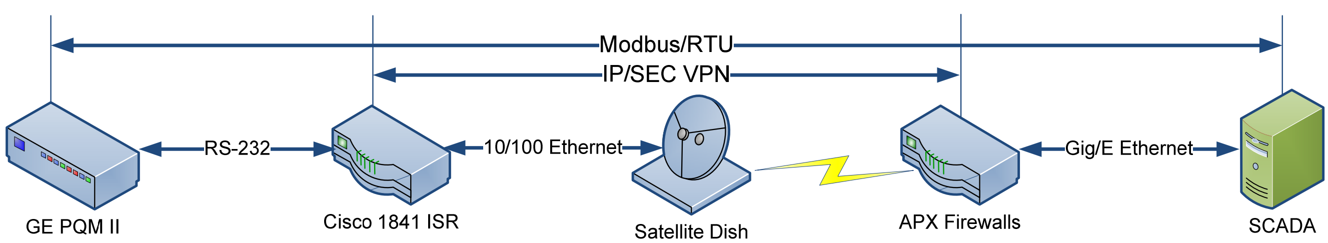

Figure 7: Customer Equipment

Hardware and labor for the telemetry equipment was approximately $10,000. The costs for installation were much higher than would typically be expected due to customer requirements that a particular vendor be used for onsite work.

Note that this communication was one-way – notifications to the customer were through a phone call.

In addition, there was a recurring service charge of $130 per month for satellite connectivity.

3.2.3.1 Communications

When looking at connectivity for customers in the Pilot, there was a strong bias towards simplicity and low cost. This resulted in the following prioritization of the different options[4], in order:

1. Existing Internet connectivity
2. Cable or DSL
3. Satellite

The Pilot customer already had Internet connectivity. Using this existing connectivity was acceptable to the customer; however, the distance between the 15 kV switch gear and existing networking hardware was prohibitive. Wireless networking was also ruled out due to concerns of interference and proximity. As a result, use of the existing Internet connection was ruled out.

Due to the location of the customer and the large area of the facility, Cable and DSL were also ruled out. Effectively, adding one of these wired solutions would not have solved the initial problems of proximity.

Satellite connectivity provided by HughesNet was chosen. This service provides a persistent connection to the Internet at speeds of up to 512Mbp/s. This solution resolved the proximity issues nicely, because it was able to be installed on a shed in close proximity to the switch gear. Note that this solution was only used for telemetry – event notifications to this particular customer were by direct telephone call to on-site operators.

3.2.3.2 Measurement Equipment – GE PQM II

The Pilot customer already had its own measurement equipment installed on premises. This is not uncommon for industrial customers since energy is often a major cost for such customers. This installation included the relevant 3-phase inputs to a GE PQM II for measuring instantaneous 3-phase real power for the plant. This meter was used to provide telemetry to the Pilot.

The GE PQM II has several communication ports for data retrieval and control and supports both the Modbus/RTU and DNP 3.0 protocols. For the Pilot, the meter was connected to the Cisco 1841 ISR using a custom RS-232 cable. Communication with the meter used the Modbus/RTU protocol.

The total power for the customer was retrieved from the appropriate Modbus/RTU register. The connectivity status (UCON) for this customer was derived in SCADA based on its ability to get valid readings over Modbus/RTU. Connectivity failures of any kind between SCADA and the meter resulted in a UCON value of 0 for this customer.

3.2.4 Aggregator Participants

There were two Aggregators enrolled in the Pilot. SDG&E did not direct the Aggregators on how to implement telemetry for their end-customers. SDG&E did require that each Aggregator retrieve their customer telemetry and combine those data to the CLAP for submission to an APX-hosted Web service. Details on the Web service can be found in section 3.2.5.1.

[4] Leased lines (e.g., a T1 or T3) were never seriously considered for the pilot considering the high installation and service cost.

Each Aggregator took a different approach to the design and implementation of their telemetry solutions. While specific details on these approaches are considered proprietary to the Aggregators, an overview of the approaches taken can be found in the following sections. Note that Aggregators have made the point on several occasions that they will always install their own parallel measurement equipment regardless of the capabilities of a pre-existing utility metering.

3.2.4.1 Telemetry Points

Each Aggregator was required to submit one set of points for the bundled CLAP as detailed in Table 3.

Item	Detail
ID	Per-Aggregator ID for this set of points.
ReadTime	Time the underlying readings were combined.
TotalAdjustedDemand	Total demand for all customers, adjusted with Distribution Loss Factors (DLF).
TotalDemand	Total demand for all customers
IncludesActual	*True* if at least one underlying customer read is actual (i.e. not estimated nor substituted); otherwise, false. This corresponds to the CAISO UCON status.
IncludesEstimate	*True* if at least one underlying customer read is an estimate; otherwise, *false*.
EarliestActualReadTime	Read time of the earliest actual read incorporated in the total demand; otherwise, *nil* if no read is actual (i.e., when IncludesActual is *False*).

Table 3: Aggregator Points

The Aggregators were directed to:

- Read their end-customer measurement equipment at least once per minute.
- Read either instantaneous demand or average demand over a short interval, whichever was more feasible based on the selected measurement equipment.
- Submit the combined measurements – the points listed in Table 3 – to the Web service at least once per minute.
- Collect and submit telemetry 24x7.
- Substitute estimated values for the underlying customers if there was a loss of connectivity. This was in line with expectations of the CAISO that zero values would not be submitted.

Note that the Pilot did not require Aggregators to synchronize their underlying readings before combining them. This topic is covered in more detail in section 4.3.1.2.2.

3.2.4.2 Aggregator 1

Aggregator 1 employed an all-in-one device for telemetry collection at customer premises. This device recorded measurements from current transformers installed on the main electrical service and communicated with the Aggregator's central location using an integrated cellular WAN solution. The Aggregator would have preferred to use the existing Internet connectivity at the customer sites; however, their customers' policy was prohibitive. The measurement used by the Aggregator was average demand over the previous minute, submitted to their central location once per minute. Note that this communication was one-way – dispatch occurred through a notification to customer email addresses.

The Aggregator needed to build new systems for archiving and combining the telemetry data for submission to the Telemetry Web service.

Hardware and labor for the telemetry equipment was approximately $4,000 per site. In addition, there was a recurring service charge of $60 per month for the cellular connectivity.

3.2.4.3 Aggregator 2

Aggregator 2 already had the telemetry design, systems, and operations in place for implementing telemetry for the Pilot. This was anticipated since their business model relies on AutoDR and as such requires frequent monitoring of customer energy usage. They did need to make some adjustments to support the level of frequency required for the Pilot as well as to support point combination and submission through the Web service.

On-site the Aggregator installed a meter and their own proprietary hardware collector to read instantaneous kW measurements every several seconds. In one case, the Aggregator installed 3 of their collectors at one site while in all other cases only one was installed per site. All connections in the Pilot sites were over physical wiring. At least every 30 seconds, the measurements were communicated back to the Aggregator using existing customer corporate networks and Internet connections. Note that this communication was one-way – dispatch occurred through separate AutoDR systems.

Measurements were stored in the Aggregator's EMS. Once per minute, these data were retrieved from the EMS, combined, and submitted to the Web service.

Hardware and labor for the telemetry equipment was approximately $4,000 per installation with no recurring service charge. These dollar figures do not include costs for AutoDR. Note that the Aggregator used TI/TA funds to mitigate AutoDR installation costs.

3.2.5 Central Systems

There were two main central systems involved in telemetry collection and delivery: the Participant Telemetry Web Service and the APX SCADA system, each discussed in turn in the following sections.

3.2.5.1 Web Services

Aggregators submitted their telemetry data to the Pilot's Participant Telemetry Web Service. This was designed to provide a simple interface to submit telemetry readings for the Pilot using standard and secure technologies. Submissions into the Web service were passed along to a live storage system for retrieval by SCADA over Modbus/RTU.

Mutual authentication, integrity, and confidentiality for the Web service were ensured through the use of mutual X.509 certificates. Participants were provided with the necessary certificates for these purposes. In addition to the certificates, the Aggregators were provided with documentation on the Web service API, WS-Metadata Exchange endpoints for tool support, as well as sample code for service submission.

3.2.5.2 Point Combination

The APX SCADA system stored all current telemetry and combined them into the points required by the CAISO (see section 3.2.2).

Point combination was required to aggregate the different retrieved points into a single pair representing the Pilot resource. To do this, SCADA was programmed to directly sum the Aggregator demand values with a synthesized value representing the Pilot customer's demand. This flow is shown in Figure 8.

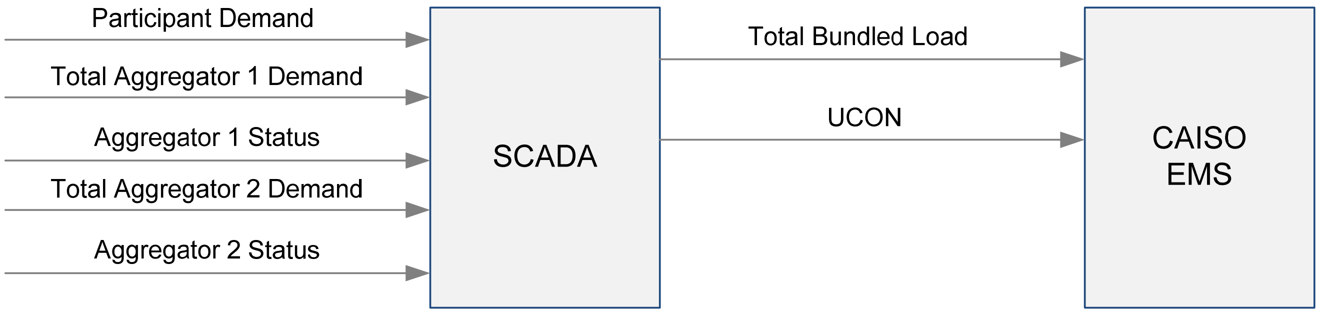

Figure 8: Telemetry Points

Aside from the need to apply distribution loss factors to this value, it also was capped to control for its high variability (see section 4.3.1.4 for more on this topic). Figure 9 shows a representation of this point combination.

$$kW_{TOTAL} = kW_{A1} + kW_{A2} + \min(kW_C \cdot DLF_C, MAX_C)$$

Figure 9: Total Demand Presented to CAISO

In addition to combining the demand values, the CAISO UCON value was also synthesized as represented in Figure 10.

$$UCON_{TOTAL} = UCON_{A1} \vee UCON_{A2} \vee \lnot badQuality(C)$$

Figure 10: Composite UCON Presented to CAISO

Incoming points were polled every 10 seconds. For the directly-enrolled customer, this resulted in data no older than 10 seconds; however, since Aggregator points were submitted once per minute, their values remained constant until subsequent update. The CAISO EMS polled for the latest values every 4 seconds.

Once per minute, current telemetry values were archived for later analysis. Figures and analyses in this document that use telemetry are based on these archived data.

3.3 Dispatch

One of the objectives of the SDG&E Pilot was to allow and explore the aggregation of many small loads into a single resource to meet the minimum MW size to qualify as a Participating Load in the CAISO market. The Pilot tariff as written did not require Participants to submit a price threshold for dispatch and, as such, there was no need to submit price differentiated bids at the wholesale level. CAISO dispatch instructions are delivered on a resource level and only provided a Dispatch Operating Target (DOT) quantity without any corresponding bid segment information.

Since a single CAISO resource ID was used in the Pilot, quantities from each Participant were aggregated when presented to the wholesale electricity market. Since Participant nominations were fixed for an entire month and it was necessary to submit on a single resource, bids to the CAISO were effectively an "all or nothing" submittal on an hourly basis. The all or nothing nature of the bids submitted to the CAISO was reflected in dispatch instructions as only a single energy bid segment could be dispatched by the CAISO. There was no possibility for the CAISO to issue a dispatch for a particular Participant in the aggregation.

On the one occasion that the CAISO dispatched an energy quantity lower than the total capacity bid, no effort was made to allocate a proportional share to Participants when providing curtailment notifications. For any given event, the Participants were expected to curtail their full monthly nominated amount.

Because the Pilot aggregated multiple resources into one pseudo-generation resource, it was necessary to disaggregate CAISO dispatch instructions into notifications directly to the appropriate Participants. As such, individual Participants received notifications that indicated the amount they were required to curtail an amount equal to their monthly nomination. The Pilot notification software contained intelligence that only delivered such messages to Participants that were in effect for the given hour of the dispatch. For example, if a dispatch occurred at 11PM, only the 24x7 Participants would be notified and the 11-7 Participants would not receive a curtailment notification.

Of particular interest in this Pilot was the ability to achieve the load drop within the 10 minute requirement of the CAISO. Figure 11 provides a graphic representation of the dispatch data flow as well as the timing for the different stages in notification.

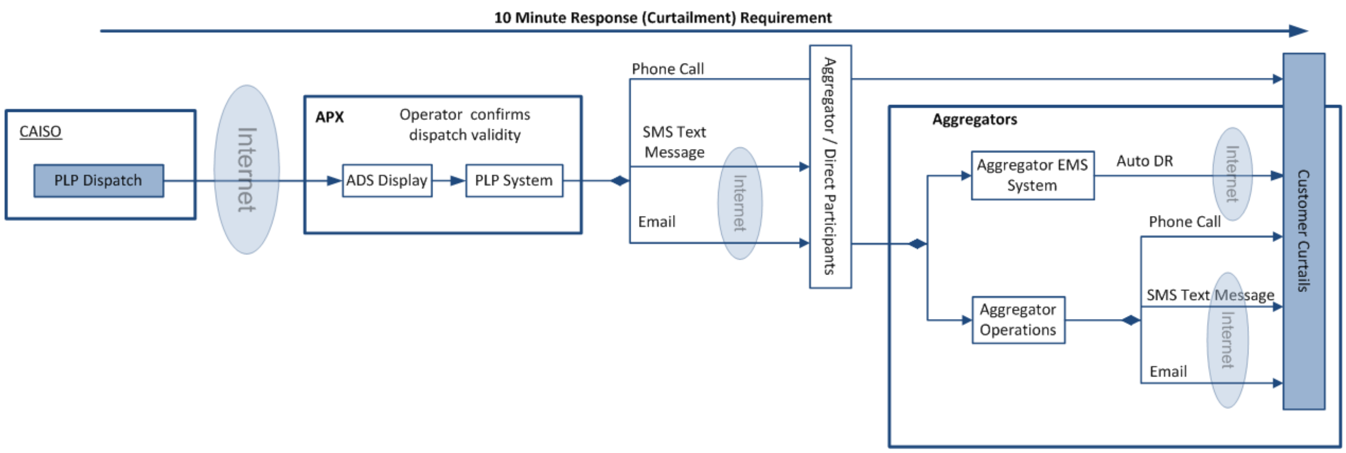

Figure 11: Dispatch Data Flow

Response to the notification varied from manually curtailing load to the automatic control of on-premises energy management systems (EMS). The specifics depended on the Participant, and if applicable, the Aggregator. Further details are provided and the following sections.

Note that in the first phase of the Pilot, SDG&E enrolled Participants into a single pseudo-generation resource identified by ELCAJN_6_DRGEN1. For brevity, this is referred to as the Pilot Resource.

3.3.1 CAISO ADS Dispatches

The CAISO initiated events for the Pilot through their Automated Dispatch System (ADS). This software application is provided by the CAISO for market Participants to securely monitor relevant instructions.

Authentication, confidentiality, and integrity for ADS communication with the CAISO are provided using industry-standard PKI encryption technology. ADS was monitored 24/7 for Pilot dispatches.

The capacity provided by Pilot Participants was bid into the CAISO Ancillary Services market daily as Non-Spinning Capacity Reserves. As such, dispatches for the Pilot held the same characteristics as dispatches for generators. Load provided by Participants was visible to the CAISO as a single pseudo-resource with a bid for this product. During Exceptional and Contingency Dispatches, the Pilot Resource was dispatched by the CAISO for a MW value up to the value bid in for that hour by SDG&E.

The PLP Resource was available for CAISO Contingency as well as Exceptional Dispatches. These dispatches are summarized in Table 4.

Dispatch Type	Description
Contingency Dispatch	A Contingency Dispatch typically entails a strain of some type on the grid, calling for the CAISO to dispatch additional resources to meet current energy needs. A Contingency Dispatch is generally triggered for a resource according to the CAISO's resource loading order.
Exceptional Dispatch	The CAISO may trigger an Exceptional Dispatch independently of resource loading order and as an override to the market dispatch software if network needs are not met.

Table 4: CAISO Dispatches Employed in the Pilot

The Pilot handled two Contingency Dispatches throughout the duration of the pilot, one on August 18^{th}, and the other on December 7^{th} with the remaining 12 CAISO initiated events being Exceptional Dispatch.

Typically, an Exceptional Dispatch requires manual intervention. This dispatch type was the preferred method for Pilot test events as it allowed SDG&E, APX and the CAISO to coordinate a predetermined event time and megawatt quantity. It is important to note that Participants were not made aware of the test schedule.

See section 7.2 for Pilot event details.

3.3.2 Retail Event Notifications

After receiving a dispatch from the CAISO, or upon initiating a non-CAISO test event, Participants in the Pilot were notified of the event. Given the 10 minute performance requirement for resources bidding Non-Spin Ancillary Services in the CAISO market, the notification functionality was built with a focus on speed and simplicity. Note that neither the initiator of the event nor the type of ADS dispatch was relevant to the Participants and therefore had no impact on the notification methodology or message delivered to the Participants.

The PLP notification is summarized in the Figure 12.

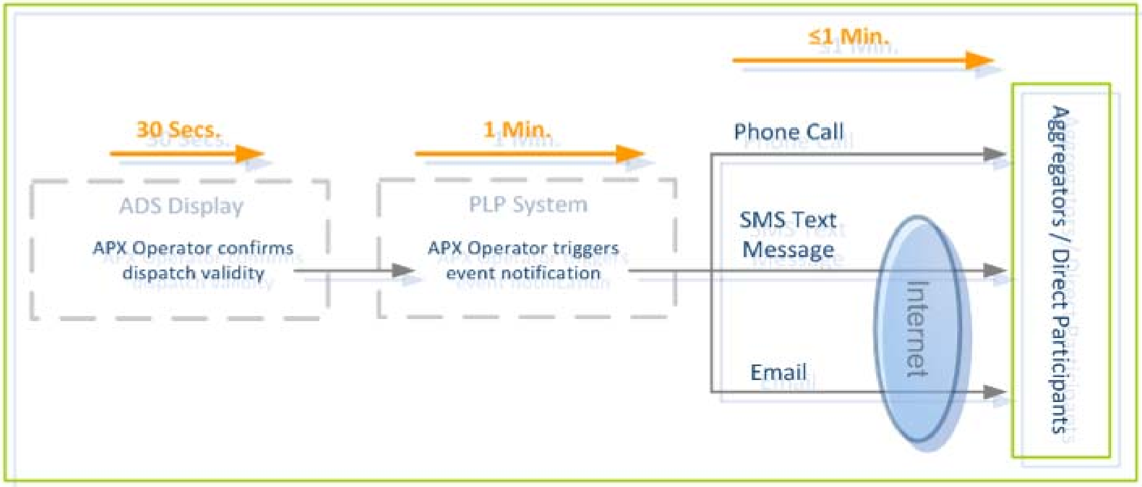

Figure 12: Pilot Notification Summary

The full process, from receiving the ADS dispatch to confirming a notification was typically completed in less than 90 seconds.

As illustrated in Figure 11 previously, APX operators received notice of CAISO Pilot dispatches through the CAISO ADS. During the Pilot, there was no automated interface between ADS and the notification system and APX Operators received training in order to identify if a dispatch met all the appropriate requirements. This precaution was implemented since errant instructions – 68 of which were dispatched during the Pilot – could create unnecessary client notifications. Operators performed a rapid verification of the validity of a Pilot dispatch and then proceeded to trigger the notification process.

In addition to Operator monitoring, validations were built into the notification system to limit errors that could violate the SDG&E PLP tariff. Notably this ensured that the time, duration and number of events per month and per day were in compliance with tariff rules.

As illustrated in Figure 12, Participants were notified using different technologies. The two Aggregators used a combination of email and SMS text messages, both sent over the Internet. In the case of the directly-enrolled customer, manual phone calls were placed to on-site plant personnel.

Participants handled the automated notification messages in different ways depending on the level of automation of their own notification processes and on the level of integration with their end-use customers. One Participant received PLP notifications automatically to a system which parsed the message and triggered an automatic process (i.e., AutoDR). Another Participant received notifications in an operations center where an operator interpreted the message and notified end-use customers.

To assist in the automated processes, standard notification message formats were developed for the Pilot – one format for email messages and another for SMS[5] messages. These formats accommodated both automated and manual response to the message.

In the event of a notification system failure, procedures were put in place such that the text of the SMS message would be sent to Participants via both email and SMS. Although outside of the PLP system,

[5] SMS, or Short Message Service also commonly referred to as *text messaging*.

this contingency message was created automatically to reduce the risk of erroneous information being communicated to Participants. This was particularly important as one of the Aggregators relied on parsing SMS messages for initiating AutoDR – an ad hoc message would not guarantee message field consistency and would have been rejected by the Aggregator system.

3.4 Metering

SDG&E meters provided the Settlement Quality Meter Data (SQMD) used for all settlements in the Pilot. This included both retail settlements with the participants as well as wholesale settlements with the CAISO. In addition, the SQMD was used as inputs into scheduling and forecasting.

All Pilot customers used existing interval meters recording 15-minute kWh usage. Customers without such metering in place were not considered for the Pilot due to the lead times required for installation. 5-minute metering – even when possible by reprogramming the installed meters – was determined not to be feasible for the Pilot.

Meters were read once per day by the SDG&E metering department through remote interrogation.

For scheduling and settlement purposes with the CAISO, the Participants needed to be removed from the SDG&E Default Load Aggregation (DLAP) and assigned to the Pilot Custom Load Aggregation (CLAP). The SQMD was used for this purpose. Meter data submitted for the CLAP was converted to 5-minute intervals as required by the CAISO for Participating Loads. The CLAP data was uploaded to the CAISO Operational Meter Analysis and Reporting (OMAR) system with the same process used to submit SQMD for the DLAP. Figure 13 provides a high level schematic of the various processes applied to meter data for the Pilot.

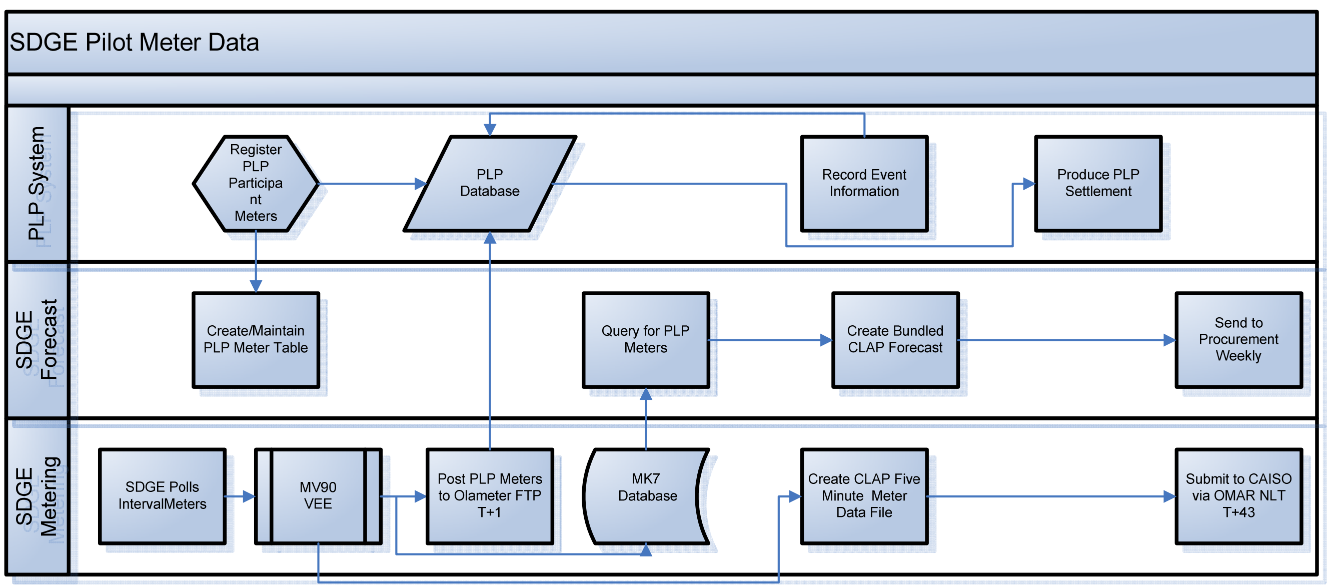

Figure 13: Meter Data Flow

For retail settlement purposes, the meter data was converted to 10-minute intervals as required by the tariff.

3.5 Settlement

3.5.1 Retail Settlement

Participants of the Pilot were paid monthly capacity payments based on their average performance for each event occurring in that month.

The tariff set a $/kW capacity payment rate for each month of the Pilot. The operational period of the Pilot ended December 15, 2009 resulting in a proration in the December payment.

Product	Capacity Incentive ($/kW - month)					
	July	August	September	October	November	December
2 hours, 11a - 7p Only	$ 20.10	$ 20.10	$ 20.10	$ 20.10	$ 20.10	$ 10.05
2 hours, 24x7	$ 21.50	$ 21.50	$ 21.50	$ 21.50	$ 21.50	$ 10.75

Table 5: Load Reduction Incentive Payment

For each event:

- The *potential capacity payment* was calculated by multiplying the Participant's nomination and the $/kW Capacity Incentive rate for the month, divided by the number of events for the month.
- The *baseline* was equal to the 15-minute interval ending at or preceding the CAISO dispatch.
- The *actual reduction* was the average of the *baseline* minus the actual metered load over the event.
- The unadjusted performance factor was the actual reduction divided by the nomination.
- The adjusted performance factor was derived from unadjusted performance factor as follows:
  - 100% or above, the adjusted performance factor was 100%
  - Between 25% and 100%, there was no adjustment.
  - Below 25%, the adjusted performance factor was 0%.
- The capacity payment was calculated by applying the adjusted performance factor to the potential capacity payment.

The total monthly capacity payment was the sum of the event capacity payments.

For the Pilot, retail settlement calculations were performed manually to allow for extensive review of calculation details.

The Settlement Quality Meter Data (SQMD) was converted from 15-minute interval data to 10-minute interval data as required for settlement calculations per the tariff.

3.5.2 Wholesale Settlement

CAISO settlements for the wholesale market are completely independent of the retail settlement process. The CAISO settles with the Scheduling Coordinator (SC) at the resource level. Wholesale settlement data comes at 7, 38 and 51 business days after the dispatch day. For this report the most recent data was considered, but due to the timing of data availability, not all data was reconciled to the same data set.

The Pilot had two distinct locations in use for the Pilot, CLAP_BUNDL_DRL for load and ELCAJN_6_DRGEN1 for the pseudo-generator, within the CAISO system to identify the two resources. While the CAISO has over 130 Charge Codes associated with Wholesale market activity, approximately

25 applied to the Pilot resources and the majority of those are associated with administrative or load share allocations. The CAISO assigns a name and a numeric value to each Charge Code to allow the identification of charges associated with each resource and related market activity.

Three charge codes associated with the pseudo generator resource, ELCAJN_6_DRGEN1 provide the information used to analyze the resource performance in the wholesale market. These are summarized in the following table:

Charge Code	Description
Day Ahead Non-Spinning Capacity Reserve Settlement	Indicates the quantities, prices and dollar amounts of capacity payment.
No Pay Non Spinning Reserve Settlement	Indicates the amount of capacity payment rescinded due to performance issues.
Real Time Instructed Imbalance Energy Settlement	Indicates the energy payment for dispatched capacity.

Table 6: Main Wholesale Charge Codes for the Pilot

The CAISO determines dispatch performance and subsequent No Pay settlement by reviewing the dispatch notices and comparing them to meter data. Meter data for the five minute interval before the dispatch notice is compared to the meter data for each subsequent five minute for the duration of the dispatch. If the meter data shows a reduction equal to or greater than the amount of MW dispatched, no capacity payment is rescinded. If the meter data shows a reduction of 90 percent or less of the dispatched MW, a corresponding portion up to the full amount of the capacity payment is rescinded.

A portion of market performance is captured in the real-time energy settlement of the load resource, CLAP_BUNDLD_DRL, in the Charge Code for uninstructed energy (Real Time Uninstructed Imbalance Energy Settlement). Real-time uninstructed energy includes differences between Day Ahead scheduled quantities (forecasting error) and metered amounts co-mingled with real-time deviations. Since different types of uninstructed energy are co-mingled within the single charge code and real-time dispatch energy contributions to the charge code are a small percentage of the overall charge, the effort to disaggregate data was not deemed justified for the purpose of this report.

3.6 Security and Protection of Customer Data

APX's role in the Pilot warrants a summary of APX system security. APX's business model is based upon providing services to clients on an outsourced basis, requiring that customer information be secure and fully protected. APX's data centers are protected using industry-standard equipment and access methods to ensure that the data is kept fully confidential and without corruption. Data exchanged between SDG&E and APX is done through SSL using 128-bit encryption keys. No customer data were available to unauthorized personnel, and no such data were transferred between sites without encryption. All databases and applications associated with the PLP are fully segregated and are password protected. They are configured to allow only the appropriate access to records depending on the individual's requirements. Customer data was only used after the proper authorization forms were filed with SDG&E and then were only used for settlement calculations and analyses for Pilot reporting.

4 Observations and Lessons Learned

As expected, the Pilot provided a wealth of lesson learned. This section contains details on these lessons as well as other observations related to the Pilot. These learnings are summarized in Table 7.

Section / Topic	Lessons Learned Overview
4.1 Program Design	
	Meter before / meter after baseline may not be sufficient for longer retail events.
	Fixed monthly nominations reduced nominated capacity, leaving DR "on the table".
	The 24x7 Product was a mixed success as it modeled actual needs of the CAISO without necessarily fitting customer requirements.
4.2 Participation	
4.2.1 General Observations	Tight timelines between tariff filing and the beginning of Pilot Operations created a challenge for all parties, in particular, with regards to effective coordination on Participant enrollment.
4.2.2 Recruitment	Understanding PL and Pilot requirements, concerns about effort to install telemetry, reluctance to be involved in a Pilot all impacted customer recruitment.
4.2.3 Enrollment	While Aggregators are familiar with DR programs in general, there is a large knowledge gap at the customer level with regards to enrollment information and operational requirements for Pilot participation. Increased customer education and program information is necessary in the early stages of the program.
4.2.4 Customer Suitability	Customers transferring from other programs that have not historically been called did not understand the operational requirements of this Pilot; Customer did not necessarily see their involvement in the Pilot as a commitment to curtail, more as an ongoing business decision with a cost/benefit analysis.
4.2.5 Customer Satisfaction	Participants were generally satisfied. Most of their issues are covered in other sections. Those that are not: desire for tariff premium for Aggregators; desire for some marketing collateral for use in recruitment.
▯ Telemetry	
4.3.1 CAISO Requirements	
4.3.1.1 Demand versus Pseudo-Generation	Pseudo-generation values reflecting curtailable load would be more valuable in real time for the CAISO than total demand.
4.3.1.2 Telemetry Measurement Requirements	Telemetry measurement requirements were flexible for the Pilot; however, the impact of different measurement techniques, latencies, and clock synchronization need to be evaluated and specific guidelines for measurement need to be established.
4.3.1.3 24x7 Requirement	Implementing 24x7 telemetry presents technology and staffing costs for Participants, and may not be necessary when the resource is not bid in to the market. Discussions with the CAISO need to continue regarding the need for 24x7 telemetry as well as implementation of an outage reporting mechanism.
4.3.1.4 High Variability	Customers with high variability create complexity for CAISO Operators using telemetry to inform dispatch decisions. The implementation of pseudo-generation could help resolve this issue.
4.3.2 Site installation variables	Characteristics of the customer site greatly impact telemetry design and costs. A general plug-and-play solution for telemetry is currently not available but attempt could be made to define a set of standardized solutions.
4.3.3 Aggregator Issues	The implementation of 24x7 combined telemetry poses a challenge for some Aggregators. Simplification of requirements for aggregator submission as well as ensuring cross-platform support could ease such challenges.
4.4 Dispatch	
4.4.1 ADS Lessons Learned	There were some challenges interpreting ADS instructions in the context of DR. Automation of the dispatch response based on Dispatch Operating Targets (DOTs) will reduce the risk of such misinterpretation.
4.4.2 Notification Lessons	Manual intervention within the notification process increased the potential for errors

Learned	or delays. An automated notification system tied to ADS would ensure on time and accurate notifications.
4.5 Metering	
4.5.1 Impact of 15-minute Metering	The use of 15-minute interval meters can negatively impact Participant performance. 5-minute interval meters should be preferred for this type of program. This effect would be exacerbated by shorter event times as proposed for a future Pilot phase.
4.5.2 Impact of Clock Drift	SDG&E's policy allows for a +/- 3 minute variation in meter clock time. The impact of this policy is within accepted norms and presented no particular issue for the Pilot.
4.6 Wholesale Market	
4.6.1 Model build delays	Updates to the CAISO Network Model are infrequent and require a 60 day lead time which constrains adding new Participants to the Pilot. Adding Participants to the Pilot resource would be simplified by the addition of default resource location in the CAISO Proxy Demand Resource.
4.6.2 Settlements Issues	Given the manual nature of CAISO test dispatches for the Pilot, there were unexpected inconsistencies between wholesale settlements and ADS dispatch times.
4.7 Multiple Participation	Dual participation – in this case with CPP-D – greatly increases the complexity of Pilot operation in ensuring that customers within mixed aggregated portfolios are not called for both a Pilot and CPP-D event. This will continue to be an issue and will need to be carefully considered in the future of the Pilot and other DR programs.

Table 7: Summary of Lessons Learned

4.1 Program Design

Wherever possible the Pilot adopted existing standards and elements that were familiar and could be implemented quickly. During the Pilot a number of these design elements were reviewed for applicability in the future.

A "meter before, meter after" baseline was chosen for the Pilot. This simple to understand baseline was intended to accurately assess the load reduction and its impact on the grid similar to baselines used with generation. In order to mirror current retail demand response programs, providing customers with an event duration that they could plan for, the Pilot used the CAISO Non Spinning Reserve maximum of two (2) hours as a standard for all Pilot events. Subsequent analysis would indicate that while this baseline meets the planned objectives, a "meter before, meter after" baseline may not be the optimal baseline for the financial settlement of events as long as two hours. An analysis of alternate baselines appears in section 5.4.

Similarly, the monthly nomination process which required Participants to designate a single quantity for a product for an entire month was used for the Pilot consistent with other retail demand response programs. While this allowed for a simple nominating process, the single quantity did not allow for any daily shaping which resulted in the nomination of the lowest amount available during the time period. During months such as September and October where the weather can vary substantially, Participants noted that a significant amount of capability was not nominated to protect them against a "worst case situation." Allowing nominations to be changed during the month, whether daily or with hour-to-hour variability, would provide the flexibility to add or drop Participants during the month or adjust nominations to reflect changes to physical capability but would add to the administrative overhead.

Since system contingencies can occur any time, 24x7, using DR for system emergencies provides an opportunity for DR to be used in the wholesale market in a manner atypical of its historical use. The Pilot included a 24x7 product with the CAISO Non Spinning Reserves procurement practices in mind. However, this doesn't necessarily match up with the DR capabilities of customers who are able to participate outside of traditional DR timeframes. As the Pilot demonstrated, there are customers with off-peak loads that can perform on 10 minutes notice, but that load may not be available all days and all hours. In consideration of the fact that the CAISO procures Non-Spinning reserves outside of traditional DR timeframes, a product that allows nomination and participation any days and any hour is prudent, especially if it is designed to provide Non Spinning Reserves. Enabling dynamic nominations that would allow for participation nominations to vary not only by day but also by hour, consistent with the CAISO market would provide the flexibility to include incorporate these customers.

4.2 Participation

4.2.1 General Observations

To leverage the experience of existing program staff, the Pilot administrative processes were modeled on the existing SDG&E Capacity Bidding Program. Nevertheless, given its pilot status and the limited systems available for program administration, the enrollment process did differ from the CBP with a number of new and unique steps.

Given the tight timeframe between the Pilot tariff filing and the first operational month, customer recruitment and setup needed to occur with much less time than would have been ideal. It was important nonetheless to recruit a sufficient number of customers for the Pilot to have a curtailable load level that would be practical for CAISO Ancillary Services and to offer a sufficiently-large mix of customers to be useful for Pilot analysis. As a result additional criteria and approval for acceptance into the Pilot were required (see section 2.1 for these criteria).

Although paperwork was collected by Aggregators for customer enrollment in time for the beginning of live Pilot operations, the limited time for the enrollment process, coupled with the lack of customer and Aggregator experience and familiarity with Pilot requirements resulted in the need for a number of adjustments to the enrollment information provided. In several instances customers transitioned from a different DR program and/or Aggregator in order to participate in the Pilot creating a need for additional validation steps.

The need to continually adjust and improve administrative processes during live Pilot operations compounded some of the issues in the early stages of customer enrollment. The most important consequences of these issues were delayed enrollment and/or the need for corrections in enrollment information during the Pilot.

4.2.2 Recruitment

The limited marketing outreach to Aggregators and customers through direct contact was effective in bringing Bundled customers to the Pilot. However, given the limited time for customer recruitment this approach was unable to address customers who were not able to quickly meet requirements or required significant education. Customers who had extensive approval processes dependent upon outside funding such as with the TI/TA program or Direct Access customers that required coordination with an Energy Service Provider (ESP) were not addressed.

Several Aggregators and customers showed early interest in enrolling in the Pilot and several informal discussions were commenced to discuss Pilot requirements. Many of these discussions ended in a “wait and see” decision from the prospects. There were several reasons impacting this:

- Some reluctance to engage until the tariff was fully approved

- Concern that the Pilot might not extend beyond 2009 therefore putting the pay-back on the investment at risk
- Concern that the telemetry requirements were too complex or costly to install
- Questions as to whether requirements would change significantly subsequent to the Pilot

Once the tariff was approved, some of the reluctance dissipated.

The primary issue for participation by Aggregators in particular was in assessing the effort involved to meet the Pilot requirements and the expected return on investment. It was clear that many of them are not prepared to deliver telemetered resources on an ongoing basis. Two Aggregators appeared to be prepared to meet the requirements in the long run, but were unable to meet them within the time frame required for the Pilot.

4.2.3 Enrollment

It was observed throughout the Pilot that while Aggregators are familiar with DR programs, they are not necessarily familiar with PL or the CAISO markets. This coupled with the knowledge gap among end use customers regarding DR and their own utility account information resulted in erroneous or incomplete information being provided to SDG&E through customer enrollment documents. For possible future phases of the Pilot, additional effort would have to be made by SDG&E and Aggregators to increase understanding by all parties involved of the requirements and constraints for participation in such a DR program.

Three major enrollment issues arose during the Pilot period:

- Submission of incorrect meter IDs
- Missing meter IDs
- Submission of ineligible meters or those participating in other DR programs

While the issues surrounding eligibility verification are not specific to PLP's enrollment process the impacts associated with these issues can be significant for customers. One such example of this related to a transition of a customer between Aggregators and programs. As a result, the customer's enrollment in PLP, which had been planned for November and December, was delayed until the final two weeks of the Pilot.

4.2.4 Customer Suitability

The directly-enrolled customer is an interesting case study in customer suitability. When they are operational they can curtail anywhere from 1.2 to over 3 MW. As they operate off-peak, such load shed can be very useful in a contingency. Due to their operating schedule, they were enrolled in the 24x7 product. This was the best fit for the Pilot because they do not operate during peak times; however, they were not truly operational around the clock. This mismatch posed some challenges in the Pilot. Note that the upper bound of possible curtailment was impacted by their highly variable load which poses several challenges (see section 4.3.1.4 for more on this topic).

One other enrollee turned out to be unsuitable for the Pilot. This Civic / Community customer -- enrolled by Aggregator 2 -- successfully lobbied to be removed from the Pilot and exited at the end of October. There were two reasons identified for why the customer wished to leave the Pilot:

- A part of the customer agreement with the Aggregator was to program the on-site EMS for AutoDR. Due to some technical difficulties the EMS was not properly handling the end of events without a manual override. While the Aggregator worked to get this issue resolved, the customer was unwilling to work through this issue.

- This customer had previously been on the SDG&E Base Interruptible Program (BIP) which has historically been very rarely called by SDG&E. It appears that the customer was interested in gaining an economic benefit for participating DR programs, but was not willing to suffer any inconvenience. The inconvenience associated with having to work through technical issues coupled with the inconvenience associated with more frequent events resulted in a desire to exit the Pilot.

Neither of these two issues is directly related to the status of this project. While these two issues are different they represent the types of challenges regularly seen. Installation and configuration issues can be complex and take time to work through and many customers expect that there will be no effort required on their part with no impact for participation. The issue of free ridership, where customers enroll in programs for an economic benefit with the expectation that they will never get dispatched arises frequently.

While the aggregated nature of the Pilot obscures some specifics about how different customer classes performed there are still several lessons to be learned about customer performance.

- Customers with AutoDR performed better than those without. This was demonstrated through the early parts of the Pilot where Aggregator 1 with no AutoDR curtailed late and often continued curtailing beyond the end of the event. This is in contrast to Aggregator 2 where curtailment began and ended on time with the assistance of AutoDR.
- More sophisticated Customers performed better than those who were not. This was demonstrated by the multi-site retailer who worked with Aggregator 1 and with Pilot administrators directly to resolve operational issues manifested by the lack of AutoDR. This is in contrast to the Directly-enrolled Participant who was operationally unable to respond to some events due to operator schedules and language issues. This is also in contrast to the customer then dropped out of the Pilot due to the inconveniences presented through participation.
- Challenges arising during the recruitment and enrollment process reinforced the perspective that a significant amount of education is necessary for all of the various stakeholders. Even some simple communications were challenging due to differences in terminology and perspectives. Use and implications of terms such as service accounts, sites, meters and customers varied.

Another interesting related aspect of customer suitability is how the customers viewed involvement in the Pilot. Virtually all customers viewed the activity as a commercial transaction with an understanding that their performance (or lack thereof) was an ongoing economic decision. Throughout the Pilot decisions regarding participation were driven by economic concerns included the decision to perform – is it better to curtail load or to ignore the notification? This evaluation clearly differs from a commitment to shed load when requested to support grid reliability.

4.2.5 Customer Satisfaction

Throughout the Pilot, open communication was maintained with the Participants to obtain regular feedback for possible improvement. This approach culminated with debriefing discussions at the end of the Pilot.

The overall feedback from Aggregators regarding the Pilot has been positive with the two Aggregators intending to participate in future phases of the Pilot. All of the Aggregator-represented customers also intend to continue, excepting for the customer which left the Pilot in November (see section 4.2.3 for details regarding that customer's unsuitability). The Directly-enrolled Participant would also like to continue in the Pilot; however, such continued participation may require enhancements to the 24x7 product as discussed in section 4.1.

There is agreement that this type of program is valuable and that the incentive level is appropriate to ensure success. There is an interest in the inclusion of PDR into the Pilot as the lack of a telemetry requirement will simplify Pilot costs and offer Aggregators a larger pool of potential customers. Having both products within one Pilot will provide flexibility and evaluation opportunities without requiring significant additional infrastructure.

During the Pilot there were two specific items that were raised by one of the Aggregators in regard to design.

- The Aggregators voiced the concern that the Pilot tariff included no premium for Aggregators over direct enrollment of customers. The fundamental concern is that with no premium in place, Aggregators must offer their customers less money for participation than the customer could get through direct enrollment with the utility. While this was not cited as an issue for the Pilot, it was identified as an issue for the future.
- A related item was the level of support that third party Aggregators should receive on an ongoing basis. While Aggregators expect to be the interface with their customers there was a desire to be provided with additional marketing and management support. In particular, Aggregators expressed interest in receiving support from SDG&E and/or the Commission for marketing materials to support enrollment. Generally speaking, a mass market education initiative is not seen as crucial and more PLP-specific materials, including Pilot requirements and generic incentive and cost information would be useful.

Other Participant feedback is enumerated here and integrated in other sections of this report:

- The enrollment process, similar to CBP is extremely manual. Streamlining the process with a possible online component would ease this process significantly.
- Nominating once per month poses challenges and creates risk that is mitigated through lower nominations. Shortening the nomination periods would allow more DR to be made available.
- The approach to telemetry in the Pilot was considered to be reasonable and comparable to other programs.
- The manual step required to interpret ADS and notify Participants was a concern in that it added variability to the advance notice time and added a latency that reduced the required response time. Participants are more comfortable with being provided a specific time to curtail consistent with current retail programs.
- The reliability of SMTP-based notifications was suitable for the Pilot and consistent with other DR programs however there was a desire to see this process improve and evolve for other programs as well as PLP. There is a consensus from Aggregators that the use of Web services would be a more secure and reliable solution.

4.3 Telemetry

4.3.1 CAISO Requirements

Once implementation of the Pilot was underway, the project team worked closely with the CAISO regarding requirements. Since the published telemetry requirements modeled existing Participating Load, they did not directly correlate with the aggregated nature of the SDG&E Pilot. As a result, many of the requirements needed to be detailed or modified. Some of these modifications are applicable in a larger implementation for a full-fledged program while others were specific to the Pilot. This section reviews these items as a first step toward codifying the guidance from the CAISO for future implementations.

4.3.1.1 Demand versus Pseudo-Generation

One purpose of the Pilot was to model DR as generation for the wholesale market. Wholesale settlement for the Pilot was performed by calculating quantities that represent this pseudo-generation. This approach was not followed for telemetry in the Pilot; instead, the telemetry reported the total load at the CLAP resource. The reasons for this decision are covered below, but in practice, it would be more useful for the CAISO to receive telemetry modeling pseudo-generation. This is because the total demand obscures the actual available capacity and as such it was not used by the CAISO for operational decisions. As a result, the telemetry provided in the Pilot was more of an opportunity to learn lessons about equipment installation and delivery than to provide operational value to the CAISO.

Total load and pseudo-generation might seem to be opposites, but they are not. Total demand varies based on any underlying usage, but pseudo-generation only varies by usage of the curtailable portion of the load. To illustrate the differences imagine a 15 MW load with a peak curtailable amount of 1.5 MW. For simplification, these diagrams assume that the load is flat between intervals and has the same values before and after the event.

The blue bars in the following figures show two examples of total load before, during, and after an event. Figure 14 shows a case where the entire 1.5 MW is available to curtail. Figure 15 shows an example where only 1 MW is available. The important point is that one cannot determine the available curtailment at time *T+1* based on the information available at time *T*.

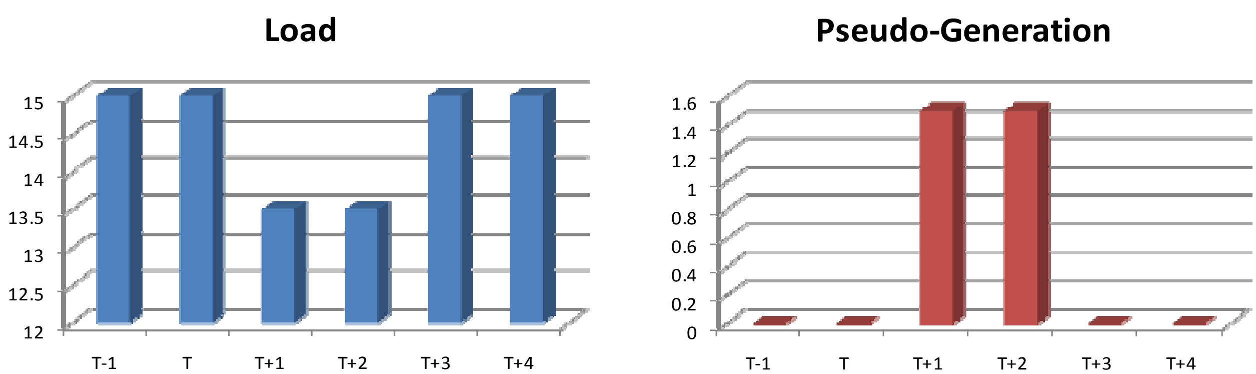

Figure 14: Load versus Pseudo-Generation with 1.5 MW Available

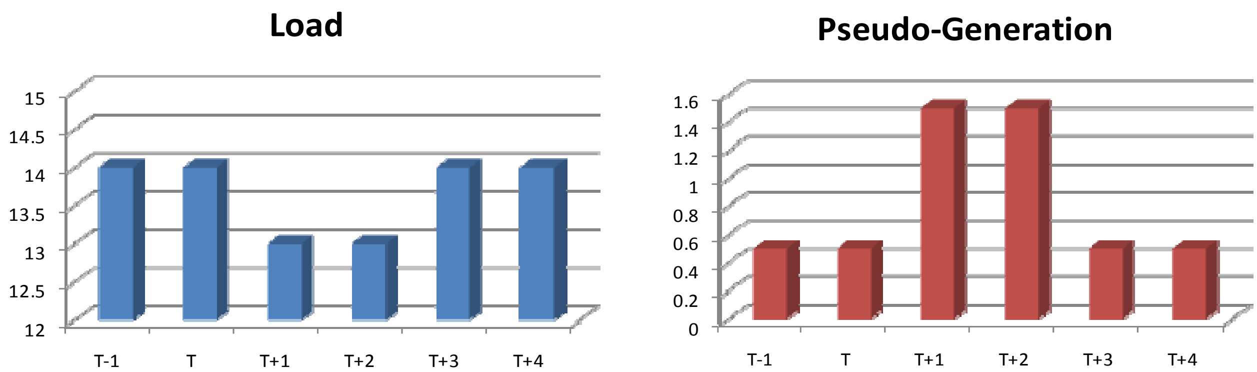

Figure 15: Load versus Pseudo-Generation with 1.0 MW Available

Looking at the companion charts with red bars, one can see that this is not the case. That is, at *T* it is clear how much is curtailable at *T+1*. This approach is consistent with the requirements and data that is delivered for a generation resource, in that it allows the CAISO to "see" what portion of a resource bid is actually available for dispatch.

The primary motivation for using total demand instead of pseudo-generation was the underlying complexity of the problem. For settlement, the CAISO models pseudo-generation based on a meter-before, meter-after approach. This approach is suitable for settlement because it does show what was actually delivered, but does not provide value in advance of dispatch. Modeling pseudo-generation for the aggregate resource requires modeling or estimating pseudo-generation for the underlying customers. To do this for a specific customer one needs to know if there is capacity for curtailment and how much of that capacity is unused. In general, this is a difficult problem to solve though there are solutions that can be applied in different situations, for example:

- By interfacing with an on-premises EMS, one can determine which end-uses are available to be controlled. Depending on the measurement capabilities of such a system a very good estimate of available capacity can be determined. Conceptually this is easy but in practice it becomes a per-customer integration project.
- For certain types of customers – the directly-enrolled customer in the Pilot is a perfect example – the pseudo-generation available can be determined with a simple mathematical gate function applied to their real-time metered demand. This is because when their load exceeds a certain threshold, a known quantity or portion of a quantity is available for curtailment. This type of customer may only be found in industrials; however, it is conceivable that there are some commercial customers that would also fit this profile.

The CAISO is aware of these limitations in the telemetry for the Pilot and would like to investigate ways to have pseudo-generation modeled if possible.

4.3.1.2 Telemetry Measurement Requirements

Initial requirements for the Pilot were that demand measurements be instantaneous and read at least once per minute. Requirements did not address aggregation of telemetry reads and as such there was no specific requirement for clock synchronization to ensure they be aligned in real time. The issue of instantaneous readings and reading alignment each posed challenges to the Pilot.

4.3.1.2.1 Instantaneous versus Averaged

One of the two Aggregators raised the concern that their measurement equipment could not provide instantaneous measurements. While certainly special hardware could have been chosen for this purpose, the issue led to a conversation with the CAISO about the significance of the instantaneous requirement. Considering that the readings themselves needed only to be submitted once per minute, SDG&E argued that average demand over a short interval was sufficient. The CAISO agreed that either instantaneous or averaged demand could be used for the Pilot. As covered in section 3.2.4, one Aggregator used averaged demand reads while the other Aggregator and the directly-enrolled customer used instantaneous reads.

4.3.1.2.2 Reading Alignment and Telemetry Freshness

Ensuring that readings across the many disparate sites were time-aligned would require clock-synchronizing all site telemetry equipment, time stamping all readings, and finally, combining readings along aligned time stamps. Due to the “fan-in” design of the telemetry for the Pilot, this would have required the Aggregators to build systems that could perform time-aligned combination. While conceptually a straight-forward problem, in reality with different systems and system latencies, such systems can be difficult to build correctly. It was decided to simplify the approach and have the Aggregators provide the most recent combined values no less frequently than once per minute.

Considering the latencies between the different systems, this meant that the telemetry from an Aggregator’s customer might be reflected at the CAISO up to 2 minutes after the read.

4.3.1.2.3 Purpose of UCON

The value of the UCON measurement point is in question. Pilot requirements indicated that UCON should present a truth value – specifically a 1 – if any of the underlying loads was connected. For aggregated loads such as used in the Pilot, the cases where this was possible were relegated to internal APX routing failures or greater problems in Internet connectivity. In a hypothetical case where only 1 of the 20 or so sites reported valid data, UCON would have continued to report a 1. The CAISO has itself raised the issue of determining whether there should be a different approach to handling such aggregated loads.

4.3.1.3 24x7 Requirement

The CAISO requirement that telemetry be delivered 24x7 raised some issues in the execution of the Pilot ranging from increased cost to develop “always on” systems to greater staffing costs. These issues directly impacted Aggregators.

The requirement for 24x7 telemetry, at all resource levels, regardless of schedule should be reviewed:

1. In the Pilot, the CAISO will not dispatch energy outside of accepted capacity bids. Why is telemetry required during times when there are no bids?
2. If Aggregators participate only in an 11-7 product should telemetry be required 24x7?

There were several times during the pilot when different services needed to be upgraded (e.g., the Web service was under active development in the beginning of the Pilot) or other aggregator-side maintenance needed to be performed. While this activity was scheduled outside of the 11-7 window the impacts of a 24x7 requirement were highlighted.

Informal discussions with the CAISO indicate that there may be some future flexibility available. As program such as this Pilot or others are implemented in the future, it would be beneficial for there to be a clear understanding of actual requirements for telemetry delivery as well as an outage reporting mechanism to clearly communicate both planned and unplanned outages.

4.3.1.4 High Variability

Customers demonstrating high variability can pose a significant problem when real-time demand measurements are used for operations. The results can be misleading if the measurements are being used for operational decisions (e.g., when determining available capacity). Figure 16 shows an example from the Pilot directly-enrolled customer. One can see that the telemetry shows a highly variable load jumping around from over 4 megawatts to below 250 kilowatts.

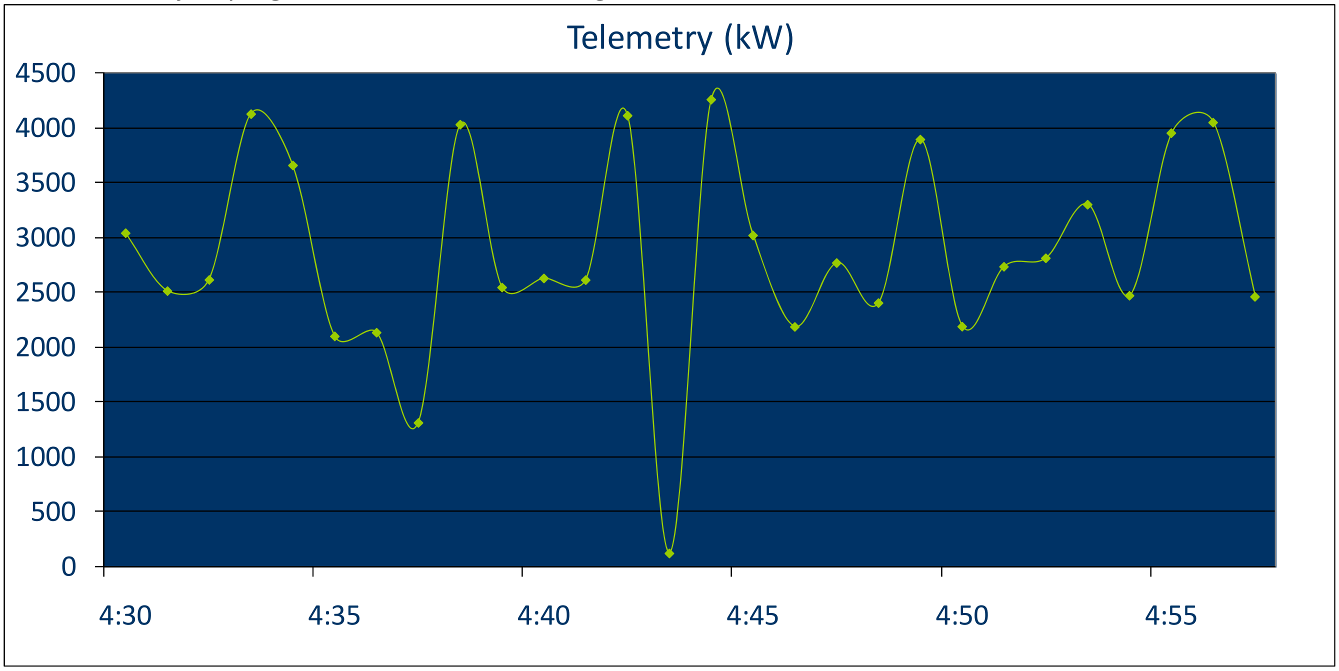

Figure 16: High variability of Directly-enrolled Customer[6]

If the CAISO used telemetry as an operational input to dispatching Pilot capacity, the variability would confuse the operators, possibly stopping such a resource from ever getting a dispatch. In addition, there is a question as to how much load can be curtailed. The instantaneous readings are highly variable, but the settlement is performed on a much smoother dataset: averaged kW over the metered interval (15-minutes for the Directly-enrolled Participant).

To mitigate these issues, the CAISO requested that highly-variable Pilot loads be smoothed. Note that if pseudo-generation were modeled in telemetry instead of total load (see section 4.3.1.1), this smoothing would not be necessary.

After some discussion about the best means to achieve this smoothing, it was decided to implement a simple cap on the telemetered demand for this customer. The rationale for this was that when telemetry indicated at least 1400 kW, then the plant was in operation and, as such, the corresponding capacity was available for curtailment. Other solutions that were discussed included averaging the value over a time interval or choosing the median value over a moving window. These solutions were dismissed due to the complexity of implementing such solutions in typical SCADA systems.

[6] This charts minutely total demand collected from the directly-enrolled Pilot customer during September 30th.

This particular solution was reasonable for the Pilot – somewhat mirroring pseudo-generation for this customer – however, it is not a general solution to such a problem:

- The load for this customer occasionally dropped below 1400 kW during operation as shown in Figure 16.
- This solution would not generally apply to other highly variable loads with different operating characteristics.

This issue will need to be revisited in a possible future version of this Pilot or other Participating Load programs.

4.3.2 Site installation variables

Characteristics of the customer site greatly impact telemetry design and costs. Most of the on-premises telemetry design and implementation for the Pilot was performed by the Aggregators – direct experience of the Pilot administrators was limited to the light industrial customer. Commercial installations such as those enrolled by the Aggregators tend to have simpler requirements; however, the issues that came up during the installation for the directly-enrolled customer are informative on a broader scale.

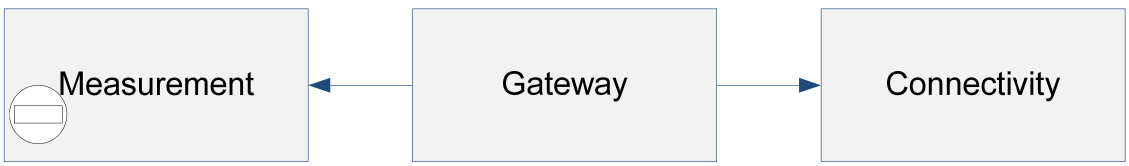

Figure 17: Three Components of Site Equipment

In many ways the directly-enrolled customer is not atypical of high-voltage installations. For example, many such industrial customers already have in-place metering technologies or EMS that could support telemetry. This is due to the importance of energy – and its associated costs – to their operations. They also will generally have a different level of safety concerns when integrating with or near high-voltage equipment. This was a clear issue with the directly-enrolled customer: while it was expected the customer would require staff with certain certifications to work near the high-voltage equipment, they went a step further and required that a specific engineering company perform the work. There is also a higher likelihood of intra-site connectivity issues and Internet access issues due to the possibly large area of an industrial site. As discussed in section 3.2.3, these latter issues drove the decision for installation of new Internet connectivity over satellite for this customer.

This highlights some of the issues for light industrial customers, but in general the issues apply to any customer and together provide the greatest challenge to broad implementation of telemetry: that each and every installation requires a site survey and implementation design. Certainly standardized solutions can be developed to fit different scenarios, but that is a leap from customer being able to self-install a plug-and-play solution. Some of the issues that come up in a site survey are enumerated in Table 8.

Measurement	Existing Device
	Is there an existing device capable of providing required demand reads?
	Does the device have an output port available from which to get these reads?
	What protocols are supported by the device?
	Existing EMS
	Is there an EMS from which to get the demand reads?
	What protocols are supported by the EMS?
	No existing device
	Need to select and install new measurement device (perhaps, all-in-one measurement and gateway)
Gateway	**An existing gateway device?**
	Does it integrate with the measurement device?
	Is it capable of supporting centralized solution?
Connectivity	**Existing Internet Connectivity**
	Does customer policy allow 3rd party access?
	Does the central technology require a persistent connection?
	If a static IP is necessary, is one available?
	Need New Internet Connection
	What types of service / providers are available at site?
	Is a static IP necessary?
	Perhaps use cellular technology for all-in-one device?
Space / Proximity	Where will the equipment be placed?
	What are the distances required between the different components?
	Are there cable-length issues at the required distances?
	Are the locations secure / what kind of security is in place?
Personnel	Does the customer require a site survey design?
	High voltage expertise?
	Insurance issues?

Table 8: Various Site Telemetry Issues

4.3.3 Aggregator Issues

While both of the Aggregators prefer a Web service interface, both did experience some technical challenges building their Web service interfaces for the Pilot. While the Web services were implemented to be WS-* standards compliant using the Windows Communication Foundation (WCF) in Microsoft .NET 3.5, the Aggregators' tools of choice were not capable of supporting these newer standards. For Aggregator 1, this simply required the use of WCF services over their preferred use of the older style ASMX services. This was a bigger issue for Aggregator 2 as they adopted Microsoft Visual Studio where they would have preferred the Java language and associated tools. In a future phase of the Pilot, it would make sense to develop client samples in Java to ensure that this popular alternative is also supported.

The Pilot required Aggregators to provide combined telemetry through the Web service as an appropriate separation of concerns; however, this required substantial software development for one of the Aggregators. This issue was exacerbated by the 24x7 requirement imposed by the CAISO on telemetry. This was possibly also impacted by the unintended requirement of using specific development tools mentioned previously.

Regardless of the overall successes of the Aggregators in providing telemetry to the Pilot, it should be noted that software development is not necessarily a core competency of Aggregators in general and could continue to prove challenging in a future possible phase of the Pilot. One way to mitigate this would be to allow Aggregators to submit telemetry for their individual customers without performing combination; however, this would put a burden on an administrator to manage additions and removals of telemetry points, substitute for missing data, and other issues.

4.4 Dispatch

4.4.1 ADS Lessons Learned

The CAISO Automated Dispatch System (ADS) is primarily designed to provide operating instructions to generators, and some instructions presented challenges for the dispatch of curtailable demand. Due to the constrained timeline to implement the Pilot, an increased reliance of manual actions added to these challenges. Further, to facilitate a robust test regime, manual intervention was also required on behalf of the CAISO. As a result, ADS issues experienced were a mix of the expected learning curve of interpreting ADS instruction for this type of program, manual error in configuring Exceptional Dispatches and miscellaneous CAISO system issues.

The Pilot provided extensive learning for Pilot staff in terms of the application of ADS dispatches to a load based resource. Below are some examples of unexpected dispatch instructions received through ADS and the lessons learned during the Pilot.

- Start up / Shut down instructions: As a resource in the CAISO resource stack, the Pilot received start up and shut down instructions daily which are not applicable to a DR resource. Such instructions were ignored for the Pilot.
- Dispatch Operating Target (DOT): For each dispatch issued by the CAISO in ADS, it was expected that the Pilot resource would receive a corresponding Dispatch Operating Target (DOT) represented as the MW output level. There were instances during the pilot when a dispatch was received with no DOT, or when a DOT was received with no corresponding dispatch.

As a result of these types of ambiguity in ADS instructions, it was determined in the Pilot that Operators would only act if a DOT was received for the resource. This best ensured that Participants were only instructed to curtail load if the CAISO actually requested energy dispatch from the Pilot resource.

One advantage to having Operators manually intervene in this process was to validate and interpret dispatches prior to Participant notification. The disadvantage was that in addition to introducing latency to the process, there isn't always a consistent interpretation of the ADS instructions. Moving forward to a future possible implementation of Web services between ADS and the PLP System would streamline the notification process and provide consistency of the dispatch instructions that are passed forward. In addition this would greatly reduce the potential for incorrect notification and notification delays due to human error.

The assumption that Participants should only be notified if a DOT is received through ADS would likely continue. This operating principle allows for more straightforward design of a fully automated notification process. Operators may retain override capability to allow for human interpretation and if known issues occur during Pilot operating hours.

4.4.2 Notification Lessons Learned

Notifications were transmitted on-time to Participants throughout the Pilot with one exception. Within this context of success, there were several areas in the process of transferring ADS instructions to the Participant that can be assigned to three distinct causes: manual intervention, operational issues and technology.

The notification process required that Operators log into a secure system and issue notifications following validation of a dispatch of the Pilot resource. The need to log on to the system during this time-constrained event introduced a small latency that could be addressed with further automation. In one instance, this latency became significant due to an Operator failing to logon to the system in a timely manner.

During the Pilot there were several instances where Participants were unable to curtail load due to either unexpected changes to the load level at which they were operating, or personnel responsible for shutting off load were not present when a curtailment notification was issued. The design of the Pilot did not provide a feature that allows a Participant to indicate if the nominated load was unavailable. Telemetry could provide this detail if it excluded uncontrolled load (see section 4.3.1.1 for a discussion of total demand versus pseudo-generation).

AutoDR systems present an effective solution to situations where they can replace physical intervention by site personnel. Despite some Participant's expectations that AutoDR would not be necessary to meet Pilot requirements, it became evident during the course of the Pilot that there was a resulting performance difference. If AutoDR is not a requirement for participation, other operational requirements should be put in place such that customer staff with the ability to curtail load be present during all product hours if a technology solution is not in place or practical for remote curtailment. AutoDR not only impacts event response times but also post-event return-to-normal. In one particular example, a customer without AutoDR was unaware that an event ended and therefore continued to curtail beyond the end of the event (see section 5.4.1). AutoDR also needs to be configured correctly to ensure return-to-normal as was not the case for the customer who dropped out of the Pilot (see section 4.2.4).

Several technological issues occurred during the Pilot due to the various methods of delivering curtailment notifications. The primary method of notification was through email and/or SMS text messages, both sent using SMTP. The use of SMTP can introduce unpredictable delays in notification and may result in a negative impact to Participant performance due to late curtailment. This is because SMTP servers can suppress or delay messages in the fight against spam and also because of other delays and latencies inherent to mail distribution. There were a few issues where notifications were incorrectly delayed or treated as spam, but notifications still occurred due to the dual reliance on email and SMS text messages. Notifications through Web services was identified as the preferred approach to eliminate these delays. In addition, Web services would eliminate the exposure of unsecured email.

The directly-enrolled Pilot customer required telephone calls for notification. In general this process worked as expected with two notable exceptions. In one example, the customer operator was non-

English speaking and was unable to understand the notification instructions. This was resolved by escalating to other customer staff. In another example, there was no answer at the customer site due to the staff being on break. Phone calls are not an efficient method for notification and it would be reasonable to require Participants to have a pager or other such device to mitigate such issues.

Given the mix of notification processes and varying levels of manual intervention across all Participants in the Pilot, backup notification processes presented an issue in the early stages of the Pilot. In the case of a system failure various levels of contingency notifications must be issued to all Participants, including manual notifications in the case of any total system breakdown. The Pilot consequently designed a contingency notification message that would provide useful information which could be interpreted by all recipients, including systems. A short SMS notification text, sent over SMTP, was used as a first level contingency message. This preserved a fast notification process by sending a single message, which human users as well as systems could easily interpret.

4.5 Metering

4.5.1 Impact of 15-minute Metering

With 5-minute interval meter data not readily available, 15 minute interval meters were used during the Pilot, consistent with other retail DR programs. 5-minute interval data is required by the CAISO – consistent with generation – Pilot meter data was disaggregated to 5-minutes. One lesson from the Pilot is that if 5-minute interval meters were required for participation in PL, the meter submittal process to the CAISO could be streamlined as well as the accuracy of the data increased. The retail settlement would benefit as well by the simplification and accuracy afforded by 5-minute interval data.

The fundamental issue at hand is the accuracy of settlement calculations when events begin or end within a 15-minute interval. For reference to the Pilot, this was the case for 20 of the 22 events (i.e., only 2 events were aligned on 15-minute interval boundaries).

The use of 15-minute metering can favor either the Participant or the market; however, cases where the Participant is favored are limited to when the Participant may be late performing but makes up for that within a short time frame. Of more concern are the times when the Participant performs perfectly but their performance is discounted because of this metering issue.

One way to analyze this latter case is to compare performance for an event not aligned on a 15-minute meter between hypothetical exact 100% compliance versus how that compliance would be metered.

Such a case is depicted in Figure 18, showing a Participant curtailing from 1200 kW down to 400 kW for an event that begins 10 minutes after the hour. The event is highlighted by the orange box. The blue bars indicate actual performance aligned on 5-minute intervals. The brown bars indicate how that performance would be measured by a 15-minute interval meter. The event starts at time *T* with the first interval ending at *T+5*, the customer achieves 400 kW, and the 15-minute meter reports 933 kW. Looking at the end of the event at time *T+120*, the customer returns to 1200 kW in the following interval, but the 15-minute meter reports 667 kW.

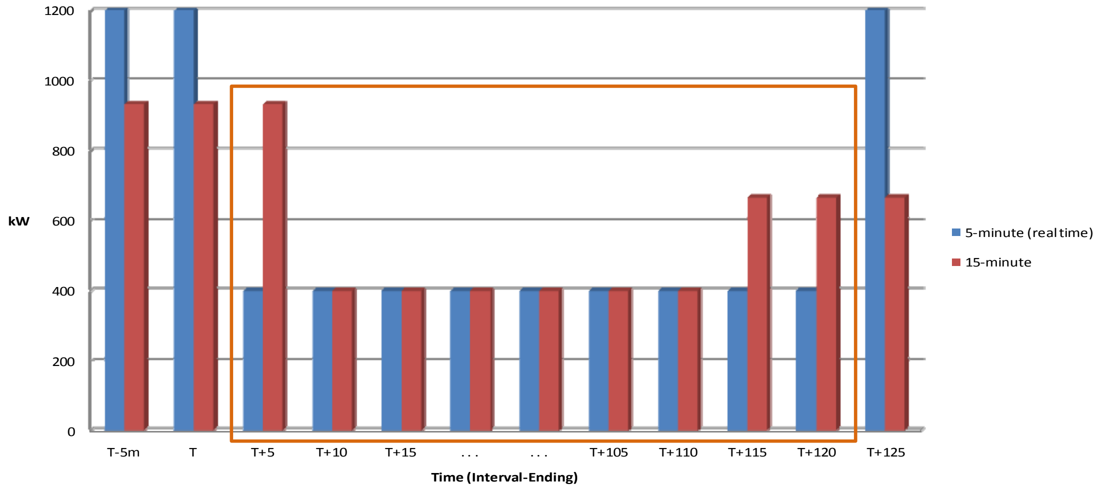

Figure 18 Worst-case depiction of 15-minute Metering with 5-minute Start Interval

This depicts the worst-case for the Participant (i.e., the worst possible negative impact given perfect compliance). This can be computed to be a 5.6% negative impact to the Participant performance and ultimately to the per-event settlement calculation for the Participant.

Note that the actual drop is not important for this comparison. It is significant that the event lasts 2 hours – longer or shorter events yield different results. For example, if the event were an hour in length, the worst-case negative impact goes up to 11.1%.

In the wholesale environment, the worst case is more severe as it could result in taking away a significant portion of capacity payment by indicating that the load drop wasn't achieved in the required time frame. The CAISO dispatches real-time energy on a five minute basis almost always on the five minute mark. If a dispatch is issued in the 10th minute of a 15 minute interval, the average of the three 15 minute interval would result in an 18.2% negative impact. Note that shifting the event start time back by 5 minutes, results in the same retail settlement, though that case could obtain a better wholesale result as it skews the drop towards a lower averaged value.

4.5.2 Impact of Clock Drift

SDG&E has a policy that interval meters must be within +/- 3 minutes of system time. Any such discrepancy has limited impact in typical billing scenarios; however, the Pilot is unique in that it creates an opportunity to see the impact of such discrepancies given the telemetry component.

Following a similar methodology of hypothetically perfect compliance as is used in section 4.5.1, Figure 19 shows an example of a Participant curtailing at exactly the correct time as noted in the blue bars. The brown bars indicate the time lag associated with the meter being 3 minutes behind schedule. The green bars show how this lag would be recorded by a 5-minute interval meter. The orange region indicates the beginning of the event – the end of the event is kept off of the chart to enhance readability.

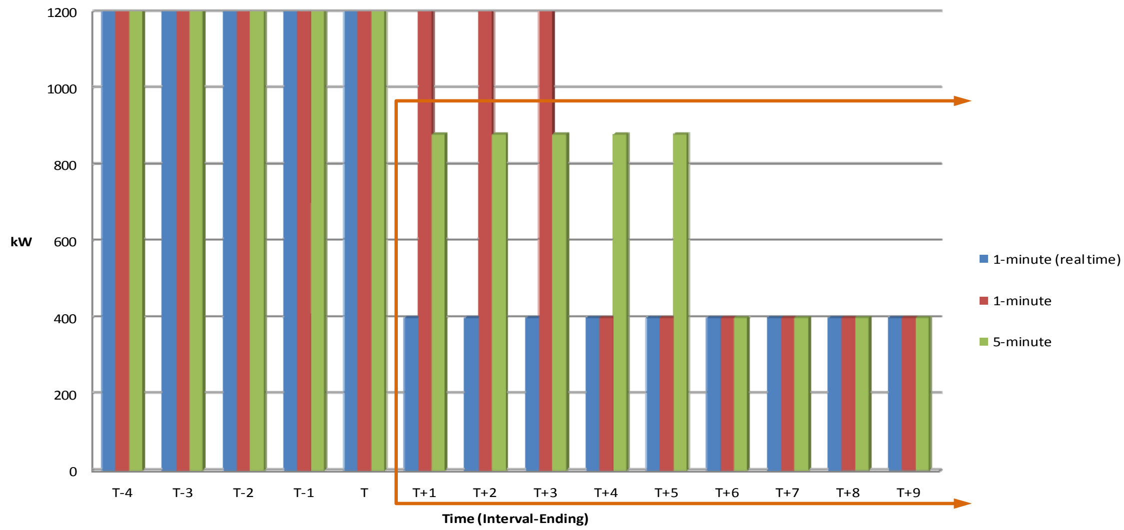

Figure 19: Worst-case Depiction of 3-minute Metering Lag

This depicts a worst-case with an impact of 2% on performance. Note that if the clock was out of synchronization 3 minutes before system time, the effect would be the same, but would occur at the tail-end of the event.

When meters are closer to perfect synchronization, this worst-case is linearly reduced. For example, the directly-enrolled customer had a clock that was 73 seconds fast. The potential impact for this customer would be approximately 2% x (73 seconds / 180 seconds) = .8%.

For the Aggregators, it is more difficult to analyze this issue since the overall impact of clock offsets depends greatly on the contribution of particular meters to the overall reduction. During the Pilot, the average magnitude of clock offset for Aggregator 1 was 71 seconds and Aggregator 2 was 47 seconds.

The potential impact of clock synchronization is not significant – it is no more or less relevant to the Pilot than to typical billing scenarios.

4.6 Wholesale Market

4.6.1 Model Build Delays

The existing CAISO Participating Load (PL) requirements are predicated on the notion that loads in each PL resource are easily identified at the grid bus locations and precisely modeled in the full network model. Model updates are relatively infrequent and require approximately 60 days lead time from submittal to the CAISO to actual deployment into the market software. For example, the announced dates of two planned model builds to be promoted to production for summer 2010 are April 28, 2010 and June 30, 2010 with data submittal deadlines of early February and early April respectively. Because of such lead times – and the fact that customers were not enrolled so many months in advance of the Pilot start date – it was impractical to precisely model the individual DR resources for the CAISO. While this was an initial limitation at the beginning of the Pilot since the customers that would participate were not known early enough, the fact the Pilot allowed new enrollments to be submitted 5 calendar days prior to an operating month would always leave open the possibility that customers would join the aggregation fewer than 60 days in advance. The CAISO allowed an accommodation that modeled the DR resource pseudo-generator and Custom Load Aggregation Point as distributed resources across the SDG&E system.

One outcome of the experience in the Pilot is that the CAISO is creating default resource locations for the Proxy Demand Resource that are distributed across each SubLAP therefore providing the flexibility to create PDR Resource IDs without the burden of being encumbered by the timing of the Model Build process.

4.6.2 Settlements Issues

There were instances where the wholesale settlements of the Pilot resources were inconsistent with test dispatches in the market, as well as what can be considered spurious dispatches (i.e., dispatches received when not expected, or dispatches that were not based on market economics). Due to the manual nature and set-up required by CAISO operations for the test dispatches, some of the Exceptional Dispatches appear to not have been transferred into the data stream for settlements and this would not be expected to be an issue during normal market operations.

One instance where it appears that the CAISO didn't transfer data from a test dispatch to the settlement system was on August 13, 2009. This appears to be an error in the CAISO ADS system which propagated an exceptional dispatch for every interval from 10:45 through 14:35 for a total of 46 intervals instead or the two 5 minute intervals that were the basis for the test. At a minimum, the Settlement for this date should have shown Instructed Energy payment for the two 5 minute intervals of the test. It would also be expected that some Non Spinning Reserve payments would have been rescinded since the full amount of load drop wasn't achieved in 10 minutes.

For the October 15, 2009 test which was initiated by the CAISO through and Exceptional Dispatch, no Non Spinning Reserve capacity payments were rescinded. Log notes indicate that the customer indicated that they were not able to perform which was confirmed by the submitted meter data. It was expected that the entire amount of Non Spinning Reserves capacity payment would have been rescinded due to these circumstances. CAISO records indicate that the Capacity Award was not present in their system for a short portion of the hour leaving no Capacity payment to process for rescission. The Exceptional Dispatch for the test would have been predicated on the Capacity Award and, after discussion with the CAISO it is not clear why the Capacity Award was missing in the data sent for settlement.

While spurious dispatches were treated as discussed in section 4.4.1 settlement data, predominantly in the form of Instructed Energy payments, appeared on settlement statements for these events. Since the energy settlement for dispatches has a corresponding settlement component in Uninstructed Energy charges, (i.e., any Instructed Energy payment is taken away in the Uninstructed Energy charge for non performance), the financial implications with the CAISO netted out.

4.7 Multiple Participation

It is desirable to allow customers to participate in multiple DR programs to provide the maximum amount of curtailable load. Multiple-program participation creates many challenges that fundamentally revolve around the same issue: avoid duplicate payments to customers. The exact methods to avoid duplicate payment vary depending upon the specific programs in which a customer participates.

The Pilot did not allow multiple participation in other programs with the exception of customers on the Capacity Peak Pricing Default rate. The Pilot included customers that were simultaneously enrolled under CPP-D. The tariff defined how to address this occurrence:

- If Customers enrolled in both the Pilot and the CPP were notified the day before of a CPP event, those customers should not to be notified for Pilot events if possible.
- When Pilot and CPP events overlapped, such customers received a reduced Pilot payment based on the ratio of overlapping event hours to total available Pilot hours.

On an individual customer basis, such an implementation is conceptually straightforward although it does imply a high degree of systems and operational integration. This is a fundamental concern for the implementation of any multiple participation solution. In general, many different and orthogonal systems and personnel are in involved in running the programs and, as a result, various issues arise when trying to implement such a solution.

The necessary processes surrounding the calling of a Pilot event illustrates one such example:

1. Adjustment of Bid

   The total capacity nominated by Participants defines the bid for the Pilot. If one or more Participants were to be unavailable due to a CPP event, then the wholesale capacity bid should be reduced to avoid submitting a bid for which it is known that a portion of the capacity is not available for real-time reduction. This requires interactions between of systems and processes that are not currently integrated.

2. Timing

   CAISO capacity bids are due at 10:00 AM the day prior to the operating day while CPP events are called at 3:00 PM and there is no current mechanism to indicate a reduction of PL capacity after the day ahead market (generators can communicate changes to availability after the Day Ahead market via the Outage Management protocols).

3. Aggregation

   An additional set of issues presents itself for aggregated customers. The basic problem in the Pilot comes about because aggregators nominated capacity and dispatched load, based on the aggregate. The capacity bid cannot be reduced correctly unless the Aggregator has provided a per-customer nomination or if the dual Participants' nominations are clearly separated from other nominations. Similarly, for dispatches, separation or distinction of customer's participating in other programs would be required.

Because of the complexity of this issue, the approach taken for the Pilot was to attempt to completely avoid the overlap of such events. In practice, this became difficult to implement because of the different organizations and systems involved in the Pilot and CPP administration. On September 24 both a CPP and Pilot event were called. Although this event only impacted one of the customers for Aggregator 2, its occurrence underscores the issues surrounding management of multiple participation.

5 Performance and Analysis

5.1 Events

Overall the resources performed as designed; delivering demand response within 10 minutes of CAISO dispatch and maintaining a load reduction for 2 hours. Performance can be broken down into three components, initial response, holding the reduction and quantity of reduction. Initial response is impacted by the efficiency of the notification process and there were a few instances where the curtailment was achieved, but it took slightly longer than 10 minutes. This can be observed by looking at the differences between the wholesale (CAISO) performance factor and the retail performance factors in Table 9.

Based on experience, the level of performance during events is in range with other resources providing Non Spinning Reserves. The wholesale performance factor chosen for this report is a measurement of how much capacity payment was rescinded for failing to achieve full delivery of the capacity bid within 10 minutes of dispatch. This metric is more granular than the performance metrics reported by the CAISO which looks at overall availability, not just dispatch performance. When compared to the CAISO standard, the Pilot resource performance was above 99%, exceeding the CAISO system-wide performance that is historically in the mid to upper 90 percent range on an annual basis

While a generator that is online with unloaded capacity and directly connected to ADS might perform at a level close to 100% during an event, an off-line combustion turbine (CT) is more comparable to a demand response resource. Both DR and CT resources are exposed to start up and notification processes that introduce latency that can result in not achieving the full dispatched energy quantities within 10 minutes. The Pilot resource only had one instance where it failed to provide any response, which is analogous to a CT failing to start when dispatched. Overall, the performance of the Pilot resource during events demonstrated that it was capable of contributing to the CAISO recovery from contingency events on par with similarly situated generation resources.

The retail performance factors look at the full two hours of an event as well as the quantity of curtailment achieved during an event. Since the retail performance looks at the event over the entire 2 hour period, a slight delay in achieving the curtailment within 10 minutes is muted in the performance measurement generally resulting in a higher performance factor than wholesale. The retail Performance can exceed 100% if the quantity of curtailment delivered is greater than the nominated amount and provides a sense of how much hedging was included in Participant nominations. The adjusted performance is capped at the nominated amount since payments to Participants could not exceed their nomination.

SDG&E PL Pilot

Below is a summary table of all SDG&E Pilot Events.

	Wholesale Event			Retail Event				
Date	Dispatch Time	Notes	MW	Start Time	End Time	Performance	Adjusted Performance	Wholesale Performance
8/13	14:00	Exceptional Dispatch	0.3	14:10	16:10	159.31%	100.00%	N/A
8/20	13:55	Exceptional Dispatch	0.3	14:05	16:05	94.59%	94.59%	0%
8/27	13:55	Exceptional Dispatch	0.3	14:05	16:05	166.68%	100.00%	83%
9/10	14:00	Exceptional Dispatch	0.6	14:10	16:10	136.68%	100.00%	85%
9/17	13:55	Exceptional Dispatch	0.6	14:05	16:05	92.70%	92.70%	92%
9/18	15:55	Contingency Dispatch	0.6	16:20	18:10	132.60%	100.00%	67%
9/23	23:35	Test	1.2	23:45	1:45	197.42%	100.00%	N/A
9/24	13:55	Exceptional Dispatch	1.8*	14:05	16:05	158.77%	100.00%	UNK**
9/30	4:55	Exceptional Dispatch	1.2	5:05	7:05	250.52%	100.00%	100%
10/1	13:55	Exceptional Dispatch	0.8	14:05	16:05	96.47%	96.47%	100%
10/9	11:25	Exceptional Dispatch	0.8	11:35	13:35	35.96%	35.96%	100%
10/14	12:35	Exceptional Dispatch	0.8	12:45	14:45	78.09%	78.09%	80%
10/15	4:55	Exceptional Dispatch	1.2	5:05	7:05	0.80%	0.00%	UNK**
11/16	15:00	Test	0.6	15:10	17:10	103.42%	100.00%	N/A
11/18	1:00	Test	1.2	1:10	3:10	41.43%	41.43%	N/A
11/19	12:06	Test	0.6	12:20	14:20	66.34%	66.34%	N/A
11/24	15:00	Test	0.6	15:10	17:10	73.60%	73.60%	N/A
12/2	4:00	Test	1.2	4:10	6:10	111.90%	100.00%	N/A
12/3	14:55	Exceptional Dispatch	0.5	15:05	17:05	68.53%	68.53%	TBD***
12/7	18:25	Contingency Dispatch	0.5	18:35	19:00	30.66%	30.66%	TBD***
12/11	2:00	Test	1.2	2:10	4:10	33.67%	33.67%	N/A
12/15	2:30	Test	1.2	2:40	4:40	170.13%	100.00%	N/A

Table 9: SDG&E Pilot Events

*This bid includes the Directly-enrolled Participant. See section 5.2.1.1 and the detail for this event in section 8.8 for more information.

**Unknown: September 24th and October 15th settlements were improperly processed by CAISO.

***To be determined: December Recalculation Statements not published until mid February.

The retail performance numbers exclude the 24x7 Directly-enrolled Participant from events that occurred in the 11-7 timeframe. This is discussed in section 5.2.1.1.

Note that the some of these events were initiated by the Pilot management and were not dispatched from the CAISO. Such events have no CAISO performance data. Participants were neither informed of who initiated an event nor, if applicable, the CAISO dispatch type. As a result, retail performance was not impacted by such details. Participants were also not provided with advance notice of an event. As such, there is no bias in the performance analysis that would come from pre-cooling or other behavior that might be associated with advance notice.

5.2 Retail Event Analysis

5.2.1 Performance Summary

5.2.1.1 Product Performance Summary

There were two products defined in the Pilot Tariff. One, the "11-7 Product" was a typical on-peak product. The other, the "24x7 Product" was an all-hours product. Since these two products were combined into the Pilot resource, the 24x7 product enrollee was notified for all Pilot events. This had a negative impact on their retail settlement because the enrollee was unavailable to curtail between the hours of 11-7 based on their production schedule. To not skew the performance reporting accordingly, the following summaries for the "11-7 Product" exclude the 24x7 enrollee. Therefore, all analysis of event performance for the "11-7 Product" is referred to as "On-Peak" as distinguished from the remaining hours which are referenced as "Off-Peak."

Note that after the September 24th event, capacity bids were adjusted to reflect that the 24x7 enrollee did not have actual capacity from 11-7, effectively excluding the 24x7 nomination from wholesale compliance.

5.2.1.1.1 On-Peak Event Performance Summary

Aggregators participating in the On-Peak Product performed generally well throughout the duration of the Pilot. As is illustrated in Figure 20, performance often reached 100% (8 out of 15 events). Furthermore, performance was above 60% for 13 of the 15 On-Peak events.

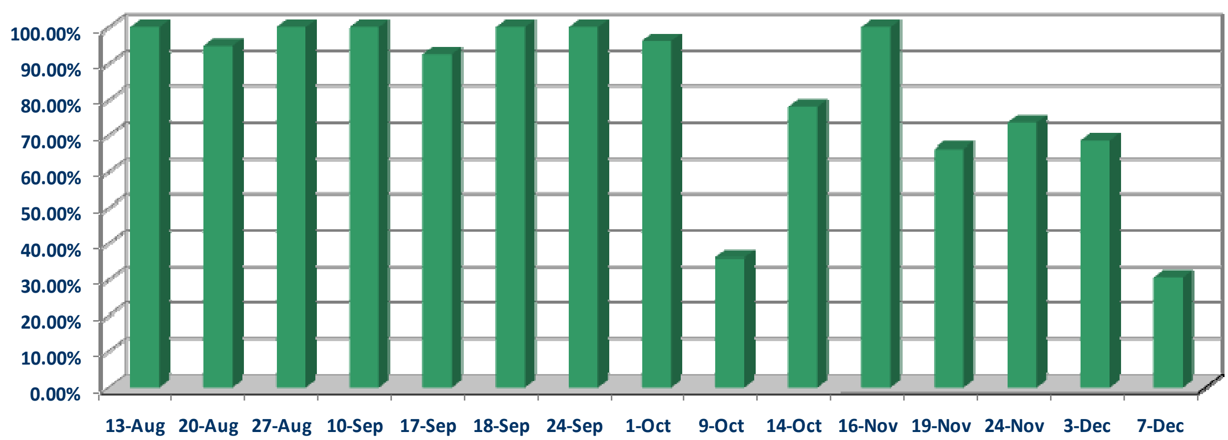

Figure 20: On-Peak Retail Performance (Tariff Adjusted)

Date	Curtailment Amount (kW)	Start Time	End Time	Performance	Adjusted Performance
13-Aug	325	14:10	16:10	159.39%	100.00%
20-Aug	325	14:05	16:05	94.59%	94.59%
27-Aug	325	14:05	16:05	166.67%	100.00%
10-Sep	600	14:10	16:10	136.68%	100.00%
17-Sep	600	14:05	16:05	92.70%	92.70%
18-Sep	600	16:20	18:10	132.44%	100.00%
24-Sep	600	14:05	16:05	158.77%	100.00%
1-Oct	800	14:05	16:05	96.47%	100.00%
9-Oct	800	11:35	13:35	35.96%	35.96%
14-Oct	800	12:45	14:45	78.09%	100.00%
16-Nov	550	15:10	17:10	103.42%	100.00%
19-Nov	550	12:20	14:20	66.34%	66.34%
24-Nov	550	15:10	17:10	73.60%	73.60%
3-Dec	550	15:05	17:05	68.53%	68.53%
7-Dec	550	18:35	19:00	30.66%	30.66%

Table 10: On-Peak Retail Performance

However, during the latter months of the Pilot period performance degraded. The reduction in performance in the later months of the Pilot is largely attributable to two factors:

- Aggressive Nominations: In the early stages of the Pilot Aggregators nominated conservatively to limit their risk. As the Pilot progressed and the Aggregators saw strong performance many times in significant excess of the nomination they increased their nominations to more accurately reflect their potential load shed. However this reduced their margin for underperformance and with a small number of customers in their aggregation unit incurred a significant impact to their performance metrics with even small issues.
- Decrease in Capability: During the later months of the Pilot with changes in weather and a reduction in base load at many clients, there was less overall load available to shed. Aggregators are unable to accurately forecast and handle this type of variability within a single month and the minimal margin for underperformance impacted the results.

5.2.1.1.2 Off-Peak Event Performance Summary

Off-peak event performance fluctuated throughout the duration of the pilot with a performance of 100% for 4 out of 7 events. This is reflective of the high load variability of the single Directly-enrolled Customer providing capacity during events occurring in off-peak hours. As is detailed in section 4.4.2, a number of operational issues also reduced performance for specific events (such as absent staff or site shut down).

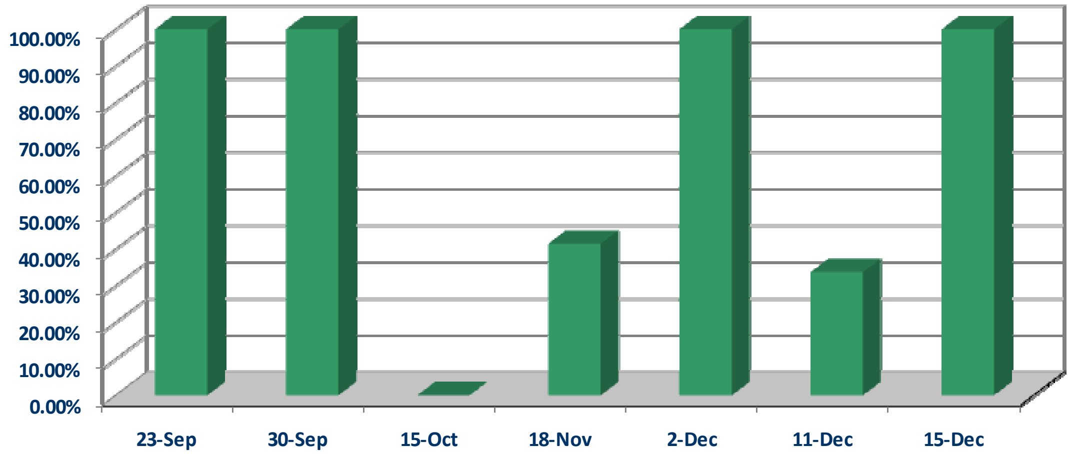

Figure 21: Off-Peak Retail Performance (Tariff Adjusted)

Date	Curtailment Amount (kW)	Start Time	End Time	Performance	Adjusted Performance
23-Sep	1,200	23:45	1:45	197.42%	100.00%
30-Sep	1,200	5:05	7:05	250.52%	100.00%
15-Oct	1,200	5:05	7:05	0.00%	0.00%
18-Nov	1,200	1:10	3:10	41.43%	41.43%
2-Dec	1,200	4:10	6:10	111.90%	100.00%
11-Dec	1,200	2:10	4:10	33.67%	33.67%
15-Dec	1,200	2:40	4:40	170.13%	100.00%

Table 11: Off-Peak Retail Performance

5.2.1.2 Participant Event Performance Summary

Performance in the aggregate is important at the wholesale level in that the CAISO only "sees" a single resource bidding in and performing in the wholesale market. While there were further aggregations at the Participant level (i.e., both Aggregators had more than one customer), the retail settlement looks only at performance at the Participant level to calculate settlement. What is not observable in the aggregate – and therefore to the CAISO – is whether one or more Participants were responsible for failing to achieving the DOT in 10 minutes. Conversely it was not observable to the CAISO if the DOT was achieved because one or more Participants exceeded their curtailment.

One event in particular, September 18, illustrates the effect of over-performance by one Participant compensating for under-performance of another. The overall event performance at the retail level was 98% despite the fact that Aggregator 1 only achieved 30% performance in this instance. The fact that Aggregator 2 performed at 166%, while raising aggregated retail performance to nearly 100%, was only enough to raise the wholesale performance to 67%. Despite 67% being relatively poor wholesale performance, it demonstrates the value of the aggregation which would have been 30% or lower if Aggregator 1 bid into the CAISO market separately.

5.2.1.2.1 Aggregator 1 Event Performance Summary

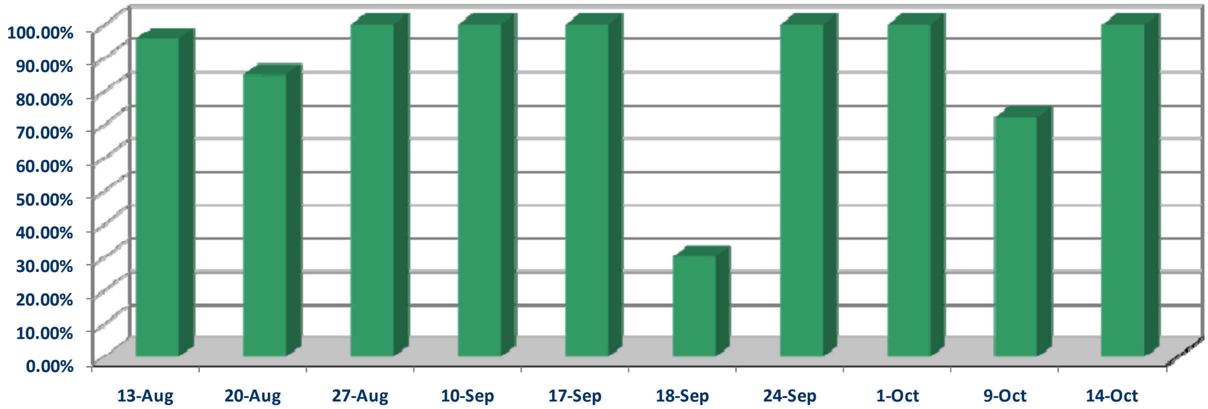

Figure 22: Aggregator 1 Retail Performance (Tariff Adjusted)

Date	Curtailment Amount (kW)	Start Time	End Time	Performance	Adjusted Performance
13-Aug	170	14:10	16:10	95.64%	95.64%
20-Aug	170	14:05	16:05	84.87%	84.87%
27-Aug	170	14:05	16:05	100.03%	100.00%
10-Sep	150	14:10	16:10	136.92%	100.00%
17-Sep	150	14:05	16:05	130.54%	100.00%
18-Sep	150	16:20	18:10	30.09%	30.09%
24-Sep	150	14:05	16:05	145.16%	100.00%
1-Oct	100	14:05	16:05	176.94%	100.00%
9-Oct	100	11:35	13:35	72.00%	72.00%
14-Oct	100	12:45	14:45	169.97%	100.00%

Table 12: Aggregator 1 Retail Performance

5.2.1.2.2 Aggregator 2 Event Performance Summary

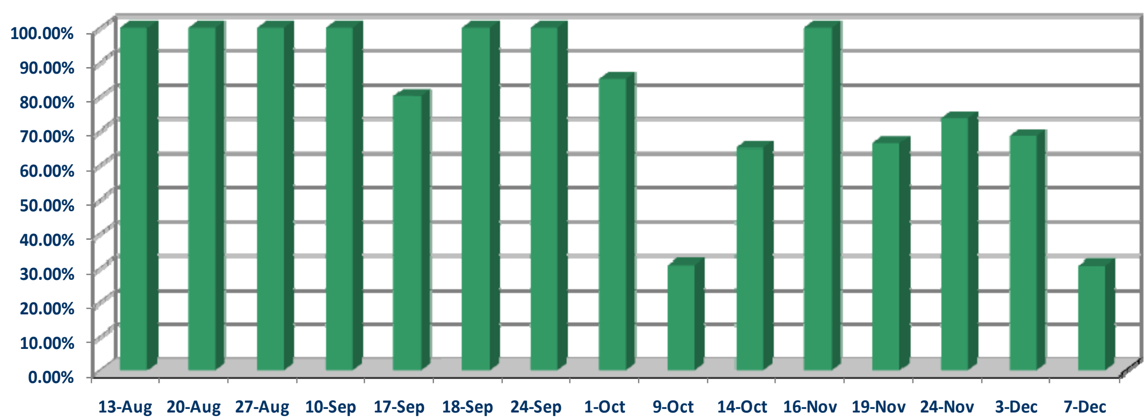

Figure 23: Aggregator 2 Retail Performance (Tariff Adjusted)

Date	Curtailment Amount (kW)	Start Time	End Time	End Time	End Time
13-Aug	155	14:10	16:10	229.14%	100.00%
20-Aug	155	14:05	16:05	105.25%	100.00%
27-Aug	155	14:05	16:05	239.77%	100.00%
10-Sep	450	14:10	16:10	136.60%	100.00%
17-Sep	450	14:05	16:05	80.09%	80.09%
18-Sep	450	16:20	18:10	166.77%	100.00%
24-Sep	450	14:05	16:05	164.30%	100.00%
1-Oct	700	14:05	16:05	84.97%	84.97%
9-Oct	700	11:35	13:35	30.81%	30.81%
14-Oct	700	12:45	14:45	64.96%	64.96%
16-Nov	550	15:10	17:10	103.42%	100.00%
19-Nov	550	12:20	14:20	66.34%	66.34%
24-Nov	550	15:10	17:10	73.60%	73.60%
3-Dec	550	15:05	17:05	68.53%	68.53%
7-Dec	550	18:35	19:00	30.66%	30.66%

Table 13: Aggregator 2 Retail Performance

5.2.1.2.3 <u>Directly-enrolled Customer Event Performance Summary</u>

Since the Directly-enrolled Customer was the only off-peak customer, its performance is shown in Figure 21 and Table 11 above.

5.2.2 Monthly Capacity Payment

The tables below provide the summary capacity payments to each Participant for each operational month of the Pilot. Total potential Pilot payout based on aggregated nominations totaled $147,083.00 while actual payouts based on performance were $62,315.74.

5.2.2.1 Aggregator 1

Please note that Aggregator 1 did not nominate capacity in the months of November and December due to the nature of the end-use customers' businesses. As retail establishments, although interested in the payments associated with the Pilot, they were concerned about any loss of sales during this economic climate and elected not to nominate. As a result, Aggregator 1 did not receive Capacity Payments for those months and this fact is reflected in the total potential payout calculation.

Month	Product	Nomination (kW)	Capacity Price ($/kW)	Total Potential Capacity Payment	Total Adjusted Capacity Payment
August	11am-7pm	170	$20.10	$3,417.00	$3,194.94
September	11am-7pm	150	$20.10	$3,015.00	$2,488.04
October	11am-7pm	100	$20.10	$2,010.00	$1,822.40
			Total	**$8,442.00**	**$7,505.38**

Table 14: Total Monthly Capacity Payments, Aggregator 1

5.2.2.2 Aggregator 2

Month	Product	Nomination (kW)	Capacity Price ($/kW)	Total Potential Capacity Payment	Total Adjusted Capacity Payment
August	11am-7pm	155	$20.10	$3,115.50	$3,115.50
September	11am-7pm	450	$20.10	$9,045.00	$8,594.77
October	11am-7pm	700	$20.10	$14,070.00	$8,476.84
November	11am-7pm	550	$20.10	$11,055.00	$8,841.86
December	11am-7pm	550	$20.10	$11,055.00	$2,741.28
			Total	$48,340.50	$31,770.24

Table 15: Total Monthly Capacity Payments, Aggregator 2

5.2.2.3 Direct Enrolled Customer

Month	Product	Nomination (kW)	Capacity Price ($/kW)	Total Potential Capacity Payment	Total Adjusted Capacity Payment
September	24x7	1200	$21.50	$25,800.00	$10,320.00
October	24x7	1200	$21.50	$25,800.00	$0.00
November	24x7	1200	$21.50	$25,800.00	$2,672.45
December	24x7	1200	$10.75	$12,900.00	$10,047.67
			Total	$90,300.00	$23,040.12

Table 16: Total Monthly Capacity Payments, Direct Enrolled Customer

5.2.3 Post-event Bounce-back

An analysis of Participant behavior immediately following Pilot events uncovered evidence of "bounce-back", whereby Participant load was raised to atypical levels for periods ranging from 1 to 3 hours. This post-event recovery can be attributed to several factors, including:

- Additional energy consumed to bring building temperature back to normal levels once thermostats are restored to their original levels after being overridden during DR events (weather sensitive Participants, such as office, retail, hotel and entertainment).
- Additional energy consumed to meet production targets/quotas during a business day or shift (industrial customers).

Measuring the bounce-back effect is not straightforward, due to the lack of an exact methodology for determining a facility's load profile in the hours after an event, had the event not taken place. The tables below use the Adjusted PDR algorithm (average of last 10 similar days, adjusted by the ratio of the 3 hours ending an hour prior to the event) to approximate the Participants' expected load profiles. This algorithm was chosen, because it models expected load better than other algorithms used in California (see section 5.4).

For the purposes of estimating the post-event bounce-back energy and its relationship to energy curtailed during the event, the difference between baseline and metered energy was computed for the event period, as well as the two-hour period immediately after each event. For comparison purposes, the same calculation was performed for the two-hour period preceding each event. The last column in the data tables displays the ratio between bounce-back and curtailed energy.

Events during which Participants failed to meet their capacity commitment by a wide margin were excluded from this analysis and are omitted from the tables.

Considering that the Directly-enrolled Participant had no post-event recovery based on their operational profile, no bounce-back analysis was done for that customer.

Participant	Date	2 hours Before (kWh)	2 hours During (kWh)	2 hours After (kWh)	After/During Ratio
Aggregator 1	8/13/2009	-4.79	297.43	136.86	46.0%
Aggregator 1	8/20/2009	-8.84	298.55	1.75	0.6%
Aggregator 1	8/27/2009	16.45	387.26	89.04	23.0%
Aggregator 1	9/10/2009	-30.54	327.96	10.41	3.2%
Aggregator 1	9/17/2009	8.41	269.19	-154.85	-57.5%
Aggregator 1	9/24/2009	7.35	416.24	-24.90	-6.0%
Aggregator 1	10/1/2009	-31.51	256.12	-22.78	-8.9%
Aggregator 1	10/9/2009	14.48	267.18	-103.62	-38.8%
Aggregator 1	10/14/2009	26.83	430.00	-4.77	-1.1%

Table 17: Aggregator 1 Bounce-Back Summary

Even though the data for Aggregator 1 shows possible evidence of bounce-back on September 18 and October 9, other days do not exhibit such evidence, which points to the conclusion that for the most part, customers associated with Aggregator 1 did not require post-event catch-up consumption.

The data for Aggregator 2, on the other hand, shows ample evidence of bounce-back consumption on the majority of event days:

Participant	Date	2 hours Before (kWh)	2 hours During (kWh)	2 hours After (kWh)	After/During Ratio
Aggregator 2	8/13/2009	-102.71	499.74	300.39	-60.1%
Aggregator 2	8/20/2009	35.14	360.98	-256.11	-70.9%
Aggregator 2	8/27/2009	-67.52	509.87	-449.77	-88.2%
Aggregator 2	9/10/2009	184.93	1,010.56	-183.58	-18.2%
Aggregator 2	9/17/2009	137.48	948.96	-722.78	-76.2%
Aggregator 2	9/18/2009	-34.27	950.94	-448.16	-47.1%
Aggregator 2	9/24/2009	-183.56	1,090.77	-345.19	-31.6%
Aggregator 2	10/1/2009	-84.83	935.78	-772.59	-82.6%
Aggregator 2	10/9/2009	169.82	825.28	-994.44	-120.5%
Aggregator 2	10/14/2009	49.88	896.68	-657.22	-73.3%
Aggregator 2	11/16/2009	124.23	925.74	159.32	17.2%
Aggregator 2	11/19/2009	45.53	666.72	-444.92	-66.7%
Aggregator 2	11/24/2009	-60.46	346.33	79.58	23.0%
Aggregator 2	12/3/2009	49.23	329.58	-442.92	-134.4%

Table 18: Aggregator 2 Bounce-Back Summary

The September 18 event for Aggregator 2 illustrates a very clear bounce-back of the load in the hours after the event is over.

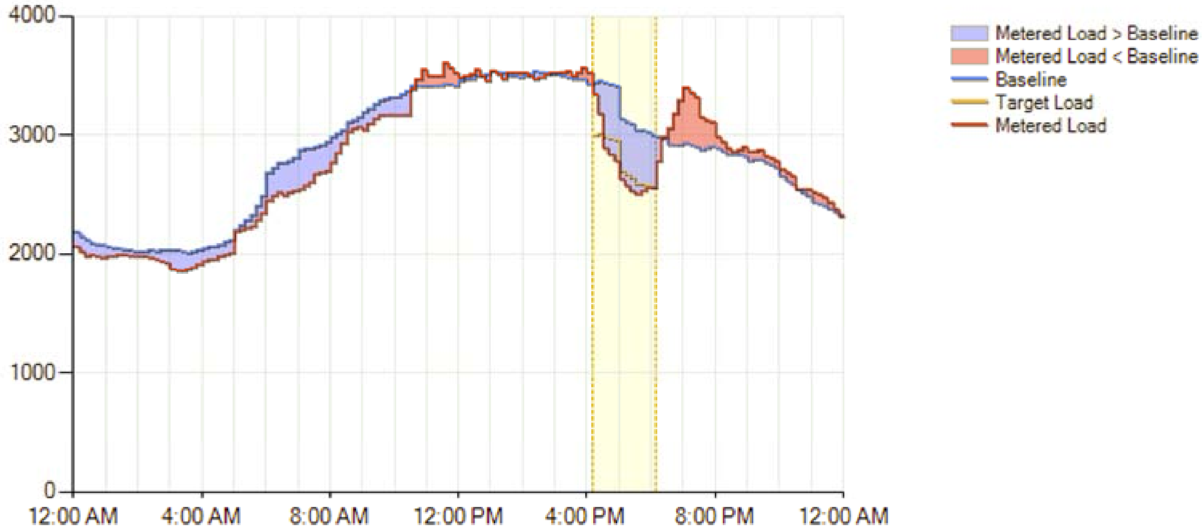

Figure 24: Bounce-back for September 18th, Aggregator 2

5.2.4 Did Weather Impact Performance?

Data for Aggregator 2 was analyzed to determine if weather and, in particular, temperature affected event performance, nominations, post-event load bounce-back and other aspects of the Pilot. Aggregator 1 was not used for this purpose because it ended nominations at the end of October and so did not contain large temperature variations, nor enough events to draw any conclusions. The Directly-enrolled Participant was also dismissed for the purposes of this study, because its metered load did not exhibit any correlation to historical temperature measurements.

The accounts represented by Aggregator 2 were in San Diego or neighboring coastal cities. In October, 6 additional accounts associated with a single hotel/entertainment customer were added to the mix, while in December an additional hotel/entertainment customer was also added. The latter two customers are in the inland valleys northeast of San Diego. The following table lists maximum temperatures for the two regions above on the 11-7 product event days:

	Max. Temperature (°F)	
	San Diego	Temecula
13-Aug-09	72	
20-Aug-09	74	
27-Aug-09	89	
10-Sep-09	80	
17-Sep-09	76	
18-Sep-09	76	
24-Sep-09	84	
1-Oct-09	81	92
9-Oct-09	70	80
14-Oct-09	75	75
16-Nov-09	72	73
19-Nov-09	68	74
24-Nov-09	75	74
3-Dec-09	64	64
7-Dec-09	60	53

Table 19: Maximum Temperatures on Event Days

The total monthly consumption for all accounts associated with Aggregator 2 during any part of the Pilot is shown below. The load pattern is consistent with increased consumption during the hot months of the year:

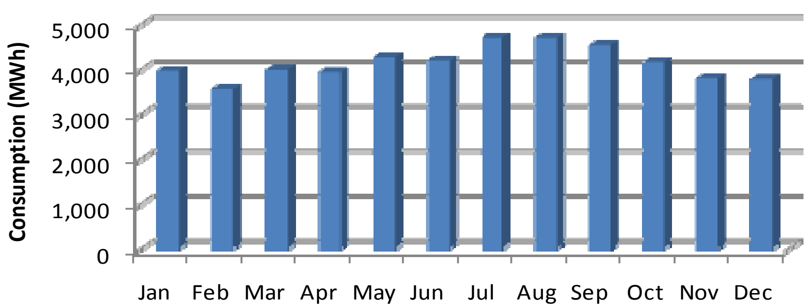

Figure 25: Monthly consumption of accounts associated with Aggregator 2

The consumption of individual accounts represented by Aggregator 2 was in some cases significantly temperature-dependent (e.g., one account had a variation of 60% between the hottest and coldest month), while in others did not appear to be affected by seasonal weather patterns at all. None of the aggregated accounts showed evidence of increased load in cold months, so only maximum temperatures and cooling degree days were taken into account in this study.

Figure 26 overlays load profiles for Aggregator 2, representing typical event days in each of the five months of the Pilot. Note that with some inconsequential exceptions, the event days omitted from the chart had similar load levels and other attributes to the included days from the same month. The event hours are clearly visible in each profile around mid-afternoon. At first it may appear strange that the hot August and September event days have the lowest daily consumption, but disaggregation of the load into its component accounts shows that the primary factor affecting load levels was the number and size of accounts included in the aggregated load in each month, rather than differences in temperature.

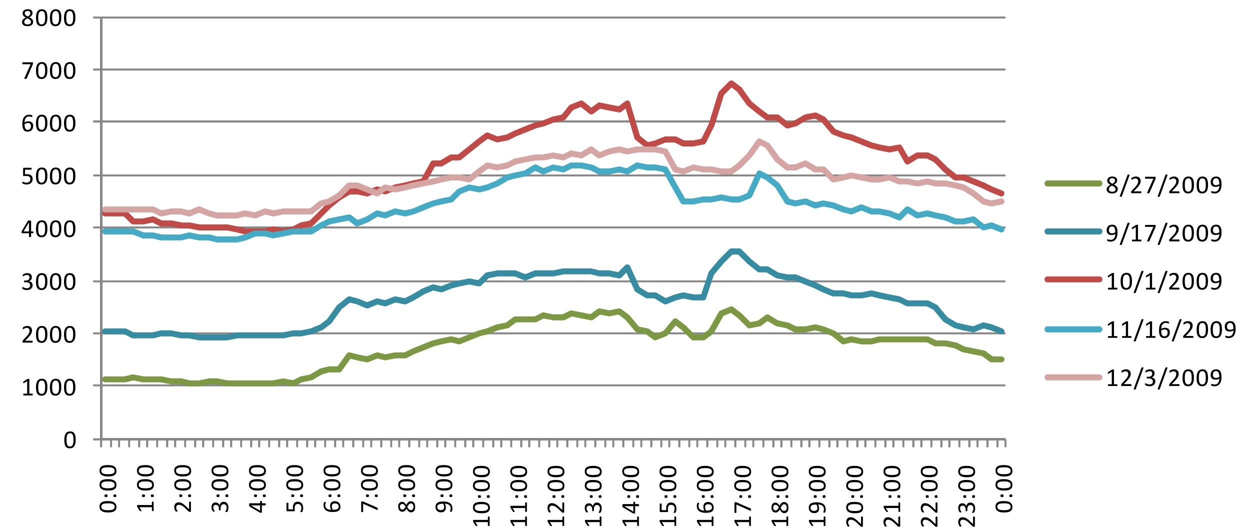

Figure 26: Aggregator 2 load profiles on select event days

Minor temperature-related seasonal variations can be observed between events in the same month (not depicted above), but they are minor and are restricted to the magnitude of the general load profile, rather than affecting the event performance factor, event load reduction, or bounce-back.

Further analysis of individual accounts included in the Aggregator 2 portfolio shows that a portion of them shed more load during events on hotter days. This seems to be an indication that the load reduction for these accounts was achieved by raising thermostat settings during event hours. Some of these accounts seem to be responsible for most of the observed post-event bounce-back load, but this was not always the case.

In general, the temperature-related patterns observed in a few individual accounts are not evident in the aggregated load. It is natural that the diversity of the aggregated accounts obscured such patterns to a great degree, but it is also likely that Aggregator 2 did a good job of setting the nominated load, monitoring telemetry data and controlling load in real time to mitigate the effects of seasonal temperature variations.

5.3 Wholesale Event Analysis

An event analysis from the wholesale market perspective was performed for each of the 14 events that were dispatched by the CAISO, as well as for the subsequent notifications sent to the Participants. The results are included in the appendix in section 8. There were several instances where the CAISO issued dispatches that were determined to be spurious or in error and no subsequent notification to curtail was issued to Participants. The wholesale market settlement results of all CAISO dispatches are included in the monthly statistics in this section. Overall the CAISO settlements accurately reflect the scheduling, bidding and dispatch activity of the Pilot in the wholesale market.

The data for wholesale analysis comes from the CAISO settlement statements. No special treatment was given to Pilot resources in the wholesale settlement process and performance and results were based on the same protocols as any Participating Load. One limitation of the wholesale settlement was the use of 15 minute interval meter data that was used to create the 5-minute SQMD required for Participating Load resources. As noted in section 4.5, 5-minute data was created by dividing 15-minute kWh intervals by three which can obscure the actual load drop on which wholesale settlement calculations are based.

In the cases where the CAISO issued dispatches, whether they were tests via Exceptional Dispatch or Contingency Dispatch, the load drop was measurable and provided the basis for wholesale settlements. The Participating Load resource size was registered with the CAISO for a maximum bid of 3 MW, adequate for the CAISO minimum size requirement of 1 MW. The market software accommodates bid segments to two decimal places (i.e., X.XX MW) and settlement quantities are returned at that level as well. Note that all compliance with the CAISO used the SQMD from the utility meter and not the telemetry data which was only used during the certification test to confirm resource response within 10 minutes to meet the requirement for Non Spinning Reserves.

Figure 27 summarizes per-event CAISO dispatch compliance. Note that events after 10/14 are not included due to incomplete CAISO settlement information at the time this report was finalized.

5.3.1 Performance Summary

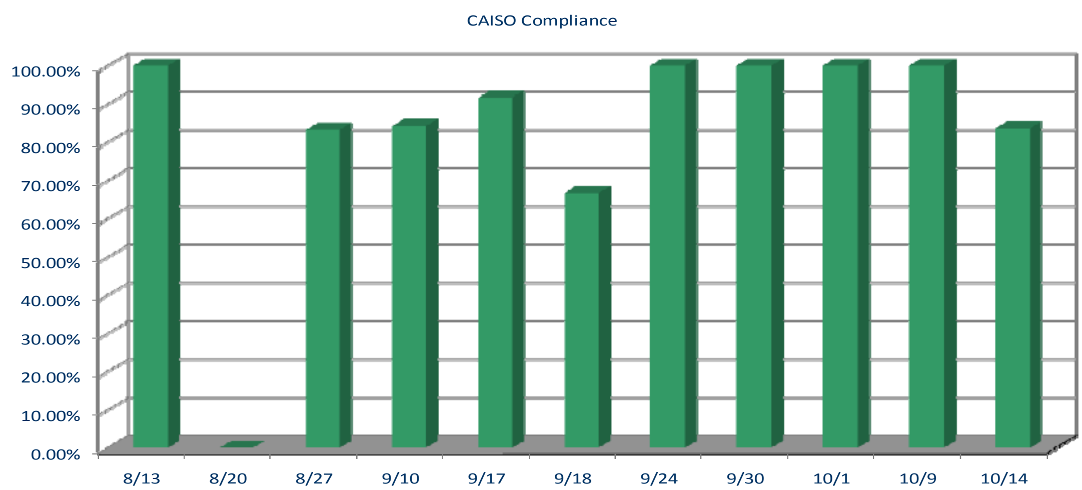

Figure 27: CAISO Dispatch Compliance

5.3.2 Delivered Capacity

The Pilot demonstrated that small aggregated resources were capable of providing Ancillary Services capacity to the CAISO market. While the quantities may not be significant in the context of the entire CAISO market, the fact that a small sample of Commercial and Industrial customers was able to bring contingency reserves to the market provides a basis for researching the scalability of the methods adopted for the Pilot.

Month	August	September	October	November	December	Total
Capacity Awarded Quantities (MW)	34.20	279.60	340.00	252.40	144.80	1051.00
No Pay Quantities (MW)	0.55	0.44	0.13	0.00	TBD	1.12
Delivered Quantities (MW)	33.65	279.16	339.87	252.40	144.80	1049.88

Table 20: Wholesale Performance

5.3.3 Event Performance

The aggregated monthly performance of the Demand Response resource during events can be measured at the wholesale level by determining what portion was deemed successfully delivered during events. To measure this, only the capacity quantities for the hours that the CAISO issued dispatches are considered and the no pay quantities (periods where the CAISO calculated non performance) include dispatches that were not forwarded to the Participants. The no pay quantities are unknown for December since recalculated settlement statements containing quantities and amounts will not be published by the CAISO until mid February 2010.

Month	August	September	October	November	December
Event Capacity Quantities (MW)	1.2	4.2	3.60	0.00	1.00
No Pay Quantities (MW)	0.55	0.44	0.13	0.00	TBD
Delivered Capacity	54%	88%	95%	N/A	N/A

Table 21: Dispatched Capacity

5.3.4 Total Wholesale Revenue

Relatively small returns were garnered from wholesale market revenues. The capacity payments are the sum of the product of the hourly capacity awards and the hourly capacity price. During the Pilot period, the price for Non Spinning Reserves capacity hovered around $1 or less with a few hourly spikes into the $10 to $20 range. Little if any revenue was returned from energy dispatch (Instructed Energy) associated with dispatched capacity in part due to the short duration of CAISO dispatches, typically 10 minutes.

Month	August	September	October	November	December	Total
Capacity Payment	$126.60	$614.47	$271.36	$161.83	$105.05	**$1279.31**
No Pay	($1.14)	($1.96)	($0.16)	$0.00	$0.00	**($3.26)**
Instructed Energy	$138.02	$83.54	$22.65	0.00	$24.21	**$268.42**
Total	**$263.48**	**$696.05**	**$293.85**	**$161.83**	**$129.26**	**$1544.47**

Table 22: CAISO Market Revenue

5.4 Alternate Baselines

The Pilot used a meter-before/meter-after baseline. The specific implementation of this baseline selects the first metered interval ending at or before the time of dispatch from the CAISO. The following sections compare Pilot performance using alternate baselines including the new Proxy Demand Resource (PDR) 10 in 10 adjusted and non-adjusted algorithms as well as the 2009 CBP 3 in 10 algorithm.

The following tables show the event performance under the Pilot compared to the other baselines for each Participant. The alternate baselines perform well for the aggregated customers with the Adjusted PDR showing the highest level of performance; however, they are inappropriate for the industrial Directly-enrolled Participant. That customer is included here for completeness and to illustrate this point. In these tables, note:

- Baseline effectiveness is calculated by averaging the absolute value of the metered load divided by the baseline (i.e., ABS((*baseline/load*) - 1)) for each interval, excluding the event and the two hours after it (to remove the effect of bounce-back). The number represents how close the baseline matches the metered load.
- The meter before/meter after baseline is not included in the Baseline Effectiveness section, because this algorithm is only effective as a performance baseline during event hours and only for relatively short events.

			Unadjusted Event Performance				Baseline Effectiveness*		
Participant	Product	Events	PLP	PDR	Adjusted PDR	CBP (3 in 10)	PDR	Adjusted PDR	CBP (3 in 10)
Aggregator 1	11am-7pm	8/13/2009	95.6%	104.1%	87.5%	131.7%	8.6%	5.3%	8.7%
Aggregator 1	11am-7pm	8/20/2009	84.9%	85.2%	82.7%	107.3%	7.5%	7.4%	6.6%
Aggregator 1	11am-7pm	8/27/2009	100.0%	37.7%	106.3%	71.5%	9.4%	13.2%	5.7%
Aggregator 1	11am-7pm	9/10/2009	136.9%	125.3%	109.3%	160.6%	5.0%	3.8%	7.0%
Aggregator 1	11am-7pm	9/17/2009	130.5%	122.8%	88.2%	151.9%	5.9%	5.3%	10.1%
Aggregator 1	11am-7pm	9/18/2009	30.1%	-19.5%	4.0%	16.2%	3.8%	4.5%	5.2%
Aggregator 1	11am-7pm	9/24/2009	145.2%	102.9%	135.6%	135.2%	11.0%	10.2%	10.0%
Aggregator 1	11am-7pm	10/1/2009	176.9%	169.1%	122.0%	256.1%	12.1%	9.1%	14.6%
Aggregator 1	11am-7pm	10/9/2009	72.0%	219.3%	125.7%	317.2%	21.6%	16.2%	34.2%
Aggregator 1	11am-7pm	10/14/2009	170.0%	157.8%	209.6%	219.7%	6.2%	5.7%	5.4%
			114.2%	**110.5%**	**107.1%**	**156.7%**	**9.1%**	**8.1%**	**10.8%**

Table 23 Alternate Baseline Performance for Aggregator 1

			Unadjusted Event Performance				Baseline Effectiveness*		
Participant	Product	Events	PLP	PDR	Adjusted PDR	CBP (3 in 10)	PDR	Adjusted PDR	CBP (3 in 10)
Aggregator 2	11am-7pm	8/13/2009	229.1%	118.7%	161.2%	189.2%	6.6%	6.8%	6.7%
Aggregator 2	11am-7pm	8/20/2009	105.3%	181.1%	112.0%	289.8%	4.0%	3.4%	8.9%
Aggregator 2	11am-7pm	8/27/2009	239.8%	77.7%	162.6%	131.8%	10.3%	11.3%	10.4%
Aggregator 2	11am-7pm	9/10/2009	136.6%	137.8%	112.3%	196.5%	6.2%	4.8%	9.7%
Aggregator 2	11am-7pm	9/17/2009	80.1%	188.1%	104.1%	232.7%	10.5%	3.0%	20.8%
Aggregator 2	11am-7pm	9/18/2009	166.8%	118.1%	101.2%	166.5%	5.0%	3.9%	14.2%
Aggregator 2	11am-7pm	9/24/2009	163.3%	134.6%	118.0%	176.5%	7.3%	6.7%	9.6%
Aggregator 2	11am-7pm	10/1/2009	85.0%	103.1%	66.6%	159.2%	4.3%	2.5%	6.3%
Aggregator 2	11am-7pm	10/9/2009	30.8%	74.1%	59.9%	153.7%	3.8%	4.1%	4.4%
Aggregator 2	11am-7pm	10/14/2009	65.0%	69.6%	64.0%	122.0%	1.0%	1.1%	4.3%
Aggregator 2	11am-7pm	11/16/2009	103.4%	102.0%	84.2%	132.2%	2.8%	1.8%	3.9%
Aggregator 2	11am-7pm	11/19/2009	66.3%	100.7%	60.6%	136.4%	3.2%	1.6%	4.6%
Aggregator 2	11am-7pm	11/24/2009	73.6%	65.0%	31.5%	108.1%	4.3%	1.6%	7.8%
Aggregator 2	11am-7pm	12/3/2009	68.5%	48.6%	32.7%	79.5%	1.1%	1.3%	1.8%
Aggregator 2	11am-7pm	12/7/2009	30.7%	77.1%	27.7%	79.7%	3.6%	3.1%	4.6%
			109.6%	**106.4%**	**86.6%**	**156.9%**	**4.9%**	**3.8%**	**7.9%**

Table 24: Alternate Baseline Performance for Aggregator 2

			Unadjusted Event Performance				Baseline Effectiveness*		
Participant	Product	Events	PLP	PDR	Adjusted PDR	CBP (3 in 10)	PDR	Adjusted PDR	CBP (3 in 10)
Customer	24/7	9/10/2009	0.3%	0.4%	-0.1%	1.1%	49.0%	45.6%	35.5%
Customer	24/7	9/17/2009	1.1%	0.1%	-0.1%	0.2%	731.4%	677.7%	728.5%
Customer	24/7	9/18/2009	0.0%	0.2%	0.1%	0.4%	1052.6%	999.6%	1026.0%
Customer	24/7	9/23/2009	197.4%	136.9%	165.9%	107.4%	82.1%	97.3%	49.6%
Customer	24/7	9/30/2009	250.6%	38.0%	44.2%	38.4%	88.5%	97.9%	19.0%
Customer	24/7	10/1/2009	0.7%	-0.5%	-0.2%	-0.1%	52.3%	53.7%	24.7%
Customer	24/7	10/9/2009	-0.3%	-0.3%	-0.1%	0.2%	1017.8%	1064.8%	1105.3%
Customer	24/7	10/14/2009	-0.3%	-1.1%	-0.6%	-0.7%	244.5%	272.5%	112.2%
Customer	24/7	10/15/2009	0.8%	37.0%	45.0%	26.0%	389.8%	464.1%	308.8%
Customer	24/7	11/16/2009	2.9%	-0.4%	-0.6%	-0.1%	1726.5%	1516.5%	2068.9%
Customer	24/7	11/18/2009	41.4%	-5.6%	14.6%	24.8%	16.6%	19.3%	18.4%
Customer	24/7	11/19/2009	-0.3%	0.3%	0.5%	0.8%	257.9%	275.6%	273.7%
Customer	24/7	11/24/2009	0.2%	0.1%	0.0%	0.3%	160.0%	152.9%	158.0%
Customer	24/7	12/2/2009	111.9%	69.1%	83.7%	100.7%	69.5%	88.7%	22.7%
Customer	24/7	12/11/2009	33.7%	94.0%	73.8%	165.1%	277.7%	231.7%	311.0%
Customer	24/7	12/15/2009	170.1%	104.4%	126.3%	156.3%	85.2%	107.4%	72.5%
			50.6%	**29.5%**	**34.5%**	**38.8%**	**393.8%**	**385.3%**	**395.9%**

Table 25 Alternate Baseline Performance for Directly-enrolled Customer

The following sections illustrate baseline performance for several specific events.

5.4.1 August 13, Aggregator 1, Adjusted PDR

During this event, the adjusted PDR baseline tracks well against actual usage. Note that Load did not return to pre-event levels until an hour after the end of the event due to a communications failure between the aggregator and its customers.

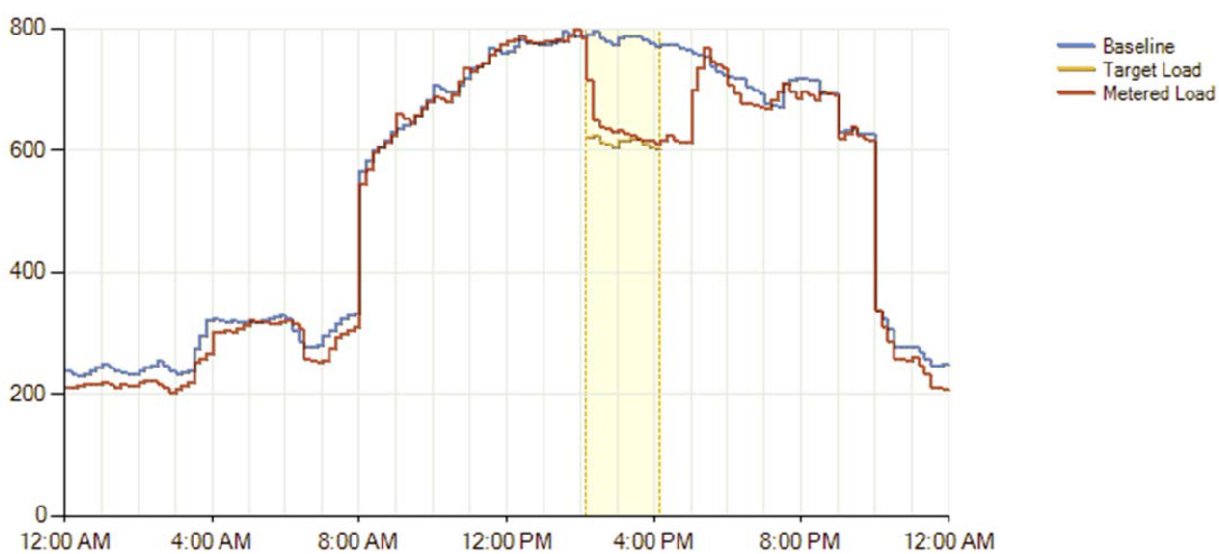

Figure 28: Adjusted PDR Comparison for Aggregator 1, August 13th

	14:20	14:30	14:40	14:50	15:00	15:10	15:20	15:30	15:40	15:50	16:00	16:10
Metered Load	717	649	639	635	631	634	629	624	620	618	617	611
Baseline	791	796	785	780	775	786	787	789	789	782	776	772
Nomination	170	170	170	170	170	170	170	170	170	170	170	170
Target Load	621	626	615	610	605	616	617	619	619	612	606	602
Actual Reduction	74	147	146	145	144	152	158	165	169	164	159	161
Percent Reduction	44%	86%	86%	85%	85%	89%	93%	97%	99%	97%	94%	95%
Average Reduction	87%											

Table 26: Metered Performance for Aggregator 1, August 13th

5.4.2 September 17, Aggregator 2, Various Baselines

This example compares the various baselines for Aggregator 2. The load on this particular day is significantly lower than in the previous days, making the unadjusted "average" baselines ineffective, as a measure of performance. For example, unadjusted performance with the CBP baseline would have been 232% instead of 80%. In fact, the difference between the CBP baseline and the Participant's actual load immediately prior to the event is 690 kW, which would have translated to a 159% performance factor, even without the participating resources actually curtailing their usage.

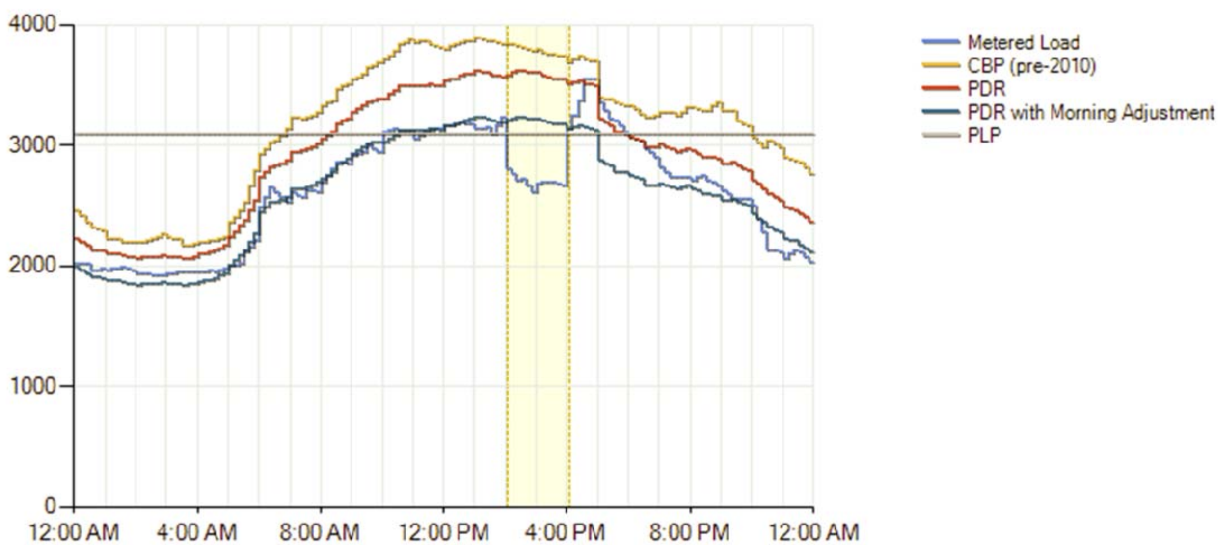

Figure 29: Adjusted PDR Comparison for Aggregator 2, September 17th

	14:10	14:20	14:30	14:40	14:50	15:00	15:10	15:20	15:30	15:40	15:50	16:00
Metered Load	2,816	2,763	2,709	2,727	2,673	2,620	2,691	2,696	2,702	2,696	2,684	2,671
Baseline	3,098	3,098	3,098	3,098	3,098	3,098	3,098	3,098	3,098	3,098	3,098	3,098
Nomination	450	450	450	450	450	450	450	450	450	450	450	450
Target Load	2,648	2,648	2,648	2,648	2,648	2,648	2,648	2,648	2,648	2,648	2,648	2,648
Actual Reduction	281	335	389	371	424	478	407	402	396	402	414	427
% Reduction	63%	74%	86%	82%	94%	106%	90%	89%	88%	89%	92%	95%
Average Reduction						87%						

Table 27: Metered Performance for Aggregator 2, September 17th

5.4.3 October 9, Aggregator 1, Various Baselines

This example compares the various baselines. It clearly shows discrepancies among the different baseline algorithms of as much as 50%. This appears to be caused by the fact that usage was significantly lower on this day than on the previous few days. The Adjusted PDR baseline works relatively well – as does the default baseline – due to the adjustment factor. Other baselines are significantly off.

Another interesting aspect of this event is that it occurs earlier in the day, at a time when load usually rises. The "averaged" baselines account for this, while the default PLP baseline does not, causing under-performance at the tail end of the event. Performance with the PDR with Morning Adjustment baseline would have been greater than 100%.

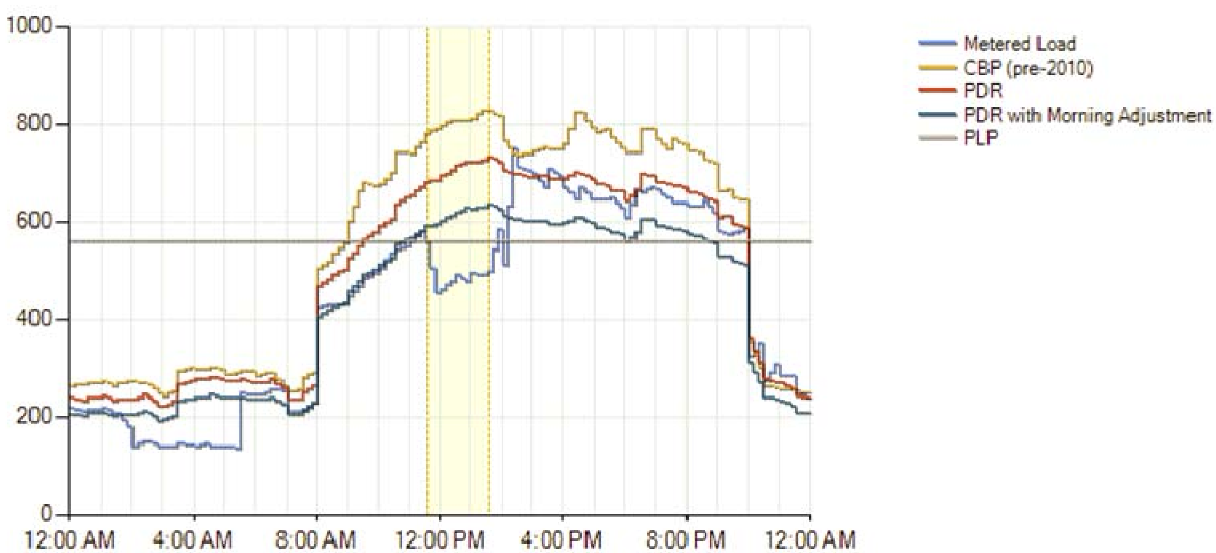

Figure 30: Adjusted PDR Comparison for Aggregator 1, October 9th

	11:40	11:50	12:00	12:10	12:20	12:30	12:40	12:50	13:00	13:10	13:20	13:30
Metered Load	561	507	453	462	471	480	494	486	477	494	493	492
Baseline	562	562	562	562	562	562	562	562	562	562	562	562

Nomination	100	100	100	100	100	100	100	100	100	100	100	100
Target Load	462	462	462	462	462	462	462	462	462	462	462	462
Actual Reduction	1	55	109	100	91	82	68	76	84	68	69	70
Percent Reduction	1%	55%	109%	100%	91%	82%	68%	76%	84%	68%	69%	70%
Average Reduction	72%											

Table 28: Metered Performance for Aggregator 1, October 9th

5.5 Alternate Products

The following sections cover what retail performance would have been for shorter events, and compares behavior between the first and second hours. The results are compared in the tables in section 5.5.3

5.5.1 1 Hour and 30-Minute Events

The rationale for performing this analysis is based on the expectation that Participants might be more willing to enroll in DR programs with lower participation requirements. Specifically, the recent change of relevant WECC standards reduces the CAISO duration requirement for Non-Spinning Capacity Reserves to 1 hour. This requirement formed the basis of the retail events duration.

The methodology for performing these comparisons takes the intervals related to the first portion of the event. That is, the 1 Hour events are based on the first half of metered intervals while the 30-minute events are based on the first quarter of intervals. Alternate methods of comparison were considered including using the ending interval of the actual event. While this other methodology might better model end of event ramp-down, it would require further computations to properly adjust the ending intervals to an earlier point in time.

Table 29 shows the comparison between Pilot performance and these alternate products for the three Participants with details in section 5.5.3. Note that events with performance below 50% are treated as outliers in this analysis and are therefore excluded.

	Aggregator 1	Aggregator 2	Directly-enrolled Customer
1 Hour	-3%	0%	-2%
30 Minute	-11%	-3%	-5%

Table 29: Relative Performance for Shorter Products

Overall the difference between the Pilot events compared to the shorter products is not significant.

5.5.2 Does Behavior Differ in the Second Hour?

The methodology compares the performance of the first hour to the second using the Pilot baseline. These results are complementary to the alternate performance for the 1 hour events (i.e., the difference in performance of the one-hour event is inversely reflected in the second hour).

Table 30 shows the comparison between Pilot performance and these alternate products for the three Participants with details in section 5.5.3. Note that events with performance below 50% are treated as outliers in this analysis and are therefore excluded.

	Aggregator 1	Aggregator 2	Directly-enrolled Customer
2nd Hour	3%	0%	2%

Table 30: Relative Performance for Second Hour

Overall the difference between the first and second hours of Pilot events is not significant.

5.5.3 Details

	13-Aug	20-Aug	27-Aug	10-Sep	17-Sep	18-Sep	24-Sep	1-Oct	9-Oct	14-Oct
Pilot	96%	85%	100%	137%	131%	30%	145%	177%	72%	170%
1 Hour	86%	77%	85%	119%	135%	17%	149%	189%	72%	182%
30 Minute	76%	65%	64%	105%	138%	11%	147%	178%	66%	179%
2nd Hour	105%	94%	117%	155%	126%	43%	141%	167%	71%	159%

Table 31: Alternate Unadjusted Product Performance, Aggregator 1

	13-Aug	20-Aug	27-Aug	10-Sep	17-Sep	18-Sep	24-Sep	1-Oct	9-Oct	14-Oct	16-Nov	19-Nov	24-Nov	3-Dec
Pilot	229%	105%	240%	137%	80%	167%	163%	85%	31%	65%	103%	66%	74%	69%
1 Hour	275%	79%	231%	126%	85%	134%	161%	87%	56%	79%	106%	74%	68%	72%
30 Minute	220%	51%	237%	145%	76%	96%	154%	88%	59%	87%	105%	83%	68%	71%
2nd Hour	184%	136%	231%	147%	76%	204%	165%	83%	7%	50%	101%	59%	80%	66%

Table 32: Alternate Unadjusted Product Performance, Aggregator 2

	23-Sep	30-Sep	15-Oct	18-Nov	2-Dec	11-Dec	15-Dec
Pilot	192%	251%	1%	41%	112%	34%	170%
1 Hour	184%	250%	1%	113%	110%	31%	169%
30 Minute	169%	249%	1%	145%	107%	25%	165%
2nd Hour	203%	251%	1%	-30%	114%	36%	172%

Table 33: Alternate Unadjusted Product Performance, Direct Enrolled Customer

6 Pilot Costs

6.1 Implementation

2009	TOTAL		
	Budget	Actual	Forecasted
Labor	223,435	211,773	211,773
Devices and Install	68,000	62,000	88,410
Systems and Technology	2,538,565	612,000	1,078,410
Incentive Payments	215,000	69,311	209,599
Other	708,000	500,000	625,000
Project Management		*350,000*	
M&V/Final Report		*150,000*	
Total	3,753,000	1,455,084	2,213,192

6.2 Cost Analysis

The short duration of the first phase of the Pilot as well as the limited time between the end of the first phase and submitting this report make it difficult to do a complete or accurate cost-effectiveness evaluation. Further, certain aspects of the Pilot, such as the relatively high capacity payment used as an incentive to attract participants, need to be considered for modification before drawing accurate conclusions regarding cost effectiveness.

SDG&E will continue to analyze program costs with two key objectives in mind:

1) Which aspects can be modified to support cost effectiveness and scalability.

2) Which aspects contribute to the goal of integrating demand response into the wholesale market.

One of the key objectives of the Pilot was to determine the requirements in systems and processes that will be required for a full integration the required specifics of which were largely unknown at the Pilot's inception. Consistent with the very nature of a Pilot, SDG&E elected to use external parties to minimize the impact on the organization with the primary goal being the learning afforded SDG&E from the Pilot.

In addition to supporting the development and implementation of the Pilot, APX was able to provide infrastructure to support the Pilot. This enabled SDG&E to implement the Pilot quickly and focus on specific issues related to the aggregation of commercial and industrial customers. This also allowed SDG&E to avoid investing in unnecessary infrastructure and review the needs and requirements thoroughly before doing so. Similarly, given the small number of Participants many processes were developed and maintained manually throughout the Pilot period being refined prior to automation efforts.

As a result, the Pilot was able to be delivered at substantially less cost than had originally been anticipated and to provide insights into what would be needed to deal with a larger number of Participants.

Deviations:

- The budgeted incentives for the Pilot assumed a fully subscribed pilot of 3 MW from June through December 2009. However the Pilots delay in start and total megawatts enrolled (nominations did not exceed 1.9 MW) resulted in lower incentive payments than had initially been planned.
- Although there was only a small deviation in the Devices and Installation category due to the specific customers needs upon enrollment, a related item to note is that there was a heavy reliance on TI/TA funds with $207,200 being spent from that budget associated with participation in the PLP.
- The deviation in the Other category was most significantly due to two factors:
  - By using APX for both management and infrastructure already supporting necessary communications with the CAISO for telemetry a significant amount of costs originally anticipated were avoided for this Pilot period.
  - The budget had included an estimate for efforts required to incorporate Direct Access customers into the Pilot. During 2009 all end use customers with bundled.
- The most significant deviation is in the Systems and Technology section. This deviation is a direct result of the decision to use APX infrastructure and limit automation for the Pilot, focusing on the broader objectives around aggregation and postponing the development of much system integration until the requirements were more fully defined.

Ongoing costs for the Pilot as it currently stands are estimated to be approximately $750,000 per year. However the majority of these costs are not highly variable and enrollment in the Pilot, 'as is', could be expanded without more investment. The expansion however is limited by the manual effort involved in some of the data transfer processes and would the Pilot would be unable to take on more than 5-7 Participants (approx 5 MW).

7 Conclusions

The Pilot was successful in demonstrating that an aggregated resource composed of disparate small Commercial and Industrial customers can participate as a Non Spinning Reserve resource in the CAISO wholesale market. In particular, the aggregated resource was able to respond to CAISO dispatches within 10 minutes with a performance factor of 88%.

The lessons learned from the Pilot ranged from minor modifications to improve processes to significant learnings regarding future design and system integration requirements. The main technology infrastructure used, including communications, proved to be a solid decision with merit, enabling the Pilot and facilitating further integration efforts. It is envisioned that the Pilot technology would continue to be used and enhanced going forward. Some automation and integration activities originally envisioned for the Pilot have not yet been implemented. The processes were able to be developed and refined relatively manually given the small number of customers so that requirements could be more fully defined. Moving forward it would be SDG&E's expectation to implement those features.

A list of potential enhancements based on lessons learned follows. Each of these items is summarized in section 7.2.

- Replacement 24x7 Product
- Hourly Bidding
- PDR and RDRP
- 5-Minute Metering
- CAISO Network Model
- Market Bidding
- Establish Clear Telemetry Guidelines
- Standardized Telemetry Solutions
- Telemetry Modeling Pseudo-Generation
- Live Distribution Loss Factors
- Evaluate Baseline Efficacy
- Automate Retail Settlement
- Include Direct Access Customers
- Better Support for Dual Participation

Note that the load impact of the Pilot was de minimis and the PLP will be included in the Load Impact Study in the spring.

7.1 Feasibility of Retail PL Resources in the CAISO Markets

Performance in the CAISO market during the Pilot demonstrates that there are no technical reasons that an aggregated DR resource could not be considered on par with a combustion turbine.

However, there remain some questions about financial viability. Transitioning Participants from utility-based programs to market-based programs presents challenges given the expected reduction in payments received by Participants. Current DR programs – as well as the Pilot – include incentives that are not expected to be achieved through wholesale markets. This disparity was illustrated during the Pilot, where the retail settlement outlays dwarfed the wholesale revenues earned by the PL resource in the CAISO Non Spinning Reserve market. While the addition of Capacity Payments for Non Spinning Reserves hold some promise of a reasonably predictable and sustainable revenue stream, a more substantial revenue source is necessary to make the PL resource financially viable in the wholesale market. The logical source would be the addition of the revenue that comes with a Resource Adequacy contract. This model would be more closely aligned with the development of a combustion turbine which is not economically viable solely based on potential revenues in the CAISO market, but has greater value due to its contribution to RA and so requires an RA contract to make it viable.

Until such time that DR capabilities qualify to be fully counted and compensated as Resource Adequacy resources will this economic gap between Utility programs and the wholesale market be closed.

7.2 Possible Next Steps

SDG&E is requesting to continue and expand the Pilot over the remaining budget cycle. The learning from the Pilot has been invaluable in identifying issues and possible solutions for further integration with the CAISO. Continuing the effort working with larger aggregations, additional Participants and Direct Access customers will increase the value significantly and provide a mechanism for standardization of telemetry solutions to improve cost-effectiveness and Pilot scalability. Additionally, the inclusion of PDR offers an opportunity to match customer segments and with appropriate products.

Possible next steps are divided into two sections. The first section describes substantive enhancements for a future Phase. The second section enumerates simple improvements over the first Phase, essentially those parts of the Pilot that could benefit from automation or could for which operational improvements can be made.

7.2.1 Potential Enhancements for Phase II

While there are a number of changes to be considered to improve processes and operations to be incorporated into a Phase II, the goal of the extension of the Pilot is to inform and support the transition of retail DR products for integration into the CAISO market.

The experiences and observations from the first year of Pilot operation inform improvements that could be implemented in future years. It is not feasible that all candidate improvements could be designed and implemented prior to the summer of 2010 and priorities need to be established. No rankings or priorities have yet been established. Key candidates for improvements in Phase II and beyond are enumerated in the following sections.

7.2.1.1 Recruitment

The focused recruitment of customers is critical for future incarnations of the Pilot. By the very nature of the Pilot, recruitment for participation requires targeting at two levels to reach Aggregator Participants as well as end-use customers. Such recruitment efforts require significant coordination and would be assisted by outreach efforts that incorporate customer education, regardless of whether they might enroll through an aggregator or directly with SDG&E. Inclusion of Direct Access customers would also require additional coordination during the recruitment process. This effort requires a significant amount of lead time to be successful.

With the requirement for telemetry for PL and the need for automation throughout the process, there is a greater lead time required to recruit customers than for traditional DR programs. This is even more so when AutoDR is to be employed.

For the 2009 Pilot period there were no impacts due to meter installations or completion of the TI/TA process; however, this may be misleading because Participants were included based on their ability to qualify in time for the Pilot. Both Aggregators have identified that these processes have the potential to create delays making it imperative that plans for future Pilot activities be defined as early as possible.

The biggest objection raised during this Pilot period was concern about the unknown, essentially that some requirements were not yet finalized and that the term of the Pilot was in question. This former issue is now more easily addressed with many implementation issues associated with the Pilot now much clearer. However the need the have a fully approved Pilot with incentives, requirements and Pilot lifetime clearly identified remains for future recruitment efforts, to support return on investment analysis, associated with participation.

The participating customers expressed a high level of satisfaction with the Pilot, especially given the short implementation and operational period; however a number of items were identified to support an ongoing or increased level of customer satisfaction for the future and to support a larger effort. Specific improvements are noted in section 7.2.2. All of these items are also expected to contribute to providing customers with clarifications limiting the 'unknown' factor.

A focused recruitment effort to identify customer segments that can readily meet the requirements associated with participation in the Pilot (whether it be PDR or PL) on a larger basis would include increased customer segment analyses, increased training, additional customer education and outreach including marketing support materials. SDG&E would intend to continue to work through third-party Aggregators (or Demand Response Providers) and provide education and support materials to third-party Demand Response Providers as well as internal Account Management with a detailed marketing plan currently being developed. The more accurately the customer's capabilities are aligned with the needs of the Pilot the greater chance of success and the higher level of customer satisfaction anticipated.

7.2.1.2 Replacement 24x7 Product

The 24x7 product was included in the Pilot to provide an opportunity for potential Participants that did not meet the criteria for the more typical 11-7 product and recognized that the CAISO procures reserves on all hours and all days. Certainly, the 11-7 product has particular value in that it provides capacity when the need is typically highest. While the 24x7 product better reflects the CAISO procurement practices, the nature of its broad stroke coverage has little bearing on the capabilities of potential customers since few if any have the same quantity of dispatchable demand available each hour of the day.

A replacement to the 24x7 product could narrow this gap between the CAISO procurement needs and the operational characteristics of potential participants. This might be enabled through a more flexible nomination profile or hourly bidding.

7.2.1.3 Hourly Bidding

While per-hour nominations would be useful for a 24x7 product, providing an ability for PL customer bidding to be more dynamic for all products would provide an environment more representative of the wholesale market. Incorporating this capability into the Pilot could significantly assist the transition, providing valuable insights into client capabilities as well as defining anticipated changes in scheduling behavior and systems changes required to support a full integration to MRTU.

The introduction of hourly bidding to the Pilot would necessitate automation of the bidding process to allow actual bids to be composed from the hourly nominations.

7.2.1.4 PDR and RDRP

Participating Load was used as the wholesale product for the Pilots since the mechanism for bidding PL currently exists under MRTU. During the operational period of the Pilot an additional product, Proxy Demand Resource (PDR), has been designed and is anticipated to be implemented by the CAISO in May 2010. PDR will support bid variation across the month and the movement of customers in and out of resources and programs provided either by a utility or a third party Aggregator termed a Demand Response Provider (DRP). Additionally, a subsequent product RDRP is planned. The expectation is that the availability of these three products in the wholesale market will support the integration of utility retail DR programs.

The inclusion of PDR within Phase II of the Pilot could provide an opportunity to educate the marketplace as well as the utility and other key stakeholders and ensure that the plans and needs associated with the transition are fully understood prior to the filing for the 2012-2014 budget cycle.

7.2.1.5 5-Minute Metering

Any change in the Pilot that results in per-hour nominations and the new CAISO limit on 1-hour events could result in a future Pilot phase that reduces the 2-hour retail events to 1-hour. Shorter events increases the worst-case impact introduced by 15-minute metering for the Pilot products. As a result, such a change would imply a transition to 5-minute metering to accurately reflect load drops for settlement purposes.

7.2.1.6 CAISO Network Model

As noted in section 4.6.1, the advance notification requirement for submitting the data to model the specific location of demand that makes up a PL resource in the CAISO network model is challenging. That coupled with the relative infrequency of the promotion of those models into production in the market systems by the CAISO doesn’t align well with a dynamic aggregation. While the CAISO adoption of default resource locations for the Proxy Demand Resources addresses this issue, there may circumstances where it is preferable to create a customized location.

A custom modeled aggregation has the benefit of being aligned with load reduction capability. In particular, there are grid locations in the SDG&E service territory that are extremely weather sensitive. Loads in Inland locations typically have higher AC requirements that provide a significant portion of load drop for a single customer that might not always be available at all locations. Specifically, if a retailer has both Coastal and Inland locations, providing the option to split the locations between two different aggregations that are location specific could facilitate broader participation.

In order to model SDG&E’s service territory more accurately, more custom aggregations would need to be created.

7.2.1.7 Market Bidding

During the Pilot, the prices bid into the market were chosen on the basis of best assuring that the Non Spinning Reserves capacity bids cleared the CAISO Day Ahead market and that the energy associated with that capacity would only be dispatched for a coordinated test or during a true system contingency. Outside of these parameters no effort was made to consider any other bidding strategy in the wholesale market. There exists the opportunity to structure bids in a manner that are coordinated with Utility procurement practices, interaction with other Utility DR programs and the relative value of the product in the wholesale market.

The use of the Pilot resource to be responsive to CAISO scarcity bidding needs also warrants consideration. The Scarcity Pricing assigns significant premiums to resources that respond to the CAISO needs and could provide an opportunity to better align the expectations of Pilot Participants with the frequency of use. While it is likely that the number of instances where the CAISO invokes scarcity pricing will be low, the premium paid could better inform a product offering and pricing structure that closes the gap between the Utility program and the wholesale market.

In order to utilitize market pricing, a more complex bidding strategy could be implemented in the future.

7.2.1.8 Automation of Dispatch and Notification

Additional automation in the dispatch and notification process could come in the form of utilizing the CAISO Automated Dispatch System (ADS) Web service features to activate the SDG&E Pilot notification system. In Phase I, the APX operator monitored the ADS for dispatches of the Pilot resource and then activated the Pilot notification system that automatically sends curtailment notices to Participants. In a subsequent phase, connectivity between ADS and the notification system could be established to remove errors and reduce latency.

7.2.1.9 Establish Clear Telemetry Guidelines

Overall, the CAISO telemetry requirements as currently established are predicated on large installations connected to the high voltage transmission grid. These requirements for Participating Load are not conducive for small Industrial and Commercial customer to adopt due to their high cost and technological complexity. SDG&E could propose coordinating with the CAISO to better clarify telemetry needs and to develop clear guidelines regarding telemetry measurement.

7.2.1.10 Standardized Telemetry Solutions

While there are myriad issues regarding telemetry – if in fact the existing requirements persist in the next phase(s) of the Pilot – standardized solutions focused on low cost and ease of installation is imperative. In Phase I much of the available implementation timeframe was used to interpret CAISO telemetry requirements and adapt any existing end use installations to those requirements. With a better understanding of what works in a variety of customer configurations, SDG&E and its contractors are better equipped to design one or more solutions that can be adapted to customer configurations without the burden of trial and error experienced in Phase I.

7.2.1.11 Telemetry Modeling Pseudo-Generation

The telemetered data being sent to the CAISO reflects the entirety of the load underlying the dispatchable demand. By changing the requirements to model pseudo-generation, that is looking only at the portion of demand that is “armed” for curtailment, the CAISO would be able to actually “see” the resource. This would better allow demand response to be treated as generation and provide real-time feedback that could be incorporated into the CAISO real-time state estimator and used as an input into the dispatch algorithms. SDG&E could investigate techniques for providing this pseudo-generation instead of total load.

7.2.1.12 Live Distribution Loss Factors

In the first phase of the Pilot, Distribution Loss Factors were fixed per voltage service level. While this simplified Pilot implementation, it would be more accurate to apply the SDG&E daily DLF values to the telemetry data. This will require some automation and process refinements for both the Pilot administrator as well as the Aggregators.

7.2.1.13 Evaluate Baseline Efficacy

There continues to be issues and questions about the suitability of baselines for various event types. Continued analysis and review of the impacts baselines to continue to resolve differences between the wholesale and retail baseline methodologies could be incorporated into additional efforts.

7.2.1.14 Automate Retail Settlement

Another area where automation enhancements could be made is to automate retail settlement calculations. While such automation would certainly allow for quicker financial settlement, it could also be used to provide more rapid post-event information and analysis to Participants.

7.2.1.15 Include Direct Access Customers

Inclusion of Direct Access (DA) customers was contemplated in the design, development and implementation of Phase I of the Pilot; however few of these elements were tested since there were no DA Participants. As such, it cannot be entirely know if those elements would provide all the rights and protections that should be afforded a DA customer. To best assure protection of any DA customers data, a separate Scheduling Coordinator ID with separate resources was established with the CAISO.

It is not clear that an entirely separate Scheduling Coordinator and resources is necessary given that the CAISO is poised to roll out the Proxy Demand Resource (PDR) in May 2010. It may be possible that all of the protections necessary to separate confidential data between SDG&E and a DA Participant can be accomplished through the use of the PDR product. Within SDG&E, preliminary thought has been given to this possibility and will continue to be considered as the next phases of the Pilot are designed with the objective of ensuring that DA customers can participate.

7.2.1.16 Better Support for Dual Participation

Participation in multiple demand response programs simultaneously provides the opportunity to earn revenues that make demand response solicitations to customers economic, but add administrative challenges. Multiple participation can only be allowed if the product being offered doesn’t provide duplicate compensation for the same product in the same period.

In the case of the Pilot where demand response is being bid into the wholesale market as real-time contingency reserves, SDG&E does not see a reason that a customer could not be enrolled in a utility Day Ahead energy product as well. The value of the Day Ahead energy product is in its ability to manage day ahead procurement costs while the real-time product is designed to respond instantaneously to a grid contingency. So long as the Participant can be known and removed from the quantity bid into the real-time capacity market, then there is no conflict between programs.

The Pilot could require the addition of certain features to better accommodate multiple participation. Among these items would be a registration process that allowed reconciliation between programs at enrollment and identify adjustments required prior to finalizing monthly compensation to the Participant, as well as a more fluid (automated) process to update the Scheduling Coordinator regarding resource availability prior to submitting bids to the CAISO wholesale market.

7.2.2 Additional Improvements

As expected with any Pilot, there were areas that presented challenges that can be improved upon with minimal effort and little, if any, program modifications or system development. In particular, and as noted throughout the report, the compressed implementation timeframe drove some of the challenges. Also there were instances where existing processes needed to be modified or new processes created that were accomplished in a “figure it out as you go/just in time delivery” mode.

Along with the implementation of items identified for the extension of the Pilot. Other improvements could be considered for implementation.

- Online Enrollment and Nomination integrated Settlement functionality
- Integration with other systems to address multiple participation
- Improved processes associated with metering and forecasting

8 Appendix I: Event Details

Unless otherwise noted, all numbers are in kilowatts (kW).

In this section there will be instances where there is limited wholesale settlement information because no event information was returned in the CAISO Settlement statement. There are two primary reasons for these discrepancies:

- The event was called outside of the CAISO market; or
- There were data propagation errors in the latest CAISO settlement statements available at the time this report was finalized.

The meaningful data component from the CAISO wholesale settlements is Ancillary Services No Pay which is indicative of whether or not the event met the CAISO standard of achieving curtailment within ten minutes of dispatch. Evaluation of this settlement component is particularly useful since it reflects any latency between CAISO dispatches and the ultimate response by the individual Participants. Energy settlement analysis at the CAISO level is generally not useful for comparison to the retail settlement since the majority of the CAISO dispatches were only for 10 minutes while the retail events lasted two hours. Further, the issues associated with the derivation of 5-minute meter data from 15-minute interval meters discussed elsewhere in this document are amplified when applied to this shorted 10 minute period (as opposed to a 120 minute period) rendering CAISO energy settlement analysis relatively meaningless. Meaningful CAISO energy analysis could only be accomplished with the application of telemetry data or a baseline other than the "meter before meter after" methodology which is only appropriate for measuring initial (10 minute) dispatch compliance.

8.1 August 13th (11-7)

The first event for the Pilot was dispatched by the CAISO on August 13th, 2009 at 14:00 for a reduction of 0.3 MW. This resulted in the notification of Participants to curtail their nominated capacity from 14:10 to 16:10. The following chart shows the metered performance for the two aggregators that participated in the event:

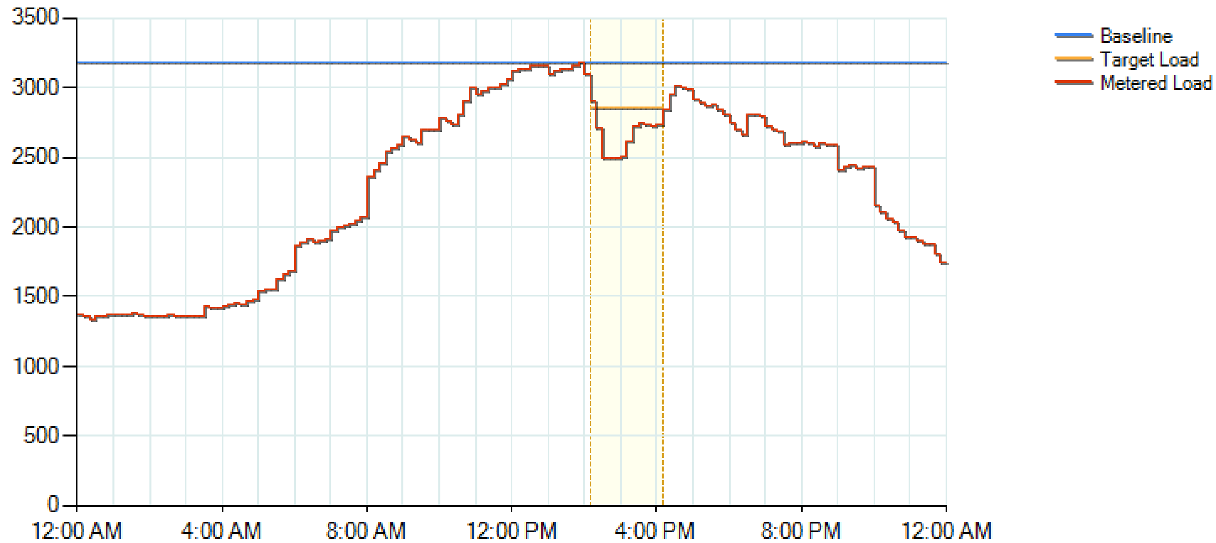

Figure 31: Aggregate Metered Results, August 13th

Although scheduled, this was the first event of the Pilot. Additional staff was on hand to ensure successful Participant notifications. Upon receiving a dispatch from the CAISO, a system issue occurred when attempting to notify Participants and the contingency notification process was triggered as a result. Participants were notified within the timeframe required per tariff and were able to perform within the 10 minute window required for the program. Below are summaries for the event.

	Aggregator 1	Aggregator 2	Total
Average Metered Load (kW)	635	2023	2658
Baseline (kW)	798	2379	3177
Nomination (kW)	170	155	325
Average Target Load (kW)	628	2224	2852
Average Reduction (kW)	163	355	518
Performance	96%	229%	159%
Adjusted Performance	96%	100%	100%

Table 34: Retail Performance Summary, August 13th

No specific wholesale settlement was associated with this test likely due to an error in the CAISO ADS system which propagated an exceptional dispatch for every interval from 10:45 through 14:35 for a total of 46 intervals instead or the two five minute intervals that were the basis for the test. As a result, no Non Spinning Reserve payments were rescinded, but it is not clear if this was a result of data issues that may have prevented the CIASO from performing No Pay calculations.

8.2 August 20th (11-7)

This scheduled event was dispatched by the CAISO on August 20th, 2009 at 13:55 for a reduction of 0.3 MW. This resulted in the notification of Participants to curtail their nominated capacity from 14:05 to 16:05. The following chart shows the metered performance for the two Aggregators that participated in the event:

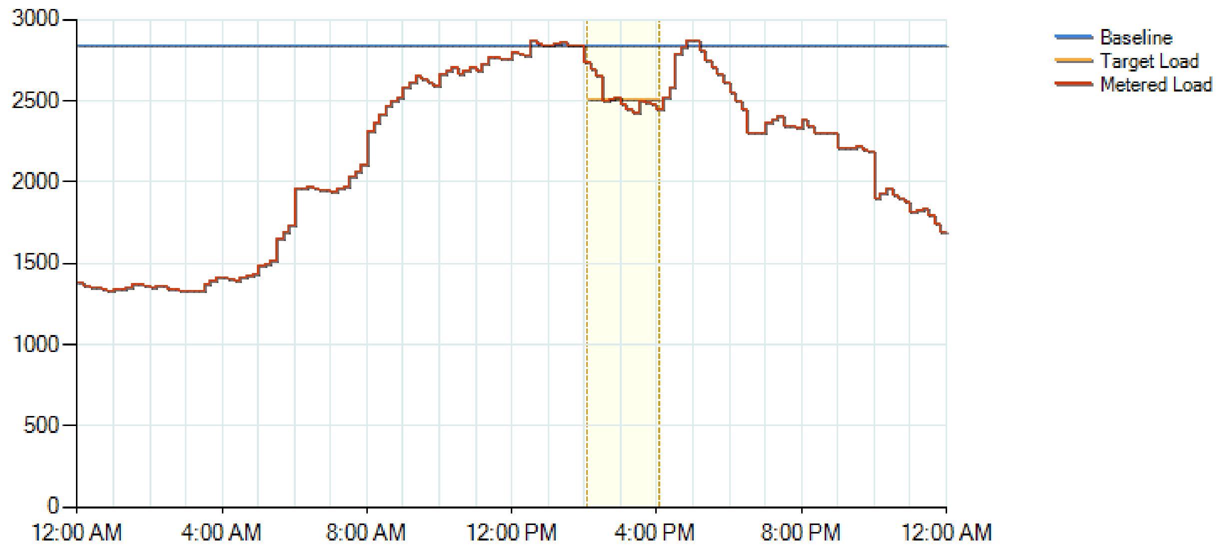

Figure 32: Aggregate Metered Results, August 20th

The Participants performed as expected during this event. Below are summaries for the event.

	Aggregator 1	Aggregator 2	Total
Average Metered Load (kW)	650	1882	2532
Baseline (kW)	794	2045	2839
Nomination (kW)	170	155	325
Average Target Load (kW)	624	1890	2514
Average Reduction (kW)	144	163	307
Performance	85%	105%	94%
Adjusted Performance	85%	100%	94%

Table 35: Retail Performance Summary, August 20th

CAISO Settlement Non Spinning Reserves No Pay for HE 15 was 0.3 MW the full amount of the day-ahead Bid/Award indicating that the load drop was not achieved within 10 minutes based on the CAISO calculation. Figure 32 clearly shows that there was a delay in achieving the expected load drop.

8.3 August 27th (11-7)

This scheduled event was dispatched by the CAISO on August 27th, 2009 at 13:55 for a reduction of 0.3 MW. This resulted in the notification of Participants to curtail their nominated capacity from 14:05 to

16:05. The following chart shows the metered performance for the two Aggregators that participated in the event:

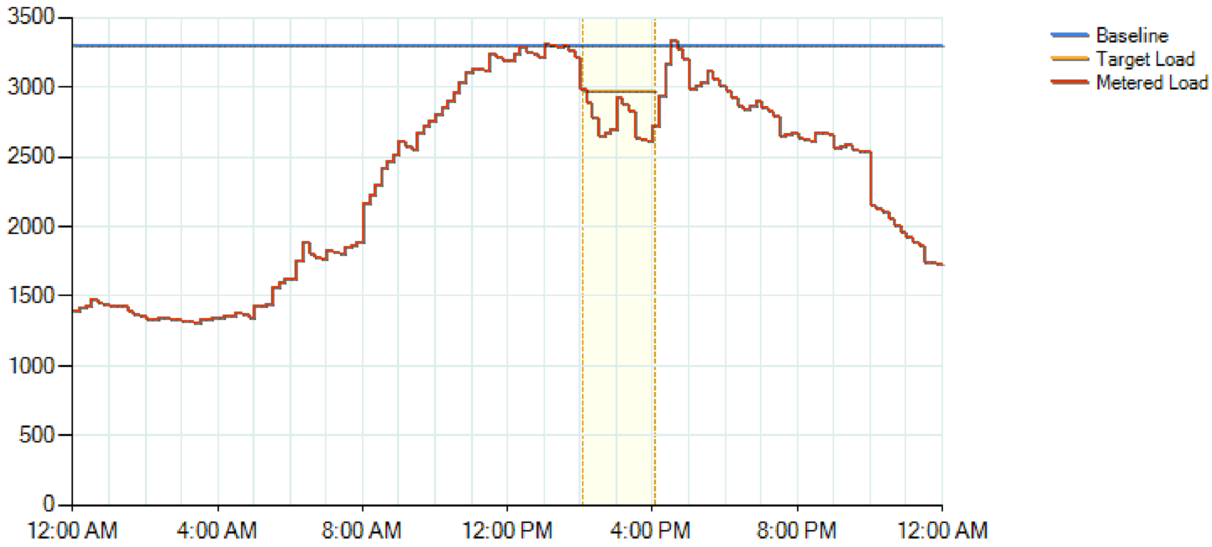

Figure 33: Aggregate Metered Results, August 27th

The Participants performed as expected during this event. Below are summaries for the event.

	Aggregator 1	Aggregator 2	Total
Average Metered Load (kW)	732	2031	2763
Baseline (kW)	902	2403	3305
Nomination (kW)	170	155	325
Average Target Load (kW)	732	2248	2980
Average Reduction (kW)	170	372	542
Performance	100%	240%	167%
Adjusted Performance	100%	100%	100%

Table 36: Retail Performance Summary, August 27th

CAISO Settlement Non Spinning Reserves No Pay quantity for HE 15 was 0.05 MW, one sixth the amount of the DA Bid/Award of 0.3 MW, resulting in a compliance factor of 83%.

8.4 September 10th (11-7)

This scheduled event was dispatched by the CAISO on September 10th, 2009 at 14:00 for a reduction of 0.6 MW. This resulted in the notification of Participants to curtail their nominated capacity from 14:10 to 16:10. The following chart shows the metered performance for the two Aggregators that participated in the event:

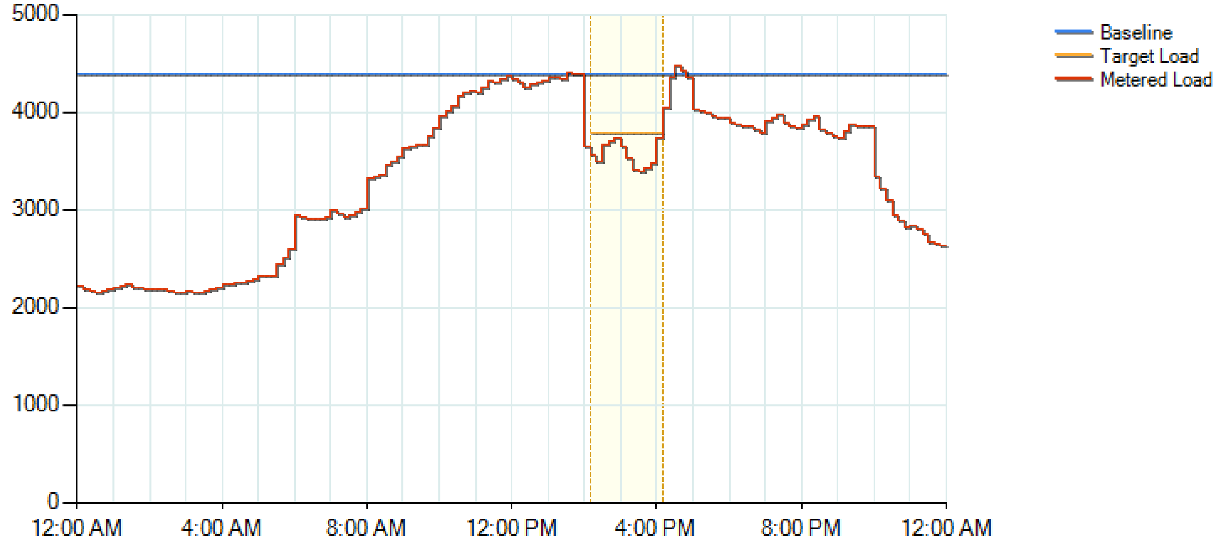

Figure 34: Aggregate Metered Results, September 10th

The Participants performed as expected during this event. Below are summaries for the event.

	Aggregator 1	Aggregator 2	Total
Average Metered Load (kW)	640	2927	3567
Baseline (kW)	846	3542	4388
Nomination (kW)	150	450	600
Average Target Load (kW)	696	3092	3788
Average Reduction (kW)	205	615	820
Performance	137%	137%	137%
Adjusted Performance	100%	100%	100%

Table 37: Retail Performance Summary, September 10th

CAISO Settlement Non Spinning Reserves No Pay quantity for HE 15 was 0.09 MW, approximately one sixth the amount of the DA Bid/Award of 0.6 MW, resulting in a compliance factor of 85%.

8.5 September 17th (11-7)

This scheduled event was dispatched by the CAISO on September 17th, 2009 at 13:55 for a reduction of 0.6 MW. This resulted in the notification of Participants to curtail their nominated capacity from 14:05 to 16:05. The following chart shows the metered performance for the two Aggregators that participated in the event:

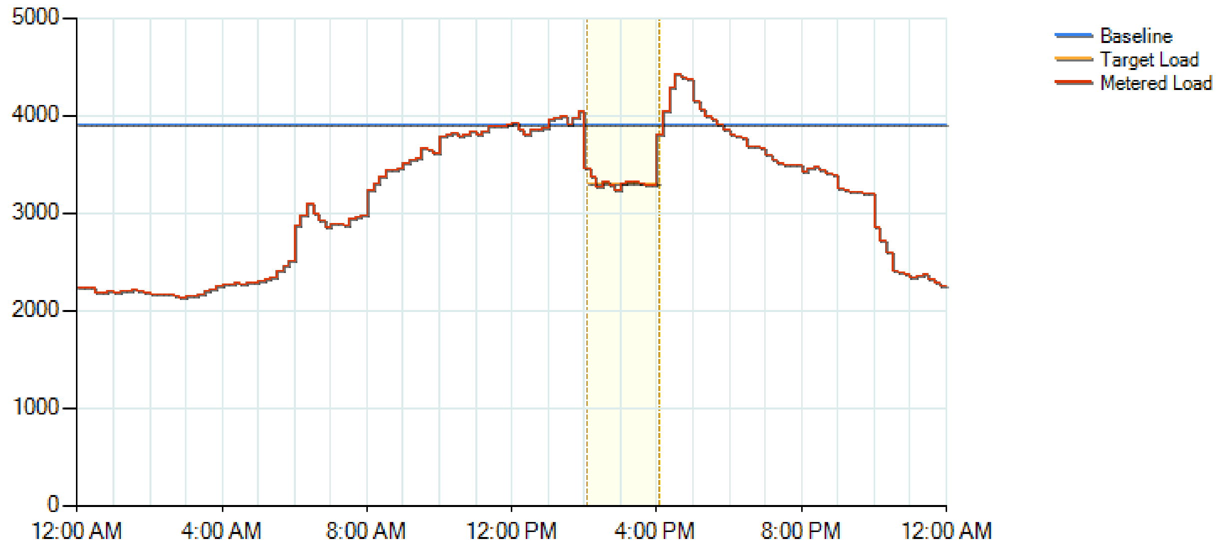

Figure 35: Aggregate Metered Results, September 17th

The Participants performed largely as expected during this event. The performance of Aggregator 2 was impacted due to an equipment timer set to count 2 hours from notification time before returning to normal operational level. Given that notifications are sent within the first five minutes of a CAISO dispatch, the equipment timer returned to normal during the last settlement interval, thus impacting the Aggregator's performance. The Aggregator subsequently configured the timer to start with the event start time, not the notification time. Below are summaries for the event.

	Aggregator 1	Aggregator 2	Total
Average Metered Load (kW)	617	2737	3354
Baseline (kW)	813	3098	3911
Nomination (kW)	150	450	600
Average Target Load (kW)	663	2648	3311
Average Reduction (kW)	196	360	556
Performance	131%	80%	93%
Adjusted Performance	100%	80%	93%

Table 38: Retail Performance Summary, September 17th

CAISO Settlement Non Spinning Reserves No Pay quantity was 0.05 MW, one twelfth the amount of the DA Bid/Award of 0.6 MW, resulting in a compliance factor of 92%.

8.6 September 18th (11-7)

This event was an unscheduled Contingency Dispatch from the CAISO on September 18th, 2009 at 15:55 for a reduction of 0.6 MW. The following chart shows the metered performance for the two Aggregators that participated in the event:

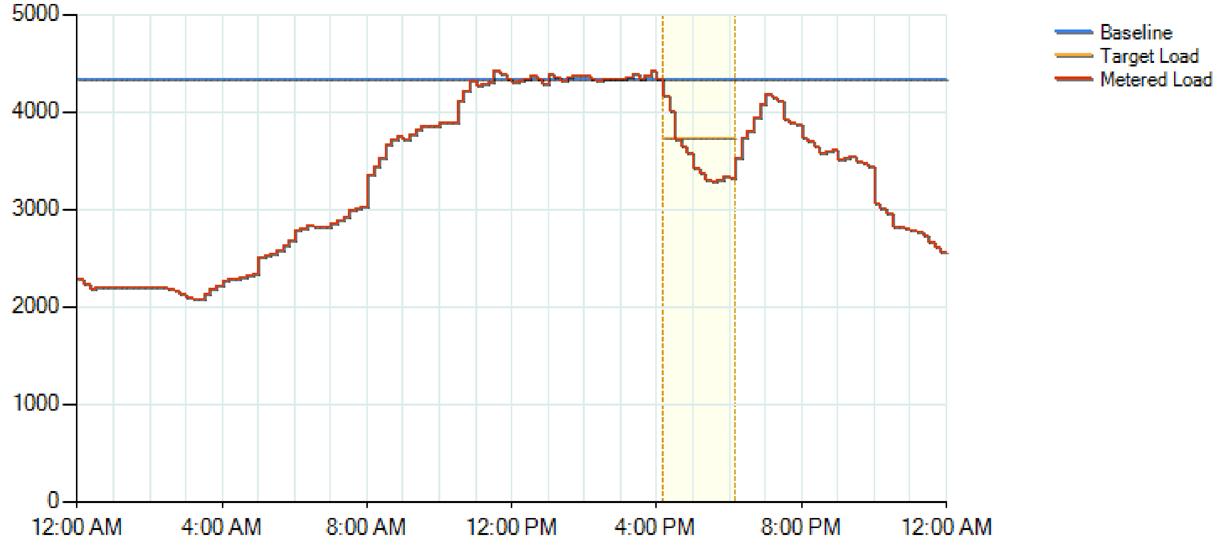

Figure 36: Aggregate Metered Results, September 18th

A notification system issue at APX prevented notifications from being sent in a timely fashion. Contingency notifications were sent at 16:06 with an event start time of 16:10. Consequently, so as to not penalize Participants, the beginning settlement interval was set at interval ending 16:20. Below are summaries for the event.

	Aggregator 1	Aggregator 2	Total
Average Metered Load (kW)	794	2746	3540
Baseline (kW)	836	3499	4335
Nomination (kW)	150	450	600
Average Target Load (kW)	686	3049	3735
Average Reduction (kW)	42	753	795
Performance	28%	167%	133%
Adjusted Performance	28%	100%	100%

Table 39: Retail Performance Summary, September 18th

CAISO Settlement Non Spinning Reserves No Pay quantity was 0.2 MW, one third the amount of the DA Bid/Award of 0.6 MW, resulting in a compliance factor of 67%. The late notification to Participants resulted in relatively poor performance in the wholesale settlement; however, retail settlement and payments to the Participants were not impacted.

8.7 September 23rd (24x7)

This scheduled event was a Retail test event counting towards Participant performance. APX Operations issued a notification to the Participant on September 23rd , 2009 at 23:35 for a reduction of 1.2 MW. The following chart shows the metered performance for the Direct Enrolled Customer that participated in the event:

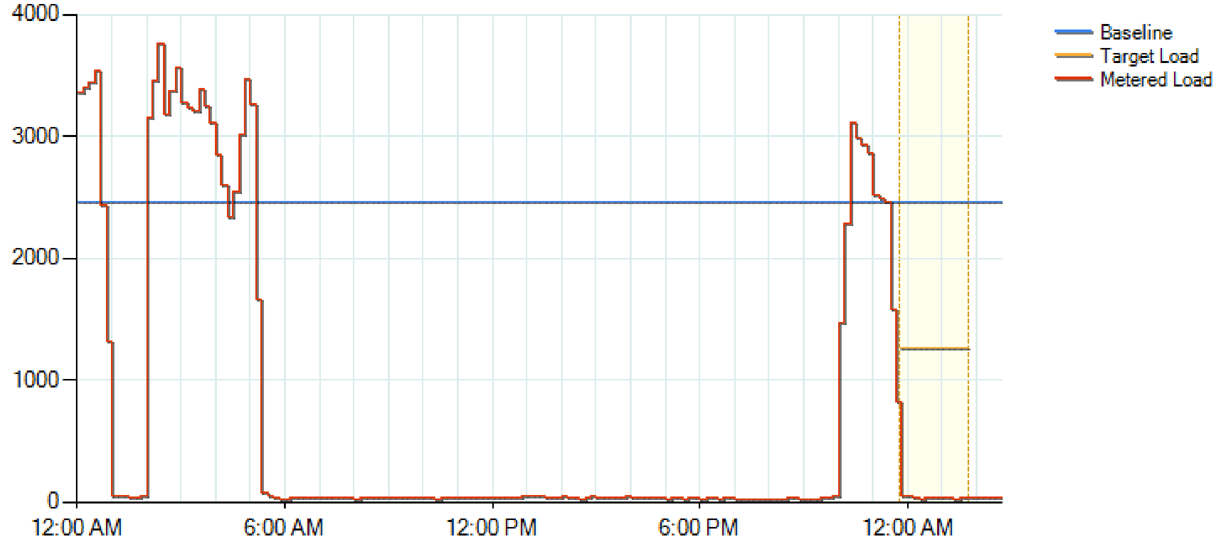

Figure 37: Aggregate Metered Results, September 23rd.

The Participants performed as expected during this event; however, Participant load remained low beyond the event end time. It was not understood by Operational staff at the Participant site that no additional instructions would be sent to return to normal operations. Participant operators contacted APX Operations after the end of the event and APX Operations confirmed that the site could resume normal operations as all PLP events have a default 2 hour duration and no event end notifications are provided. Below are summaries for the event.

	Direct Enrolled Customer
Average Metered Load (kW)	99
Baseline (kW)	2467
Nomination (kW)	1200
Average Target Load (kW)	1267
Average Reduction (kW)	2368
Performance	197%
Adjusted Performance	100%

Table 40: Retail Performance Summary, September 23rd

This event was called by the Pilot administrator independent of the CAISO and as such has no wholesale settlement associated with it.

8.8 September 24th (11-7)

This scheduled event was dispatched by the CAISO on September 24th, 2009 at 13:55 for a reduction of 1.8 MW. This resulted in the notification of Participants to curtail their nominated capacity from 14:05 to 16:05. The following chart shows the metered performance for the two Aggregators that participated in the event:

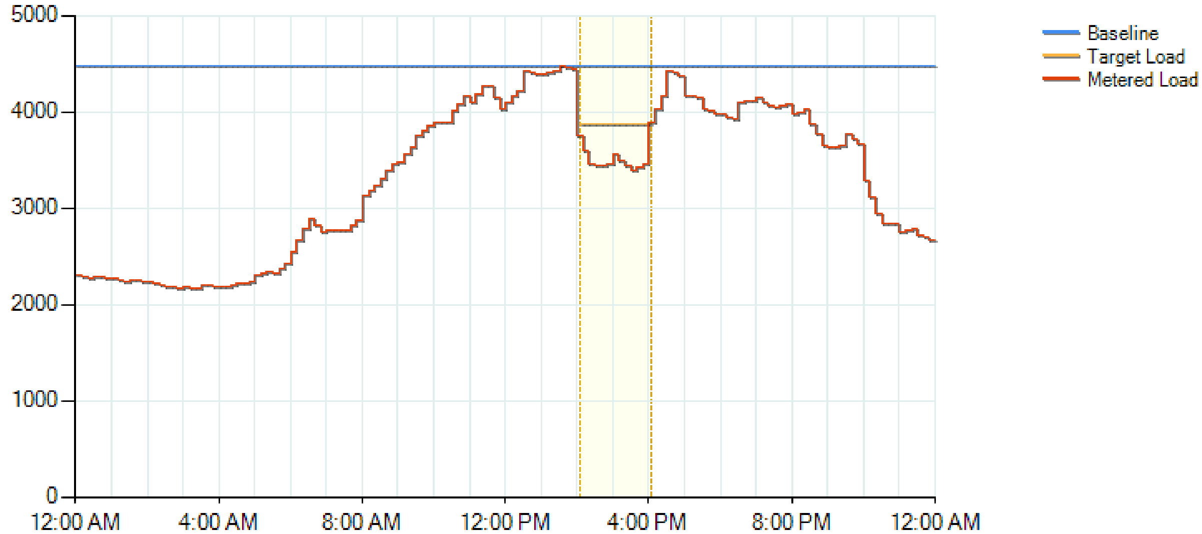

Figure 38: Aggregate Metered Results, September 24th

The Participants performed as expected during this event. Below are summaries for the event.

	Aggregator 1	Aggregator 2	Total
Average Metered Load (kW)	642	2883	3525
Baseline (kW)	860	3618	4478
Nomination (kW)	150	450	600
Average Target Load (kW)	710	3168	3878
Average Reduction (kW)	218	735	953
Performance	145%	163%	159%
Adjusted Performance	100%	100%	100%

Table 41: Retail Performance Summary, September 24th

While no Non Spinning Reserve payments were rescinded for the event indicating that the full amount of the DA Bid/Award of 1.8 MW was curtailed within 10 minutes, this doesn't appear to be correct. Both the 11 – 7 and 24x7 were bid into the wholesale market. This was a deliberate action with the purpose to acquire wholesale settlement data to evaluate the financial impact for the 24 x 7 enrolled customer not being truly available around the clock. Once it became evident that performance during the day would not be feasible, subsequent bids were adjusted to reflect that properly in the wholesale market. It is unknown why the CAISO did not process settlement data in a manner that would have resulted in a capacity payment rescission and the intended analysis could not be completed.

8.9 September 30th (24x7)

This scheduled event was dispatched by the CAISO on September 30th, 2009 at 04:55 for a reduction of 1.2 MW. This resulted in the notification of the Direct Enrolled Customer to curtail their nominated capacity from 05:05 to 07:05. The following chart shows the metered performance for the Direct Enrolled Customer that participated in the event:

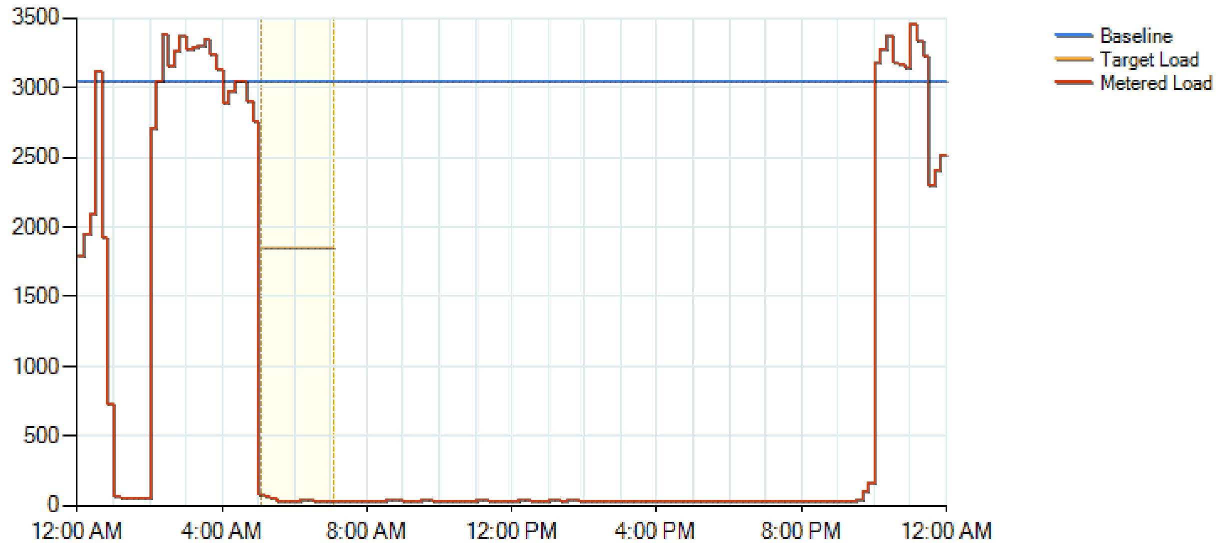

Figure 39: Aggregate Metered Results, September 30th

The Participants performed as expected during this event. Below are summaries for the event.

	Direct Enrolled Customer
Average Metered Load (kW)	45
Baseline (kW)	3053
Nomination (kW)	1200
Average Target Load (kW)	1853
Average Reduction (kW)	3008
Performance	251%
Adjusted Performance	100%

Table 42: Retail Performance Summary, September 30th

No Non Spinning Reserve payments were rescinded for the event indicating that the full amount of the hourly capacity of 1.2 MW was curtailed within 10 minutes resulting in a compliance factor of 100%.

8.10 October 1st (11-7)

This scheduled event was dispatched by the CAISO on October 1st, 2009 at 13:55 for a reduction of 0.8 MW. This resulted in the notification of Participants to curtail their nominated capacity from 14:05 to 16:05. The following chart shows the metered performance for the two Aggregators that participated in the event:

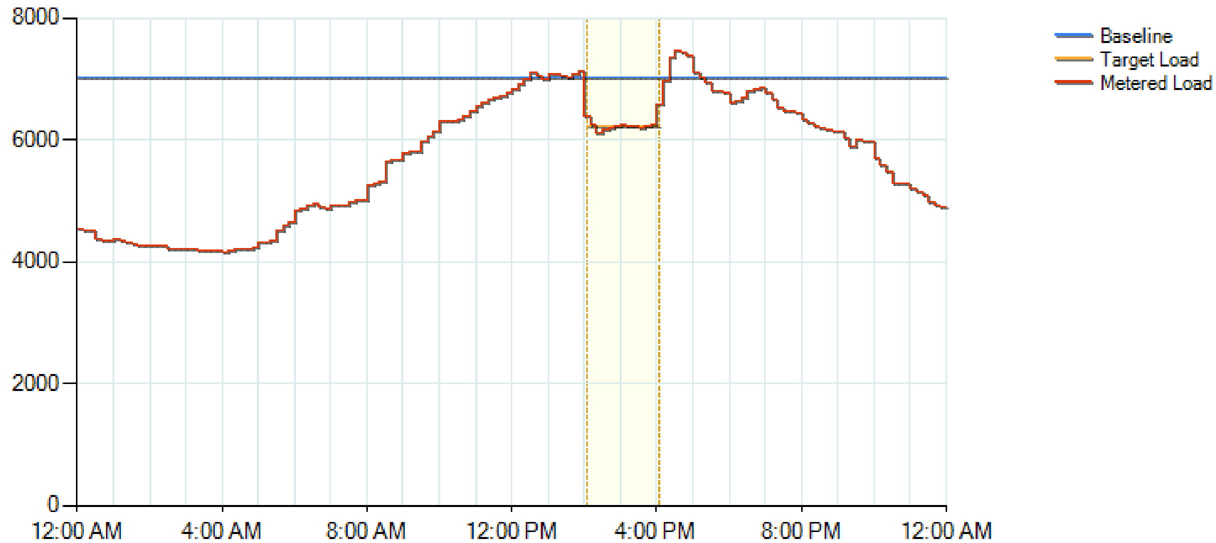

Figure 40: Aggregate Metered Results, October 1st

The Participants performed as expected during this event. Below are summaries for the event.

	Aggregator 1	Aggregator 2	Total
Average Metered Load (kW)	591	5663	6254
Baseline (kW)	768	6258	7026
Nomination (kW)	100	700	800
Average Target Load (kW)	668	5558	6226
Average Reduction (kW)	177	595	772
Performance	177%	85%	97%
Adjusted Performance	100%	85%	97%

Table 43: Retail Performance Summary, October 1st

No Non Spinning Reserve payments were rescinded for the event indicating that the full amount of the DA Bid/Award of 0.8 MW was curtailed within 10 minutes resulting in a compliance factor of 100%.

8.11 October 9th (11-7)

This scheduled event was dispatched by the CAISO on October 9th , 2009 at 11:25 for a reduction of 0.8 MW. This resulted in the notification of Participants to curtail their nominated capacity from 11:35 to 13:35. The following chart shows the metered performance for the two Aggregators that participated in the event:

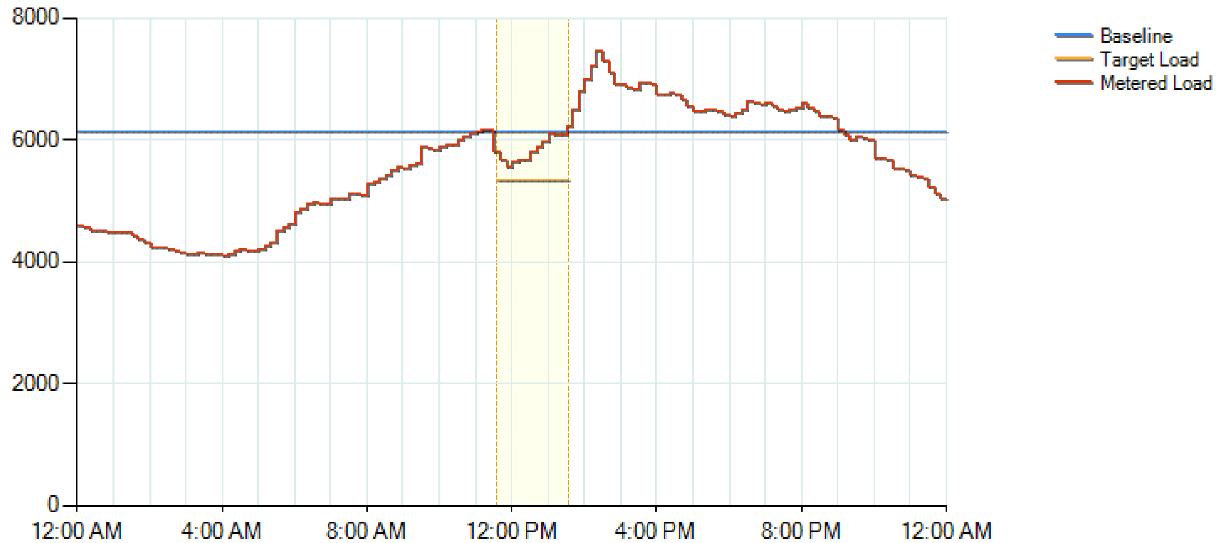

Figure 41: Aggregate Metered Results, October 9th

Participants did not perform as well as during previous events. Further research is needed to understand what operational factors may have caused lower performance for both Participants on this day. Below are summaries for the event.

	Aggregator 1	Aggregator 2	Total
Average Metered Load (kW)	490	5373	5863
Baseline (kW)	562	5588	6150
Nomination (kW)	100	700	800
Average Target Load (kW)	462	4888	5350
Average Reduction (kW)	72	216	288
Performance	72%	31%	36%
Adjusted Performance	72%	31%	36%

Table 44: Retail Performance Summary, October 9th

No Non Spinning Reserve payments were rescinded for the event indicating that the full amount of the DA Bid/Award of 0.8 MW was curtailed within 10 minutes resulting in a compliance factor of 100%. Good performance in the beginning of the event (see Figure 41) and the fact that the CAISO dispatch period was only 10 minutes create the circumstance where CAISO performance exceed the retail performance.

8.12 October 14th (11-7)

This scheduled event was dispatched by the CAISO on October 14th , 2009 at 12:35 for a reduction of 0.8 MW. This resulted in the notification of Participants to curtail their nominated capacity from 12:45 to 14:45. The following chart shows the metered performance for the two Aggregators that participated in the event:

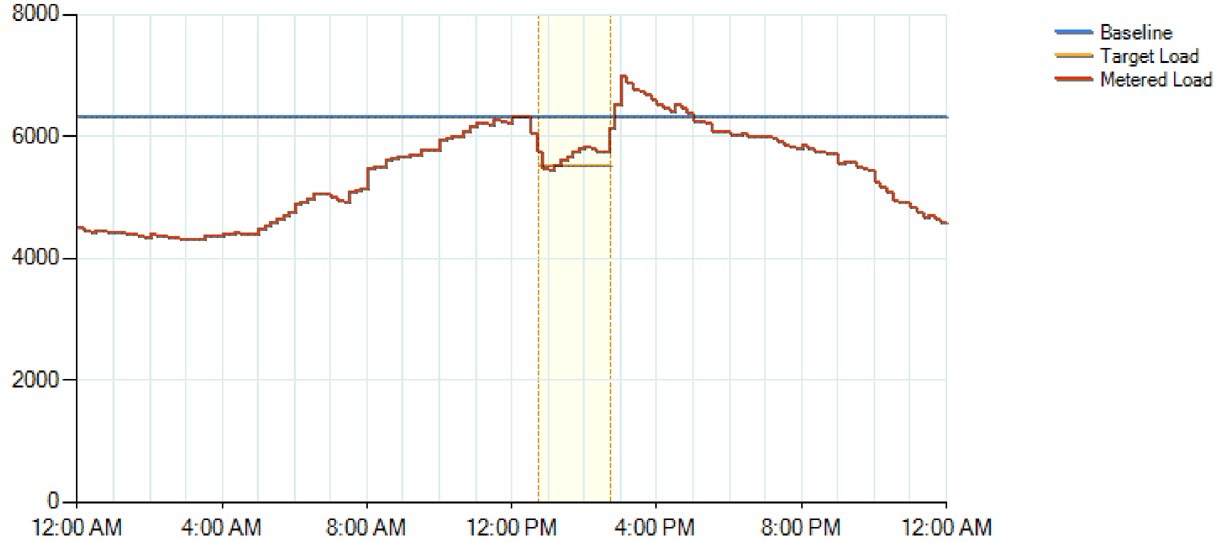

Figure 42: Aggregate Metered Results, October 14th

Aggregator 2 did not perform as well as during previous events. Further research is needed to understand what operational factors may have caused lower performance for Aggregator 2 on this day. Below are summaries for the event.

	Aggregator 1	Aggregator 2	Total
Average Metered Load (kW)	525	5197	5722
Baseline (kW)	695	5652	6347
Nomination (kW)	100	700	800
Average Target Load (kW)	595	4952	5547
Average Reduction (kW)	170	455	625
Performance	170%	65%	78%
Adjusted Performance	100%	65%	78%

Table 45: Retail Performance Summary, October 14th

CAISO Settlement Non Spinning Reserves No Pay quantity was 0.13 MW, approximately one sixth the amount of the DA Bid/Award of 0.8 MW, resulting in a compliance factor of 67%.

8.13 October 15th (24x7)

This scheduled event was dispatched by the CAISO on October 15th, 2009 at 04:55 for a reduction of 1.2 MW. This resulted in the notification of the Direct Enrolled Customer to curtail their nominated capacity from 05:05 to 07:05. The following chart shows the metered performance for the Direct Enrolled Customer that participated in the event:

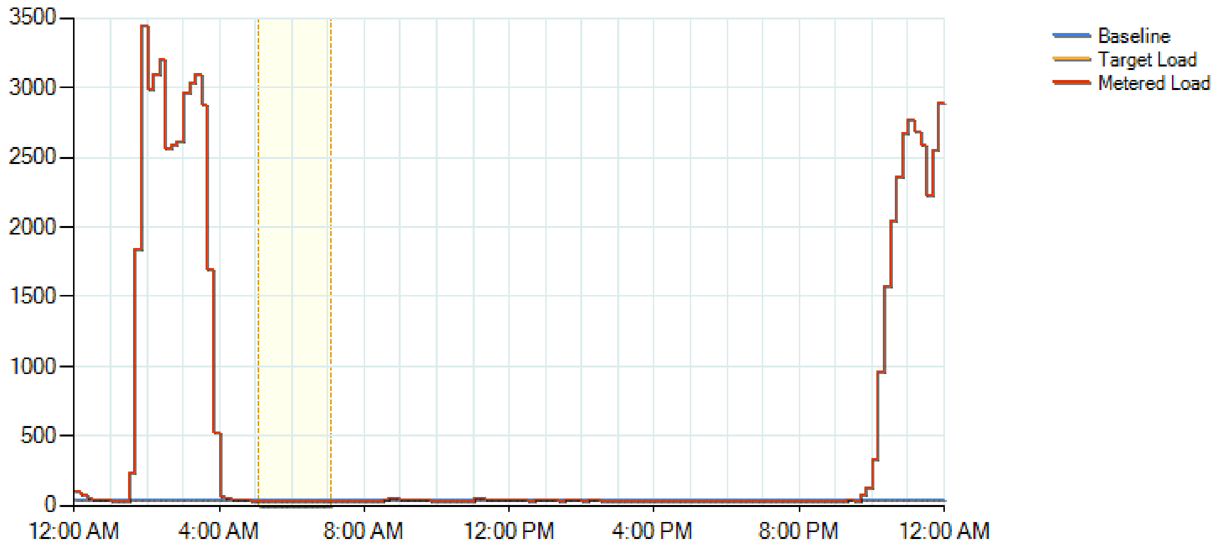

Figure 43: Aggregate Metered Results, October 15th

The Direct Enrolled Participant did not perform during this event as the site was shut down during event hours. Below are summaries for the event.

	Direct Enrolled Customer
Average Metered Load (kW)	38
Baseline (kW)	48
Nomination (kW)	1200
Average Target Load (kW)	-1152
Average Reduction (kW)	10
Performance	1%
Adjusted Performance	0%

Table 46: Retail Performance Summary, October 15th

No Non Spinning Reserve capacity payments were rescinded for the event which is due to a data processing error by the CAISO evidenced by the fact that there was insufficient load available to meet the hourly bid quantity of 1.2 MW (see Figure 43). CAISO records indicate that the Capacity Award was not present in their system for the portion of the hour that the event was called leaving no capacity quantity in settlement data to process for payment rescission.

8.14 November 16th (11-7)

The PLP period was originally scheduled to last through 10/31. To study the results of such a pilot in a period outside of typical DR months, SDG&E extended their pilot period through 12/15/09. The CAISO possessed limited resources to support PLP test events beyond 10/31 however. Consequently, most of the events in November and December were Retail test events.

This scheduled event was dispatched on November 16th, 2009 at 15:00 for a reduction of 0.55 MW. This resulted in the notification of Participants to curtail their nominated capacity from 15:10 to 17:10. The following chart shows the metered performance for the aggregator that participated in the event:

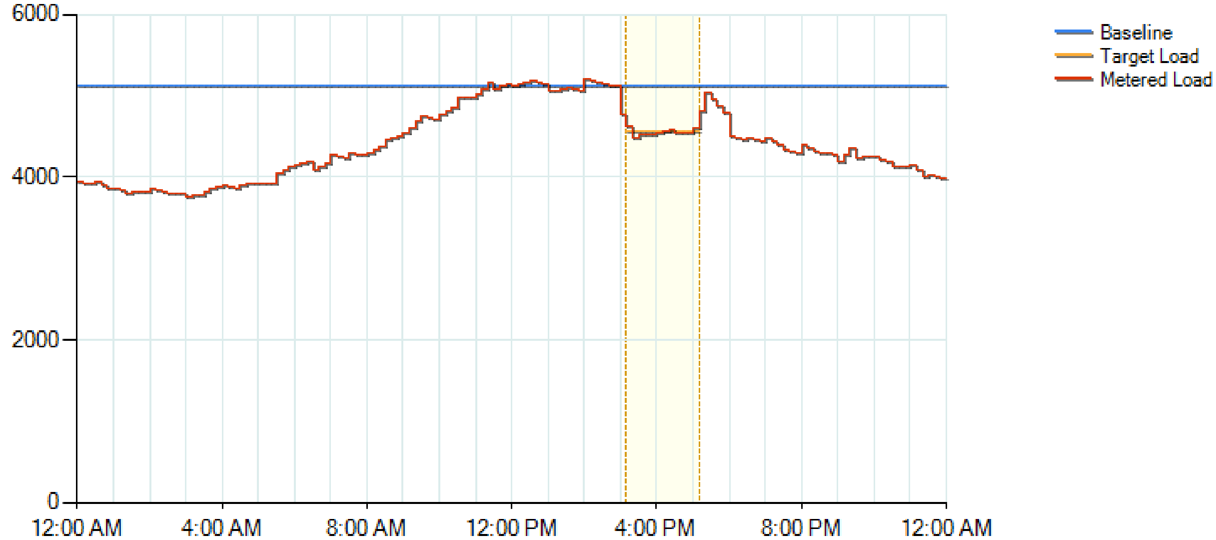

Figure 44: Aggregate Metered Results, November 16th

Only Aggregator 2 nominated capacity in the PLP for the month of November. Participant 2 performed as expected during this event. Below are summaries for the event.

	Aggregator 1	Aggregator 2	Total
Average Metered Load (kW)	n/a	4552	4552
Baseline (kW)	n/a	5120	5120
Nomination (kW)	n/a	550	550
Average Target Load (kW)	n/a	4570	4570
Average Reduction (kW)	n/a	569	569
Performance	n/a	103%	103%
Adjusted Performance	n/a	100%	100%

Table 47: Retail Performance Summary, November 16th.

This event was called by the Pilot administrator independent of the CAISO and as such has no wholesale settlement associated with it.

8.15 November 18th (24x7)

This Retail test event was dispatched on November 18th, 2009 at 01:00 for a reduction of 1.2 MW. This resulted in the notification of the Direct Enrolled Customer to curtail their nominated capacity from 01:10 to 03:10. The following chart shows the metered performance for the Direct Enrolled Customer that participated in the event:

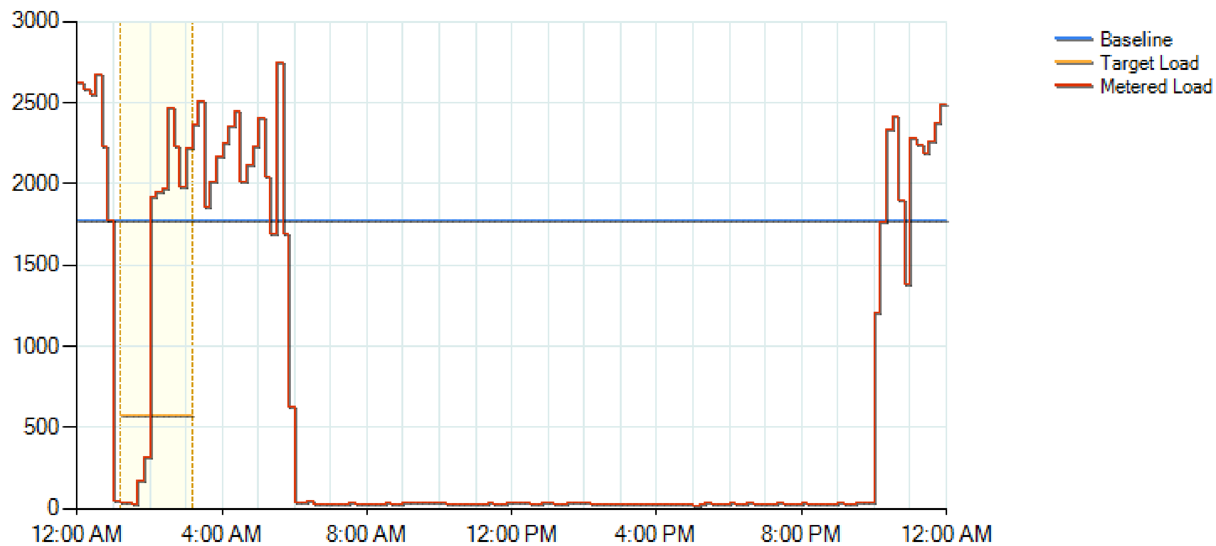

Figure 45: Aggregate Metered Results, November 18th

The Direct Enrolled Participant's performance was lower during this event due to staff leaving the site for their meal break. This meal break coincided with an event and as such, a baseline value along with a load drop was recorded for the first hour of the event. The site staff returned to normal operations approximately one hour later which resulted in lower performance for the second hour of the event. Below are summaries for the event.

	Direct Enrolled Customer
Average Metered Load (kW)	1279
Baseline (kW)	1776
Nomination (kW)	1200
Average Target Load (kW)	576
Average Reduction (kW)	497
Performance	41%
Adjusted Performance	41%

Table 48: Retail Performance Summary, November 18th

8.16 November 19th (11-7)

This Retail test event was dispatched on November 19th, 2009 at 12:06 for a reduction of 0.55 MW. When a notification is issued within a five minute interval, i.e. XX:X1 – XX:X4 or XX:X6 – XX:X9, the notification system defaults to the next five minute interval to calculate an event start time so as to not penalize Participants with reduced notification times. For this event, Participants we notified to curtail their nominated capacity from 12:20 to 14:20. The following chart shows the metered performance for the aggregator that participated in the event:

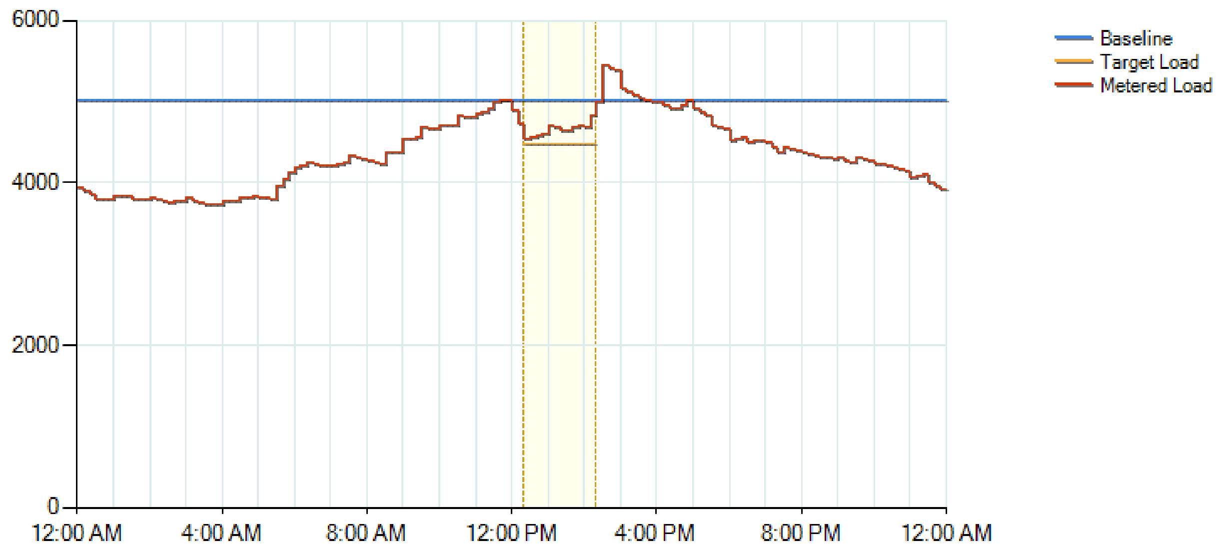

Figure 46: Aggregate Metered Results, November 19th

Only Aggregator 2 nominated capacity in the PLP for the month of November. Participant 2 performed as expected during this event. Below are summaries for the event.

	Aggregator 1	Aggregator 2	Total
Average Metered Load (kW)	n/a	4660	4660
Baseline (kW)	n/a	5025	5025
Nomination (kW)	n/a	550	550
Average Target Load (kW)	n/a	4475	4475
Average Reduction (kW)	n/a	365	365
Performance	n/a	66%	66%
Adjusted Performance	n/a	66%	66%

Table 49: Retail Performance Summary, November 19th

This event was called by the Pilot administrator independent of the CAISO and as such has no wholesale settlement associated with it.

Note: Due to an SDG&E scheduling system limitation (i.e., its inability to schedule in increments smaller than .1 MW), only 0.5 MW were bid for the 11-7 product hours in the month of November, in spite of total Participant nominations of 0.55 MW.

8.17 November 24th (11-7)

This Retail test event was dispatched on November 24th, 2009 at 15:00 for a reduction of 0.55 MW. The following chart shows the metered performance for the aggregator that participated in the event:

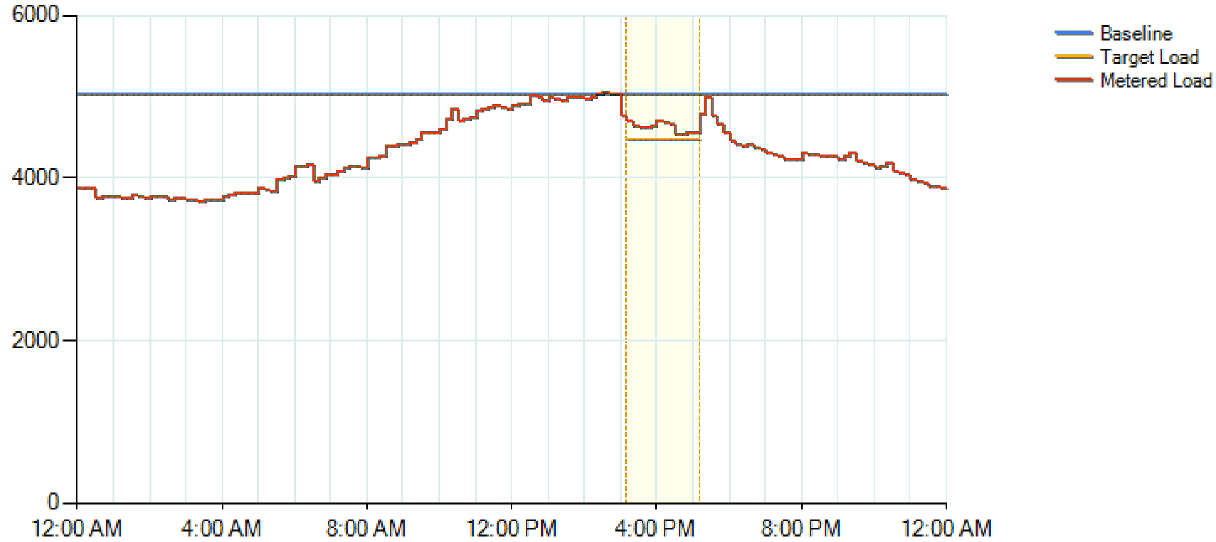

Figure 47: Aggregate Metered Results, November 24th.

Only Aggregator 2 nominated capacity in the PLP for the month of November. Participant 2 performed as expected during this event. Below are summaries for the event.

	Aggregator 1	Aggregator 2	Total
Average Metered Load (kW)	n/a	4630	4630
Baseline (kW)	n/a	5035	5035
Nomination (kW)	n/a	550	550
Average Target Load (kW)	n/a	4485	4485
Average Reduction (kW)	n/a	405	405
Performance	n/a	74%	74%
Adjusted Performance	n/a	74%	74%

Table 50: Retail Performance Summary, November 24th.

This event was called by the Pilot administrator independent of the CAISO and as such has no wholesale settlement associated with it.

Note: Due to an SDG&E scheduling system limitation (i.e., its inability to schedule in increments smaller than .1 MW), only 0.5 MW were bid for the 11-7 product hours in the month of November, in spite of total Participant nominations of 0.55 MW.

8.18 December 2nd (24x7)

This Retail test event dispatched on December 2nd, 2009 at 04:00 for a reduction of 1.2 MW. This resulted in the notification of the Direct Enrolled Customer to curtail their nominated capacity from 04:10 to 06:10. The following chart shows the metered performance for the Direct Enrolled Customer that participated in the event:

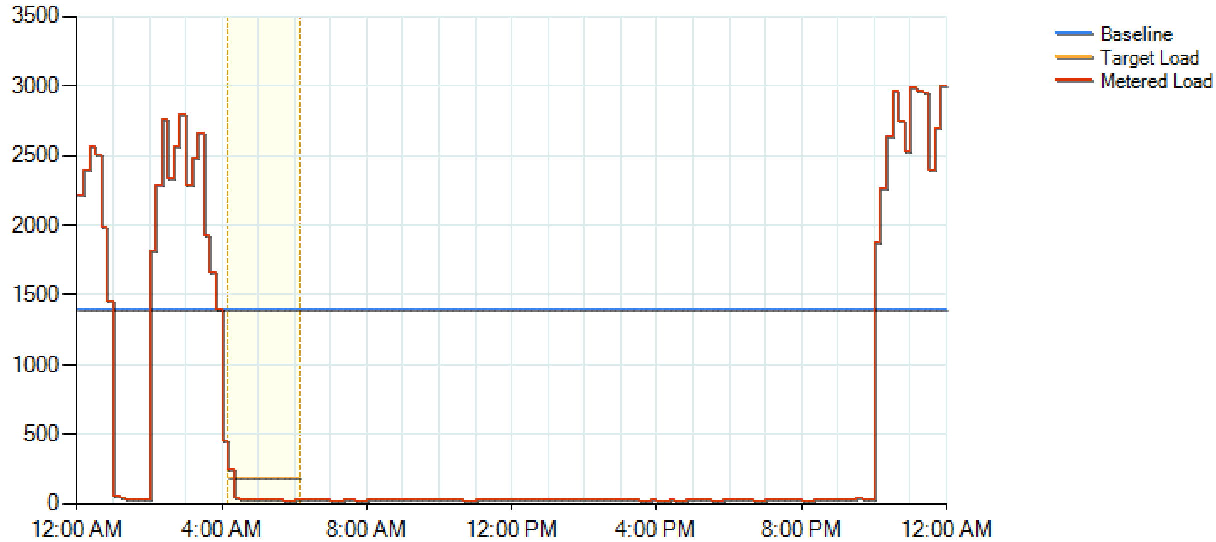

Figure 48: Aggregate Metered Results, December 2nd

The Direct Enrolled Participant performed as expected. Below are summaries for the event.

	Direct Enrolled Customer
Average Metered Load (kW)	49
Baseline (kW)	1392
Nomination (kW)	1200
Average Target Load (kW)	192
Average Reduction (kW)	1343
Performance	112%
Adjusted Performance	100%

Table 51: Retail Performance Summary, December 2nd

CAISO settlement data currently available shows that no Non Spinning Reserve capacity payment was rescinded, but the CAISO acknowledged an error in processing event for Initial Settlement statements. With the current information, the compliance factor cannot be accurately determined.

8.19 December 3rd (11-7)

This scheduled event was dispatched by the CAISO on December 3rd, 2009 at 14:55 for a reduction of 0.55 MW. The following chart shows the metered performance for the aggregator that participated in the event:

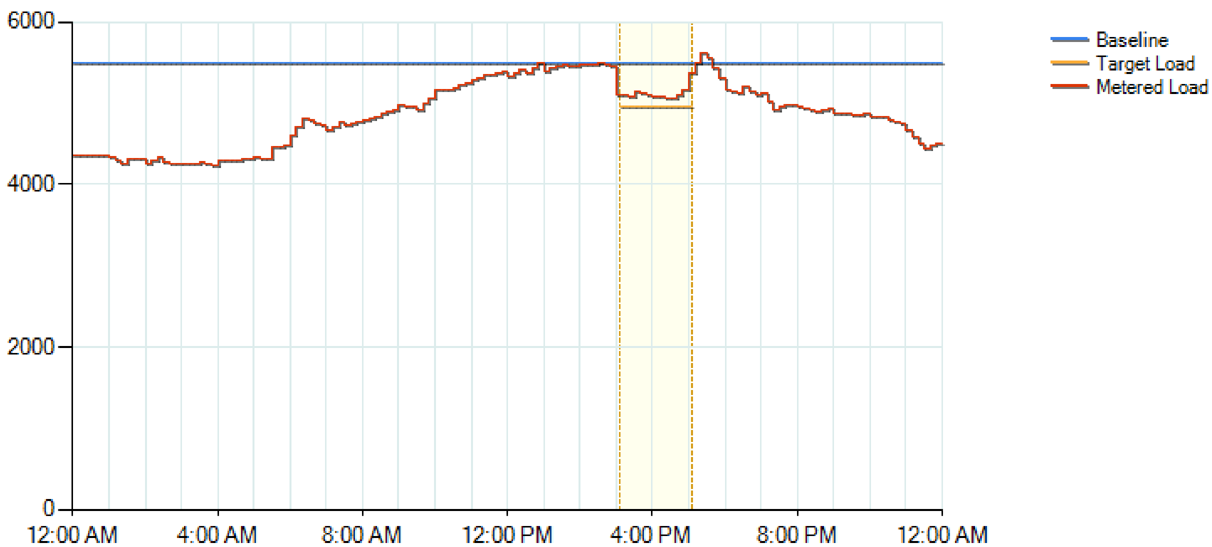

Figure 49: Aggregate Metered Results, December 3rd.

Only Aggregator 2 nominated capacity in the PLP for the month of December. Participant 2 performed as expected during this event. Below are summaries for the event.

	Aggregator 1	Aggregator 2	Total
Average Metered Load (kW)	n/a	5123	5123
Baseline (kW)	n/a	5500	5500
Nomination (kW)	n/a	550	550
Average Target Load (kW)	n/a	4950	4950
Average Reduction (kW)	n/a	377	377
Performance	n/a	69%	69%
Adjusted Performance	n/a	69%	69%

Table 52: Retail Performance Summary, December 3rd.

CAISO settlement data currently available shows that no Non Spinning Reserve capacity payment was rescinded, but the CAISO acknowledged an error in processing event for Initial Settlement statements. With the current information, the compliance factor cannot be accurately determined.

Note: Due to an SDG&E scheduling system limitation (i.e., its inability to schedule in increments smaller than .1 MW), only 0.5 MW were bid for the 11-7 product hours in the month of December, in spite of total Participant nominations of 0.55 MW.

8.20 December 7th (11-7)

This event was an unscheduled Contingency Dispatch from the CAISO on December 7th, 2009 at 18:25 for a reduction of 0.5 MW. Scheduled PLP events were set to have default duration of 2 hours; however, APX's notification system is configured to be able to notify 11am-7pm product Participants of events until 19:00 so this live contingency dispatched triggered an event from 18:35 to 19:00. The following chart shows the metered performance for the aggregator that participated in the event:

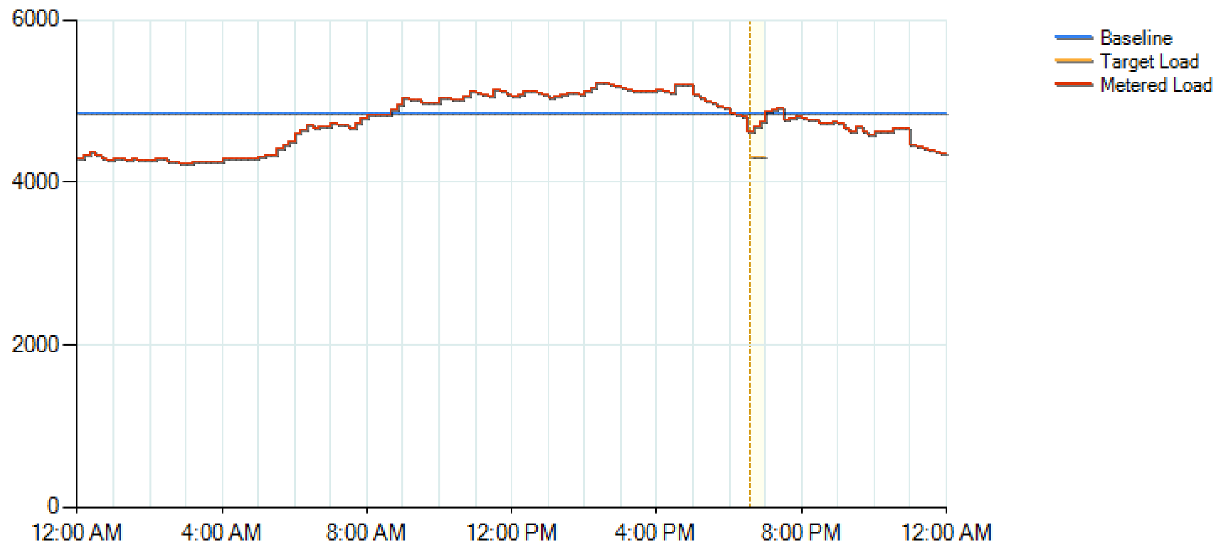

Figure 50: Aggregate Metered Results, December 7th

Only Aggregator 2 nominated capacity in the PLP for the month of December. Participant 2 performed as expected during this event. Below are summaries for the event.

	Aggregator 1	Aggregator 2	Total
Average Metered Load (kW)	n/a	4690	4690
Baseline (kW)	n/a	4858	4858
Nomination (kW)	n/a	550	550
Average Target Load (kW)	n/a	4308	4308
Average Reduction (kW)	n/a	169	169
Performance	n/a	31%	31%
Adjusted Performance	n/a	31%	31%

Table 53: Retail Performance Summary, December 7th

This event was called by the Pilot administrator independent of the CAISO and as such has no wholesale settlement associated with it.

Note: Due to an SDG&E scheduling system limitation (i.e., its inability to schedule in increments smaller than .1 MW), only 0.5 MW were bid for the 11-7 product hours in the month of December, in spite of total Participant nominations of 0.55 MW.

8.21 December 11th (24x7)

This Retail test event was dispatched on December 11th, 2009 at 02:00 for a reduction of 1.2 MW. This resulted in the notification of the Direct Enrolled Customer to curtail their nominated capacity from 02:10 to 04:10. The following chart shows the metered performance for the Direct Enrolled Customer that participated in the event:

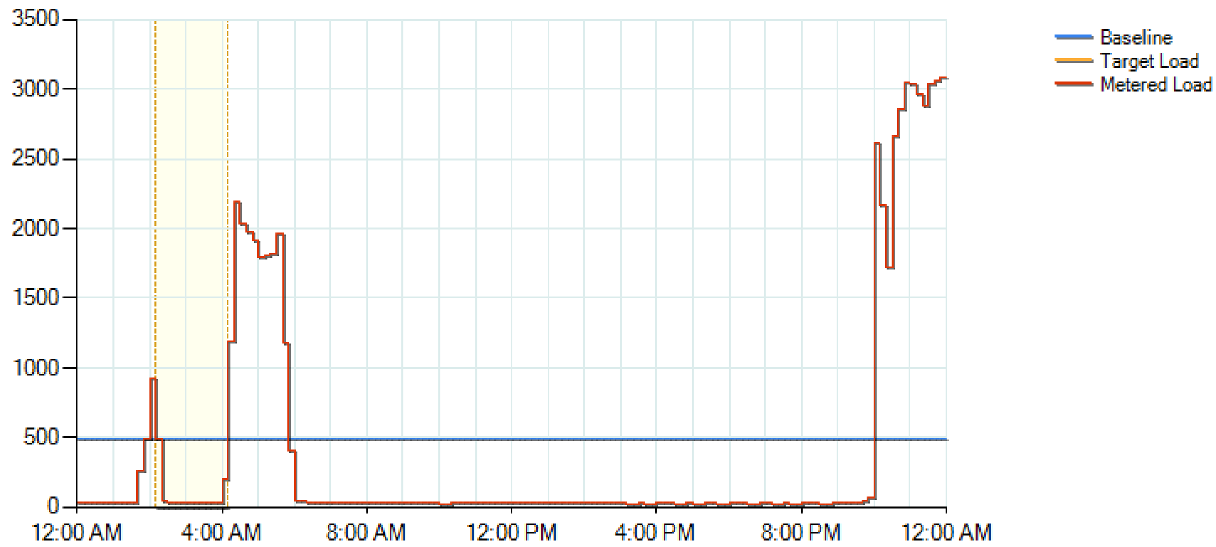

Figure 51: Aggregate Metered Results, December 11th

The Direct Enrolled Participant performed as expected, although a lower baseline drove down overall performance. Below are summaries for the event.

	Direct Enrolled Customer
Average Metered Load (kW)	86
Baseline (kW)	490
Nomination (kW)	1200
Average Target Load (kW)	-710
Average Reduction (kW)	404
Performance	34%
Adjusted Performance	34%

Table 54: Retail Performance Summary, December 11th

This event was called by the Pilot administrator independent of the CAISO and as such has no wholesale settlement associated with it.

8.22 December 15th (24x7)

This Retail test event was dispatched on December 15th, 2009 at 02:30 for a reduction of 1.2 MW. This resulted in the notification of the Direct Enrolled Customer to curtail their nominated capacity from 02:40 to 04:40. The following chart shows the metered performance for the Direct Enrolled Customer that participated in the event:

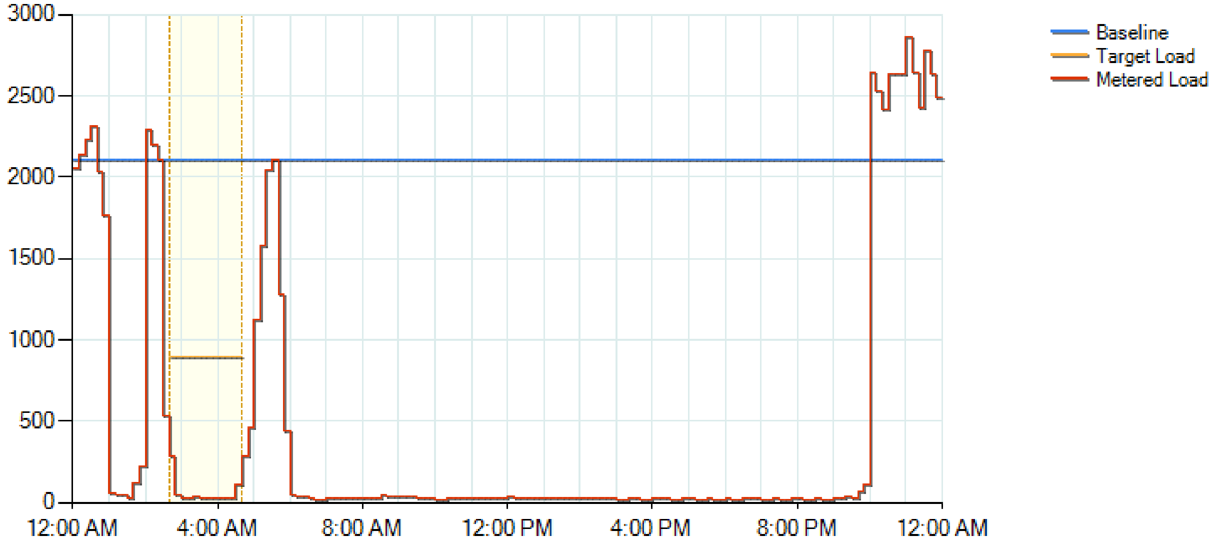

Figure 52: Aggregate Metered Results, December 15th.

The Direct Enrolled Participant performed as expected. Below are performance summaries for the event.

	Direct Enrolled Customer
Average Metered Load (kW)	61
Baseline (kW)	2102
Nomination (kW)	1200
Average Target Load (kW)	902
Average Reduction (kW)	2042
Performance	170%
Adjusted Performance	100%

Table 55: Retail Performance Summary, December 15th.

This event was called by the Pilot administrator independent of the CAISO and as such has no wholesale settlement associated with it.

9 Appendix II: Disaggregating 15-Minute Intervals

As is covered in section 4.5.1, 5-minute interval metering would have provided more accurate retail and wholesale settlements for the Pilot. The method used in the Pilot for converting 15-minute intervals into 5-minute intervals is to divide each 15-minute kWh value by three. This section covers three alternate ways of disaggregation:

- Roll-up telemetry kW reads into 5-minute intervals.
- Shape 5-minute intervals using Pilot telemetry
- Interpolate 5-minute intervals from the surrounding 15-minute intervals

The following sections go into the methodology and in detail results for and several Pilot events.

9.1 Telemetry Instead of Utility Meter Data

The first alternate approach is to use Pilot telemetry directly for settlement. This is an interesting idea to many as perhaps one way to cut costs. The rationale is that if telemetry devices are required for PL, then perhaps they can also provide settlement meter data. There are many reasons both institutional and practical that make this an unlikely proposition; however, it is an interesting enough idea that it gets coverage here.

The methodology used to compile these data was to take the 1-minute archived telemetry demand reads and use them to compile average kW over 5-minute intervals. There are a few downsides to this approach:

- Whether the telemetry is instantaneous demand or averaged demand, the aggregate of the archived telemetry reads is not necessarily indicative of the actual average demand.
- Latency introduced in the system from telemetry-read to archive skews the results in ways similar to those discussed in section 4.5.2.

If telemetry measurements were to be truly used for settlement, the collection of valid intervals would need to be correctly handled.

9.2 Telemetry-shaped Utility Meter data

Another approach is to continue to use utility meter data but to shape it with the telemetry. This has the advantage of maintaining the total 15-minute energy as recorded by the utility meter while recognizing that a straight "divided by three" algorithm does not recognize the ramp up and ramp-down effects at the boundaries of an event.

The methodology used was to take 5-minute intervals as calculated in section 9.1 and use them as ratios between the related 15-minute intervals. Then the 15-minute intervals are converted to 5-minute intervals using the same ratios.

9.3 Interpolated Utility Meter data

The final – and by far the simplest – approach is to use utility meter data alone and shape the 3 5-minute values for a 15-minute interval based on the surrounding 15-minute intervals. This has an advantage over the approach in section 9.2 as it eliminates clock-synchronization issues between the telemetry measurement device and the utility meter.

The methodology used for this calculation was to compute the slope for each 15-minute interval (i.e., the ratio between the preceding and subsequent interval). Then the 15-minute intervals are converted to 5-minute intervals using the same linear ratio.

9.4 Conclusions

Section 9.5 includes details of the different calculations. It is difficult to glean a strong conclusion from such a small sample; however, some general observations can be made:

- Using telemetry systems instead of utility metering is less a technical hurdle and more a policy hurdle on which the California utilities are in complete agreement. While this analysis used minutely telemetry data, more standard 5-minute average kW reads modeling utility metering would not make this policy hurdle go away. As such, telemetry metering is unlikely to be a viable solution in the foreseeable future.
- Using telemetry systems to shape utility metering is straightforward though challenging. Integrating such calculations alongside SQMD into real-world settlement and billing systems would be complex.
- While interpolating meter data may appear to be fair and reasonable, more analysis needs to be done to determine if such an algorithm truly works well, where it falls short, and if there are alternate approaches to the algorithm that more accurately reflect transitions.

Certainly the best option for products requiring 5-minute fidelity it is to eschew any kind of disaggregation and use 5-minute meters.

9.5 Details

9.5.1 Aggregator 1, August 20th

The following table provides details for these four alternate calculation scenarios.

Interval (10 min)	14:10	14:20	14:30	14:40	14:50	15:00	15:10	15:20	15:30	15:40	15:50	16:00	16:10
Nomination							170						
SQMD / 3: Event Performance Factor							**85%**						
Baseline							794						
Target Load							624						
Actual Load	757	699	640	638	638	638	637	638	639	634	630	627	632
Load Reduction	36	95	154	156	156	156	157	156	155	160	164	167	162
% Load reduction	21%	56%	91%	92%	92%	92%	92%	92%	91%	94%	96%	98%	95%
Telemetry: Event Performance Factor							**82%**						
Baseline							783						
Target Load							613						
Actual Load	767	704	629	627	626	635	630	630	627	624	620	617	626
Load Reduction	17	80	155	156	158	149	153	153	156	159	164	167	158
% Load reduction	10%	47%	91%	92%	93%	87%	90%	90%	92%	94%	96%	98%	93%
Telemetry-Shaped SQMD: Performance Factor							**88%**						
Baseline							794						
Target Load							624						
Actual Load	754	649	634	635	636	633	636	639	636	633	627	630	634
Load Reduction	40	145	160	159	158	161	158	155	158	161	167	164	160
% Load reduction	23%	85%	94%	93%	93%	95%	93%	91%	93%	95%	98%	96%	94%
Interpolated SQMD: Performance Factor							**87%**						
Baseline							794						
Target Load							624						
Actual Load	770	678	620	637	638	638	636	639	637	635	628	627	612
Load Reduction	24	116	174	157	156	156	158	155	157	159	166	167	182
% Load reduction	14%	68%	102%	92%	92%	92%	93%	91%	92%	94%	98%	98%	107%

Table 56: August 20th Alternate Performance for Aggregator 1

	Unadjusted Event Capacity Payment	Event Performance Factor	Tariff Adjusted Performance Factor	Event Adjusted Capacity Payment ($)
Actual Meters	$1,139.00	84.87%	84.87%	$966.61
Telemetry Data	$1,139.00	82.40%	82.40%	$938.52
Telemetry-shaped	$1,139.00	87.97%	87.97%	$1,002.01
Interpolated	$1,139.00	87.11%	87.11%	$992.22

Table 57: August 20th Alternate Capacity Payment Variations for Aggregator 1

9.5.2 Aggregator 2, September 17th

The following table provides details for these four alternate calculation scenarios.

Interval (10 min)	14:10	14:20	14:30	14:40	14:50	15:00	15:10	15:20	15:30	15:40	15:50	16:00	16:10
Nomination							450						
SQMD / 3: Event Performance Factor							**80%**						
Baseline							3098						
Target Load							2648						
Actual Load	2816	2763	2709	2727	2673	2620	2691	2696	2702	2696	2684	2671	3138
Load Reduction	281	335	389	371	424	478	407	402	396	402	414	427	-40
% Load reduction	63%	74%	86%	82%	94%	106%	90%	89%	88%	89%	92%	95%	-9%
Telemetry: Event Performance Factor							**80%**						
Baseline							3051						
Target Load							2601						
Actual Load	2802	2690	2651	2718	2630	2598	2617	2683	2667	2677	2634	2634	2989
Load Reduction	249	362	400	333	421	453	434	368	384	374	417	417	62
% Load reduction	55%	80%	89%	74%	94%	101%	96%	82%	85%	83%	93%	93%	14%
Telemetry-Shaped SQMD: Performance Factor							**83%**						
Baseline							3098						
Target Load							2648						
Actual Load	2774	2722	2673	2754	2607	2610	2693	2699	2705	2681	2657	2712	3120
Load Reduction	324	376	425	344	491	488	405	399	393	416	441	386	-22
% Load reduction	72%	83%	94%	76%	109%	108%	90%	89%	87%	93%	98%	86%	-5%
Interpolated SQMD: Performance Factor							**80%**						
Baseline							3098						
Target Load							2648						
Actual Load	2765	2741	2697	2748	2643	2626	2701	2699	2702	2699	2604	2818	3177
Load Reduction	333	357	401	350	455	472	397	399	396	398	494	280	-79
% Load reduction	74%	79%	89%	78%	101%	105%	88%	89%	88%	89%	110%	62%	-18%

Table 58: August 17th Alternate Event Performance for Aggregator 2

	Unadjusted Event Capacity Payment	Event Performance Factor	Tariff Adjusted Performance Factor	Event Adjusted Capacity Payment ($)
Actual Meters	$2,261.25	80.09%	80.09%	$1,811.02
Telemetry Data	$2,261.25	79.90%	79.90%	$1,806.80
Telemetry-shaped	$2,261.25	83.14%	83.14%	$1,880.06
Interpolated	$2,261.25	79.50%	79.50%	$1,797.73

Table 59: August 17th Alternate Capacity Payments for Aggregator 2

9.5.3 Direct Enrolled Customer, September 30th

The following table provides details for these four alternate calculation scenarios.

Interval (10 min)	05:10	5:20	5:30	5:40	5:50	6:00	6:10	6:20	6:30	6:40	6:50	7:00	7:10
Nomination							1200						
SQMD / 3: Event Performance Factor							**251%**						
Baseline							3053						
Target Load							1853						
Actual Load	86	86	58	38	38	29	38	38	48	38	38	29	38
Load Reduction	2966	2966	2995	3014	3014	3024	3014	3014	3005	3014	3014	3024	3014
% Load reduction	247%	247%	250%	251%	251%	252%	251%	251%	250%	251%	251%	252%	251%
Telemetry: Event Performance Factor							**227%**						
Baseline							2783						
Target Load							1583						
Actual Load	99	85	62	45	35	43	40	52	49	60	44	51	41
Load Reduction	2684	2698	2721	2738	2748	2740	2743	2730	2734	2723	2739	2732	2742
% Load reduction	224%	225%	227%	228%	229%	228%	229%	228%	228%	227%	228%	228%	229%
Telemetry-Shaped SQMD: Performance Factor							**251%**						
Baseline							3053						
Target Load							1853						
Actual Load	88	70	47	52	30	26	33	51	48	47	25	25	25
Load Reduction	2965	2983	3006	3001	3023	3027	3020	3002	3005	3006	3028	3028	3028
% Load reduction	247%	249%	250%	250%	252%	252%	252%	250%	250%	250%	252%	252%	252%
Interpolated SQMD: Performance Factor							**251%**						
Baseline							3053						
Target Load							1853						
Actual Load	14	70	47	37	30	30	38	46	46	44	22	22	22
Load Reduction	3039	2983	3006	3016	3023	3023	3015	3007	3007	3009	3031	3031	3031
% Load reduction	253%	249%	250%	251%	252%	252%	251%	251%	251%	251%	253%	253%	253%

Table 60: September 30th Alternate Event Performance for the Direct Enrolled Customer

	Unadjusted Event Capacity Payment	Event Performance Factor	Tariff Adjusted Performance Factor	Event Adjusted Capacity Payment ($)
Actual Meters	$5,160.00	250.52%	100.00%	$5,160.00
Telemetry Data	$5,160.00	227.39%	100.00%	$5,160.00
Telemetry-shaped	$5,160.00	250.76%	100.00%	$5,160.00
Interpolated	$5,160.00	251.39%	100.00%	$5,160.00

Table 61: September 30th Alternate Capacity Payments for the Direct Enrolled Customer

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing document upon the parties listed on the official service list in the captioned proceedings, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated at Folsom, California this 18th day of February, 2010.

/s/ Daniel Klein

Daniel Klein